STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF MICHAEL BACA

My name is Michael Baca, and I am the Control Strategies Manager for the Air Quality Bureau ("Bureau") of the New Mexico Environment Department ("NMED" or "Department"). I am presenting this written testimony on behalf of the Department in this proceeding on proposed new air quality regulations at 20.2.50 NMAC ("Part 50"). My testimony will address the following topics: the federal and state statutory authorities and regulatory frameworks for ozone, NMED's Ozone Attainment Initiative, and the EPA Ozone Advance program.

I. QUALIFICATIONS

I have been an employee of the Department for 16 years, 13 of which have been with the Bureau. In my current position as the staff manager for the Bureau's Control Strategies Unit, I oversee a staff of six that are responsible for the development of air quality plans and regulations, including the State Implementation Plan ("SIP") for New Mexico. I hold a B.A. degree in Chemistry from Carleton College.

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 2.

II. THE CLEAN AIR ACT REGULATORY FRAMEWORK FOR OZONE

The federal Clean Air Act ("CAA") requires the U.S. Environmental Protection Agency ("EPA") to set National Ambient Air Quality Standards ("NAAQS") for pollutants that EPA determines are harmful to public health and the environment. *See* 42 U.S.C. § 7408. These standards are in the form of maximum allowable concentrations in the ambient air during a

specified time period and are designed to protect the most sensitive individuals from harm from airborne pollutants. The CAA identifies two sets of NAAQS to accomplish this: Primary standards provide public health protection, including protecting the health of vulnerable populations such as asthmatics, children, and the elderly; Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. *Id* at § 7408(b).

The EPA has set NAAQS for six principal pollutants, known as "criteria" air pollutants: ozone, nitrogen dioxide, sulfur dioxide, carbon monoxide, particulate matter 10 microns or less, particulate matter 2.5 microns or less, and lead. *See* 40 C.F.R. Part 50. The CAA requires EPA to review the standards on a periodic basis, which may result in the standards being revised based on health and environmental criteria that apply to the concentration of a pollutant in outdoor air to limit harmful exposures and detrimental effects. 42 U.S.C. § 7409(d). The primary ozone NAAQS are set to protect people most at risk from breathing ozone in the ambient air, including asthmatics, children, older adults and people who are active outdoors, such as workers. Children are at greatest risk from ozone exposure because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Some of the health problems caused by ozone include coughing, sore throat, difficulty breathing, inflammation and damage to airways, increased frequency of asthma attacks, and aggravation of lung diseases such as asthma, emphysema and chronic bronchitis. *See* NMED Exhibit 3 – EPA Integrated Science Assessment ("ISA") for Ozone and Related Photochemical Oxidants, Executive Summary (April 2020);[1] *see also* 85 Fed. Reg. 87256, 87268-87275.

[1] Full ISA available at https://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=348522

Air quality management agencies use data from monitors to calculate a "design value" to determine an area's compliance status with the NAAQS. The design value represents the metric used to compare monitoring data to the level specified by the standard. Ozone monitoring and the federal requirements for monitoring equipment are addressed in the testimony of NMED witness Brent Ellington. Calculation of design values, quality assurance of data, and submission of data to EPA are addressed in the testimony of NMED witness Andrew Ahr.

Following promulgation of a new or revised NAAQS, EPA undertakes a process of designating all areas within each state as in attainment, nonattainment, or unclassifiable for the standard. *See* 42 U.S.C. § 7407(d). This process entails collaborating with states and tribes and considering their recommendations, including proposed nonattainment boundaries based on data and information from air quality monitors or modeling. If the concentrations of a criteria pollutant in a geographic area meets or fall below the NAAQS, the area is designated as in "attainment" of the standard. Areas that exceed the NAAQS are designated as "nonattainment" areas. Areas that do not have monitoring data available are designated as "attainment/unclassifiable" or "unclassifiable". EPA is required to designate areas of the States within two years of promulgating a new or revised NAAQS. *Id.*

In October 2015, following a periodic review, EPA revised the ozone NAAQS downward from 0.075 parts per million (ppm) to 0.070 ppm. *See* 80 Fed. Reg. 65291. For the 2015 ozone NAAQS, all states were required to submit their designation recommendations to EPA by October 1, 2016. Ozone data collected by NMED from 2014 through 2016 showed that a monitor located in the Sunland Park area in southern New Mexico was violating the revised ozone standard. NMED submitted a nonattainment area recommendation for the Sunland Park area and recommended attainment or attainment/unclassifiable designations for the remainder of

New Mexico. EPA concurred with the recommendations and finalized the area designations for New Mexico on August 3, 2018. *See* 83 Fed. Reg. 25776.

On December 23, 2020, EPA retained the existing 2015 ozone NAAQS. *See* 85 Fed. Reg. 87256. The CAA does not require EPA to promulgate area designations when an existing NAAQS is retained following the periodic review process. In line with this and historical practice, EPA did not designate new nonattainment areas following this periodic NAAQS review. However, the current EPA administration has indicated that it intends to revisit the review process, including the available scientific evidence and exposure/risk information, to assess the adequacy of public health and welfare protection provided under the current NAAQS.

Ozone monitoring data for 2018-2020 indicate that other areas of the state are approaching or violating the 2015 ozone NAAQS. In particular, Eddy County and sites in southern Doña Ana County are monitoring ozone levels in violation of the NAAQS, while San Juan, Lea, Santa Fe, Sandoval and Valencia Counties are within 95% of the standard. Additionally, oil and gas sources located in Rio Arriba and Chaves Counties contribute to elevated ozone concentrations in the San Juan and Permian Basins, respectively.

The New Mexico Air Quality Control Act ("AQCA"), NMSA 1978, Sections 74-2-1 to -17, requires the State to plan for ozone mitigation in areas where sources cause or contribute to ozone levels greater than or equal to 95% of the ozone standard. NMED is addressing these areas through the Ozone Attainment Initiative and EPA's Ozone Advance program, as discussed below.

III. OZONE REGULATION UNDER THE NEW MEXICO AIR QUALITY CONTROL ACT AND REGULATIONS

The Environmental Improvement Board ("Board") is authorized to adopt Part 50 pursuant to the AQCA. Section 74-2-5(A) of the AQCA provides that the Board "shall prevent or

abate air pollution." Section 74-2-5(B)(1) states that the Board shall "adopt, promulgate, publish, amend, and repeal rules and standards consistent with the Air Quality Control Act to attain and maintain national ambient air quality standards and prevent or abate air pollution . . ." The AQCA defines "air pollution" as

> the emission, except emission that occurs in nature, into the outdoor atmosphere of one or more air contaminants in quantities and of a duration that may with reasonable probability injure human health or animal or plant life or as may unreasonably interfere with the public welfare, visibility or the reasonable use of property.

NMSA 1978, § 74-2-2(B). "Air contaminant" is defined as "a substance, including any particulate matter, fly ash, dust, fumes, gas, mist, smoke, vapor, micro-organisms, radioactive material, any combination thereof or any decay or reaction product thereof." NMSA 1978, § 74-2-2(A).

The AQCA also contains provisions that specifically authorize the Board to adopt regulations to ensure attainment and maintenance of the ozone NAAQS. Section 74-2-5(C) of the AQCA mandates that the Board take action to control VOC and NOx emissions when the Board determines that emissions from sources within its jurisdiction cause or contribute to ozone concentrations in excess of ninety-five percent of the ozone NAAQS. Under this statutory provision, the Board is required to "adopt a plan, including rules, to control emissions of oxides of nitrogen, or NO_X, and volatile organic compounds, or VOCs, to provide for the attainment and maintenance of the standard."

IV. THE DEPARTMENT'S OZONE ATTAINMENT INITIATIVE

Currently, nine counties under the Board's jurisdiction are registering or contributing to ozone design values exceeding 95% of the NAAQS: San Juan, Rio Arriba, Santa Fe, Sandoval, Valencia, Eddy, Lea, Chaves and Doña Ana.

To address the statutory requirement in Section 74-2-5(C) of the AQCA, the Bureau has embarked upon the Ozone Attainment Initiative ("OAI") to develop a plan that consists of a series of mandatory rules and voluntary measures to mitigate emissions of NO_X and VOCs in the aforementioned counties. This rulemaking is the first of the mandatory rules being brought before the Board under the OAI. The Department intends to propose addition rules targeting other sectors. For instance, Section 177 of the Clean Air Act allows other states to adopt California's motor vehicle emission standards, and the Department intends to bring before the Board regulations setting standards for low emission vehicles ("LEV"), and zero emission vehicles ("ZEV") for adoption in 2022 that will provide further mitigation of ozone precursors.

The Department has also submitted a letter of participation to EPA for the Ozone Advance Program. The Advance Program is a means to promote local actions in areas designated as in attainment to reduce ozone levels for the continued maintenance of the NAAQS. The Bureau will coordinate efforts with local governments, industry, academia, and the public to take proactive steps towards the protection of air quality. In addition to positioning areas to avoid a nonattainment designation, the Advance Program can allow communities to choose control measures that are cost effective and that make the most sense for their area, potentially resulting in multi-pollutant benefits.

The Department has developed a path forward for Ozone Advance that outlines all the activities, programs, and control measures to be included as part of our program. A copy of the "Ozone Advance Path Forward for New Mexico" is included as NMED Exhibit 4. The Department requests that the Board adopt this document as the "Plan" required by Section 74-5-3(C) of the AQCA.

Because the ozone design value in Bernalillo County also exceeds 95% of the ozone NAAQS, the Bureau is coordinating its efforts for ozone mitigation with the City of Albuquerque's Environmental Health Department, which has jurisdiction over air quality in Bernalillo County. In addition to the OAI, Ozone Advance and vehicle emissions standards, the Department is also working with the City of Albuquerque on preparing revised Regional Haze SIPs for submittal to EPA in July of 2021. The goal of the Regional Haze provisions of the CAA is to improve visibility in protected national parks and wilderness areas (referred to as "Class I" areas), and states are required to make reasonable progress over time towards the long-term goal of attaining natural visibility conditions by 2064. The Regional Haze program requires states to submit Regional Haze SIPs approximately once every ten years. Based on data collected at monitors operated by federal land managers, visibility impairment at the Class I areas in New Mexico is driven by sulfates and nitrates, so the Department is evaluating potential additional controls for sulfur dioxide (SO_2) and NO_X emissions from twenty-three major sources within our jurisdiction. Three of these sources are electric generating units, and the remainder are in the oil and gas sector, specifically, natural gas compressor stations and processing plants. Any additional NO_X controls for these sources adopted as part of this Regional Haze SIP revision will also serve to reduce the formation of ozone.

MICHAEL G. BACA

EDUCATION

September 1999-June 2004 Carleton College Northfield, MN
Bachelors Degree in Chemistry

PROFESSIONAL EXPERIENCE

January 2019-Present
New Mexico Environment Department, Air Quality Bureau
Staff Manager

- Manage the Control Strategies Section to insure proper implementation of the federal Clean Air Act in New Mexico through the development and revision of the State Implementation Plan and other air quality management plans and rules for the state.
- Oversee, lead and assist with rulemaking and section projects including the preparation of testimony and exhibits to present before the Environmental Improvement Board for adoption of rules and management plans.
- Manage air quality programs and research projects to ensure proper procurement procedures, awarding of contracts and grants, timely submission of deliverables and appropriate financial expenditures to meet contractual obligations and compliance with state rules.
- Ensure that the Bureau's Performance Measures are achieved through high technical and professional standards while maintaining the section as a desirable place to work.
- Assign, prioritize and oversee completion of tasks and projects by reviewing work products and providing timely, substantive feedback including guidance to staff on programs, policies, rules, regulations, and resources.
- Conduct meaningful and constructive employee evaluations by providing appropriate recognition of strengths, weaknesses and recommendations for improvement.
- Fill vacancies by completing efficient and effective personnel hiring actions.

July 2008-December 2018
New Mexico Environment Department, Air Quality Bureau
Environmental Analyst-Advanced

- Represent the State of New Mexico as the air quality liaison with border air quality agencies and stakeholders, participating in the Joint Advisory Committee and the USEPA Border 2020 Program.
- Develop and prepare technical testimony and exhibits for public hearings in front of the Environmental Improvement Board to present and defend air quality plans and rules for adoption in New Mexico, including state implementation plans required by the USEPA.
- Analyze ambient air quality monitoring data and prepare technical support documents for submission to the USEPA for high wind blowing dust events that cause air pollution episodes.

- Conduct public education and outreach meetings and develop educational material regarding air quality, rule requirements, and rule development.
- Review and comment on Title V and PSD permits, Environmental Impact Statements and Environmental Assessments in the border region for compliance with federal and state rules and standards.
- Manage air quality research projects and contracts in the border area to ensure timely submission of deliverables and appropriate financial expenditures.

February 2005 -July 2008
New Mexico Environment Department, Field Operations
Environmental Scientist and Specialist-Advanced

- Review engineering plans and approve permits for construction of swimming pool and bath facilities.
- Oversee district operations to ensure adequate permitting and inspection of public swimming pool facilities.
- Conduct training for swimming pool department staff and operators.
- Permit and inspect restaurants and food processors, swimming pool facilities, and liquid waste disposal system installations for compliance with applicable regulations.
- Conduct public education and outreach to help the regulated and general public comply with administrative requirements and state regulations.

EPA/600/R-20/012
April 2020
www.epa.gov/isa

Integrated Science Assessment for Ozone and Related Photochemical Oxidants

April 2020

Center for Public Health and Environmental Assessment
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, NC

NMED Exhibit 3 - 0001

EXECUTIVE SUMMARY

ES.1 Purpose and Scope of the Integrated Science Assessment

This Integrated Science Assessment (ISA)[1] is a comprehensive evaluation and synthesis of the policy-relevant science aimed at characterizing the health and welfare[2] effects caused by ozone. It communicates critical science judgments of the health-based and welfare-based criteria for ozone and related photochemical oxidants in ambient air. In 2015, the U.S. EPA lowered the health- and welfare-based National Ambient Air Quality Standards (NAAQS) for ozone to 0.070 ppm (annual fourth-highest daily max 8-hour concentration averaged over 3 years[3]). The health-based ozone NAAQS is meant to protect public health, including at-risk populations such as children and people with asthma, with an adequate margin of safety. The welfare-based ozone standard is intended to protect the public welfare from known or anticipated adverse effects associated with the presence of ozone in ambient air.

The ISA identifies and critically evaluates the most policy-relevant scientific literature across scientific disciplines, including epidemiology, controlled human exposure studies, animal toxicology, atmospheric science, exposure science, vegetation studies, agricultural science, ecology, and climate-related science. Key scientific conclusions (e.g., causality determinations; Section ES.4) are presented and explained. These conclusions provide the scientific basis for developing risk and exposure analyses, policy evaluations, and policy decisions for the review. This ISA draws conclusions about the causal nature of the relationships between ozone exposure and health and welfare effects by integrating recent evidence across scientific disciplines with the evidence base evaluated in previous reviews. U.S. EPA engages the Clean Air Scientific Advisory Committee (CASAC) as an independent federal advisory committee to conduct peer reviews of draft ISA and other materials. Peer review comments provided by the CASAC and public comments about the external review draft were considered in the development of this ISA (Section 10.4). The ISA thus provides the policy-relevant scientific information necessary to conduct a review of the NAAQS.

This Executive Summary provides an overview of the important conclusions drawn in the ISA across scientific disciplines, beginning with information on sources, concentrations, estimated background concentrations of ozone and ozone exposure, followed by health and welfare effects. A more detailed summary of the evidence is presented in the Integrated Synthesis, and individual Appendices for

[1] The general process for developing an ISA, including the framework for evaluating weight of evidence and drawing scientific conclusions and causality determinations, is described in a companion document, Preamble to the Integrated Science Assessments (U.S. EPA, 2015), www.epa.gov/isa.

[2] Under Clean Air Act section 302(h), effects on welfare include, but are not limited to, "effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being."

[3] Final rule signed October 1, 2015, and effective December 28, 2015 (80 FR 65291).

NMED Exhibit 3 - 0002

each topic area include study-level information and an in-depth characterization of the weight-of-evidence conclusions.

ES.2 Ozone in Ambient Air

The general photochemistry of tropospheric ozone is well-established. Ozone is produced in urban areas and downwind of sources mainly by the reaction of volatile organic compounds (VOCs) with oxides of nitrogen (NO_X) in the presence of sunlight, and outside of polluted areas mainly by reactions of carbon monoxide (CO) and methane (CH_4) with NO_X (Section 1.4). Recent developments in understanding ozone chemistry include observations of higher ozone concentrations during the winter in some western U.S. mountain basins (Section 1.4.1) and new research on the role of marine halogen chemistry in suppressing coastal ozone concentrations (Section 1.4.2). Air monitoring data for the period 2015−2017 show that U.S. daily max 8-hour avg concentrations of ozone (MDA8) are higher in spring and summer (median = 46 ppb) than in autumn (median = 38 ppb) and winter (median = 34 ppb). Figure ES-1 shows the highest values of the 3-year avg of annual fourth-highest MDA8 ozone concentrations (design values above 70 ppb) occur in central and southern California, Arizona, Colorado, Utah, Texas, along the shore of Lake Michigan, and in the Northeast Corridor, typically during the ozone season between May and September (Section 1.2.1.1).

NMED Exhibit 3 - 0003

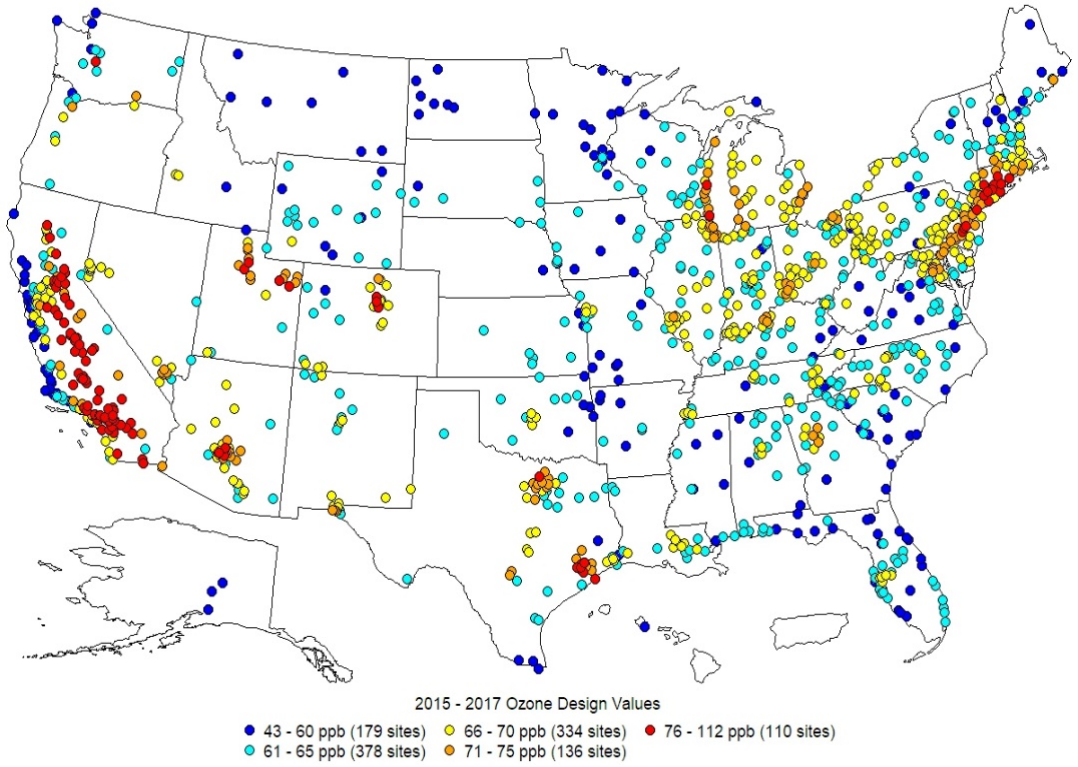


Figure ES-1 Individual monitor ozone concentrations in terms of design values (i.e., 3-year avg of annual fourth-highest max daily 8-hour avg ozone concentration) for 2015−2017.

A better understanding of the origins of ground-level U.S. background (USB) ozone and its concentration trends has emerged since the 2013 Ozone ISA. USB ozone concentration is defined as the ozone concentration that would occur if all U.S. anthropogenic ozone precursor emissions were removed (Section IS.2.2). Major contributors to USB ozone concentrations are stratospheric exchange, international transport, wildfires, lightning, global methane emissions, and natural biogenic and geogenic precursor emissions. Ozone monitors cannot discern the portion of ambient ozone concentrations that come from USB. Instead, USB concentrations are estimated using photochemistry and transport models. The estimates of USB ozone concentrations include uncertainties of about 10 ppb for seasonal average concentrations, with higher uncertainty for MDA8 concentrations. Models consistently estimate higher USB ozone concentrations at higher elevations of the western U.S. than in the eastern U.S. or along the Pacific coast. The estimated seasonal pattern in USB ozone concentrations tends to indicate lower USB in the summer than during the rest of the year. Several modeling studies using different approaches indicate that for MDA8 concentrations above 50−60 ppb, USB concentration estimates generally do not increase with increasing total ozone concentration (i.e., USB ozone concentrations are no higher on high ozone days than on low or moderate ozone days). The temporal trend in estimated USB ozone concentrations indicates increasing concentrations at high elevation western U.S. sites through approximately 2010.

NMED Exhibit 3 - 0004

Recently, however, this trend has shown signs of slowing or even reversing, possibly due to decreasing East Asian precursor emissions.

ES.3 Exposure to Ozone

Ambient air ozone concentrations, either measured at fixed-site monitors or estimated by models, are often used as surrogates for personal exposure in epidemiologic studies. Exposure measurement error can lead to reduced precision and an underestimation of the association between short-term ambient ozone exposure and a health effect (Section 2.6.1). For studies of long-term exposure, the true effect of exposure to ambient ozone may be underestimated or overestimated when the exposure model respectively overestimates or underestimates ozone exposure. It is much more common for the effect to be underestimated, and bias in the effect estimate is typically small in magnitude (Section 2.6.2). The availability and sophistication of models to predict ambient ozone concentrations to estimate exposure have increased substantially in recent years (Section 2.3.2). For effects elicited by ozone, the use of exposure estimates that do not account for population behavior and mobility (e.g., via use of time-activity data) may result in underestimation of the true effect and reduced precision (Section 2.4.1).

Tropospheric ozone can cause plant damage, which can then have negative impacts on terrestrial ecosystems as shown in observational and controlled exposure studies and in models using experimental data to extrapolate to effects at the community and ecosystem scale. Robust exposure indices that quantify exposure as it relates to measured plant response (e.g., growth) have been in use for decades and are derived from hourly ozone concentrations. Exposure duration influences the degree of plant response, and ozone effects on plants are cumulative. Cumulative indices summarize ozone concentrations over time and provide a consistent metric for reviewing and comparing exposure-response effects obtained from various studies. Cumulative indices of exposure that differentially weight hourly concentrations have been found to be best suited to characterize vegetation exposure to ozone with regard to reductions in vegetation growth and yield (Section 8.1.2.1).

ES.4 Health and Welfare Effects of Ozone Exposure

Broad health and welfare effect categories are evaluated independently in the Appendices of this ISA. Determinations are made about causation by evaluating evidence across scientific disciplines and are based on judgments of consistency, coherence, and biological plausibility of observed effects, as well as related uncertainties. The ISA uses a formal causality framework to classify the weight of evidence using a five-level hierarchy described in Table II of the Preamble (U.S. EPA, 2015). The subsequent sections characterize the evidence that forms the basis of causality determinations for health and welfare effect categories of a "causal relationship" or a "likely to be causal relationship," or describe instances where a causality determination has changed (i.e., "likely to be causal" changed to "suggestive of, but not sufficient to infer, a causal relationship"). Other relationships between ozone and health effects are *"suggestive of, but not sufficient to infer*" and "*inadequate to infer*" a causal relationship. These causality

NMED Exhibit 3 - 0005

determinations appear in Table ES-1, and are more fully discussed in the respective health effects Appendices.

ES.4.1 Health Effects of Ozone Exposure

Ozone-induced effects can occur through a variety of complex pathways within the body. After inhalation, ozone reacts with lipids, proteins, and antioxidants in the epithelial lining fluid of the respiratory tract, creating secondary oxidation products (Section 5.2.3). Initial ozone exposure leads to physiological reactions that may induce a host of autonomic, endocrine, immune, and inflammatory responses throughout the body at the cellular, tissue, and organ level. Recent evidence continues to support ozone-induced effects on the respiratory system. In addition, recent evidence indicates that short-term exposure to ozone is likely to induce metabolic effects, as shown in Figure ES-2. There is also some evidence that ozone exposure can affect the cardiovascular and nervous systems, reproduction and development, and mortality, although there are more uncertainties associated with interpretation of the evidence for these effects.

NMED Exhibit 3 - 0006

Table ES-1 Summary of causality determinations by exposure duration and health outcome.

Health Outcome[a]	Conclusions from 2013 Ozone ISA	Conclusions in the 2020 ISA
Short-term exposure to ozone		
Respiratory effects	Causal relationship	Causal relationship
Cardiovascular effects	Likely to be causal relationship	Suggestive of, but not sufficient to infer, a causal relationship[c]
Metabolic effects	No determination made	Likely to be causal relationship[b]
Total mortality	Likely to be causal relationship	Suggestive of, but not sufficient to infer, a causal relationship[c]
Central nervous system effects	Suggestive of a causal relationship[d]	Suggestive of, but not sufficient to infer, a causal relationship
Long-term exposure to ozone		
Respiratory effects	Likely to be causal relationship	Likely to be causal relationship
Cardiovascular effects	Suggestive of a causal relationship[d]	Suggestive of, but not sufficient to infer, a causal relationship
Metabolic effects	No determination made	Suggestive of, but not sufficient to infer, a causal relationship[b]
Total mortality	Suggestive of a causal relationship[d]	Suggestive of, but not sufficient to infer, a causal relationship
Reproductive effects	Suggestive of a causal relationship[d]	Effects on fertility and reproduction: suggestive of, but not sufficient to infer, a causal relationship[b]
		Effects on pregnancy and birth outcomes: suggestive of, but not sufficient to infer, a causal relationship[b]
Central nervous system effects	Suggestive of a causal relationship[d]	Suggestive of, but not sufficient to infer, a causal relationship
Cancer	Inadequate to infer a causal relationship	Inadequate to infer the presence or absence of a causal relationship[e]

[a]Health effects (e.g., respiratory effects, cardiovascular effects) include the spectrum of outcomes, from measurable subclinical effects (e.g., decrements in lung function, blood pressure) to observable effects (e.g., medication use, hospital admissions) and cause-specific mortality. Total mortality includes all-cause (nonaccidental) mortality, as well as cause-specific mortality.

[b]Denotes new causality determination.

[c]Denotes change in causality determination from 2013 Ozone ISA.

[d]Since the 2013 Ozone ISA, the causality determination language has been updated and this category is now stated as suggestive of, but not sufficient to infer, a causal relationship.

[e]Since the 2013 Ozone ISA, the causality determination language has been updated and this category is now stated as inadequate to infer the presence or absence of a causal relationship.

NMED Exhibit 3 - 0007

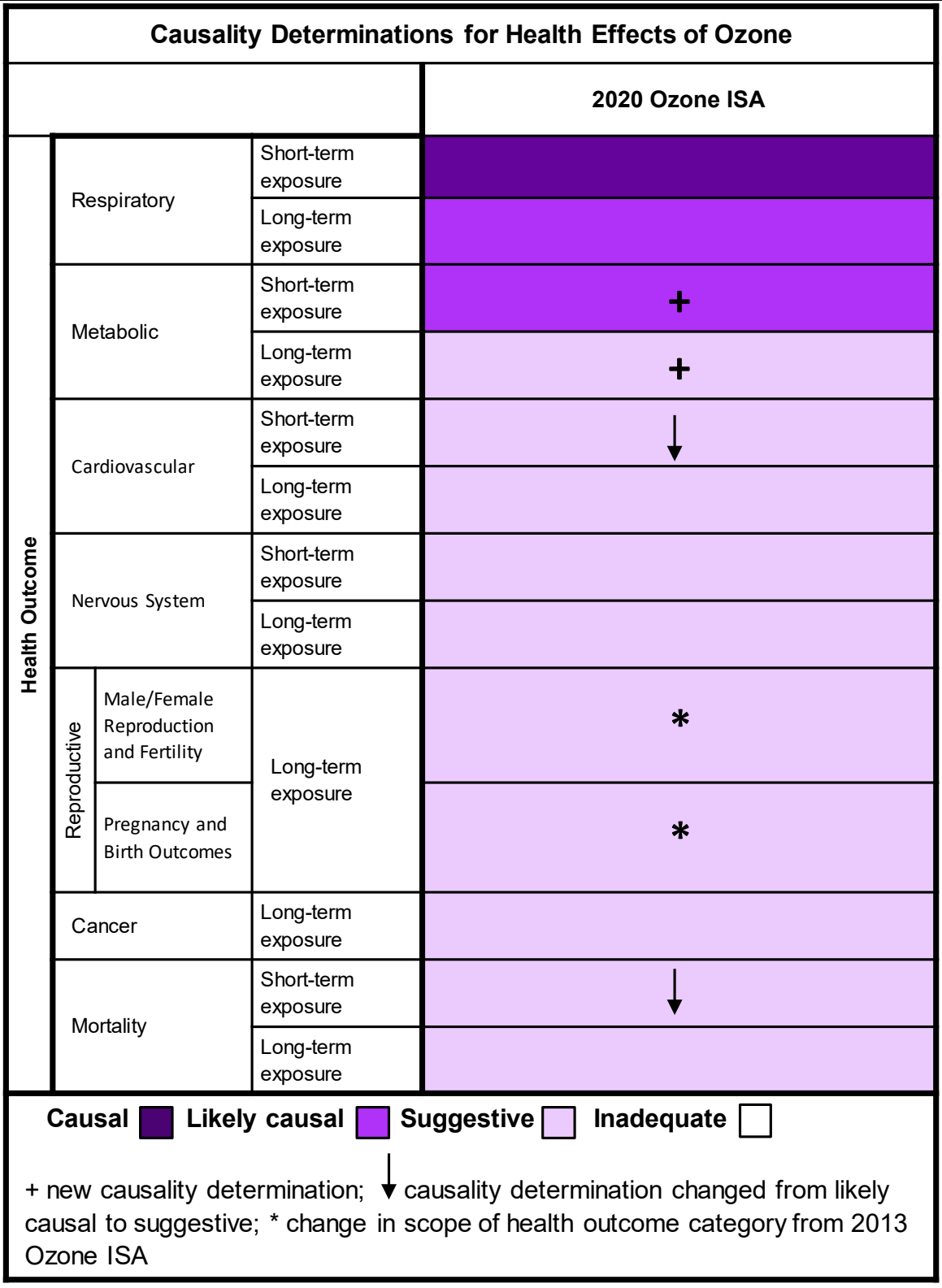


Figure ES-2 Causality determinations for health effects of short- and long-term exposure to ozone.

NMED Exhibit 3 - 0008

The strongest evidence for health effects due to ozone exposure continues to come from studies of short- and long-term ozone exposure and respiratory health, and this evidence is detailed in Appendix 3. Consistent with conclusions from the 2013 Ozone ISA (Table ES-1), **there is a "causal relationship" between short-term ozone exposure and respiratory effects** (Section 3.1.11), and **there is a "likely to be causal relationship" between long-term ozone exposure and respiratory effects** (Section 3.2.6).

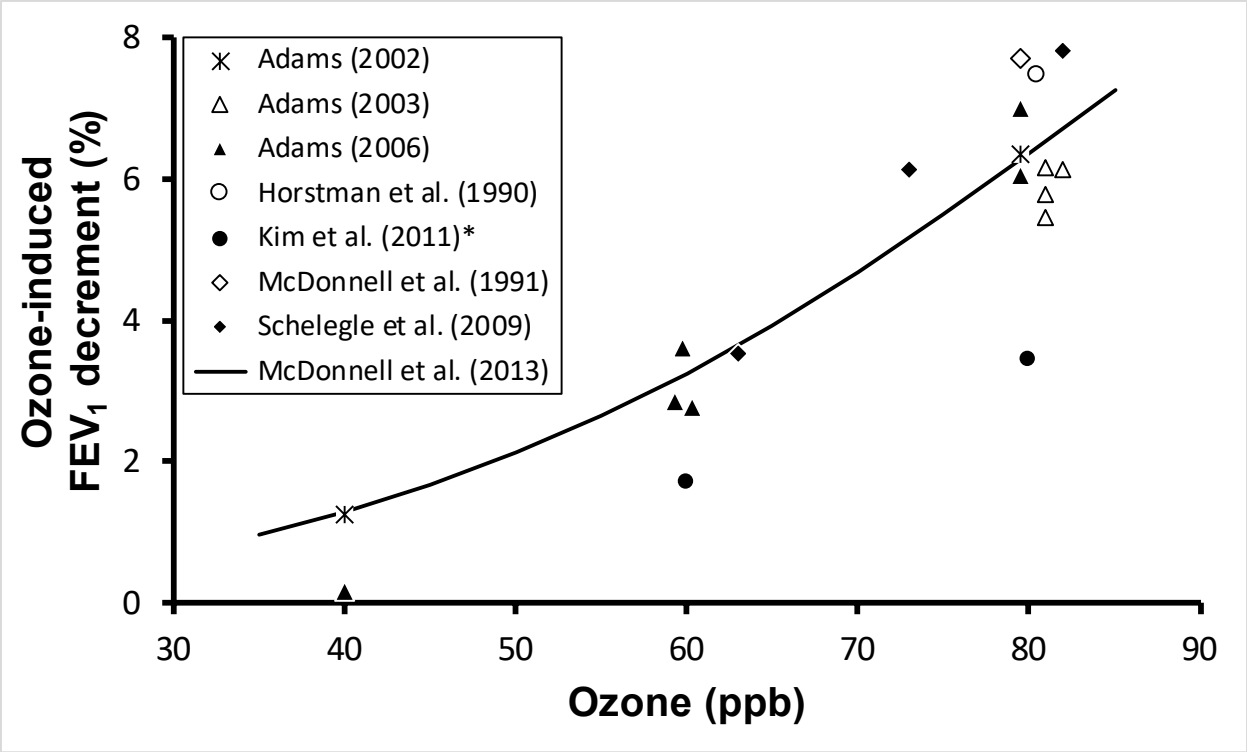
For short-term ozone exposure, controlled human exposure studies conducted over many decades provide experimental evidence for ozone-induced lung function decrements (Figure ES-3), airway responsiveness, respiratory symptoms, and respiratory tract inflammation. Epidemiologic studies continue to provide evidence that ozone concentrations in ambient air are associated with a range of respiratory effects, including asthma exacerbation, chronic obstructive pulmonary disease (COPD) exacerbation, respiratory infection, and hospital admissions and emergency department (ED) visits for combined respiratory diseases.

A large body of animal toxicological studies demonstrate ozone-induced alterations in lung function, inflammation, increased airway responsiveness, and impaired lung host defense. These animal toxicological studies also aid in our understanding of potential mechanisms underlying respiratory effects at the population level and the biological plausibility of epidemiologic associations between short-term ozone exposure and respiratory-related ED visits and hospital admissions.

With respect to long-term ozone exposure, there is strong coherence between animal toxicological studies of changes in lung morphology and epidemiologic studies reporting positive associations between long-term ozone exposure and new-onset asthma, respiratory symptoms in children with asthma, and respiratory mortality. Furthermore, the experimental evidence provides biologically plausible pathways through which long-term ozone exposure could lead to respiratory effects reported in epidemiologic studies.

Metabolic effects related to ozone exposure are evaluated as a separate health endpoint category for the first time in this ISA (Appendix 5). Recent evidence from animal toxicological, controlled human exposure, and epidemiologic studies indicate that **there is a "likely to be causal relationship" between short-term ozone exposure and metabolic effects** (Section 5.1.8). The strongest evidence for this determination is provided by animal toxicological studies that demonstrate impaired glucose tolerance, increased serum triglycerides, fasting hyperglycemia, and increased hepatic gluconeogenesis in various stocks/strains of animals across multiple laboratories. Biological plausibility is provided by results from controlled human exposure and animal toxicological studies that demonstrate activation of sensory nerve pathways following ozone exposure triggers the central neuroendocrine stress response, which includes increased corticosterone, cortisol, and epinephrine production. These findings are coherent with epidemiologic studies that report associations between ozone exposure and perturbations in glucose and insulin homeostasis. In addition, these pathophysiological changes are often accompanied by increased inflammatory markers in peripheral tissues and by activation of the neuroendocrine system.

NMED Exhibit 3 - 0009



All responses at and above 70 ppb (targeted concentration) were statistically significant ($p < 0.05$). Adams (2006) found statistically significant responses to square-wave chamber exposures at 60 ppb based on the analysis of Brown et al. (2008) and Kim et al. (2011). During each hour of the exposures, subjects were engaged in moderate quasi-continuous exercise (20 L/minute per m^2 BSA) for 50 minutes and rest for 10 minutes. Following the 3rd hour, subjects had an additional 35-minute rest period for lunch. The data at 60 and 80 ppb have been offset on the *x* axis for illustrative purposes. The solid line illustrates the predicted FEV_1 decrements using Model 3 coefficients at 6.6 hours as a function of ozone concentration for a 23.8-year-old with a BMI of 23.1 kg/m^2 from McDonnell et al. (2013).

*80 ppb data for 30 health subjects were collected as part of the Kim et al. (2011) study, but only published in Figure 5 of McDonnell et al. (2012).

Adapted from Figure 6-1 of 2013 Ozone ISA (U.S. EPA, 2013). Studies appearing in the figure legend are: Adams (2006), Adams (2003), Adams (2002), Horstman et al. (1990), Kim et al. (2011), McDonnell et al. (2013), McDonnell et al. (1991), and Schelegle et al. (2009).

Figure ES-3 Cross-study comparisons of mean decrements in ozone-induced forced expiratory volume in 1 second (FEV_1) in young, healthy adults following 6.6 hours of exposure to ozone.

Notably, there are changes in the causality determinations for short-term ozone exposure and cardiovascular effects (Appendix 4), as well as for total mortality (Appendix 6). In both instances, the evidence synthesized in the 2013 Ozone ISA was sufficient to conclude a "likely to be causal relationship," but after integrating the previous evidence with recent data, **the collective evidence is "suggestive of, but not sufficient to infer, a causal relationship" between short-term ozone exposure and cardiovascular effects (Section 4.1.17) or total mortality (Section 6.1.8)** in this ISA. The evidence that supports this change in the causality determinations includes: (1) a growing body of controlled human exposure studies providing less consistent evidence for an effect of short-term ozone exposure on

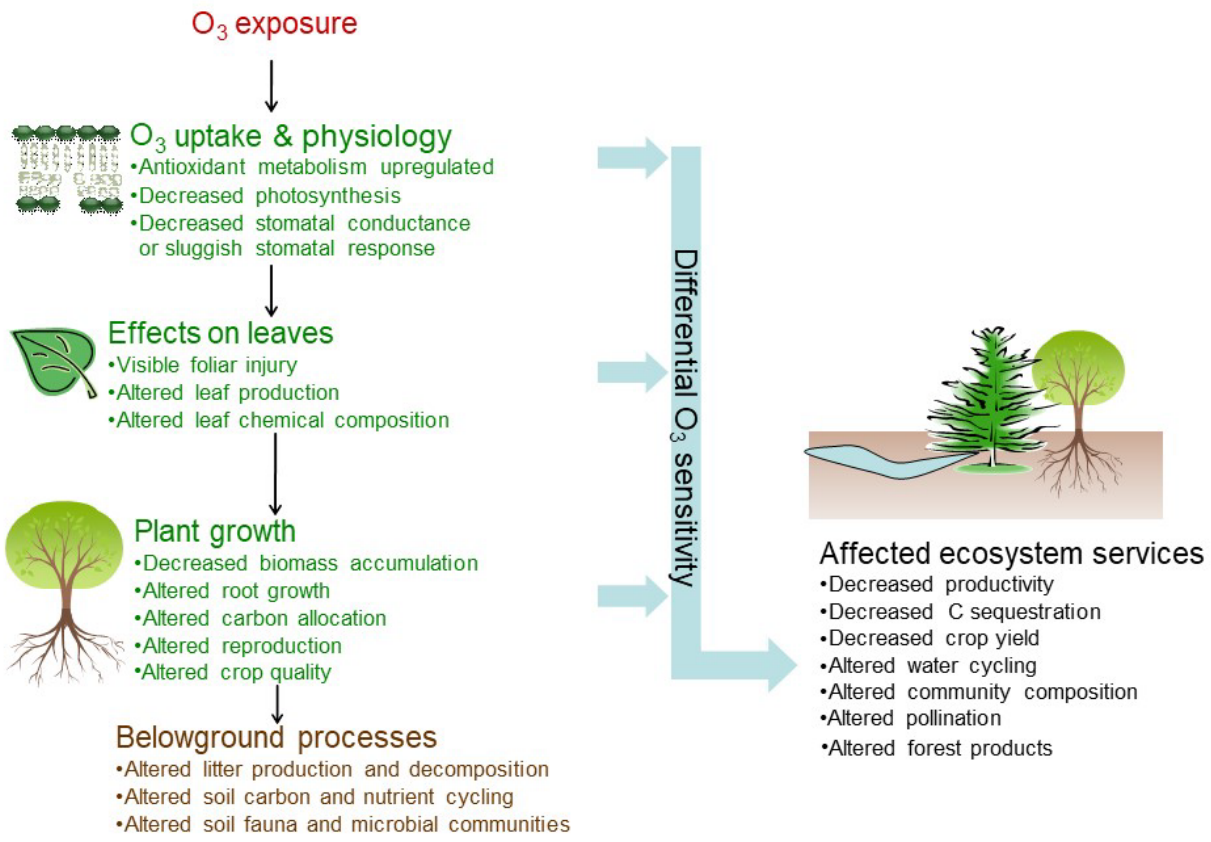
NMED Exhibit 3 - 0010

cardiovascular health endpoints; (2) a paucity of positive evidence from epidemiologic studies for more severe cardiovascular morbidity endpoints (i.e., heart failure, ischemic heart disease and myocardial infarction, arrhythmia and cardiac arrest, and stroke); and (3) uncertainties due to a lack of control for potential confounding by copollutants in epidemiologic studies. Although there is generally consistent evidence for a limited number of ozone-induced cardiovascular endpoints in animal toxicological studies and for cardiovascular mortality in epidemiologic studies, these results are not coherent with results from controlled human exposure and epidemiologic studies examining cardiovascular morbidity endpoints. There remains evidence for ozone-induced cardiovascular mortality from epidemiologic studies. However, inconsistent results from a larger number of recent controlled human exposure studies that do not provide evidence of cardiovascular effects in response to short-term ozone exposure introduce additional uncertainties.

ES.4.2 Ozone Exposure and Welfare Effects

The scientific evidence for welfare effects of ozone consists mainly of effects on vegetation and ecosystems (Appendix 8) and effects on climate (Appendix 9). For ecological effects, damage to terrestrial ecosystems as evaluated through controlled exposure studies, observational studies and modeling based on experimental data, is largely a function of uptake of ozone into the leaf via stomata (gas exchange openings on leaves). Subsequent reactions with plant tissues alter whole-plant responses that cascade up to effects at higher levels of biological organization (i.e., from the cellular and subcellular level to the individual organism up to ecosystem level processes and services; Figure ES-4). At the leaf level, ozone uptake produces reactive oxygen species that affect cellular function (Section 8.1.3 and Figure 8-2). Reduced photosynthesis, altered carbon allocation, and impaired stomatal function lead to observable responses in plants. Observed vegetation responses to ozone include visible foliar injury (Section IS.5.1.1), and whole-plant level responses (Section IS.5.1.2), which encompass reduction in aboveground and belowground growth, reproduction and yield. Plant-fauna linkages affected by ozone include herbivores that feed on ozone-damaged vegetation and interactions of ozone with compounds emitted by plants that can alter attraction of pollinators to plants (Section IS.5.1.3). A combination of observational and experimental data, and modeling output provides evidence for broad changes in ecosystems such as decreased productivity and carbon sequestration (Section IS.5.1.4), altered belowground processes (Section IS.5.1.5), terrestrial community composition (Section IS.5.1.6), and water cycling (Section IS.5.1.7).

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Source: Adapted from U.S. EPA (2013).

Figure ES-4 Illustrative diagram of ozone effects cascading from the cellular level to plants and ecosystems.

There are 12 causality determinations for ecological effects of ozone generally organized from the individual-organism scale to the ecosystem scale in Figure ES-5. Like the findings of the 2013 Ozone ISA (Table ES-2), five are causal relationships (i.e., visible foliar injury, reduced vegetation growth, reduced crop yield, reduced productivity, and altered belowground biogeochemical cycles) and two are likely to be causal relationships (i.e., reduced carbon sequestration, altered ecosystem water cycling). One of the endpoints, alteration of terrestrial community composition, is now concluded to be a causal relationship whereas in the 2013 Ozone ISA this endpoint was classified as a likely to be causal relationship. Three new endpoint categories (i.e., increased tree mortality, alteration of herbivore growth and reproduction, alteration of plant-insect signaling) not evaluated in the 2013 Ozone ISA, are all determined to have a likely to be causal relationship with ozone. Plant reproduction, previously considered as part of the evidence for growth effects, is now a stand-alone causal relationship.

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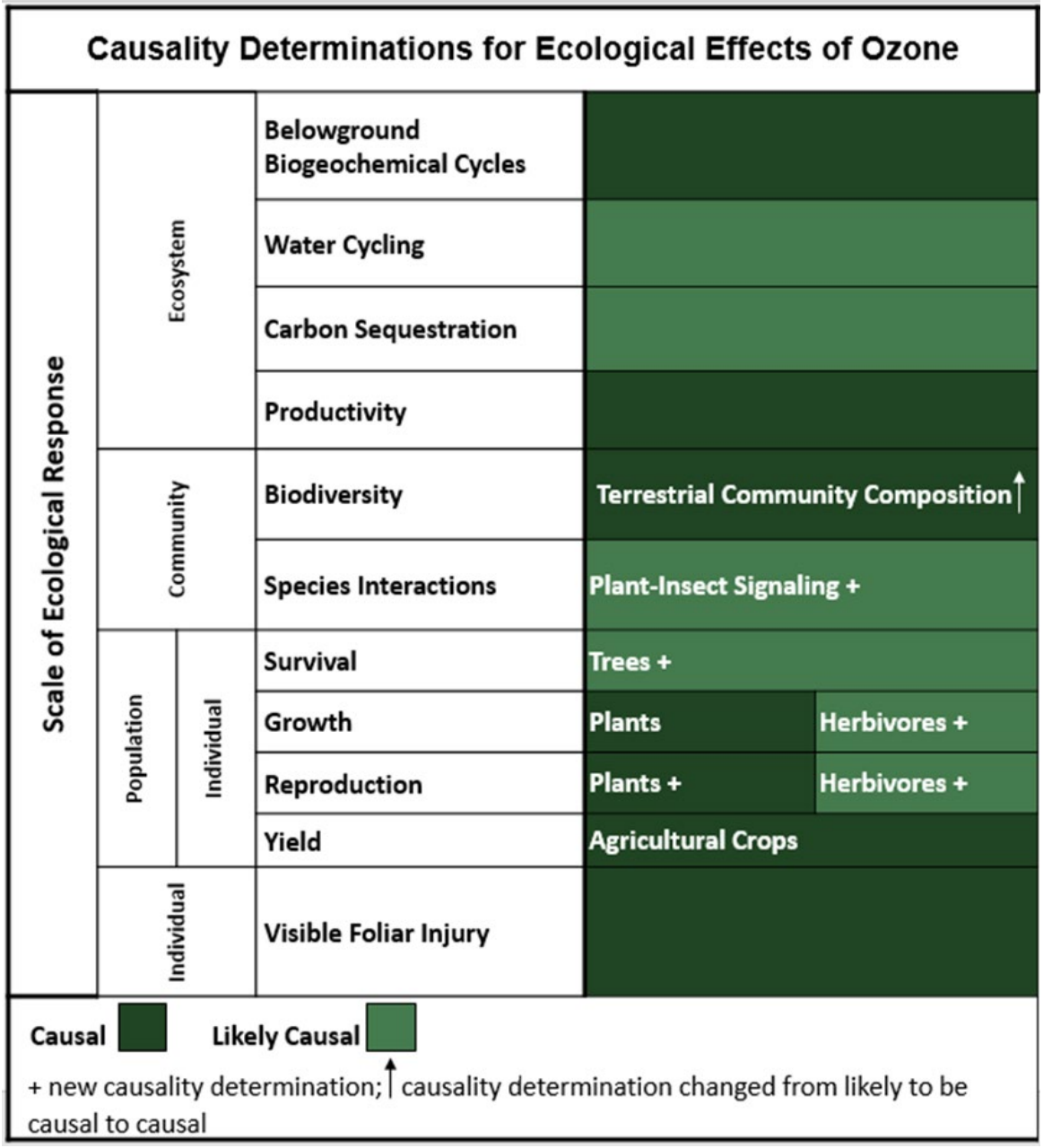


Figure ES-5 Causality determinations for ozone across biological scales of organization and taxonomic groups.

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Table ES-2 Summary of causality determinations for ecological effects.

Endpoint	Conclusions from 2013 Ozone ISA	Conclusions in the 2020 ISA
Visible foliar injury	Causal relationship	Causal relationship
Reduced vegetation growth	Causal relationship	Causal relationship
Reduced plant reproduction	No separate causality determination; included with plant growth	Causal relationship[a]
Increased tree mortality	Causality not assessed	Likely to be causal relationship[a]
Reduced yield and quality of agricultural crops	Causal relationship	Causal relationship
Alteration of herbivore growth and reproduction	Causality not assessed	Likely to be causal relationship[a]
Alteration of plant-insect signaling	Causality not assessed	Likely to be causal relationship[a]
Reduced productivity in terrestrial ecosystems	Causal relationship	Causal relationship
Reduced carbon sequestration in terrestrial ecosystems	Likely to be causal relationship	Likely to be causal relationship
Alteration of belowground biogeochemical cycles	Causal relationship	Causal relationship
Alteration of terrestrial community composition	Likely to be causal relationship	Causal relationship[b]
Alteration of ecosystem water cycling	Likely to be causal relationship	Likely to be causal relationship

[a]Denotes new causality determination.

[b]Denotes change in causality determination from 2013 Ozone ISA.

Visible foliar injury resulting from exposure to ozone has been well characterized and documented in over six decades of controlled experimental research involving many tree, shrub, herbaceous, and crop species and using both long-term field studies and laboratory approaches. Recent experimental evidence (Section 8.2) continues to show a consistent association between visible injury and ozone exposure supporting the conclusion of the 2013 Ozone ISA that, **there is a "causal relationship" between ozone and visible foliar injury.** Measured changes in photosynthesis and carbon allocation in ozone-exposed plants scale up to reduced growth documented in natural and managed (e.g., agriculture, forestry, landscaping) species (Section 8.3), as well as impaired reproduction in individual plants (Section 8.4.1). Consistent with the conclusions in the 2013 Ozone ISA, there is **a "causal relationship"**

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between ozone and reduced plant growth and **a "causal relationship" between ozone and reduced crop yield and quality**. In the 2013 Ozone ISA, reproduction was considered in the same category with plant growth. Increased information on metrics of plant reproduction (e.g., observed flower number, fruit number, fruit weight, seed number, rate of seed germination) and evidence for direct negative effects on reproductive tissues as well as for indirect negative effects (resulting from decreased photosynthesis and other whole-plant physiological changes) warrants a separate causality determination of **a "causal relationship" between ozone exposure and reduced plant reproduction**. Since the 2013 Ozone ISA, a large-scale multivariate analysis of factors contributing to tree mortality (1971−2005) concluded that county-level ozone concentrations averaged over the study period significantly increased tree mortality in 7 out of 10 plant functional types in the eastern and central U.S. (Section 8.4.3). This evidence, combined with observations of long-term declines of conifer forests in several high ozone regions and new experimental evidence that sensitive genotypes of aspen have increased mortality with ozone exposure, supports **a "likely to be causal relationship" between ozone exposure and tree mortality.**

In addition to effects on plants, ozone can alter ecological interactions between plants and other species including herbivores consuming ozone-exposed vegetation. Studies of insect herbivores in previous ozone assessments and newer experimental studies covering a range of species at varying levels of ozone exposure frequently show statistically significant effects; however, effects on growth and reproduction are highly context- and species-specific, and not all species tested show a response (Section 8.6). **The collective evidence supports "a likely to be causal relationship" between ozone exposure and altered herbivore growth and reproduction.** Many plant-insect interactions are mediated through volatile plant signaling compounds which plants use to signal other community members. In the 2013 Ozone ISA, a few experimental and modeling studies reported altered insect-plant interactions that are mediated through chemical signaling. New evidence from multiple studies show altered/degraded emissions of chemical signals from plants and reduced detection of volatile plant signaling compounds by insects, including pollinators, in the presence of ozone (Section 8.7). **The collective evidence supports "a likely to be causal relationship" between ozone exposure and alteration of plant-insect signaling.**

At the ecosystem scale, ozone-caused decreases in plant photosynthesis can lead to reduced ecosystem carbon content. Changes in patterns of aboveground and belowground carbon allocation associated with ozone effects on plants can alter ecosystem properties of storage (e.g., productivity, carbon sequestration) and cycling (e.g., biogeochemistry) through both experimental and modeling studies. Consistent with the conclusions of the 2013 Ozone ISA, there is **a "causal relationship" between ozone exposure and reduced productivity and a "likely to be causal relationship" between ozone and reduced carbon sequestration** (Section 8.8). As described in the 2013 Ozone ISA and new experimental studies, processes such as carbon and nitrogen cycling and decomposition in soils are indirectly affected via ozone effects on the quality and quantity of carbon supply from plants and leaf litter (Section 8.9). **Recent evidence continues to support a "causal relationship" between ozone exposure and the alteration of belowground biogeochemical cycles**. Ozone can affect water use in plants through several mechanisms including damage to stomatal functioning, loss of leaf area, and

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changes in wood anatomy (e.g., vessel size and density) that can affect plant and stand evapotranspiration and may lead, in turn, to possible effects on hydrological cycling as shown through a combination of experimental data and modeling (Section 8.11). Evidence continues to support the conclusion of the 2013 Ozone ISA that, **there is a "likely to be causal relationship" between ozone and alteration of ecosystem water cycling.** In terrestrial ecosystems, ozone may alter community composition by uneven effects on co-occurring species, decreasing the abundance of sensitive species, and giving tolerant species a competitive advantage. Alteration of community composition of some ecosystems including conifer forests, broadleaf forests, and grasslands and altered fungal and bacterial communities in soils reported in the 2013 Ozone ISA is augmented by additional experimental and modeling evidence for effects in forest and grassland communities (Section 8.10); collective evidence indicates a change in the causality determination to **a "causal relationship" between ozone exposure and altered terrestrial community composition of some ecosystems.**

For effects on climate, changes in the abundance of tropospheric ozone perturb the radiative balance of the atmosphere by interacting with incoming solar radiation and outgoing longwave radiation. This effect is quantified by radiative forcing.[1] Through this effect on the Earth's radiation balance, tropospheric ozone plays a major role in the climate system and increases in tropospheric ozone abundance contribute to climate change. **Recent evidence continues to support a "causal relationship" between tropospheric ozone and radiative forcing and a "likely to be causal relationship," via radiative forcing, between tropospheric ozone and temperature, precipitation, and related climate variables** (referred to as "climate change" in the 2013 Ozone ISA; the revised title for this causality determination provides a more accurate reflection of the available evidence; Table ES-3). The new evidence comes from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) and its supporting references, as well as a limited number of more recent studies, and builds on evidence presented in the 2013 Ozone ISA. The new studies further support the causality determinations included in the 2013 Ozone ISA.

Table ES-3 Summary of causality determinations for tropospheric ozone effects on climate.

	Conclusions in 2013 Ozone ISA	Conclusions in the 2020 ISA
Radiative forcing	Causal relationship	Causal relationship
Temperature, precipitation, and related climate variables	Likely to be causal relationship	Likely to be causal relationship

[1] Radiative forcing is the perturbation in net radiative flux at the tropopause (or top of the atmosphere) caused by a change in radiatively active forcing agent(s) after stratospheric temperatures have readjusted to radiative equilibrium [stratospherically adjusted radiative forcing; Myhre et al. (2013)].

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ES.5 Key Aspects of Health and Welfare Effects Evidence

There is extensive scientific evidence that demonstrates health and welfare effects from exposure to ozone. As documented by the evaluation of evidence throughout the subsequent Appendices to this ISA, the U.S. EPA carefully considers uncertainties in the evidence, the extent to which recent studies have addressed or reduced uncertainties from previous assessments, and the strengths of the evidence. Uncertainties do not necessarily change the fundamental conclusions of the literature base. In fact, some conclusions are robust to such uncertainties. Where there is clear evidence linking ozone with health and welfare effects—with or despite remaining uncertainties—the U.S. EPA makes a determination of a causal or likely to be causal relationship. The identification of the strengths and limitations in the evidence will help in the prioritization of research efforts to support future ozone NAAQS reviews.

ES.5.1 Health Effects Evidence: Key Findings

A large body of scientific evidence spanning many decades clearly demonstrates there are health effects related to both short- and long-term exposure to ozone. The strongest evidence supports a relationship between ozone exposure and respiratory health effects. The collective body of evidence for each health outcome category evaluated in this ISA is considered systematically and assessed; this assessment includes evaluation of the inherent strengths, limitations, and uncertainties in the overall body of evidence for the health outcome, resulting in the causality determinations detailed in Table ES-1.

An inherent strength of the evidence integration in this ISA is the extensive amount (in both breadth and depth) of available evidence resulting from decades of scientific research that describes the relationship between both short- and long-term ozone exposure and health effects. The breadth of the enormous database is illustrated by the different scientific disciplines that provide evidence (e.g., controlled human exposure, epidemiologic, animal toxicological studies), the range of health outcomes examined (e.g., respiratory, cardiovascular, metabolic, reproductive, and nervous system effects, cancer and mortality), and the large number of studies within several of these outcome categories. The depth of the literature base is exemplified by the examination of effects that range from biomarkers of exposure, to subclinical effects, to overt clinical effects, and even mortality.

There is strong and consistent experimental evidence linking short- and long-term ozone exposure with respiratory effects and short-term ozone exposure with metabolic health effects. However, several uncertainties should be considered when evaluating and synthesizing evidence from these studies. Experimental animal studies are often conducted at ozone concentrations higher than those observed in ambient air (i.e., 250 to >1,000 ppb) to evoke a response within a short time period. These studies are informative and the conduct of studies at these concentrations is commonly used for identifying potential human hazards. There are also substantial differences in exposure concentrations and exposure durations between animal toxicological and controlled human exposure studies. Additionally, a number of animal toxicological studies are performed in rodent models of disease states, while controlled human exposure studies generally are conducted in healthy individuals. Controlled human exposure studies do not

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typically include unhealthy or diseased individuals for ethical reasons; therefore, this exclusion represents an important uncertainty to consider in interpreting the results of these studies (i.e., that other individuals may be more sensitive and at risk to ozone than those in the study groups). Additional factors that differ between human and experimental animal exposures include: exposure concentration and disease status; differences in physiology (e.g., rodents are obligate nose breathers); differences in the duration and timing of exposure (e.g., rodents are exposed typically during the day, during their resting cycle, while humans are exposed during the day when they are normally active); and differences in the temperature at which the exposure was conducted. These factors may contribute to any lack of coherence between results of experimental animal and human studies. Despite these factors, there is consistent and coherent evidence that spans scientific disciplines for respiratory and metabolic health effects.

Epidemiologic studies contribute important evidence supporting the relationship between short- and long-term ozone exposure with respiratory effects. Although susceptible to chance, bias, and other potential confounding due to their observational nature, epidemiologic studies have the benefit of evaluating real-world exposure scenarios and can include sensitive populations that cannot typically be included in controlled human exposure studies. Innovations in epidemiologic study designs and methods have substantially reduced the role of chance, bias, and other potential confounders in well-designed, well-conducted epidemiologic studies. The most common source of uncertainty in epidemiologic studies of ozone is exposure measurement error. The exposure assignment methods used in short- and long-term ozone exposure epidemiologic studies have inherent strengths and limitations, and exposure measurement errors associated with those methods contribute bias and uncertainty to health effect estimates. For short-term exposure studies, exposure measurement error generally leads to underestimation and reduced precision of the association, whereas in long-term exposure studies exposure measurement error has the potential to bias effect estimates in either direction, although it is more common that they are underestimated. Furthermore, disentangling the effects of short-term ozone exposure from those of long-term ozone exposure (and vice versa) is an inherent uncertainty in the evidence base. When combined with coherent evidence from animal toxicological and controlled human exposure studies, the epidemiologic evidence can support and strengthen determinations of the causal nature of the relationship between health effects and exposure to ozone at relevant ambient air concentrations.

ES.5.2 Welfare Effects Evidence: Key Findings

The collective body of evidence for each welfare endpoint evaluated in this ISA was carefully considered and assessed, including the inherent strengths, limitations, and uncertainties in the overall body of evidence, resulting in the causality determinations for ecological effects detailed in Table ES-2 and effects on climate in Table ES-3. A large body of scientific evidence spanning more than 60 years clearly shows effects on vegetation due to ozone exposure. Decades of research on many plant species confirm effects on visible foliar injury, plant growth, reproduction and yield. The use of visible foliar injury to identify phytotoxic levels of ozone is an established and widely used methodology. There are robust exposure-response functions for reduced growth and yield (i.e., from carefully controlled

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experimental conditions, involving multiple concentrations and based on multiple studies) for about a dozen important tree species and a dozen major commodity crop species. Newer evidence supports a role for ozone in tree mortality and shifts in community composition of forest tree and grassland species. While the effect of ozone on vegetation is well established in general, there are some knowledge gaps regarding precisely which species are sensitive, what exposures elicit adverse responses for many species and how plant response changes with age and size.

There is high certainty in ozone effects on impairment to leaf physiology as mechanisms for effects at higher levels of biological organization (i.e., from the cellular level through individual organisms to the level of communities and ecosystems) and how those can ultimately affect aboveground and belowground processes such as productivity, carbon sequestration, biogeochemical cycling, and hydrology. However, ecosystems are inherently complex, and it is difficult to partition observed responses within a suite of multiple stressors. Scaling ozone effects to the ecosystem level remains a challenge, but there is a large body of knowledge of how ecosystems work through ecological observations and models. Interactive effects in natural ecosystems with multiple stressors (e.g., drought, disease) are difficult to study, but some have been investigated using different statistical methods. Although models and methods for characterizing ecosystem-level responses to ozone are accompanied by inherent uncertainties, more research will strengthen understanding of scaling across different levels of biological organization.

There are multiple pathways in which ozone can affect plant-insect interactions. Studies that characterize volatile plant signaling compounds in ozone-enriched environments and assess insect response to altered chemical signals suggest that ozone alters scent-mediated interactions in ecological communities. A relatively small number of insect species and plant-insect associations have been assessed, and there are knowledge gaps in the mechanisms and consequences of modulation of signaling by ozone. There are multiple studies demonstrating ozone effects on fecundity and growth in insects that feed on ozone-exposed vegetation. However, no consistent directionality of response is observed across studies and uncertainties remain in regard to different plant consumption methods across species and the exposure conditions associated with particular severities of effects.

Changes in the abundance of tropospheric ozone affect radiative forcing, and thus tropospheric ozone is considered an important greenhouse gas. The recent IPCC AR5 estimates global tropospheric ozone radiative forcing to be 0.40 (0.20 to 0.60) W/m^2 and recent studies reinforce the AR5 estimates. Consistent with previous estimates, the effect of global, total tropospheric ozone increases on global mean surface temperature, through its impact on radiative forcing, continues to be estimated at roughly 0.1 to 0.3°C since preindustrial times with larger effects regionally. Some new research has explored certain additional aspects of the climate response to ozone radiative forcing beyond global and regional temperature change. Specifically, ozone changes are understood to have impacts on other climate metrics such as precipitation and atmospheric circulation patterns, and new evidence has continued to support and further quantify this understanding.

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While the warming effect of tropospheric ozone in the climate system is well established in general, precisely quantifying changes in surface temperature due to tropospheric ozone changes, along with related climate effects, requires complex climate simulations that include all relevant feedbacks and interactions. For example, trends in free tropospheric ozone and upper tropospheric ozone (where radiative forcing is particularly sensitive to changes in ozone concentrations) are not captured well by models. In addition, substantial variation exists across models. Such modeling uncertainties make it especially difficult to provide precise quantitative estimates of the climate effects of regional-scale ozone changes. Uncertainties in estimates of preindustrial ozone concentrations represent another important source of uncertainty in climate effects resulting from long-term ozone concentration changes.

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Ozone Advance Path Forward

Prepared by the New Mexico Environment Department
Air Quality Bureau

Submitted to United States Environmental Protection Agency, Region VI
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Introduction

Ozone Basics

Ozone (O_3) is a highly reactive gas composed of three oxygen atoms. It is both a natural and a man-made product that occurs in the Earth's upper (stratosphere) and lower (troposphere) atmosphere. Ground level ozone, the ozone EPA sets national standards for, is both harmful to human health and damaging to the environment

Both short- and long-term exposure to ozone can lead to adverse health impacts. Short-term exposures to ozone can make it more difficult to take a full, deep breath by inflaming the airways and causing symptoms such as chest pain, coughing, wheezing and shortness of breath. These short-term exposures can also aggravate asthma and other respiratory diseases and can make people more susceptible to infections.

Long-term exposure to ozone is linked to the development and aggravation of asthma and a variety of other impacts to the respiratory system. Through continued research, scientists are finding that long-term exposure (i.e., for periods longer than eight hours) may increase the risk of early death. Anyone who spends time where ozone concentrations are high may be at risk of experiencing adverse health effects.[1]

According to the Environmental Protection Agency (EPA), ozone affects sensitive vegetation and ecosystems, including forests, parks, wildlife refuges and wilderness areas. Ozone can especially cause damage during the growing season. When enough ozone enters the leaves of a sensitive plant, it can reduce photosynthesis; slow the plant's growth; and increase sensitive plants' risk of disease, damage from insects, effects of other pollutants, and harm from severe weather. [2]

EPA Advance Program

The EPA Advance Program began in April 2012 as a collaborative effort to encourage ozone and particulate matter (PM) emission reductions in attainment areas. Participants determine goals and measures they want to implement and achieve. Although participation in the program does not guarantee an attainment designation in the future, actions taken as part of the Ozone Advance Program could better position future non-attainment areas to develop an effective State Implementation Plan (SIP).

Ozone Advance provides emissions reductions that could result in a lower nonattainment classification or be credited in a future SIP. A key benefit to participating in the program is the flexibility to voluntarily reduce air pollution through control measures chosen to suit an area's social and economic demographics. Once designated nonattainment, the Clean Air Act affords less flexibility to select control measures.

Geographic Scope

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[1] From *Health effects of ozone pollution*, Environmental Protection Agency, https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution

[2] From *Ecosystem effects of ozone pollution*, Environmental Protection Agency, https://www.epa.gov/ground-level-ozone-pollution/ecosystem-effects-ozone-pollution

The New Mexico Environment Department (NMED) is participating in the Ozone Advance Program with respect to three full counties and one partial county in New Mexico to preserve or improve the air quality in these areas. These counties are San Juan (northwest NM), Lea (southeast NM), Eddy (southeast NM) and Doña Ana, excluding the Sunland Park nonattainment area (south central NM). Since our acceptance into the Ozone Advance Program in April 2019, ozone levels in Rio Arriba, Sandoval, Santa Fe, and Valencia counties either currently or recently have exceeded 95% of the 2015 8-hour Ozone NAAQS (67 ppb) and could soon violate this standard. In total, the Ozone Advance Path Forward and outreach efforts will include the following nine counties (figure 1): Chaves, Doña Ana, Eddy, Lea, Rio Arriba, San Juan, Santa Fe, Sandoval, and Valencia.

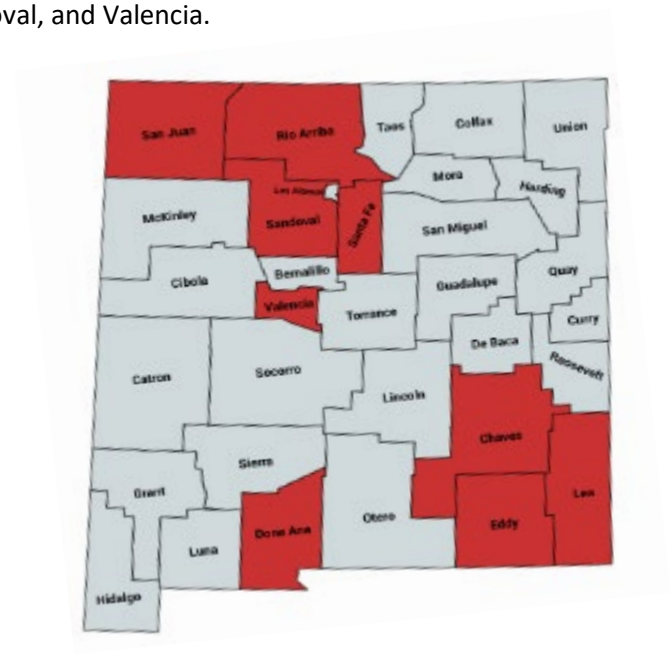


Figure 1: Map of New Mexico Counties to be included in Ozone Advance Path Forward

Although Chaves County does not have ozone monitors, the Bureau will include it in the Ozone Advance planning effort as it is part of the Permian Basin with Oil and Gas emissions that contribute to high ozone levels in Lea and Eddy counties. NMED understands our efforts under Ozone Advance may benefit these areas by potentially (1) reducing air pollution in terms of ozone as well as other air pollutants, (2) ensuring continued healthy ozone levels, (3) maintaining the ozone NAAQS and helping the Sunland Park Nonattainment Area attain the 2015 Ozone NAAQS, (4) helping avoid violations of the NAAQS that could lead to a future nonattainment designation, (5) increasing public awareness about ozone as an indirect air pollutant, and (6) targeting limited resources toward actions to address ozone problems quickly. NMED's goal is to implement measures and programs to reduce ozone in the near term, and ultimately to effect changes that will protect community well-being into the future. NMED agrees it is in our best interest to work together and in coordination with stakeholders and the public to proactively pursue this goal.

This path forward plan outlines several relevant strategies to realize this vision. It recommends measures that we, as a state, can and are implementing to protect air quality across New Mexico.

Background

Ground-level ozone is created by chemical reactions between nitrogen oxides (NO_X) and volatile organic compounds (VOCs), with sunlight as the driver. VOC and NO_X come in two forms: biogenic (natural), which is produced by vegetation: and anthropogenic, which is created by humans, primarily in industrial processes, and by modern transportation modes, particularly diesel and gas-driven motor vehicles. Hot, sunny days may produce unhealthy levels of ozone, especially in urban environments. Smoke from wildfires can also contribute pollutants that increase the formation of ozone.

High ozone levels in New Mexico are driven by different sources in different parts of the state. For example, NO_X and VOC emissions from the oil and gas industry in Eddy, Lea, Rio Arriba and San Juan counties combined with abundant desert sunshine create some of the highest ozone levels in New Mexico. Likewise, plentiful sunshine mixed with concentrated vehicle emissions in the Albuquerque metro area contribute to high ozone in the Sandoval and Valencia counties. By and large, Doña Ana County's high ozone levels are influenced by emissions from the large metropolitan area of El Paso, Texas and Juárez, Mexico.

Ozone Monitoring & Trends

The Air Quality Bureau (AQB) operates and maintains fourteen (14) continuous ozone monitors across the state. Except for a small portion of Doña Ana County near the City of Sunland Park, all of New Mexico is currently classified as "attainment" for the 2015 8-hour ozone NAAQS. The Sunland Park area's ozone levels are largely influenced by sources and emissions from outside of New Mexico.

Although the health-based ozone standard is set at .070 ppm, New Mexico law [74-2-5.3 NMSA 1978] requires that NMED develop plans to reduce ozone once monitored design values (DVs) in an area that exceed 95% of the standard (i.e., 0.067 ppm). In Table 1, 2018-2020 Design Value data indicate ozone levels at or above 95% of the ozone NAAQS at several New Mexico air quality monitors in eight counties.

County	Monitoring Location	2018-2020 Design Value
Doña Ana	La Union	70 ppb
	Chaparral	72 ppb
	Desert View	78 ppb
	Santa Teresa	74 ppb
	Solano	70 ppb
Eddy	Carlsbad	78 ppb
Lea	Hobbs	68 ppb
Rio Arriba	Coyote Ranger Station	65 ppb
Sandoval	Bernalillo	70 ppb
San Juan	Bloomfield	66 ppb
	Navajo Lake	68 ppb
	Substation	69 ppb
Santa Fe	Santa Fe	68 ppb
Valencia	Los Lunas	69 ppb

Table 1: 2018-2020 Design Values for Monitoring Locations in New Mexico

As shown in Figure 2, DVs for Doña Ana County have consistently exceeded the 2015 NAAQS standards, and have been continuing to rise since 2016-2018.

Eddy and San Juan counties' DVs remained constant from 2010-2012 through 2012-2014, dropped from 2013-2015 through 2014-2016, rose modestly from 2015-2017, then increased sharply from 2016-2018 through 2017-2019. San Juan has managed to remain just under the 2015 NAAQS standards in 2018-2020, but Eddy has shown a dramatic increase in ozone levels with a peak of 79 ppb in 2017-2019.

Sandoval County and Lea County have shown steady increases in ozone DVs between 2010-2012 and 2018-2020, rising from 61 to 70 ppb and 61 to 68 ppb, respectively. Valencia county has been steadily rising since 2014-2016.

The monitoring site at Rio Arriba first reported in 2014-2016 with an ozone DV of 64 ppb and rose to reach a peak of 70 ppb in 2017-2019, then decreased to 65 ppb for 2018-2020.

Between 2013-2015 and 2015-2017, all counties except Dona Ana showed a decrease in ozone DVs beginning to rise. Rio Arriba, Eddy, and Lea all had decreases in DV in 2018-2020, with the rest of the counties still rising.

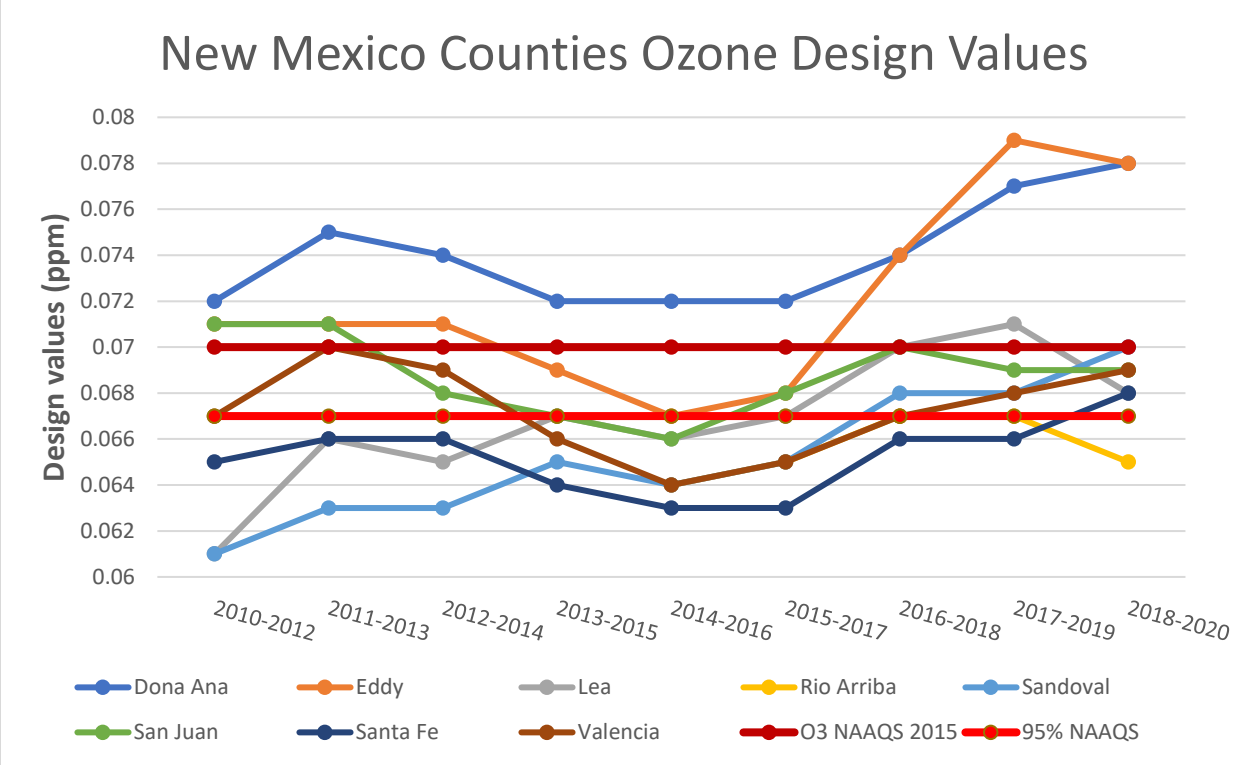


Figure 2: Design values for New Mexico counties included in the Advance Program, 10-year trends

Key Sources of Ozone and Precursor Pollutants

In addition to historical design value trends from 2010 through 2020, the 2017 NEI data was used to identify the major source categories. The National Emissions Inventory (NEI) is a comprehensive and detailed estimate of air criteria pollutant emissions, precursors, and hazardous air pollutants from air emissions sources.[3] Air pollution sources are separated into main source categories – point, nonpoint, on-road, and nonroad.

The point source category contains larger sources that are located at fixed, stationary locations. It includes large and certain smaller industrial facilities, (e.g., electric power plants, airports, non-industrial, and

[3] From *National Emissions Inventory*, Environmental Protection Agency, https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei

commercial facilities). This category also includes a small number of portable sources, such as some asphalt or rock crushing operations, aircraft engine emissions (occurring during landing and takeoff operations), airport ground support and power unit equipment, and locomotive emissions at rail yards.[4]

Nonpoint sources include sources that individually are too small in magnitude to report as point sources. Examples include residential heating, commercial combustion, asphalt paving, and commercial and consumer solvent use. Non-railyard locomotive emissions, commercial marine vessel emissions (both underway and port emissions), dry cleaners, gas stations, and livestock facilities are also included as nonpoint sources.[5]

On-road sources are vehicles that use gasoline, diesel, and other fuels. These sources include light-duty and heavy-duty vehicles from operation on roads, highway ramps, and during idling.[6] Nonroad sources consist of off-road mobile sources that use gasoline, diesel, and other fuels. Source types in this category include construction equipment, lawn and garden equipment, locomotives, and commercial marine vessels.[7]

General NO_X and VOC Emission Trends

The National Emissions Inventory provides data on criteria pollutants to better understand current emissions in different areas. Several monitors are placed throughout New Mexico which collect and report data spanning multiple years. Table 2 shows total emissions in tons of NO_X and VOCs reported in the 2017 NEI in the counties that are included in the Ozone Advance Program. Both NO_X and VOCs are precursors of ozone, meaning they interact with other compounds in the atmosphere to create ozone.

	Dona Ana	Chaves	Eddy	Lea	Rio Arriba	Santa Fe	San Juan	Sandoval	Valencia
NOx	6,503	X,xxx	4,418	7,493	1,512	3,999	23,135	2,556	1,656
VOC	3,508	X,xxx	6,380	1,779	1,744	2,047	5,599	1,475	6,289

Table 2: 2017 NEI NOx and VOC Emissions in tons for New Mexico Ozone Advance Counties

NOx Emissions

Overall, San Juan County has the highest levels of estimated NO_X emissions at 23,135 tons. Doña Ana and Lea counties' NO_X emission estimates are 6,503 tons and 7,493 tons, respectively. NO_X emissions for Eddy, Rio Arriba, Santa Fe, Sandoval, and Valencia counties are estimated below 5,000 tons for each county.

Eddy, Valencia, and San Juan counties have the highest and nearly equal estimated levels of VOC emissions at 6,380; 6,289; and 5,600 tons; respectively. Likewise, Lea, Rio Arriba and Sandoval counties had nearly equal but much lower estimated levels of VOC emissions at 1,779; 1,745; and 1,475 tons, respectively. Doña Ana County's estimated VOC emissions were 3,508 tons, with Santa Fe County at approximately 2,047 tons.

[4] Ibid.
[5] Ibid.
[6] Ibid.
[7] Ibid.

NMED Exhibit 4 - 0007

According to 2017 NEI data shown in Figure 3, the on-road sector accounts for 61% (Rio Arriba) to as much as 96% (Santa Fe) of estimated NO_X emissions in Doña Ana, Rio Arriba, Santa Fe, Sandoval, and Valencia counties. The percentage of on-road NO_X emissions in Eddy, Lea, and San Juan County are considerably lower at 28%, 20%, and 9%, respectively.

Point sources in San Juan account for 90% estimated NO_X emissions in the county, this is 32% of all NO_X emissions in the counties that are a part of the Ozone Advance plan. Lea County point source emissions account for 76% of NO_x emissions in the county. Percentages for point source estimated NO_X emissions for Eddy and Rio Arriba counties are significantly lower at 26% and 21%, respectively. Doña Ana and Valencia have low estimated NO_X emissions at 15% and 11%, respectively, of the total NO_X emissions for those counties. Santa Fe County point source emissions only account for 1.5% of NO_x and Sandoval County's point source emissions are negligible at <1%.

Of all nine counties, Eddy County's Nonpoint sources are the greatest at 45% of estimated NO_X emissions. Rio Arriba County's nonpoint source emissions account for 13% of NO_X emissions. Santa Fe, Sandoval, Valencia, Doña Ana, Lea, and San Juan counties have 5% or less of nonpoint NO_X emissions.

Non-road sources account for less than 10% of total estimated NO_X emissions for Doña Ana, Eddy, Lea, Rio Ariba, San Juan, Santa Fe, and Valencia counties. Sandoval is the only county with non-road estimated NO_X emissions slightly higher at 14%.

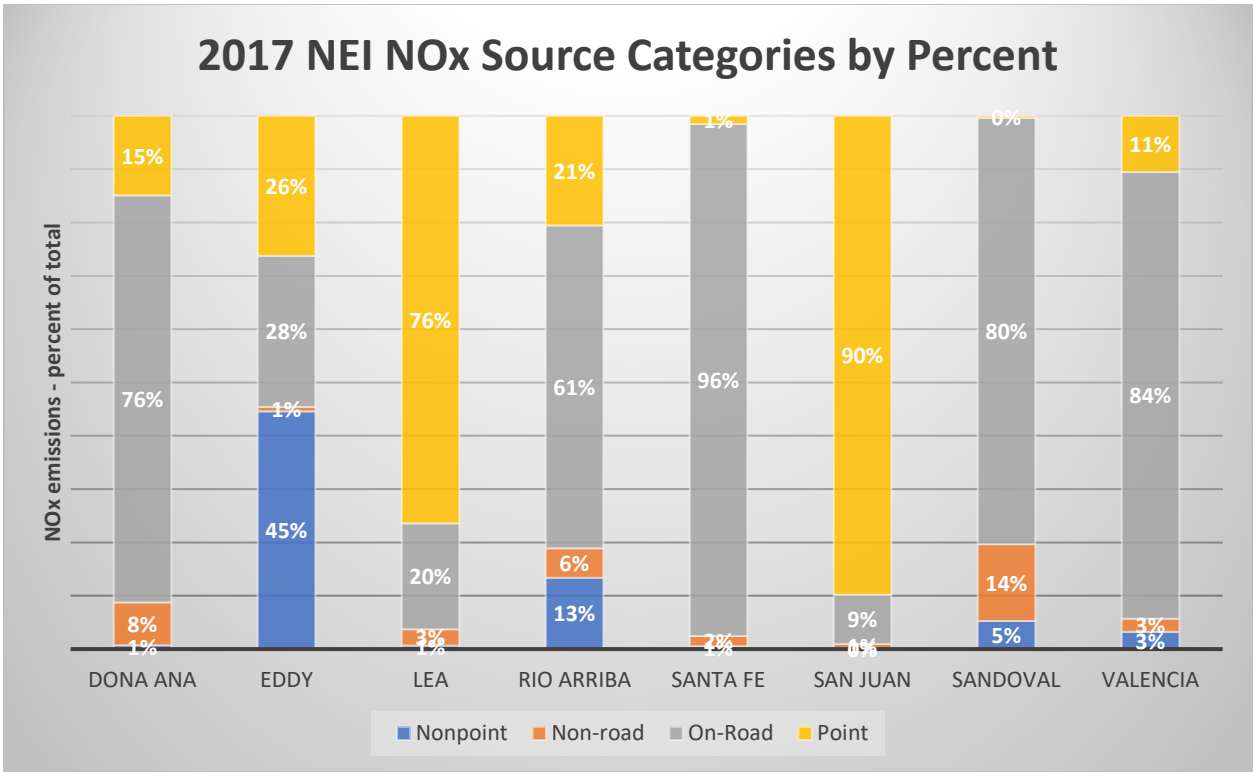


Figure 3: 2017NEI NOx Source Categories for Counties within 95% of the Ozone Standard.

VOC Emissions

According to 2017 NEI data (Figure 4), on-road source emissions in Santa Fe, Sandoval, and Doña Ana counties are 88%, 83%, and 64%, respectively, of the total estimated VOC emissions for these counties. Lea, Rio Arriba, & San Juan counties have moderate percentages of VOC emissions, between 21% and 38% from the on-road source sector. Eddy and Valencia counties have relatively low on-road VOC emissions at 9% and 12%, respectively.

Valencia and Eddy counties have the highest percentage of nonpoint VOC emissions at 87% and 78%, respectively. San Juan County has a moderately high percentage of nonpoint VOC emissions at 44%. Lea, Rio Arriba, and Doña Ana counties have relatively low percentages of nonpoint VOC emissions between 18% and 29%. Santa Fe and Sandoval Counties have a low percentage of nonpoint VOC emissions at 5% and 8% respectively.

Rio Arriba, Lea, and San Juan counties have moderately high percentages of point source VOC emissions at 43%, 42% and 33%, respectively. Eddy, Doña Ana, & Sandoval counties have point source VOC emissions percentages of 10% and less. Santa Fe County has the second lowest point source VOC emissions with just 1% and Valencia County's point source emissions are negligible at <1%. All seven counties have relatively low percentages of non-road VOC emissions of 11% or less.

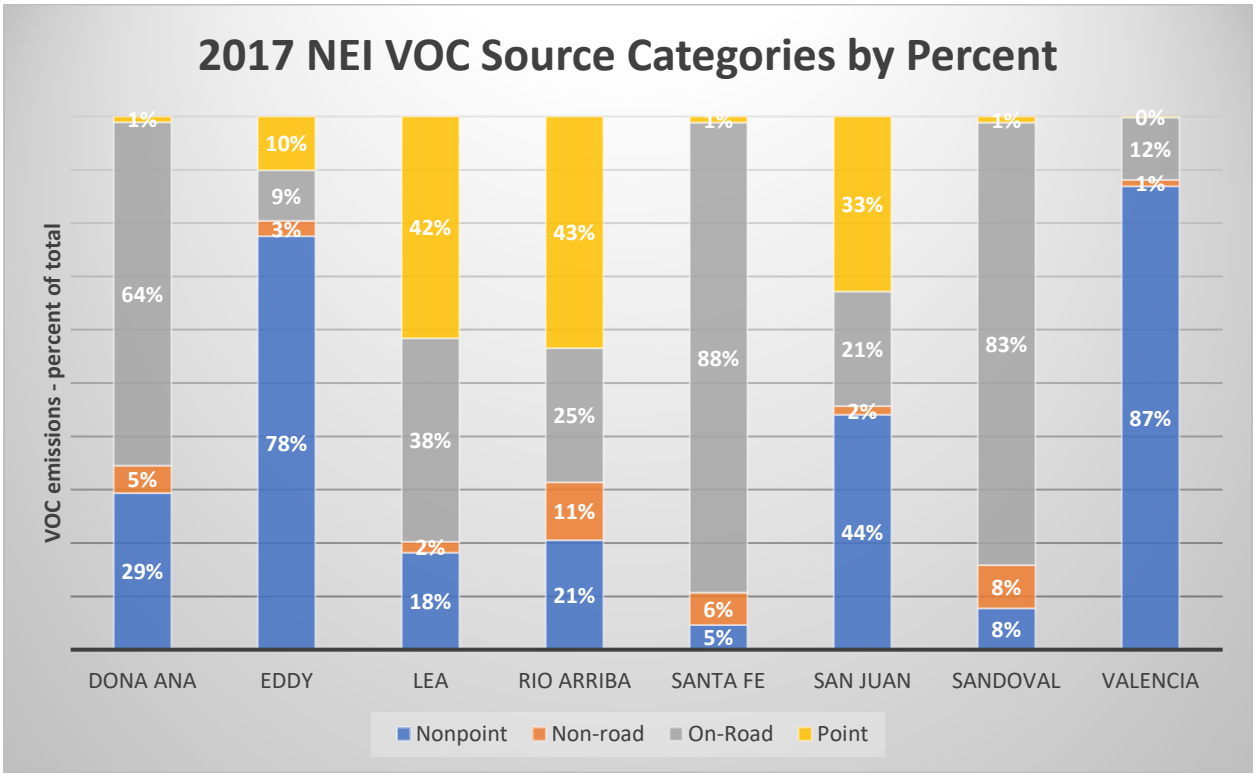


Figure 4: 2017 NEI VOC Source Categories for Ozone Advance Counties

Technical Analyses and Modeling

There are four interrelated but distinct conceptual models of ozone formation within New Mexico's airsheds: Albuquerque and surrounding areas, southcentral New Mexico, southeastern New Mexico, and northwestern New Mexico. They share the attribute that ozone transport from outside of New Mexico and/or the continental U.S. dominates ozone concentrations on all days. Days with the highest local ozone

formation are typically hot summer days with slow winds and without an excessive amount of precipitation (summer monsoon).[8] To study how ozone forms in the state, NMED has participated in photochemical modeling studies over the past twenty years. Most recently, photochemical modeling was completed in May of 2021 for New Mexico's draft ozone rule with a focus on the counties included in this path forward.

Photochemical Modeling for New Mexico

The modeling study for the draft ozone rule leverages the 2014 Photochemical Grid Model (PGM) modeling platform developed by the Western Regional Air Partnership (WRAP) in the Western Air Quality Study (WAQS). It enhances the PMG by adding a 4-km grid resolution modeling domain over New Mexico and surrounding areas, especially the oil and gas production regions in the Permian and San Juan Basins. The PGM modeling consists of 2014 base year modeling and model performance evaluation as well as 2028 future year modeling. The results of the 2028 future year modeling, source apportionment and control measure evaluation will assist the NMED in ozone air quality planning and rule development for the state.[9]

Preliminary conclusions indicate the draft ozone rule would reduce projected 2028 ozone DVs across New Mexico when compared to 2012-2016 DVs (Table 3). While the DVs from 2012-2016 show most sites to be within attainment of the NAAQS standards and the 95% threshold set for Ozone Advance, it should be noted that all sites have shown increases in Ozone levels in recent years (Table 1). The largest DV reductions by site are projected to be at the La Union monitoring site in Dona Ana County (6.3 ppb) and the Bernalillo site in Sandoval County (5.6 ppb).

The photochemical modeling shows a total of 60.3 ppb of ozone reduced in the Ozone Advance counties as a result of the Proposed Ozone Rule. Tables 3-5 show the predicted changes in DVs at 15 monitoring sites in the Ozone Advance counties in New Mexico.

	Site	2012-2016 DVC (ppb)	2028 DVF (ppb)	Difference
Rio Arriba	Coyote Ranger District	64	60.8	-3.2
Sandoval	Bernalillo	64	58.4	-5.6
San Juan	Bloomfield	64.3	61	-3.3
	Navajo Lake	67	64.8	-2.2
	Substation	63.7	60.8	-2.9
Santa Fe	Santa Fe Airport	64.3	60.6	-3.7
Dona Ana	La Union	66.3	60	-6.3
	Sunland Park City Yard	67	61.9	-5.1
	Chaparral	67	62.3	-4.7
	Desert View	72	67	-5.0
	Santa Teresa	71.3	66.1	-5.2
	Solano	65	60.3	-4.7
Eddy	Carlsbad	69	66.7	-2.3
Lea	Hobbs Jefferson	66	64	-2.0
Valencia	Los Lunas	66.3	62.2	-4.1

Table 3: Differences in Design Values in ppb by Site in Ozone Advance Counties throughout New Mexico

[8] New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Modeling Protocol, May 2020, Ramboll, https://www.wrapair2.org/pdf/NM_OAI_Modeling_Protocol_v5.pdf

[9] Ibid.

County	Site Difference Average (ppb)
San Juan	-2.8
Dona Ana	-5.2

Table 4: Average ozone Design Value differences in counties with multiple monitors.

County	Total Ozone Reduced (ppb)
Rio Arriba	-3.2
Sandoval	-5.6
San Juan	-8.4
Santa Fe	-3.7
Dona Ana	-3.1
Eddy	-2.3
Lea	-2.0
Valencia	-4.1

Table 5: Total projected reductions in ozone as a result of the proposed rule.

Path Forward – Planning Measures and Emission Reduction Strategies

Ozone Attainment Initiative and Ozone Precursor Rulemaking

To address the high observed ozone concentrations in New Mexico, the NMED has embarked on an Ozone Attainment Initiative ("OAI")[10] to protect the ozone attainment status of the state and ensure health and welfare of the residents of the state for future generations.[11] In total, the Initiative's planning and outreach efforts will include the following nine counties: Chavez, Doña Ana, Eddy, Lea, Rio Arriba, San Juan, Santa Fe, Sandoval and Valencia. This Initiative is undertaken pursuant to the Air Quality Control Act at NMSA 1978, Section 74-2-5(C), which states:

> If the environmental improvement board ... determines that emissions from sources within [its] jurisdiction cause or contribute to ozone concentrations in excess of ninety-five percent of a national ambient air quality standard for ozone…[the] board shall adopt a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds to provide for attainment and maintenance of the standard.

The OAI is a multi-year planning effort, beginning in the summer of 2018 and continuing indefinitely, as necessary. Three phases of implementation include: (1) an effort to educate the public and gather initial information and ideas; (2) development of appropriate rules and other programs based on scientific analysis and public input; and (3) development and implementation of the OAI plan, including rules to control sources contributing significantly to high ozone levels. NMED intends to use this Ozone Advance Path Forward document as the OAI plan required by New Mexico's Air Quality Control Act.

Ozone Precursor Rule – 20.2.50 NMAC, Oil and Gas Sector

[10] From *Ozone Attainment Initiative*, NMED, https://www.env.nm.gov/air-quality/o3-initiative/

[11] New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Modeling Protocol, May 2020,Ramboll, https://www.wrapair2.org/pdf/NM_OAI_Modeling_Protocol_v5.pdf

Beyond the statutory authority provided to NMED by the Air Quality Control Act, Governor Michelle Lujan Grisham issued Executive Order ("E.O.") 2019-003, which directs NMED and the New Mexico Energy, Minerals, and Natural Resources Department ("EMNRD") to "jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources". EMNRD adopted rules effective at the beginning of 2021 that prohibits venting and limits flaring at oil and gas well sites to minimize methane emissions.

Under the statutory authority of the OAI and E.O. 2019-003, the Department has developed its first rule to reduce emissions of ozone precursors. Regulations developed under the OAI to reduce emissions of ozone precursor pollutants will have the co-benefit of reducing methane emissions because methane is released along with volatile organic compounds in oil and gas operations. Thus, the Department worked in close coordination with EMNRD in developing 20.2.50 NMAC, and the agencies endeavored to align their respective regulatory regimes as much as possible to avoid duplicative or conflicting requirements.

Beginning in the summer of 2019, the Department began an extensive stakeholder and public outreach process for its OAI and the NMED/EMNRD joint Methane Strategy. In June through August of 2019, NMED and EMNRD held numerous meetings throughout the State to provide information regarding the need for the regulatory initiatives and the relevant authorities for the regulatory actions; to hear input from stakeholders and members of the public; and to answer questions regarding the rulemaking process.

The agencies also convened a Methane Advisory Panel ("MAP"), consisting of technical stakeholders focusing on processes and equipment associated with oil and gas exploration, production, gathering, and processing. The MAP was comprised of 27 members with expertise in various parts of the oil and gas industry and included local and national environmental nongovernmental organizations as well as major and independent industry representatives from the upstream and midstream sectors. Additional expertise was provided by representatives from Los Alamos National Laboratory, Colorado State University, and the New Mexico Institute of Mining and Technology. The MAP met every other week over a four-month period and covered technical topics related to controlling VOC and methane emissions from equipment and operations employed in the oil and natural gas sector. Draft topic reports and all meeting presentations from the MAP meetings were posted online on both agencies' websites. In December of 2019, the MAP released a technical report for public review and input, and the agencies accepted comments on the report through February 20, 2020.

On July 20, 2020, NMED released an early stakeholder engagement draft of its ozone precursor regulation for the purpose of soliciting public and stakeholder input. In August of 2020, the Department met with stakeholder groups and held a public listening session during which participants were encouraged to provide both verbal and written feedback. The Department accepted written comments on the preliminary draft through September 20, 2020. A total of 524 written comments were received during the two-month comment period. From September 2020 through May 2021, the Department reviewed the input received from stakeholders and the public and made substantial revisions to the regulation based on that input.

The proposed draft regulation is the result of this two-year process of extensive public and stakeholder outreach and engagement, all of which is in addition to the public hearing process provided for by the Board's rulemaking procedures at 20.1.1 NMAC. the Department will continue to work diligently beyond the requirements of those procedures to communicate and work with stakeholders and the public regarding the proposed regulation and the hearing process to ensure that everyone who has an interest in the rules can participate in the rulemaking process to the fullest extent possible. NMED's proposed rule

will be brought before the Environmental Improvement Board ("Board") for adoption at a public hearing scheduled to begin on September 20, 2021.

Low Emission/Zero Emission Vehicle Standard

In 2019, Gov. Lujan Grisham announced New Mexico will adopt clean car standards that are more stringent than the federal standards. Pollution from transportation accounts for a large portion of New Mexico's greenhouse gas emissions and contributes heavily to the area's growing ozone problem. New Mexico's rule will adopt California's Low-Emission Vehicle criteria pollutant and greenhouse gas emission regulations and Zero-Emission Vehicle regulations under Section 177 of the Clean Air Act (42 U.S.C. §7507). The timeline for New Mexico to adopt the CA standards is in development, but the standards are likely to have an impact in areas with high levels of on-road emission sources.

DERA Program

In 2005, the U.S. Congress passed the Diesel Emission Reduction Act (DERA) as an amendment to the Energy Policy Act. DERA was designed to reduce diesel emissions from existing diesel fleets that did not meet the recently adopted federal emission standards. The goal of the New Mexico Clean Diesel Program is to reduce the amount of air pollution created by diesel-fueled heavy-duty trucks and buses to which the residents of New Mexico are exposed.[12] Diesel-powered vehicles and equipment account for nearly half of all NO_x and more than two-thirds of all PM emissions from US transportation sources.[13] Since 2008, NMED has administered grant funds for the qualifying diesel emissions reduction projects in San Juan, McKinley, Luna, Santa Fe, Taos, and Bernalillo counties:

- School bus retrofits in Bloomfield, Central Consolidated, Farmington, and Gallup/McKinley County School District;
- Replacement of diesel vehicles with natural gas vehicles for the cities of Deming and Santa Fe, Taos County, and Albuquerque Public Schools; and
- Dock outlets for trailer refrigeration units, aerodynamic fairings, and low rolling resistance tires for New Mexico Association Food Banks.

VW Settlement

In 2015, Volkswagen admitted to purposely employing defeat devices on emissions controls for NOx on some of their Volkswagen, Audi, and Porsche diesel-fueled vehicles. In 2017, the U.S. District Court for the Northern District of California finalized Consent Decrees between Volkswagen, the United States, and the State of California, adopting revisions made by the Trustee. New Mexico was eligible to receive over $17,900,000 to be used for NO_x emission reduction projects.[14]

[12] From *Diesel Emissions Reduction Act*, NMED, https://www.env.nm.gov/air-quality/diesel/

[13] From *Smog, Soot, and Other Air Pollution from Transportation*, Environmental Protection Agency, https://www.epa.gov/transportation-air-pollution-and-climate-change/smog-soot-and-local-air-pollution

[14] From *Volkswagen Settlement Information Fact Sheet*, NMED, https://www.env.nm.gov/wp-content/uploads/sites/26/2017/03/VW_Settlement_InBrief_November2017-1.pdf

The NMED has had two rounds of funding for the Volkswagen Settlement Allocation. NMED approved funding for seven projects in the first funding cycle and 43 projects in the second funding cycle of New Mexico's Volkswagen Settlement Allocation.

First funding cycle projects include new school buses in the Gallup-McKinley and Albuquerque School Districts; a new Public Works Vehicle for San Juan County; electric ground support equipment and associated infrastructure for Southwest Airlines and the Albuquerque International Sunport; as well as compressed natural gas-powered refuse vehicles; and replacing diesel delivery trucks for Sysco Leasing. In total, 123 vehicles in New Mexico were replaced or repowered, reducing NO_x emissions from both on-road and off-road diesel-fueled vehicles and equipment by roughly 160 tons in urban, rural, and Native communities in New Mexico.

In 2019, the Beneficiary Mitigation Plan (BMP) was revised and directed the remaining unallocated funds for future funding cycles to be used for the replacement of diesel-fueled vehicles with electric vehicles (EV), alternate-fueled vehicles, and light-duty zero emission vehicle (LDZEV) supply equipment. These projects will reduce emissions of NO_X by more than 40 tons in areas of New Mexico where residents bear a disproportionate share of NO_X pollution and in areas that are nearing the 2015 National Ambient Air Quality Standard for ground-level ozone.

The State remains committed to allocating the remaining 15% of the total funding (approximately $2.7 million) towards LDZEV infrastructure and has added a goal to focus efforts on a complete statewide electric vehicle charging network.[15]

Provisions for Public and Stakeholder Involvement

The AQB will conduct presentations for the industry, local governments, environmental groups, and school districts to garner support and participation in Ozone Advance. Also, the AQB will hold outreach and education events for businesses and private citizens to involve them in developing a "path forward" program for implementation. This will be done through a variety of projects including the existing partnerships and air quality improvement groups that NMED participates in and the creation of the Permian Basin Air Quality Task Force. NMED will provide additional opportunities to gather stakeholder input, hold ozone community workshops and develop voluntary ozone alert programs. Periodic update meetings will be held to keep stakeholders informed of progress and study results (e.g. rulemaking and modeling results) for all ozone advance path forward initiatives. This will allow for continuous feedback and participation as voluntary control measures, rules and programs are developed.

Joint Advisory Committee

On May 7, 1996, the United States and Mexico included Appendix 1 to Annex V to the "La Paz Agreement" that defined the bi-national Paso del Norte Air Basin and created the committee The Joint Advisory Committee (JAC) is a bi-national group charged with the development and recommendation of air quality improvement initiatives under the La Paz Agreement and EPA's Border Program (i.e., Border 2025). It is comprised of a mixture of federal, state, and local government officials along with private citizens, university officials, and non-governmental organizations from the United States and Mexico. The JAC is governed by operating procedures contained in their by-laws and meets triennially at a rotating location in southern Dona Ana County, New Mexico, El Paso, Texas and Cd. Juárez, Mexico. The JAC's priorities are

[15] From *Volkswagen Settlement*, NMED, https://www.env.nm.gov/vw-settlement/

NMED Exhibit 4 - 0014

developed from the ground up, building upon local stakeholder input and concerns. All JAC meetings are open to the public and time is set aside at the beginning and end of each meeting for public comments.

Four Corners Air Quality Group

The original purpose of the 4CAQTF was to bring together a diverse group of interested parties to learn about and discuss air quality issues in the Four Corners area. Increased development in the Four Corners area including power plants, oil and gas production, and population growth were contributing to air quality concerns. Ozone levels in the region were close to exceeding the health-based national air quality standards for outdoor air. Task Force members developed a broad list of options for improving air quality in the area to aid the regulatory agencies in managing air quality impacts. These options were included in a report that was finalized in November 2007.[16]

Initial work of the 4CAQTF resulted in the implementation of one "interim" recommendation: the Bureau of Land Management required new and replacement internal combustion gas field engines to comply with more stringent emission standards in New Mexico and Colorado. These requirements apply to oil and gas development within the Bureau of Land Management's jurisdiction.[17] As a result of this work, the 4CAQTF continues to operate as the Four Corners Air Quality Group.

The Four Corners Air Quality Group (4CAQG) is a forum for individuals interested in air quality to meet, learn about current conditions, review progress on mitigation of air quality impacts, and generally contribute to clean air in the Four Corners Area. The 4CAQG includes NMED, Colorado Department of Public Health and Environment, US EPA, US Department of the Interior's National Park Service and Bureau of Land Management, US Department of Agriculture's Forest Service, the Southern Ute Indian Tribe, and the Navajo Nation. The Group meets at least once per year and more often if circumstances warrant it.

Permian Basin Air Quality Task Force

The NMED plans to create the Permian Basin Air Quality Task Force to bring together a diverse group of interested parties to learn about and discuss air quality issues in the Permian Basin. Increased oil and gas well development and population growth in the Permian Basin are contributing to air quality concerns. Ozone levels in the region are close to exceeding the health-based national air quality standards.

The first step will be to engage the Texas Commission on Environmental Quality (TCEQ) and the U.S. EPA to join NMED as a founding task force partner. Once this trilateral commitment is established, we can engage and invite other stakeholders in the basin to become task force partners. Potential stakeholders include the oil and gas industry, local governments, environmental groups, and concerned citizens.

The Group will meet annually, biannually, and more often when necessary to discuss rule planning and initiatives. The Task Force members will be encouraged to develop a broad list of options that will aid the regulatory agencies in managing air quality impacts and improving air quality in the basin. These options will be included in a final report.

[16] From *Four Corners Air Quality Group*, NMED, https://www.env.nm.gov/air-quality/fcaqg/
[17] Four Corners Air Quality Task Force Report of Mitigation Options, November 2007, https://www.env.nm.gov/wp-content/uploads/sites/2/2016/11/4CAQTF_Report_FINAL.pdf

Gather Stakeholder Input

Understanding the concerns of impacted communities and stakeholders is an important part of creating an effective plan. As part of this initiative and in addition to the air quality groups listed above, NMED will hold meetings with various groups of stakeholders including environmental groups, tribes, the public, the regulated community, and local governments. The goal of these meetings will be to gather information about stakeholder concerns regarding ozone in their respective region and identify popular strategies that stakeholders are willing to participate in. NMED may also utilize focus groups comprised of various stakeholders to gather feedback on possible emission reduction activities. All these concerns will be taken into consideration as we assess our Ozone Advance plan in the future.

NMED understands that some people may not have the time or means to attend these meetings. To this end, NMED will also provide an opportunity for these groups and individuals to submit concerns and comments electronically, over the phone, or by mail. NMED may also provide surveys and other useful materials for stakeholders to complete.

Ozone Community Workshops and Voluntary Ozone Alert Programs

Community involvement in the Ozone Advance program will include workshops and voluntary ozone alert programs. The workshops will bring together community members and various stakeholders to learn about ozone and its impacts to their health, community, and the environment. This will also include training on how to minimize these impacts, particularly health impacts, during high ozone events and what voluntary actions individuals can do to minimize their ozone contribution.

If communities choose to, they can opt to creating a Voluntary Ozone Alert Program, crafted to the needs of their community. This program can include a variety of activities and projects such as, community-based air monitoring, flag programs, alert programs, and air quality training. These programs will also raise awareness for issues surrounding ozone in these communities.

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF ELIZABETH BISBEY-KUEHN

My name is Elizabeth Bisbey-Kuehn and I am the Bureau Chief of the Air Quality Bureau ("Bureau") of the New Mexico Environment Department ("NMED" or "Department"). I am presenting this written testimony on behalf of the Department in this proceeding on the Department's proposed new air quality regulation at 20.2.50 NMAC ("Part 50"). This part of my direct testimony will address public and stakeholder engagement in development of Part 50. I will also be presenting testimony on other topics in this rulemaking in separate pieces of pre-filed testimony.

I. QUALIFICATIONS

I have been an employee of the Bureau for over seventeen years, working as a staff member for seven years, staff manager for seven years, and in my current position as Bureau Chief for over three years. As a staff member and staff manager, I oversaw several complex, high-profile projects for the Department, including serving as the Department's technical expert for the Best Available Retrofit Technology analysis for the San Juan Generation Station. I developed multiple general construction permits for the oil and gas industry, led bi-monthly technical meetings for the State's Associated Contractors, drafted technical guidance and policy documents, and represented the Department in multiple public meetings and public hearings.

As the Air Quality Bureau Chief, I am charged with overseeing the air program and ensuring that the program is administered in accordance with the Department's enabling statutes

and the Board's regulations, and with the requirements of the federal Clean Air Act ("CAA") and regulations promulgated by the U.S. Environmental Protection Agency ("EPA") pursuant to the CAA. I manage the four Section Chiefs who oversee the four Sections of the Bureau. I direct the overall management of the Bureau, including the Bureau's resources; staff who enforce the state and federal air quality standards; air quality related planning and policy, operational, permitting, and compliance and enforcement services; financial oversight of the bureau's federal grant and state matching funds; and support services for the Bureau.

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 6.

II. THE NMED AND EMNRD METHANE STRATEGY

In Executive Order 2019-03 ("EO 2019-03), Governor Michelle Lujan Grisham directed the New Mexico Environment Department ("NMED") and the Energy, Minerals and Natural Resources Department ("EMNRD") to "jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources and enact such rules as soon as practicable." *See* NMED Exhibit 7. At the time EO 2019-03 was issued, the Board did not have authority under the AQCA to pass regulations for methane that were more stringent than federal regulations, but it did have authority to pass more stringent regulations for VOCs for purposes of reducing ambient ozone concentrations. Because the ozone precursor VOC is emitted along with methane in oil and gas operations, requirements that reduce VOC emissions necessarily reduce methane emissions. Thus, the Boards regulatory authority for ozone precursors formed the basis for NMED's regulatory strategy under to the Governor's directive in EO 2019-03.

Methane Strategy Public Outreach

NMED held public engagement sessions to provide an initial opportunity for the public to be heard and ask questions answered early in the rulemaking process. Figure 1 shows NMED's Methane Strategy public participation schedule.

January 2019	Gov. Lujan Grisham signs Executive Order 2019-03 committing New Mexico to essential climate change action	
NMED Public Participation		
August 6, 2020	Listening session on NMED/EMNRD draft rules	Presentation (NMED Exhibit 8)
May 19, 2020	Methane Advisory Panel public meeting	
March 19, 2020	Community Impacts Meeting	Following initial public outreach meetings in the summer of 2019 community members expressed a strong interest in holding a Community Impacts Meeting to discuss the health, cultural, and economic impacts of the oil and gas industry and future methane regulations.
	Webcast: Developing New Mexico's Oil and Natural Gas Methane Strategy: Community Impacts Presentation (NMED Exhibit 9)	
Public Stakeholder Meetings		
July 29, 2019	San Juan Community College IT Building, Room 7103, 4601 College Blvd., Farmington, NM 87402	These initial public engagement sessions were an opportunity for the public to be heard and have questions answered early in the rulemaking process.
July 30, 2019	University of New Mexico School of Law, Room 2401, 1117 Stanford Dr. NE, Albuquerque, NM 87106	
Aug 6, 2019 (open house)	Skeen-Whitlock Building, Weart Auditorium, 4021 National Parks Highway, Carlsbad, NM 88220	
Aug. 7, 2019	Walter Gerrells Performing Arts Center Annex, 4012 National Parks Highway, Carlsbad, NM 88220	
Aug. 12, 2019	Counselor Chapter House	
	Counselor, NM	

Figure 1. NMED's Methane Strategy public participation schedule

The Methane Advisory Panel

To move forward on the Governor's directives in a manner grounded in science, innovation, collaboration and compliance, NMED and EMNRD sought nominations for, and then convened, a technical Methane Advisory Panel ("MAP"). The purpose of the MAP was to bring together technical stakeholders to: (1) identify processes and equipment used in oil and gas production, gathering, and processing operations that are associated with release of methane gas; (2) to develop emission and waste-based standards for those processes and equipment; and (3) propose monitoring, recordkeeping and reporting structures. The MAP process yielded a technical background document identifying specific oil and natural gas equipment and processes for consideration in moving forward with an enforceable regulatory strategy.

The MAP was comprised of 27 individual members representing environmental organizations, the Nations, tribes and pueblos in New Mexico, and the oil and gas industry including small and large independent operators as well as the major, vertically-integrated companies. Industry representatives included companies with interests in the Permian and San Juan Basins that drill, develop, complete, and operate oil and natural gas wells and infrastructure. Additional technical expertise was provided by professionals from Los Alamos National Laboratory, Colorado State University and the New Mexico Institute of Mining and Technology.

The MAP met in series of four-hour meetings held every other week over a twelve-week period from August through November 2019. During these meetings, there were facilitated discussions focused on reducing methane waste and VOC emissions by equipment type and processes. There were ten topics covered during the MAP meetings:

- Section 1 - Pneumatic Controller/Pump
- Section 2 – Leak Detection and Repair

- Section 3 – Dehydration Units
- Section 4 – Compressors and Engines
- Section 5 – Infrastructure and Planning
- Section 6 – Venting and Flaring
- Section 7 – Workovers/Liquids Unloading
- Section 8 – Separators/Heaters/Storage Vessels
- Section 9 – Completions/Recompletions and Stimulations
- Section 10 – Cross-Cutting Path Forward Report

All technical documents were posted online throughout the process, along with the final draft technical report.

The MAP process culminated with a draft technical report, attached as NMED Exhibit 10, which provides an informational foundation on the technical side of the ways in which the oil and gas industry emits methane (and therefore VOCs), and what methods can curb methane emissions and prevent waste of this resource. The Draft MAP technical report was released for public comment December 19, 2019 through February 20, 2020, and approximately 42 comments were received.[1]

III. THE OZONE ATTAINMENT INITIATIVE

The Ozone Attainment Initiative ("OAI") is a state program developed by NMED for the purpose of reducing emissions of ozone precursor chemicals NOx and VOCs in areas of the State where ozone levels are within 95% of the 2015 8-hour ozone NAAQS. Through the OAI, NMED

[1] Comments for the Draft MAP technical report can be found at: https://www.env.nm.gov/new-mexico-methane-strategy/methane-advisory-panel.

has developed a plan, including voluntary measures and mandatory regulations, to reduce ozone precursors in areas with high ozone levels.[2]

In conjunction with NMED's Methane Strategy Public Participation, the Bureau hosted four public outreach events that focused on the development of the Ozone Attainment Initiative and associated rulemakings. These meetings were held at key locations throughout the state, including the Permian and San Juan Basins. The September 2019 Initial Public Outreach meeting presentation, attached as NMED Exhibit 11, provides a brief summary of ozone and its health effects, the OAI, and stakeholder involvement. Figure 2 provides an outline of the AQB's public outreach.

Spring 2018	Ozone Attainment Initiative (OAI) kickoff meeting (In house)
October 24, 2018	OAI poster presented at the annual Four Corners Air Quality Group Meeting
Ozone Attainment Initiative Public Outreach Meetings	
September 9, 2019	Farmington, NM
September 12, 2019	Santa Fe, NM
September 25, 2019	Las Cruces, NM
September 26, 2019	Carlsbad, NM
July 20, 2020	NMED/AQB releases draft rule for public comment. To accommodate the number commenters, the comment period was extended to September 16.
August 3rd, 4th, and 6th 2020	Listening session on NMED, EMNRD draft rules. NMED and EMNRD OCD hosted a series of joint public listening sessions where NGOs and industry were able to ask questions and provided comments on NMED's Draft 20.2.50 NMAC Oil and Gas Sector-Ozone Precursor Pollutants and EMNRD OCD's 19.15.27 Venting and Flaring of Natural Gas.
June 22, 2021	Hearing Notice Published in NM Register, Albuquerque Journal, Santa Fe New Mexican, Farmington Daily Times, Carlsbad Current Argus, and Hobbs Daily News Sun in English and Spanish. The hearing notice was sent to

[2] The OAI webpage is located at: https://www.env.nm.gov/air-quality/o3- initiative/

	the NM Sunshine Portal, Tribal contacts. A listserv announcement was also released.

Figure 2. OAI Public Outreach

IV PRE-PETITION DRAFT OF PART 50 AND PUBLIC COMMENT PERIOD

Proposed Part 50 is the first rulemaking under the OAI. The Department conducted extensive pre-petition outreach on the proposed rules, including a pre-petition draft rule, attached as NMED Exhibit 12, issued for stakeholder and public input. The pre-petition draft of Part 50 was released on July 20, 2020 for a 30-day informal comment period, which was extended to September 16, 2020. *See* Figure 2. The stakeholder and public comments received on the July 20, 2020 pre-petition draft are available on the Department's website.[3] During this comment period, NMED received comments from the general public, environmental organizations, industry, elected officials, local governments, tribal officials, and EPA. Based on the comments received on the July 20, 2020 draft, the Department made substantial revisions to the proposed rule that are reflected in the version included as part of the Department's Petition for Regulatory Change filed with the Board on May 6, 2021.

[3] https://www.env.nm.gov/air-quality/ozone-precursor-rule-hearing/

Liz Bisbey-Kuehn
Bureau Chief
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87507
505-476-4305

Education

Attended M.Sc. Program in Soil Science, 08/2003-12/2004
University of Kentucky, Lexington, KY

B.S. in Environmental Studies
University of Iowa, Iowa City, IA., conferred May 2002.

Employment Experience

08/2013 to 03/2018 - Bureau Chief, Air Quality Bureau, NMED
My responsibilities include providing leadership and supervision of the administrative, financial, compliance, permitting, operations, and planning sections of the Air Quality Bureau. I direct the overall management of resources, including staff who enforce the state and federal air quality standards; provide air quality related planning and policy, operational, permitting, and compliance and enforcement services to New Mexico employers; financial oversight of the Bureau's federal grant and state matching funds, and support services for the Bureau.

08/2013 to 03/2018 - Minor Source Section Manager, Air Quality Bureau, NMED
My responsibilities included management of the Minor Source Permitting Section and direct management of six (6) full time Environmental Scientists and Specialists. The Section reviews complex air quality permit applications for the most technically complex and diverse industrial facilities, including oil and gas, construction, manufacturing, agricultural, power generation, and chemical processing plants.

01/2013 to 08/2013 - Acting Technical Services Manager, Air Quality Bureau, NMED

05/2012 – 10/2012 - Acting Minor Source Section Manager, Air Quality Bureau, NMED

02/28/2005 to 08/2013 - Permit Specialist, Minor and Major Source Permit Section, Air Quality Bureau, NMED
My primary responsibilities involve performing technical analyses of air quality permit applications; drafting permits in accordance with federal and state regulations; accomplishing special projects in support of the section, mentoring new staff, and assisting the regulated community and concerned citizens.

08/2002-05/2003 and 08/2003-12/2004
Teaching and Research Assistant, University of Kentucky, Lexington, KY
Introduction to Soil Science, Agronomy Department

Teaching Assistant, University of Iowa, Iowa City, IA
Introduction to Earth Systems Science, Geography Department
Introduction to Environmental Science, Geoscience Department

Professional Development and Training Courses

Effective Permit Writing
Sources and Control of PM Emissions
Introduction to Hazardous Air Pollutants
Control of Gaseous Emissions
Advance PSD Permitting
Permit Practices and Procedures I and II
NSR Reform and Advanced PSD
Basic NSR/PSD
Environmental Negotiations

EXECUTIVE ORDER 2019-003

EXECUTIVE ORDER ON ADDRESSING CLIMATE CHANGE AND ENERGY WASTE PREVENTION

I. Background and Purpose

To further New Mexico's responsibility and opportunity to build a clean energy future for our people, limit adverse climate change impacts that harm our natural and cultural heritage, prevent the waste of New Mexico energy resources and reduce pollution that threatens human health, I hereby issue this Executive Order.

II. Climate Change

WHEREAS, climate change creates new risks and exacerbates existing vulnerabilities in communities across New Mexico and presents growing challenges for human health and safety, quality of life, and the rate of economic growth.

WHEREAS, in a special report authored by the United Nations and World Meteorological Organization Intergovernmental Panel on Climate Change ("IPCC"), it was found that the planet has as little as 12 years to take meaningful climate action in order to limit the increase in global average temperature to 1.5°C – the level necessary to forestall dramatic climatic changes that will further imperil our water supplies.

WHEREAS, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), perfluorocarbons, and sulfur hexafluoride are recognized as the six greenhouse gases contributing to climate change.

WHEREAS, in 2009, the U.S. Environmental Protection Agency ("EPA") found that these "six greenhouse gases taken in combination endanger both the public health and the public welfare of current and future generations."

WHEREAS, in May 2010, the National Research Council, the operating arm of the National Academy of Sciences, published an assessment which concluded that "climate change is occurring, is caused largely by human activities, and poses significant risks for - and in many cases is already affecting - a broad range of human and natural systems."

WHEREAS, carbon dioxide is emitted through the combustion of fossil fuels for electricity generation and for combustion-engine vehicles.

WHEREAS, the U.S. Energy Information Administration finds that the transportation sector is the largest anthropogenic source of carbon dioxide emissions in the United States.

WHEREAS, methane is a powerful greenhouse gas, 84 times more effective at trapping heat than carbon dioxide over a 20-year timeframe.

WHEREAS, the oil and gas industry is the largest industrial source of methane emissions.

WHEREAS, HFCs are potent greenhouse gases used in the refrigeration, air conditioning, and foam industries, for which alternatives are readily available and approved for use by the EPA.

WHEREAS, governments and global industries have expressed widespread support for a global transition to alternatives to HFCs, as agreed to in the 2016 Kigali Amendment to the Montreal Protocol.

WHEREAS, New Energy Conservation Code templates are developed by the International Code Council every three years. New Mexico adopted and is using the 2009 International Energy Conservation Code (IECC), which puts the state three full code cycles behind. As newer, safer, and more durable building materials, technologies, and techniques become more commonplace, they are voted on and incorporated into the model energy code.

WHEREAS, energy codes create safe, resilient, and habitable structures based on building science and physics principals for heat, air, and moisture transfer—all of which have real and significant impacts on human lives and health; they also can cut utility bills in buildings.

WHEREAS, low- and zero-emission vehicles can provide long-term public health, environmental, and climate benefits.

WHEREAS, federal rollbacks of climate protections, waste prevention, and clean air rules have made it imperative for New Mexico to act to protect our citizens and our economy from the damages of climate change impacts.

WHEREAS, emissions, venting, flaring, and leaks of natural gas by New Mexico's oil and gas industry results in the waste of an important source of domestic energy to the tune of an estimated $244 million per year.

WHEREAS, oil and gas production growth in the New Mexico Permian Basin resulted in an 18% increase in venting and flaring volumes during the first seven months of 2018 compared to 2017 according to official state statistics.

WHEREAS, efforts to reduce methane emissions throughout New Mexico will have a significant climate benefit as well as prevent the waste of energy resources.

WHEREAS, science, innovation, collaboration and compliance efforts can prevent waste, methane emissions and improve air quality while creating jobs for New Mexicans.

III. Directives

NOW, THEREFORE, by the authority vested in me as Governor by the Constitution and laws of the State of New Mexico, IT IS ORDERED:

1. The State of New Mexico will support the 2015 Paris Agreement Goals by joining the U.S. Climate Alliance. New Mexico's objective is to achieve a statewide reduction in greenhouse gas emissions of at least 45% by 2030 as compared to 2005 levels.

2. The Secretary (or designee) of each state agency shall serve on an interagency Climate Change Task Force which is hereby established. The Secretary (or designee) of the Energy, Minerals and Natural Resources Department ("EMNRD") and the Environment Department ("NMED") shall serve as the Co-Chairs, convening meetings, facilitating stakeholder participation, and providing strategic direction for achieving the above goals in developing a New Mexico Climate Strategy document.

3. All State Agencies shall evaluate the impacts of climate change on their programs and operations and integrate climate change mitigation and adaptation practices into their programs and operations. The agencies shall share these actions with the Climate Change Task Force for inclusion into the New Mexico Climate Strategy document.

4. EMNRD and NMED shall work with stakeholders on legislation to increase the New Mexico renewable portfolio standard ("RPS") and increase New Mexico's energy efficiency standards for electric utilities.

5. The Climate Change Task Force shall evaluate policies and regulatory strategies to achieve reductions in greenhouse gas pollution, consistent with the targets set out above, across all categories of emission sources. Such policies and regulatory strategies shall include, but not be limited to, the following:

    a. Adoption of a comprehensive market-based program that sets emission limits to reduce carbon dioxide, and other greenhouse gas pollution across New Mexico;
    b. Adoption of approaches to reduce greenhouse gas and criteria pollutant emissions from light-duty vehicles sold in state, including Low Emission Vehicle (LEV) emission standards and Zero Emission Vehicle (ZEV) performance standards;
    c. Adoption of building codes; and
    d. Collaboration with the Renewable Energy Transmission Authority (RETA) to identify transmission corridors needed to transport the state's renewable electricity to market.

6. EMNRD and NMED shall jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources and enact such rules as soon as practicable.

7. EMNRD and NMED shall coordinate as much as possible with the New Mexico State Land Office and federal bureaus and agencies that manage land and natural resources in New Mexico to help advance the priorities identified in this Executive Order.

8. The Climate Change Task Force will develop a *New Mexico Climate Strategy* document with initial recommendations and a status update, where applicable, to the Governor by September 15, 2019.

IV. Disclaimer

Nothing in this Executive Order is intended to create a private right of action to enforce any provision of this Order or to mandate the undertaking of any particular action pursuant to this Order; nor is this Order intended to diminish or expand any existing legal rights or remedies.

THIS ORDER supersedes any other previous orders, proclamations, or directives in conflict. This Executive Order shall take effect immediately and shall remain in effect until such time as it is rescinded by the Governor.

ATTEST:

Maggie Toulouse Oliver

MAGGIE TOULOUSE OLIVER
SECRETARY OF STATE



DONE AT THE EXECUTIVE OFFICE
THIS 29th DAY OF JANUARY, 2019

WITNESS MY HAND AND THE GREAT
SEAL OF THE STATE OF NEW MEXICO

Michelle Lujan Grisham

MICHELLE LUJAN GRISHAM
GOVERNOR

Informal Public Comment of New Mexico's Draft Oil and Natural Gas Methane Waste Rule

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

NEW MEXICO ENVIRONMENTAL DEPARTMENT

August 2020

NMED Exhibit 8 - 0001

Agenda

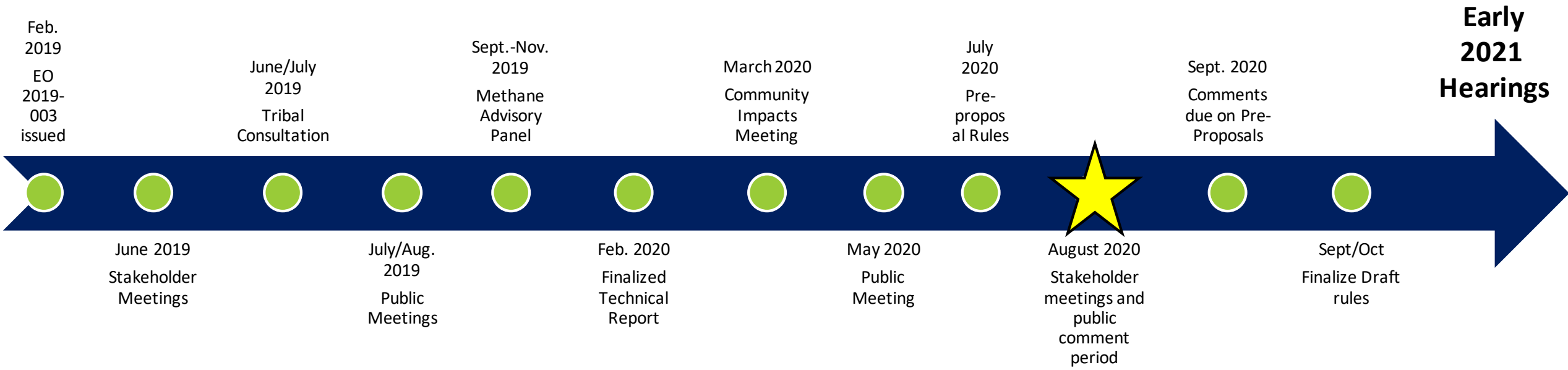
➢ **Introductions of NMED and EMNRD Teams**	**5 mins**
➢ **Strategy Timeline**	**5 mins**
➢ **Overview of the goal and methane strategy process**	**5 mins**
➢ **NMED rule overview**	**10 mins**
➢ **EMNRD rule overview**	**10 mins**
➢ **Statement and feedback period**	**85 mins**

NMED and EMNRD Teams Present Today

NMED – Air Quality Bureau	
Liz Bisbey-Kuehn	Bureau Chief
Kerwin Singleton	Planning Section Chief
Ted Schooley	Permit Section Chief
Lara Katz	Legal
Planning Section Staff	
ERG Representatives	

EMNRD Oil Conservation Division	
Tiffany Polak	Deputy Director
Gabe Wade	Deputy Director
Eric Ames	Legal
Brandon Powell	District 3 Supervisor
Insight Energy Representatives	

New Mexico's Methane Strategy Timeline



Overview & Process

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

NEW MEXICO ENVIRONMENTAL DEPARTMENT

NMED Exhibit 8 - 0005

Developing New Mexico's Methane Strategy



*"**EMNRD and NMED shall jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources and enact such rules as soon as practicable."***

- Governor Michelle Lujan Grisham

Developing the Rule



Science: Using the best available science to inform our decision-making in protecting public health, the environment and minimizing waste.



Innovation: Employing creative engineering and technological solutions to address the public health, environmental and waste challenges.



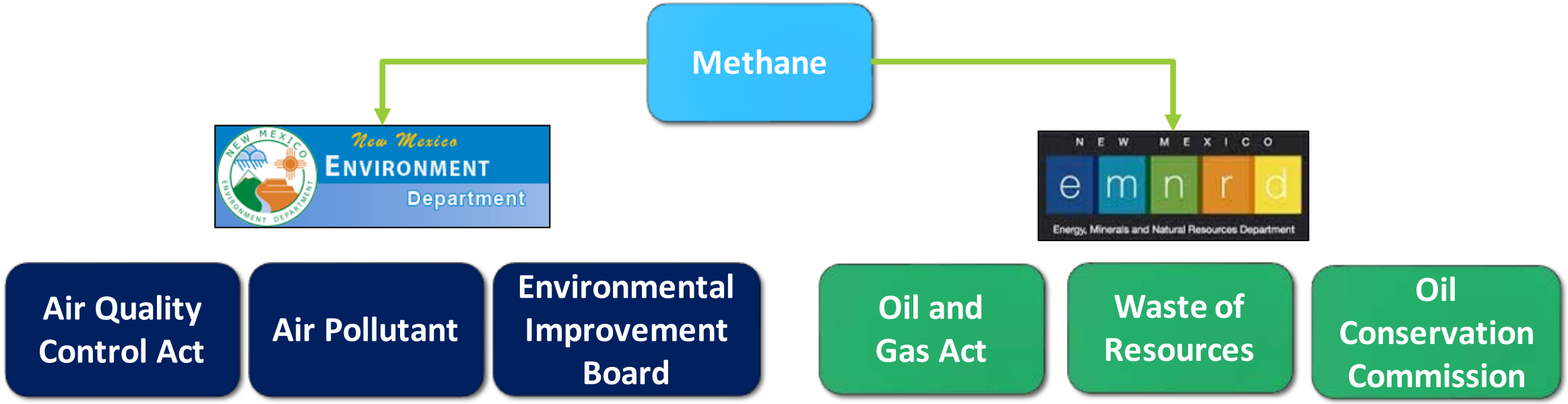
Collaboration: Engaging communities and interested stakeholders in our methane strategy decision-making.



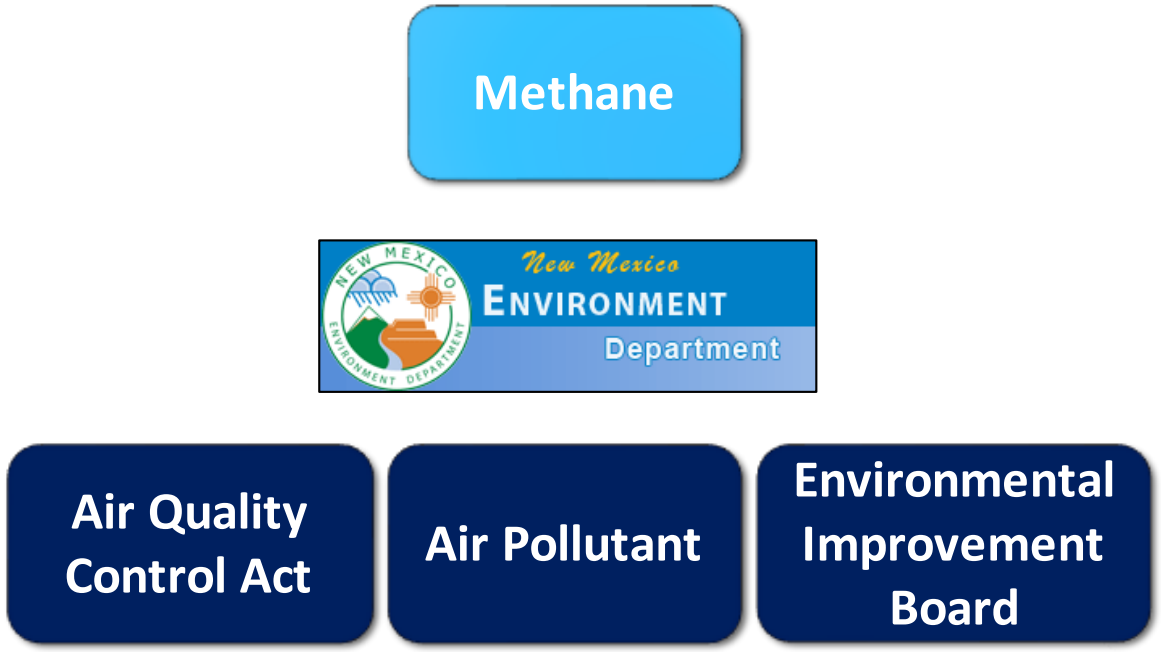
Compliance: Ensuring meaningful compliance with state regulations and permits.

NMED Exhibit 8 - 0007

Developing New Mexico's Methane Strategy



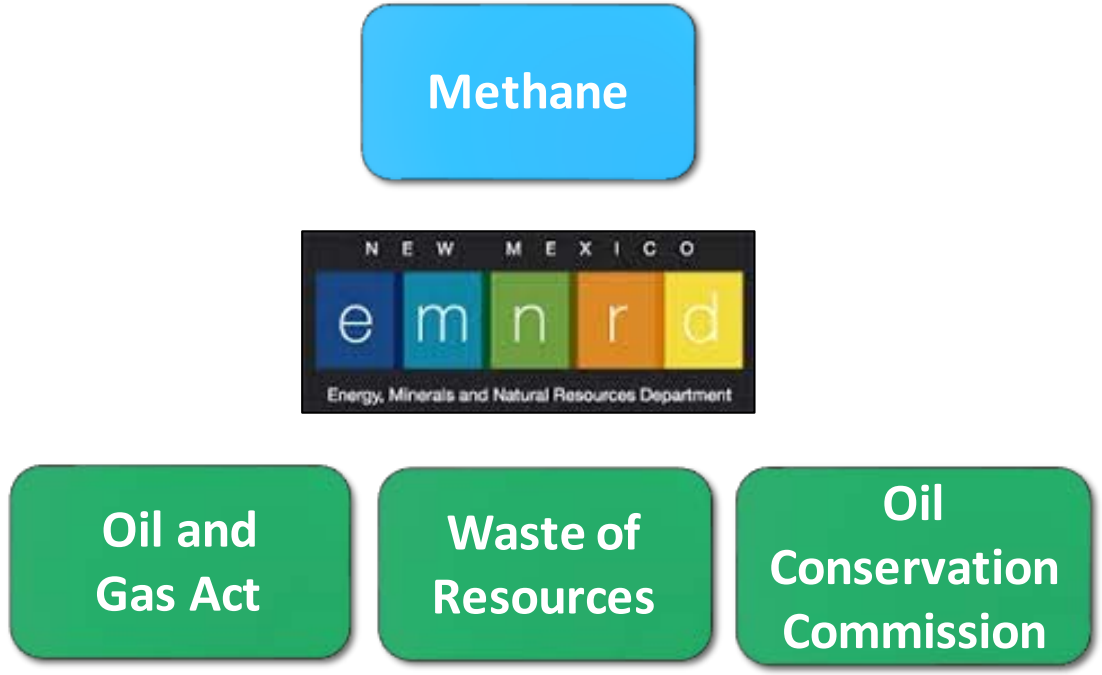
Developing New Mexico's Methane Strategy



- The New Mexico Environment Department will regulate methane emissions from oil and natural gas operations.
- The Air Quality Control Act provides the legal authority.
- Proposed rules are reviewed and adopted through the Environmental Improvement Board.

Developing New Mexico's Methane Strategy

- The New Mexico Energy, Minerals and Natural Resources Department will regulate to prevent the waste of methane from oil and natural operations.
- The Oil and Gas Act provides the legal authority.
- Proposed rules are reviewed and adopted through the Oil Conservation Commission.



NMED Draft Rule Summary

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

NEW MEXICO ENVIRONMENTAL DEPARTMENT

NMED Draft Ozone Precursor Rules

- NMED's enabling statute prohibits the state from directly regulating methane
- Statute requires the EIB to adopt regulations to control emissions of ozone precursors in areas of the state that exceed 95% of the ozone NAAQS (70 ppb)
- Currently seven counties exceed 95% of the standard. At least five of those counties are located in the San Juan and Permian Basins
- A preliminary draft was released for public input in advance of the formal rulemaking petition with the EIB
- We invite the public and stakeholders to provide us with feedback during this initial public input period, including feedback on the proposed language.
- Specifically seeking feedback on Alternative Monitoring Strategies (AMS) for to-be developed technology to have an onramp into the rule
- Need feedback on how to ensure AMS are enforceable, effective, and equivalent

NMED Draft Ozone Precursor Rules

NMED's draft rules target oil and gas industry equipment that emits VOCs and NOx. The draft rules establish requirements to reduce VOCs and NOx emissions from several types of equipment and processes:

- Hydrocarbon liquid loading/unloading: Requires control of VOC emissions from new and existing sources. Current requirements are zero control; rule requires 95% control
- Pig launching/receiving: Requires reductions of VOC emissions from new and existing sources. Current requirements are zero control; rule requires 95% control
- Glycol dehydrators: Requires control of VOC emissions from new and existing sources; more stringent than current state or federal standards
- Engines: Requires reduction in NOx and VOC from new and existing sources
- Equipment leaks: Requires control of VOC emissions from new and existing sources
- Heaters: Requires reduction of NOx emissions from existing sources.

NMED Draft Ozone Precursor Rules

NMED's draft rules target oil and gas industry equipment that emits VOCs and NOx. The draft rules establish requirements to reduce VOCs and NOx emissions from several types of equipment and processes:

- Storage tanks: Requires control of VOC emissions from new and existing sources with a potential to emit greater than 2 tons per year
- Well workovers: Requires methods to reduce VOC emissions from new and existing sources and notification to nearby residents
- Gas well liquids unloading: Requires methods to reduce VOC emissions from new and existing sources
- Compressor seals: Requires control of VOC emissions from new and existing sources
- Pneumatic controllers: Requires control of VOC emissions from new and existing sources with incentives to use low- to no-emission equipment through monitoring, recordkeeping and reporting
- Evaporative ponds: Requires control of VOC emissions from new and existing sources
- Standards for stripper wells and low emitting facilities: Requires monitoring of actual oil and gas throughput, emissions tracking for new and existing individual facilities and affirmative requirements to maintain equipment to prevent emissions

EMNRD Draft Rule Summary

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

NEW MEXICO ENVIRONMENTAL DEPARTMENT

NMED Exhibit 8 - 0015

EMNRD Draft Waste Rule – Phase 1 Data and Reporting

- Having accurate data is critical to establishing meaningful baselines and enforceable goals to reduce natural gas waste.

- Data currently being reported is often inconsistent

- What does Phase 1 include?
  - Defines waste to include gas that is vented and flared;
  - Requires operators to measure and report all venting and flaring during operations;
  - Requires operators to disclose venting and flaring to mineral interest owners who own a share of the natural gas being wasted;
  - Exempts venting and flaring during emergencies;
  - Provides flexibility for stripper wells, which operate on the economic margin; and
  - Establishes an enforceable target for Phase 2, which requires operators to reduce natural gas waste

NMED Exhibit 8 - 0016

EMNRD Draft Waste Rule- Phase 2 Gas Capture Plan

- Starting from the current level of natural gas waste identified in Phase 1, each operator must reduce their waste by a fixed amount each year to achieve a gas capture rate of 98% by December 31, 2026.

- What does Phase 2 include?
  - Applies to operators in upstream (production) and midstream (gas gathering and boosting) sectors;
  - Includes design standards for gathering pipelines;
  - Allows each operator to decide how it will meet the statewide target, providing flexibility and opportunity for innovation in the industry;
  - Increases the statewide target each year to reduce natural gas waste over time
  - Incentivizes methane detection flyovers
  - Authorizes enforcement action if operators do not meet the gas capture targets:
    - Operators may be forced to cut back on production or shut in wells
    - Establishes new drilling permit approval criteria based off meeting gas capture targets, operators must demonstrate compliance or be at risk of not receiving new permit approval

Statements/Feedback Time

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

NEW MEXICO ENVIRONMENTAL DEPARTMENT

NMED Exhibit 8 - 0018

How to Submit Comments

Comments on NMED draft rules may be submitted by September 16th to: nm.oai@state.nm.us

NMED's Draft Rule is available here: https://www.env.nm.gov/new-mexico-methane-strategy/public-participation/

Comments on EMNRD draft rules may be submitted by September 16th to: EMNRD.wasterule@state.nm.us

EMNRD's Draft Rule is available here: http://www.emnrd.state.nm.us/OCD/documents/NaturalGasWasteDraftRules-July202020.pdf

Developing New Mexico's Oil and Natural Gas Methane Strategy:

Community Impacts Meeting

NEW MEXICO ENVIRONMENT DEPARTMENT

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

Spring 2020

1

1

Developing New Mexico's Methane Strategy

Meeting Overview –

- 2:00 to 3:30- Slide Presentations with Questions and Answers
  1. **Updates and Background on NM Methane Strategy**
  2. **Culture Impacts and Outreach to Communities**
  3. **Health Impacts**
  4. **Economic Impacts**
  - 3:30 to 3:45- Intermission
  - 3:45 to 4:15- Moderated Panel Question and Answers
  - 4:15 to 5:00- Public Input
  - 5:00 to 6:00- Open House Format

2

2

Developing New Mexico's Methane Strategy



*"**EMNRD and NMED shall jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources and enact such rules as soon as practicable."***

- Governor Michelle Lujan Grisham

3

3

Developing New Mexico's Methane Strategy

Science: Using the best available science to inform our decision-making in protecting public health, the environment and minimizing waste.

Innovation: Employing creative engineering and technological solutions to address the public health, environmental and waste challenges.

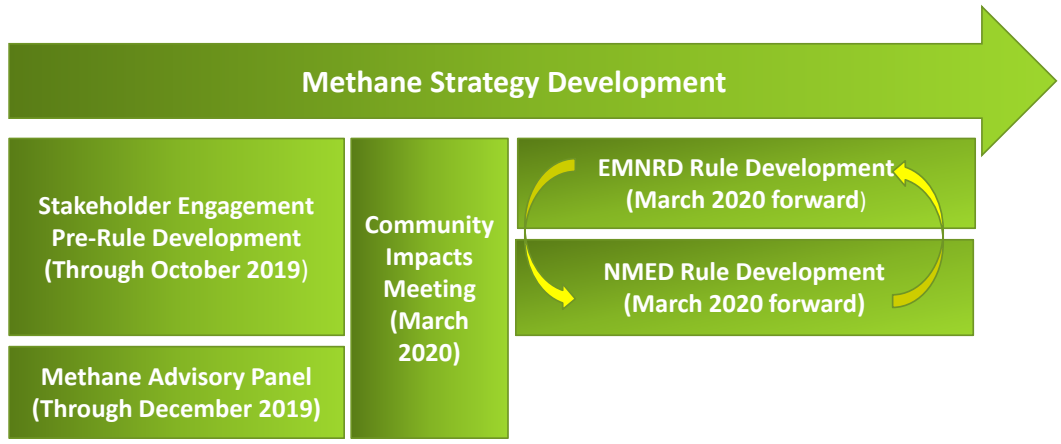
Collaboration: Engaging communities and interested stakeholders in our methane strategy decision-making.

Compliance: Ensuring meaningful compliance with state regulations and permits.

4

4

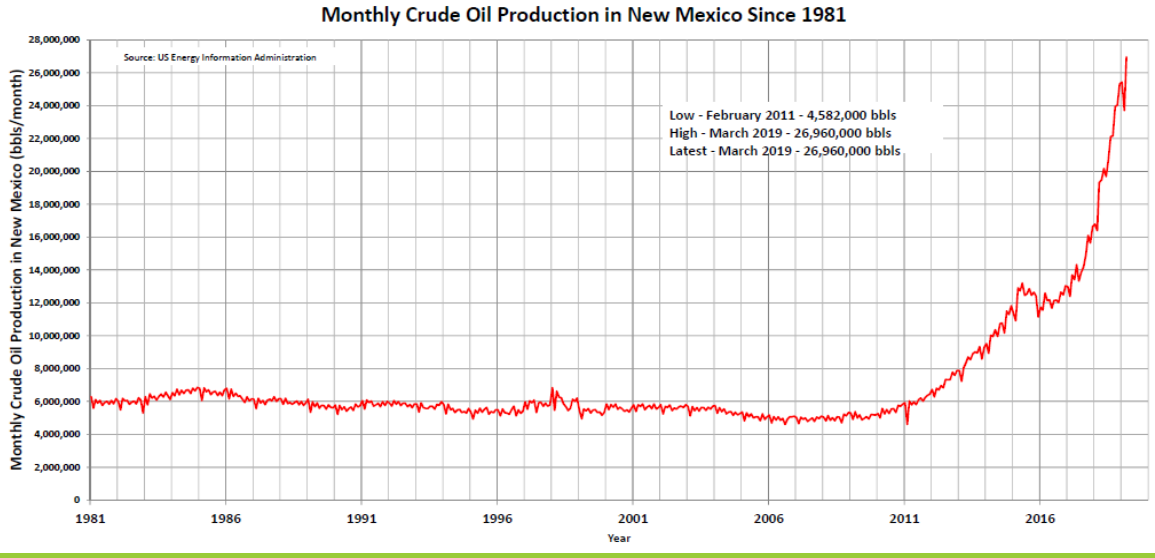
Developing New Mexico's Methane Strategy



5

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Developing New Mexico's Methane Strategy



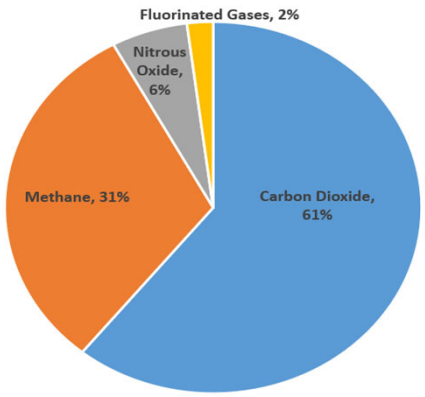
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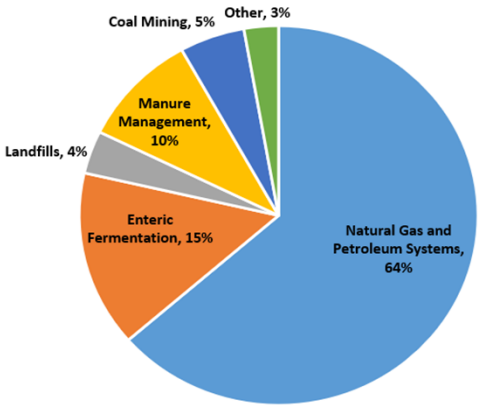
Developing New Mexico's Methane Strategy

Methane is a **potent greenhouse gas** with a global warming potential 25 times greater than that of carbon dioxide.

New Mexico Greenhouse Gas Emissions



New Mexico Methane Emissions



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Developing New Mexico's Methane Strategy

In 2018, oil and natural gas companies reported over **36 billion cubic feet of vented or flared natural gas**. This information was collected using the New Mexico Oil Conservation Division's required production reports (known as C115 reports).

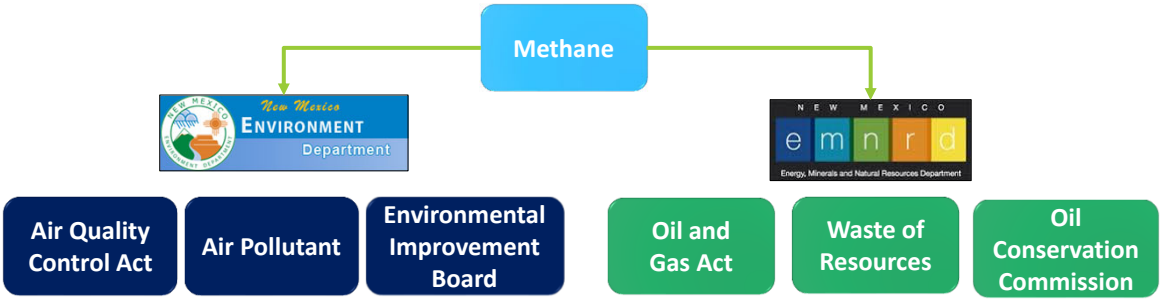
This equated to approximately **$10 million in lost revenues** to New Mexico in 2018.



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Developing New Mexico's Methane Strategy



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Developing New Mexico's Methane Strategy

New Mexico Environment Department

Methane from the oil and natural gas industry is **packaged with other pollutants:** volatile organic compounds (VOCs), which are a key ingredient in ground-level ozone (smog); and a number of other pollutants known as "air toxics" – in particular, benzene, toluene, ethylbenzene and xylene.

N E W M E X I C O e m n r d Energy, Minerals and Natural Resources Department

Methane can be a **waste product** from the oil and natural gas industry. This occurs through the venting and flaring of methane at various points across the oil and gas value chain. When a resource is wasted, the state of New Mexico is no longer able to collect royalties on the waste, and the resource is not available for future beneficial use.

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Developing New Mexico's Methane Strategy

Waste Reported to EMNRD

Year	Venting	Flaring	Total
2016	3,376,009	21,799,677	25,175,686
2017	2,123,452	14,886,332	17,009,784
2018	3,462,237	32,749,804	36,212,041

*Values in Mscf
**Values reported in C115 form

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Developing New Mexico's Methane Strategy

- The Air Quality Control Act requires the State to develop a plan, including the adoption of regulations, to reduce ozone precursors (VOC and NOx) in areas where monitored ozone levels are greater than 95% of the ozone standard.
- NMED is developing rules targeting VOC and NOx reductions in seven counties. **Such reductions in VOC will collaterally reduce methane.**
- Multiple stages of stakeholder and public engagement are planned.
- Outreach to the general public, industry, local and tribal governments will be followed by draft rules.

Seven Counties:

Bernalillo

Chavez

Doña Ana

Eddy

Lea

Rio Arriba

San Juan

New Mexico Environment Department

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Developing New Mexico's Methane Strategy

- NMED is currently gathering or developing information related to ozone formation science in the seven counties; ozone-related health effects; monitoring data and source-specific emission information.
- In adopting regulations, state law requires the EIB to consider:

1. Public interest, including the social and economic value of the sources of emissions;
2. Energy, environmental, and economic impacts;
3. Efforts by sources to reduce emissions prior to the effective date of the rule; and the remaining useful life of existing sources.

New Mexico Environment Department

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Developing New Mexico's Methane Strategy

- New Mexico Oil and Gas Act:
  - Written in 1935 and amended to prevent waste, protect correlative rights, and protect public health and the environment (70-2-12 NMSA)
  - The Oil and Gas Act prohibits "waste" from oil and gas production.
- To prevent waste of gas resources, the OCD has a "no vent or flare" rule.
  - Rule 19.15.18.12(A) NMAC, titled "Casinghead Gas" states: An operator shall not flare or vent casinghead gas produced from a well after 60 days following the well's completion

NEW MEXICO emnrd Energy, Minerals and Natural Resources Department

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Developing New Mexico's Methane Strategy

- EMNRD will review the current rules governing the prevention of waste to determine what changes in rules and procedures are necessary.
- EMNRD will seek feedback from stakeholders on various options to address waste issues.
- EMNRD will develop draft rule proposals based on feedback during initial outreach.
- Draft rule changes will be made available for comment as part of the public outreach.

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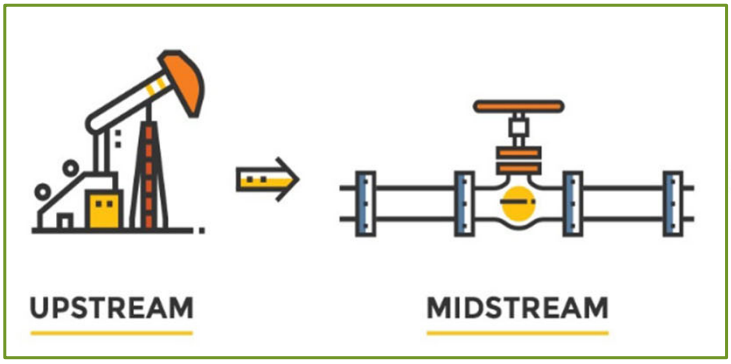
Developing New Mexico's Methane Strategy



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Developing New Mexico's Methane Strategy



Source: Energy HQ

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Developing New Mexico's Methane Strategy

- Methane Advisory Panel (MAP) formed, consisting of technical stakeholders focusing on processes and equipment associated with exploration, production, gathering and processing.
- Members included local and national eNGOs, major and independent upstream/midstream industry.
- Technical guests included academia and technology companies
- Charge to the MAP:
  - Develop emission- and waste-based standards for equipment and operations
  - Propose monitoring, recordkeeping and reporting structures

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Developing New Mexico's Methane Strategy

- MAP Meeting Structure-
  - Two, four hour meetings every other week
  - Held over a twelve week period (mid August thru November)
  - Facilitated discussion focused on reducing waste and VOC emissions by equipment type and processes
  - Draft topic reports, documents and presentations posted online as developed
- Draft MAP report posted for a 60 comment period ending 2/20/2020

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Developing New Mexico's Methane Strategy

Report Topics:

- Completions and Simulations
- Workovers
- Heater Treaters
- Venting and Flaring
- Infrastructure Planning
- Pneumatic Controllers and Pumps
- Leak Detection
- Compressors and Engines
- Workovers Liquids Unloading
- Separators/Heaters/ Storage Vessels
- Completions/Recompletions and Stimulations
- Dehydration Units

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Developing New Mexico's Methane Strategy

How to engage in the process:

- **Phase 1 (2019):** Follow the MAP, attend public meetings, and provide input.
- **Phase 2 (2020):** Follow and provide public input during rulemaking development for OCC and EIB: https://www.env.nm.gov/new-mexico-methane-strategy/

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Developing New Mexico's Methane Strategy

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Acronyms

AQCA = Air Quality Control Act

CAA = U.S. Clean Air Act

EIB = Environmental Improvement Board

NM EMNRD = New Mexico Energy, Minerals and Natural Resources Department

NMED = New Mexico Environment Department

OCC = Oil Conservation Commission

OCD= Oil Conservation Division

OGA = Oil and Gas Act

eNGO = environmental non-governmental organization

Community
Impacts Meeting
March 19, 2020

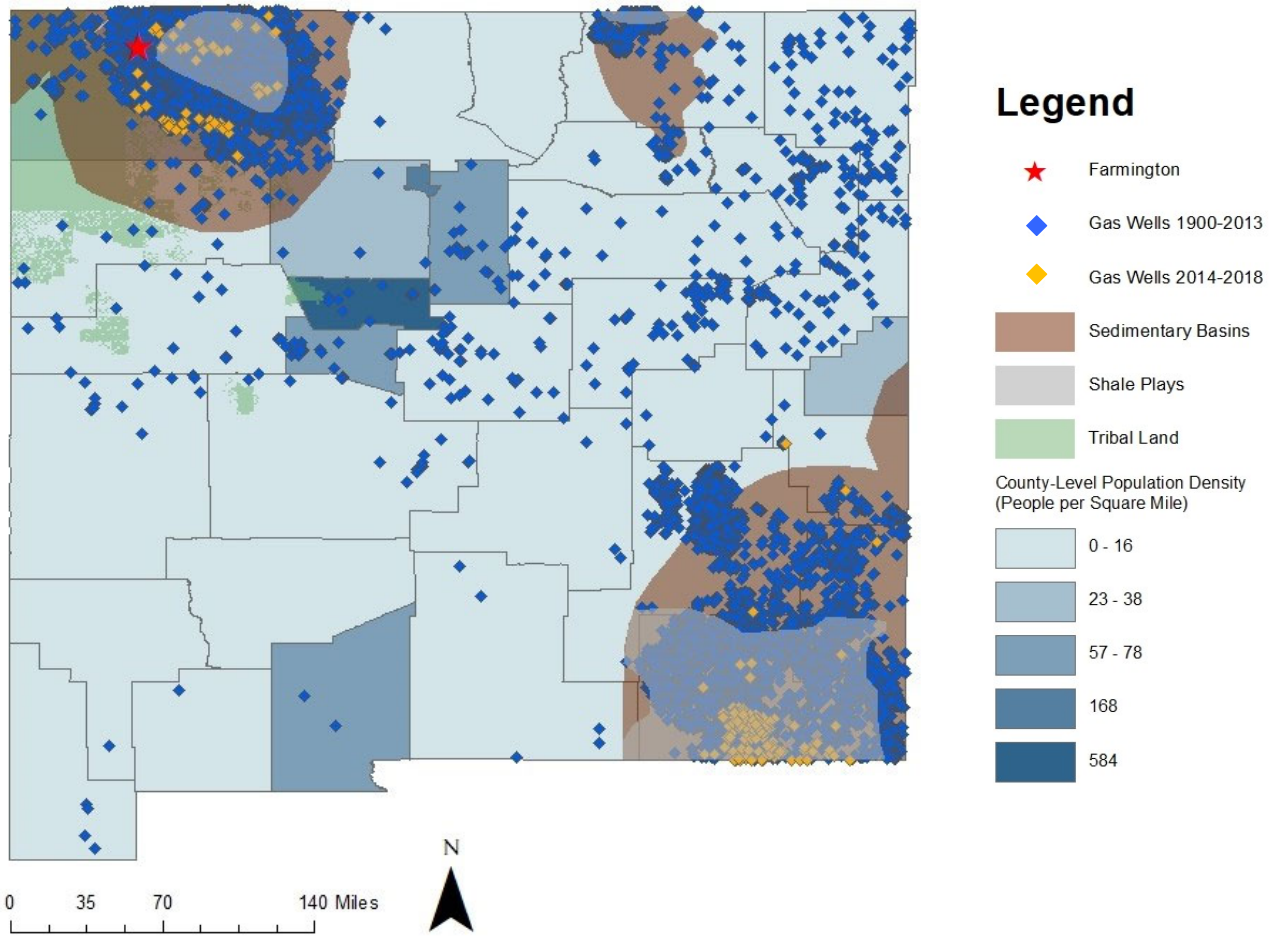
Hosted by:
New Mexico
Departments
of Environment
(NMED) and Energy,
Minerals and Natural
Resources (EMNRD)

Oil and gas development in the United States:

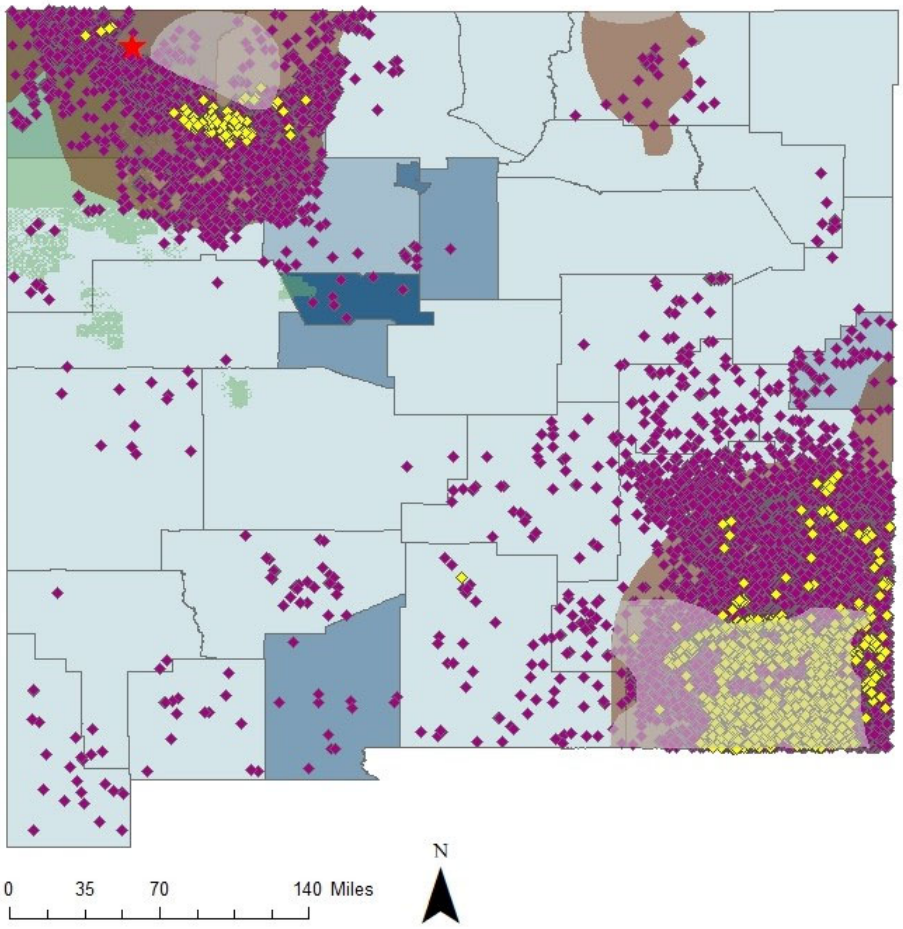
Potential Human Exposures and Health Effects

Donna Vorhees, ScD
Health Effects Institute-Energy
Boston, MA

NMED Exhibit 9 - 0013



Gas wells and population density in New Mexico



Oil wells and population density in New Mexico

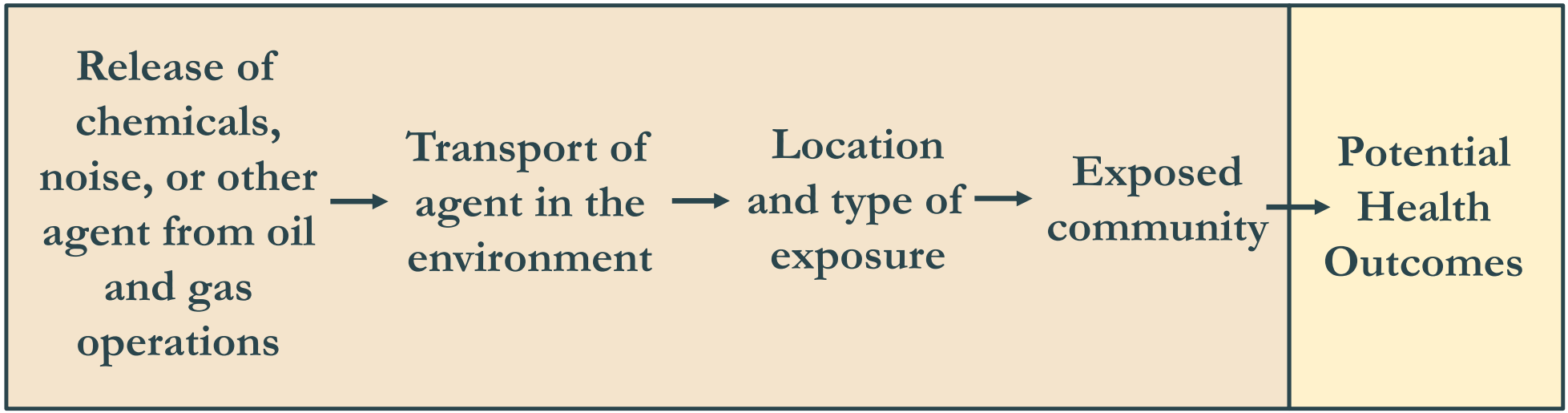
Health Effects Institute-Energy

A ***new national research program***

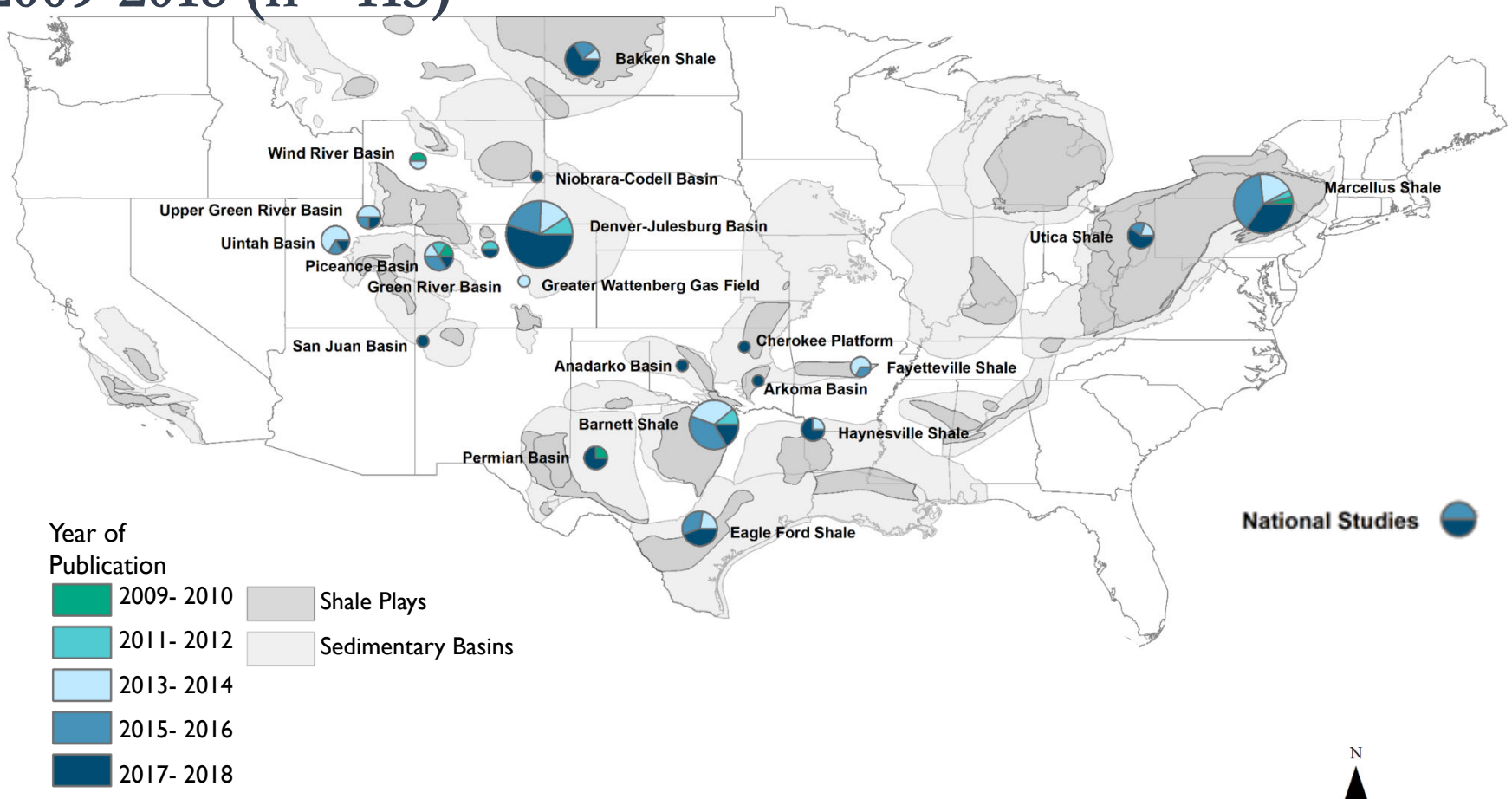
- Research on human exposures associated with onshore development of oil and natural gas from shale and other unconventional resources across the United States
- As feasible and appropriate based on findings from the exposure studies, targeted efforts to assess the potential health effects that might result from exposures

- Independent, nonprofit corporation chartered to provide policy-relevant, high-quality, and impartial science
- Funded jointly by government and the oil and natural gas industry
- Funds research that is selected, conducted, overseen, and reviewed independently of our sponsors

What we would like to know to assess health risk

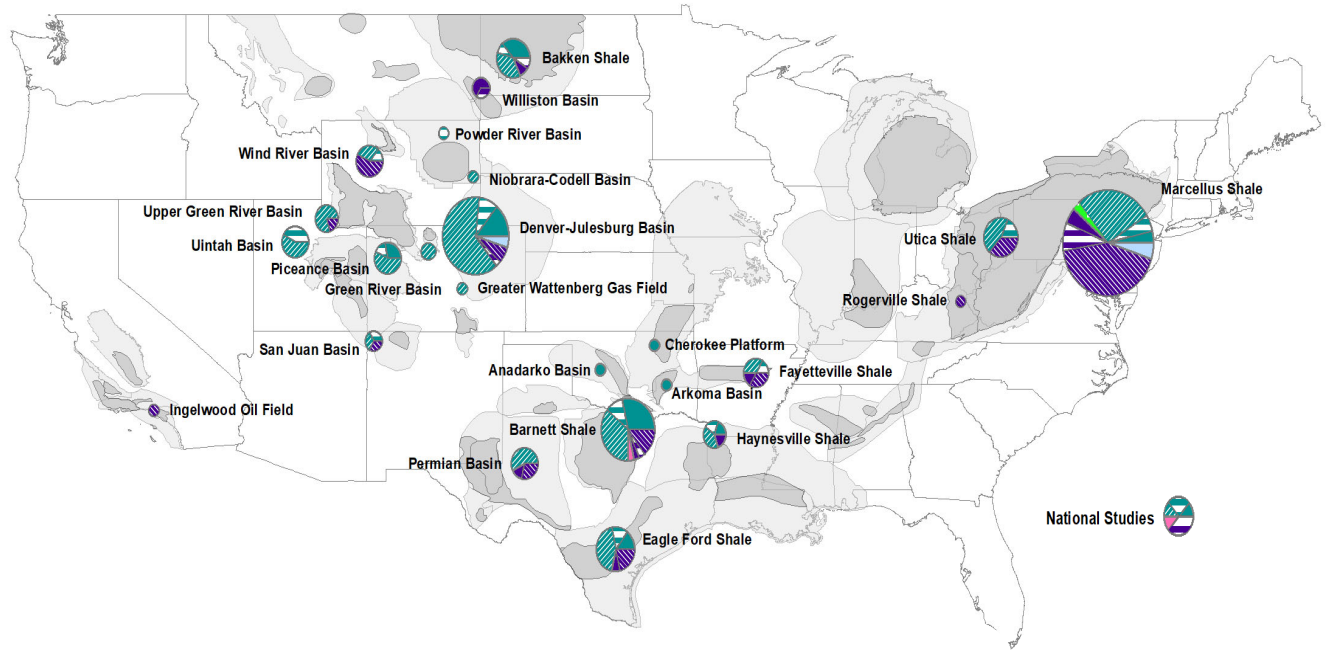


Air Studies by Location and Year of Publication for 2009-2018 (n= 113)



*Largest chart represents 37 studies. Smallest represents 1 study.

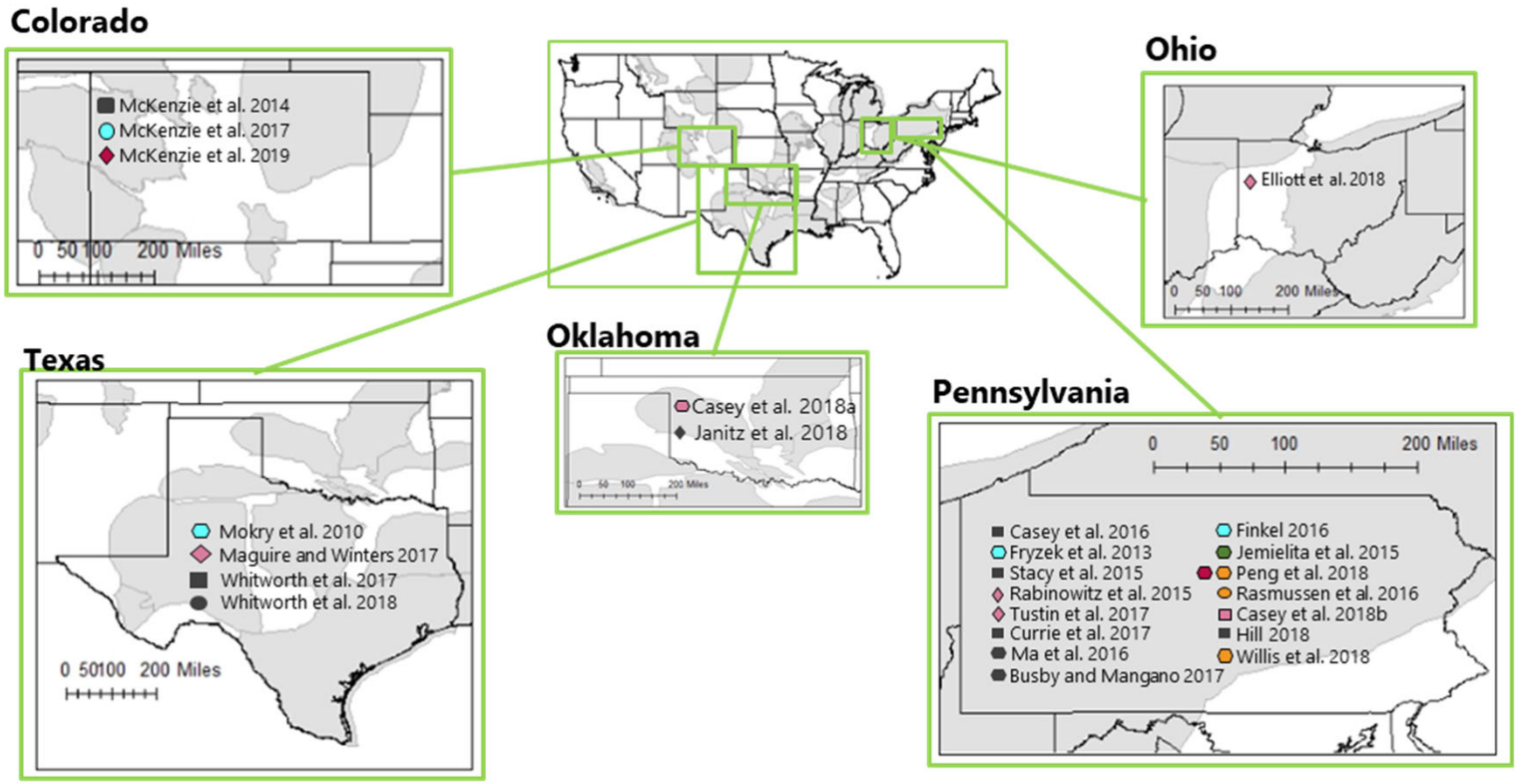
Studies Monitoring or Modeling Levels of Chemical and Non-Chemical Agents (n=187)



Largest chart represents 80 studies. Smallest represents 1 study

HEI-Energy 2019 review of epidemiology literature

Studies displayed by location, study design, and assessed outcomes



Studies published since review:
Apergis et al. 2019; Brown et al. 2019; Casey et al. 2019; Denham et al. 2019; McKenzie et al. 2019.

Concluding Remarks

- Ongoing research about potential exposures and health effects associated with unconventional oil and gas development
- Next steps for the *Health Effects Institute-Energy*: funding community exposure research in multiple regions of the United States



Reports available at: hei-energy.org

Thank You

For more information:

Website: hei-energy.org

or

Contact: energy@healtheffects.org

NEW MEXICO LEGISLATIVE FINANCE COMMITTEE

Overview of Economic and Fiscal Impacts of the Oil and Gas Industry in New Mexico

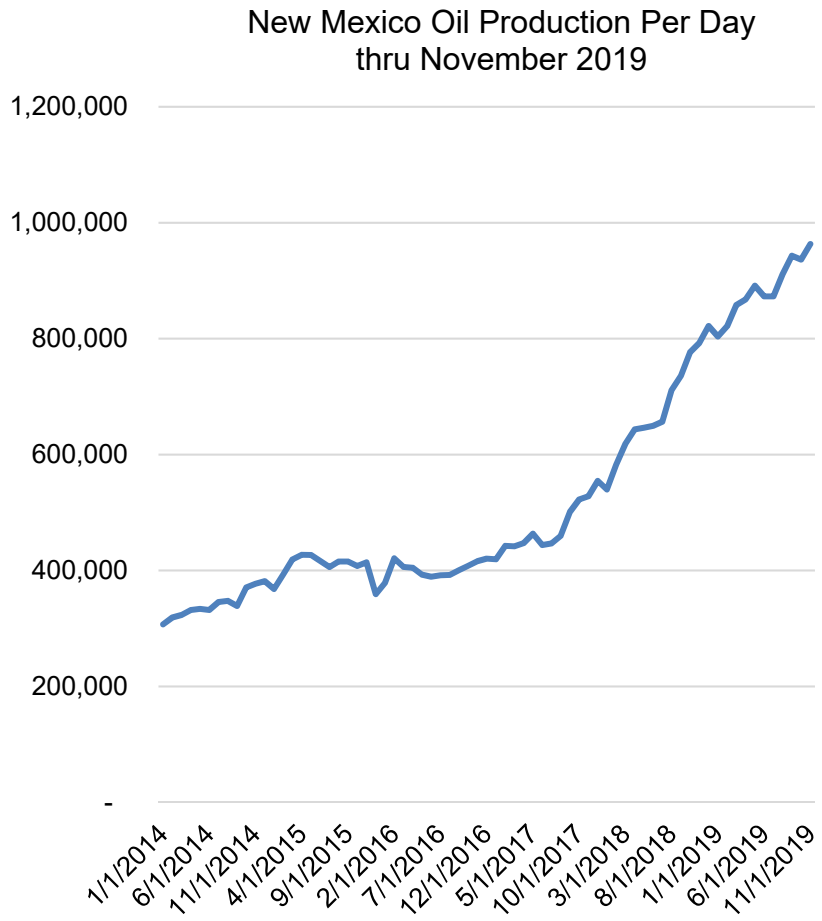
Presented to the Energy, Minerals, and Natural Resource Department's Community Input Meeting
March 19, 2020

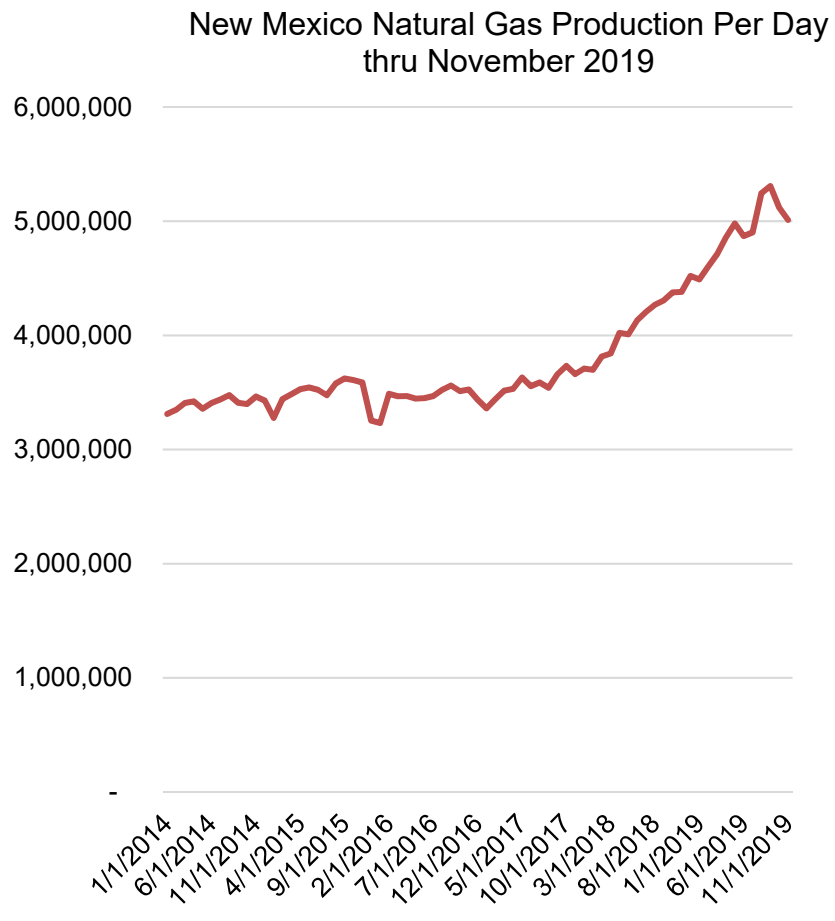
Dawn Iglesias, Chief Economist, LFC

Summary

- Oil producing regions enjoy significant economic growth during boom time, boosting state an local investment, employment, and household income.
  - Growth comes with its own challenges – strains on local housing, school, and infrastructure, as well as environmental considerations.
- Energy markets are volatile, adding uncertainty for state and local governments and residents over when, and to what extent, prices and production could fall.
- When prices drop, local and state economies face sharp declines, and decisions or investments made during the boom may become obsolete.
  - Create challenges for planning in both public and private sectors, with substantial risks for residents of oil producing regions

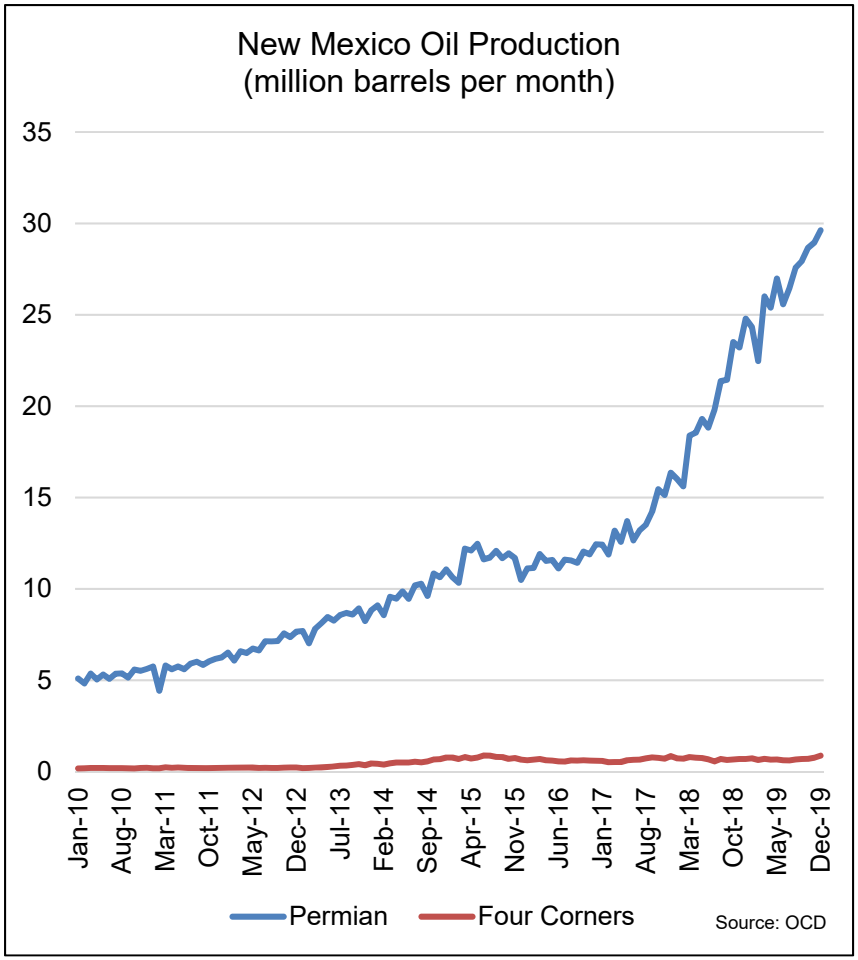
Unprecedented growth in oil and gas production in New Mexico…

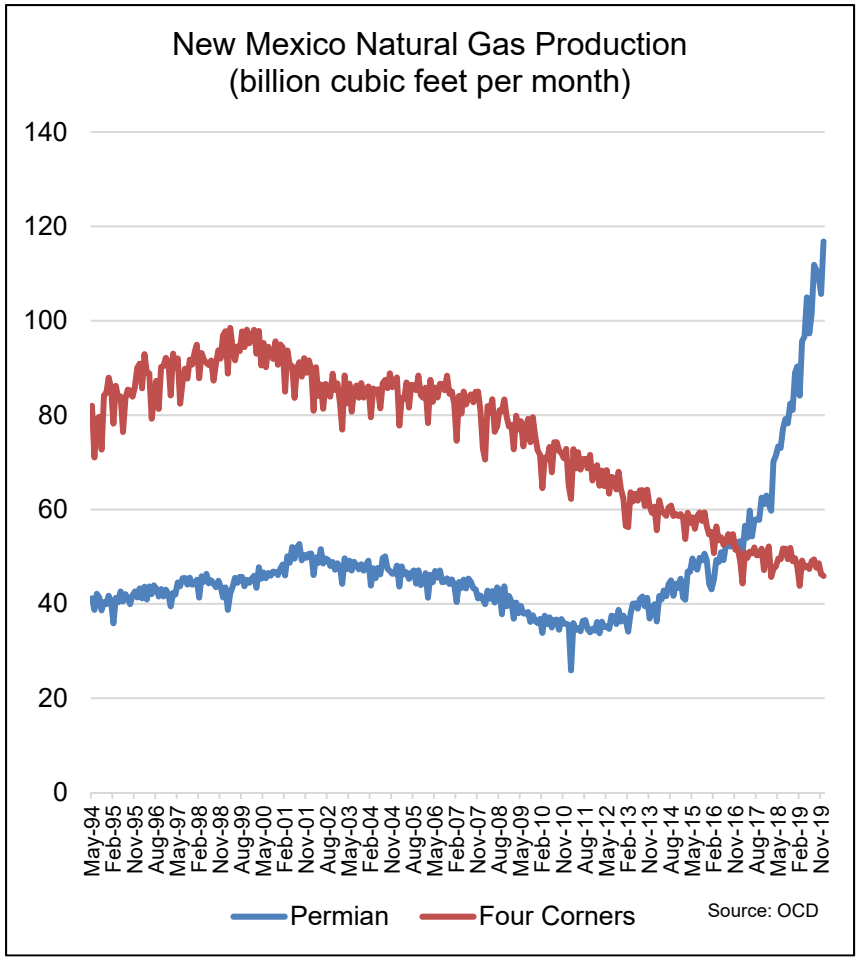




Source: OCD

… with production growing in the Permian basin while San Juan basin continues gradual decline.





New Mexico Gross State Product by Industry

Rank	Sector	2019Q3 Nominal GSP
1	Government and government enterprises	24,278.3
2	Real estate and rental and leasing	13,799.2
3	Mining, quarrying, and oil and gas extraction	9,779.2
4	Health care and social assistance	7,940.1
5	Professional, scientific, and technical services	7,666.2
6	Retail trade	5,750.5
7	Manufacturing	4,411.9
8	Construction	4,020.5
9	Finance and insurance	3,620.7
10	Accommodation and food services	3,491.8
11	Wholesale trade	3,417.0
12	Administrative and support and waste management and remediation services	2,961.3
13	Transportation and warehousing	2,935.1
14	Information	2,884.5
15	Other services (except government and government enterprises)	2,263.7
16	Utilities	1,806.6
17	Agriculture, forestry, fishing and hunting	1,385.3
18	Arts, entertainment, and recreation	764.9
19	Management of companies and enterprises	593.8
20	Educational services	578.9

Source: Bureau of Economic Analysis

New Mexico Gross State Product by County

Rank	County	2018 Nominal GSP
1	Bernalillo, NM	37,865,783
2	Doña Ana, NM	7,516,342
3	Lea, NM	7,505,999
4	Eddy, NM	7,354,225
5	Santa Fe, NM	6,685,324
6	San Juan, NM	5,833,607
7	Sandoval, NM	3,226,655
8	Curry, NM	3,173,812
9	Otero, NM	2,858,450
10	McKinley, NM	2,671,053
11	Los Alamos, NM	2,348,290
12	Chaves, NM	2,099,949
13	Valencia, NM	1,439,258
14	Grant, NM	1,204,979
15	Rio Arriba, NM	1,198,329
16	Taos, NM	980,375
17	Luna, NM	846,225

Rank	County	2018 Nominal GSP
18	Cibola, NM	683,956
19	San Miguel, NM	680,396
20	Lincoln, NM	680,055
21	Roosevelt, NM	661,710
22	Socorro, NM	519,956
23	Colfax, NM	442,675
24	Torrance, NM	364,554
25	Quay, NM	312,748
26	Sierra, NM	311,272
27	Hidalgo, NM	206,777
28	Union, NM	184,718
29	Guadalupe, NM	138,801
30	Mora, NM	84,182
31	Catron, NM	84,094
32	Harding, NM	77,483
33	De Baca, NM	54,801

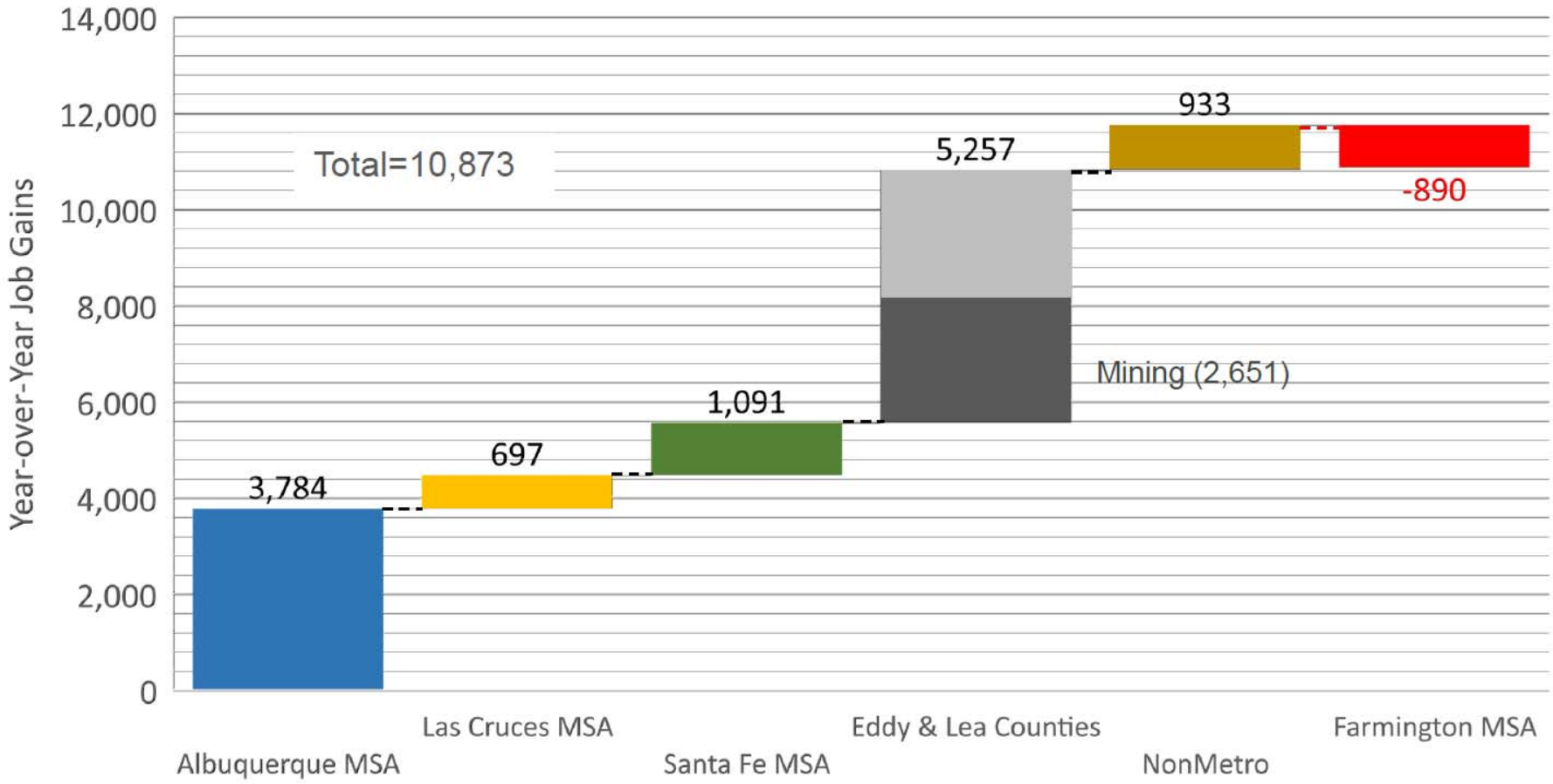
Source: Bureau of Economic Analysis

New Mexico Employment by Sector

Rank	Sector	2019 Employment Estimates (thousands)
1	Healthcare & Social Assistance	120.898
2	Local Government (includes schools)	100.89
3	Retail Trade	92.177
4	Accommodation & Food Services	88.554
5	Professional & Technical Services	58.113
6	Construction	48.043
7	State Government	47.072
8	Administrative & Waste Services	44.068
9	Federal Government	29.16
10	Manufacturing	26.333
11	Mining	23.056
12	Finance & Insurance	22.875
13	Wholesale Trade	21.25
14	Other Services & Unclassified	20.8
15	Transportation & Warehousing	18.782
16	Military Employment	17.013
17	Information	12.902
18	Agriculture, Forestry, Fishing & Hunting	10.57
19	Real Estate, Rental & leasing	10.136
20	Arts, Entertainment & Recreation	10.026
21	Educational Services	9.81
22	Management of Companies & Enterprises	5.265
23	Utilities	4.231

Source: Bureau of Labor Statistics

In 2018, oil and gas activity accounted for 55 percent of new jobs statewide, and oil and gas related employment grew by 21.6 percent.



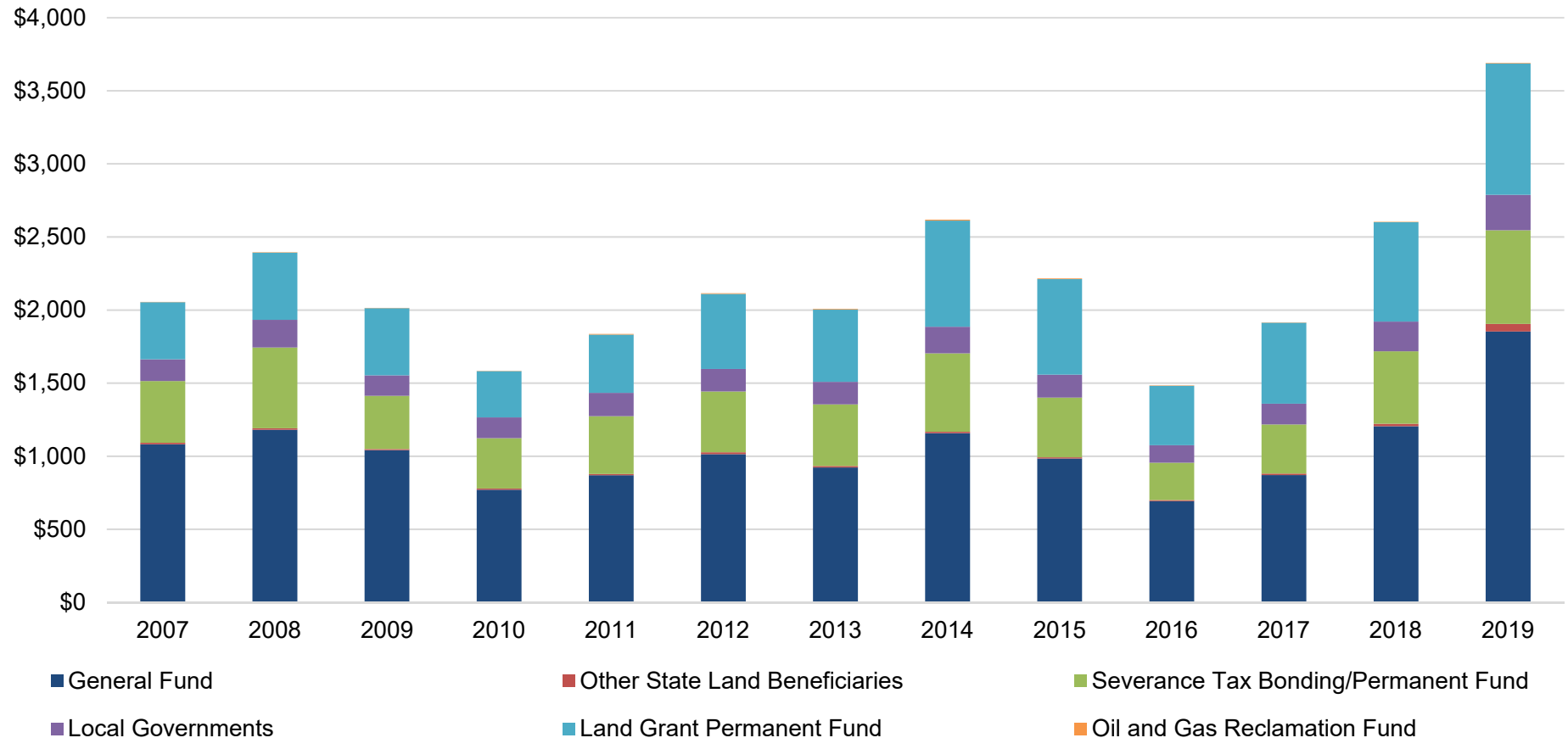
Source: UNM Bureau of Business and Economic Research analysis of BLS data

New Mexico Oil and Natural Gas Revenues

	Type	Name	Rate	Destination	FY18 Amount
Taxes	Production Tax	Oil & Gas Emergency School Tax	3.15% (oil) 4.0% (gas)	General Fund	$451 million
		Oil & Gas Conservation Tax	0.19%	General Fund	$23 million
		Oil and Gas Severance Tax	3.75%	Severance Tax Bonding Fund, Severance Tax Permanent Fund	$496 million
	Property Tax	Ad Valorem Production Tax	Varies	Local Governments	$173 million
		Ad Valorem Equipment Tax	Varies	Local Governments	$29 million
	Processing Tax	Natural Gas Processers Tax	Formula	General Fund	$11 million
	Sales & Use Taxes	Gross Receipts Tax & Compensating Tax	Varies by Location	General Fund, Local Governments	$1 billion
	Income Taxes	Personal Income Tax & Corporate Income Tax	Varies by Income	General Fund	Unknown
Land Income	Federal Royalties, Rents, & Bonuses	Federal Royalties	12.5%	General Fund, Federal Government	$1.1 billion
		Federal Bonuses & Rents	Varies	General Fund, Federal Government	$164 million
	State Royalties, Rents, & Bonuses	State Oil and Gas Royalties	Varies	Land Grant Permanent Fund, Other Land Beneficiaries	$679 million
		State Oil and Gas Bonuses and Rents	Varies	General Fund, Other Beneficiaries	$112 million

Source: LFC Files

Distribution of New Mexico Oil and Gas Production Revenue: Production Taxes, Property Taxes, and Land Income (in billions)

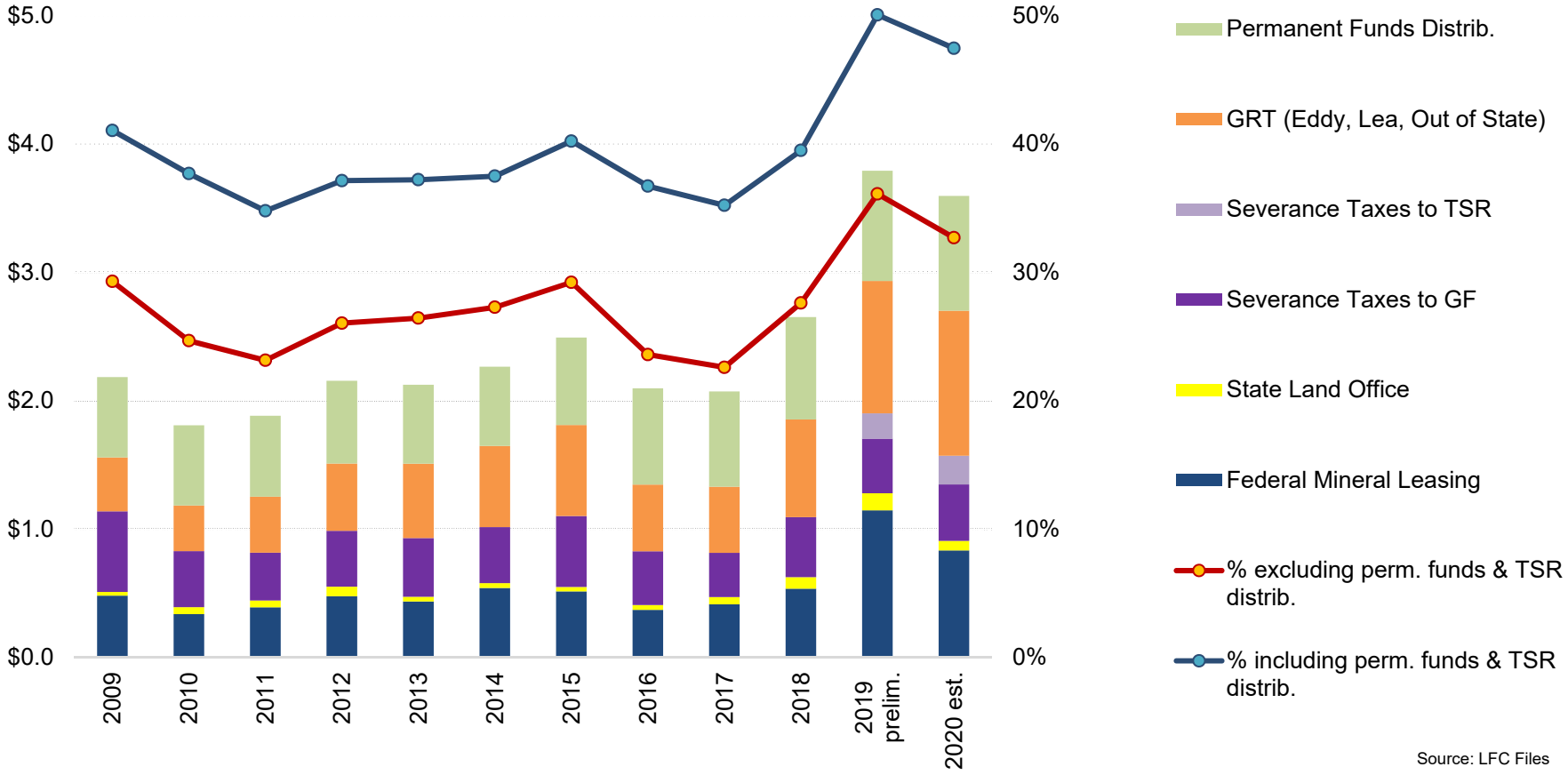


Note: Excludes federal distributions of royalty payments

Source: US Department of Interior, SLO, TRD, LFC Files

Growing dependence on general fund revenues from the oil and gas industry.

General Fund Revenues Dependent on Oil & Gas Industry ($ billions)

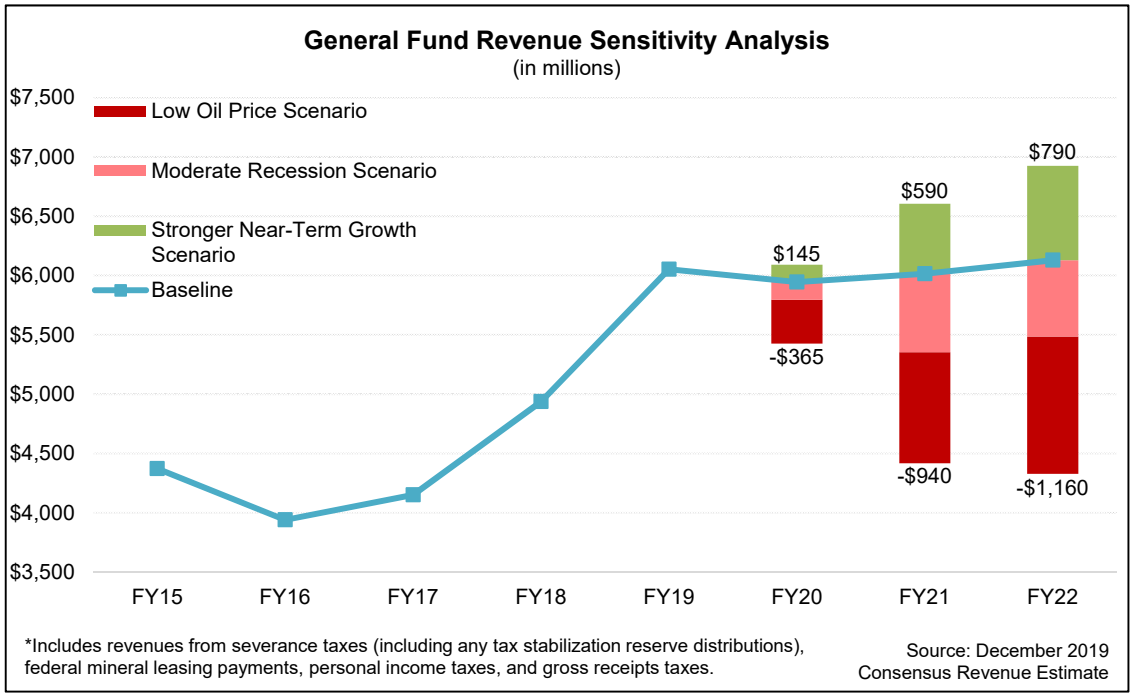


Source: LFC Files

What do changes in production and prices mean for the state general fund?

- Reliance on oil and gas related revenues increases general fund volatility and makes revenues forecasts particularly sensitive to changes in commodity prices and production.
- Based on projected FY20 direct oil and gas revenues (production taxes and federal royalties),
  - A $1 change in the annual average NM price of oil has about a $22 million impact on the general fund
  - A $0.10 change in the annual average NM price of natural gas has about a $17 million impact on the general fund
  - Each additional million barrels of oil generates about $3 million for the general fund
  - Each additional 10 billion cubic feet of natural gas generates about $2 million for the general fund

Stress tests show an energy downturn could impact general fund revenues greater than a moderate recession.



*Includes revenues from severance taxes (including any tax stabilization reserve distributions), federal mineral leasing payments, personal income taxes, and gross receipts taxes.

Source: December 2019 Consensus Revenue Estimate

	FY20			FY21			FY22		
Scenario	Low Oil Price	Moderate Recession	Stronger Growth	Low Oil Price	Moderate Recession	Stronger Growth	Low Oil Price	Moderate Recession	Stronger Growth
Severance Taxes	-$70	-$5	$70	-$220	-$140	$275	-$225	-$105	$320
Federal Mineral Leasing	-$45	-$5	$35	-$190	-$110	$205	-$245	-$130	$320
Gross Receipts Taxes	-$225	-$100	$25	-$480	-$290	$55	-$615	-$285	$85
Personal Income Taxes	-$25	-$35	$15	-$50	-$125	$55	-$75	-$120	$65
Total Difference from Baseline	-$365	-$145	$145	-$940	-$665	$590	-$1,160	-$640	$790

Note: in millions

Questions?

METHANE ADVISORY PANEL

Fall, 2019

Convened by

New Mexico Environment Department

and

New Mexico Energy, Minerals and Natural Resources Department

DRAFT

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NMED Exhibit 10 - 0004

INTRODUCTION

In Executive Order 2019-03, Governor Michelle Lujan Grisham directed the New Mexico Environment Department (NMED) and Energy, Minerals and Natural Resources Department (EMNRD) to:

"…jointly develop a statewide, enforceable regulatory framework to secure reductions in oil and gas sector methane emissions and to prevent waste from new and existing sources and enact such rules as soon as practicable."

To move forward in a manner grounded in science, innovation, collaboration and compliance, NMED and EMNRD sought nominations for a technical Methane Advisory Panel (MAP). The 27 individual MAP members represented environmental organizations, the interests of the Nations, tribes and pueblos in New Mexico and the oil and gas industry – including small and large independent operators as well as the major, vertically-integrated companies. Industry representatives included companies with interests in the Permian and San Juan Basins that drill, develop, complete and operate oil and natural gas wells and infrastructure. Additional technical expertise was provided by professionals from Los Alamos National Laboratory, Colorado State University and the New Mexico Institute of Mining and Technology. The MAP developed the following draft report, which provides an informational foundation on the technical side of how the oil and gas industry emits methane and what methods can curb methane emissions and prevent waste of this resource. A list of MAP members, presentations and draft technical documents were posted online throughout the process, along with this full draft technical report.

The MAP's draft technical report is a New Mexico-specific treatise on methane emissions and potential reduction mechanisms. Once final, the Departments will use this report as a resource as they move into formal rulemaking next year. The MAP was tasked with considering a wide range of perspectives, so there is robust discussion of methane issues representing a diversity of technical opinions. The group was not asked to provide recommendations or to reach consensus. Rather, they were asked to provide a full description of processes that could result in methane emissions and waste and to identify multiple methane reduction strategies for NMED and EMNRD to investigate further. Through the lens of their varied individual experiences, the MAP members considered new and innovative technologies, as well as existing and proposed solutions found in other states.

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METHANE ADVISORY PANEL MEMBERS

Member Name	Affiliation
Mario Atencio	Chaco Canyon Coalition
David Baake	Sierra Club
Bruce Baizel	Earthworks
Milind Bhatte	ConocoPhillips
Ryan Davis	Merrion Oil and Gas Corporation
Matt Eales	Lucid Energy Group
Robert Eales	EOG Resources, Inc.
Mike Eisenfeld	San Juan Citizens Alliance
Tim Friesenhahn	Enduring Resources, LLC
Kerry Harpole	Marathon Oil
Matt Henderson	Hilcorp Energy
Donna House	Bio-cultural diversity/Healthy indigenous communities advocate
Ernie Johnson	Whiptail Midstream
Zach LaCount	Mewbourne Oil Company
Scott Lindsay	DJR Energy
John Maxey	Hanson Operating Company Inc.
Dennis Newman	Occidental Petroleum Corporation
Gabe Pacyniak	Center for Civic Policy
Elizabeth Paranhos	Environmental Defense Fund
Karen Pratt	XTO Energy, Inc.
Vanessa Ryan	Chevron Corporation
Charlie de Saillan	New Mexico Environmental Law Center
Jason Sandel	Aztec Well Servicing
Don Schreiber	Rancher/ Environmental advocate
Tom Singer	Western Environmental Law Center
Mike Smith	Devon
Paul Thompson	Epic Energy

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NMED/EMNRD METHANE ADVISORY PANEL

SECTION 1, PNEUMATIC CONTROLLERS/PUMPS

Discussion for MAP members on September 27, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

Pneumatic controllers are process control devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves and may be actuated using pressurized natural gas. Natural gas- powered pneumatic controllers use natural gas as motive force operate valves that regulate safety shut-down, position, fluid level, pressure, temperature and flow rate. Methane emissions occur from natural-gas powered pneumatic controllers when the pressurized gas is directed to atmosphere after the control action is performed.

Pneumatic pumps are used to inject chemicals into the wellbore, to circulate glycol in cold climates/weather and to move liquids from one place to another (sump pumps). From US EPA's Control Technique Guidelines (2016):

https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf

"Chemical injection pumps are positive displacement, reciprocating units designed to inject precise amounts of chemical into a process stream. Positive displacement pumps work by allowing a fluid to

NMED Exhibit 10 - 0007

flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged.

Typical chemicals injected in an oil or natural gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H2S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Because the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.

Diaphragm pumps are positive displacement pumps, meaning they use contracting and expanding cavities to move fluids. Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid."

Methane emissions occur from pneumatic pumps when the pressurized natural gas that is used to drive the pumping action is released to atmosphere after being used for the pumping action. The amount of methane emitted will depend on the type of pump utilized and the concentration of methane in the associated gas stream.

Gas-assisted glycol pumps, are a specific type of pneumatic pump used to circulate the glycol fluid used in glycol dehydrators. The MAP process discussed this type of pump during the dehydrator session and they will not be discussed in this document.

Provide the segment(s) of the industry that the equipment or process is found:

The equipment is found throughout the production, midstream, gas plants and transmission sectors.

Describe how the equipment or process is used:

Pneumatic controllers are used to control multiple processes based on a sensed process parameter. Pneumatic controllers can be used as emergency shut off devices, to regulate flow or liquid levels, as temperature and pressure regulators, etc. An example of the function of a pneumatic controller would be to control liquid level in a separator. When the liquid level in a separator reaches a high set-point in the separator based on the setting of a level gauge, the associated pneumatic controller sends a signal

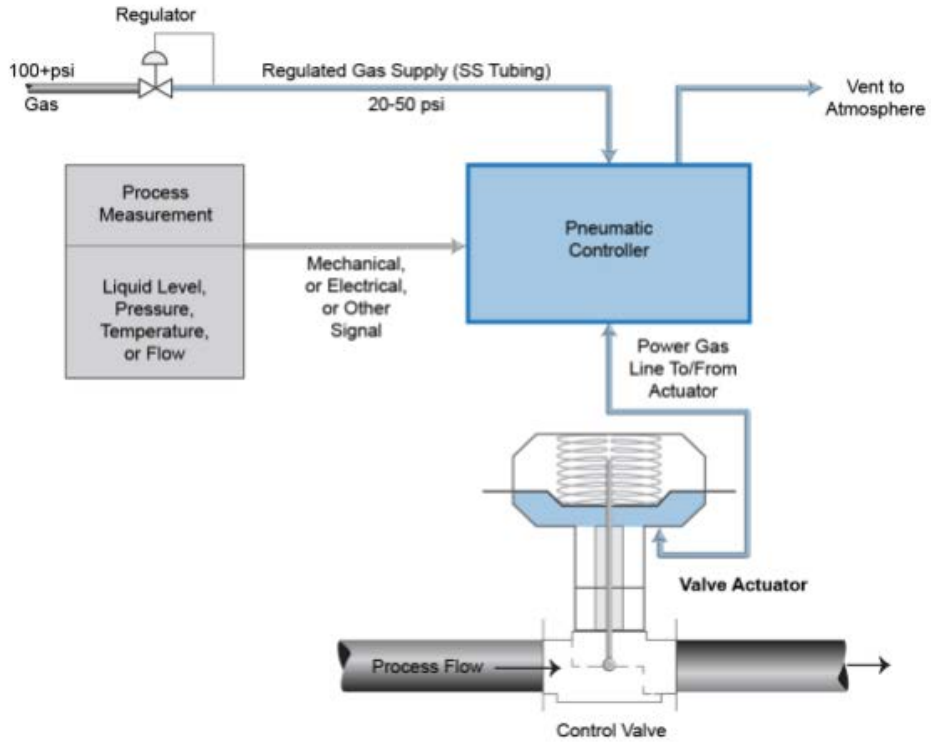
NMED Exhibit 10 - 0008

to open the control valve between the separator and the tank. For an emitting pneumatic controller, this signal would consist of pressurized pneumatic gas to turn the valve from the "closed" to the "open" position. When the level in the separator reaches a low level, the pneumatic controller sends a signal to the control valve to close and to stop flow from the separator to the tank.

Pneumatic pumps range from chemical injection pumps which may inject a few tablespoons of corrosion inhibitor to a wellbore to large diaphragm pumps which move thousands of gallons of product an hour from one tank to another, to pump water out of containment areas after wet weather, or for heat trace to protect pipes from freezing in cold weather.

Provide the common process configurations that use this equipment or process:

Pneumatic controllers can be installed in many types of service. The controller is placed at or near the valve to actuate it. The placement of the valve depends on the type of service. The diagram below from the University of Texas demonstrates where a typical controller is placed in a generic process: http://dept.ceer.utexas.edu/methane2/study/docs/UT%20Study%20Pneumatics%20FAQ%20to%20SC.pdf



Pneumatic Piston Pump

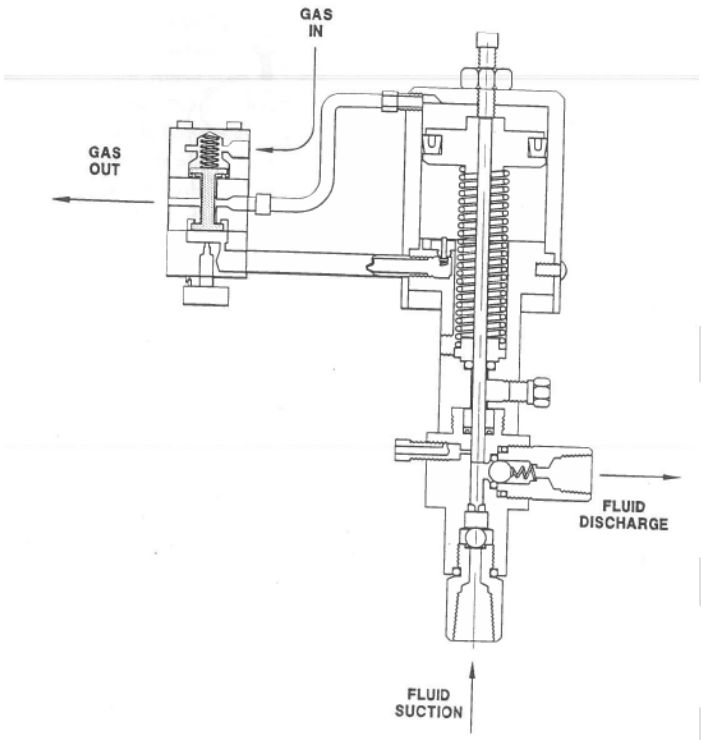


Figure 3-2. Piston Pump Cut-away Schematic

Pneumatic Diaphragm Pump

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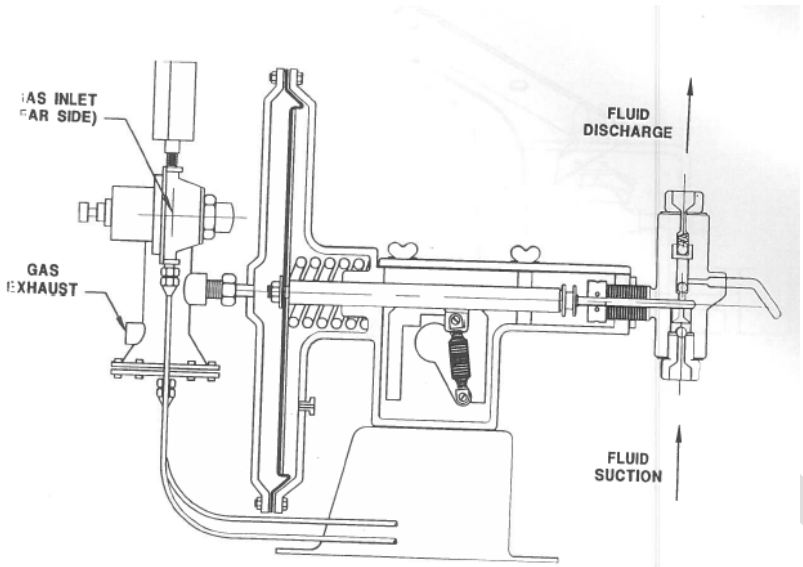


Figure 3-6. Diaphragm Pump Cut-away Schematic

What is the distribution of the equipment or process across business segments?

This equipment is found in upstream, midstream and transmission segments.

How has this equipment or process evolved over time?

The technology remains similar, though there may be greater application of compressed air in new oil well locations where there is electricity. Manufacturers have focused on developing lower bleed devices which industry has been adopting for new facilities.

In recent years, low-powered electric controllers have become available for some pneumatic controller applications, including controllers that can be powered with air-powered systems with battery storage.

Solar-powered electric injection pumps have become options in recent years.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

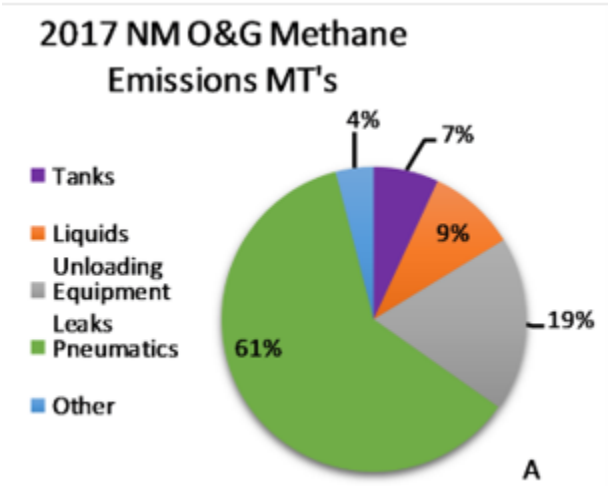
NMED Exhibit 10 - 0011

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

Natural gas driven pneumatic controllers are a direct source of methane emissions (see diagram in section one). Continuous bleed controllers emit natural gas all the time, while intermittent vent controllers emit natural gas only when actuating if operating properly. In the Control Technique Guidelines, EPA found that continuous low bleed controllers emit between 0.2 scfhr up to 5 scfhr, while high bleeds vent from 7 scfhr to 100 scfhr. (US EPA Control Technique Guidelines 6.2.2.2 https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf)

Analysis of GHGRP data found in the New Mexico Oil and Gas Association's Methane Mitigation Roadmap below: https://www.nmoga.org/methaneroadmap



New Wells:

Pneumatic controllers and pumps are used in both new and existing facilities.

Existing Wells:

Pneumatic controllers and pumps are used in both new and existing facilities.

How are the emissions calculated for this equipment or process?

US EPA defines pneumatic controllers in three different categories, each with its own emissions factor in the production and gathering and boosting segments (link):

- Continuous high bleed: these controllers vent continuously at a rate of over 6 scf/hour per manufacturer specifications. EPA Emissions Factor: 37.3 scf/hr/device

- Continuous low bleed: these controllers vent continuously at a rate of less than 6 scf/hour per manufacturer specifications. EPA Emissions Factor: 1.39 scf/hr/device
- Intermittent: These controllers vent only when actuating. Depending on the type of service or operation the controller is in, it can actuate only a few times a year or multiple times per hour. Current regulatory emission factors do not account for the frequency of actuation or other parameters than may influence emissions and are intended to be an average emission rate over a large population of devices. EPA Emissions Factor: 13.5 scf/hr/device. It is important to note that intermittent vent controllers make up a large majority of the inventory in most basins. Also, some studies conclude that emission factors for intermittent vent controllers are too high. The variability in these factors are dependent on geographical area. Should an alternate emission factor be used to estimate emissions from these devices, the total emissions would be vastly lower than what is reflected in GHGRP.

The latest multi-region emission factor study for pneumatic controllers in the United States (Allen 2014) does not include sufficient information to develop a basin-specific emission factor for the Permian or San Juan as emission factors were developed based on regions used in EPA GHG Inventory estimation at that time. The study found a national-average emission of 5.5 scf/hr/device. The study-average emission rate in the Midcontinent region, which geographically includes the Permian Basin, was 5.8 scf/hr/device. The study-average emission rate in the Rocky Mountain region, which geographically includes the San Juan Basin, was 0.8 scf/hr/device. It is not possible to discern if any of the regional measurements occurred in the Permian or San Juan basins.

For pneumatic controller emission reporting, US EPA requires that operators provide an actual count of devices that emit natural gas to atmosphere by each of the three categories at the basin (i.e. Permian or San Juan) and segment (i.e. production or gathering and boosting) level in each year. The count of devices, the emission factor, and a gas composition (i.e. percent of methane in the gas) drive the emission calculation for this source. There is no requirement to report or count of other types of pneumatic controllers that do not have associated emissions to atmosphere.

Equation from GHGRP Subpart W: https://www.ecfr.gov/cgi-bin/text-idx?SID=3393fe39418e975c59618f6249f55516&mc=true&node=se40.23.98_1233&rgn=div8

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types "t" (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

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$Count_t$ = Total number of natural gas pneumatic devices of type "t" (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1) or (a)(2) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type "t" listed in Tables W-1A, W-3B, and W-4B to this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W-1A to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i), (iii), and (iv) of this section.

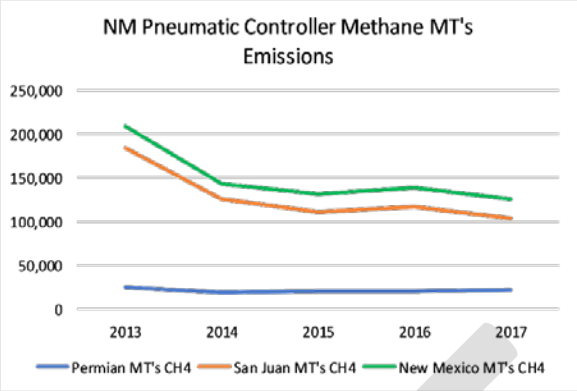
T_t = Average estimated number of hours in the operating year the devices, of each type "t", were operational using engineering estimates based on best available data. Default is 8,760 hours.

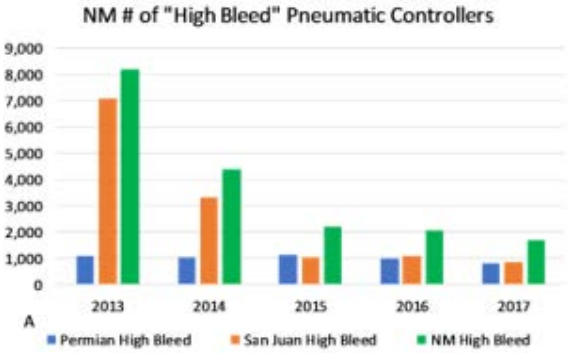
US EPA has a single emission factor for all pneumatic pumps (link) that is 13.3 scf/hr/pump and are defined as any natural gas-driven pneumatic pump that is not part of a dehydration system since those types of pumps are reported with emissions from dehydrators. As with pneumatic controllers, operators provide a count of pneumatic pumps in operation at the basin-level for each segment. Emissions are then estimated based on the emission factor, the count of pneumatic pumps, and the gas composition.

What data is available to quantify emissions/waste for this equipment or process?

The US EPA publishes most of the emission information and activity data that it receives as part of the US GHG Reporting Program annually (https://ghgdata.epa.gov/ghgp/main.do?site_preference=normal#). By March 31st of each year, operators upload their emission information to the EPA website for the previous year (i.e. 2018 emission information was reported in March 2019), EPA undertakes a quality assurance process, and uploads the information in October to a publicly accessible website. Care should be taken in estimating emissions from this inventory for New Mexico since both the Permian and San Juan Basins span multiple states and are challenging to separate emissions between states for all source categories. In the analysis below, NM data was separated from surrounding state data. Also, operators with less than 25,000 MT CO_2e emissions are exempt from reporting emissions to the GHGRP. Therefore, the production segment, all emissions were scaled up to the total well count reported by the New Mexico Oil Conservation Division (NMOCD) (EIA for national). For the G&B segment, there is no information to enable scaling-up GHGRP reported emissions and raw GHGRP reported emission quantities are shown.

NMED Exhibit 10 - 0014





Analysis of GHGRP data found in the New Mexico Oil and Gas Association's Methane Mitigation Roadmap: https://www.nmoga.org/methaneroadmap

The large discrepancy in emissions from Permian vs San Juan Basin reflects distinguishing characteristics of the two basins. In gas plays, the per site controller counts are much lower than oil plays, thus, creating a disincentive for the use of more expensive compressed air applications as those installations are uneconomic unless there is a significant number of controllers needed for the process. Also, Permian basin gas also contains less methane by composition in the stream than San Juan Basin gas, therefore, the resulting methane concentration as a variable to calculating emissions result in lower per-controller emissions in the Permian.

What are the data gaps in quantifying emissions/waste for this equipment?

Current US EPA emission factors are based on a relatively small sample of pneumatic controller measurements that were conducted in the early 1990's. More recently, several direct measurement studies have been undertaken to try to update the US EPA emission factor by directly measuring emissions from a population of devices as they were encountered in the field. On average, these studies, which are outlined in the table below, have found that aggregate emissions per pneumatic controller measured are lower than those used in the GHGRP. It is recognized that each study

conducted has certain limitations such as equipment reliability and calibration, measurement techniques, duration of sample collection, sample size and representativeness, etc.

There have been a number of studies, some of which find that the EPA emission factors are overestimated in some cases:

Study Name	# PC Samples	Application	Duration of Measurement	Whole gas (avg ER) (scf/hr)
EDF/UTexas 2014	377	Well pads natural gas production, several U.S. basins	15 minutes	5.5
EPA – Thoma Utah Study 2016	80	Unitah Basin well pads, oil and gas production	1 hour or more	0.36
Oklahoma Independent Producers Association	680	Oil and gas production in Oklahoma	NA	1.05 (calc)
Prasino 2013	601	British Columbia oil and gas sites, measured high bleeds only	30 minutes	8.7 – 9.2
Luck et al 2019 (Gathering facilities) (data quality affected by meter problem)	72	US gathering facilities Due to potential biases associated with flow meter errors, updates to EPA emission factors based on these data are not proposed	76 hours (avg) Authors found that many of the problems observed would not have been observed using typical measurement durations	Low-bleed: 7.6 High-bleed: 19.3 Intermittent-bleed: 11.1 Overall: 10.9
Cap-On Energy BC Oil and Gas Methane Emissions Field Study (Data tables here)		British Columbia wellpads	Direct equip. cts. from 266 pads, with EFs calculated based on counts of specific models and recent measured EFs for each model	Emissions reported by controller function (irrespective of continuous-bleed / intermittent-bleed distinction. See figure below.
Measurement-Based Emissions Factors Using	34	Fugitive emissions including 34	Continuously over 8 months on some	Level Controllers: (Intermittent) 16.92

NMED Exhibit 10 - 0016

BHGE Advanced Methane Sensing Technologies and Analytics		pneumatic controllers (18 level controllers, 13 pressure controllers and 2 methanol pumps)	site and 4 months on other sites	Pressure Regulators: (intermittent) 11.94 Methanol Pumps: 42.54

Results from Cap-On study for British Columbia pneumatic controllers (and pumps). The horizontal line (0.17 m^3/hr) corresponds to 6 scf/hr:

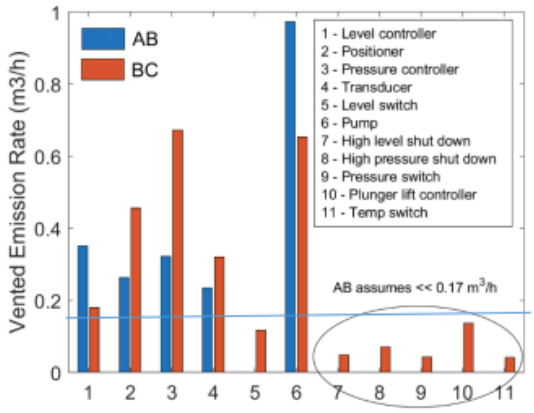


Figure 17: Comparison of vented emissions between this study (red) and Greenpath 2016 study in AB (blue).

From Cap-On BC study. Cap-On Energy BC Oil and Gas Methane Emissions Field Study. Page 53.

Challenges persist in the national extrapolation of emission factors from any single measurement study as different studies have noted regional, company, and service-level emission differences in emissions of pneumatic controllers. Most notably, studies such as EDF/UTexas have found large variation in emission rates for intermittent vent controllers with a small subset of devices (~19%) being responsible for the majority of the device emissions (~95%) and more than 50% of the sampled devices had no recorded emissions over the sample period. Based on analysis of time series data from the study measurements, the team was able to identify that most of the devices with elevated emissions were emitting in a manner that was inconsistent with manufacturer design.

A significant contribution to the uncertainty in emissions from pneumatic controllers is the high incidence of improper operations for pneumatic controllers. These problems have been identified in a number of studies, including the Ft. Worth AQ Study, the Prasino study linked above, and EDF/UTexas 2014. A recent study from Colorado State and U Texas (Luck et al. 2019) found that 42% of the 72 controllers successfully measured at US gas gathering sites were operating abnormally, with much higher emissions than from devices operating normally. 25 of the 40 (62.5%) intermittent-bleed controllers the researchers examined were operating abnormally, with high average emissions for the devices operating abnormally (about 16

scfh). The researchers also noted that in many cases the high emissions and abnormal operations were only observed because of the long observation time (average was over three days). Note that the precision and accuracy of the emission factors produced by this study was degraded by an instrumental problem described in the paper, but the authors concluded that the qualitative results of the study are robust despite the instrumental problem.

Baker Hughes, a GE Company, (BHGE) has released a report for Environmental and Climate Change Canada (ECCC) and Petroleum Technology Alliance Canada (PTAC) on 7-site (54 component) case study on the performance of a new component-level continuous monitoring technology (LUMEN). Briefly, the LUMEN technology is placed 12-16 inches from a known methane vent point to collect real-time part per million (ppm) methane readings. The methane reading is combined with on-site meteorological data into a model to infer associated emission rates. BHGE does not provide references or supporting information in the report to show the expected accuracy of the method relative to controlled releases. Experience in US-based testing of ambient methane detection technologies has shown that new technologies are often better at detection than emission rate quantification due to the inherent uncertainties in generating near-field dispersion characteristics directly. Components selected for the study were found to have emissions from an on-site screening, and 34 pneumatic controllers (3 dump valves, 18 level controllers, and 13 pressure controllers) were selected for long-term LUMEN deployment. In particular, several high bleeds were selected to show the difference between pre and post retrofits with lower emission technologies. Care should be taken in drawing conclusion between the long-term LUMEN measurements, and other methods of reporting emissions since the comparison to High Flow measurements is based on spot samples (versus time series, as is best practice in emission studies) and to emission factors as the comparison is being made in the report to emission factors from components (like valves) rather than pneumatic devices.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

Costs vary widely based upon type of unit and type of service.

Table 1 of the "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico" lists per unit costs for low-bleed pneumatic controller abatement technology as $49.30 per mcf of reduced methane ($2,563.40 per tonne).[1]

[1] "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico," Erin Camp, PhD, Nate Garner, Asa Hopkins, PhD, Synapse Energy Economics, Inc., September 13, 2019, page 9, Table 1, http://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf.

What are the annualized operating costs for the equipment or costs associated with the process?

Costs vary widely based upon type of service.

If the equipment or process is powered, what are the costs?

If electricity is available, some process controls and/or very small pumps may be able to be electrically powered. Air compression may be required. Solar-powered systems to power electric controllers have been demonstrated at production sites. Costs for solar-powered systems vary by facility size / configuration. Tools are available to estimate costs of solar-powered systems for a given site configuration.

Carbon Limits' produced a report with cost information for electric controllers (including solar power) and air-driven systems. https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/

Additionally, Carbon Limits produced an Excel Tool which can be used to calculate costs and emission reductions, using data from their report, for a site with a given configuration (power already available or not, various numbers of controllers and pumps, etc.). This Excel file is provided.

There is not a "one size fits all" tool (such as the Carbon Limits tool) that works on every oil and gas site with pneumatic controllers and pumps. For example, many tools apply tax break scenarios or credits that are assumed to be in the future or credits available today but are scheduled to not be available in the next few years. Oil and gas operators have internal tools to access feasibility, application, emission reductions and cost scenarios that can provide site specific applications.

Much of California has access to electricity in the oil and gas fields which changes feasibility and costs associated with applications of electric or air driven pumps. Colorado regulations have specific scenarios where implementation of the regulations are dependent on electrical availability and/or existing control devices. It is important to consider various conditions of existing location infrastructure on a site by site basis when developing costs for existing sources

What are the maintenance and repair costs for existing or new equipment?

Costs vary widely based upon type of service and type of unit.

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

There may be greater application of compressed air on new oil well locations with access to electricity. Manufacturers have focused on developing lower bleed devices which industry has been adopting for new facilities. EPA's New Source Performance Standard OOOO (2012) limited the installation of continuous high

NMED Exhibit 10 - 0019

bleed controllers in new construction, so over time, controllers are more likely to be low bleed, intermittent or compressed air. There are some services that require high bleed for safety or process purposes.

Existing LDAR quarterly reporting procedures may capture additional emissions reductions from malfunctioning pneumatic controllers with minimal extra cost to operators.[2]

New Wells:

N/A

Existing Wells:

N/A

How have the emission/waste reductions been measured?

Utilizing EPA emissions factors.

How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

Federal Regulations

EPA's New Source Performance Standard OOOO (2012) limited the installation of continuous high bleed controllers in new construction, so over time, controllers are more likely to be low bleed, intermittent or compressed air. https://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.oooo

NSPS OOOOa requires that natural gas driven diaphragm pump constructed or modified after September 18, 2015 and in use more than 90 days per year must reduce emissions by 95% unless there is not a control device; i.e., a flare or combustion device, or process available onsite. If a device is available but not capable of 95% reduction, operators must still route emissions to the device. If it is technically infeasible to capture and route the gas to a control device (for example if no low-pressure devices are available), operators are not required to meet the control standard. It is important to note that chemical injection pumps are exempt from these requirements.
https://ecfr.io/Title-40/sp40.8.60.oooo_0a

In 43 CFR 3178, BLM considers the use of produced gas as a motive force for actuating pneumatic controllers and pumps a beneficial use and, therefore, not waste. However, the original BLM methane

[2] "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico," Erin Camp, PhD, Nate Garner, Asa Hopkins, PhD, Synapse Energy Economics, Inc., September 13, 2019, page 9, Table 1, http://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf.

waste prevention rule did consider such gas a source of waste if the controller emits in excess of 6 scf per hour and required the operator to replace such pneumatic controllers with a controller (including but not limited to a continuous or intermittent pneumatic controller) having a bleed rate of 6 scf per hour or less within established timeframes. It also required the operator to ensure pneumatic controllers are functioning within manufacturers' specifications. For pneumatic diaphragm pumps, the rule required operators to replace all existing pumps with zero emissions pumps, which may be an electric-powered pump; or route the pump exhaust gas to processing equipment for capture and sale. 43 CFR 3179 [link to be identified]

State Regulations

Colorado's Regulation 7 Section XVIII
https://drive.google.com/file/d/168v7vMsFJtS7D8BWlnMbaXWA6uZUlyj8/view

Requires continuous bleed controllers to be replaced or retrofitted to be low bleed unless a high bleed is required for safety or process purposes. New controllers installed after May 2, 2014 use no-bleed where there is on-site electrical grid power and is technically and economically feasible. Controllers at gas processing plants installed after 1/1/2018 must be zero bleed. This is a statewide requirement.

In the ozone nonattainment control area, beginning 1/1/2018, owners or operators of natural gas driven pneumatics must inspect controllers at a frequency aligned with existing leak detection requirements.

California no longer allows installation of continuous-bleed pneumatic controllers (high-bleed or low-bleed). Continuous bleed natural gas-powered pneumatic devices installed prior to January 1, 2016 may be used. Emissions from existing continuous-bleed pneumatic controllers must be measured annually to ensure that the device emits below 6 scfh; any device emitting above 6 scfh must be repaired. Furthermore, California requires operators to inspect each intermittent-bleed controller during each (quarterly) LDAR inspection to ensure that the device is not emitting gas between actuations. Finally, pneumatic pumps may not vent to atmosphere in California. Note LDAR inspection frequency is summarized above as quarterly but frequency could be annual depending on whether it was subject to an LDAR program at the district level prior to the state rule implementation.

See https://ww2.arb.ca.gov/sites/default/files/2018-06/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf, § 95668(e) (pages 18-19)

British Columbia will not allow the installation of pneumatic controllers venting gas to atmosphere at new facilities built after 1/1/21, and will not allow existing pneumatic controllers to vent from large (>4000 HP) compressor stations after 1/1/22, in addition to limiting venting from all remaining controllers (including intermittent-bleed controllers) to 6 scfh (with exceptions for process/safety needs). BC will prohibit venting from new pneumatic pumps installed after 1/1/21 that operate more than 750 hours/year.

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See http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286 2018, pp 6-7.

Alberta requires that 90% of new controllers (at all facilities, new and existing) installed after 1/1/22 not vent to atmosphere. Alberta will also limit emissions from all controllers (intermittent-bleed and continuous-bleed), with the exception of level controllers, to 6 scfh. Level controllers that actuate more than 4x per hour must either "use a relay that has been designed to reduce or minimize transient or dynamic venting or adjust the actuation frequency to ensure that the time between actuations is greater than 15 minutes." Alberta will prohibit venting from new pneumatic pumps installed after 1/1/22 that operate more than 750 hours/year.

See https://www.aer.ca/documents/directives/Directive060_2020.pdf, §8.6.1 (pp 77-79).

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

In some situations, you can route gas from a pump back to a process or control. Feasibility depends on access to low pressure process device in close proximity for the pumps.

As described above, Colorado and California require regular inspection of pneumatic controllers at all sites to ensure that they are not emitting excessively.

As described above, Alberta requires specific actions for level controllers which actuate more than 4x per hour – either reducing actuation frequency, or installing a "relay that has been designed to reduce or minimize transient or dynamic venting."

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
Replace or retrofit high bleed pneumatic controllers	https://theenvironmentalpartnership.org/what-were-doing/pneumatic-controllers-upgrades/	**In use**	High	**Low**
Replace natural gas with air to actuate	https://www.epa.gov/sites/production/files/2016-06/documents/ll_instrument_air.pdf	**In use**	Medium – need access to reliable	Medium

pneumatic devices air on newly constructed oil wells	(note older document, cost of controls and price of gas are no longer accurate) https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/		grid power and only economic with a very large number of controllers on one site	
Route gas from a pump back to a process or control	https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf	**In use**	Low/Medium – need to have a low pressure process device in close proximity to the pump	
Electrical alternatives, including solar powered	http://www.calscan.net/solutions_ZeroGHGVenting.html (solar-powered package) https://exlar.com/content/uploads/2014/10/Venting-Solutions.pdf Small air compression solutions: https://westgentech.com/epod/ https://lcotechnologies.com/crossfire-compressor.html Electric/Solar Controllers: https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/	**In use**	Medium - Solar systems are in use in Canada and therefore should be feasible in NM. Supplier has not verified feasible in NM, power demand may be greater than solar can supply.	**Varies with site size / amt of pneumatic equipment.**

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

Replace or retrofit continuous, gas powered high bleed pneumatic controllers.

What are the pros and cons of the alternatives?

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Replacement or retrofit of high bleed devices is, in almost all cases, an effective emissions reduction.

For compressed air applications, economic drawbacks and challenges will create barriers for gas plays and smaller scale locations. In gas plays, the per-controller counts are much lower than oil plays, thus, creating a disincentive for the use of more expensive compressed air applications as those installations are uneconomic unless there is a significant number of controllers needed for the process. There are also application limitations as some services require rapid actuation response times; electric (including solar) may not be appropriate for pneumatic operations that require such rapid actuation response times.

With respect to controlling pumps, there are numerous potential safety and operational issues with connecting the discharge from a pneumatic pump to an existing control device and closed vent system. These issues can impact both the performance of the pump and result in back pressure on the other sources being controlled.

Whether considering a VRU, flare, enclosed combustion device, or any other control technique, control devices are designed for a specific set of conditions with a number of key assumptions. For example, a flare header might be designed to allow enough flow to permit two pressure safety valves (PSV) to open simultaneously without creating so much back pressure as to take either PSV out of critical flow. The design is sensitive to other flow streams in the pipe and putting a pump exhaust into that header could result in too much backpressure for the safety devices to function as intended. Conversely, but equally important, a pneumatic pump is chosen for a specific backpressure and the backpressure imposed by a PSV could stop the pump from functioning at a critical moment, exacerbating the already unstable situation that resulted in the opening of the PSVs.

Typically, pneumatics operate on a low-pressure gas stream. If the control device on a site is located a long distance from the pneumatic, the gas emitted from the controller make not make it to the control device, which can cause backpressure on the pneumatic and not allow for operation of the device. In particular, flares are often located at a safe setback distance from operational equipment. At times, control devices, such as flares, may operate at higher pressures than pneumatic devices, which would not allow for routing to the control device.

Additionally, enclosed combustion devices are designed for a maximum BTU load and may not be able to accommodate the exhaust gas from a pneumatic pump affected source without replacing the control device.

The design process for VRUs are even more sensitive to changes than other control devices. The VRU equipment is designed to recover vapors and raise their pressure enough to be useful, is expensive, and has a limited range of possible flow rates. Adding vapor loads to a VRU must be carefully evaluated on a case-by-case basis.

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In some instances, an existing control device on a particular site may be owned and operated by a third party, such as a control device owned and operated by a gathering and collection system operator with a glycol dehydration unit on a well site. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.

When evaluating use of compressed air on a location one important consideration is the system can introduce water into the pneumatic lines. Instrument air system have a tendency to introduce water into the pneumatic lines. Water can freeze in colder climates damaging the line or the device/pump. Water that makes it way to the device itself could cause the device to not operate or mis-operate. This could result in excess emissions on site.

What is needed and available for new wells?

NSPS OOOO already applies to new devices since October 2013. Pumps have been subject to NSPS OOOOa since late 2015.

Zero bleed solutions, including solar-powered, have been demonstrated at wellsites in Canada (noted above).

What is needed and available for existing wells?

Continuous high bleed pneumatic devices can be replaced in existing wells. NSPS OOOOa requirements are triggered for pumps that are replaced.

For larger existing wellpads (multiwell), retrofit with zero-bleed technology may be cost-effective.

What technology alternatives exist for this equipment or process itself?

In some cases, mechanical valves can be utilized without a pneumatic controller, but there are significant limitations including the control must be in close proximity to the process, can only be used for liquid level, and it may not be sufficient for some processes (like larger process flow or pressure). Retrofit is not feasible.

What are the pros and cons of the alternatives?

See above.

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

The cost of switching from a continuous high bleed controller to a lower emitting option depends on the option chosen, which is dependent on the type of service, and can be dependent on access to electricity. US EPA's control technique guidelines cite an average capital cost per unit as $2,698. https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf

What would be the implementation cost?

For new wells?

See above

Costs for compressed air vary depending on the size of the location the presence of reliable grid power, etc. Bringing power to a location for the sole purpose of a compressed air system is not cost effective.

For zero-bleed solutions such as solar-powered electric systems, cost and cost-effectiveness are a function of site size (chiefly, the number of controllers and pumps on site). Larger multi-well pads are more cost-effective for solar systems because of common equipment required for any size site (batteries, control panels, etc.) so costs do not scale with the number of controllers at the low end.

For existing wells?

See above

Clean Air Task Force prepared cost estimates of zero-bleed systems for existing wellsites in Colorado, as part of participation in rulemaking hearings in Colorado. Cost estimates were based on data from Carbon Limits' report, linked above. CATF used a tool prepared by Carbon Limits to calculate cost-effectiveness of the use of zero-bleed controllers (electric with solar power, or air-driven) at wellpads with various numbers of wells/controllers. Costs are shown in exhibit A, attached, pages 14-20.

There is not a "one size fits all" tool (such as the Carbon Limits tool) that works on every oil and gas site with pneumatic controllers and pumps. For example, many tools apply tax break scenarios or credits that are assumed to be in the future or credits available today but are scheduled to not be available in the next few years. Oil and gas operators have internal tools to access feasibility, application, emission reductions and cost scenarios that can provide site specific applications.

Much of California has access to electricity in the oil and gas fields which changes feasibility and costs associated with applications of electric or air driven pumps. Colorado regulations have specific scenarios where implementation of the regulations are dependent on electrical availability and/or existing control devices. It is important to consider various conditions of existing location infrastructure on a site by site basis when developing costs for existing sources.

Are there low-cost solutions available?

See above

If a solution is high-cost, why is that the case?

Solutions requiring the addition of reliable electricity would be cost prohibitive in most applications. In addition to the cost of bringing power to the site, the cost of electric counterparts to pneumatic devices could be about double the price in some applications.

Solar powered systems add costs to electric systems. Note that operators have reported lower maintenance costs for electric systems compared to field gas-driven pneumatic systems. See https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/ These lower costs offset higher equipment costs relative to venting gas-driven pneumatics.

Are there additional technical analyses needed to refine benefits/costs estimates?

N/A

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

With sufficient time for manufacturers to stock parts, it is feasible to replace or retrofit continuous high bleed controllers with a reasonable implementation period. For some replacements or retrofit activities, it is necessary to conduct such work during a turnaround.

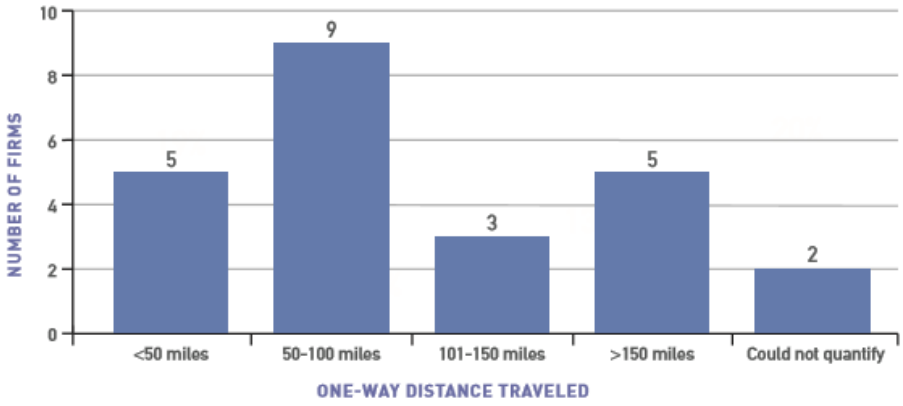
For leak detection, intermittent bleed controllers which are part of an existing LDAR program can be surveyed by waiting for the device to be non-actuating before using an optical gas imager or sniffer to see if there are emissions. For continuous bleed controllers, it is very difficult and subjective, to determine if the device is operating as designed or not. Conducting LDAR on a site just to monitor a controller can be very expensive, the variability is primarily driven by the cost of bringing out an operator to a site for an inspection. In 2017, EDF published a study called “The Emerging Methane Detection Industry” which indicates that median one-way travel distance to a site for an LDAR contractor is 50-100 miles. The study notes that 21% of firms interviewed have a typical travel distance of 300-1,000 miles one way to a site.

California also subjects both continuous and intermittent bleed natural gas pneumatic devices to LDAR. 17 C.C.R. § 95668 (e). Colorado subjects natural gas driven pneumatics to LDAR requirements (with stricter requirements for non-attainment areas). 5 CO ADC 1001-9:XVIII.D.

See final MAP Leak Detection and Repair Report.

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FIGURE 7. Typical One-Way Travel Distance Reported



SOURCE: Industry Interviews
NOTE: Based on a sub-sample of 24 LDAR firms

https://www.daturesearch.com/wp-content/uploads/Methane-Mitigation-Industry-Report_Final.pdf

What is the useful life of equipment?

N/A

What are the maintenance and repair requirements for equipment required for methane reduction?

There is no difference in maintenance and repair between a high and low bleed continuous emitting controller.

How would emissions be detected, reductions verified and reported?

Operators report the number of devices through the GHGRP if they meet the emissions threshold per basin to require reporting.

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

Gaps filled by proposed continuous high bleed retrofit or replacement.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

None

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

No

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc?):

None

DRAFT

5. PNEUMATICS PATH FORWARD[3]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EMISSIONS REDUCTIONS ARE EASY TO ACHIEVE AND ARE COST EFFECTIVE 1 = EASY 5 = HARD	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
1.1	Replace or retrofit continuous high bleed pneumatic controllers to low bleed	https://theenvironmentalpartnership.org/what-were-doing/pneumatic-controllers-upgrades/ 76% - 97% reduction (sources: https://www.edf.org/nm-oil-gas/scenarios, https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf	1 2 3 4 5 HIGHLY Bleed rate per EPA	GHGRP reporting	San Juan Permian **Both**
	COMMENT A. Safety and process needs may warrant high bleed installations. [page 20] B. Cost recovery of about 1 year in the SJB [page 25]		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
1.2	Replace natural gas with air to actuate pneumatic devices on newly constructed oil wells	https://www.epa.gov/sites/production/files/2016-06/documents/ll_instrument_air.pdf (note older document, cost of controls and price of gas are no longer accurate) Economic drawbacks and challenges will create barriers for gas plays and smaller scale locations •Low or high bleed to zero bleed, or zero-bleed at new facilities: 100% reduction (https://www.edf.org/nm-oil-gas/scenarios)	1 2 3 4 5 Depends on site scale, etc. 11.3 scf/hour for intermittent	No Reporting because no emission source.	San Juan **Permian** Both (Access to electricity and multi-well head

[3] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

NMED Exhibit 10 - 0030

					sites more likely in the Permian.)
	COMMENT A. Adequate, reliable electric service is not always readily available when needed. See electricity-cross cutting issues. [page 19]		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE: B. If electrical infrastructure available and site with sufficient number of pneumatics. [page 22] C. Need to identify equipment that must be operated on speed. [page 24]		
1.3	Replace natural gas driven pneumatics with electric actuators / pumps when direct power (line power) is available.	https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/	1 2 3 4 5 Depends on site scale, etc. Cost spreadsheet (as function of site size, etc.) available from CATF		San Juan Permian **Both**
	COMMENT A. Use is application specific-not general. [page 24] Actuation response of electric actuators may be inadequate for certain controllers. Introduction of electric actuation can result in reliability/control issues due to additional mechanical complexity. [Devices too slow in some cases.] [page 24] B. Many cases may be general and it is possible to identify exceptions. [page 24]		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
1.4	Replace natural gas driven pneumatics with electric actuators / pumps, using	https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/	1 2 3 4 5 Depends on site scale, etc.		San Juan Permian **Both**

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	solar or on-site generation when grid power is not on-site		Cost spreadsheet (as function of site size, etc.) available from CATF		
	COMMENT A. The economics being run could not just be for solar power. It would need to include some sort of back-up power source (battery, etc.) to allow for controllers to function at night and during less sunny periods. [page 19] B. Solar power (unless for running an air compressor) would force the use of electric controllers, which are not as common as pneumatic controllers in oil and gas applications. [page 11] C. Actuation response may not be adequate in certain applications. [page 24] D. Insufficient solar/battery capacity can result in inadequate action and/or additional shutdowns which may result in flaring. [page 26] E. Acreage requirements prohibitive [for solar]. Also cost prohibitive to obtain adequate motive force using solar. [page 26] F. Be sure there is consideration of the whole volume of emissions – gas driven generation vs 2 pneumatic valves.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE: Workability of suggestion is application specific		
1.5	Where technically feasible and considering safety and backpressure issues, route gas from a diaphragm	https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf	1 2 3 4 5 LOW	GHGRP, OOOOa reports	San Juan Permian **Both**

NMED Exhibit 10 - 0032

	pump back to a process.				
	COMMENT A. This is only feasible if there is a low-pressure device in close proximity to the pump. Otherwise there is not enough pressure. [page 20] B. Limited applicability (b/c of number of diaphragm pump.) Requires low pressure process device to take the gas in close proximity to the pump. [page 22] C. Maybe used at a large site. [page 25]		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
1.6	LDAR on intermittent bleed pneumatics when not actuating	Quarterly LDAR for malfunctioning: 68% reduction (Source: https://www.edf.org/nm-oil-gas/scenarios)	1 2 3 4 5 HIGH If part of an existing LDAR program.		San Juan Permian **Both**
	COMMENT A. If there is an existing LDAR program. Would add an additional 15 minutes if already conducting LDAR inspection. [page 27] B. Not a binary decision – see citation for CO rule and how pneumatics are treated differently. [page 22]		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

DRAFT

SECTION 2, LEAK DETECTION AND REPAIR

Discussion for MAP members on November 7 and 8, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

Oil and gas production facilities contain numerous equipment components such as connectors, covers, closed vent systems (CVS's), flanges, instruments, meters, open ended lines (OEL's), pressure relief devices (PRD's), thief hatches, valves and others (see list from EPA 4/12/2018 Memo: Equivalency of State Fugitive Emissions Programs…). These components are manufactured and installed in ways intended to contain gases or liquids. Although these equipment components are designed to be gas tight, over time leaks can occur. The leaks (emissions) from these components are called fugitive emissions[4]. Fugitive emissions do not include equipment that is designed to vent or release emissions as part of normal operations or equipment that is already subject to monthly AVO inspections under NSPS 60.5411a or 60.5395a (see OOOOa definition of Fugitive Emission Component). Fugitive emissions result from changes in pressure, temperature or mechanical stresses or when seals and gaskets are not fitted or deteriorate over time.

The largest sources of fugitive emissions are generally detected quickly without advanced detection tools. These events are usually detected by observable changes by operators conducting routine inspections using sight, sound or smell (specifically in older facilities, and in operating parameters (i.e. Supervisory Control and Data Acquisition (SCADA) system detection when available, change in sales volume at the meter, compressor shut down).

Leak detection and repair (LDAR) programs employ specialized detection equipment to detect fugitive emissions, which also sometimes include audio, visual, and olfactory observations, generally target sources of fugitive emissions. The most commonly used leak detection equipment is an optical gas imager, but in some areas like parts of California, companies

[4] Where devices are designed to vent as part of normal operations, such as natural gas-driven pneumatic devices or uncontrolled storage vessels, the natural gas and associated VOC emissions are not considered a fugitive emission. These emissions are covered in other MAP papers.

also use handheld "sniffers" (portable hydrocarbon detectors) and Tunable Diode Laser Absorption Spectroscopy devices. The detection technology space has received significant investment over the past several years, including the U.S. Department of Energy's MONITOR program[5]. The results of this investment are just beginning deployment and are beginning to approach commercial scale for some technologies.

In 1990, the Clean Air Act was enacted to address several subject matters including volatile organic compounds (VOCs). This action included the implementation of a Leak Detection and Repair (LDAR) Program to use portable instrumentation and processes to locate emission leaks on process equipment that includes, but is not limited to, things such as compressors, flanges, and valves. If leaks are discovered, they are scheduled for repair.
Traditional technology leak detection technologies allowed by Method 21 include: gas sniffers such as Toxic Vapor Analyzers, organic vapor analyzers, and flame ionization detectors (FID). Moreover, the traditional Method 21 protocol also allows the use of soap bubbles for leak detection which can be very sensitive for small leaks but is not appropriate for hot surfaces. With the introduction of handheld optical gas imaging (OGI) in 2005, the EPA was urged to enact "smart LDAR." Thus, the EPA's Alternative Work Practice (AWP) was enacted to allow OGI in lieu of the "sniffer" method in December 2008. In June 2016, the EPA published an amendment to the NSPS regulations that recognized OGI as the Best System for Emissions Reduction (BSER). Traditional Method 21 is now an alternative to OGI with conditions.

Provide the segment(s) of the industry that the equipment or process is found:

Components that have potential to leak can be found throughout the production, midstream, gas plants, transmission and distribution sectors.

Describe how the equipment or process is used:

Components serve numerous purposes throughout the value chain. They are all intended to contain gas, but may develop leaks.

Provide the common process configurations that use this equipment or process

N/A

What is the distribution of the equipment or process across business segments?

This equipment is found in upstream, midstream, transmission and distribution segments.

How has this equipment or process evolved over time?

Over time, awareness of the potential for leaks has grown, so has the number of technology solutions available to detect leaks. Over time, operators minimize threaded connections, receive specific training, conduct preventive maintenance and utilize tools such as SCADA to monitor for changes in process parameters which may indicate a leak.

Federal regulations first specifically addressed oil and natural gas related emissions with the implementation of the Method 21 Alternative Work Practices (AWP) in 2008 and later with the NSPS 2012 OOOO and 2016 OOOOa regulations. Though traditional Method 21 sampling methodologies have been in existence for years, the LDAR components of these most recent regulations were aided by the introduction of OGI and various vent gas recovery infrastructure and procedures.

[5] https://arpa-e.energy.gov/?q=arpa-e-programs/monitor

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

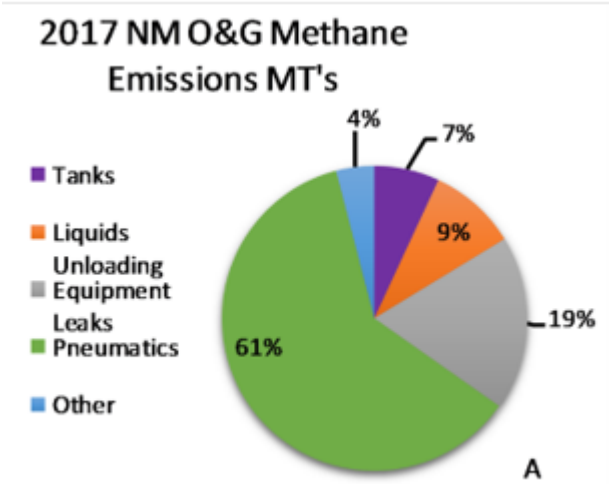
Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

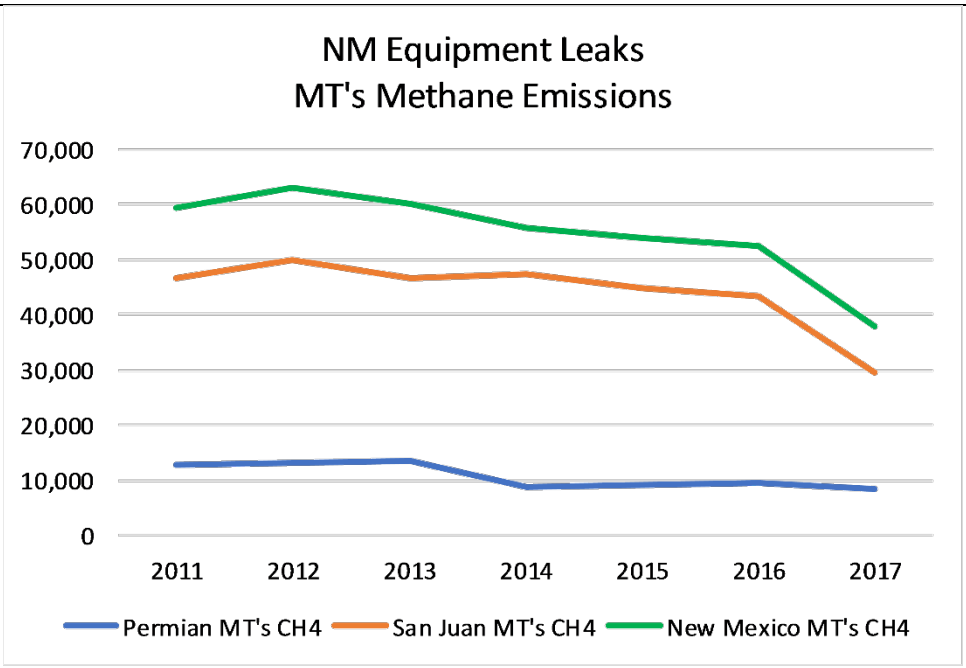
Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

Leaks, or fugitive emissions, can develop in a range of equipment that is widely deployed across the value chain. Connectors, valves, seals, tubing, open ended lines, and flanges, while designed to contain gas, can develop leaks over time.

Analysis of GHGRP data found in the New Mexico Oil and Gas Association's Methane Mitigation Roadmap below: https://www.nmoga.org/methaneroadmap





NM equipment leak methane emissions

Leaking components, and equipment as well as improperly operating or malfunctioning equipment, contribute leaks that can be addressed by frequent inspections. The following summarizes studies identifying leaks from a variety of oil and gas sources.

I. Field Studies Using Direct Measurement Demonstrate the Need for Frequent Instrument-Based Inspections: Significant Emissions May Emanate From Individual Components and Operations

The scientific consensus, based on numerous studies involving direct measurement of oil and gas leaks, demonstrates the heterogeneous, unpredictable, and ever-shifting nature of equipment leaks. These characteristics strongly point toward the need for frequent, *if not continuous*, inspections to identify and repair leaking components and equipment. Specifically:

- **Leaks are Heterogeneously Distributed.** There is considerable evidence that emissions from equipment leaks are heterogeneously distributed—with a small percentage of sources accounting for a large portion of emissions.[6] The concentration of emissions within a relatively small proportion of sources has been observed both among groups

[6] *See, e.g.*, Allen, D.T., *et al.*, "Measurements of methane emissions at natural gas production sites in the United States," *Proc. Natl. Acad.*, 110 (44) pp. 17768–17773 ("Allen (2013)"), *available at* http://www.pnas.org/content/110/44/17768.full; ERG and Sage Environmental Consulting, LP, "City of Fort Worth Natural Gas Air Quality Study, Final Report" ("Fort Worth Study") (July 13, 2011), *available at* http://fortworthtexas.gov/gaswells/default.aspx?id=87074 (finding that the highest 20 percent of emitting sites account for 60–80 percent of total emissions from all sites; the lowest 50 percent of sites account for only 3–10 percent of total emissions); Zavala-Araiza, *et al.*, (2015) "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," *Environ. Sci. Technol.*, 49, at 8167−8174 ("Zavala-Araiza (2015)"), *available at* http://pubs.acs.org/doi/pdfplus/10.1021/acs.est.5b00133 (finding that "functional super-emitter" sites represented approximately 15% of sites within each of several different "cohorts" based on production, but accounted for approximately 58 to 80% of emissions within each production cohort); Zavala-Araiza et al., (2015) "Reconciling divergent estimates of oil and gas methane emissions," Proceedings of the National Academy of Sciences, vol. 112, no. 51, 15597 at 15600 (finding that "at any one time, 2% of facilities in the Barnett region are responsible for 90% of emissions, and 10% are responsible for 90% of emissions.") ("Barnett Synthesis").

of components within a site and among groups of entire facilities.[7] One study in particular found that a small number of sources are responsible for a disproportionate amount of emissions, noting specifically that "sites with high proportional loss rates have excess emissions resulting from abnormal or otherwise avoidable operating conditions, such as improperly functioning equipment."[8]

- **Super-Emitters Are Not Included in Inventories**. Existing inventories do not accurately reflect the presence of disproportionally high emissions or "super-emitters."[9] A recent series of studies in the Barnett Shale region in Texas (the "Barnett Coordinated Campaign")—incorporating both top-down and bottom-up measurement—found that emissions were 50 percent greater than estimates based on the GHGI.[10] This study confirms the findings of various prior studies.

  The first of these studies, conducted by an independent team of scientists at the University of Texas, found that emissions from equipment leaks, pneumatic controllers and chemical injection pumps were each 38%, 63% and 100% higher, respectively, than as estimated in national inventories.[11] This study also found that 5% of the facilities were responsible for 27% of the emissions.[12]

  Two follow-up studies focused specifically on emissions from pneumatic controllers and liquids unloading activities at wells found similar results.[13] Specifically, the studies found that 19 percent of the pneumatic devices accounted for 95 percent of the emissions from the devices tested, and about 20 percent of the wells with unloading emissions accounted for 65 to 83 percent of those emissions. The average methane emissions per pneumatic controller were 17 percent higher than the average emissions per pneumatic controller in EPA's national greenhouse gas inventory.[14]

  These findings were reiterated again in a series of direct measurement studies focusing on emissions from compressor stations in the gathering and processing segment and in the transmission and storage segment. The gathering and processing study found substantial venting from liquids storage tanks at approximately 20 percent of the sampled gathering facilities.[15] Emission rates at these facilities were on average four times higher than rates observed at other facilities and, at some of these sites with substantial emissions, the authors found that company representatives made adjustments resulting in immediate reductions in emissions. In the study on transmission and storage emissions, the two sites with very significant emissions were both due to leaks or venting at isolation

[7] *See* EPA, "Oil and Natural Gas Sector Leaks: Report for Oil and Natural Gas Sector Leaks" (2014), *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.
[8] Zavala-Araiza (2015), supra note 1, at 8167−8174.
[9] Barnett Synthesis, supra note 1, at 15599
[10] Harriss, *et al.*, (2015) "Using Multi-Scale Measurements to Improve Methane Emissions Estimates from Oil and Gas Operations in the Barnett Shale, Texas: Campaign Summary," *Environ. Sci. Technol.*, **49**, ("Harriss (2015)"), *available at* http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305 (providing a summary of the 12 studies that were part of the coordinated campaign).

[11] Allen (2013), supra note 1, at 110.
[12] *See* Allen, D.T., et al, (2015), "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environ. Sci. Technol*., 2015, 49 (1), pp. 633–640 (referencing 2013 Allen study), ("Allen (2015)"), available at http://pubs.acs.org/doi/abs/10.1021/es5040156 (Allen 2014).
[13] Allen, D.T. et al., "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings," *Environ. Sci. Technol*., 2015, 49 (1), pp 641–648, available at http://pubs.acs.org/doi/abs/10.1021/es504016r.
[14] Allen (2015), supra note 7, pp 633–640.

[15] Mitchell, A.L., et al, (2015) "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants," *Environ. Sci. Technol*, 2015, 49 (5), pp 3219–3227, available at http://pubs.acs.org/doi/abs/10.1021/es5052809.

valves.[16] The study also found that leaks were a major source of emissions across sources, concluding that measured emissions are larger than would be estimated by the emission factors used in EPA's reporting program.

- **Equipment Leaks are Unpredictable**. Recent studies have assessed whether well characteristics and configurations can predict super-emitters, concluding that they are only weakly related,[17] and that these emissions are largely stochastic. A recent helicopter study of 8,220 well pads in seven basins confirms that leaks occur randomly and are not well correlated with characteristics of well pads, such as age, production type or well count.[18] That study focused only on very high emitting sources, given the helicopter survey detection limit which ranged from 35–105 metric tons per year of methane. The paper reported that emissions exceeding the high detection limits were found at 327 sites. 92 percent of the emission sources identified were associated with tanks, including some tanks with control devices that were not functioning properly and so could be expected to be addressed through a leak detection and repair program. While the study did not characterize the individually smaller but collectively significant leaks that fell below the detection limit, it nonetheless confirms that high-emitting leaks occur at a significant number of production sites and that total emissions from such leaks are very likely underestimated in official inventories.

- **Super-Emitters Shift in Time and Space**. Abnormal operating conditions, such as improperly functioning equipment, can occur at different points in time across facilities.[19] While it is true that at any one time roughly 90% of emissions come from 10% of sites, these sites shift over time and space—meaning that, at a future time, a different 10% of sources could be responsible for the majority of emissions.[20]

Other studies resulted in similar findings. In a 2013 study measuring emissions from 200 well pads in the Barnett Shale researchers found that approximately 20% of the well pads were responsible for 80% of the emissions detected.[21] Another study focusing on short-term and maintenance-related emissions at well pads in Texas, Wyoming and Colorado found "a weak correlation between emission and production rates."[22] This multi-state study suggests that maintenance-related stochastic variables and the ways in which facilities and control equipment are designed can be important factors affecting emissions. (NOTE: to be determined if this is a modeling or measurement study.)

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[16] R. Subramanian, et al, (2015) "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol*, available at http://pubs.acs.org/doi/abs/10.1021/es5060258.

[17] Lyon, *et al.*, (2015), "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region," *Environ. Sci. Technol.*, 49, at 8147-57, *available at* http://pubs.acs.org/doi/pdf/10.1021/es506359c; *See also* Brantley, H.L., *et. al.*, "Assessment of methane emissions from oil and gas production pads using mobile measurements," Environmental Science & Technology, 48(24), pp.14508-14515, *available at* http://pubs.acs.org/doi/abs/10.1021/es503070q (assessing where well characteristics can predict emissions, concluding that they are weakly related and that emissions are largely stochastic); Zavala-Araiza (2015) ("large number of facilities in the Barnett region cause high emitters to always be present, and these high-emitters seem to be spatially and temporally dynamic. . . .To reduce those emissions requires operators to quickly find and fix problems that are always present at the basin scale but that appear to occur at only a subset of sites at any one time, and move from place to place over time.").

[18] Lyon, et al., "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environ. Sci. Technol.*, 2016, *50* (9), pp 4877–4886, available at http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705.

[19] Barnett Synthesis, supra note 1 at 15600.

[20] *Id*.

[21] Rella, Chris W., et al, (2015), "Measuring Emissions from Oil and Natural Gas Well Pads Using the Mobile Flux Plane Technique," *Environ. Sci. Technol*., 2015, 49 (7), available at http://pubs.acs.org/doi/abs/10.1021/acs.est.5b00099.

[22] Brantley, supra note 12, at 48.

A recent synthesis of the U.S. studies conducted over the past six years concluded that U.S. production emissions are 60% higher than inventories suggest.[23] Data for this study included measurement of emissions from over 400 individual well pads in six different US basins, validated against "top-down" airborne measurements of emissions from nine oil and gas producing basins. The authors of this synthesis study, as well as the underlying studies analyzed in the synthesis paper, include academics from twenty-five different research institutions. These scientists have concluded that the substantial extra emissions observed in these studies, compared to official inventories, likely arise from improper and abnormal operating conditions at the site level that are best addressed by frequent, if not continuous, inspections.

The nature of these events, specifically that they are unforeseen and unpredictable, require that operators vigilantly inspect their equipment and operations for leaks. Frequent inspections using modern leak detection equipment is one of the most effective way to minimize the pollution associated with these stochastic events.

The table and summary below, taken from the 2018 Omara et al study (link also below) shows the kg/hr of various studies in various basins. When compared to the EDF report referenced above there appears to be some information that stands out. In the recent report EDF says the following about the kg/hr emissions rates, the weighted average is about 14. The Omara study had an average of 1.79 kg/hr.

	Basin-level activity					Basin-level CH4 emissions					CH4 distribution			
Major O&NG Basin (EIA sedimentary basin boundary)	Total # well pad sites	# Wells /Pad	CH4 fraction in NG	CH4 fraction in NG reference	Basin-level CH4 prod (kg/h)	Mean Basin-level CH4 (kg/h)	Basin-level CH4, Lower bound (kg/h)	Basin-level CH4, Upper bound (kg/h)	CH4 kg/h/ site	Basin-level mean prod-normalized CH4 emissions (%)	% of mean total CH4 contributed by <10 Mcfd sites	% of mean total CH4 contributed by 10 to 100 Mcfd sites	% of mean total CH4 contributed by 100 to 1,000 Mcfd sites	% of mean total CH4 contributed by >1,000 Mcfd sites
Appalachian	150,000	1.13	0.83	O&G estimation tool	15,500,000	140,000	95,000	180,000	0.91	0.9%	37%	36%	2.9%	23%
Permian	59,000	1.05	0.79	O&G estimation tool	4,360,000	110,000	67,000	150,000	1.80	2.5%	9.7%	58%	24%	7.8%
Western Gulf	33,000	1.12	0.88	O&G estimation tool	7,860,000	82,000	51,000	130,000	2.50	1.0%	4.8%	38%	37%	22%
TX-LA-MS-Salt	40,000	1.10	0.88	O&G estimation tool	6,460,000	79,000	50,000	110,000	2.00	1.2%	5.4%	43%	38%	13%
Anadarko	25,000	1.08	0.91	O&G estimation tool	3,460,000	59,000	39,000	91,000	2.30	1.7%	4.0%	51%	36%	9.5%
Fort Worth	20,000	1.40	0.88	O&G estimation tool	3,360,000	47,000	28,000	71,000	2.40	1.4%	7.1%	34%	43%	17%
Arkoma	13,000	1.31	0.94	O&G estimation tool	3,090,000	33,000	23,000	55,000	2.50	1.1%	4.7%	42%	36%	15%
Denver	20,000	1.35	0.82	O&G estimation tool	1,330,000	37,000	24,000	49,000	1.90	2.8%	12%	68%	11%	9.6%
San Juan	16,000	1.06	0.83	O&G estimation tool	681,000	31,000	20,000	41,000	2.00	4.5%	3.7%	77%	16%	1.4%
Uinta-Piceance	12,000	2.08	0.81	O&G estimation tool	1,950,000	29,000	17,000	40,000	2.40	1.5%	4.0%	48%	34%	15%
Greater Green River	8,800	1.59	0.78	O&G estimation tool	2,850,000	25,000	14,000	34,000	2.90	0.9%	0.9%	31%	44%	25%
Williston	11,000	1.45	0.51	Brandt et al.[23]	1,020,000	22,000	9,900	24,000	2.00	2.2%	3.3%	55%	30%	14%
San Joaquin	16,000	1.50	0.83	O&G estimation tool	312,000	15,000	10,000	21,000	0.94	4.8%	26%	54%	19%	0.9%
Cherokee Platform	7,000	1.14	0.88	O&G estimation tool	182,000	8,700	6,100	12,000	1.30	4.8%	23%	61%	15%	2.0%
Powder River	3,400	1.09	0.85	O&G estimation tool	292,000	4,900	3,400	7,600	1.40	1.7%	21%	49%	20%	8.8%
Michigan	2,500	1.00	0.83	O&G estimation tool	193,000	5,400	3,500	8,100	2.20	2.8%	4.9%	59%	33%	4.5%
Ardmore	2,100	1.38	0.83	O&G estimation tool	236,000	4,300	2,400	5,600	2.00	1.8%	10%	47%	33%	11%
Other Basin	56,000	1.11	0.84	O&G estimation tool	2,330,000	100,000	69,000	140,000	1.80	4.4%	9.3%	77%	14%	2.7%
US Total	498,000	1.16			55,466,000	830,000	530,000	1,170,000	1.67	1.50%	12%	51%	24%	13%

For the 42 complex sites, there was a good log-normal fit; bootstrapping from the log-normal function resulted in a mean and 95% confidence interval EF of 18.2 (5.2 - 79) kg CH_4 site^{-1} h^{-1}. Human classification of satellite imagery outsourced with Amazon Mechanical Turk estimated that 33% of Permian well pad sites were complex with a slight dependence of percentage of complex sites on gas production. The 15th percentile lower bound EF of 9.2 kg CH_4 h^{-1} was applied to ~8,600 complex sites; the 0.04 kg CH_4 h^{-1} detection limit was applied to the ~17,200 simple sites. (LINK: https://pubs.acs.org/doi/10.1021/acs.est.8b03535)

[23] Alvarez, et al., "Assessment of methane emissions from the U.S. oil and gas supply chain" Science, June 2018, http://science.sciencemag.org/content/early/2018/06/20/science.aar7204.full.

I also think this table is interesting. In 7 months, EDF went from saying GHGRP is 3.5 times too low to 5 times too low.

EDF Study or Report Title	Primary Study Author	Compared to GHGRP	Methane (metric tons)
EDF Report	EDF - April 11, 2019	5 times too low	1,000,000
Methane emissions from natural gas production sites in the United States: Data synthesis and national estimate	Omara – Sept 2018	3.5 times too low	570,000

Recent studies show a dynamic change in leak rate. It appears the Littlefield study and the Alvarez study used the same measurement data, but there is a significant increase in leak rate between the two.

EDF Study or Report Title	Primary Study Author	Methane Leak Rate
Methane emissions from natural gas production sites in the United States: Data synthesis and national estimate	Omara – Sept 2018	3.4%
Assessment of methane emissions from the US oil and gas supply chain	Alvarez – July 2018	2.3%
Synthesis of Recent Ground-level Methane Emission Measurements from the U.S. Natural Gas Supply Chain	Littlefield - January 2017	1.7%

New Wells:

Leaks can be found at new and existing facilities. Data provided by the American Petroleum Institute (API) to EPA shows that the number of leaking components per site during initial instrument-based inspection is less than 2, and falls to less than 1 in subsequent surveys. (link) This dataset consisted of 6,000 total surveys across 3,482 sites and 13

operators across CO, LA, ND, NM, OH, OK, PA, TX, WY. The percent of sites where zero leaks were found is 58% and the average number of leaks found per site was 1.42 for the first survey and declines for subsequent surveys.

Existing Wells:

Leaks can be found at new and existing facilities.

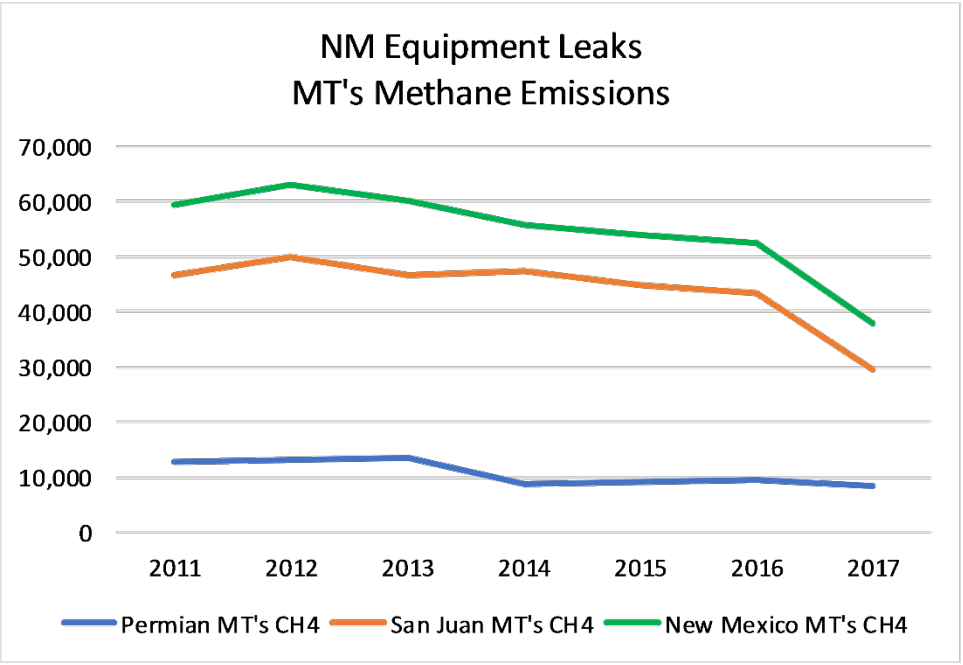
How are the emissions calculated for this equipment or process?

US EPA provides multiple methods for estimating fugitive emissions which can be found at the link below. Traditionally, most operators use an approach that was based on site major equipment counts (i.e. number of separators, wellheads, etc.), default component counts (i.e. valves, flanges, etc.) per piece of major equipment, and default emission factor per component (i.e. average scf per hour per valve) that includes an assumed percentage of leaking components based on field work in the 1990s. Revisions to the EPA methods linked to OOOOa reporting, but voluntarily open to operators for use for sites not subject to OOOOa sites, use actual leak occurrence rate from instrumented surveys and a leak/no leak emissions factor. This method is just beginning to be required for OOOO sites but it does appear that when operators switch from the assumed leak occurrence rate to actual leak occurrence rate, emissions estimates are lower.

Equation from GHGRP Subpart W: https://www.ecfr.gov/cgi-bin/text-idx?SID=3393fe39418e975c59618f6249f55516&mc=true&node=se40.23.98_1233&rgn=div8

What data is available to quantify emissions/waste for this equipment or process?

The US EPA publishes most of the emission information and activity data that it receives as part of the US GHG Reporting Program annually (https://ghgdata.epa.gov/ghgp/main.do?site_preference=normal#). By March 31st of each year, operators upload their emission information based up on the annual national average and prescribed EPA methodologies to the EPA website for the previous year (i.e. 2018 emission information was reported in March 2019), EPA undertakes a quality assurance process, and uploads the information in October to a publicly accessible website. Care should be taken in estimating emissions from this inventory for New Mexico since both the Permian and San Juan Basins span multiple states and it's challenging to separate emissions between states for all source categories. In the analysis below, NM data was separated from surrounding state data utilizing DrillingInfo data (a database of state well permit information). Also, operators with less than 25,000 MT CO_2e emissions are exempt from reporting emissions to the GHGRP. Therefore, for the production segment, all emissions were scaled up to the total well count reported by the New Mexico Oil Conservation Division (NMOCD) (EIA for national). For the G&B segment, there is no information to enable scaling-up GHGRP reported emissions and raw GHGRP reported emission quantities are shown.



NM equipment leak methane emissions

Analysis of GHGRP data found in the New Mexico Oil and Gas Association's Methane Mitigation Roadmap: https://www.nmoga.org/methaneroadmap

What are the data gaps in quantifying emissions/waste for this equipment?

Numerous studies have measured emission rates from specific types of oil and gas sources, including equipment components that are the primary focus of LDAR programs. Other types of studies have conducted off-site measurements (such as ambient methane concentration data collected on roads near sites using OTM33a) or detection of emissions (such as from aerial helicopter surveys) and have inferred emission rates based on atmospheric modeling or other indirect methods. While different study approaches can provide different information on methane emissions, the most useful studies for assessing emission detection and mitigation from LDAR components focus on approaches that provide component-specific information and that utilize proven tools deployed in the upstream oil and gas industry.

Leak data on marginal wells is very limited and warrants further study through objective, transparent, repeatable, and reliable emissions measurements.

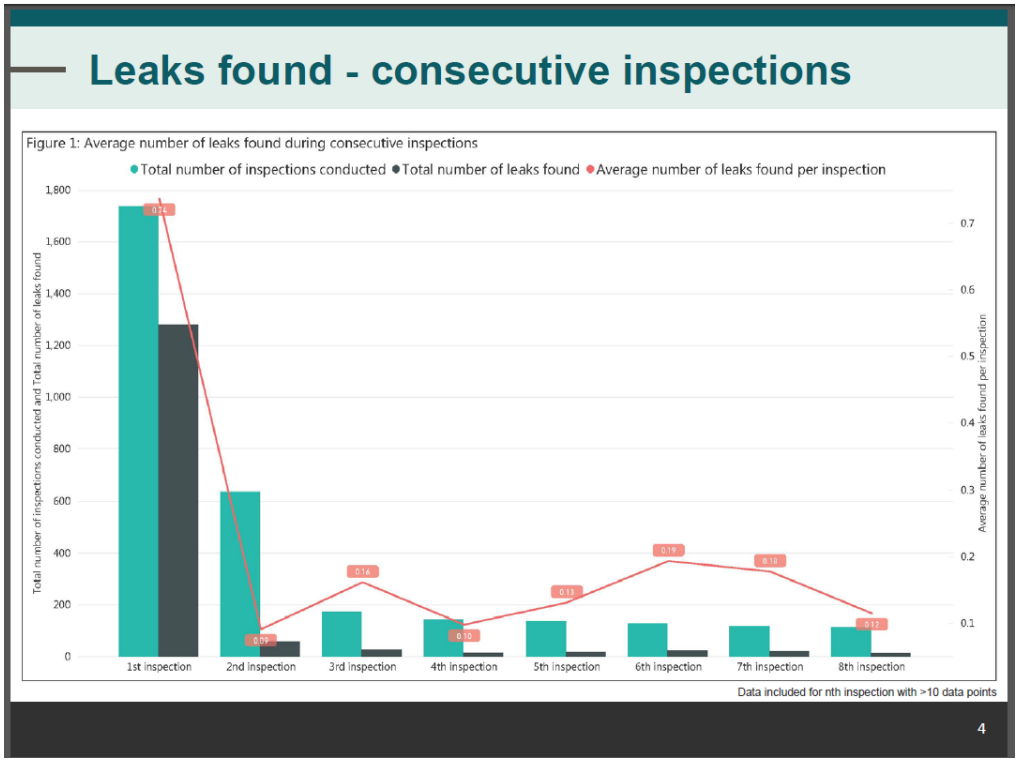
Different industry trade associations have collected information on the number and frequency of leaks detected under existing Federal and state-level programs. As with typical LDAR programs, the number of leaks detected and repaired are recorded but quantification of the detected leaks was not reported.

- A recent review of NSPS OOOOa leak survey data indicates that annual inspection frequency is appropriate for non-marginal well sites or facilities.[24] . (link) Data from various federal and state and inspection programs, including Colorado, demonstrates that the initial component leak rate from initial inspection surveys, show a significantly lower

[24] https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-0015

number of leaks than previously assumed. For example, an API analysis of initial NSPS OOOOa inspections showed that only 0.4% of components are found to be leaking during the initial inspection. (link)

- West Slope Colorado data represented in the figure below from 6 operators at 1,700 facilities showed a 0.74 component leaks per site with emissions less than 6 tons per year VOC. (link)



- Additionally, the number of leaks found in inspections at subject facilities in Colorado show a 52% decrease in the number of leaks from 2015 to 2017, while the number of facilities inspected increased by 9%.[25].

Several peer-reviewed studies have also assessed equipment leak emissions more directly by utilizing typical LDAR tools (FLIR cameras, sniffers, etc.) to detect leaks on sites and specialized tools like high volume samplers to quantify emissions from detected leaks. Due to the time requirements for quantification, the sample sizes of sites tend to be smaller than the data presented from industry LDAR programs like those mentioned in the bullets above. In total, these studies have typically found that emission estimates for equipment leaks (leaking valves, flanges, etc.) that are similar to or lower than emission estimates used in EPA reporting. These studies include:

- Researchers at the University of Texas at Austin led a field campaign (link) that measured methane emissions at 190 new onshore gas well sites in the United States, including from 278 identified equipment leaks. The study developed regional emission factors for estimated methane emissions from equipment leaks per well to compare with methods that EPA had utilized for estimating emissions for national emission inventories at the time of the study and found that emissions per well were similar to EPA emission factors at the time. EPA has since changed its approach for estimating equipment leaks nationally to reflect the equipment-specific information that is available through the GHGRP.
- A 2015 field campaign (link) that was funded by the American Petroleum Institute (API) included leak detection at 67 production and gathering and boosting sites throughout the Western United States with both a FLIR camera and

[25] https://www.colorado.gov/pacific/cdphe/2017-ldar-annual-reports-regulation-7-section-xvii

a sniffer as well as quantification of all leaks determined with either method. The study found a leak rate of 0.39% of components surveyed and that quantified emission rates from equipment leaks were 22%-36% less than would have been calculated from EPA emission factors based on site-level component counts. The study also notes that the study upon which current EPA emission factors were based from the early 1990's identified 1.77% of components as leaking with a sniffer versus 0.35% with the same technology (sniffer) and leak definition (500 ppm) in the 2015 field campaign.

- A study of 25 natural gas sites in California (link) found that component-level emission factors (i.e. methane emissions per valve) were lower than those used in EPA GHG reporting.

To our industry knowledge, no specific peer-reviewed studies have been undertaken to develop New Mexico-specific emission factors for equipment leaks. The API 2015 field campaign did include measurements in the San Juan and Permian Basins, but metadata to identify the location at the state-level was not provided with the study results. The table below compares the study results in the Permian and San Juan Basins to the other basins in the study (Anadarko and Eagle Ford). Note that the study sample sizes at the basin level are small and the statistical significance of such comparisons has not been verified. Sites measured in the Permian Basin tended to have a smaller fraction of leaking components and overall emissions than those in other geographic regions in the study.

Basin	Number Sites	Number of Components Screened	# Leaks Identified	Equipment Leak Emissions Measured (scfh)	Percent of Components Identified as Leaking	Emissions (scfh)/Site
San Juan	10	10012	45	241.3	0.45%	24.13
Permian	13	19027	43	65.7	0.23%	5.05
Other Basins	42	54921	238	1125.8	0.43%	26.81

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

Costs vary widely based upon type of component and type of service.

A good quality FID might cost approximately $10-$15,000, while a new OGI camera costs an estimated between $85,000 and $110,000 depending on whether it has one fixed lens or multiple lenses.
https://www.trinityconsultants.com/news/federal/the-tangled-web-of-ldar-requirements-for-the-oil-and-gas-industry
FLIR® and Opgal® are the two main players in the OGI market, with both companies supplying EPA-recognized cameras that can be used to demonstrate compliance with federal LDAR rules. If quantification of emissions is desired, the FLIR GF320 camera can be used with a Providence Photonics QL320 tablet to quantitate the emissions. This QL320 tablet has an

approximate $20,000 cost. The FLIR® GF77® is a new uncooled infrared camera on the market that can visually detect methane for a lower estimated price of $50,000.

Neither camera is capable of speciation.

What are the annualized operating costs for the equipment or costs associated with the process?

Costs vary widely based upon type of service.
Depending on financial constraints or business models, companies have two basic options to conduct LDAR inspections. First, a company can purchase its own equipment and hire employees to conduct its LDAR functions. However, a company can also hire a third-party contractor to use its equipment to perform LDAR services. Though pricing can fluctuate, a 2014 study determined that average cost of hiring an external service provider to conduct OGI LDAR surveys was estimated to be $2,300 for a compressor station, $5,000 for a gas plant, $1,200 for a multi-well battery, $600 for a single well battery, and $400 for a well site. https://ourenergypolicy.org/wp-content/uploads/2014/03/Carbon_Limits_LDAR.pdf

That being said, the state of Colorado estimates an estimated inspection cost of $450, Rebellion Photonics was quoted at $250 per site, and Jonah Energy estimated a cost of $99-$29 per inspection.
http://www.methanefacts.org/files/2016/05/LDAR-Fact-Sheet-FINAL.pdf

If a company chooses to hire its own employees for the LDAR function, the starting salary for such a technician is somewhere in the $15-$20 per hour range, though shortages in a hot market may affect that cost.

Glassdoor's "Gas Leak Survey Technician" job category shows the following average rates:– $47,831 annual/2080 hours (conservative, no vacation, no sick leave, no benefits) = $23/hour
https://www.glassdoor.com/Job/gas-leak-survey-technician-jobs-SRCH_KO0,26.htm?srs=TAB_OVER_SALARY_SEARCH

Permian salary: $1,100/week or $27.5 per hour per Dallas Federal Reserve.

Maintenance procedures are occasionally required on gas sniffers and are estimated to be $500 - $1,500 annually. This would not include the replacement of photo-ionization bulbs or calibration gases. Calibration gas costs are estimated to be $500 - $1,500 annually, while carrier gas costs may double that estimate if not readily available. If conducting soap bubble-based LDAR procedures, annualized equipment and supply costs are minimal.
Though not mandated, internal and third-party audits of a facility LDAR program are considered an LDAR best practice per the EPA's *Leak Detection and Repair – Best Practices Guide*. An audit checks that the correct equipment is being monitored and that Method 21 procedures are being followed, leaks are being fixed, and that the required records are being kept. Note: EPA's guide is intended for refineries and chemical plants.

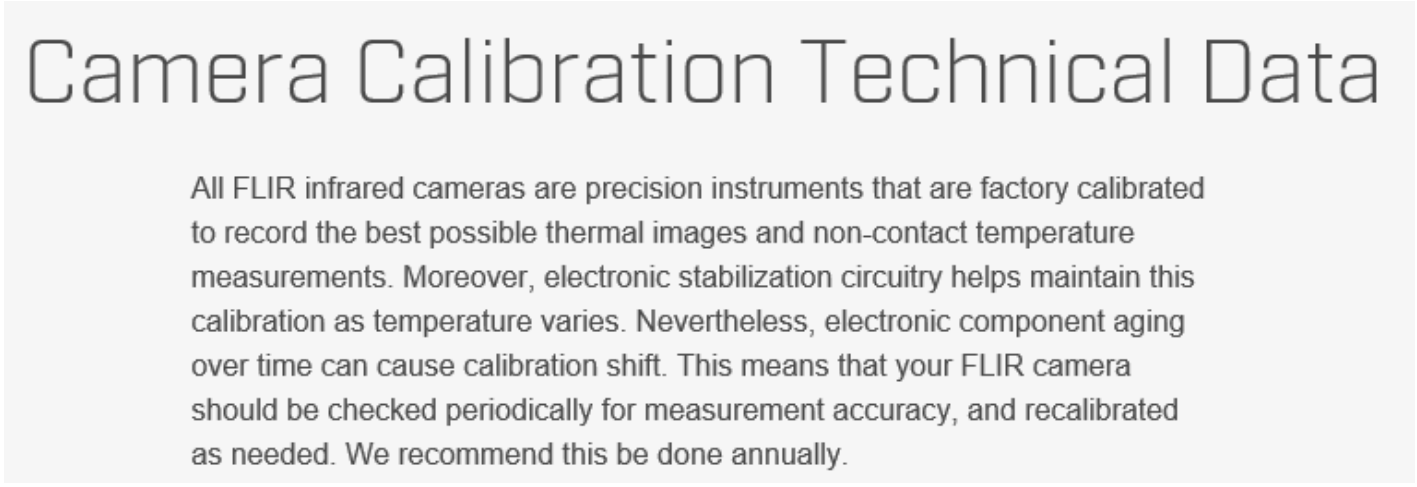
Camera users require training. One course with publicly available information shows $2,000 and three days for the basic certification. https://courses.infraredtraining.com/index.cfm?action=registration.schedule&courseId=3

The below text is from FLIR, a manufacturer of optical gas imagers, noting their recommendation that cameras be calibrated annually.
https://www.flir.com/support-center/Instruments/service/calibration-technical-data/

Camera Calibration Technical Data

All FLIR infrared cameras are precision instruments that are factory calibrated to record the best possible thermal images and non-contact temperature measurements. Moreover, electronic stabilization circuitry helps maintain this calibration as temperature varies. Nevertheless, electronic component aging over time can cause calibration shift.

This means that your FLIR camera should be checked periodically for measurement accuracy and recalibrated as needed. We recommend this be done annually.



https://www.flir.com/discover/professional-tools/how-do-you-calibrate-a-thermal-imaging-camera/

How Do You Calibrate a Thermal Imaging Camera?

Calibrating a thermal camera is the process of correlating what the camera sees (infrared radiation) with known temperatures, so that the camera can accurately measure the radiation it detects. All FLIR cameras are calibrated to factory specifications, but over time, electronic component aging can cause calibration shift and produce inaccurate temperature measurements.

If this happens, can you recalibrate your thermal camera by yourself? Unfortunately, the answer is no: to maintain the accuracy of your thermal camera, you will need to send it in for regular calibration by the camera manufacturer. We recommend this be done annually.

End text from FLIR website.

Annual maintenance costs about $1500 - $2000.

If the equipment or process is powered, what are the costs?

Electricity need varies based upon the type of component. Most components in a leak program do not require electricity.

What are the maintenance and repair costs for existing or new equipment?

Costs vary widely based upon type of service and type of unit.

If measuring accurate temperatures are important, an annual calibration is required on FLIR GF320 cameras. This cost for this required factory calibration is estimated to be $2,000 per single lens. Annual calibrations are not recommended for FLIR gas finding cameras. Toxic vapor analyzers, flame ionization and photo-ionization detectors, and OGI's have a useful life of an estimated 10-15 years, if properly maintained.

Additional costs include mapping, tagging and recordkeeping

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

There are two main strategies for reducing leak emissions:

1. Operator Routine Duties: Operators and contractors are given training and/or a checklist of activities to complete on each visit, including listening for leaks, looking for signs of potential leaks (i.e. frozen equipment), and examining operating parameters (drop in sales, SCADA indicators). Operators wear LEL (lower explosive limit) monitors for safety that detect emissions. These strategies are generally employed more frequently and are successful at catching larger leaks.
2. Instrument Based Leak Detection and Repair: Utilizing an instrument (generally optical gas imaging or a handheld gas detector "sniffer") at a prescribed frequency. Sniffer based programs have existed for decades, optical gas imaging is newer, but has been in use for a decade. In the past few years, there has been significant investment into new technologies, outlined below.

New Wells:

N/A

Existing Wells:

N/A

How have the emission/waste reductions been measured?

Utilizing EPA GHGRP emissions calculations.

How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

Federal Regulations

NSPS OOOOa requires semi-annual inspections at well sites and quarterly inspections at compressor stations. The definition of modification of a wellsite includes adding production to an existing battery, even if that battery remains below the original throughput levels. This means that many centralized facilities built before OOOOa was in effect are subject to the leak provisions. Similarly, the definition of a modification at a compressor station includes adding a compressor to an existing compressor station or replacing an existing compressor with one of greater horsepower. Modified compressor stations also become subject to leak provisions even if they were built before OOOOa went into effect.

OOOOa allows for surveys using optical gas imaging or handheld gas detectors. There is a process to request permission to utilize alternative technologies but the process is generally viewed as onerous and no technology has been approved. The approval process requires over one year, and is only applicable to one site if approval is received. At this point, we are aware of no operator who has requested approval of an alternative technology.
https://ecfr.io/Title-40/sp40.8.60.oooo_0a

State Regulations

The April 12, 2018 EPA Memo regarding the *Equivalency of State Fugitive Emission Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* summarizes the requirements of various state fugitive emissions programs. Summary tables for each state program are in the memo. https://www.epa.gov/sites/production/files/2018-09/documents/equivalency_of_state_fugitive_emissions_programs_for_well_sites_and_compressor_stations.pdf

Texas requires fugitive emission leak inspections at various frequencies, depending on the level of facility-wide potential emissions and the type of air permit issued to the facility. Under certain permitting mechanisms, the inspection frequency can be reduced to annual if the percentage of leaking components is consistently low. If the percentage of leaking components increases, then the inspection frequency also increases. The state allows optical gas imaging, handheld sniffers, and routine personnel duty AVO inspections under the various programs. Fugitive emission control credits are also allowed depending on the stringency of the Best Available Control Technology (BACT) program implemented.

https://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/fugitives/nsr_fac_eqfug.html
https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/fugitive-guidance.pdf

Colorado's Regulation 7 Section XVIII https://drive.google.com/file/d/168v7vMsFJtS7D8BWlnMbaXWA6uZUIyj8/view Requires inspections at a frequency determined by the sites potential to emit and by whether it is in an attainment or non-attainment area. The state allows optical gas imaging, handhelds, and has approved a small number of alternative technologies.

In Colorado, regulations require an initial survey within 30 days of commencing operation or rule application for existing sources. The inspection frequency is tiered depending on actual fugitive VOC tpy emissions as follows: Compressor stations: 0-12: Annual; 13-50: Quarterly; Over 50: Monthly. Well sites: 0-6: One-time; 7-12: Annual; 13-50: Quarterly; 50 and above: Monthly; Multi-well sites >20TPY without tanks: Monthly. Additionally, Colorado operators must use OGI, Method 21 or another approved technology. The rules also create incentives for using continuous emission monitors. If operators choose to use Method 21, there is a 500 ppm leak threshold (new compressor stations and new and existing well sites) and 2,000 ppm (existing compressor stations). Monitoring for LDAR applies to storage tanks and traditional components as well. Repairs must be made within 5 days, unless a delayed repair is warranted. If delayed, repairs must be made within 15 days after the delay ceases (e.g., receipt of part if part not in stock).[26] Colorado is also proposing new rules for LDAR which would increase the inspection frequency to semi-annual for compressor stations with VOC emissions greater than 0 and less than 12 tpy, on a rolling 12-month basis. The proposed rules would also require owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to 2 but less than or equal to 12 tpy, based on a rolling twelve-month total, to inspect components for leaks using an approved instrument monitoring method at least semi-annually.[27]

In a review of the Colorado Air Pollution Control Division (APCD) analysis, it references "cost effectiveness" of various components of the LDAR program in units of cost($)/ton, but does not reference LDAR as highly cost effective implying positive net present values, particularly in the marginal well sector of the industry. In fact, the cited COST-BENEFIT ANALYSIS SUBMITTED PER 24-4-103(2.5), C.R.S. states that in addition to the direct costs of LDAR, implementation of the proposed strategies could potentially result in the shut-in of marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost

[26] Colorado Air Quality Control Commission, 5 C.C.R. 1001-9, CO Reg. 7, § XVII.F. (Feb. 24, 2014), available at https://drive.google.com/file/d/168v7vMsFJtS7D8BWlnMbaXWA6uZUIyj8/view

[27] Colorado Air Quality Control Commission, proposed revisions to Regulation 7, available at https://drive.google.com/drive/folders/14fvt4C0Tzl79to4c2tVuLDKucksk5uaB

severance taxes. Based on available information the CAPCD found it could not reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rule. All this at a natural gas price of $3.50 Mcf that the CAPCD used for calculation purposes in preparation for the 2014 hearing. After deducting lease bonus and New Mexico production tax deductions, $3.50/Mcf is a Henry Hub wellhead price that has not been seen on an annualized basis for the last 10 years, nor during the first 9 months of 2019 (EIA data). The average 9-month year-to-date Henry Hub wellhead price is $1.93/Mcf before basis, midstream or pipeline transportation, processing, dehydration, or compression costs are deducted. Furthermore, the CAPCD recognized that smaller companies cannot fully utilize an in-house inspection program and therefore would have to use a higher cost third party contractor for inspections. For well and well production facilities, the CAPCD assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use third party contractors. Using this assumption in New Mexico with the IHS statewide dataset of over 400 New Mexico operators reveals 4.8% operate 500 or more wells each, and 95.2% operate less than 500 wells each and would be using the more costly third-party services.

California requires LDAR at an annual or quarterly frequency depending on when the component came under an LDAR program. The state allows optical gas imaging or handhelds, though Air District programs may require handhelds. Heavy oil (API gravity 20 or less) bearing components are exempt from the program.
See https://ww2.arb.ca.gov/sites/default/files/2018-06/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf

In California, owners or operators must conduct quarterly inspections using Method 21. After January 1, 2020, there will be a 1,000 ppm leak threshold for repairs. Leaks must be repaired within 2, 5 or 14 days, depending on the size of the leak. Components or component parts which incur 5 repair actions within a continuous 12-month period must be replaced and re-measured to determine that the component is below the minimum leak threshold.[28]

In Wyoming, New and Existing facilities must be inspected quarterly for leaks of 4 tpy or more of VOCs. Operators in Wyoming must record dates and results of LDAR inspections, including the date and type of corrective action taken as a result of the inspections. Components to be inspected include flanges, connectors, open-ended lines, pumps, valves, and "other" components listed in EPA Table 2-4. Operators must inspect using OGI, Method 21 or another approved technology.[29] Note this is for the non-attainment area.

Utah requires operators to develop an emissions monitoring plan that must include: (i) monitoring frequency; (ii) monitoring technique and equipment; (iii) procedures and timeframes for identifying and repairing leaks; (iv) recordkeeping practices; and (v) calibration and maintenance procedures for monitoring equipment. The plan must address monitoring for difficult-to-monitor & unsafe-to-monitor components. Operators must conduct monitoring surveys on site to observe each fugitive emissions component. The schedule for monitoring surveys is as follows: (i) No later than 180 days after 1/1/2018, or no later than 60 days after startup of production, whichever is later. (ii) Semiannually after the initial monitoring survey. Consecutive semiannual monitoring surveys conducted at least 4 months apart. (iii) Annually after the initial monitoring survey for "difficult-to-monitor" components. (iv) As required by the owner/operator's monitoring plan for "unsafe-to-monitor" components. Operators must use OGI or Method 21 or both. If fugitive emissions are detected, operators must repair the component as soon as possible but no later than 15 calendar days. If repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, repair or replacement shall be completed during the next well shutdown, well shut-in, after an unscheduled,

[28] 17 C.C.R. § 95669 (March 24, 2006), available at https://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20Appx%20A%20Regulation%20Text.pdf
[29] WDEQ, Oil and Gas Production Facilities Ch. 6, Section 2 Permitting Guidance for the UGRB (2016), available at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf

planned or emergency vent blowdown or within 24 months, whichever is earlier. Operators must resurvey repaired or replaced fugitive emission component no later than 30 calendar days after fugitive emission component is repaired.[30]

Ohio and Pennsylvania both require LDAR for new sources. In Ohio, the Initial inspection must be within 90 days of startup and then quarterly for the next 4 quarters. Operators can step down to semi-annual after 4 consecutive quarters with no more than 2% of components leaking and down to annual after 2 consecutive semi-annual inspections if no more than 2% of components leaking. Operators must step up to the original quarterly inspections whenever 2% of more of components are leaking. Acceptable inspection methods include FLIR cameras or Method 21 compliant analyzers.[31] In Pennsylvania, GP 5 covers sources at natural gas compression stations, processing plants, and transmission Stations, and requires quarterly LDAR. GP 5A covers sources at unconventional natural gas well sites, and requires quarterly LDAR with step down to semi-annual based on 2% of components leaking after 2 consecutive inspections. Operators must step back up to quarterly inspections if more than 2% of components are found leaking at any time. Modified existing wells (those that are re-fracked) are also subject to this requirement.[32]

The field of leak detection technology is evolving rapidly. Emerging technologies and inspection methods, such as mobile mounted IR cameras and lasers, and continuous stationary monitors, have the potential to significantly cut down on inspection time while also increasing the speed at which leaks are detected. EPA, a handful of states including Colorado, Wyoming, and Pennsylvania, and the countries of Canada and Mexico have revised their rules and General Permits to include a provision that allows operators to request approval to use an alternative leak detection method or technology in order to provide a pathway for approval of these innovative approaches. Colorado's alternative compliance pathway provides a good example. Colorado requires that an alternative method must be able to demonstrate it is capable of achieving emission reductions that are at least as effective as the emissions reduction achieved using an IR camera or EPA Reference Method 21.[33] In addition, the proposed alternative must be commercially available.[34] Applicants must provide detailed information on the alternative technology or method, including but not limited to, its limitations, the process for recordkeeping, whether it has been approved for other applications or by other regulators, and any modeling results or test data.[35] Colorado allows manufacturers of alternative instrument monitoring methods (AIMM), as well as operators, to apply to use an alternative AIMM. Approved AIMM may be used by any operator in Colorado to comply with well production facility and compressor station LDAR inspections. In addition, approved AIMM may be used to conduct inspections of pneumatic controllers in the Denver nonattainment area.[36] In Colorado, the application and approval process are subject to public notice and comment if the request is for use in the Denver metropolitan ozone nonattainment area.

Internationally, Mexico requires quarterly LDAR and inspection frequency is tied to emission thresholds.[37] Canadian operators must have an LDAR program and inspections must occur three times a year. LDAR in Canada applies to all sources of unintentional venting and traditional components but is not applicable at standalone well heads.[38]

[30] U.A.C. Rule 307-509, available at https://rules.utah.gov/publicat/code/r307/r307-509.htm
[31] Ohio EPA General Permit 12.1 and 12.2, available at http://epa.ohio.gov/dapc/genpermit/oilandgaswellsiteproduction.aspx; Ohio GPs for compressor stations, available at http://epa.ohio.gov/dapc/genpermit/ngcs.aspx
[32] Department of Environmental Protection, Air Quality Permit Exemption 38, available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf
[33] *5 C.C.R. 1009-1* § XII.L.8.a(ii)(I); CDPHE, *Alternative AIMM Guidance and Procedures*, p. 1 (May 31, 2018) (accessible at https://drive.google.com/file/d/1reFIFX_DVl_Wcu82853NNekmhjOtljui/view).
[34] Id. at § XII.L.8.a(ii)(B); Alternative AIMM Guidance and Procedures, p. 2.
[35] Id. at § XII.L.8.a(i); Alternative AIMM Guidance and Procedures, p. 1.
[36] Alternative AIMM Guidance and Procedures, p. 1.
[37] Mexico, Agencia de Seguridad, Energia y Ambiente (ASEA) regulations, available at http://www.dof.gob.mx/nota_detalle.php?codigo=5543033&fecha=06/11/2018
[38] Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (July 2019). Available at https://laws-lois.justice.gc.ca/PDF/SOR-2018-66.pdf

Note, no current state or federal rules allow for easy adopting of new technologies, nor do they allow the flexibility that would be required for companies to adopt new technologies.

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

Limiting the number of components where leaks can occur is one potential process modification, however, this is not often feasible due to operational needs for components. Lowering pressure could potentially reduce the volume of emissions from a leak. Other papers provide information on need for and opportunities to reduce components.

Per the EPA's *Leak Detection and Repair – Best Practices Guide*, "Facilities can control emissions for equipment leaks…by modifying/replacing leaking equipment with "leakless" components. Emissions from pumps and valves can also be reduced through the use of "leakless" valves and "sealless" pumps. Common leakless valves include bellows and diaphragm valves, while common sealless pumps include diaphragm pumps, canned motor pumps, and magnetic drive pumps. Leaks from pumps can also be reduced by using dual seals with or without barrier fluid.https://www.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf

(note this guidance document is for refineries and chemical plants)

Regarding potential emission leaks from tank hatches, gates, valves, and other mechanisms, the Unico UWS™ Hatch Sense wireless sensor is designed to monitor those devices. https://www.unicous.com/products/uws-hatch-sense-system It contains a magnetic proximity switch that detects if the latch on the hatch is open or closed by using Bluetooth Low Energy technology to communicate with a mobile device or a Unico UWS™ Gateway.https://www.unicous.com/sites/default/files/user_files/UWS%20Hatch%20Sense%204.25%20-%20Gateway%20UWS%20Hatch%20Sense.pdf

Moreover, the use of low bleed or no bleed pneumatic devices, including but not limited to controller boxes, would reduce existing and new methane emissions. Such emissions are relevant as they add to total airshed methane concentrations that would be readily detected by OGI's while conducting LDAR surveys.

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
Satellite Technologies	https://www.ghgsat.com/ https://www.edf.org/climate/space-technology-can-cut-climate-pollution-earth/satellite-ted-talk?gclid=Cj0KCQjwoqDtBRD-ARIsAL4pviCVquAnSTU-omgAqlYBASV79h5DJ	**In use, though not for site level leak detection**	Current detection threshold makes identifying specific sites with emissions a challenge	Not yet in common use

	PuZpSXejYAwyZlT5pnyHK4Wwb4aAvouEALw_wcB&utm_campaign=edf_methanesat_upd_acq&utm_id=1524073537&utm_medium=cpc&utm_source=google http://bluefield.co/			
Aerial basin level surveys	http://kairosaerospace.com/ https://www.bridgerphotonics.com/ http://www.scientificaviation.com https://www.leaksurveysinc.com/ https://www.ball.com/aerospace/newsroom/features/light_the_way_with_methane_monitoring	**In some commercial use**	Range of detection thresholds, generally an order of magnitude or more greater than optical gas imaging. Therefore, the technologies generally serve as a screening method. If emissions are detected, a crew with a secondary device will need to visit the site to isolate the piece of equipment.	Medium
Site level surveys (aerial drone or truck)	https://www.seekops.com/ http://www.aerodyne.com/aerodyne-mobile-laboratory https://www.bhge.com/news/bhge-launches-lumen-ground-drone-based-advanced-methane-detection-reduction-system https://www.elementascience.org/articles/10.1525/elementa.373/	**In use.** For the drone, until there is beyond visual line of site, this is nearly as limited for many places in terms of personnel needing to visit each site, but now requires a much more specialized skilled operator to operate. The cost of the LDAR technician goes up for similar time, resulting in a solution with slightly less detection sensitivity but just as much resource.	Detection at the equipment level is still being piloted, so serves as a screening method. Also may detect non fugitive sources. If emissions are detected, a crew with a secondary device will need to visit the site to isolate the piece of equipment.	Medium -High depending on density and proximity. Currently not approved by regulators except for Optical Gas Imager on drone. Drones provide major equipment group level information that requires more detailed inspection to identify a specific leaking component. Trucks provide site-level information

				that will require more detailed inspection to locate component level information (directed LDAR).
Equipment level surveys	https://www.flir.com/browse/industrial/gas-detection-cameras/ https://www.raesystems.com https://heathus.com/products/rmld-cs/	**In use**	Medium – Instruments range from ~10-15K (handheld sniffer – see above) to ~100k (optical gas imaging – sited in various regulatory impact assessments), significant personnel time required for both technologies. Handheld sniffer may require significant tagging expense and generally require more time in the field.	**Varies with site size / amount of travel time**
Fixed/Continuous Monitoring	Troposphere Quanta3 Lumen IBM https://www.projectcanary.com/ https://rebellionphotonics.com/	Being piloted	Generally works as an alarm requiring follow-up. Does not quantify or identify the specific piece of equipment or component. May require meteorological data to corroborate source of readings. Has certain electricity and data management/network requirements.	Still in development with some pilot testing. Provides site-level information that will require more detailed inspection to locate component level information (directed LDAR).

Though not mandated, FLIR GF320 OGI's can be equipped with a QL 320 quantification tool developed by Providence Photonics. This QL320 can also be used in other FLIR GF series cameras by asking the factory to add the Q Mode for offline processing. By combining these two technologies, it is possible to quantitate emission losses. The QL320 calculates the leak quantity in multiple units (as desired) based on the image and response factors unique to each gas. With continued changes to the software and post-processing capabilities, accuracy of measurements has increased substantially since the first release of the technology. Under correct use, the QL320 can achieve field accuracy of +/- 10% of a one minute running average of emissions rates. Lab results using measured releases have achieved 2% accuracy.

In 2018 – 2019, Earthworks has used the QL 320 to quantify emissions from storage tanks, pipe fitting leaks, pneumatic controller exhaust, unlit flares, and other sources in several states, including 30 measurements in New Mexico from ten different sites in Eddy, Rio Arriba, Sandoval, and San Juan counties. Average leak rates for the New Mexico sites have ranged from 52.44 to 0.2 lbs/hr. The QL 320 quantification software is still in the development phase.

https://broomfield.ajax-analytics.com/
This link goes to the Broomfield monitoring site where the monitoring technology, parameters and data are all posted. A year's worth of data has been collected and posted.

TCEQ helicopter flyover program is internally funded by TCEQ's air quality division. There is some information about the TCEQ helicopter program in this presentation:
https://tipro.org/UserFiles/TCEQ_OG_Update_TIPRO_August_2018.pdf.

What are the pros and cons of the alternatives?

While new technologies have shown great promise in detecting emissions at a lower cost, there is generally a tradeoff in terms of detection limit and ability to pinpoint the location of a leak. There is some funding at Colorado State University, who has convened discussions, to continue to develop a next generation of FEAST model which will help inform this and an associated technical project.

What is needed and available for new wells?

NSPS OOOOa applies to facilities built after September 18, 2015 or taking new production after that same date. Due to the small number of components, EPA exempts wellhead only facilities.

What is needed and available for existing wells?

Marginal wells (< 15 barrels of oil equivalent per day) should be excluded from the LDAR program. Marginal wells, by their nature, are lower producing and generally requires less equipment with fewer components. In fact, data (see API study noted above) has indicated that leak detection is most effective on the initial inspection to ensure that all components and equipment are tightened from the outset and that the frequency of detection lowers over time. These factors mean that the cost of each marginal well LDAR survey often outweighs the benefits of the potential emission reductions and can threaten their financial viability. In the oil-and-gas Control Technique Guidelines, EPA expressly recognized that fugitive emissions at low-production sites are inherently low and thus included an exemption from the LDAR program for well sites with an average production of less than 15 barrels of oil equivalent per day. Unless and until additional comprehensive and conclusive data has been collected to suggest that marginal wells warrant inclusion in an LDAR program, these wells should be excluded. Leak data on marginal wells is very limited and warrants further study through objective, transparent, repeatable, and reliable emissions measurements. The sample size of the current data set is too small to provide conclusive results. Proper inspection methods and associate frequency must be informed by well-established data that can correlate production and emissions. Other factors that must be weighed are type and quantity of equipment, frequency of episodic emission events, equipment age/condition, and absolute contribution to total emissions. The Department of Energy is co-funding such a study titled "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells" being conducted by GSI Environmental Inc.

Wellhead only locations should not be included in the LDAR program due to very limited equipment, therefore limited potential to emit, on location, consistent with NSPS OOOOa. Facilities that do not require permits similarly have very limited equipment and should be exempt from a LDAR program. Facilities without controlled equipment would not benefit from an LDAR program as a low level of emissions will occur under allowable permit limits with or without an inspection program.

What technology alternatives exist for this equipment or process itself?

N/A

What are the pros and cons of the alternatives?

See above.

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

It is very difficult to generalize costs due to the wide range of technology applications and other variables such as distance to survey, repair costs, etc. See API LDAR paper in the data section.

Information from various U.S. jurisdictions and independent consulting groups demonstrates that quarterly LDAR inspections are highly cost effective: [note – one member's opinion]

- **Colorado**. The final cost benefit analysis prepared by the Colorado Air Pollution Control Division (APCD) in support of its LDAR program demonstrates that quarterly inspections are cost effective. For mid-sized well sites, Colorado found the cost effectiveness of quarterly LDAR inspections to be $1,019 per ton of VOC reduced and $679 per ton of CH4/ethane reduced for facilities located in the Denver non-attainment area. For remote facilities located outside the Denver-Julesburg basin, Colorado determined quarterly inspections to be cost effective at $1,268 per ton of VOC reduced and $648 per ton of CH4/ethane reduced.[39] Colorado determined that requiring quarterly inspections for compressor stations is cost effective, estimating a control cost of $2,273 per ton of VOC reduced.[40] In a review of the APCD analysis, it references "cost effectiveness" of various components of the LDAR program in units of cost($)/ton, but does not reference LDAR as highly cost effective implying positive net present values, particularly in the marginal well sector of the industry. In fact, the cited COST-BENEFIT ANALYSIS SUBMITTED PER 24-4-103(2.5), C.R.S. states that in addition to the direct costs of LDAR, implementation of the proposed strategies could potentially result in the shut-in of marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the CAPCD found it could not reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rule. All this at a natural gas price of $3.50 Mcf that the CAPCD used for calculation purposes in preparation for the 2014 hearing. After deducting lease bonus and New Mexico production tax deductions, $3.50/Mcf is a Henry Hub wellhead price that has not been seen on an annualized basis for the last 10 years, nor during the first 9 months of 2019 (EIA data). The average 9 month year-to-date Henry Hub wellhead price is $1.93/Mcf before basis, midstream or

[39] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) ("CAPCD Cost-Benefit"), at 28, Table 34, *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573.

[40] Colorado Air Pollution Control Division, Economic Impact Analysis (Final) for Regulation 7, Sections II., XII., XVII., XVIII. p.5 (October 4, 2017).

pipeline transportation, processing, dehydration, or compression costs are deducted. Furthermore, the CAPCD recognized that smaller companies cannot fully utilize an in-house inspection program and therefore would have to use a higher cost third party contractor for inspections. For well and well production facilities, the CAPCD assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use third party contractors. Using this assumption in New Mexico with the IHS statewide dataset of over 400 New Mexico operators reveals 4.8% operate 500 or more wells each, and 95.2% operate less than 500 wells each and would be using the more costly third party services.

- **California**. The California Air Resources Board (CARB) has found conducting quarterly inspections at production facilities to be highly cost effective. CARB estimates the costs are $23 per metric ton of CO_2e reduced (accounting for savings from recovered product) to $26 per metric ton of CO_2e reduced (not accounting for savings).[41] These estimates assume a 20-year global warming potential for methane. (Note: current carbon trading price in California is $15 per metric ton). Again, as in the Colorado citation above, CARB made cost effectiveness comparisons on a cost/ton basis, but made no claim in the citation that quarterly inspections are "highly cost effective" implying positive net present value. Also, as in the California study, an overly optimistic natural gas price of $3.44/Mcf was used as compared to current and historic Henry Hub wellhead pricing discussed above. The CARB citation was abbreviated as compared to the Colorado study and did not break out the LDAR abatement costs for the well and well facility sector. The LDAR abatement metrics found on page 3 not only included both onshore and offshore well and well facilities, but also facilities involving natural gas processing and natural gas storage. There is a comment about "idle wells" but marginal wells were not mentioned in the CARB study. The LDAR abatement costs in the CARB study are most likely skewed downward by the larger facilities and "super leaker" data and not representative of the well and marginal well sector alone.

- **Carbon Limits Study**. This study is based on actual leak data from over 4,000 LDAR inspections of oil and gas facilities, such as well sites, gas compressor stations, and gas processing plants. The inspectors used infrared cameras to identify over 58,000 individual components that were leaking or venting gas. The inspection firms provided facility inspection costs and, for every leak they found, data such as the size of the leak and how much it would cost to repair. LDAR surveys performed quarterly would abate methane at a net cost of less than $280 per metric ton ($11/ton CO_2e using a global warming potential of 25) for all types of facilities. Per this study, over 90% of the gas leaking from these facilities is from leaks that can be fixed with a payback period of less than one year (assuming gas prices of $3 per thousand cubic feet).[42]

- The study breaks down facilities into three categories, 1) compressor stations, 2) gas plants, and 3) well and well batteries that include anywhere from 1 to 15 wells per battery. This last category is beneficial to exam as it relates to marginal wells. There were 1,764 surveys of well and well batteries which represents 41% of all surveys. Although the well and well batteries are nearly half of the surveyed components, the study found that fully 36% (one third) of the well sites and batteries had no leaks. The remaining 64% of the well and well facilities were only 5.5% of the total leak rate attributed to all facilities combined. Fully 94.5% of the leak rate is attributed to compressor stations and gas plants. Within the study an economic assessment was run on the well and well batteries category in the form of three economic cases at varying gas prices. The three cases were run at a natural gas price of $3, $4, and $5 per Mcfg respectively with the average or base case being at $4/Mcfg. As discussed previously this $4/Mcf base case price is over 2 times higher than the average 9 month year-to-date Henry Hub wellhead price, and repeating, before any basis, transportation, processing, dehydration, or compression costs are deducted from the Henry Hub price. The study found that the LDAR program on the well and well battery category has the highest percentage of surveys with a negative NPV (positive or negative NPV being the difference between a project being economic versus uneconomic),

[41] CARB. Revised Emission and Cost Estimates for the Leak Detection and Repair Provision, (February, 2017). Available at: https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf.

[42] Carbon Limits, Fact Sheet, Fixing the Leaks: What would it cost to clean up natural gas leaks?, available at http://www.catf.us/resources/factsheets/files/LDAR_Fact_Sheet.pdf. Full report available at http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

concluding that over 80% of surveys are uneconomic even with the inflated natural gas pricing. Quoting the study, "This is because leak rates for well sites and batteries are generally smaller than that for gas plants or compressor stations". As far as a payback of less than one year for repair as stated above, it was found that the repair costs used in the study were seriously underestimated. As an example, an average valve repair is stated to cost $90. Adding transportation and roustabout crew time in Southeastern New Mexico for the repair puts the cost at $610 thus the realistic cost of a valve repair is nearly 7 times more than the study states, seriously calling into question the method of costing repairs in the study. The implication derived from this study is that all surveys on marginal wells would be uneconomic, particularly if economics were run at a more realistic natural gas wellhead price. Mandated quarterly surveys on marginal wells would create a situation of premature abandonment and underground waste of resource from the absolute lowest category of emitting facilities as identified by the Carbon Limits study.

- Concerning the exorbitant natural gas pricing used in economics within the older reports and studies cited heretofore, a more recent report prepared for the Environmental Defense Fund by Synapse Energy Economics, Inc. dated September of 2019 is available.[38A] This report utilizes Henry Hub natural gas index pricing and NYMEX forward pricing, less basis, to project the natural gas price for the next 10 years. Per the Synapse report "*Gas prices paid to producers in New Mexico are lower than the Henry Hub price (the most common national benchmark for natural gas prices) because of the cost to transport gas to the national market. This difference between Henry Hub and New Mexico gas prices is called the "basis.*"" Deducting lease burdens and New Mexico production taxes from the Synapse forward pricing yields an average 10 year forward projection of natural gas wellhead pricing in the Permian Basin of $1.60/MCF. This is a much more realistic natural gas price to utilize for average case economics. The Synapse study projected Permian gas price is 54% lower than the price used in Colorado economics, and 60% lower than the price used for base case economics in the Carbon Limits study.

- **Center for Methane Emissions Solutions**, **Colorado Case Study**. CMES interviewed 10 companies in Colorado operating after Colorado adopted its LDAR program in 2014. It found that 7 out of 10 companies interviewed reported that additional revenues from fixing leaks more than covers the costs of finding and fixing leaks.[43] An attempt to open the citation rendered a message "website expired".

- **ICF.** ICF developed a complex model to investigate the distribution of LDAR cost profiles at well sites (Attachment 1). This analysis seeks to develop facility models that replicate real world situations and capture variations in these characteristics by using a Monte Carlo simulation to analyze facility emissions, reductions and costs. These results further demonstrate that quarterly monitoring is cost-effective. ICF's estimate of the control costs for quarterly LDAR are equal to $262 per short ton of methane reduced, assuming $3 gas; $234 per short ton of methane reduced, assuming $4 gas; and $187 per short ton of methane reduced assuming $3 gas and the use of a contractor to perform the inspection.[44] The attached PowerPoint describes the modeling concepts and model inputs in greater detail. Page 8 of Attachment 1 indicates that the cost($)/Mcf-reduced metric is the "ratio of the total cost to conduct an LDAR survey to the difference in Mcf of emissions from the baseline each year where the baseline is assumed to be the uncontrolled emissions in the first year". This assumption is problematic for monitoring emissions on a depleting hydrocarbon flow rate as the emissions in the first year will diminish from year to year, even without emission controls, as the well producing rate declines. With many southeast New Mexico horizontal wells having an initial hyperbolic decline rate of 90% or more in the first year, this could be a large misrepresentation of the $/Mcf-reduced metric.

[43] Center for Methane Emissions Solutions, Colorado Case Study, available at https://static1.squarespace.com/static/558c5da5e4b0df58d72989de/t/57110da386db43c4be349dd8/1460735396217/Methane+Study.pdf.

[44] ICF's cost effectiveness estimates have been converted into dollars per short tons of methane.

- **Industry**. Jonah Energy—an operator in the Upper Green River Basin in Wyoming— has expressed its support of at least quarterly instrument-based inspections,[45] noting that it already complies with the proposal because "each month, Jonah Energy conducts infrared camera surveys using a forward-looking infrared camera ("FLIR") camera at each of our production facility locations."[46] According to Jonah, "[b]ased on a market value of natural gas of $4/MMBtu, the estimated gas savings from the repair of leaks identified exceeded the labor and material cost of repairing the identified leaks" while also significantly reducing pollution.[47] Jonah has reported that this highly cost-effective quarterly LDAR program has reduced fugitive VOC emissions from its facilities by over 75%, indicating that methane and other hydrocarbon losses have also been reduced by a similar proportion.[48] Jonah's experience that gas savings from repairs often exceed the cost of performing repairs to identified leaks is also borne out by the Carbon Limits report[49] and analysis carried out by Colorado.[50] There is mounting industry-supplied evidence that frequent LDAR is cost-effective.[51]

When Colorado and EPA initially drafted their rules, they had very little data to estimate the number of leaks and the baseline fugitive emissions, so based on aEPA's1995 Protocol for Equipment Leak Emission Estimates, EPA and Colorado relied upon VOC emission factors in Table 2-4 of the 1995 EPA Leak Protocol. (link) Figures 5-16 through 5-34 of the 1995 EPA Leak Protocol demonstrate that the VOC emission factors within Table 2-4 correspond to between 1.6% and 2.5% of components that are assumed to be leaking. The lower value represents an assumed 10,000 ppm Method 12 leak definition and the higher value assumes a 500 ppm leak definition. NSPS OOOOa's leak definition is 500 ppm, which would correlate to the 2.5% component leak rate. In contrast, API surveyed its members and found an average initial leak incidence for all well sites was 0.4% of the components surveyed. (link)The 1995 EPA Leak Protocol contains an alternate set of VOC emission factors in Table 2-8, which allows for the incorporation of an actual % component leak rate that is based upon more recent data such as the API dataset. Establishing a more realistic baseline emission total using Table 2-8 will more accurately reflect the emissions benefit for a cost benefit analysis. Another key component to establishing an accurate and basin specific baseline is to have an accurate and representative % VOC and an accurate and representative fugitive component count by basin.

What would be the implementation cost?
For new wells?

[45] Jonah Energy stated: "We support the [recent Wyoming rule for existing sources in the UGRB], as proposed, with some minor suggested changes [to the proposed tank requirements] outlined below." Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Permit by Rule for Existing Sources (April 13, 2015).
[46] *Id*.
[47] Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Existing Source Regulations (Dec. 10, 2014).
[48] Jonah Energy, Presentation at WCCA Spring Meeting at 16 (May 8, 2015).
[49] Carbon Limits, Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras, 16 (Mar. 2014) ("Carbon Limits 2014"), available at http://www.catf.us/resources/publications/files/.
[50] Colorado Air Pollution Control Division used an entirely different method than Carbon Limits to predict that almost 80 percent of repair costs for well facilities will be covered by the value of conserved gas. *See* CAPCD Cost-Benefit, at Table 30. .Table 30 also identifies Total Annual Inspection and Repair Cost at $22,150,520 and the Total Annual Value of Recovered Natural Gas at $4,503,532 therefore the value of recovered gas will only cover 20% of the annual inspection and repair cost at the inflated natural gas price of $3.50/MCF used by CAPCD. At the average 10 year forward wellhead price of $1.60/MCF derived from the Synapse Report, the recovered gas will only cover 9% of the annual inspection and repair cost.
[51] Several companies that engaged in the development of Colorado's regulations provided evidence that frequent LDAR is cost-effective. In particular, Noble estimated the cost-effectiveness of Colorado's tiered program at "between approximately $50/ton and $380/ton VOC removed" at well production facilities. (Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the Matter of Proposed Revisions to Regulation Number 3, Parts A, B, and C, Regulation Number 6, part A, and Regulation Number 7 Before the Colorado Air Quality Control Commission, at 7).

The cost is ongoing depending on the number and type of repairs, frequency, technology, personnel and distance to sites. There are initial costs linked to purchasing software to plan and track results of surveys, purchasing and insuring equipment and operator training.

For existing wells?

See above – costs are the same for new and existing wells. Marginal oil and gas wells (10 BOE/day or less per IOGCC definition) make up 66% of all wells in New Mexico. These wells average 2.5 BOPD for marginal oil wells and 23.3 Mcfd for marginal gas wells[1]. Under an LDAR program, marginal well operators would need third party LDAR inspection services which are currently $2,000 to $2,500 per day per day plus travel[2] for optical services. Inspection time per location would need to include prorated travel time for third party vendors from service point to operating basin, travel time from site to site, along with the time required for each site survey. Travel and survey times range from 2.7 to 6.4 hours per site per studies below (Colorado rulemaking)[3]. A quarterly LDAR program using the average time of 4.6 hrs per inspection would increase the average marginal oil well annual direct operating expense[4] by 24% and marginal gas wells would be a larger increase in direct operating expense. The indirect administrative and reporting costs are not included, but would further reduce marginal well profitability. This would have the effect of rendering some marginal wells uneconomic, and increasing the abandonment producing rate on all marginal wells creating a situation of premature abandonment and underground waste of resource.

[1] https://www.eia.gov/petroleum/wells/pdf/full_report.pdf

[2] Telecon w/ Trinity Consultants, Albuquerque NM [3] "*Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries"*, ICF International (2.7 hrs travel time per site), CDPHE Regulatory Analysis https://www.sos.state.co.us/CCR/Upload/AGORequest/RegulatoryAnalysisAttachment2013-01217.PDF (6.4 hrs travel and inspection time per site), Louis Berger Group (5.75 hrs travel and inspection time per site), Terracon (3.6 hrs travel and inspection time per site).

[4] http://www.nswa.us (National Stripper Well Association)

Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Report):

This report created an array of cost effectiveness calculations in $/mcf based on a series of critical assumptions. The report touts its findings as demonstrating that methane emissions can be reduced with technologies that only cost cents per day. While aggregating all of the cost effective technologies with the cost ineffective technologies might produce such a result, individual technology options do not. Equally significant are the ICF report assumptions of the value of natural gas in calculating the benefits of regulations and the efficiency of the requirements. These are particularly important in the context of the fugitive emissions proposals.

The ICF Report concludes that a quarterly fugitive emissions program for natural gas wells would recover 264 mcf/y using a 60 percent recovery rate on emissions of 440 mcf/y and have a cost burden of $7.60/mcf without recovery benefits and $2.52/mcf with recovery.

Putting this evaluation in some context changes the perspective. First, looking at the emissions and recovery quantities on a daily basis shows them to be 0.72 mcfd and 1.2 mcfd, respectively. These are small volumes for even the average well. The ICF Report does not indicate the average production rate for the wells it assumes for the average emissions, but the average US natural gas well produces about 127 mcfd. Therefore, the approximate emissions rate would be about 1.0 percent. Nor does The ICF Report appear to distinguish sources of emissions in its fugitive discussion. For example, it does not discuss the share of emissions coming from equipment and those coming

from storage tanks that have permitted releases. Since an LDAR program would not apply to these allowable emissions, the efficiency/cost estimates must be questioned.

A second key point of the analysis relates to the value of natural gas where The ICF Report assumes a price of $4.00/mcf. Producers have not received such a price for a long time and do not foresee such a price for many years. Assuming a price for natural gas at $2.22/mcf of which the producer receives approximately $1.67/mcf, the value of the recovered natural gas would drop from $1360 to $440 annually. Correspondingly, the cost effectiveness would change in the net case from $2.52/mcf to $5.48/mcf.

A third point relates to the scope of fugitive leaks of the Leak Detection and Repair (LDAR) program. A study done by Carbon Limits (described below) concluded that fugitive leak emissions at well sites accounted for 17 percent of the total site emissions. Using this assessment of the 440 mcf/y of site emissions, only 75 mcf/y would be addressed by the LDAR program. And using the generous assumption of a 60 percent recovery, 45 mcf/y (0.12 mcfd) would be recovered. This would result in $75 in recovered value. The cost effectiveness would then become $44.58/mcf in the gross case and $42.91/mcf in the net case

More critically, the issue of larger significance here is the application of an LDAR program to low production wells. These wells average about 24 mcfd rather than 127 mcfd. Moreover, in some significant natural gas producing states the average low production natural gas well is much less; in Pennsylvania, for example, it is 6.1 mcfd. Using the same ratio of emissions to production for the average national well would yield low production emissions rates of 0.24 mcfd nationally and 0.06 mcfd for Pennsylvania. On this basis the potential recovery would be 9 mcf/y for the national average low production well and 2.2 mcf/y for the Pennsylvania well. The gross and net cost effectiveness values would be $222.89/mcf and $221.22/mcf for the national wells and $911.81/mcf and $910.15/mcf for the Pennsylvania wells, respectively. Setting aside that most of the likely emissions would be from permitted storage tank vents, these assessments argue that the Optical Gas Imaging OGI LDAR approach is not cost effective.

Are there low-cost solutions available?

Operators conducting routine inspections using sight, sound and smell. OOOOa allows the use of a soap solution to confirm leak repairs (60.5397a(h)(3)(iii)(A)). This method, listed under Alternative Screening Procedures from Method 21, Section 8.3.3, is a cost-effective, efficient and acceptable way to confirm leak repairs.
https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks

If a solution is high-cost, why is that the case?

The cost of leak detection depends on many variables and is difficult to generalize. However, the primary driver of cost effectiveness is the baseline emissions estimates and the number of leaks detected. When Colorado and EPA initially drafted their rules, they had very little data to estimate the number of leaks and the baseline fugitive emissions, so based on aEPA's1995 Protocol for Equipment Leak Emission Estimates, EPA and Colorado relied upon VOC emission factors in Table 2-4 of the 1995 EPA Leak Protocol. (link) Figures 5-16 through 5-34 of the 1995 EPA Leak Protocol demonstrate that the VOC emission factors within Table 2-4 correspond to between 1.6% and 2.5% of components that are assumed to be leaking. The lower value represents an assumed 10,000 ppm Method 12 leak definition and the higher value assumes a 500 ppm leak definition. NSPS OOOOa's leak definition is 500 ppm, which would correlate to the 2.5% component leak rate. In contrast, API surveyed its members and found an average initial leak incidence for all well sites was 0.4% of the components surveyed. (link) The 1995 EPA Leak Protocol contains an alternate set of VOC emission factors in Table 2-8, which allows for the incorporation of an actual % component leak rate that is based upon more recent data such as the API dataset. Establishing a more realistic baseline emission total using Table 2-8 will more accurately reflect the emissions benefit for a cost benefit analysis. Another key component to establishing an accurate and basin specific

baseline is to have an accurate and representative % VOC and an accurate and representative fugitive component count by basin.

Capital costs, personnel time, training, travel time to sites all make instrument-based programs high.

Are there additional technical analyses needed to refine benefits/costs estimates?

Continued piloting and testing of new technologies in field and controlled settings such as the studies conducted at Colorado State University. METEC[52] Colorado State University is a project in collaboration with US Department of Energy's ARPA-E and their methane initiatives. The goal of the METEC facility is to provide a location that models natural gas facilities, so that researchers can test methane sensing technologies and evaluate their performance. In order to evaluate the performance of each Methane Observation Networks with Innovative Technology to Obtain Reductions (MONITOR) technology to locate and quantify fugitive methane emissions, the MONITOR Field Test Site develops a representative test facility that simulates real-world natural gas operations—at the wellpad and further downstream. Specifically, the MONITOR Test Site supports the operation of a multi-user field test site for MONITOR performers to validate performance under realistic use-case scenarios–and meet the MONITOR program's required metrics related to localization, quantification, communications and cost. Data generated during the field tests demonstrates the performance capabilities of the technologies and could be used by the MONITOR performers to accelerate the commercialization and/or regulatory approval of their technologies.

The Stanford/EDF Mobile Monitoring Challenge also provides results from 10 vehicle, drone, and plane based leak detection technologies. In this test, 6 of the 10 technologies correctly detected 90% of the test scenarios. All technologies demonstrated site-level localization of leaks, while 6 of the 10 technologies could assign a leak to the specific piece of equipment in at least 50% of test scenarios. Even as this study provides the first independent verification of the performance of mobile technologies, it only represents the first step in the road to demonstrating that these technologies will provide emissions reductions that are equivalent to existing regulatory approaches. (link)

To better understand cost effectiveness, the emissions benefits from these various tests should be considered.

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

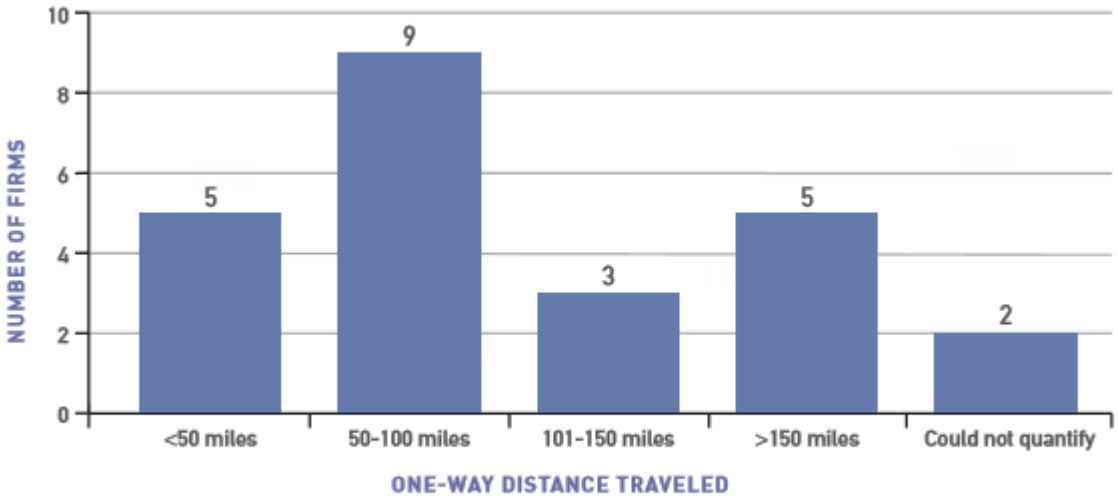
Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

Leak detection is feasible, and contractors are available, though may have to travel significant distances to visit sites.

[52] https://energy.colostate.edu/metec/

FIGURE 7. Typical One-Way Travel Distance Reported



SOURCE: Industry Interviews
NOTE: Based on a sub-sample of 24 LDAR firms

https://www.daturesearch.com/wp-content/uploads/Methane-Mitigation-Industry-Report_Final.pdf

What is the useful life of equipment?

N/A

What are the maintenance and repair requirements for equipment required for methane reduction?

Optical gas imagers generally need to be sent back to the manufacturer for calibration and testing on a regular basis. Sniffers need to be calibrated on a daily basis to ensure accurate ppm readings.

How would emissions be detected, reductions verified and reported?

Operators can report using EPA's leak/no leak emissions factors through existing reporting processes (GHGRP).

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

Inspections are currently required for all gas plants (NSPS KKK) and for new and modified production facilities under OOOOa.

NM does not have its own LDAR requirements

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

None

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

In other states and with EPA, there is very limited ability to adopt new technologies. New Mexico has an opportunity to avoid the unintended consequence of requiring old technology by creating flexibility.

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc.?):

None

DRAFT

5. LDAR PATH FORWARD[53]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EFFECTIVENESS OF COST NOW (choose one)	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
2.1	Annual inspections for existing facilities, avoiding duplication with existing federal programs, such as the LDAR provisions of NSPS OOOOa and NSPS KKK. Low production wells (less than 15 BOEPD) should be excluded Wellhead only locations should not be included in the LDAR program due to very limited equipment on location, consistent with NSPS OOOOa. Facilities that do not require permits similarly have very limited equipment and should be exempt from a LDAR program. Facilities without	Reduce leaks where there will be the most emissions reduction benefit.	Medium	GHGRP reporting using leaker emission factor method	

[53] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

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	controlled equipment would not benefit from an LDAR program as a low level of emissions will occur under allowable permit limits with or without an inspection program.				
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
2.2	Quarterly LDAR	Independent research across the United States has shown that emissions at oil and gas sites from leaks, broken or worn out equipment, and improper operations are substantial and greatly underestimated in inventories. Regular, quarterly LDAR is needed to mitigate these unnecessary and harmful emissions and can be implemented for a reasonable cost. A recent synthesis of the U.S. studies conducted over the past six years concluded that U.S. production emissions are 60% higher than inventories suggest.[54] California Air Resources Board, 17 C.C.R. § 95669 (March 24, 2006), available at https://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20Appx%20A%20Regulation%20Text.pdf; Colorado Air Quality Control Commission, 5 C.C.R. 1001-9, CO Reg. 7, § XVII.F. (Feb. 24, 2014), available at https://drive.google.com/file/d/168v7vMsFJtS7D8BWlnMbaXWA6uZUIyj8/view	LOW MODERATE HIGH		

[54] Alvarez, et al., "Assessment of methane emissions from the U.S. oil and gas supply chain" Science, June 2018, http://science.sciencemag.org/content/early/2018/06/20/science.aar7204.full. Data for this study included measurement of emissions from over 400 individual well pads in six different US basins, validated against "top-down" airborne measurements of emissions from nine oil and gas producing basins. The authors of this synthesis study, as well as the underlying studies analyzed in the synthesis paper, include academics from twenty-five different research institutions. These scientists have concluded that the substantial extra emissions observed in these studies, compared to official inventories, likely arise from improper and abnormal operating conditions at the site level that are best addressed by frequent, if not continuous, inspections.

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	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
2.3	Include a robust alternative compliance pathway in rules that would allow operators to request approval to use an alternative leak detection technology or method to an IR camera or Method 21	Colorado: 5 C.C.R. 1009-1 § XII.L.8.a(ii)(I); CDPHE, Alternative AIMM Guidance and Procedures, p. 1 (May 31, 2018) (available at https://drive.google.com/file/d/1reFIFX_DVl_Wcu82853NNekmhjOtljui/view)	LOW MODERATE HIGH		
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
2.4	Use of emissions quantitation technology during inspections	Use of OGI with quantitation software would allow for simultaneous leak detection and emissions volume measurement	LOW MODERATE HIGH		
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

DRAFT

SECTION 3, DEHYDRATION UNITS

Discussion for MAP members on September 13, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

Operators are often required to dehydrate natural gas streams that are saturated with water vapor to meet pipeline specifications. Water in natural gas pipelines can result in hydrates (solids) formation that obstruct or plug the pipe. Also, water vapor in a pipeline can cause corrosion. Commonly, operators use liquid desiccant dehydrators to remove water from natural gas to meet pipeline water content requirements, where the liquid desiccant most often utilized is triethylene glycol (TEG or 'glycol'). Glycol also will absorb volatile organic compounds (VOCs), some Hazardous Air Pollutants (HAPs) and methane in this process.

In the dehydration unit process, wet gas enters near the bottom of the glycol contactor tower(absorber) and comes into contact with lean glycol (water poor) in the contactor tower. In the glycol contactor tower, water in the natural gas is absorbed by the glycol circulating in the tower. This reduces water in the natural gas and the gas dew point is reduced. It is in this process that the glycol also absorbs methane, HAPs and VOCs. The dehydrated gas, referred to as dry gas, exits through the top of the glycol contactor tower. The glycol that absorbed the water is called rich glycol. The rich glycol exits from the bottom of the glycol contactor and flows to the regeneration system. The regeneration system typically includes a glycol flash tank (gas-condensate-glycol separator) and a reboiler. If a glycol flash tank is not installed, the rich glycol is routed directly to the reboiler.

NMED Exhibit 10 - 0068

The glycol flash tank (gas-condensate-glycol separator) serves as a separator to recover entrained gas and condensate from the glycol. It also reduces the pressure of the rich glycol prior to entering the reboiler. After the flash tank, the glycol enters the reboiler. Here, the glycol is heated to boil off water from the glycol to produce lean glycol. The lean glycol is cooled using a heat exchanger and pumped back to the glycol contactor tower to repeat the cycle. It is within this process that methane, HAPs and VOCs are boiled off and separated from the glycol.

Typical dry gas pipeline requirements range from 4 to 7 lbs water per mmscf of natural gas.

A glycol circulation pump is used to circulate glycol through the system. There are many varieties of pumps used including positive displacement (gas-injection) pumps, other pneumatic pumps and electric reciprocating and centrifugal pumps. Larger glycol dehydrators often use electric motor-driven pumps.

The reboiler uses a still column (reflux condenser coil) to separate water from the glycol. The still column's vent gas will contain water vapor and VOCs. The heat from the reboiler is generated by burning natural gas.

Although glycol dehydrators are most common, solid desiccant dehydration is another process which can be used. Solid desiccants use salt crystals with large surface areas to attract water molecules. Refrigeration is another method of dehydration. This involves cooling gas to a temperature below the condensation point of water.

Provide the segment(s) of the industry that the equipment or process is found:

The equipment/process is largely found in the oil and gas midstream gathering segment of industry. In addition, the equipment/process is commonly found in the upstream and natural gas processing sector.

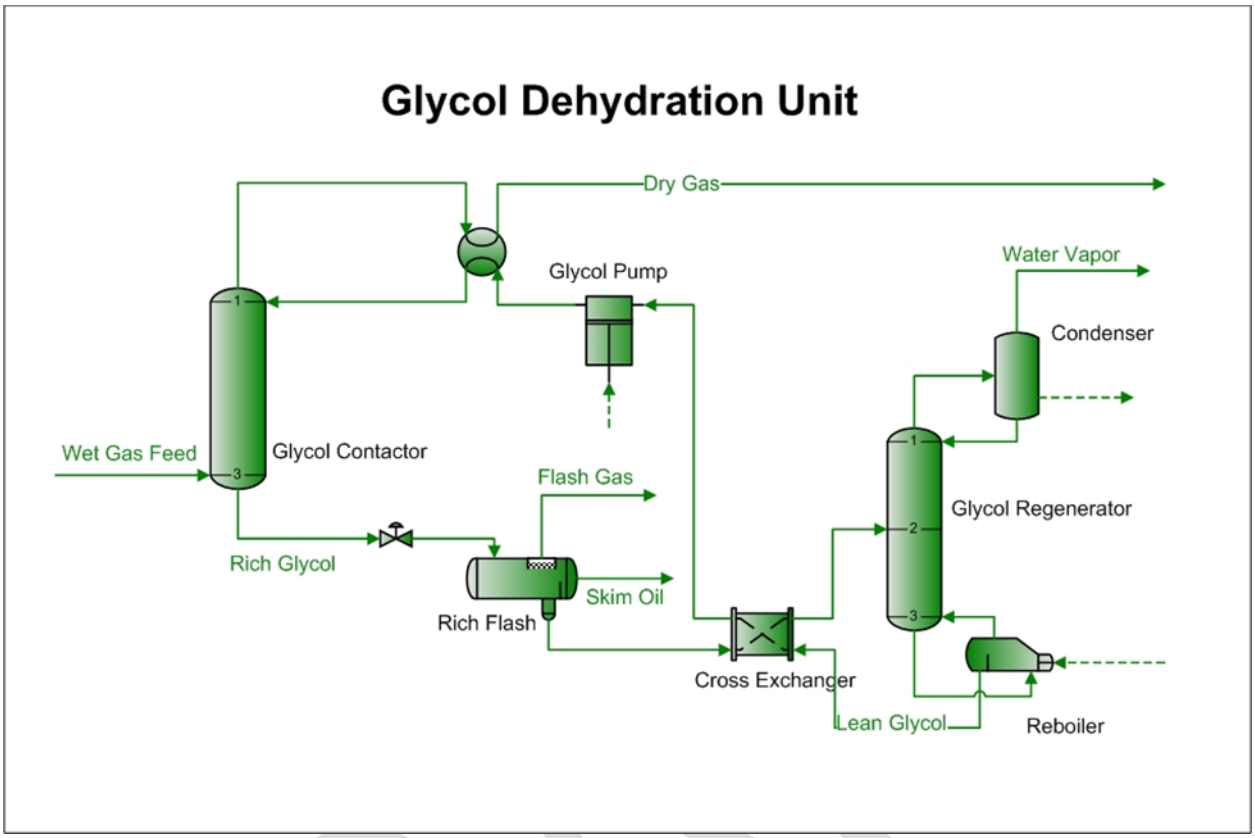
Describe how the equipment or process is used:

Dehydration units are used to remove water from natural gas.

Provide the common process configurations that use this equipment or process:

Below is a schematic of the common process configuration of this process. There are slight variations of the configuration that are commonly utilized. For example, some configurations exclude the flash tank so that all flashing occurs in the regenerator. There are many variations regarding control of the two primary emission points (the regenerator vent and the flash tank vent) discussed below.

NMED Exhibit 10 - 0069



The emission streams from the flash tank (labeled flash gas on the schematic) and the condenser (labeled water vapor on the schematic) are typically controlled by one of several methods, including combustion in the reboiler firebox of by a flare and captured by a VRU, among others discussed in Section 2.

What is the distribution of the equipment or process across business segments?

This equipment is largely found in the oil and gas midstream gathering segment of industry. In addition, the equipment/process is commonly found in the upstream and natural gas processing segment.

How has this equipment or process evolved over time?

This equipment or process has not changed much over time. The development of the cryogenic gas plant (early '70s) necessitated the need to remove almost all water from the gas stream in order to prevent freezing in the cryogenic portion of the plant.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

Natural gas streams contain varying amounts of methane, VOCs and hazardous air pollutants (HAP). HAPs in natural gas include benzene, toluene, ethylbenzene, xylenes, (BTEX), n-hexane and 2,2,4-trimethylpentane. These HAPs are slightly soluble in the TEG used and as a result, HAPs are absorbed in the glycol contactor. Also, methane and VOCs (other than BTEX) will be entrained in the rich glycol due to the high operating pressure of the glycol contactor (600 to >1000 psig).

Flash gas liberated from the flash tank (located between glycol contactor and reboiler) will be natural gas that is mostly methane and some VOCs and small amounts of BTEX.

Regeneration of the rich glycol in the reboiler results in emissions of methane, VOCs and HAPs to be released with the water vapor exiting the still column vent.

The sources of and types of air pollution from a TEG glycol dehydrator include the following:

1. Still Column (Regenerator) Vent – water, methane, VOCs, HAPs
2. Flash Tank – primarily natural gas similar to fuel gas (primarily methane and some VOC and BTEX)
3. Reboiler – combustion emissions from the reboiler burning natural gas.

Methane is absorbed into the glycol in the absorber tower. The methane will flash off in the flash gas separator, if installed. Flash gas separators are typically controlled and not vented to the atmosphere. If a flash gas separator is not installed, the methane will be removed from the glycol in the regenerator and vented through the still vent stack

New Wells:

Dehydration units are typically located at gathering compressor stations but can be located at new well sites.

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Existing Wells:

Dehydrations units are typically located at gathering compressor stations. However, there are instances in which a small dehydration unit may be placed at an existing well site.

How are the emissions calculated for this equipment or process?

Emission rate calculations involve using a process simulator to estimate emissions. Simulators typically used include GRI-GLYCalc, PROMAX and HYSYS. Manufacturer's data and state/federal guidance are utilized to determine the control efficiencies of the various types of controls.

What data is available to quantify emissions/waste for this equipment or process?

https://www.epa.gov/ghgreporting

Dehydration unit emissions range from less than 1% to 5% of a site's emissions. Specifically, within processing facilities, dehydration unit emissions represent less than 1% of processing facility emissions.

What are the data gaps in quantifying emissions/waste for this equipment?

There are no gaps identified for emissions of glycol dehydration units as emissions are quantified in air permits and reporting to NMED. The NMED AQB NSR and TV document on glycol dehydrators (May 23, 2011) notes that there is a 'lack of experience with field tests on glycol dehydrators'. As above reference provided in emissions calculations, NMED AQB requires proven process simulator modeling. Data gaps for this source category include lack of measurement data and the reporting threshold for Subpart W of the Greenhouse Gas Reporting Program.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

Costs vary widely based upon size.

Table 1 of the "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico" lists unit costs for VRU abatement technology as $4.18 per mcf of reduced methane ($217.36 per tonne).[55]

What are the annualized operating costs for the equipment or costs associated with the process?

Costs vary widely based upon size.

If the equipment or process is powered, what are the costs?

Costs vary widely based upon size.

[55] "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico," Erin Camp, PhD, Nate Garner, Asa Hopkins, PhD, Synapse Energy Economics, Inc., September 13, 2019,page 9, Table 1, http://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf.

What are the maintenance and repair costs for existing or new equipment?

Costs vary widely based upon size.

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

Glycol dehydration units are already regulated under 40 CFR 63, Subpart HH. While this regulation covers benzene emissions, the controls placed on dehydration units will also reduce methane emissions. The primary driver for emissions reductions has been to meet this requirement which, in turn, captures and controls methane.

The GCP asks to control the glycol circulation rate, and as control has options of

1. installing a BTEX condenser, which is a common control for the still column
2. route flash tank emissions to a combustion device
3. route flash tank emissions to a closed loop system
4. VRU for the still vent and/or flash tank
5. Other control devices such as flare or thermal oxidizer
6. Install electric or instrument-air recirculation pumps (using onsite electricity, solar, etc.).

NSPS Subpart HH

The control device used to reduce HAP emissions in accordance with the standards of this subpart shall be one of the control devices.

1. An enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) to control TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater
2. A vapor recovery device (e.g., carbon adsorption system or condenser)
3. A flare

In addition to the federal rules, the states of Colorado, Wyoming and Pennsylvania regulate emissions from dehydration units. Citations to rules are provided below.

Note: NSPS Subpart HH does not regulate for methane.

New Wells:

N/A

Existing Wells:

N/A

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How have the emission/waste reductions been measured?

Dehydration emissions are included during the permitting process and simulated prior to the development of a facility to ensure emissions meeting required permitted limits. Additionally, dehydration methane and GHG emissions are reported under the GHG Reporting Rule.

How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

Glycol dehydration units have been regulated under 40 CFR 63, Subpart HH. While this regulation covers benzene emissions, the controls placed on dehydration units also reduce methane emissions. The primary driver for emissions reductions has been to meet this requirement which, in turn, captures and controls methane. The control device used to reduce HAP emissions in accordance with the standards of this subpart include enclosed combustion devices, vapor recovery devices and flares. This regulation was updated as recently as 2012 to include small dehydrators.

These regulations typically require the units to control still column vent and flash tank emissions and may require that the unit operate below a calculated glycol circulation rate. EPA regulations affecting glycol dehydration units include the hazardous air pollutant rules (HAPs) in 40 CFR 63, Subpart HH—National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This regulation impacts onshore oil and gas production facilities glycol dehydrators and some oil storage tanks. This rule regulates Major HAP sources as well as glycol units at small sources, called Area Sources. The requirements for area sources are less robust than those for major sources.

NESHAP Subpart HH for Oil and Natural Gas Production Facilities distinguishes between “Large” and “Small” glycol dehydration units. Large units are defined as units that process >85,000 standard cubic meters per day and emit greater than 1 tpy benzene. Both new and existing small glycol dehydrators at major sources must meet the unit-specific BTEX (benzene, toluene, ethylbenzene and xylene) limit for emissions that is based on the unit’s natural gas throughput and gas composition. Newly constructed “small” glycol dehydrators (dehy), built after August 23, 2011, must meet the exemption requirement to demonstrate the gas throughput is less than 85,000 standard cubic meters per day or emit less than 1 tpy benzene. To ensure compliance, this exemption demonstration should be reviewed and documented on an annual basis. If the small dehy does not meet the emission control exemption, the unit must meet the control standards upon startup. Existing small glycol dehydrators were required to be in compliance by October 15, 2015.

In Colorado, state-wide rules require that all existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of 6 tpy or greater be controlled with air pollution control equipment achieving at least a 95%

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reduction. The rules also require that all new glycol natural gas dehydrators with uncontrolled actual VOC emissions of 2 tpy or greater be controlled with air pollution control equipment achieving at least 95% reduction. If a combustion device is used, it must have a design destruction efficiency of at least 98%, with few exceptions.

(Colorado Air Quality Control Commission, 5 C.C.R. 1001-9, CO Reg. 7, XVII.D.3. (Feb. 24, 2014)). The Colorado Oil and Gas Conservation Commission also has a rule requiring all glycol dehydrators with uncontrolled actual emissions of VOC of 5 tpy or greater, located within 1,320 feet of a Building Unit, or a Designated Outside Activity Area use an emission control device capable of achieving 90% control efficiency of VOC. (COGCC Rule 805b(2)B). These rules apply to production facilities, compressor stations and gas processing plants.

At existing facilities in Wyoming, when a combustion unit is required for control of dehydration unit emissions, all non-condensable still vent vapors must be collected and routed to a combustion unit for at least 98% control of VOC and HAP emissions. All glycol flash separator vapors must be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and/or used as fuel for process equipment burners. For new PAD facilities in Wyoming, upon first day of production, all dehydration unit VOC and HAP emissions must be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed if total potential VOC and HAP emissions from all units are less than 4 tpy and all units are equipped with still vent condensers. At new single-well facilities, within 60 days of the first day of production, if total potential uncontrolled VOC and HAP emissions from all units are greater than or equal to 6 tpy (4 tpy in the UGRB), emissions from all units must be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed if the total potential VOC and HAP emissions from all units are less than 4 tpy and all units are equipped with still vent condensers. Removal of controls is not allowed in the Jonah Pinedale Anticline Development Area. WDEQ, Air Quality Division Rules, Chapter 8, section 6(d)(i) (May 19, 2015), WDEQ, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance (May 2016). These rules apply to production facilities.

In Pennsylvania, for new glycol dehydrators, whose uncontrolled emissions are greater than or equal to the methane de minimis level of 200 tpy, VOC de minimis level of 2.7 tpy, single HAP limit of 0.5 tpy, or combined HAP limit of 1 tpy, emission controls must be installed and emissions must be reduced by at least 98%. Existing glycol dehydrators installed prior to February 2, 2013, which have a total uncontrolled PTE of VOC in excess of 10 tpy, must be controlled by at least 85% with a condenser, enclosed flare, or other air cleaning device approved by the Department. Existing glycol dehydrators installed on or after February 2, 2013, but before August 8, 2018 at a natural gas compression station or processing plant, with total uncontrolled PTE of VOC in excess of 5 tpy, must be controlled by at least 95% with a condenser, enclosed flare or other air cleaning device approved by the Department. Existing glycol dehydrators installed on or after August 10, 2013, but before August 8, 2018 at an unconventional

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natural gas well site or remote pigging station, with a total uncontrolled VOC emission rate greater than or equal to 2.7 tpy, an uncontrolled single HAP emission rate greater than or equal to 0.5 tpy, or a total HAP emission rate greater than or equal to 1.0 tpy, must be controlled by at least 95%. (PA DEP, Bureau of Air Quality, Technical Support Document, June 2018).

In Ohio, General Permits for Natural Gas Compressor Stations and Similar Facilities mandate a 0.42 ton per month of VOC limit for dehydrators with throughput less than 90 MMscf/day and a 0.70 limit for dehydrators with greater than 90 but less than 150 MM scf/d throughput. (Ohio General Permits, https://www.epa.ohio.gov/dapc/genpermit/ngcs).

The NMED General Construction Permit (GCP) requires controls reducing VOCs and HAPs, which also reduce methane. Moreover, the NMED permits require conditions to ensure that the controls remain effective. For example, the GCP Oil and Gas requires inspection of controls, periodic gas sampling of the gas routed to the glycol dehydration unit, monitoring of glycol pump rates and other requirements. The requirements (conditions) are intended to ensure the emissions from glycol dehydrators remain below permit allowances.

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

The addition of the controls and/or practices outlined above can reduce methane emissions from glycol dehydrators. These strategies are widely utilized and required by permit.

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
Use Zero Emissions Dehydrators These dehydrators combine flash tanks, electric pumps, and electric control valves to virtually eliminate emissions.	https://www.epa.gov/sites/production/files/2016-06/documents/zeroemissionsdehy.pdf	In use	No feasibility limitations. Combines a set of widespread technologies—flash tanks, electric pumps, and electric control valves.	Low – Medium **High**
Use solid desiccant dehydrators	https://www.epa.gov/sites/production/files/2016-06/documents/ll_desde.pdf	In use	Not viable when gas temperatures	Low **Medium** High

Use salt crystals with large surface areas to attract water molecules—are used in the oil and gas industry. These dehydrators do not require an external power supply, have no moving parts, and are capable of reducing emissions by 99 percent.			are high. Especially difficult in remote areas to properly maintain can lead to increased methane emissions.	
Optimize glycol circulation. The manner in which a glycol dehydrator is used can also impact emission rates. For example, both the efficiency and emission rate of a glycol dehydrator are directly proportional to the rate at which gas is circulated. In certain cases, operators may be able to reduce circulation rates to reduce emissions, while still removing enough water from the gas to meet sales specifications.	https://www.epa.gov/sites/production/files/2016-06/documents/ll_flashtanks3.pdf	In use	No feasibility limitations, however, many operators may already be operating at optimal circulation rates.	**Low** Medium High
Install flash tank separator. A flash tank separator brings the rich glycol to a lower pressure at which hydrocarbons will evaporate but water will remain in solution with the glycol. The flash tank captures approximately 90 percent of the methane	https://www.epa.gov/sites/production/files/2016-06/documents/ll_flashtanks3.pdf	In use	No feasibility limitations.	Low **Medium** High

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and 10 to 40 percent of the VOCs entrained by the glycol. The captured gas is then routed to a fuel line, a compression suction, or a flare.				
Use Electric Pumps Instead of Pneumatic Pumps. A pneumatic pump must circulate significantly more gas, because gas pressure drives the circulation process. Pneumatic pumps may also leak rich (wet) glycol into the lean (dry) glycol, which decreases the efficiency of the system and requires greater circulation—leading to greater emissions.	https://www.epa.gov/sites/production/files/2016-06/documents/ll_glycol_pumps3.pdf	In use	Requires electricity	Low **Medium** High
Reroute Glycol Skimmer Gas. In the glycol dehydration process, rich glycol is circulated through a regenerator where the liquid is heated and water and hydrocarbons are vaporized and vented to the atmosphere. Some glycol dehydrators have glycol vent condensers and condensate separators to recover natural gas liquids and reduce VOC and HAP emissions. The condensate gas can be rerouted to the reboiler or other low-pressure	https://www.epa.gov/sites/production/files/2016-06/documents/rerouteglycolskimmer.pdf	In use		Low **Medium** High

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fuel gas system for fuel use.				
Route Recovered Gas to Vapor Recovery Unit. *Rather than venting gas that evaporates from the rich glycol in the flash tank separator, some operators have piped this gas to a vapor recovery unit, where it can be put to beneficial use.*	*https://www.epa.gov/sites/production/files/2016-06/documents/pipeglycoldehydratortovru.pdf* *California includes the following language regarding low-NOx VRU:* *If the vapor control device is to be installed in a region classified as non-attainment with, or which has not been classified as in attainment of, all state and federal ambient air quality standards, the owner or operator must install one of the following devices that meets all applicable federal, state, and local air district requirements:* *(A) A non-destructive vapor control device that achieves at least 95 percent vapor control efficiency of total emissions and does not result in emissions of nitrogen oxides (NOx); or,* *(B) A vapor control device that achieves at least 95 percent vapor control efficiency of total emissions and does not generate more than 15 parts per million volume (ppmv) NOx when measured at 3 percent oxygen and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.* Source: https://ww3.arb.ca.gov/regact/2016/oilandgas2016/ogfro.pdf Example: http://www.aereon.com/enclosed-combustion-systems/certified-ultra-low-emissions-burner-ceb	In use		Low **Medium** High

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

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No new controls are necessary due to current control mechanisms and efficiency of process. The cost to achieve additional reductions would be high due to glycol dehydrators already being heavily regulated and there being little opportunity to make further reductions.

Various states identified above have determined that there is a need for state requirements in addition to the federal NESHAP requirements. The NESHAP MACT requirements apply only in certain circumstances, e.g., at major sources and the NESHAPs require less-protective requirements for dehydration units located at area sources. State requirements apply at minor sources and to dehydration units located at production facilities with emissions that may not trigger the application of the NESHAP requirements.

What are the pros and cons of the alternatives?

This is discussed above in the table. Many of them are already in use per best practice and regulation.

What is needed and available for new wells?

Discussed above in table.

See WY, CO, and PA requirements.

What is needed and available for existing wells?

Discussed above in table.

See WY and CO requirements

What technology alternatives exist for this equipment or process itself?

Discussed above in table

What are the pros and cons of the alternatives?

Discussed above in table.

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

No new controls are necessary due to current control mechanisms and efficiency of process.

ICF found that replacing positive displacement pumps with electric pumps results in overall savings of $4.17/Mcf of methane reduced. (Source: ICF 2014, https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf) Gas price at which this savings occurs is unknown.

What would be the implementation cost?

For new wells?

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N/A

For existing wells?

N/A

Are there low-cost solutions available?

N/A

If a solution is high-cost, why is that the case?

N/A

Are there additional technical analyses needed to refine benefits/costs estimates?

N/A

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

N/A

What is the useful life of equipment?

Standard life of control equipment

What are the maintenance and repair requirements for equipment required for methane reduction?

Discussed in table

How would emissions be detected, reductions verified and reported?

Most dehydration units are covered in the GHGRP.

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

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What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

None.

As noted above, the NESHAPs have limited applicability to major sources and large dehydration units. There is a gap for the state to fill with respect to controlling minor source emissions and emissions from smaller dehydration units located at major sources.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

None

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

No

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc?):

None

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5. DEHYDRATORS - PATH FORWARD[56]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EMISSIONS REDUCTIONS ARE EASY TO ACHIEVE AND ARE COST EFFECTIVE 1 = EASY 5 = HARD	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
3.1	In general, no new controls are necessary for this process due to current control mechanisms		1 2 3 4 5	Covered in NMED permit conditions	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
3.2	Require use of zero emissions dehydrators. [page 76]	This option is not available where there is no line power https://www.epa.gov/sites/production/files/2016-06/documents/zeroemissionsdehy.pdf	1 2 3 4 5	Covered in NMED permit conditions	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
3.3	Require use of flash tanks, conversion to electric pumps and optimization of circulation rate. [page 76]	Electric pumps require presence of electricity. https://www.epa.gov/sites/production/files/2016-06/documents/ll_flashtanks3.pdf	1 2 3 4 5	Covered in NMED permit conditions	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

[56] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

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NMED/EMNRD METHANE ADVISORY PANEL

SECTION 4, COMPRESSORS AND ENGINES

Discussion for MAP members on September 26, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

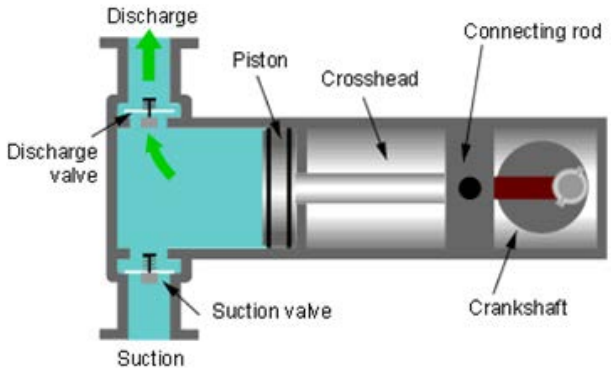
1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

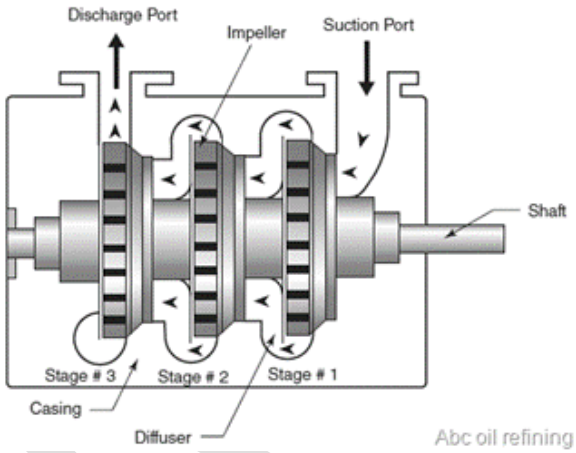
Technical description of the process or equipment:

One of the most common processes in the natural gas sector is compression. Compressors are mechanical devices that increase the pressure of natural gas to allow the natural gas to move through the natural gas value chain. Compressors are also used within processes at natural gas processing facilities and at oil and gas production facilities to enable production. In the oil and natural gas sector, the most prevalent types of compressors are reciprocating and centrifugal compressors. The choice between a reciprocating and centrifugal compressor is always a case-by-case determination and depends on a variety of operating conditions, such as required discharge pressure, gas volume and temperature, efficiency and cost.

> **Reciprocating compressor** increase the pressure of a gas by positive displacement. Natural gas enters the compression cylinder through the suction manifold, where it is compressed by a piston driven in a reciprocating motion by the crankshaft. See diagram below.



Centrifugal compressor increases pressure of a gas by drawing in low pressure natural gas through the suction port and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. See Diagram below.

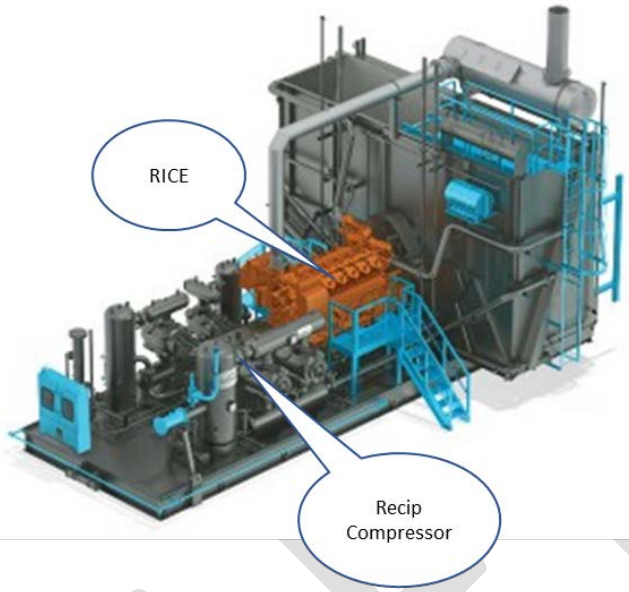


Compressors are paired with a driver. In the oil and natural gas sector, compressors are commonly powered by gas fired reciprocating internal combustion engines (RICE) for reciprocating compressors and gas fired combustion turbines for centrifugal compressors. In some cases, compressors may be paired with electrical motors rather than gas fired RICE or turbines.

Gas fired reciprocating internal combustion engines use pistons that alternatively move back and forth to convert pressure into rotating motion, which drives the crankshaft of the compressor. These are similar to the engines in most cars, with the exception that vehicles typically use gasoline as fuel.

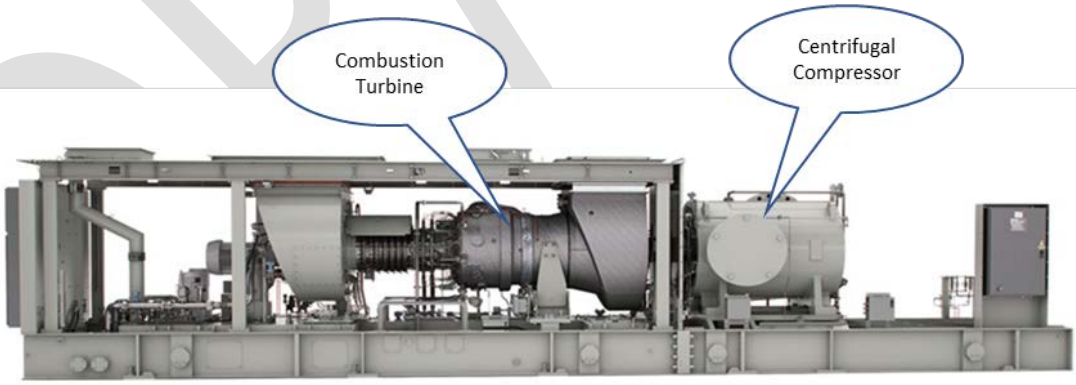
NMED Exhibit 10 - 0085

Reciprocating Compressor and RICE Engine



Gas fired combustion turbines heat a mixture of air and fuel at very high temperatures resulting in combustion of the gases, causing the turbine blades to spin at a very high speed, which drives the shaft of the centrifugal compressor. These are similar to the engines on a jet plane.

Centrifugal Compressor and Combustion Turbine



Provide the segment(s) of the industry that the equipment or process is found:

Production, gathering, processing, transmission, storage.

Describe how the equipment or process is used:

This link to the EPA GHG Reporting Program, includes a description of the oil and gas value chain and identifies some of the locations where compression occurs.

To produce oil and natural gas and keep natural gas pressures at the level required to move gas from the wellhead to the consumer, compressors and the associated driver are found at multiple locations in the natural gas value chain, including:

- Oil and gas production operations for enhanced oil recovery, maintaining reservoir pressures, gas lift, gas reinjection, wellhead compression of natural gas, and capturing tank vapors for recovery (vapor recovery unit).
- Gas gathering compressor stations to move raw natural gas from the wellhead to natural gas processing plants
- Moving gas into and out of natural gas processing plants and within the natural gas processing plant to pressurize process gasses, for example to increase the pressure of gasses used in the refrigeration or cryogenic processes at a natural gas processing facility
- Downstream of the natural gas processing plant in the gas transmission sector to move natural gas long distances in large diameter pipelines to
    - natural gas storage facilities
    - natural gas distribution systems for delivery to end users
    - directly to large industrial, commercial, or power generation customers
- Moving natural gas into and out of natural gas storage facilities

In addition to driving compressors, engines may also be used as the driver for power generators that provide electrical power to sites that are not connected to the commercial electrical grid or may be used as backup power supply in case of a power outage. Engines are also used to drive pumpjacks in the oil production sector. Pumpjacks are used to mechanically lift liquid out of the well if bottom hole pressure is not high enough to allow liquid to flow to the surface.

Provide the common process configurations that use this equipment or process:

A diagram of the configuration of a typical natural gas compressor station (from enbridge.com) is provided below. This configuration is similar for gas gathering and gas transmission compressor stations. The configuration of compressors at gas processing facilities is similar, but perhaps more complex. At gas processing plants, compression can take place at the front end of the plant (inlet gas compression), as the processed natural gas exits the plant (residue compression), or within the process to compress refrigeration gases.

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2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

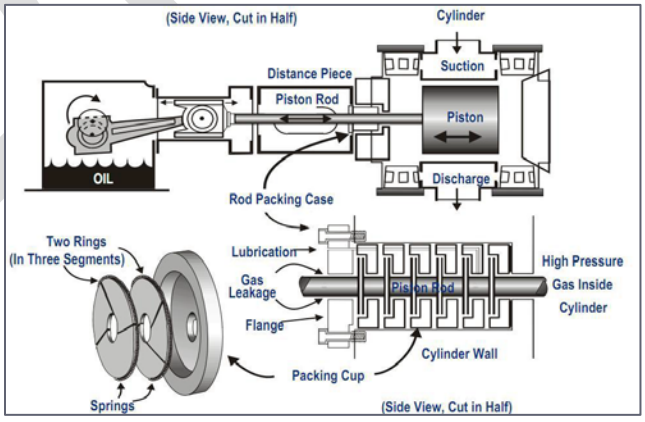
Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

Compressors

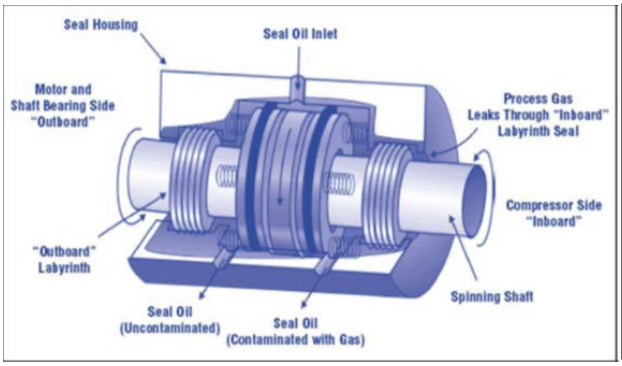
The primary source of methane emissions from compressors are from seals around the piston rod of a reciprocating compressor and around the spinning shaft of a centrifugal compressor. There are two types of seals for centrifugal compressors, dry seals and wet seals. In all cases the seals prevent natural gas from exiting the compression chambers and entering the atmosphere. The following link to a paper published by USEPA Office of Air Quality Planning and Standards (OAQPS) titled "Oil and Natural Gas Sector Compressors, Report of oil and Natural Gas Sector Compressors Review Panel, April 2014", provides a good description of the seals systems in both reciprocating compressors (see top diagram below and section 2.1 of the EPA paper) and centrifugal compressors (see bottom diagrams below and section 2.2 of the EPA paper).

Rod Packing Seal System in Reciprocating Compressor

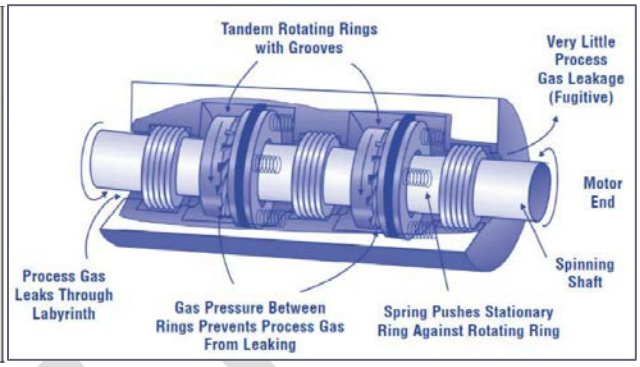


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Wet Seal System in Centrifugal Compressor



Dry Seal System in Centrifugal Compressor



Another source of methane emissions from compressors are the fugitive emissions from piping components, such as valves, flanges, and connectors. These sources of fugitive emissions are not unique to compressors and will be considered in more detail during the LDAR discussion topic.

Engines

Emissions from engines are typically associated with engine exhaust from combustion of fuel, in this case natural gas. Combustion emissions include primarily NOx, CO, VOC and CO2. In addition, methane is emitted from the engine exhaust (often referred to as "methane slip" or "combustion slip") and is the result of unburned methane from the fuel that is emitted with the engine exhaust. Methane slip emissions are the result of the fundamental combustion design and type of combustion system for various engine types. The following link to a paper published by the International Council on Combustion Engines (CIMAC) titled "CIMAC Position Paper, Methane and Formaldehyde Emissions of Gas Engines, April 2014" provides details about methane in engine exhaust.

How are the emissions calculated for this equipment or process?

Emissions for individual compressors and engines can be calculated using emissions factors (for example EPA AP-42 emission factors for engines or GHGRP protocols) in combination with activity data, using engineering calculations, or by direct measurement of emissions.

What data is available to quantify emissions/waste for this equipment or process?

There have been many papers written by a variety of governmental agencies, non-governmental organizations, academia, and industry groups related to methane emissions from compressors and engines. In addition, there have been documents generated during rulemaking activities, primarily the EPA, that include data about emissions from these sources. While not exhaustive, below are links to some of these documents, each citing additional data sources, for example the U.S. EPA Greenhouse Gas

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Inventory data. Some of the papers, or cited data sources, generated emission data by direct measurement of emissions.

1) EPA Office of Air Quality Planning and Standards (OAQPS), April 2014. From the introduction: "The purpose of this paper is to summarize the EPA's understanding of vented VOC and methane emissions from compressors, and the EPA's understanding of available mitigation techniques (practices and equipment) to reduce vented emissions from compressors. Included in the mitigation techniques discussion is our understanding of the efficacy and cost of these technologies and the prevalence of use of the technologies in the industry". "Oil and Natural Gas Sector Compressors, Report for Oil and Natural Gas Sector Compressors Review Panel"
2) EPA Air Emissions Factors and Quantification. This is a link to EPA background information on natural gas fired reciprocating internal combustion engines (RICE) and Chapter 3.2 of EPA's *Compilation of Air Pollutant Emissions Factors (AP-42)* for RICE. AP 42, Fifth Edition, Volume I, Chapter 3: Stationary Internal Combustion Sources.
3) EPA Greenhouse Gas Reporting Program.
    a. This link contains EPA basic information on sources of GHG emissions in the petroleum and natural gas industries (Subpart W), emissions data reported, and guidance for reporters. This subpart covers compressors venting and most fugitive and venting sources from oil and gas facilities, plus engines in the production and gathering and boosting segments. GHGRP for Petroleum and Natural Gas Systems (Subpart W).
    b. This link contains EPA information on sources of GHG emissions from stationary fuel combustion sources, including engines (Subpart C). This subpart covers engine exhaust emissions at gas processing plants and transmission compressor stations. GHGRP for General Stationary Fuel Combustion Sources (Subpart C).
4) Colorado State University, Energy Institute, 2019. From the introduction: "The study had two primary objectives: 1) Collect data on equipment counts and types (activity data) of gathering stations and 2) Perform component level leak measurements suitable for developing new emission factors". "Characterization of Methane Emissions from Gathering Stations: Final Report"
5) Colorado State University, Energy Institute, 2019. This paper presents the technical information related to the CSU Gathering Station study direct measurement of methane emissions in the exhaust of engines. "Methane Emissions from Gathering and Boosting Compressor Stations in the U.S. Supporting Volume 2: Compressor Engine Exhaust Measurements"
6) Climate & Clean Air Coalition, 2017. From the introduction: "This is a technical guidance document for Partners to the CCAC Oil and Gas Methane Partnership (OGMP). This document is one in a series that describes a core source of methane emissions. The document introduces suggested source-specific methodologies for quantifying methane emissions and describes established mitigation options that Partners should reference when determining if the source is

“mitigated””. This document is specific to centrifugal compressors with wet seals. "Technical Guidance Document Number 3: Centrifugal Compressors with "Wet" (Oil) Seals"

7) Climate & Clean Air Coalition, 2017. From the introduction: “This document provides technical guidance to Partners of the CCAC Oil and Gas Methane Partnership (OGMP). It is one in a series describing a core source of methane emissions from oil and natural gas production operations. The guidance documents introduce suggested methodologies for quantifying methane emissions from specific sources and describe established mitigation options that Partners should reference when determining if the source is “mitigated””. This document is specific to reciprocating compressors. "Technical Guidance Document Number 4: Reciprocating Compressors Rod Seal/Packing Vents”
8) Joint Institute for Strategic Energy Analysis, August 2015. From the Executive Summary: “Based on a review of recent research and analysis of the U.S. GHGI emission estimates, this report briefly summarizes the methods and results of the 2014 U.S. GHGI (EPA 2014a), discusses challenges to constructing the U.S. GHGI, and suggests some opportunities that could improve the accuracy of the methane emissions estimates”. "Estimating U.S. Methane Emissions from the Natural Gas Supply Chain: Approaches, Uncertainties, Current Estimates, and Future Studies"
9) INGAA, August 2018. From the introductory comments of the whitepaper: “This white paper supplements those commitments by explaining the sources of methane emissions for the interstate natural gas transmission and storage sector, which is comprised of a network of high-pressure pipelines, compressor stations, and storage assets (salt caverns and reservoirs), as well as the basis for the methane emissions commitments that INGAA members voluntarily adopted”. "Improving Methane Emissions from Natural Gas Transmission and Storage"
10) One Future/ICF International, May 2016. From the Executive Summary: “Our Nation’s Energy Future Coalition (ONE Future) 1 commissioned ICF to conduct this analysis of the marginal abatement cost (MAC) of various methane emission abatement technologies and work practices for the natural gas industry. The goal of this MAC analysis is threefold: (1) to identify the emission sources that provide the greatest opportunity for methane emission reduction from the natural gas system, (2) to develop a comprehensive listing of known emission abatement technologies for each of the identified emission sources, and (3) to calculate the cost of deploying each emission abatement technology and to develop a MAC curve for these emission reductions”. "Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems"
11) EPA & EC/R Inc., July 2011. From the forward: “This background technical support document (TSD) provides information relevant to the proposal of New Source Performance Standards (NSPS) for limiting VOC emissions from the Oil and Natural Gas Sector”. "Oil and Natural Gas

Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards"

12) EPA & GRI, June 1996. From the introduction: "This report describes how the emissions from compressor driver exhaust were determined. Section 3 discusses the data used to make the emission estimates. Section 4 presents the development of the emission factors for engines and turbines. Section 5 describes the development of the activity factors for each industry segment (production, processing, and transmission, including storage and generators). The annual emissions for each segment and the overall national emissions estimate are provided in Section 6. Conclusions are given in Section 7". "Methane Emissions from the Natural Gas Industry, Volume II: Compressor Driver Exhaust, Final Report"

What are the data gaps in quantifying emissions/waste for this equipment?

Numerous studies have published estimates of methane emissions from compressors and engines, using either top-down or bottom-up methodologies. Each methodology has its associated pros and cons, which results in varying emission estimates and activity data for these sources. Some of the data quality issues or data gaps that impact emission estimates, and therefore the ability to assess effectiveness of reduction efforts, include:

- Variation in emissions between source sub-types, for example different engine designs and configurations.
- Variation in emissions for similar equipment due to specific operational conditions at facilities or across geographic areas.
- Consistency of and lack of activity data and data regarding the number of sources, by type and sub-type, as well as by industry sector.
- Due to changing regulations and application of best practices, data more than a few years old may no longer be representative of actual emissions.
- It has proven difficult to reconcile differences between emission estimates, for example there are some significant inconsistencies between the EPA GHG Inventory and the EPA GHG reporting program data.

Arbitrary categorizations that may obscure important information. For example, EPA GHGRP only uses a single emissions factor, appropriate for a small compressor, for vented gas from any reciprocating compressor located at a well pad. While many compressors at well pads are small, no data is collected on the prevalence of larger compressors at these facilities, which would be expected to have higher emissions.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

Equipment costs for engines and compressors vary greatly across the natural gas value chain based on facility requirements, operational conditions, and location. As such, equipment costs must be determined on a case-by-case basis.

What are the annualized operating costs for the equipment or costs associated with the process?

Operating costs for engines and compressors vary greatly across the natural gas value chain based on equipment type, facility requirements, operational conditions, and location. As such, operating costs must be determined on a case-by-case basis.

If the equipment or process is powered, what are the costs?

The cost to power compressors is related to the fuel cost to operate a combustion engine or turbine, or the cost of electricity for compressors that are driven by electric motors. Fuel and electricity costs vary greatly across the natural gas value chain based on equipment type and location. As such, power costs must be determined on a case-by-case basis.

What are the maintenance and repair costs for existing or new equipment?

Maintenance costs for engines and compressors vary greatly across the natural gas value chain based on equipment type, facility requirements, operational conditions, and location. As such, maintenance costs must be determined on a case-by-case basis.

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

Voluntary methane emission reduction best practices used in the oil and natural gas industry for compressors and engines are identified in the following link to the EPA Natural Gas STAR Program "Recommended Technologies to Reduce Methane Emissions".

It should be noted that the information presented by NG STAR partners related to costs to implement methane reduction opportunities may be specific to a location or an individual company. The decision to implement and the cost to implement a voluntary methane reduction technology is always a case-by-case determination based on facility requirements, operational conditions, and location. One example of variation in the feasibility analysis is related to the value of natural gas. Many of the NG STAR opportunities assess cost benefits based on natural gas values that are dated and may not reflect the lower values of natural gas in today's market.

For example, many of the NG STAR examples use a range of value for natural gas of $3-$7/Mcf. Gas values today, and for the past 5 years, are typically below $3/Mcf. It is notable that in some producing basins, including the Permian Basin of SENM, gas values are even more depressed due to local market conditions. Permian Basin spot natural gas prices (at Waha Hub) averaged less than $0.75/Mcf during

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the first eight months of 2019, after touching a record low of negative $9.00 in April 2019, and compared with an average of $2.10 in 2018 and a 2014-18 average of $2.80.

The EIA notes that low Permian Basin spot prices are largely the result of constraints on pipeline capacity, and that prices rose in September in anticipation of the opening of the Gulf Coast Express Pipeline. EIA notes that "Limited natural gas pipeline takeaway capacity from the region has kept prices very low" and that seven additional natural gas pipelines are planned in the region. https://www.eia.gov/todayinenergy/detail.php?id=41213.

Primary reduction strategies include:

- Centrifugal Compressor Wet Seals - Replacing Wet Seals with Dry Seals
    - EPA NG STAR Partner Reported Opportunity
    - May not be technically feasible in some cases due to design of existing compressor or operational conditions, such as:
        - Sour gas service, i.e. gas with H2S, common in SENM
        - Certain pressure & temperature conditions
    - If feasible, potential to reduce methane emissions by 95%
    - High cost to implement reported by a NG STAR partner as $324,000 in 2006 dollars ($475,000 in today's dollars w/ 3% inflation)
    - May be offset over time by lower OPEX
- Centrifugal Compressor Wet Seals - Wet Seal Degassing Capture
    - EPA NG STAR Partner Reported Opportunity
    - Collect vapor from seal oil degassing and route for other uses or destruction, such as:
        - Compressor suction
        - High pressure turbine fuel gas
        - Low pressure fuel gas for heaters/burners
        - Flare purge gas
        - Flared, if no use is feasible
    - If feasible, potential to reduce methane emissions by 95%. Some of the above uses may not feasible, e.g. for sour gas.
    - Requires capital costs to install seal oil separator, oil demister/filter, piping, flow controls, and instrumentation
    - Cost to implement can be highly variable based on facility requirements. One NG STAR partner reported costs to be $33,000 in 2014 dollars.
- Reciprocating Compressor Rod Packing – Rod Packing Replacement
    - EPA NG STAR Partner Reported Opportunity
    - Rod packing emissions increase over time due to wear at the seal surfaces

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    - Replacement of rod packing is routine maintenance task
    - Cost to replace compressor rod packings is highly variable
        - Dependent on size of the compressor, composition of the gas being compressed, operating pressures, operating temperatures, other operating conditions (such as demand and speed), technology selected, and materials selected.
    - One NG STAR partner reported costs to be $1,350 - $1,700 per compression cylinder. For a typical compressor with 4 cylinders this would equate to a range of $5,400 - $6,800 for parts & labor
- Reciprocating Compressor Rod Packing – Vapor Capture
    - Collect vapor from rod packing and route for engine fuel
    - May not be feasible for all application, for example sour gas

With regards to methane slip in engine exhaust, the paper published by the International Council on Combustion Engines (CIMAC) titled "CIMAC Position Paper, Methane and Formaldehyde Emissions of Gas Engines, April 2014" also provides a list of potential methods to reduce methane slip emissions. Many of the reduction methods are related to changing the fundamental design of the combustion chambers in engines to reduce methane slip and improve engine efficiency (Section 6 of the paper). There is also discussion regarding exhaust gas after-treatment using oxidation catalyst to lower methane slip (Section 7 of the paper). At this time, it appears there are unresolved technical issues related to methane conversion at low exhaust temperature and catalyst degradation. Using catalyst to reduce methane emissions appears to be unproven and further development is required to make this technology available. The paper published by One Future/ICF International (May 2016), "Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems", states in section 2.3, "Several of the sources identified in Table 2-1 do not have commercially available mitigation technologies (e.g., engine exhaust) …".

How have the emission/waste reductions been measured?

Voluntary methane emission reductions are reported by Natural Gas STAR Partners and summarized in EPA's annual program reports in this link to the "Natural Gas STAR Program Accomplishments"

How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

New compressors have been regulated since 2012 by the New Source Performance Standard at 40 CFR 60, subpart OOOO and New Source Performance Standard at 40 CFR 60, subpart OOOOa. Under these rules, new centrifugal compressors are required to reduce methane and VOC emissions from wet seal systems by at least 95%, which also provides a similar reduction in methane emissions. Reciprocating

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compressors are required to change the rod packing at least every 26,000 operating hours or every 3 years. Modification to existing compressors triggers these NSPS requirements if the change results in an increase in horsepower. Compressors located at a well site, or an adjacent well site and servicing more than one well site, are not subject to these requirements. In leu of changing the rod packing, NSPS OOOO/OOOOa allows the operator to collect and route emissions from the compressor rod packing to a process through a closed vent system.

Some states have implemented regulations that are more stringent than the federal rules, to reduce VOC emissions in ozone non-attainment areas or as regulations to reduce methane emissions. In Colorado, for example, per CO Air Quality Control Commission, Regulation 7, the federal OOOO/OOOOa compressor requirements generally apply to compressors regardless of installation date (see Reg 7, Sections XII.J.1 & XVII.B.3.b for Centrifugal Compressors and Reg 7, Sections XII.J.2 & XVII.B.3.c for Reciprocating Compressors). In addition, centrifugal compressors with wet seal systems must complete annual inspections and leak monitoring of wet seal capture systems. Unless a compressor is already subject to OOOO/OOOOa, Reg 7, Section XVII.B.3.b & c do not include the same intensive recordkeeping and reporting requirement as provided for in Reg 7, Section XII.J. The recordkeeping and reporting in Section XII.J are a function of ensuring the related emissions reductions can be credited toward the attainment demonstration.

California, Canadian Federal rules, and two Canadian provinces have taken a somewhat different, more protective approach. Canadian jurisdictions require control (approx. 95%) of rod-packing emissions from any new reciprocating compressor.

Effective dates – after which new reciprocating compressors must be controlled

Canadian Federal 1/1/2023
Alberta 1/1/2022 (Only recips with 4 or more cylinders)
British Columbia 1/1/2021 (Only recips with 4 or more cylinders)

For existing reciprocating compressors, these jurisdictions require periodic measurement of rod packing vent volumes. Typically, the measurement must be performed annually. After the effective dates listed above (1/1/2019 for California), when an operator measures vent volume in excess of a threshold, the compressor must be repaired (e.g., rod-packing replacement or similar).

Vent Volume Repair Thresholds (per cylinder, scf/minute)

California 2.0
Canadian Federal 0.81
Alberta & British Columbia 0.49, *averaged across all compressors in an operator's provincial fleet.*

In Canadian jurisdictions, these rules are applied to all recips except those under 100 HP and (for the provincial rules) those operated less than 450 hours per year. California applies standards to all

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compressors operated 200 or more hours per year. The standards described above are applied to all recips except those at wellpads. California subjects wellpad compressors that do not route rod-packing emissions to a process or control to LDAR requirements. If there is any significant amount of vent gas from rod-packing for these compressors, the LDAR program must treat the compressor as a leak source and it must be repaired.

Links for rules discussed above:

Canadian federal standards: http://gazette.gc.ca/rp-pr/p2/2018/2018-04-26-x1/pdf/g2-152x1.pdf
Compressor seal rules are in sections **14** to **19**, which are on pages 10-15 of the pdf

Alberta: https://www.aer.ca/documents/directives/Directive060_2020.pdf
See section 8.6.2, pages 79-82

BC: http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018
See pages 4-6 (section 52.04)

Calif.: https://ww2.arb.ca.gov/resources/documents/oil-and-gas-regulation
See sections 95668(c) and (d), pages 13-18.

New and existing engines have been regulated by the EPA and states for many years, dating to 2004, with a regulatory focus on criteria pollutants (NOx, CO, VOC) and hazardous air pollutants (formaldehyde). Federal engine regulations include the National Emission Standard for Hazardous Air Pollutants at 40 CFR 63, subpart ZZZZ, and the New Source Performance Standard at 40 CFR 60, subpart JJJJ. Requirements in NESHAP ZZZZ and NSPS JJJJ for engines vary depending on age, engine type, size, and location. While emission limits and control requirements of these two regulations target NOx, CO, VOC, and formaldehyde, methane is also reduced. For example, catalytic controls that reduce other pollutants, also reduce methane, although to a lesser degree. In addition, the maintenance, inspection and testing requirements in these regulations and state issued permits ensure that engines operated in an efficient manner that minimizes methane emissions along with criteria and hazardous air pollutants.

EPA requires annual reporting of GHG emissions from these sources at plants/basins with over 25,000 mtCO2e. Also, annual monitoring of vented wet seal and rod packing emissions at subject gas processing plants.

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

Voluntary emission reduction best practices used in the industry for compressors and engines are identified in the following link to the EPA Natural Gas STAR Program "Recommended Technologies to Reduce Methane Emissions"

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Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Voluntary methane emission reduction best practices used in the industry for compressors and engines are listed the following link to the EPA Natural Gas STAR Program "Recommended Technologies to Reduce Methane Emissions"

Feasibility and cost of the NG STAR partner reported opportunities are always a case-by-case determination based on facility requirements, operational conditions, and location. One example of variation in the feasibility analysis is related to the value of natural gas. Many of the NG STAR opportunities assess cost benefits based on natural gas values that are dated and may not reflect the lower values of natural gas in today's market.

For example, many of the NG STAR examples use a range of value for natural gas of $3-$7/Mcf. Gas values today, and for the past 5 years, are typically below $3/Mcf. It is notable that in some producing basins, including the Permian Basin of SENM, gas values are even more depressed due to local market conditions. Permian Basin spot natural gas prices (at Waha Hub) averaged less than $0.75/Mcf during the first eight months of 2019, after touching a record low of negative $9.00 in April 2019, and compared with an average of $2.10 in 2018 and a 2014-18 average of $2.80.

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

See above link to EPA NG STAR reported opportunities for complete discussion on each reduction technology.

What are the pros and cons of the alternatives?

See above link to EPA NG STAR reported opportunities for complete discussion on each reduction technology.

What is needed and available for new wells?

These emissions are not specific to wells.

What is needed and available for existing wells?

These emissions are not specific to wells.

What technology alternatives exist for this equipment or process itself?

Compression is a basic, must run process for the natural gas industry. No alternatives exist to replace the use of compressors to move natural gas through the value chain.

As discussed in earlier sections, the driver for a compressor can be an internal combustion engine, a combustion turbine, or an electric motor. In some situations, oil and gas operators determine that electrified compression is a viable and preferred technology in place of natural gas fired engines or turbines.

What are the pros and cons of the alternatives?

With regards to electric driven compression:

Pros:

- Eliminates local engine/turbine related emissions of criteria pollutants and HAPs, along with methane emissions. There are still emissions, including GHG emissions, related to power generation.

Cons:

- Many locations do not have access to adequate and reliable third-party power
- Cost

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

Cost of the NG STAR reported opportunities is discussed in the EPA Natural Gas STAR Program "Recommended Technologies to Reduce Methane Emissions".

Costs are always a case-by-case determination based on facility requirements, operational conditions, and location. Many of the NG STAR opportunities assess cost benefit based on natural gas values that are dated and may not reflect the lower values of natural gas in today's market.

For example, many of the NG STAR examples use a range of value for natural gas of $3-$7/Mcf. Gas values today, and for the past 5 years, are typically below $3/Mcf. It is notable that in some producing basins, including the Permian Basin of SENM, gas values are even more depressed due to local market conditions. Permian Basin spot natural gas prices (at Waha Hub) averaged less than $0.75/Mcf during the first eight months of 2019, after touching a record low of negative $9.00 in April 2019, and compared with an average of $2.10 in 2018 and a 2014-18 average of $2.80.

Table 1 of the "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico" lists per unit costs for centrifugal compressor abatement technology as $0.82 per mcf of reduced methane ($42.64 per tonne).[57]

[57] "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico," Erin Camp, PhD, Nate Garner, Asa Hopkins, PhD, Synapse Energy Economics, Inc., September 13,

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What would be the implementation cost?

For new wells?

These emissions are not specific to wells.

For existing wells?

These emissions are not specific to wells.

Are there low-cost solutions available?

See EPA Natural Gas STAR opportunities linked above.

If a solution is high-cost, why is that the case?

See EPA Natural Gas STAR opportunities linked above.

Are there additional technical analyses needed to refine benefits/costs estimates?

Costs are always a case-by-case determination based on facility requirements, operational conditions, and location.

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

See EPA Natural Gas STAR opportunities linked above.

What is the useful life of equipment?

See EPA Natural Gas STAR opportunities linked above.

What are the maintenance and repair requirements for equipment required for methane reduction?

See EPA Natural Gas STAR opportunities linked above.

How would emissions be detected, reductions verified and reported?

2019, page 9, Table 1, http://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf.

Emissions for individual compressors and engines can be calculated using emissions factors (for example EPA AP-42 emission factors for engines or GHGRP protocols) in combination with activity data, using engineering calculations, or by direct measurement of emissions.

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

See Section 2 above regarding regulation of compressors and engines. Potential gaps are related to sources that are not covered by NSPS OOOO/OOOOa (grandfathered) or are located at wellsites.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

Engines and compressors are stationary sources located at facilities subject to NMED air quality rules and permits.

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

NA

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc.?):

5. COMPRESSORS AND ENGINES- PATH FORWARD[58]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EMISSIONS REDUCTIONS ARE EASY TO ACHIEVE AND ARE COST EFFECTIVE 1 = EASY 5 = HARD	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
4.1	Centrifugal Compressor Wet Seals - Wet Seal Degassing Capture: retrofit wet seal installations with equipment that directs gas from seal oil degassing unit to other use, or flare for destruction.	https://www.epa.gov/sites/production/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf Capture for use may not be technically feasible in some cases due to design of existing compressor or operational conditions, such as: • Sour gas service, i.e. gas with H2S, common in SENM If feasible, potential to reduce methane emissions by 95%. Some of the above uses may not be feasible, e.g. for sour gas. Requires capital costs to install seal oil separator, oil demister/filter, piping, flow controls, and instrumentation. Cost to implement can be highly variable based on facility requirements. One NG STAR partner reported costs to be $33,000 in 2014 dollars.	1 2 3 4 5		San Juan Permian Both

[58] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

NMED Exhibit 10 - 0102

		While flaring is less preferred than capture for use due to waste & emissions of CO2 and other pollutants, it is certainly preferable to venting.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
4.2	Centrifugal Compressor Wet Seals - Replacing Wet Seals with Dry Seals	https://www.epa.gov/sites/production/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf May not be technically feasible in some cases due to design of existing compressor or operational conditions, such as: • Sour gas service, i.e. gas with H2S, common in SENM • Certain pressure & temperature conditions If feasible, potential to reduce methane emissions by 95%. High cost to implement reported by a NG STAR partner as $324,000 in 2006 dollars ($475,000 in today's dollars w/ 3% inflation). Costs may be offset by lower opex after retrofit.	1 2 3 4 5		San Juan Permian Both
	COMMENT A. Wet seals do not apply to reciprocating compressors. [page 88]		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
4.3	Reciprocating Compressor Rod Packing – Vapor Capture and route for engine fuel [page 95]	May not be feasible for all application, for example sour gas	1 2 3 4 5		San Juan Permian Both
	COMMENT A. The concerns raised by EPA are still valid. In the Federal Register notice dated August 23, 2011 regarding proposed NSPS Subpart OOOO regulation, EPA evaluated the possibility of reducing VOC emissions from a control device but did not propose it due to technical considerations at Page 53762: "Although it is possible to construct an enclosure around the rod packing area and vent the emissions outside for safety purposes, connection to a closed vent system would		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

NMED Exhibit 10 - 0103

	create back pressure on the leaking gas. This back pressure would cause the leaked gas instead to be forced inside the crankcase of the engine, which would dilute lubricating oil, causing premature failure of engine bearings, pose an explosion hazard and eventually be vented from the crankcase breather, defeating the purpose of a control device." B. Allowed in other states [cite in paper]				
4.4	Reciprocating Compressor Rod Packing – Rod Packing Replacement [page 94]	https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf	1 2 3 4 5		San Juan Permian Both
	COMMENT A. Cost to replace compressor rod packings is highly variable. Dependent on size of the compressor, composition of the gas being compressed, operating pressures, operating temperatures, other operating conditions (such as demand and speed), technology selected, and materials selected. [page 95] B. One NG STAR partner reported costs to be $1,350 - $1,700 per compression cylinder. For a typical compressor with 4 cylinders this would equate to a range of $5,400 - $6,800 for parts & labor [page 95] C. [Reference not in paper.] In the Federal Register notice dated August 23, 2011 regarding proposed NSPS Subpart OOOO regulation, EPA considered the cost-effectiveness of replacing rod packing replacement costs for reciprocating compressors at wellheads at Page 53762: "Reciprocating compressors at wellheads are small and operate at lower pressures, which limit VOC emissions from these sources. Due to the low VOC emissions from these compressors, about 0.044 tpy, combined with an annual cost of approximately $3,700, the cost per ton of VOC reduction is rather high. We estimated that the cost effectiveness of controlling wellhead compressors is over $84,000 per ton of VOC reduced which we believe to be too high, and therefore, not reasonable."		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

	EPA estimated the cost effectiveness of VOC emissions by rod packing replacement would be $870 per ton of VOC at gathering and boosting stations. The cost effectiveness numbers would have to be evaluated for the new well site compressors which may be larger. However, for many of the older, existing well site compressors these numbers may still be valid.				
4.5	Reciprocating Compressors: Annual volumetric measurement of rod-packing venting; repair compressor when emissions exceed threshold level.	See California & Canadian rule material. California rules distinguish between compressors at production facilities and other facilities (including gathering and boosting, transmission etc.). At production facilities, the rules require leak detection measurement. Volumetric measurement is required at facilities other than production.	1 2 3 4 5		San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

DRAFT

SECTION 5, INFRASTRUCTURE PLANNING

Discussion for MAP members on October 10, 2019

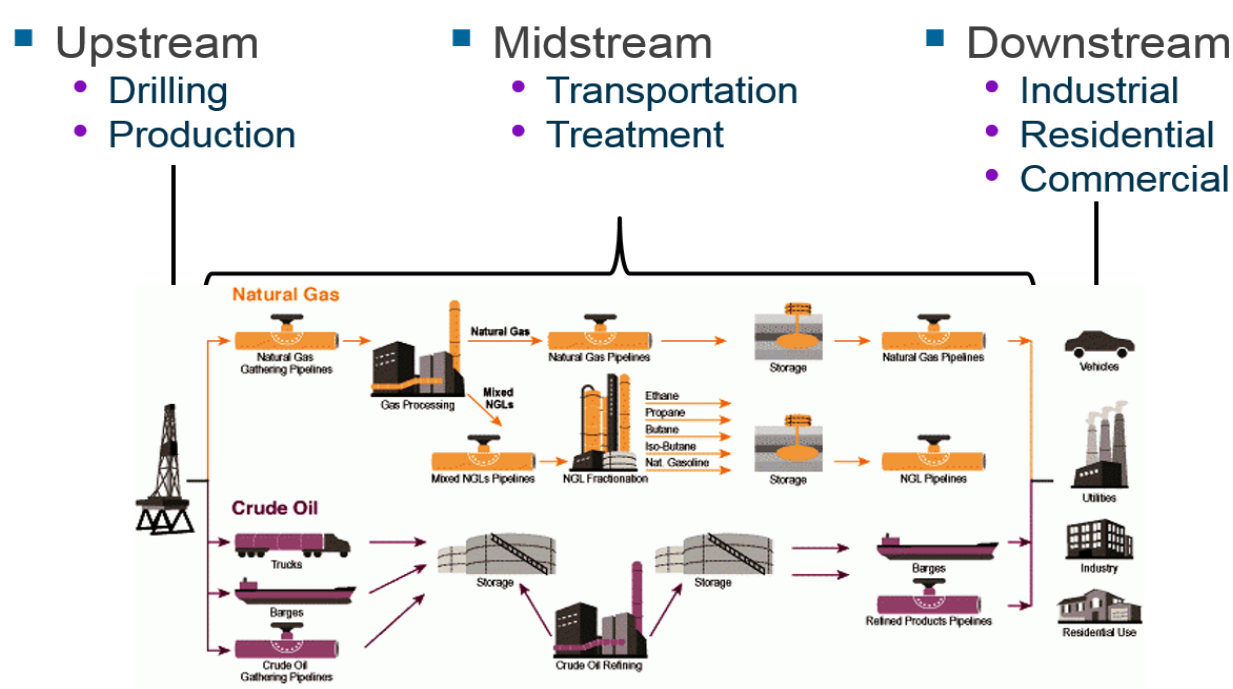
NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

Infrastructure is a broad topic within the oil and gas space. This paper will mainly focus on pipelines and associated facilities, as well as the planning process for well development and gathering facility infrastructure. As a general matter, however, oil and gas infrastructure can include pipelines, gas compression, gas processing, NGL fractionation, gas storage, oil terminals, oil refining, trucks, barges and downstream operations such as residential, commercial, and industrial. Here is a graphic to demonstrate such infrastructure:



1. The Growth Project Planning Process (Business Development)
   a. Buildout of midstream (gathering and processing, intrastate pipelines) and downstream (interstate pipelines, storage, fractionation and refining) facilities is a complex commercial process that requires collaboration between operators in each industry segment. New capacity won't be constructed without some degree of certainty around future drilling activity and production, which are ultimately driven by market demand, pricing, producer financing/growth strategy, regulatory climate, etc.
      i. Midstream gas gathering and processing facilities. Natural gas may be produced from gas wells, which are drilled primarily to produce natural gas (together with some component of natural gas liquids (NGLs) and/or condensate), or as associated gas that is produced essentially as a byproduct of wells that are drilled primarily to produce crude oil. In either case, in order to facilitate and provide a market for growing natural gas production, midstream companies must make long-term capital investment decisions in advance to construct the infrastructure necessary to gather and process producers' gas volumes.

         Those midstream facilities are generally comprised of gathering pipeline systems that connect to individual wells, field compression or "booster" facilities, and natural gas processing plants (collectively, gathering and processing or "G&P" facilities). These G&P facilities are designed to operate over a long useful life (30+ years) in order to service production in a particular geographic area; they are permanently located facilities that require ongoing maintenance capital and have a much lengthier capital recovery horizon when contrasted to an upstream producer's investment in an individual well. While upstream producers can elect how and where to drill their acreage, reallocating their capital budgets from basin to basin, G&P assets remain in place once built.

         As a result, in order to construct new G&P capacity, midstream companies seek to secure substantial acreage commitments or minimum volume dedications from producers in advance of a final investment decision. Producers benefit from these arrangements by having a market for their production, often at preferable terms offered by the midstream operator in order to secure their advance commitment. Absent these types of commitments, a midstream company faces the risk that competitors might

undercut their growth strategy by obtaining similar dedications, or that drilling activity might shift to another basin or geographic region, leaving their own newly constructed G&P facilities behind as stranded investments.

ii. Downstream long-haul takeaway pipelines. Before pipeline developers break ground on the construction of a new pipeline, which can cost billions of dollars, the developers seek long-term commitments to ship oil, gas, or NGLs through the pipeline. Shippers may elect to sign long-term contracts during a period called an "open season." During the open season, a shipper can sign a Transportation Services Agreement, or TSA, agreeing to ship a certain quantity at a certain rate for a certain term if the pipeline is built, thereby securing "firm" or guaranteed pipeline access for the volume committed.

Before a pipeline company commits to building a pipeline, the company tries to obtain a minimum level of shipping commitments through TSAs. Shippers typically benefit from committing during the open season because the rates offered during an open season to shippers willing to make a long-term shipping commitment are usually lower than the rates charged to other shippers who do not commit yet seek access after the pipeline is constructed.

b. Over time, the necessary midstream and downstream infrastructure will ultimately be developed to accommodate long term production trends, but not without encountering periods marked either by bottlenecks or by excess capacity. Bottlenecks or capacity constraints are particularly relevant to and may result in periodic increases in flaring.

c. Notably, additional constraints may and in recent years have developed further downstream, in the form of limited NGL fractionation capacity. Long-haul NGL pipelines typically ship "Y-grade" NGL product, which is a blend of NGLs (ethane, propane, butane, isobutene, etc.) in their mixed, unfractionated form. Once the Y-grade product reaches downstream markets – which for Permian Basin production is generally centered on the Texas gulf coast in and around Mont Belvieu, Texas – downstream purchasers fractionate or separate the Y-grade into constituent purity products for further marketing and use.

d. As drilling activity fluctuates over time and initial production levels from new wells tapers off, G&P systems typically have capacity available to connect new wells from existing and/or new producer customers, whether from dedicated acreage or not.

2. Connecting Wells to Midstream Gathering Pipelines: Right-of-Way Acquisition

a. The process of connecting wells to gas gathering systems begins with right-of-way (ROW) acquisition. Once commercial negotiations are complete and an agreement is in place between the upstream producer and the midstream operator, midstream ROW professionals receive authorization to initiate the process beginning with a survey that is used to determine the planned route of the gathering pipeline and any associated compression facilities or other appurtenances. Depending upon land ownership patterns along the selected route, the process and permitting requirements vary as outlined below.

i. Federal Lands (primarily BLM, but also Tribal, USFS, BOR, etc.). The same general process and requirements apply to securing ROW for gathering pipelines, compressor stations, or gas processing plants. The midstream operator as applicant submits to the agency a route or location survey together with an environmental assessment, archaeological study, geologic survey (karsts) and all other materials required to be submitted with the ROW application in conformance with all applicable federal laws (separate authorization is required for the U.S. Army Corps of Engineers for regulated crossings of navigable waters). The application goes through multiple levels of review by Natural Resource Specialists, each of whom has a specific area of expertise in determining the completeness and adequacy of the application and considering any potential conditions to be placed on the ROW grant. The standard term for a BLM ROW grant is 30 years.

Each year BLM offices in New Mexico ask operators for any available planning information or forecast of anticipated ROW activity for the upcoming year, in an effort to budget their own offices and activities. While these can be difficult for midstream operators to forecast with accuracy, efforts are made in an effort to ensure adequate agency staffing levels, which is a persistent and historical source of project delay.

ii. State Lands. The New Mexico State Land Office (SLO) has jurisdiction over a vast amount of state trust lands located in the heart of the oil and gas producing areas of the state. While the process for obtaining ROW grant on state lands is very similar to that for federal lands, there are some differences. Gathering pipelines are laid under a ROW agreement, which is initiated by filing a completed application that includes a survey (conducted under the prior approval of the SLO) . The ROW application is reviewed by the appropriate SLO District Resource Manager, which can be a source of delay based solely on personnel limitations and workloads: currently, the SLO needs to staff more appropriately. After staff review, a grant agreement is sent back to the applicant for review and signature, after which it is submitted for final approval by the Land Commissioner and execution of the ROW grant agreement. The standard term for an SLO ROW grant is 35 years.

Natural gas compressor stations and processing plants can be located on state lands pursuant to a business lease, rather than a ROW grant. Application requirements are similar to those required for ROW, but at times delays are incurred if the surface area is already subject to a grazing lease. In these instances, the SLO leaves it to the midstream operator to obtain from the grazing lessee either (a) a relinquishment of acreage from the grazing lease, or (b) a right to lease leased lands, an arrangement that must thereafter be renewed every 5 years.

iii. Private Lands. ROW acquisition on private lands is a private negotiation and transaction between the midstream operator and the landowner. The midstream company determines the intended pipeline route and initiates contact with the affected landowner(s) that are identified. ROW agents typically obtain permission to conduct survey while negotiations are taking place, and once the parties reach agreement the ROW easement is conveyed and the landowner is compensated with the amount agreed to. If a landowner wishes not to engage in negotiations and grant an easement, the company seeks alternate routes and/or works with the upstream producer to potentially lay gathering lines pursuant to their rights of access under the oil and gas lease or landowner surface agreement.

iv. Tribal Nations
    1. Navajo Nation
    2. Jicarilla Apache Nation
    3. Pueblo
    4. Ute
    5. Indian Allottee

3. Permitting Requirements for Midstream Facilities (non-ROW)
    a. Upstream, midstream, and downstream operators each face their own unique suite of regulatory schemes that entail numerous but often varying federal and state permitting agencies, which operate pursuant to different organic statutes. Ultimately, project timing and execution can be impacted by agency funding and/or staffing issues, changes in laws, regulation, or political leadership, opposition by landowners, NGOs, and others, etc. For projects located in New Mexico, the relevant agencies and processes are summarized below.
        i. U.S. Federal Energy Regulatory Commission (FERC)
            1. Certificate of Public Convenience and Necessity (interstate pipelines)

2. Regulation of rates, terms and conditions of service (interstate pipelines)

ii. U.S. Environmental Protection Agency (EPA)
   1. NPDES discharge permits
   2. Spill Prevention, Control, and Countermeasure (SPCC) permits

iii. U.S. Army Corps of Engineers
   1. Nationwide permits (navigable water crossings)

iv. New Mexico Environment Department
   1. Air construction/operation permits (state and federal EPA requirements)
   2. Hazardous waste generation/transport/storage
   3. Underground storage tanks
   4. Drinking water systems

v. New Mexico EMNRD, Oil Conservation Division
   1. Pipeline hydrostatic test water discharge (pipeline construction)
   2. WQCC/discharge permits
   3. Below-grade tanks/pit permits
   4. AGI/disposal wells

4. Planned Maintenance Activities
   a. As with our own personal vehicles, in order to responsibly maintain the reliable and safe operation of midstream G&P systems, these assets are subject to regular and routine maintenance activities. Depending on production volumes flowing from upstream wells and space available on downstream takeaway pipelines, these planned activities can either be performed with little or no interruption in production flow or may result in upstream curtailment, which may at times lead to flaring.

      Gas processors make volume commitments or "nominations" for residue gas sales into downstream interstate pipelines one to two days ahead of actual delivery. If, on a Monday, a processor is making nominations for Wednesday deliveries and knows that planned maintenance activities are scheduled at either a compressions station or a processing plant on that date, the processor will lower the volume of gas nominated accordingly. In some circumstances, the processor will be able to reroute volumes upstream of the compressor or plant to another facility with available capacity, increasing nominations on an alternate pipeline and proceeding with little or no upstream disruption. If gas cannot be rerouted, the planned maintenance may require upstream production volumes to be shut in at the wellhead. G&P field personnel will inform producer customers usually a full day in advance, communicating the nature and expected duration of the maintenance activity.

      For extended maintenance activities that will keep G&P operations offline for an extended period of time, midstream companies will typically send written notice of curtailment or volume allocation to their customers. Different equipment and components have different maintenance schedules, with defined maintenance due at 30/60/90,000 operating hour intervals, or annual vs. 5-year shutdowns and repair. A "turnaround" is a scheduled maintenance activity that may keep a facility down for 5-10 days for engine overhauls, vessel inspection and repair, fixing of leaks identified by LDAR inspection, etc.

5. Infrastructure Challenges
   a. Not all assets are created equally. Gas processing facilities, for example, can vary greatly in how they are designed and operated, based in part on whether they are paired with a certain level of field treatment, and variables such as the quality characteristics of the raw product at the inlet (e.g., wet vs. dry gas, SO2 content, contaminants, etc.). Age of the system, variations in field pressures, and third-party incidents can also cause system-wide disruptions irrespective of any regulatory scheme that might be imposed. Often overlooked,

human resources can often be an overriding and sometimes persistent factor in achieving optimal operation of various assets, implicating regulatory compliance and emissions performance.

The age or "vintage" of a G&P system often dictates how new production is connected. Much of the recent production growth in SENM is being serviced by newly constructed facilities in which gathering systems, compression and processing are all designed to accommodate the high volumes and pressures associated with horizontal drilling. In many instances, older existing systems may have been designed for lower-pressure vertical (legacy) production and were not constructed to standards that allow for the safe gathering of gas at the volumes and pressures associated with most modern horizontal shale wells.

Fluctuations in any one or more of these variables may result in operational upsets of midstream facilities that lead to unplanned maintenance and repair events, whether that be in response to an issue or event or something else, such as the installation of system upgrades.

b. Availability of electrical infrastructure can create operational issues. The need for available and reliable power can create operational challenges for infrastructure. Onsite power generation may be needed to control or power a process. The ability, or the lack thereof, to have power can slow or impede infrastructure development.

Electricity reliability and voltage requirements-Oilfield equipment power requirements are quite varied ranging from instrumentation at a single well pad needing approximately 35W to operate up to approximately 2,000 kW (note unit change) to operate a single frac/stimulation pump. The power demand required to operate equipment determines if single phase power (household) is adequate or if three phase power (industrial) is necessary.

In the overall electrical grid, distribution substations connect to the transmission system and lower the transmission voltage to medium voltage (2kV and 35kV) using transformers. Primary distribution lines carry this medium voltage power to distribution transformers located closer to end users. Most customers are connected to the secondary distribution system through service drops. Customers demanding much larger amounts of power may be connected directly to the primary distribution level or the subtransmission level.

Much of the commonly seen distribution lines are secondary distribution systems for domestic and commercial needs that do not require high voltage transmission. The proximity of primary distribution level or subtransmission level to the required location is critical in determining 1) the economic feasibility of utilizing high voltage (3 phase) grid power to operate upstream and midstream higher HP equipment and 2) the timing around getting the local utility to run the necessary lines to the site. In many cases, higher HP equipment will need to be operated on generators due to both proximity of adequate transmission lines, lead times for connecting lines, and potential issues with grid instability resulting from high demand users on a system not originally designed for industry load.

In general, most of the compressors, engines and motors utilized in the oilfield require 3 phase power. This equipment is utilized for artificial lift, dehydration, gas compression, etc. Equipment that has the potential to operate on potentially more readily available single phase power, such as instrumentation and controllers, are critical to safe operation of the facilities. Due to the critical nature of this equipment, an unreliable or unstable grid, will result in unnecessary facility shutdowns when power is insufficient. The system upsets caused by potential outages from an unstable grid can result in equipment damage, well damage, and flaring. In addition, even secondary transmission lines may not be available in very rural areas. It can sometimes take

months of working with the local utilities to get even secondary transmission lines run to the facility, which is only adequate to operate a small amount of onsite equipment.

Due to the challenges around the development of adequate power supply to remote locations, many sites are supplied by onsite generation.

Infrastructure planning for oil and natural gas is the process by which producers, midstream operators, state and federal regulators, and state and federal land managers collectively, but not necessarily in coordination, determine the timing, extent, and location of new or re-fractured oil and gas wells, natural gas gathering and boosting systems (i.e., pipelines and compressors) and processing plants, as well as oil transport modes and facilities which are not addressed here.

Currently, infrastructure planning occurs primarily within individual segments of the oil and gas value chain or within individual firms, and it takes the form of multiple individual decisions by those entities, with some, but limited, information exchange and coordination. Producers make decisions to acquire new leases, drill new wells, re-complete existing wells, operate and maintain existing wells, and sometimes invest in flow lines and compressors. Midstream companies build or expand gathering, boosting, and processing infrastructure. Planning for a particular segment, for example production, may take place amongst several companies whose leaseholds are unitized.

As noted above, federal, tribal, state, and local agencies oversee and approve different aspects of such activities, including by determining, for federal public lands and state trust lands, where lands should be leased for development or where rights-of-way for infrastructure, such as pipelines, are appropriate. This oversight is also often fragmented, a function of "checkerboarded" land ownership prevalent in New Mexico and distinct, if sometimes overlapping, legal and regulatory authorities.

A critical outcome of infrastructure planning, or the lack thereof, is the alignment, or misalignment, between the volumes and locations of gas produced, particularly with respect to the associated natural gas produced at oil wells, and the capacity of natural gas gathering and processing systems to bring that gas to market.[59] Where there is insufficient available gathering, compression, and processing capacity for the amount of gas produced, operators must handle the gas through other means. Gas that is produced but not beneficially used by the producer at the well or fed into the gathering system is typically vented or flared. Both venting and flaring release pollution and constitute waste—the loss of the natural gas resource that could otherwise be sold into the market.

A substantial volume of gas is vented or flared in New Mexico, and the volume has been rising with the recent production boom, as discussed below in Section 2. However, there is tremendous variation among producers in the share of production that is reported as vented or flared, ranging from zero methane waste to 100% waste, with rates from 10% to almost 70% seen among major producers. Producers with associated gas and relatively little reported venting and flaring presumably have coordinated their planning with midstream companies to optimize the location and timing of anticipated production for takeaway. Associated gas producers with high reported rates of venting and flaring presumably have insufficient access to gathering and processing system infrastructure, which can indicate insufficient development planning and coordination with midstream companies.

[59] Associated gas is defined as natural gas that is produced from oil wells during unconventional oil production (also referred to as shale oil or tight oil). "Improving utilization of associated gas in U.S. tight oil fields", Carbon Limits, April 2015. https://www.catf.us/wp-content/uploads/2015/04/CATF_Pub_PuttingOuttheFire.pdf

While inadequate infrastructure planning is one explanation for infrastructure misalignment and waste, there are other plausible explanations as well. These include violation of the state's ban on venting from gas wells (NMAC 19.15.19.10 http://164.64.110.134/parts/title19/19.015.0019.pdf), violations of the state's time limit for venting and flaring from oil wells (NMAC 19.15.18.12 http://164.64.110.134/parts/title19/19.015.0018.html), and abuse of the No-Flare Rule Exception process; i.e., long-term flaring via serial approvals (Form C-129 Application for Exception to No-Flare Rule http://www.emnrd.state.nm.us/OCD/documents/C-12920110801.pdf). It is also possible that of the venting and flaring reported to OCD on the C-115s, venting is from oil wells only and venting and flaring is within the 60-day limit after completions or authorized through C-129 exceptions. In any case, industry, states, and the Federal government have recognized the strong connection between methane emissions and waste, and infrastructure planning, as discussed below in Section 2.

Provide the segment(s) of the industry that conduct infrastructure planning ~~the equipment or process is found~~:

Infrastructure can be found in upstream, midstream, and downstream business segments.

Upstream and midstream. As noted, the U.S. Bureau of Land Management (BLM) and State Land Office also influence infrastructure planning activity through the leasing of, respectively, federal public or state trust lands for oil and gas development and issuance of rights-of-way. To illustrate how this plays out for federal public lands, BLM manages oil and gas development through a three-stage process. First, BLM prepares "Resource Management Plans" that govern what lands are open to leasing and under what conditions. Second, BLM sells leases, which are specifically conditioned via the use of lease stipulations. Third, the BLM approves specific Applications for Permit to Drill or rights-of-way. In this third and site-specific stage, BLM may impose Conditions of Approval consistent with law and lease rights. BLM also plays a role in the unitization and communitization of leases with the goal of facilitating orderly and efficient development of federal leases.

Describe how the equipment or process is used:

Oil and gas infrastructure in New Mexico includes pipelines, natural gas compression facilities, natural gas processing, oil terminals, and oil refinery/fractionation.

Infrastructure planning by upstream producers can generate information for midstream companies about the timing and location of well development and projected production volumes with sufficient advance notice to enable midstream companies to respond with adequate gathering and processing capacity. While midstream companies may view the current process and level of information exchange as generally adequate for their own business purposes, the large volumes of venting and flaring indicate that additional large volumes of gas could be marketed if gathering capacity were sufficiently available where and when operators develop oil wells with associated gas. Midstream entities evaluate expected regional volumes for assessment in their hydraulic analyses and improved gas capture planning with better information about expected gas takeaway strategy and capacity at the future date of completion could improve the ability of midstream entities to conduct these analyses and support investment planning. Conversely, midstream companies could share existing and planned future capacity information with E&P operators during the commercial and business development process to better align E&P operators' drilling schedules and other investments.

Conversely, planning by midstream companies can inform producers of existing capacity, projected capacity additions, and capacity constraints, allowing producers to respond proactively, such as by locating and timing development to coincide with projected available gathering capacity, or by pausing or slowing production. For example, "Some companies have recently opted to scale back production in the gassier portions of the Permian. In April, Houston's

Apache Corp. said it dramatically cut back natural gas production in its Alpine High development in the Permian because of steep pricing discounts caused by pipeline shortages."
"Permian gas flaring hits new record highs for 'widespread waste,' pollution." The Houston Chronicle, June 4, 2019
https://www.houstonchronicle.com/business/energy/article/Permian-methane-emissions-back-on-the-rise-after-14412700.php
Also, midstream companies can inform producers of short-term capacity constraints from, e.g., planned maintenance activities, to allow producers to prepare to use other means to capture gas or temporarily pause production during such activities.

Provide the common process configurations that use this equipment or process:

n/a

What is the distribution of the equipment or process across business segments?

The process to build infrastructure is application, geographic, weather, and terrain specific.

How has this equipment or process evolved over time?

n/a

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

Possible sources of methane can come from Natural Gas and Oil infrastructure.

The main source of methane emissions and waste linked to poor infrastructure planning is the venting and flaring of associated gas. According to production statistics reported by Operators to the OCD, Operators vented 3.1 MMcf or 0.2% of total production in 2018 and 1.4 MMcf or 0.2% of production in the first half of 2019. Operators flared 33.4 MMcf or 2.2% of total production in 2018 and 16.8 MMcf or 2% of total production for the first half of 2019. As discussed below, venting and flaring rates are considerably higher when only oil wells are considered.

Venting emits methane directly, as methane is the largest constituent of natural gas. Flaring also emits some methane due to incomplete combustion, and the amount of methane will be large if the flare is malfunctioning or unlit. Where air permits are required, compliant flares should achieve methane destruction rates of between 95-98%, with 2-5% of the gas emitted uncombusted.

https://www.env.nm.gov/wp-content/uploads/2018/04/GCP-Oil__Gas.pdf

It is important to note that while substituting flaring substantially reduces the climate impacts of venting methane, flaring still directly releases CO2 and smaller quantities of methane, as well as wasting the resource. At large volumes of flaring, the combined CO2 and methane emissions from flares can have climate impacts comparable to those of other large sources. For example, if venting and flaring from oil and gas production in NM continue at the current pace for the remainder of 2019, the resulting volume of GHG emissions will be equivalent to the GHG emissions from two units of the coal-fired San Juan Generating Station over the same period (see Exhibit 1 for calculations).

New Wells:

See venting and flaring topic paper.

Venting and flaring will occur at new wells if take-away capacity or field use does not accommodate all of the gas that is produced. New wells, by virtue of high initial production pressures, may also "bump off" older, lower-pressure wells from natural gas gathering systems, leading to operators deciding to vent or flare natural gas at those older sites.

Existing Wells:

See venting and flaring, pneumatics, compression topic papers.

Venting and flaring will occur at existing wells if take-away capacity or field use does not accommodate all of the gas that is produced. Again, existing wells may also get "bumped off" of gathering systems if they lack needed compression when new, higher-pressure wells come on-line, resulting in venting or flaring of natural gas that, before the new well came on-line, was able to flow through the natural gas gathering system.

How are the emissions calculated for this equipment or process?

NMED currently regulates midstream facilities, such as natural gas compression and oil terminals.

Vented and flared volumes are reported to OCD by operators on Form C-115 Operator's Monthly Report, which records the volumes of oil and gas production and disposition by well. For a description see http://www.emnrd.state.nm.us/OCD/documents/C115_Instructions2019.pdf

Any Vented/blowdown volumes greater than 50 MCF released from a pipeline are required to be reported to NMOCD via the C-141 report. NMAC 19.15.29.7

http://164.64.110.134/parts/title19/19.015.0029.html

What data is available to quantify emissions/waste for this equipment or process?

Depending on size, midstream facilities (e.g. most compressor stations, gas plants, or oil terminals) require NMED air permits and any excess emission during a routine or predictable startup, shutdown, or scheduled maintenance event (20.2.7.7 D. & 20.2.7.110 NMAC). The Air Quality Bureau has recently announced a new initiative to post excess emissions online on a monthly basis. See https://content.govdelivery.com/accounts/NMED/bulletins/2664784

"Excess emission" means the emission of an air contaminant, including a fugitive emission, in excess of the quantity, rate, opacity or concentration specified by an air quality regulation or permit condition.

http://164.64.110.134/parts/title20/20.002.0007.html

EPA Greenhouse Gas Reporting Rule also include pipelines and gathering systems under the gathering and boosting.

Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production wells and to compress and transport gas to a natural gas processing facility, transmission pipeline, or a distribution pipeline.

https://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl
https://www.epa.gov/ghgreporting/ghgrp-and-oil-and-gas-industry

As shown in Table 1 below, overall reported venting and flaring from all oil and gas operations in New Mexico increased by 115% in 2018 and by 21% for the first half of 2019, far outpacing increased gas production in 2018 and keeping pace with the gas production increase thus far for this year, which is also up by 21%. Reported flaring increased by 125% in 2018 and by 28% in the first half of 2019. Reported venting increased by 47% in 2018 and, due to a dramatic decrease by one major operator, fell by 23% in the first half of 2019. Statewide, 2.1% of gas production was reported vented and flared in both 2018 and the first half of 2019. See also Venting/Flaring Report Tables 1 and 2 for additional information and analysis regarding total associated gas venting and flaring.

Recent reporting by the Houston Chronicle highlights these trends:

> Methane emissions and pollution in the booming Permian Basin likely hit a new record high in the second quarter after taking a small, but surprising, dip early this year, according to a new study. [This] is more than triple the amount of pollution and waste from just two years ago, according to the Norwegian research firm Rystad Energy. . . . The report estimates that the volumes of methane from natural gas burned off or vented into the atmosphere averaged of 663 million cubic feet per day in the second quarter ... For context, flaring in the Permian was less than 200 million cubic feet a day in mid-2017 and was less than 20 million cubic feet daily at the beginning of 2011 before the recent Permian boom took off.

"Permian gas flaring hits new record highs for 'widespread waste,' pollution." The Houston Chronicle, June 4, 2019
https://www.houstonchronicle.com/business/energy/article/Permian-methane-emissions-back-on-the-rise-after-14412700.php

Table 1: Total Reported Venting and Flaring: Change 2017-2019 (mcf) (Source: OCD C-155 data see http://www.emnrd.state.nm.us/OCD/statistics.html)

January – June (mcf)	**2017**	**2018**	**2019**	**17-18 % change**	**18-19 % change**
Flared	6,777,979	13,146,398	16,791,319	94%	28%
Vented	1,092,445	1,864,133	1,436,580	71%	-23%
Vented+Flared	7,870,424	15,010,531	18,227,899	91%	21%
Gas Production	630,088,033	705,510,340	855,313,871	12%	21%
% of gas production	1.2%	2.1%	2.1%		
Full Year (mcf)	2017	2018	17-18 % change		

Flared	14,886,176	33,421,502	125%
Vented	2,123,438	3,115,734	47%
Vented+Flared	17,009,614	36,537,236	115%
Gas Production	1,296,993,949	1,503,246,867	
% of gas production	1.3%	2.4%	

Table 2 shows that reported venting and flaring rates are consistently higher in the NM Permian than they are in the San Juan Basin. This is not surprising since the San Juan Basin has a far greater proportion of natural gas wells, and, presumably, Operators conduct extensive infrastructure planning to ensure that wells are connected to gathering systems and have adequate processing capacity to move produced gas to market. It is important to note that the C-115 data may not include venting and flaring during completion and production testing, possibly undercounting the amount of venting and flaring actually occurring in the San Juan Basin.

(See Exhibit 1 at the end of this paper for conversion into metric tons.)

Table 2: Reported venting and flaring as a percent of total gas production by basin: 2017-2019 (mcf) (Source: OCD C-155 data see http://www.emnrd.state.nm.us/OCD/statistics.html)

2019 January-June							
Basin	**Gas Production**	**Flared**	**% Flared**	**Vented**	**% Vented**	**Flared + Vented**	**% V/F**
Permian	564,945,638	16,746,992	3.0%	1,413,178	0.3%	18,160,170	3.2%
San Juan	283,270,130	44,327	0.0%	23,402	0.0%	67,729	0.0%
Other	7,094,031	-		-		-	
Grand Total	855,309,799	16,791,319	2.0%	1,436,580	0.2%	18,227,899	2.1%

2018 January-June							
Basin	**Gas Production**	**Flared**	**% Flared**	**Vented**	**% Vented**	**Flared + Vented**	**% V/F**
Permian	404,123,297	12,949,526	3.2%	1,816,922	0.4%	14,766,448	3.7%
San Juan	292,276,293	196,872	0.1%	47,211	0.0%	244,083	0.1%
Other	9,110,750	-		-		-	
Grand Total	**705,510,340**	**13,146,398**	**1.9%**	**1,864,133**	**0.3%**	**15,010,531**	**2.1%**

2017 January-June							
Basin	**Gas Production**	**Flared**	**% Flared**	**Vented**	**% Vented**	**Flared + Vented**	**% V/F**
Permian	324,512,815	6,506,095	2.0%	662,985	0.5%	7,169,080	2.2%
San Juan	295,739,969	271,884	0.1%	429,460	0.1%	701,344	0.2%
Other	9,835,249						
Grand Total	**630,088,033**	**6,777,979**	**1.1%**	**1,092,445**	**0.2%**	**7,870,424**	**1.2%**

2018 Full year							
Basin	**Gas Production**	**Flared**	**% Flared**	**Vented**	**% Vented**	**Flared + Vented**	**% V/F**
Permian	889,318,021	32,684,460	3.7%	3,047,930	0.3%	35,732,390	4.0%

San Juan	595,686,659	737,042	0.1%	67,804	0.0%	804,846	0.1%
Other	18,097,587	-		-		-	
Grand Total	**1,503,102,267**	**33,421,502**	**2.2%**	**3,115,734**	**0.2%**	**36,537,236**	**2.4%**
2017 Full year							
Basin	**Gas Production**	**Flared**	**% Flared**	**Vented**	**% Vented**	**Flared + Vented**	**% V/F**
Permian	679,745,262	14,280,729	2.1%	1,583,845	0.2%	15,864,574	2.3%
San Juan	597,718,136	605,447	0.1%	539,593	0.1%	1,145,040	0.2%
Other	19,530,551					-	
Grand Total	**1,296,993,949**	**14,886,176**	**1.1%**	**2,123,438**	**0.2%**	**17,0 09,614**	**1.3%**

Operators vary widely in the amount of production they report vented and flared, as shown in Table 3, with some reporting 100% methane waste and others reporting zero waste. Among major producers, many report high rates of venting and flaring, ranging from 10% to 70%. Some of these differences, particularly reports of zero volumes of venting or flaring, may be due to reporting discrepancies rather than real differences between operators. Even so, there is clearly substantial variation in venting and flaring rates across operators. While location and well production are factors, it also appears likely that some operators are more successfully capturing more of their produced gas, and infrastructure planning is likely to be playing a role in this. See also Venting/Flaring Report Table 3 for additional information and analysis regarding variation in the amount of production operators report as vented or flared.

Table 3: 2019 reported V/F data by company ranked by percent V+F in descending order (mcf) Companies numbered in descending order of gas production (Source: OCD C-155 data see http://www.emnrd.state.nm.us/OCD/statistics.html)

Company	Flared	% Flared	Vented	% Vented	Vented + Flared	% V+F	Gas Production
22	41,611	100%			41,611	100%	41,611
34	6,177	100%			6,177	100%	6,177
36	2,747	100%			2,747	100%	2,747
40		0%	151	100%	151	100%	151
41		0%	150	100%	150	100%	150
61	13	100%			13	100%	13
62	9	100%			9	100%	9
50		0%	9,683	94%	9,683	94%	10,297
57		0%	557	87%	557	87%	643
51		0%	3,118	79%	3,118	79%	3,959
7	1,064,029	67%			1,064,029	67%	1,594,741
17	107,650	43%			107,650	43%	252,803
27	27,929	38%			27,929	38%	74,156
35	5,608	28%			5,608	28%	20,307
49		0%	18,794	27%	18,794	27%	69,128
11	785,810	27%			785,810	27%	2,950,123
46		0%	132,888	26%	132,888	26%	507,060
65		0%	31	24%	31	24%	127

24	35,117	20%			35,117	20%	175,531
13	551,886	20%			551,886	20%	2,765,155
4	1,418,580	17%	121,443	1%	1,540,023	18%	8,397,349
26	28,974	13%	421	0%	29,395	14%	217,678
19	61,788	12%			61,788	12%	511,951
15	231,469	12%			231,469	12%	1,959,823
10	912,654	10%	166,101	2%	1,078,755	12%	9,198,417
2	1,541,514	10%	109,856	1%	1,651,370	11%	15,266,940
3	1,470,907	10%	21,855	0%	1,492,762	10%	14,387,730
21	50,568	9%			50,568	9%	567,256
53		0%	1,856	7%	1,856	7%	25,989
18	90,515	4%	73,000	3%	163,515	7%	2,423,931
20	51,999	6%			51,999	6%	909,746
1	2,250,606	4%			2,250,606	4%	55,888,477
5	1,401,131	4%			1,401,131	4%	39,379,314
12	594,823	3%			594,823	3%	17,259,354
14	366,909	3%			366,909	3%	11,726,775
29	19,529	3%			19,529	3%	636,929
60		0%	169	3%	169	3%	6,407
42		0%	621,981	3%	621,981	3%	24,305,442
16	199,494	2%	1,429	0%	200,923	3%	7,984,513
33	8,825	2%			8,825	2%	364,740
47		0%	110,758	2%	110,758	2%	4,765,409
32	11,411	2%			11,411	2%	576,454
23	36,268	2%			36,268	2%	2,147,384
30	14,611	2%			14,611	2%	911,201
9	999,721	1%			999,721	1%	72,319,073
8	1,042,110	1%			1,042,110	1%	81,135,258
6	1,289,238	1%			1,289,238	1%	114,654,079
54		0%	1,529	1%	1,529	1%	143,801
48		0%	21,788	1%	21,788	1%	3,319,713
38	2,073	1%			2,073	1%	353,476
66		0%	14	0%	14	0%	3,684
25	31,914	0%			31,914	0%	14,574,999
39	45	0%			45	0%	23,362
37	2,094	0%			2,094	0%	1,370,442
31	12,413	0%	6,304	0%	18,717	0%	16,696,358
28	20,550	0%	7,365	0%	27,915	0%	37,802,026
63		0%	63	0%	63	0%	87,969
58		0%	449	0%	449	0%	687,356

59		0%	379	0%	379	0%	2,052,483
56		0%	696	0%	696	0%	3,977,391
64		0%	63	0%	63	0%	676,334
55		0%	1,281	0%	1,281	0%	42,120,791
52		0%	2,408	0%	2,408	0%	166,477,967

In addition, the rates vary over time, with several major producers doubling or tripling the amount of gas flared so far in 2019.

Table 4: 2018 and 2019 reported venting and flaring change by operator (Jan-June) (Source: OCD C-155 data see http://www.emnrd.state.nm.us/OCD/statistics.html)

	Flared (January - June)		
Company	**2018**	**2019**	**Percent Change '18-'19**
1	2,207,775	2,250,606	2%
2	494,948	1,541,514	211%
3	1,302,579	1,470,907	13%
4	685,554	1,418,580	107%
5	816,429	1,401,131	72%
6	516,427	1,289,238	150%
7	300,128	1,064,029	255%
8	1,915,770	1,042,110	-46%
9	1,156,207	999,721	-14%
10	297,487	912,654	207%
11	197	785,810	398788%
12	1,161,496	594,823	-49%
13	331,476	551,886	66%
14	461,156	366,909	-20%
15	258,047	231,469	-10%

	Vented (January - June)		
Company	**2018**	**2019**	**Percent Change '18-'19**
42	806,124	621,981	-23%
10	791,003	166,101	-79%
46	26,367	132,888	404%
4	6,191	121,443	1862%
47		110,758	X
2	135,473	109,856	-19%
18		73,000	X
3	1,353	21,855	1515%

48	31,317	21,788	-30%
49		18,794	X
50	9,835	9,683	-2%
28	10,605	7,365	-31%
31	17,231	6,304	-63%
51	2,357	3,118	32%
52		2,408	X

The data above represent the percentage of venting and flaring based on total gas production, including production from gas wells, which generally have little to no flaring. With respect to venting and flaring that might be avoided through improved infrastructure planning, it is more relevant to look at venting and flaring of associated gas from oil wells, which occur at significantly higher rates. As shown in Table 5, in the Permian, a reported 5.2% of associated gas was vented and flared in 2018, while 4.2% was vented and flared in the first half of 2019.

Table 5: Reported venting and flaring % of production, oil wells only (mcf) (Source: OCD C-155 data see http://www.emnrd.state.nm.us/OCD/statistics.html)

	total gas production	oil well gas production	total gas production	oil well gas production	total gas production	oil well gas production
	Permian		San Juan		State Wide	
	Jan-June					
2019	3.2%	4.3%	0.0%	0.4%	2.1%	4.2%
2018	3.7%	4.8%	0.1%	1.3%	2.1%	4.6%
2017	2.2%	2.9%	0.2%	4.2%	1.2%	3.0%
	Full Year					
2018	4.0%	5.4%	0.1%	2.3%	2.4%	5.2%
2017	2.3%	0.3%	0.2%	3.1%	1.3%	3.1%

What are the data gaps in quantifying emissions/waste for this equipment?

Emissions from smaller operators that emit less than 25,000 metric tons CO2e are not captured under the GHGRP.

There are also significant gaps in the volumes of gas reported as vented and flared through the C-115 forms. In a Notice to Operators in 2017, OCD "determined that not all Operators are following the requirement to report flared and vented volumes. Out of 603 well Operators active in the state, only 51 Operators are reporting volumes using the "V" and "F" code. It is very important that all Operators in New Mexico report flared and vented volumes since part of the evaluation will help determine any policy or requirements setting goals for reduction of flared gas. We urge all companies to work with their operations and production accounting groups to ensure proper production reporting."

Notice to Oil and Gas Operators, Vented & Flared Volumes Reporting Communication, March 8, 2017. Available at http://www.emnrd.state.nm.us/OCD/documents/20173-8NoticetoOperators.pdf

Another significant gap in the data is identification of the amount of flaring that is authorized under NMAC 19.15.18.12 (60 days following completion) or under the Form C-129s Exception to No-Flare Rule. For the latter, information is needed on the extent to which operators have obtained repeated exceptions to continue to flare for long period of time.

There is currently no information publicly available about the role that New Mexico's current gas capture planning requirement has played in facilitating the flow of information between producers and midstream companies and resulting effects on the volumes of vented and flared associated gas.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

n/a

What are the annualized operating costs for the equipment or costs associated with the process?

n/a

If the equipment or process is powered, what are the costs?

n/a

What are the maintenance and repair costs for existing or new equipment?

n/a

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

New Wells:

See state/federal discussion below

Existing Wells:

See state/federal discussion below

How have the emission/waste reductions been measured?

How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

In response to public concern about substantial increases in venting and flaring, i.e., waste, of associated gas accompanying the growth of drilling for oil in shale formations in the period 2014-2016, several states and the federal government adopted requirements for gas capture planning. The requirements were intended to strengthen the infrastructure planning process by ensuring that producers: (1) evaluate and acquire gathering and processing capacity prior to well development; and (2) communicate expected volumes, location and timing of production to midstream companies to facilitate timely investment in expanded capacity. Continued growth of venting and flaring in the New Mexico Permian and other shale-oil producing regions of the country suggest that additional improvements are needed for gas capture planning to reach its full potential.

North Dakota pioneered requirements for producers to prepare gas capture plans and coordinate with midstream companies to reduce wasteful venting and flaring. In 2014, the state adopted a proposal developed by the North Dakota Petroleum Council ("State moves to capture 90% of flared gas by 2020", Energy Wire, July 2, 2014 https://www.eenews.net/energywire/stories/1060002259). The North Dakota rule requires that gas capture plans accompany all Applications for Permit to Drill (Order 24665, available at https://www.dmr.nd.gov/oilgas/or24665.pdf). Detailed instructions for the contents of the plan were issued in a May 8, 2014 Letter to Operators from the North Dakota Oil and Gas Division (Available at https://www.dmr.nd.gov/oilgas/Gas%20Capture%20Plans%20Required%20on%20All%20APD's%20050814.pdf). Gas Capture Plans must include information about well location and anticipated production, the location and capacity of existing pipeline systems, current levels of flaring, and producers and midstream gas gathering companies must meet semi-annually. The North Dakota rule also requires operators to develop Gas Capture Plans for "increased density, temporary spacing, and proper spacing cases." (See Order 24665).

Wyoming adopted a gas capture plan requirement in April, 2016. The WY requirements are significantly less detailed that North Dakota's, requiring only information about gas gatherer(s) available to provide take-away capacity and available processing plant capacity. (Wyoming Administrative Code Chapter 3 Section 39.H https://docs.google.com/a/wyo.gov/viewer?a=v&pid=sites&srcid=d3lvLmdvdnxvaWwtYW5kLWdhc3Rlc3R8Z3g6NzE2ZjM3ODg3NmU5ZWQzYg

New Mexico adopted a requirement for producers to develop gas capture plans for all new drilling permits on April 8, 2016. Notice to Operators, October 19, 2015 (Notice to Operators, April 8, 2016. Available at http://www.emnrd.state.nm.us/OCD/documents/20164-25GasCapturePlan.pdf). The requirements were developed by a New Mexico Gas Capture Plan Committee established in late 2015 to review activities related to venting and flaring of natural gas and consisting of representatives from state and federal agencies and operators including Agave, Concho, Conoco-Phillips, Devon, Mack, Oxy, Synergy, and WPX. The stated goal for gas capture planning was "to reduce natural gas emission[s]." A plan template was adopted requiring Operators to "outline actions to be taken by the Operator to reduce well/production facility flaring/venting for new completion[s] (new drill, recomplete to new zone, re-frac) activity." Information required in a plan includes, for each well covered by the plan, expected production, planned volumes to be vented or flared (in conjunction with the No-Flare exemption), and identification of the Gas Transporter, gathering system to be connected to if one is in place, miles of pipeline required, and the processing plant where the gas will be processed. Operators are required to "provide (periodically) to Gas Transporter a drilling, completion, and estimated first production date for wells that are scheduled to be drilled in the foreseeable future," and "Operator and Gas Transporter [are to] have periodic conference calls to discuss changes to drilling and completion schedules." The plan template also includes the statement, presumably affirmed when submitted, that

"Based on current information, it is Operator's belief the system can take this gas upon completion of the well's." The Notice states that these requirements apply to State, Fee, Federal, & Tribal wells.

Pennsylvania requires the use of a pigging device with 95% control if emissions are 200 tpy of CH_4, or 2.7 TPY of VOC. If emissions are less than these thresholds, operators must use best management practices to minimize liquids and emissions.[1] In Ohio, operators must use an add-on pigging control which includes flare or vapor recovery to limit VOC emissions to 0.27 tpy, on average, over a rolling 12-month period.[2]

[1] Department of Environmental Protection, Air Quality Permit Exemption 38, available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf
[1] Ohio GPs for compressor stations, available at http://epa.ohio.gov/dapc/genpermit/ngcs.aspx

The Bureau of Land Management adopted a waste minimization planning requirement in its 2016 methane waste prevention rule, *Waste Prevention, Production Subject to Royalties, and Resource Conservation; Final Rule*, 81 Fed. Reg. 83,008 (Nov. 18, 2016) (https://www.federalregister.gov/documents/2016/11/18/2016-27637/waste-prevention-production-subject-to-royalties-and-resource-conservation). Waste minimization plans were required to accompany Applications for Permit to Drill for federal oil wells to "explain how the operator plans to capture associated gas upon the start of oil production." Failure to submit a complete and adequate plan was grounds for denying or disapproving the APD. Information required in the plan included expected completion and production dates and production rates, identification of the intended destination gas pipeline or, alternatively, information about pipeline systems in the field where the well would be located, and identification of the intended destination or nearest processing plant. Operators were also required to include information about all venting and flaring in the field where the well would be located. The rule also required "certification that the operator has provided one or more midstream processing companies with information about the operator's production plans." These requirements were subsequently rescinded by BLM in *Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements; Final Rule,* 83 Fed. Reg. 49,184 (Sept. 28, 2018).
https://www.federalregister.gov/documents/2018/09/28/2018-20689/waste-prevention-production-subject-to-royalties-and-resource-conservation-rescission-or-revision-of
BLM's 2018 rescission of the 2016 Methane Waste Rule is the subject of ongoing litigation. Of note, the preamble to the 2016 Methane Waste Rule also, in response to requests for integration of front-end planning requirements into the rule, stated the following:

> The BLM already has land use planning and NEPA tools and processes in place that can be used to help achieve the specific goals of this rulemaking—to reduce the wasteful and environmentally harmful loss of gas through venting, flaring, and leaks. The BLM conducts NEPA analyses for both regional planning decisions and project level decisions. These analyses take a hard look at the direct effects, indirect effects, and cumulative effects of the proposed federal action on various resources during the land use planning or project approval process, such as the effects on wildlife, air quality, or recreation opportunities. The BLM's NEPA analyses also quantify GHG emissions associated with the proposed planning decision alternatives under consideration. In particular, the land use planning and NEPA processes for new RMPs and MLPs provide important opportunities to consider the effects of oil and gas development over a larger area and to optimize planned development to minimize impacts from venting and flaring, among other activities. The planning process gives the BLM the opportunity to consider how a specific land management plan could address the timing and location of development of oil and gas and related infrastructure, such as pipelines, and the projected consequences of such decisions in terms of the quantities of vented and flared gas and the impacts associated with those emissions.

81 Fed. Reg. 83,008, 83040.

Both the North Dakota and 2016 BLM gas capture planning provisions also required information about volumes of venting and flaring from existing wells in the field where the proposed well would be located to provide a more holistic picture of methane waste, flag current capacity constraints, and help identify opportunities to aggregate production volumes to justify new gathering system infrastructure investment. Because midstream pipelines, compression and processing facilities are systems designed to serve many wells, a well-by-well approach to planning and approvals can provide an incomplete view of the costs to minimize waste. Colorado has adopted a rule providing for Comprehensive Drilling Plans wherein operators identify "all foreseeable oil and gas activities in a defined geographic area, facilitate discussions about potential impacts, and identify measures to minimize adverse impacts" including methane emissions. Information to be submitted in these plans include "all proposed oil and gas facilities to be installed within the area covered by the Comprehensive Drilling Plan over the time of the Plan and the anticipated timing of the installation." Colorado Rules and Regulations 216 Comprehensive Drilling Plans. See https://cogcc.state.co.us/documents/reg/Rules/LATEST/200Series.pdf

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

In addition to better gas capture planning, other potential modifications include:

1. Oil and gas lessees and operators, in their proposals for well spacing and density rules, and in applications seeking to intensify well density and spacing, could be required to estimate surface loss of natural gas as complement to estimates regarding underground recovery efficiency and to identify infrastructure investment and other actions they will take across the oil and gas pool to prevent surface waste. This would provide a basis for OCD to consider and impose conditions to minimize surface waste in association with spacing and density decisions.

2. Proposals for unitization or unit agreements, intended to ensure more orderly and efficient development of leases within a given field, could also include plans to better synchronize production from unitized fields with midstream oil and gas operations. Operators could elevate surface waste management and not defer consideration of need/opportunity to prevent waste to the drilling stage, where field-level opportunities to prevent waste may be lost.

3. Operators could package into a single application all planned/foreseeable drilling/infrastructure approval requests anticipated over a 6- to 12-month time period within a given field or unit and based on geographic proximity or potential use of shared infrastructure such as gathering systems, compressor stations, or processing facilities. This would facilitate more holistic decision-making across an entire field/unit (or, at least, an area larger than the footprint of an individual well pad), inclusive of existing oil and gas wells that may be operating at lower production pressures than new wells.

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
		In use or in development		Low Medium High

n/a

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

n/a

What are the pros and cons of the alternatives?

n/a

What is needed and available for new wells?

n/a

What is needed and available for existing wells?

n/a

What technology alternatives exist for this equipment or process itself?

n/a

What are the pros and cons of the alternatives?

n/a

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

Gas capture planning is already required. Costs from deploying onsite capture or use equipment, re-injecting gas, and/or delaying development of new wells to better align with gathering and/or processing infrastructure development would be associated with requirements to limit venting and flaring rates or volumes, rather than attributed to requirements to improve the infrastructure planning process. Other process changes, for example multi-well "Comprehensive Drilling Plans" or "Master Development Plans" and integration of methane waste capture and marketing provisions in unitization agreements make use of existing oil and gas development decision points. While they impose new requirements that presumably come with additional planning and analytical costs, a front-end investment in planning would presumably lead to additional natural gas capture and thus boost sales and profits. In addition, multi-well "Comprehensive Drilling Plans," "Master Development Plans," and unitization agreements are intrinsically designed to promote orderly and efficient development of resources—i.e., they are a wise investment that pays dividends through orderly and efficient resource development.

For reducing emissions from gathering station blowdowns, the Synapse report estimates installing technology for Transmission Station Venting -Redesign Blowdown Systems/ESD Practices to have a unit cost of $3.84 per mcf of reduced methane and $199.68 per tonne of reduced methane.[3] The Synapse report also estimates the cost of installing LDAR (weighted average) for gathering stations to be $7.35 per mcf of reduced methane and $382.20 per tonne of reduced methane.[4]

[1] Synapse, Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico (Sept. 2019), available at http://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf
[1] *Id*.

What would be the implementation cost?
For new wells?

n/a

For existing wells?

n/a

Are there low-cost solutions available?

Yes, improved infrastructure planning and coordination is very low cost.

If a solution is high-cost, why is that the case?

n/a

Are there additional technical analyses needed to refine benefits/costs estimates?

Given the very low cost of and fairly broad agreement on the value of improving infrastructure planning, as well as the difficulty in directly measuring results, it does not appear that this would be a high priority area of focus for refining benefit/cost estimates, relative to other technologies and processes under consideration.

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

Implementation requires gathering information and developing a plan, both of which are straightforward activities. "In the past, Operators have objected to proposals for gas capture plans with detailed information regarding gathering system availability, asserting that Operators do not have access to some of the information that would be necessary to develop such plans. Specifically, Operators have objected to including the following information:
—the name and location of the nearest gas processing plant and the intended destination gas processing plant;
—maximum current daily capacity, current throughput, and anticipated daily capacity of the gas pipeline to which the operator plans to connect; and

—any plans known to the operator for expansion of pipeline capacity in the area of the well.

BLM believed that Operators would generally be able to obtain such information from midstream companies. *See* BLM, *BLM's Responses to Public Comments on Final Rule,* 171-172 (2016).

The commercial agreements between E&P and midstream operators typically dictate what information can and cannot be shared. E&P operators may be constrained to share or provide information during the APD process. Commercial contracts typically restrict the sharing of sensitive or proprietary information, with respect to midstream infrastructure. The constraints could include not knowing downstream details of midstream operator's pipeline or facilities, or details around pipeline or gas plant capacities could be proprietary and not shared with the E&P operators. These details could include information to E&P or midstream operator's competitors and makes it difficult, to share in a public process.

Midstream operators, by virtue of iterative communications with E&P sector operators and completion of hydraulic analysis of pipeline and compressor infrastructure, may be in an excellent position to complement E&P gas capture planning. This could involve an aggregation of reasonably foreseeable regional volumes of natural gas to provide regulators with information pertinent to infrastructure planning across the value chain that nonetheless complies with any legal restrictions on the sharing of sensitive or proprietary information. Also, commercial agreements are adopted by E&P and midstream operators for their mutual benefit and may, of course be modified. To the extent that such commercial agreements may constrain information sharing necessary to comply with any regulatory requirements established for gas capture plans and infrastructure planning, those provisions of the agreements are likely unenforceable and certainly may be changed. Furthermore,

What is the useful life of equipment?

n/a

What are the maintenance and repair requirements for equipment required for methane reduction?

n/a

How would emissions be detected, reductions verified and reported?

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

Given continuing increases in venting and flaring in states with gas capture plan requirements, this measure has not yet reached its potential to reduce methane waste. See, for example,

"Flaring reaches record high amid pipeline, gas plant shutdowns," Bismarck Tribune, August 15, 2019
https://bismarcktribune.com/bakken/flaring-reaches-record-high-amid-pipeline-gas-plant-shutdowns/article_610d6c94-6b03-57df-b5b2-9a25a82d9271.html
"Wyoming Ranks Third Nationally in Natural Gas Flaring," Wyoming Public Media, September 24, 2019
https://www.wyomingpublicmedia.org/post/wyoming-ranks-third-nationally-natural-gas-flaring?utm_source=1500+CWP+List+Daily+Clips+and+Updates&utm_campaign=29104083dd-EMAIL_CAMPAIGN_2019_09_24_07_51&utm_medium=email&utm_term=0_4369a4e737-29104083dd-75462645#stream/0
"Permian gas flaring hits new record highs for 'widespread waste,' pollution." The Houston Chronicle, June 4, 2019
https://www.houstonchronicle.com/business/energy/article/Permian-methane-emissions-back-on-the-rise-after-14412700.php

According to research conducted in 2017, compliance with the NM gas capture plan requirement has been uneven.

APD's and Gas Capture Plans Submitted 9/18/17–11/5/17

Total APDs	GCP submitted		GCP not submitted	
286	132	46%	154	54%

APD's and Gas Capture Plans By Mineral Owner

	Total APDs	GCPs submitted		GCPs not submitted	
State	100	19	19%	81	81%
Federal	157	110	70%	47	30%
Private	29	3	10%	26	90%

"Curbing Methane Pollution and Waste: New Mexico's Problem and Opportunity," presentation by EDF to the Water and Natural Resources Interim Committee, November 20, 2017 (see Exhibit 4).

A key regulatory gap in gas capture planning is that plans have not been adequate to provide certainty that, at least for development oil wells, takeaway capacity will be in place once the well has been completed and begins producing. Redesigning the gas capture plan template to require additional information and assurance of projected outcomes is needed to close this regulatory gap. For adequate planning, more detailed information is needed on when the proposed well is expected to be completed and the anticipated volume of production, as well as the anticipated capacity of the gathering system to which the operator intends to connect. To ensure results – i.e., that gathering capacity is consistently available when and where it is needed – requires more certainty up front that takeaway capacity will be available when new wells begin production, such as documentation of contracts or agreements indicating that the operator has obtained firm takeaway capacity from a midstream company. To enhance compliance, plans should be a mandatory element of the drilling permit approval process; i.e., APD approvals should be deferred or denied if plans are inadequate. To address changed circumstances, Operators should be required to update plans when material changes occur, such as if drilling is delayed or more information becomes available about well characteristics.

The current gas capture plan requirements also fail to require operators to consider alternatives to venting or flaring where gathering capacity is not available. See the MAP Report on Venting and Flaring for discussion of this issue.

In addition to gas capture planning by operators, planning requirements could also be developed for midstream companies to "plan backwards/upstream" when seeking state approvals, i.e., that they have reviewed gas capture plans for new wells in the locations to be served by their projects. For example, a gas capture planning requirement could be adopted by the State Land Office for ROW applications and by NMED for air permit applications. These plans could also be shared with operators to inform their planning.

A gap also exists in providing information about other wells in the vicinity of the proposed well, both existing wells that may be venting or flaring and new wells that are planned to be developed by the Operator, to provide midstream companies with a more complete picture of production that may be available to be aggregated to support takeaway capacity. This information is not available in piecemeal, well-by-well drilling applications. This gap could be addressed by requirements for Operators to package into a single application all planned/foreseeable drilling/infrastructure approval requests anticipated over a 6- to 12-month time period within a given field or unit based on geographic proximity or potential use of shared infrastructure such as gathering systems, compressor stations, or processing facilities. The U.S. Bureau of Land Management, in its Gold Book (*see* p. 8), provides for a "master development plan" type approach that illustrates the utility of moving from well-by-well permitting to multi-well permitting in a developing field. This approach is echoed in Bureau of Land Management Information Bulletin No. 2018-061 (June 26, 2018) which provides, in section III.A., for the consolidation of multiple drilling permit applications in a single Master Development Plan accompanied by a single environmental review process (promoting efficiencies and streamlining the process relative to APD-specific environmental reviews). In accord with this BLM guidance, the Master Development Plan can also encompass sundry notices and proposed oil & gas rights-of-way. If coupled with requirements that such plans account for infrastructure planning to reduce methane pollution and waste, this approach to drilling permits would create incentives for industry to conduct planning, investment, and permitting activities in a more efficient and comprehensive manner. Under this approach OCD would not approve multiple drilling requests in one fell swoop that would fail to address site-level considerations; on the contrary, OCD would still make its drilling approval decisions on an individual-well basis, if based on an omnibus, overarching infrastructure plan. The effectiveness of this state-level comprehensive drilling plan would be optimized by considering the full life-cycle of infrastructure development in a given field or drilling unit, providing information that can be used to synchronize infrastructure development to facilitate methane capture and marketing and to understand how to best reduce the loss of methane as the field declines and its wells are eventually plugged and abandoned. In addition, comprehensive drilling plans should be designed to facilitate multi-jurisdictional coordination between OCD, BLM, SLO, and NMED and to minimize redundancies.

A regulatory gap also exists in preventing methane waste in spacing and density rules. The Oil and Gas Act, N.M. Stat. § 70-2-3, expressly provides that "surface waste" can result from the "manner of spacing." 19.15.15 NMAC. Yet a gap currently exists in addressing surface waste management issues in OCC and OCD decision-making on well spacing and density rules. This gap could be addressed by placing "surface waste" management on an equal footing with "underground waste" management by requiring oil and gas lessees and operators to identify infrastructure investment and other actions they could take to prevent surface waste in their proposals for spacing and density, and in applications seeking to intensify well density and spacing. This would provide a basis for OCD to consider and impose conditions to minimize surface waste in association with spacing and density decisions. Well spacing and density rules set the spatial pattern of development across a particular oil and gas pool. As such, they provide an early and essential opportunity to consider ways to prevent methane waste across an entire pool.

Similarly, a gap in addressing methane waste exists in unitization or unit agreements. These agreements facilitate the orderly development and reduce the total costs of operating oil and gas fields owned by multiple lessees. They do this by consolidating and coordinating operations across all lessees under a single operator, sharing the risks and costs of development, improving the economics of production, and consolidating infrastructure. In so doing, unit

agreements set the stage for the development and approval of individual drilling permits in specific locations within an oil and gas field. Requirements to include consideration of methane waste in unitization agreements could drive better synchronization of production from unitized fields with midstream companies. Addressing waste in unitization would avoid deferring consideration of the need and opportunity to prevent waste to the drilling stage where unit-level opportunities to prevent waste may be lost. OCC and OCD could exercise authority to deny or condition unit agreements to ensure that they acknowledge and account for methane waste at the field level.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

Opportunities exist for integrated data systems, information sharing/notifications, and coordinated approval processes to support achievement of each other's missions:

- SLO could provide information to OCD about planned lease sales, enabling OCD to anticipate APDs, unitization, and spacing applications
- OCD could provide information to SLO about areas with high venting or flaring rates to consider reorienting leasing to areas with more available takeaway capacity.
- OCD could provide Gas Capture Plan information to NMED about planned venting and flaring during well completion and production testing to monitor for AQ violations
- NMED could utilize C-115 venting and flaring data to monitor for AQ violations
- NMED could provide methane emissions data to support OCD verification of C-115 venting and flaring reporting

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

n/a

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc.?):

There may be a need to study the end-of-life of the well infrastructure plans for wells as improperly plugged or abandoned well are not done up to standard process that ensures methane is not released. ("Measuring methane emissions from abandoned and active oil and gas wells in West Virginia" https://www.princeton.edu/~mauzeral/papers/Measuring%20methane%20in%20West%20Virginia.pdf; "Measurement of methane emissions from abandoned oil and gas wells in Hillman State Park, Pennsylvania" https://www.tandfonline.com/doi/figure/10.1080/17583004.2018.1443642?scroll=top&needAccess=true)

The PHMSA Gas Transmission Integrity Management rule resulted in regulations (49 CFR Part 192, Subpart O) which specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas (HCAs) within the United States.

https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/gas-transmission-integrity-management-gt-im-overview

5. INFRASTRUCTURE - PATH FORWARD[60]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EFFECTIVENESS OF COST NOW (choose one)	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
5.1	Statutory/regulatory changes to allow for industry and New Mexico agencies to use third party contractors, who are approved by the State, for surveys and analysis for ROWs and other approvals. This option will help facilitate infrastructure installation. This type of process is currently utilized by NMOCD to help with the approval of surface waste facilities. The industry participant enters into a contract with a local New Mexico college, selected by NMOCD. The NMOCD creates a scope of work and the necessary report is created by the college. This mechanism helps reduce workload burdens on the agency and helps facilitate a timely approval, while ensuring adequate studies are performed.		1 = Easy 5 = Hard 1 – Easy to achieve and cost effective. However, statutory changes may be needed for NMSLO to implement this type of procedure to assist with ROWs for infrastructure needs.	The state would obtain copies of all the work performed and still be responsible for approving the analysis/surveys. This would allow the state to obtain more data from third-party contractors funded by industry bonding or through government contracts.	Both
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		

[60] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

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	A. Where this option is being exercised, it should be noticed and comment allowed for in administrative policy/rule changes that do not already require a public process. [page 108]				
5.2	Reform of PRC statutes to create mandatory deadlines for the approval of electric lines needed to service oil and gas facilities. The creation of an administrative application process for the PRC to issue timely approvals for electrical lines needed to service oil and gas facilities. During the MAP meetings, Xcel Energy indicated that PRC approval times for electric lines can run 18 – 24 months. Industry members indicated that they have experienced delays in ability to install electric lines to service oil and gas facilities – particularly in Southeastern, New Mexico. Creating mandatory deadlines or a shortened administrative approval process will help facilitate the installation of electric lines.		3 – Moderate. Consultation would be required with the PRC and statutory reform would likely need to be supported by utility companies. If deadlines to approve lines can be imposed, this should encourage the use of electricity and result in the potential for emissions reductions.		Both, more so in Permian.
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.3	A Memorandum of Understanding between BLM, NMSLO, EMNRD, NMED, affected tribes, and BIA regarding ROW and infrastructure coordinated considerations. This MOU could help the agencies prioritize ROW approvals and discuss the timelines for these approvals. In		1 – Easy. This, however, would involve agency coordination, which may create a different assessment of feasibility by each agency. If the	An MOU could also cover data sharing and data collection needs between the agencies.	Both

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	particular, NMSLO and BLM may be able to work together or better share data to assist with pipeline ROW projects.		ROW process can be streamlined and coordinated, it will help with the construction of infrastructure which will impact emissions.		
	COMMENTS: A. Ensure that this type of coordination would not alter individual agency's obligations to protect public health and the environment. [page 131]		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.4	Revise gas capture plan (GCP) requirements. Specify plan elements to include: --well location; expected drilling, completion, and first production date; expected volumes and pressures; --from multiple wells for the above if operator is planning multiple wells in same area within relevant timeframe; --information about the operator's other current production, and venting and flaring, in the vicinity of the proposed well; --identification of intended gathering system and processing facility for gas production, including pipeline size, pressure, and available capacity now and for the period over which the well is projected to produce, and plan for additional compression if needed; --showing/certification that the operator has communicated projected gas volumes and timing for all operations in the vicinity of the destination pipeline to	Compliance with comprehensive GCP requirements would improve greatly information available to midstream operators to plan their systems to align with expected gas production in a timely fashion. It would also document for OCD that the producer has obtained transportation and processing capacity for wells that are drilled at the time they go into production. See ND, BLM 2016 rules. Expanding the elements required for an adequate GCP would ensure that the operator produces a plan that results in capturing (or disposing through a means other than venting / flaring) the projected volumes of gas over the projected lifetime of the well. For operators seeking APDs for wells without a drilling schedule or sufficient information to forecast production, OCD should consider establishing a process for conditional APD approvals with requirements to update the GCP when required information is available before final drilling approval is granted.	LOW MODERATE HIGH	GCPs should be submitted electronically in machine-readable form.	

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	the midstream company, including current venting and flaring; --showing/certification that midstream company projects there will be available capacity to accept the projected gas production from the specified well; --if pipeline capacity not projected to be available, specific plan for alternative gas use/disposal, with demonstration that the operator has the ability to implement such plan (e.g., if plan to reinject gas, show permit applications submitted; if plan to generate for grid, show communications with grid operator, etc.) -measures to prevent waste over the life of the well, including additional compression and plugging and abandonment				
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.5	Condition grant of APD on submission of adequate GCP with APD.	Conditioning grant of APD on submission of an adequate GCP provides operators a strong incentive to submit plans that identify firm transportation and processing capacity and makes the submittal of the GCPs readily enforceable with minimal state effort.	LOW MODERATE HIGH	n/a	
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.6	Explore opportunities for sharing information between OCD, NMED, EMNRD, affected tribes, BLM, BIA, and SLO to support permitting and approval processes and achieve methane	Information sources: SLO lease sales and ROWs Form C-115 venting and flaring data Gas Capture Plans NMED excess emissions data	LOW MODERATE HIGH	n/a	

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	emissions and waste reductions. For example, • SLO could provide information to OCD about lease sales and rights-of-way applications, enabling OCD to anticipate the location and timing of APD, unitization, and spacing applications • OCD could provide information to SLO about areas with high venting or flaring rates to consider reorienting leasing to areas with more available takeaway capacity. • OCD could provide Gas Capture Plan information to NMED about planned venting and flaring during well completion and production testing to monitor for AQ violations • NMED could utilize C-115 venting and flaring data to monitor for AQ violations • NMED could provide excess emissions data to support OCD verification of C-115 venting and flaring reporting	OCD, NMED and SLO have information that could be useful to their sister agencies. Making this information more easily available could improve agency performance in achieving methane emissions and waste reductions.			
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.7	OCD should commission a study of C-129 Applications for Exception to No-Flare Rule to identify the prevalence of operators and wells seeking repeated exemptions for long-term venting or	Form C-129s are currently part of well files as scanned documents.	LOW MODERATE HIGH	Form C-129s should be submitted electronically in machine-readable form.	

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	flaring. Follow-up research could look into the causes of long-term venting and flaring.				
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.8	OCD should issue a Notice to Operators that have reported long-term volumes of vented gas on C-115 reports requiring them to provide OCD with the reasons for such venting to support possible enforcement action	C-115 data on venting is readily available to the agency. Venting is significantly more damaging to the climate than flaring, and near-term action to prevent this form of waste and pollution will provide substantial climate benefits.	LOW MODERATE HIGH		
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.9	Require that well spacing/density for a given pool be set only after consideration by regulators of surface waste concerns, including by requiring that operators provide estimates of natural gas/methane potentially lost from spacing/density and actions/opportunities to prevent waste (operators already provide estimates of underground reservoir recovery efficiency). Ensures "waste" and methane reduction opportunities are considered by operators before well spacing/density pattern is set across a particular oil or gas pool and provides basis for OCD to determine that changes to well spacing/density to improve underground recovery efficiency do not cause undue or unnecessary surface waste of natural gas. At present, OCC/OCD spacing/density decisions are	Oil & Gas Act defines "surface waste" of natural gas as, in part, "resulting from the manner of spacing." NMSA § 70-2-3(B). The Oil Conservation Commission has, of note, justified a decision between two different proposals by selecting the proposal that they believed would result in greater environmental protection and less surface waste. *See* OCC Order No. R-14876 (2019).	LOW MODERATE HIGH		

NMED Exhibit 10 - 0137

	typically focused on underground reservoir recovery, with surface waste issues given short shrift.				
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.10	Strengthen unitization agreement provisions regarding surface waste prevention, including by requiring information regarding the nature and effectiveness of infrastructure to capture and market (versus vent, flare or leak) natural gas and to better synchronize E&P sector development of that unit with midstream operations.	The model U.S. Bureau of Land Management unit agreement (see 43 C.F.R. § 3186.1) includes provisions regarding the "proper conservation of the oil and gas resources in the unitized area," requiring information regarding the number and locations of wells, proposed order and time for such drilling, and a summary of operations and production for the previous year." These elements provide a starting point for providing that unitization agreements, for all oil and gas resources in New Mexico, not just federal public oil and gas resources, account for surface waste of natural gas.	LOW MODERATE HIGH		
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.11	Comprehensive Drilling Plans/Master Development Plans/Geographic Area Plans. These would be mandated for all foreseeable oil & gas infrastructure, ensuring that regulators are afforded a more expansive picture of field-level development and avoid piecemeal review and approvals. These Plans should also be used to assess opportunities to retrofit existing infrastructure that results in vented/flared/leaked natural gas as a condition of approving new	Colorado Oil & Gas Commission Rule 513 provides for "Geographic Area Plans" that "are intended to enable the Commission to adopt basin-specific rules" and are intended to cover an entire oil and gas field or geologic basin, likely encompassing the activities of multiple operators, in multiple sub-basins or drainages, over a period of ten (10) years or more." Colorado Oil & Gas Commission Rule 216 provides for voluntary "Comprehensive Drilling Plans" that can encompass multiple operators (but are more typically limited to a single operator)	LOW MODERATE HIGH		

	infrastructure and ensuring that new, high-pressure wells do not "knock off" existing, lower-pressure wells within the same field. Such plans should be designed as opportunities for multi-jurisdictional engagement by OCD, SLO, BLM, and NMED.	and are "intended to identify foreseeable oil and gas activities in a defined geographic area, facilitate discussions about potential impacts, and identify measures to minimize adverse impacts to public health, safety, welfare, and the environment, including wildlife resources, from such activities." The U.S. Bureau of Land Management's "Gold Book" also provides for "Master Development Plans" for "all or a portion of the wells proposed in a developing field" (Gold Book, p. 8). *See also* Bureau of Land Management Information Bulletin No. 2018-061 (June 26, 2018) (providing for consolidation of multiple well applications as well as sundry notices and rights-of-way applications in a given field or area within a single Master Development Plan).			
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.12	Consider more pipeline integrity strategies including iPipe. iPipe (intelligent pipeline integrity program) is an industry-led consortium whose focus is to contribute to the advancement of near-commercial, emerging technologies to prevent and detect gathering pipeline leaks. The program is a direct response to North Dakota Governor Burgum's May 2017 challenge to industry to think outside the box and apply new technology to address the challenge of eliminating pipeline leaks.	https://www.ipipepartnership.com/ This unique program is currently funding approximately $4 million in development and demonstration activities over the course of almost 4 years. As additional pipeline operators join the program as members, additional funding will be applied to pursue more technology development efforts. iPIPE consortium members contribute research and development funding to advance new technologies in pipeline leak detection and leak prevention. Members	MODERATE HIGH		

		participate in research forum meetings, offer operating pipelines upon which new technology can be developed and improved, and have immediate access to research and development results.			
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.13	Work towards providing more grid power through master development plans, faster right of way acquisition for oil and gas and utility providers.	Work towards MOU with SLO, BLM, Tribes to accelerate ROW for utilities to provide grid power.	MODERATE HIGH		
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.14	Consider streamline permit for power generation.	Streamline permitting for onsite power generation may allow creative solutions to exist to prevent venting and flaring by both E&P operators and by midstream operators.	LOW MODERATE	As a result of the permit, this could include permitting calcs, thresholds and/or data collection to quantify or reduce venting and flaring.	
	COMMENTS: A. Ensure that this type of coordination would not alter individual agency's obligations to protect public health and the environment. [page 111]		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.15	Portable flares for pipeline blowdowns	Consider the allowance of a portable flare to be used without permit and reported via a C-129 or C-141.	LOW MODERATE	This may require and update on the C-141 or C-129 depending on implementation.	
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.16	Reduce pigging emissions	Pennsylvania requires the use of a pigging device with 95% control if emissions are 200 tpy of CH_4, or 2.7 TPY of VOC. If emissions are less than these thresholds, operators must use best management practices to	LOW MODERATE HIGH		

		minimize liquids and emissions.[1] In Ohio, operators must use an add-on pigging control which includes flare or vapor recovery to limit VOC emissions to 0.27 tpy, on average, over a rolling 12-month period.[2]			
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		
5.17	Reduce blowdown emissions	The EPA's Natural Gas Star program recommends saving the gas from compressors and/or pipeline segments that are taken out of service for operational or maintenance purposes, thereby reducing methane emissions by depressurizing to a connected or nearby low-pressure fuel or product system.[3]	LOW MODERATE HIGH		
	COMMENTS:		SUGGESTIONS TO MAKE THIS OPTION MORE WORKABLE:		

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SECTION 6, VENTING/FLARING

Discussion for MAP members on October 11, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

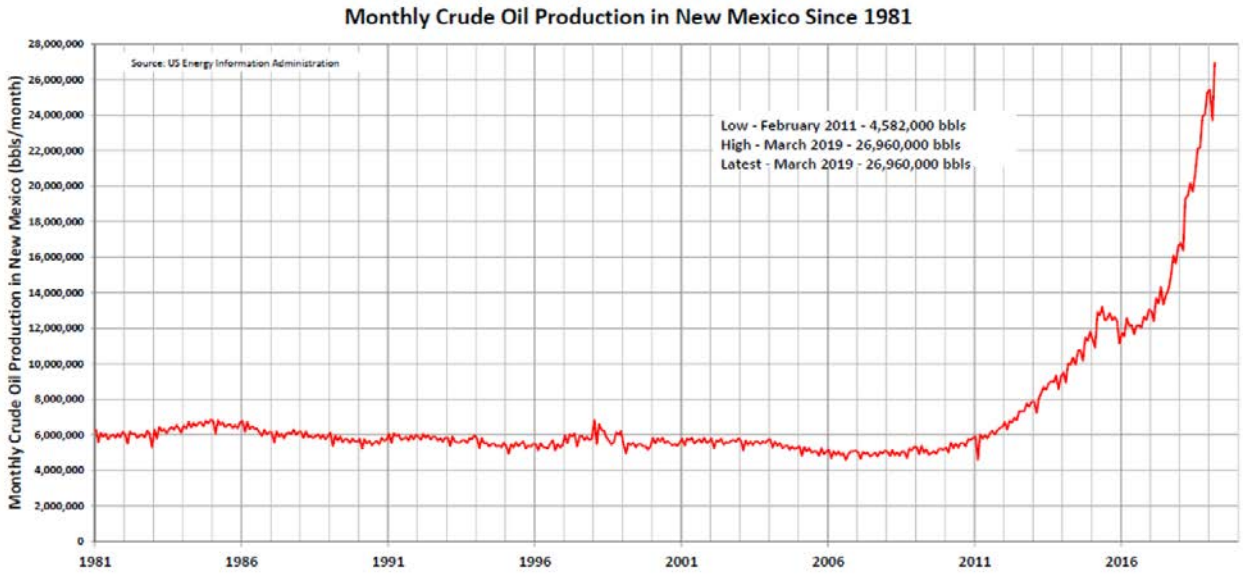
Technical description of the process or equipment:

In the oil and natural gas industry, flaring is the controlled combustion of natural gas that can occur during drilling and completion activities, oil and natural gas field production, pipeline gas gathering, and facility processing of oil and natural gas. Flaring refers to routing natural gas from anywhere in the flow path to a device where the gas is combusted as it leaves the tip of the flare, typically elevated well above ground level.

As most sources of venting will be addressed in the other topic reports, this document focuses primarily on flaring. Also, tank vapor flaring will be discussed in other topic reports; therefore, the scope will be further limited to associated gas (casinghead gas) flaring, with some discussion of associated gas venting as well. Associated gas described in this report is raw, unprocessed gas from the separator and treater and is not marketable at the wellhead for industrial, power generation, and feedstock applications without the pipeline and gas processing infrastructure that is necessary to reduce the heating content and liquid content suitable to meet downstream pipeline specifications, although there may be other potentially un-economic ways to utilize gas at wellheads

The economics of these alternative means of gas utilization will vary.

Beginning in 2011, the Delaware Basin shale boom in southeast New Mexico resulted in a dramatic increase in oil production along with associated natural gas, which led to capacity constraints in the existing pipeline infrastructure. Since that time, oil and gas (upstream and midstream companies) have permitted significant pipeline and gas plant projects and upgrades to alleviate the constraints.



During 2015 Legislative Session, SM 29 was issued requesting EMNRD, NMED, the Indian Affairs Department, and the Department of Finance and Administration to convene a joint task force to study the economic and environmental impact of the increase in natural gas flaring and venting in New Mexico. While SM 29 requested a study to be conducted, the Senate did not allocate funding for such a study. Instead, EMNRD chose to use the committee's time to address the Oil Conservation Division's (OCD) current rules about venting and flaring.

A Gas Capture Plan Committee (GCPC) was formed in July 2015 consisting of NMOCD and Industry representatives. First meeting was held on August 19th, 2015. Below is timeline of events of the group:

- November 2015 - Implemented new "F" code for flared volumes to be reported on C-115s.
- November 2015 – The GCPC expanded to include representatives from New Mexico Environment Department (NMED), State Land Office (SLO), Bureau of Land Management (BLM), and Energy Conservation and Management Division (ECMD). The purpose is to inform and ensure that other State Departments/Agencies are working together to achieve same goal in the reduction of flaring without duplicating or conflicting each other.
- May 1, 2016 – Gas Capture Plan required to be submitted for new drill, recomplete to new zone, or re-frac applications.
- November 2017 – Sec. McQueen prepared report for House Energy Committee on GCPC efforts.
- November 2017-November 2018 – monitored vented and flared volumes being reported.

Subsequent to the GCPC activities, several other flaring related agency and administration actions have occurred:

- October 5, 2018 – General Construction Permit to allow temporary flares at NOI oil and gas production facilities was issued.
- January 29, 2019 – Executive Order on addressing Climate change and Energy Waste Prevention issued by Governor Lujan Grisham.
- June 2019 – NMED and EMNRD begin statewide public stakeholder engagement meetings.
- August 2019 – NMED and EMNRD convene Methane Advisory Panel as it begins the process of developing new methane emission and flaring reduction rules.

Provide the segment(s) of the industry that the equipment or process is found:

Flares can be found throughout the production and midstream segments.

NMED Exhibit 10 - 0143

Describe how the equipment or process is used:

Equipment

Flaring refers to routing natural gas from anywhere in the flow path to a device where the gas is combusted as it leaves the tip of the flare.

The flare system will consist of a header, stack, tip, and ignition system. Gas is sent to the flare through a header system and is combusted as it exits the flare stack at the tip. The flare tip is designed to ensure the proper mix of gas and air to achieve the proper burn efficiency. Ignition of the gas stream is through the use of a continuously burning pilot or auto-ignition system.

Process

Flaring is an essential and necessary part of drilling and completion activities, oil and natural gas field production, pipeline gas gathering, and facility processing of oil and natural gas because of safety considerations (personnel and equipment) and its effectiveness in combusting harmful emissions (environmental). Even at the global level, an entity called the World Bank has identified certain categories where flaring is acceptable and necessary as well as acknowledged that some 'routine' flaring was to be anticipated under certain circumstances. http://documents.worldbank.org/curated/en/755071467695306362/pdf/106662-NEWS-PUBLIC-GFR-Gas-Flaring-Definitions-29-June-2016.pdf

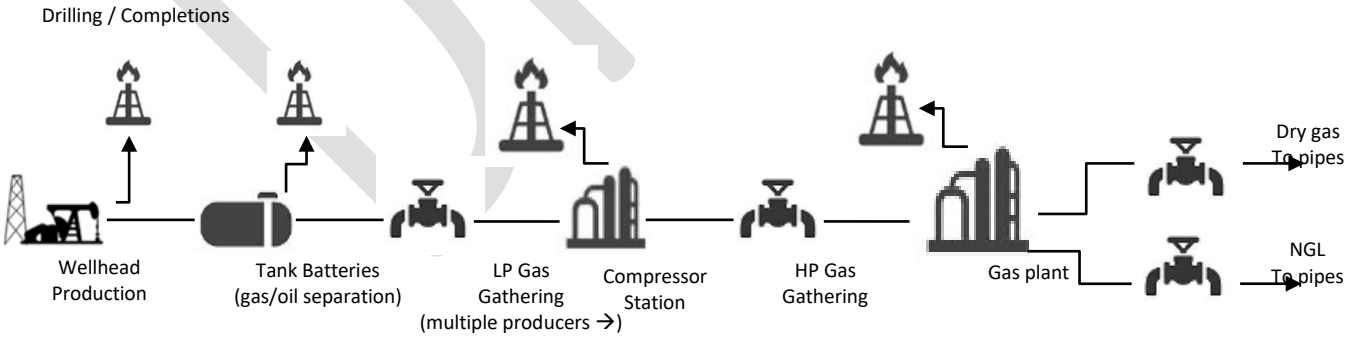
The Bank defines routine flaring "of gas at oil production facilities as flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market." It includes "flaring from oil/gas separators; flaring of gas production that exceeds existing gas infrastructure capacity; and flaring from process units such as oil storage tanks, tail gas treatment units, glycol dehydration facilities, produced water treatment facilities, except where required for safety reasons." The Bank is calling upon governments, development institutions, and oil companies to endorse the "Zero Routine Flaring by 2030 Initiative." https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030.

There are several reasons why natural gas may be flared at any step during producing and processing of crude oil and natural gas. The following is a list of situations where flaring may be necessary. Data currently reported on C-115 does not provide enough detail to differentiate what would or would not constitute waste.

- Temporary flaring during drilling and completion activities or flowback/well testing.
- To protect personnel or the public from potentially unsafe conditions that would result in exceeding the maximum allowable operating pressure (MAOP) of vessels or components. For example, natural gas processing plants rely on safety flares in emergency situations in which piping becomes over-pressured to mitigate risks of fires and explosions.
- To combust gas that may have hydrogen sulfide or other contaminants that are unsafe to human health.
- Required maintenance outages. Maintenance on equipment at any step in the gas transportation process may result in flaring (e.g. transmission pipelines must be taken out of service for inspections causing a cascading effect on production all the way back to the wellhead). For producers this might be maintenance at a gathering/processing facility. For gathering/processing companies this might be maintenance by the downstream gas/NGL pipeline operators resulting in flaring at a gas plant, perhaps shutting down the gas plant, which can then cause producers to flare.
- Instances where the gas takeaway capacity is interrupted with little notice for a variety of reasons. Examples can include, but are not limited to, unplanned upsets or malfunctions at gas gathering or processing facilities. When the flow of gas through a facility is stopped due to an unplanned upset or malfunction, the flow of gas is shut off immediately resulting in quickly increasing upstream pressures, potentially all the way back to the

wellhead. Flaring the gas released by the pressure control valves or the pressure safety valves is the safest, most expedient way to handle that situation.

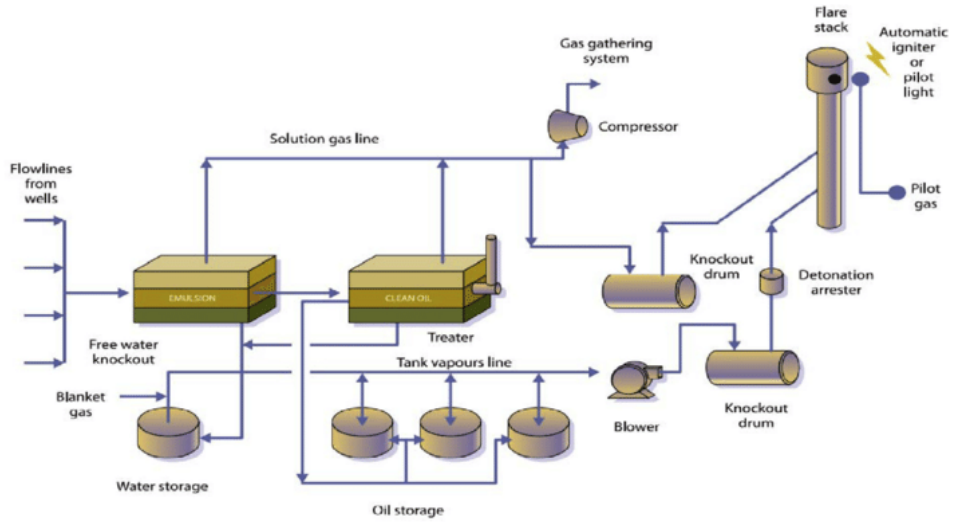
- Regulatory constraints, including permitting, may impact any step in the development and production of crude oil and natural gas. The long lead time to receive Right of Ways (ROWs) necessary to construct and install electrical infrastructure and natural gas pipelines and facilities cause delays that may lead to flaring if well development and completion moves forward without supporting infrastructure in place.
- Limited infrastructure capacity to move natural gas or natural gas liquid (NGL) volumes out of NM Basins, including gas gathering capacity, gas processing capacity and/or capacity on long haul transmission pipelines for natural gas or NGL. Takeaway restrictions may not be predictable. For example, gas processing plants may experience limits on takeaway volumes when the sales valve is suddenly closed by the pipeline operator, resulting in the gas plant flaring, perhaps shutting down, which can then cause producers to flare. Or, oil and gas producers may experience capacity limitations on common gathering pipelines when higher than expected volumes of gas enter the lines by other operators, resulting in insufficient take-away capacity for the natural gas produced.
- Valuable information is needed in order to make decisions regarding future well and infrastructure requirements in step out or wildcat areas; therefore, flaring may be prevalent until the field fills in and infrastructure is built out.
- During pigging operations, additional backpressure on the system may cause flaring. Pigging is a necessary maintenance procedure to manage liquids buildup in the gathering lines.
- Flaring may also occur during hydrate remediation on gathering lines.
- Gas quality or composition can vary such that the gas is not suitable for pipeline transportation, processing plants, or for sales (e.g., H2S from the reservoir, oxygen introduced into the line via vapor recovery unit and other processes, temperature), that leads to flaring.
- Gas pressure at the well or facility is insufficient and the gas cannot be routed to a sales line. This is an issue for both the producer and the midstream operators.
- Electrical infrastructure issues
    - Lightning strikes and localized weather events that knock out power to compression facilities and require the use of flares.
    - Power availability and reliability needed to transport, treat, and process the hydrocarbon vapors and natural gas.



Provide the common process configurations that use this equipment or process:

Flaring is a common process as it is the safer alternative to venting. The figure below shows a simplified oil and gas production operation with a number of wells connected to a central tank battery by flowlines. The wellhead fluids flow to the battery where separation can occur in one or more vessels. Each vessel will be designed for a maximum allowable operating pressure (MAOP) and the system will be equipped with a variety of safety relief devices to ensure

safe operation. Safety relief devices include pressure control valves that can either stop the flow of fluids through the vessel or route excess fluid to a safety system which typically results in vapor flowing to a flare and the liquids to a tank.



http://dx.doi.org/10.1016/j.jestch.2016.09.012

What is the distribution of the equipment or process across business segments?

Although flaring occurs in the production segment, flaring also occurs in the midstream segment. Midstream activities may include any or all of the following: compression; dehydration; treating to remove any contaminants; and processing the hydrocarbons to recover natural gas liquids (NGL's) and saleable residue natural gas. At any of those steps, if the flow of the gas through a facility is stopped due to an unplanned upset or malfunction, the flow of gas is shut off immediately resulting in quickly increasing upstream pressures, potentially all the way back to the wellhead. Flaring the gas released by the pressure control valves or the pressure safety valves is the safest, most expedient way to handle that situation.

Note: Natural gas flared in the midstream operations is downstream of the sales meter.

How has this equipment or process evolved over time?

Equipment

Over the past several years, there have been advancements in tip design in order to yield a broader range of smokeless burn, as well as advancements in the accessories associated with the flare that aid in their reliability. Auto-ignition pilots, thermocouples, pressure switches, feasible flow measurement, malfunction alarms, etc. are technical advances that have improved operation of flares, both on location and remotely.

Process

In November 2015, flared volumes began to be reported as a separate non-transported disposition (F code) on the NMOCD C-115 Form (Operators Monthly Report). Prior to November 2015, vented and flared volumes were reported as one non-transported disposition. NMOCD posts the vented and flared volumes on their website at this link: http://www.emnrd.state.nm.us/OCD/documents/C-115Non-TransportedProductDispositionFlared2016-2019.pdf

The current Gas Capture Plan was made part of the application process through "Notice to Operators" issued on April 8, 2016, with an effective date of May 1, 2016.

- Per the Notice to Operators - The Gas Capture Plan outlines actions to be taken by the Operator to reduce well/production facility flaring and venting, for new completion (new drill, recomplete to new zone, re-frac)

activity. The requirement applies to Federal, State, Fee, & Tribal Wells.

- A Gas Capture Plan's purpose is to ensure that operators are working with gatherers/processors to provide a way to get the gas to market for sales rather than flare.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

The flare is elevated well above ground level, and combusted. Modern, properly operated flares have a destruction efficiency of at least 98%, thus reducing the methane and volatile organic compounds (VOCs) that would otherwise be emitted to the atmosphere had the gas been vented (the destruction efficiency of older flares generally ranges from 95%-98%). The remaining 2-5% of uncombusted gas contains methane, and is reported to EPA under the GHGRP.

A recent study of flaring in the Bakken found that while the median destruction efficiency for methane and ethane was 98%, "the efficiency distribution is skewed, exhibiting log-normal behavior." The researchers concluded: "this suggests incomplete combustion from flares contributes almost 1/5 of the total field emissions of methane and ethane measured in the Bakken shale, more than double the expected value if 98% efficiency was representative."[61]

Also, some flares have one or more continuously burning pilot flames, while others automatically ignite pilot flames in preparation for use. Pilots can be blown out by wind and gas is occasionally released to an unlit flare. In addition to the volume of methane that is vented when the pilot is blown out, there are emissions from incomplete combustion of the fuel gas used for the pilot.

Venting of associated gas directly releases methane (and other pollutants) into the atmosphere. Flaring releases methane from the unburned portion of the gas, and whenever the flare sputters or is unlit, such as when the pilot light goes out. Flaring also results in the loss of large quantities of natural gas through intentional combustion for means of disposal, and flaring is a significant source of the GHG CO_2 and many other pollutants.

Venting and flaring of associated gas largely occurs in situations where oil development outpaces infrastructure to take the gas to market. In the Permian, while almost all of the producing wells are connected to gas-gathering infrastructure, gas production growth is nonetheless overwhelming the capacity of the gathering system.[62] This is

[61] Gvakharia et al, Methane, Black Carbon, and Ethane Emissions from Natural Gas Flares in the Bakken Shale, North Dakota, *Environ. Sci. Technol.* 2017, 51, 9, 5317-5325 (April 12, 2017) (https://pubs.acs.org/doi/10.1021/acs.est.6b05183#).

[62] See BLM, Waste Prevention, Production Subject to Royalties, and Resource Conservation; Proposed Rule, 81 Fed Reg. 6616, 6638 (Feb. 8, 2016) (https://www.federalregister.gov/documents/2016/02/08/2016-01865/waste-prevention-production-subject-to-royalties-and-resource-conservation) (hereinafter BLM Proposed Rule).

also true in North Dakota, where the North Dakota Industrial Commission noted that "the majority of the gas flared . . . is from wells already connected to a gas gathering system."[63]

Inadequate pipeline/gathering capacity is commonly identified as a reason for venting and flaring, and certainly, given the choice, operators would prefer to sell gas to market than flare it. But even as substantial additional gathering, processing, and pipeline capacity has come online in recent years, associated gas production has increased more rapidly and outpaced available capacity.[64] This mismatch between the volume of gas being produced and the available midstream or downstream capacity is occurring in part because the volume and timing of gas production in areas such as the Permian and Bakken is being driven not by the value of the gas, but the value of oil.[65] Because oil prices are relatively so much higher than gas prices, there is an incentive for operators in certain basins to pursue oil development and treat associated gas as a waste product. As noted by the Government Accountability Office, even though it may be profitable for operators to make investments to capture gas, it can be even more profitable for operators to invest in further oil development instead.[66] Absent a regulatory requirement or price incentive to capture associated gas (or significant changes in the relationship between oil and gas prices), operators are likely to continue to ramp up associated gas production faster than gas takeaway capacity is expanded in oil-producing basins, all else being equal.

The conclusions in the October 2010 GAO report mentioned above and throughout this document assumed the following gas prices. More recent data from the U.S. Energy Information Administration is included below:

	GAO	U.S. Energy Information Administration
Natural Gas	$4.01/MMBtu	$1.44/MMBtu[67] - Southwest

This is not the only factor driving flaring, however. There is frequently a time lag between initial production or expansion of associated gas production in a given area and the development of additional gathering system capacity, as various barriers may prevent midstream companies from acquiring adequate information about operators' production plans and midstream companies do not generally build infrastructure without some assurance of supply.

Also, even when there is sufficient capacity on a gathering system as a general matter, new hydraulically fractured wells initially produce at very high pressures and can bump older, lower-pressure wells off the system until pressures decline (or until operators boost compression at the older wells), effectively creating takeaway capacity shortfalls for a period of time.[68]

Finally, planned or unplanned maintenance or upsets on gathering lines, processing plants, and pipelines also temporarily reduce takeaway capacity and drive flaring.

[63] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 102215.
[64] See North Dakota Department of Mineral Resources, Oil & Gas Update (Oct. 25, 2018) (https://www.dmr.nd.gov/oilgas/policies.asp, link to Gas Capture Background Sheet) ("From 2014-2017 midstream built out 1 BCFD of processing capacity."); Bismark Tribune, Industrial Commission gives oil industry more flexibility on flaring (Nov. 20, 2018) (ND Governor "commended the industry for investing nearly $5 billion in gas capture infrastructure").
[65] See Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019) "prices have cratered, dropping as low as minus $9 per [mmBtu] in early April" 2019).
[66] GAO, Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas Which Would Increase Royalty Payments and Reduce Greenhouse Gases, GAO-11-34, 24 (Oct. 2010) (https://www.gao.gov/products/GAO-11-34).
[67] https://www.eia.gov/todayinenergy/prices.php
[68] See North Dakota Department of Mineral Resources, Oil & Gas Update (Oct. 25, 2018) (https://www.dmr.nd.gov/oilgas/policies.asp, link to Gas Capture Background Sheet) ("Seeing increased frequency of new high=producing wells and historically compliant wells in non-compliance du to their location on the same gathering system.").

New Wells:

Flares are used at both new and existing wells.

Venting and flaring occurs at new and existing wells. New wells may not be connected to gathering lines, or the capacity of those lines may not have been expanded to handle the additional gas being produced.

Existing Wells:

Flares are used at both new and existing wells.

Venting and flaring occurs at new and existing wells. Existing lower pressure wells that are connected to gathering systems may be bumped off the system by new wells operating at much higher pressures.

How are the emissions calculated for this equipment or process?

Flaring volumes may be included in any of these three categories; well testing venting and flaring, associated gas flaring, and/or flare stacks.

Equations from GHGRP Subpart W:

(l) *Well testing venting and flaring.* Calculate CH_4 and CO_2 annual emissions from well testing venting as specified in paragraphs (l)(1) through (5) of this section. If emissions from well testing venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (l)(6) of this section.

(3) Estimate venting emissions using Equation W-17A (for oil wells) or Equation W-17B (for gas wells) of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq. W-17A)}$$

$$E_{a,n} = PR * D \qquad \text{(Eq. W-17B)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Average annual flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the calendar year that the well(s) is tested.

(m) *Associated gas venting and flaring.* Calculate CH_4 and CO_2 annual emissions from associated gas venting not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as specified in paragraphs (m)(1) through (4) of this section. If emissions from associated gas venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (m)(5) of this section.

(3) Estimate venting emissions using Equation W-18 of this section.

$$E_{s,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} [(GOR_{p,q} * V_{p,q}) - SG_{p,q}] \qquad \text{(Eq. W-18)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting at standard conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in sub-basin q, in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year during time periods in which associated gas was vented or flared.
$SG_{p,q}$ = Volume of associated gas sent to sales, for well p in sub-basin q, in standard cubic feet of gas in the calendar year during time periods in which associated gas was vented or flared.
x = Total number of wells in sub-basin that vent or flare associated gas.
y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as specified in paragraphs (n)(1) through (9) of this section.

(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W-19 and W-20 of this section.

$$E_{s,CH_4} = V_s * X_{CH4} * \left[(1-\eta) * Z_L + Z_U\right] \quad \text{(Eq. W-19)}$$

$$E_{s,CO2} = V_s * X_{CO2} + \sum_{j=1}^{5}\left(\eta * V_s * Y_j * R_j * Z_L\right) \quad \text{(Eq. W-20)}$$

Where:
$E_{s,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, at standard conditions.
$E_{s,CO2}$ = Annual CO_2 emissions from flare stack in cubic feet, at standard conditions.
V_s = Volume of gas sent to flare in standard cubic feet, during the year as determined in paragraph (n)(1) of this section.
η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare (default is 0.98).
X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare as determined in paragraph (n)(2) of this section.
X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare as determined in paragraph (n)(2) of this section.
Z_U = Fraction of the feed gas sent to an un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.
Z_L = Fraction of the feed gas sent to a burning flare (equal to $1 - Z_U$).
Y_j = Mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare as determined in paragraph (n)(1) of this section.
R_j = Number of carbon atoms in the hydrocarbon constituent j in the feed gas to the flare: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

Metering of gas sent to flares. In some cases, vented or flared amounts are calculated using gas/oil ratios (GORs) that are measured periodically, with gas then calculated from measured oil production. In cases where a portion of gas from a system is sold, this portion will be metered, and operators may calculate vented or flared volumes by subtracting the captured portion from the total volume. These approaches are generally less accurate than direct metering of flared or vented streams because of issues such as temporal variation in GOR, the accuracy of emissions factors for gas diverted to use for engines and such, and other problems.

In the final 2016 BLM Methane and Waste Prevention Rule, BLM allowed for "either metering or a GOR-based calculation of flare volumes in circumstances where a GOR-based approach would allow the BLM to independently verify the volume, rate, and heating value of the flared gas.[69]

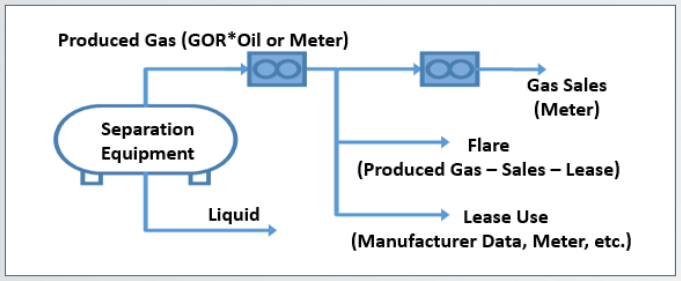
[69] BLM, Waste Prevention, Production Subject to Royalties, and Resource Conservation; Final Rule, 81 Fed Reg. 83008, 83053 (Nov. 18, 2016) (https://www.federalregister.gov/documents/2016/11/18/2016-27637/waste-prevention-production-subject-to-royalties-and-resource-conservation).

During the 2016 BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation rulemaking, BLM acknowledged that due to the performance limitations of many commonly used meters, a properly designed GOR based approach to estimating flare volumes could also produce adequately accurate results.[70] A GOR-based method for calculating volumes of flared gas uses known GOR and measured volumes of oil production and sold gas. The GOR itself is determined based on a test that directly measures in a controlled manner all of the oil and gas produced by the well over a given period of time. Calculating the volumes of flared gas based on GOR can be quite accurate, if the GOR value used is accurate and the well conditions are relatively stable. This is consistent with BLM's long standing (January 1, 1980) policy.[71]

BLM continued: "Since the GOR will vary as well conditions change, the accuracy of the GOR value for a well can be enhanced by more frequent GOR testing, either on a set frequency and/or in response to changes in the well's production. The BLM expects that to meet the standards of § 3179.9, GOR tests would need to be performed at least monthly for most wells."[72]

Both the state of North Dakota also considers calculation methods to be an acceptable method for compliance with NDIC Order #24665 as outlined in implementation Flaring Questions.[73]

Below is an example of the subtraction method:



What data is available to quantify emissions/waste for this equipment or process?

The US EPA publishes most of the emission information and activity data that it receives as part of the US GHG Reporting Program annually (https://ghgdata.epa.gov/ghgp/main.do?site_preference=normal#). By March 31st of each year, operators upload their emission information to the EPA website for the previous year (i.e. 2018 emission information was reported in March 2019), EPA undertakes a quality assurance process, and uploads the information in October to a publicly accessible website. Care should be taken in estimating emissions from this inventory for New Mexico since both the Permian and San Juan Basins span multiple states and it is challenging to separate emissions between states for all source categories.

Here, we present an analysis of methane emissions from the oil and gas production and gathering & boosting (G&B) segments as reported to the EPA's Greenhouse Gas Reporting Program (GHGRP). GHGRP reporting began in 2011 for the production segment and in 2016 for the G&B segment. Operators with less than 25,000 MT CO_2e emissions are exempt from reporting emissions to the GHGRP.

[70] BLM, Waste Prevention, Production Subject to Royalties, and Resource Conservation; Final Rule, 81 Fed Reg. 83053 (Nov. 18, 2016) (https://www.federalregister.gov/documents/2016/11/18/2016-27637/waste-prevention-production-subject-to-royalties-and-resource-conservation).

[71] Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases, Royalty or Compensation for Oil and Gas Lost

[72] BLM, Waste Prevention, Production Subject to Royalties, and Resource Conservation; Final Rule, 81 Fed Reg. at 83053 (Nov. 18, 2016) (https://www.federalregister.gov/documents/2016/11/18/2016-27637/waste-prevention-production-subject-to-royalties-and-resource-conservation).

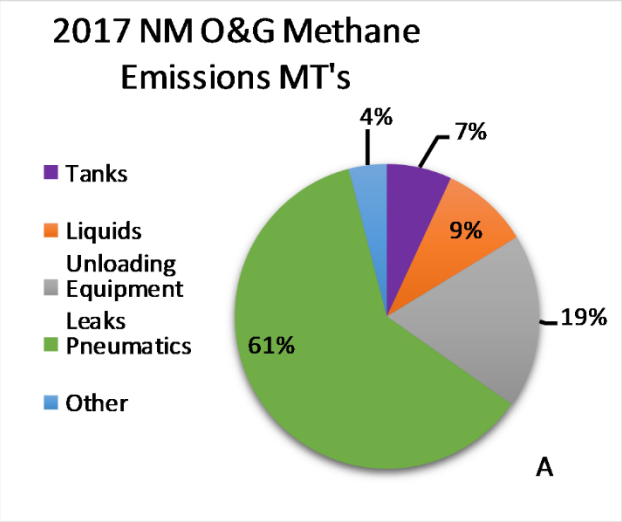
[73] Hicks, Bruce E. "NDPC Flaring Questions ICO#24665." Letter to Mr. Ron Ness. 4 July 2014.

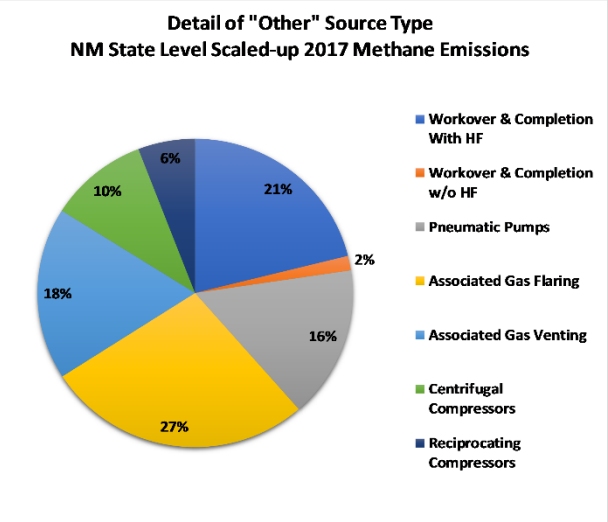
However, it is important to note that in this analysis we have scaled emissions to account for exempt operators by basin.

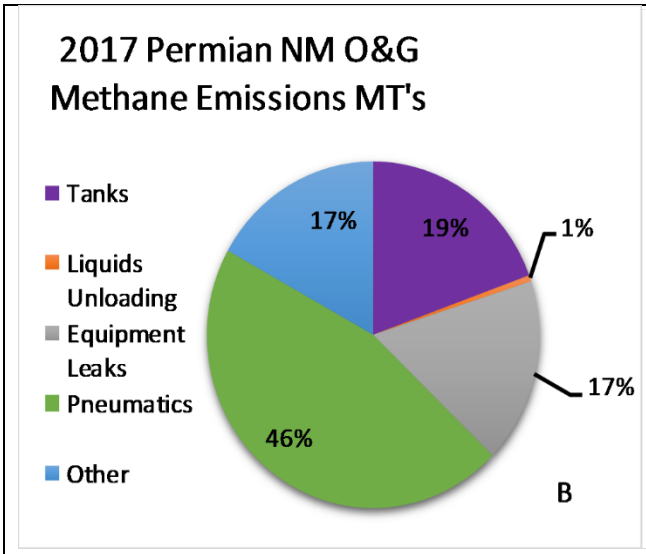
In 2011, 50% of wells in the Permian basin were included in GHGRP reporting, and by 2017 coverage increased to 72%. In the San Juan Basin, over 85% of wells have been included in GHGRP reporting since 2011. For the production segment, we have scaled all emissions in each year up to the total well count reported by the New Mexico Oil Conservation Division (NMOCD) (EIA for national). For the G&B segment, no information to enable scaling-up GHGRP reported emissions is available and raw GHGRP reported emission quantities are shown.

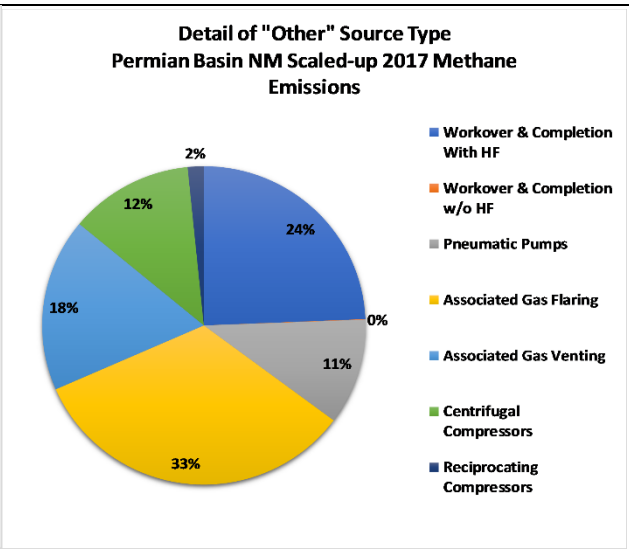
In 2017, scaled-up New Mexico statewide GHGRP reported methane emissions totaled 205,470 metric tonnes (MT's). Of these, associated gas flaring accounted for approximately 3,536 metric tons. This amounts to 1.7% of the total New Mexico statewide methane emissions.

In 2017, scaled-up New Mexico Permian GHGRP reported methane emissions totaled 48,805 metric tonnes (MT's). Of these, associated gas flaring accounted for approximately 3,536 metric tons. This amounts to 7.2% of the total New Mexico Permian methane emissions.
*This data does not include CO2 emissions from flaring. CO2 equivalent data is of interest as well.









When both methane and carbon dioxide are considered, flaring contributes a larger portion of Oil and Gas greenhouse gas. For example, considering GHGRP data for 2018 for Permian wellpads, 29% of reported greenhouse gas emissions is from associated gas venting and flaring (considering the sum of CO_2-equivalent emissions, using a GWP of 25 to convert methane emissions to CO_2e):

Permian Wide-Emissions by Category, 2018	GHG, tCO2e	%
Combustion Equipment	7,449,180	32%
Associated Gas Venting and Flaring	**6,684,148**	**29%**
Natural Gas Pneumatic Devices	2,260,725	10%
Atmospheric Storage Tanks	2,237,552	10%
Flare Stacks [98.236(n)]	1,840,021	8.0%
Completions and Workovers with Hydraulic Fracturing	1,257,098	5.5%
Equipment Leaks Surveys and Population Counts	714,443	3.1%
Centrifugal Compressors	312,546	1.4%
Natural Gas Driven Pneumatic Pumps	112,017	0.5%
Well Venting for Liquids Unloading	41,775	0.2%
Other Equipment	82,542	0.4%
SUM	**22,992,045**	**100%**

Data downloaded from Envirofacts and summarized by CATF. GWP of 25 used to convert methane emissions to CO_2e.

While this data is Permian-wide and therefore not specific to NM, the large contribution from associated gas venting & flaring to basin-wide greenhouse gas indicates that this source is an important GHG source.

A primary source of data on the quantities of gas vented and flared are the producers' C-115 reports, which require reporting of the volumes of produced gas disposed of through flaring and, separately, through venting. In addition, the report template provides disposition codes for "gas lift," "lost," "repressurizing," "used on property," and "other." As discussed elsewhere in this section, US EPA Greenhouse Gas Reporting Program data is another source of data on methane emissions, although it does not include data from smaller entities.

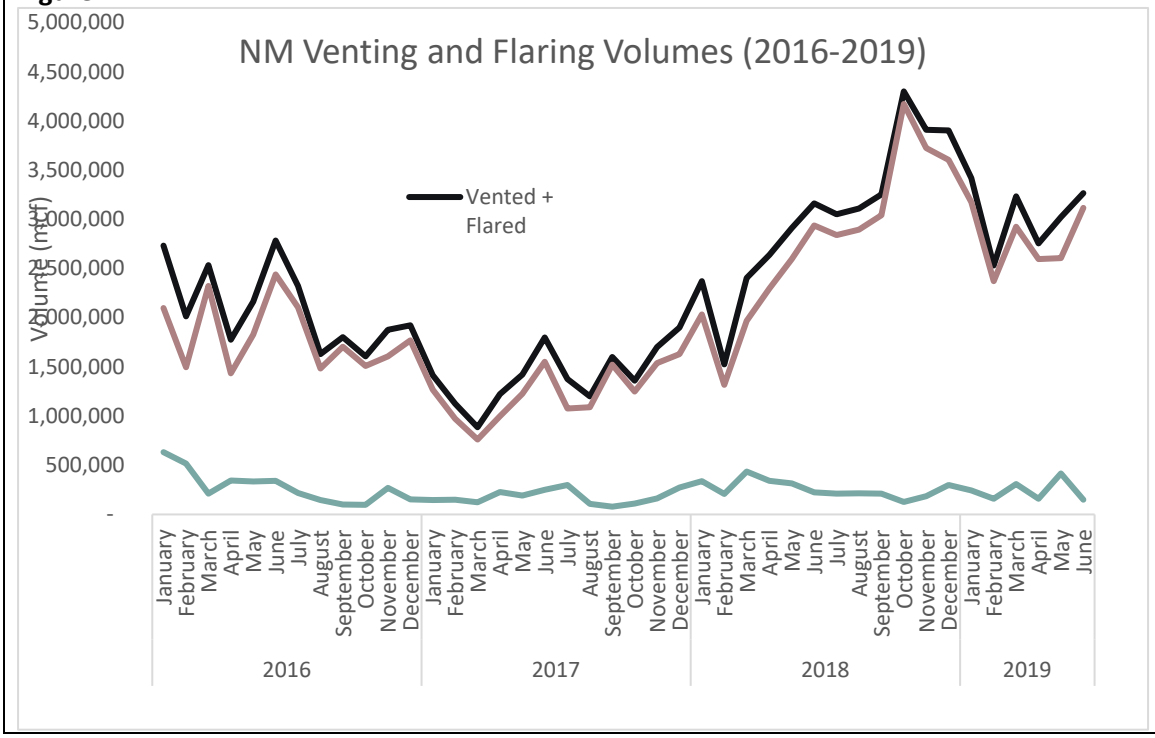
As shown in Table 1 and Figure 1 below, reported venting and flaring increased significantly since 2016 (even with a small decline in the first half of 2019). Reported venting has declined significantly since early 2016, which indicates that operators have reduced the practice of simply venting gas. However, the increase in reported flaring has more

than made up for the decreased venting; as gas production from oil wells has increased, development has outpaced infrastructure to handle the increased gas production. However, in New Mexico, capacity constraints may not be the main or only cause of flaring (see section on "Describe how the equipment or process is used").

Table 1*	Total Reported Volume (mcf)		
	Vented	Flared	Vented + Flared
2019 Q2	724,641	8,319,266	9,043,907
2019 Q1	711,939	8,472,053	9,183,992
2018 Q4	613,390	11,499,805	12,113,195
2018 Q3	638,211	8,775,299	9,413,510
2018 Q2	880,210	7,828,529	8,708,739
2018 Q1	983,923	5,317,869	6,301,792
2017 Q4	544,849	4,418,534	4,963,383
2017 Q3	486,144	3,689,663	4,175,807
2017 Q2	669,194	3,774,982	4,444,176
2017 Q1	423,251	3,002,997	3,426,248
2016 Q4	521,433	4,886,637	5,408,070
2016 Q3	466,377	5,290,614	5,756,991
2016 Q2	1,020,546	5,702,331	6,722,877
2016 Q1	1,361,619	5,919,156	7,280,775

*Data derived from C-115 reports.

Figure 1*



*Data derived from C-115 reports.

As shown in Table 2, the average rate of reported venting and flaring for the past four years is over 4% (as a percent of gas production at oil wells[74]). While the data shows some monthly and quarterly fluctuations, the overall story is clear -- venting and flaring rates are high, and the situation is not improving.

Table 2*	% of oil well gas production		
	Vented	Flared	Vented + Flared
2019 Q2	0.3%	3.6%	3.9%
2019 Q1	0.3%	4.1%	4.5%
2018 Q4	0.3%	5.9%	6.2%
2018 Q3	0.4%	4.9%	5.2%
2018 Q2	0.5%	4.6%	5.1%
2018 Q1	0.6%	3.5%	4.2%
2017 Q4	0.4%	3.0%	3.4%
2017 Q3	0.4%	2.7%	3.0%
2017 Q2	0.5%	2.8%	3.3%
2017 Q1	0.3%	2.3%	2.6%
2016 Q4	0.4%	3.8%	4.2%
2016 Q3	0.4%	4.0%	4.3%
2016 Q2	0.8%	4.3%	5.1%
2016 Q1	1.1%	4.9%	6.0%

*Data derived from C-115 reports.

Table 3 shows Operators vary widely in the amount of production they report as vented or flared as shown in Tables 3 and 4, with several major producers significantly increasing the amount of gas flared and vented so far in 2019.[75]

Top 10 Flaring Companies (January - June) *			
Anonymized Company	**2018**	**2019**	**Percent Change '18-'19**
1	2,207,775	2,250,606	2%
2	494,948	1,541,514	211%
3	1,302,579	1,470,907	13%
4	685,554	1,418,580	107%
5	816,429	1,401,131	72%

[74] Note: We calculate these rates as a percent of reported gas production at oil wells because the significant majority of the venting and flaring problem occurs at these oil wells and the discussion in this MAP report focuses on the associated gas problem. While there is a small amount of flaring occurring at gas wells, we assume that this is mainly driven by upsets and emergency situations rather than routine well operation. There is also non-trivial venting from gas wells, from activities such as liquids unloading and maintenance operations. This produces methane emissions, but is addressed in other MAP reports.

[75] Note: Company names have been removed and replaced with a number.

6	516,427	1,289,238	150%
7	300,128	1,064,029	255%
8	1,915,770	1,042,110	-46%
9	1,156,207	999,721	-14%
10	297,487	912,654	207%

*Data derived from C-115 reports.

Top 10 Venting Companies (January - June)*			
Anonymized Company	**2018**	**2019**	**Percent Change '18-'19**
42	806,124	621,981	-23%
10	791,003	166,101	-79%
46	26,367	132,888	404%
4	6,191	121,443	1862%
47	None reported	110,758	X
2	135,473	109,856	-19%
18	None reported	73,000	X
3	1,353	21,855	1515%
48	31,317	21,788	-30%
49	None reported	18,794	X

*Data derived from C-115 reports.

Note that as a generality, about half of the lifetime well production of associated gas occurs in the first two years of production, which has important implications for the timing of flaring reduction measures.[76] Gas-to-oil ratios and production decline vary greatly by well and basin.

Given the lack of consistency and standardization of reporting vented and flared volumes, it is difficult to make conclusions with the existing C-115 dataset. Industry supports a more detailed reporting program to establish consistency across the state.

What are the data gaps in quantifying emissions/waste for this equipment?

When reporting of flared volumes (F code) was rolled out, the only guidance given to operators was "The new code "F" is to be used to report the volume of gas that is flared on a well basis, or total volume if flared at a common battery or gathering system and reported under one point of disposition." There was no formal standard or protocol that detailed what types of flaring to report or how to measure or estimate flared volumes.

Also, C-115s are a requirement for operators of oil and gas wells. Midstream flaring is either permitted or reported to NMED.

[76] Carbon Limits, Improving utilization of associated gas in US tight oil fields, 8 (April 2015) (https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=2ahUKEwiEw6T9j_vkAhVyU98KHWW5DSkQFjABegQIABAC&url=http%3A%2F%2Fwww.catf.us%2Fresources%2Fpublications%2Ffiles%2FFlaring_Report.pdf&usg=AOvVaw3ishdgM_o2N8haqov8YIBf). Carbon Limits, a consultant to Clean Air Task Force, is headquartered in Oslo, Norway.

The quality of the data from C-115 reports is not robust, for several reasons. First, incomplete or inaccurate reporting results in incomplete data, which biases the emissions/waste estimates downwards. We do not know the extent of such reporting noncompliance, but in the past, it has been substantial, and there is no basis to conclude that the problem has been fully corrected.[77]

Second, there is a lack of guidance to operators from OCD on how to categorize the various losses of gas. Consequently, it is highly likely that there are inconsistencies across operators regarding whether all disposed gas is actually reported, and which disposition codes are used for which sources of gas. For example, it appears likely that most operators include as "vented" only the intentional direct venting of associated gas, but this excludes gas vented at temporarily unlit flares and the portion of gas that is emitted unburned from operating flares. It is also unclear whether all operators include in the flared or vented volumes gas that is flared or vented, for example, during completions or well-testing. It is also unclear, for example, whether operators are including in their C-115 reports flaring volumes that they reported on their C-129s (requests for approval to flare) or C-141s (release notification and corrective action), or whether operators are including in their C-115s only volumes that they have not otherwise reported.

Third, this data may depend to some extent on estimates of flared and vented volumes. For example, some operators may calculate flared/vented volume based on periodic GOR tests and ongoing measurement of quantities of oil production, not direct metering, as described above.

Fourth, according to OCD, it has had little capacity to audit or verify reported quantities, and operators do not generally use third party audits to spot check the accuracy of their venting and flaring reporting. As a result, there is little external incentive for operators to prioritize complete and accurate reporting of venting and flaring volumes.

Finally, it is worth noting that C-115s do not include data on venting and flaring that occurs during midstream operations. It is not clear what data is available on those volumes, although it may be possible to derive data on this from NMED permits, excess emissions reporting, and/or the GHGRP.

The likelihood that C-115 data captures only a subset of overall venting and flaring from oil and gas activities is reinforced by NOAA satellite flaring data for recent years, which indicates that that OCD flaring data is too low.[78]

NOAA Quantification of Flaring from NM

[77] For example, in a Notice to Operators in 2017, OCD "determined that not all Operators are following the requirement to report flared and vented volumes. Out of 603 well Operators active in the state, only 51 Operators are reporting volumes using the "V" and "F" code. It is very important that all Operators in New Mexico report flared and vented volumes since part of the evaluation will help determine any policy or requirements setting goals for reduction of flared gas. We urge all companies to work with their operations and production accounting groups to ensure proper production reporting." Notice to Oil and Gas Operators, Vented & Flared Volumes Reporting Communication, March 8, 2017. Available at http://www.emnrd.state.nm.us/OCD/documents/20173-8NoticetoOperators.pdf

[78] https://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html; see also Elvidge et al Methods for Global Survey of Natural Gas Flaring from Visible Infrared Imaging Radiometer Suite Data, *Energies* **2016**, *9*(1), 14; https://doi.org/10.3390/en9010014.

Year	Bcf gas flared
2012	14.4
2013	24.3
2014	31.3
2015	41.2
2016	30.5
2017	22.4
2018	41.5

These NOAA estimates are derived from radiance measurements in the SWIR part of the spectrum (nonvisible light, falling roughly between 1400 and 3000 nanometers) measured by the VIIRS instrument (whiskbroom scanning radiometer that collects imagery and radiometric measurements) at night. There are several steps that are required to derive flaring emission estimates from radiance measurements from VIIRS:

1. First, a determination as to which bright pixels are flares or fires – this requires a certain set of assumptions that introduce uncertainty;
2. Once a determination of whether a bright pixel is a flare, flaring duration must be assessed. VIIRS provides data for one second of a day unless a cloud is blocking the bright pixel. Based upon that one second, a determination as to whether the observed flare is persistent or intermittent must be made. The easiest assumption is persistence, but may not always be valid and could lead to overestimates of flared gas.
3. The next step requires a conversion of flare radiance to an emission rate. This conversion is performed by a logarithmic fit between measured radiance-derived Fire Radiative Power and reported flared gas volumes from the Cedigaz database. Such a calibration neglects very real variability in flare combustion efficiency as well as variability in gas composition (gas heating values). Also, the Cedigaz database includes both flaring and venting, however, this study assumed venting was negligible in the Cedigaz numbers.

In summary the emissions estimates presented here are only as good as the aforementioned assumptions used to derive them. In the table below, it is important to note that there is no uncertainty of ranges included. Without a secondary verification through correlating direct measurement at these bright pixelated locations, it is impossible to determine the accuracy of these emissions estimates. Emissions estimates such as these may be more useful in understanding year-to-year trends in flared gas volume, rather than the absolute amount of gas flared.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

Equipment costs for flares vary greatly and must be determined on a case-by-case basis.

What are the annualized operating costs for the equipment or costs associated with the process?

Equipment costs for flares vary greatly and must be determined on a case-by-case basis.

If the equipment or process is powered, what are the costs?

N/A

What are the maintenance and repair costs for existing or new equipment?

Maintenance costs for flares vary greatly and must be determined on a case-by-case basis.

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

Engineering advancements of flare tip designs to improve combustion efficiency. Also, Gas Capture Plans ensure operators are working with gatherers/processors to develop solutions to get the gas to market for sales rather than flare. Operators are proactively working with midstream solution providers, internal and 3rd party, to construct and commission facilities and pipelines in advance of drilling. Leases and other oil and gas agreements often require operators to drill in given time frames, although these terms may be subject modification by regulations. When possible, operators are shifting drilling and production schedules to minimize the number of stranded wells and the need to flare gas due to a lack of take away pipelines or downstream facilities.

Operators are designing multiple well pads which provide additional time to install the required pipelines and facilities and reduce the number of stranded wells. Operators will occasionally shut in production to mitigate a flaring event. However, shutting in production results in the loss of royalties paid to all interest holders, including the public if the New Mexico State Land Office or Federal Bureau of Land Management receive revenue from that particular lease and may result in formation damage which could impact total recovered hydrocarbons.

Companies also utilize several technological advancements to increase the destruction and removal efficiency of flares and identify beneficial uses in oil and gas operations.

It is important to note that the best solution to flaring is always having a sales pipeline.

With respect to temporary shut in of production, royalties should be considered deferred, not lost, as the production from the well is delayed, not ended.

New Wells:

Existing Wells:

How have the emission/waste reductions been measured?

Emissions from a flare rely heavily upon flow to the flare which can be estimated or measured. Estimation in this instance involves the use of known well or reservoir information such as periodic well tests or a well's gas to oil ratio to estimate a well's gas production rate. For example, if a production flow test is conducted monthly on a well, the resulting rate could provide a reliable basis to calculate the well's gas production for the entire month. Similarly, if a well has a gas to oil ratio that is uniform over time, the operator could estimate the rate of gas production based on the measured rate of oil production and the gas to oil ratio. Gas volume estimation using these protocols is suitable for reporting flared gas volumes in many cases.

There are also various technologies for measuring flow to the flare. Measurement options are primarily limited to volumes sent to the high pressure flare. In these operating circumstances there is enough volume and energy in the

process stream to measure the flowrate. However, in low pressure conditions, such as storage tank vent headers, emissions/flare volumes are typically calculated from process conditions using EPA guidance due to technical feasibility issues with measurement of these low flow, low energy flows.

High pressure flare volumes fluctuate widely: from small volumes under normal conditions to full gas stream under upset or emergency conditions, even changing repeatedly throughout the day depending on sales line capacity. Any meter for a high pressure flare must accurately accommodate this broad production range.

Conversely, to improve accuracy at low volumes, a smaller orifice size is required but such a restriction in the flare piping introduces intolerable safety concerns when flow increases. Furthermore, an orifice meter will restrict the line to the flare such that when large volumes are flared for emergency purposes, it will result in an explosion. Other meter options such as ultrasonic or thermal mass can be more costly, and depending on technology, can be very sensitive to operating and ambient conditions at low flow conditions, e.g. thermal mass meter.

North Dakota Petroleum Council Summary			
Common Meter Types	**Accuracy**	**Limitations**	**Cost**
Differential Pressure (Orifice)	Poor	Adds pressure drop (safety), poor for high variability, calibration challenge	Low - High
Thermal Mass	Poor	Gas composition, moisture	Medium
Ultrasonic	<10%	Low velocity, moisture	High

API Manual of Petroleum Measurement Standards (MPMS) Chapter 14, Section 10, Measurement of Flow to Flares addresses measurement of flow to flares and includes:

- application considerations,
- selection criteria and other considerations for flare meters and related
- instrumentation,
- installation considerations,
- limitations of flare measurement technologies,
- calibration,
- operation,
- uncertainty and propagation of error, and
- calculations.

Technology	Sensitivity to Entrained Mist or Liquid	Sensitivity to Fouling	Ability to Detect Fouling
Differential Pressure	Low to Moderate (varies with liquid load)	Moderate	Physical Inspection
Thermal Flow	High	High	Physical Inspection
Optical	Moderate	High	Meter Diagnostics
Ultrasonic	Low (unless sensor is immersed in liquid, then very high)	High	Meter Diagnostics
Vortex	Low (if meter is installed in horizontal line and bluff body is horizontal)	Low to High (varies with meter design)	Physical Inspection

Waste reductions are measured as the change in the measured volumes and percentages of produced gas that are vented or flared per well/lease/operator/state over time.

How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

VOLUNTARY

Some oil and gas companies have committed to voluntary initiatives to reduce flaring. Companies also utilize several technological advancements to increase the destruction and removal efficiency of flares and identify beneficial uses in oil and gas operations. (See "Existing Reduction Strategy" section above).

FEDERAL - BLM

43 CFR Subpart 3179 Waste Prevention and Resource Conservation includes requirements and determinations of waste for oil well flaring.

- §3179.4(a) & (b) outline what is considered avoidable (royalty bearing) and unavoidable (non-royalty bearing) lost production.
- §3179.6(b). The operator must flare, rather than vent, any gas that is not captured, except under certain circumstances.
- §3179.101 – 104 outlines "Authorized Flaring and Venting of Gas." "Authorized" is described as being unavoidable royalty-free gas.
    - §3179.101 Initial production testing
    - §3179.102 Subsequent well tests
    - §3179.103 Emergencies
    - §3179.104 Downhole well maintenance and liquids unloading
- §3179.201(a) Oil-well gas
    - Except as provided in §§ 3179.101,3179.102, 3179.103, and 3179.104, vented or flared oil-well gas is royalty free if it is vented or flared pursuant to applicable rules, regulations, or orders of the appropriate State regulatory agency or tribe. Applicable State or tribal rules, regulations, or orders are appropriate if they place limitations on the venting and flaring of oil-well gas, including through general or qualified prohibitions, volume or time limitations, capture percentage requirements, or trading mechanisms.

BLM

Prior to 2016, BLM addressed venting and flaring of associated gas under NTL-4A, which prohibited operators from venting or flaring oil well gas unless approved in advance by BLM. Approval could be granted if justified by "(1) an evaluation report supported by engineering, geologic, and economic data which demonstrates to the satisfaction of [BLM] that the expenditures necessary to market or beneficially use such gas are not economically justified and that conservation of the gas, if required, would lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered if the venting or flaring were permitted to continue or (2) an action plan that will eliminate venting or flaring of the gas within 1 year from the date of application."[79] NTL-4A further provided that "[w]hen evaluating the feasibility of requiring conservation of the gas, the total leasehold production, including both oil and gas, as well as the economics of a field wide plan shall be considered by [BLM] in determining whether the lease can be operated successfully if it is required that the gas be conserved."[80] Thus, the text of NTL-4A required an assessment of whether the operator could still successfully operate the entire leasehold, including the profits from both oil and gas production, while conserving gas (not merely a showing that it would cost the operator more to conserve the gas than to capture it, as has at times been asserted).

[79] NTL-4A, 3-4.

[80] NTL-4A, 4.

In practice, however, BLM appears to have accepted more minimal showings as a basis for routinely approving requests to allow venting and flaring.

Concerned about growing volumes of waste of gas, particularly from venting and flaring of associated gas, and with reforms urged by oversight entities such as the Government Accountability Office (GAO) and the IG Inspector General, BLM undertook a multi-year rulemaking to replace NTL-4A with far more effective requirements to control the waste of natural gas.[81] The final Methane and Waste Prevention Rule, issued in November 2016, established new controls on venting and flaring of associated gas.[82] With respect to venting and flaring, the rule: (1) required operators to file Waste Minimization Plans as a condition of receiving approval of an Application for Permit to Drill (43 CFR 3162.3-1); (2) prohibited flaring or venting of gas well gas, except where the gas was "unavoidably lost" as defined in the regulations (43 CFR 3179.6(a)); (3) required operators to flare rather than vent any gas that is not captured, except under specific circumstances detailed in the regulations (43 CFR 3179.6(b)); and (4) established gas capture requirements to ensure that operators must, over time, capture rather than flare an increasing volume of their gas (43 CFR 3179.7).

Specifically, the percentage of gas that operators were required to capture (which includes beneficial on-lease use) ratcheted up from 85% beginning in 2018, to 90% in 2020, to 95% in 2023, to 98% in 2026. These percentages applied to the "adjusted total volume of gas produced" by an operator each month. This "adjusted total volume of gas produced" was the operator's total volume of gas captured, plus the total volume of gas flared from high pressure flares from development oil wells, minus an allowable amount of flaring per well, all calculated on a monthly basis. The allowable amount of flaring per well ratcheted down over time (as the percentage capture requirement ratcheted up) from 3,600 Mcf/well beginning in 2019, to 1,800 Mcf/well in 2020, to 1,500 Mcf/well in 2021, to 1,200 Mcf/well in 2022, to 900 Mcf/well in 2024, to 750 Mcf/well from 2025 on.[83] Operators had the option of complying on a lease-by-lease, county-by-county, or state-wide basis, which gave operators the maximum flexibility to average capture volumes across all of an operator's wells within each state.

Note that because the BLM rule applied to then-current conditions across multiple states, it was calibrated to assure feasibility even in the most extreme venting and flaring circumstances, which were then (and still are) occurring in North Dakota. Absent those circumstances, BLM's flaring data analysis underlying the rule would likely have supported lower limits. The percentage and volume limitations considered appropriate for a national rule promulgated in 2016 would not necessarily be directly applicable for a single state-specific rule promulgated in 2020. The BLM 2016 percent gas capture rule dataset was limited to federal minerals and relied upon the broad application of uneconomic temporary capture technologies and unrealistic market assumptions. These percent capture provisions were stayed by a federal district court on April 4, 2018, therefore, were never observed for effectiveness in any real-world field-wide practice.

[81] See, e.g., GAO, Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas Which Would Increase Royalty Payments and Reduce Greenhouse Gases, GAO-11-34, 24 (Oct. 2010) (https://www.gao.gov/products/GAO-11-34). CITE GAO, IG reports.

[82] BLM, Waste Prevention, Production Subject to Royalties, and Resource Conservation; Final Rule, 81 Fed Reg. 83008 (Nov. 18, 2016) (https://www.federalregister.gov/documents/2016/11/18/2016-27637/waste-prevention-production-subject-to-royalties-and-resource-conservation).

[83] BLM selected these values based on its analysis of flaring rates of gas from oil wells in 15,530 records from data of the Office of Natural Resources Revenues, representing monthly flared volumes on a lease or unit basis from over 2,000 unique leases or units over a yearlong period from October 1, 2013 to September 30, 2014, as well as BLM data on the number of wells per lease. BLM Proposed Rule at 6639.

The rule also established measurement and reporting requirements for all volumes of gas vented or flared (43 CFR 3179.9).

In 2018, BLM largely rescinded the 2016 rule, although the constraints on venting remain in place (43 CFR 3179.6).[84] The 2018 rule provides that venting or flaring oil-well gas does not require approval from BLM and is royalty free, "if it is vented or flared pursuant to applicable rules, regulations, or orders of the appropriate State regulatory agency or tribe." (43 CFR 3179.201)

NEW MEXICO

Current NMOCD regulation:

The current regulatory framework in New Mexico requires approval from the NMOCD if an operator needs to flare beyond the first 60 days after completion (NMAC 19.15.18.12.A & B).

- 19.15.18.12.A. NMAC An operator shall not flare or vent casinghead gas produced from a well after 60 days following the well's completion.
- 19.15.18.12.B. NMAC An operator seeking an exception to Subsection A of 19.15.18.12 NMAC shall file an application for an exception on form C-129 with the appropriate division district office. The district supervisor may grant an exception when the flaring or venting casinghead gas appears reasonably necessary to protect correlative rights, prevent waste or prevent undue hardships on the applicant. The district supervisor shall either grant the exception within 10 days after the application's receipt or refer it to the director who shall advertise the matter for public hearing if the applicant desires a hearing.

In addition, current NMOCD regulation authorizes flaring and requires volumes to be reported on C-115 (NMAC 19.15.18.12.F.)

- 19.15.18.12.F. NMAC Pending connection of a well to a gas-gathering facility, or when a well has been excepted from the provisions of Subsection A of 19.15.18.12 NMAC, the operator shall burn all gas produced and not used, and report the estimated volume on form C-115.

From a midstream perspective, NMOCD requires notification of prolonged mechanical difficulties or plant shut downs (NMAC 19.15.18.12.E.)

- 19.15.18.12.E. NMAC In the event of a more prolonged mechanical difficulty or in the event of plant shut-downs or curtailment because of scheduled or non-scheduled maintenance or testing operations or other reasons, or in the event a plant is unable to accept, process and market all of the casinghead gas produced by wells connected to its system, the plant operator shall notify the division as soon as possible of the full details of the shut-down or curtailment, following which the division shall take such action as is necessary to reduce the total flow of gas to the plant.

Current NMAC 19.15.7.24. Operators Monthly Report (Form C-115) requires complete information and data indicated, which includes Non-transported volumes (disposition codes F-flared and V-vented), on the forms to be submitted. Also, NMOCD has authority to cancel the operator's authority to transport from or inject into all wells it operates for failure to file an acceptable and complete form C-115 (19.15.7.24.C. NMAC).

- 19.15.7.24.A. NMAC An operator shall file a form C-115 for each non-plugged well completion for which the division has approved a form C-104 and for each secondary or other enhanced recovery project or pressure maintenance project injection well or other injection well within the state, setting forth complete information and data indicated on the forms in the order, format and style the director prescribes. The operator shall

[84] BLM, Waste Prevention, Production Subject to Royalties, and Resource Conservation; Rescission or Revision of Certain Requirements; Final Rule, 83 Fed Reg. 83008 (Sept. 28, 2018) (https://www.federalregister.gov/documents/2018/09/28/2018-20689/waste-prevention-production-subject-to-royalties-and-resource-conservation-rescission-or-revision-of).

estimate oil production from wells producing into common storage as accurately as possible on the basis of periodic tests.

- 19.15.7.24.C. NMAC If an operator fails to file a form C-115 that the division accepts, the division shall, within 30 days of the appropriate filing date, notify the operator by electronic mail or letter of its intent to cancel the operator's authorization to transport or inject if the operator does not file an acceptable and complete form C-115. The notice shall inform the operator of the right to request a hearing pursuant to 19.15.4.8 NMAC. If the operator does not either file an acceptable and complete form C-115 or request a hearing on the proposed cancellation within 60 days of the original due date of the form C-115, the division may cancel the operator's authority to transport from or inject into all wells it operates.

The current Gas Capture Plan was made part of the application process through "Notice to Operators" issued on April 8, 2016, with an effective date of May 1, 2016.

- Per the Notice to Operators - The Gas Capture Plan outlines actions to be taken by the Operator to reduce well/production facility flaring and venting for new completion (new drill, recomplete to new zone, re-frac) activity. The requirement applies to Federal, State, Fee, & Tribal Wells.
- A Gas Capture Plan purpose is to ensure operators are working with gatherers/processors to provide a way to get the gas to market for sales rather than flare.

Current NMED regulations:
Emissions from venting and flaring is authorized by NMED:

- 20.2.72.200. Permits must be obtained from the department by: (1) Any person constructing a stationary source which has the potential emission rate greater than 10 pounds per hour or 25 tons per year of any regulated air contaminant for which there is a National or New Mexico Ambient Air Quality Standard.
- Combustion emissions resulting from routine flaring is authorized through one or more air permits.
  - The GCP-Temporary Control Major and Minor permits authorize the flaring or combustion of stranded gas for a period not to exceed 12 consecutive months.
  - The GCP-Oil & Gas may also be used to authorize routine process flaring.
  - The GCP-6 permit authorizes flares and other methods to reduce emissions from oil and gas storage tanks.
  - Per 20.2.70, an NSR/Title V Operating Permit is required for stationary sources that have actual or potential emissions equal to or greater than 100 tons per year of any regulated air pollutant.
- The flaring emissions to be authorized will be dependent on specific facility configuration, operating conditions, gas composition, and volume of gas sent to the flare.
- Per 20.2.7, flaring in excess of an authorization is required to be reported to NMED as an excess emission event.

<u>New Mexico</u>
The applicable NM law defines "surface waste" to include "the unnecessary or excessive surface loss of destruction without beneficial use . . . of natural gas of any type or in any form . . . including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage or fire, especially such loss or destruction incident or resulting from the manner of spacing, equipping, operating or producing, well or wells, or incident to or resulting from . . . the production of . . . natural gas in excess of the reasonable market demand."[85] The NM regulations clearly prohibit "the production or handling" of gas "in a manner, under conditions or in an amount as to constitute or result

[85] New Mexico Statutes Annotated, section 70-2-3 B.

in waste."[86] The regulations further provide that operators "shall conduct their operations in or related to the drilling, equipping, operating, producing . . . of oil, gas . . . wells or other facilities . . . in a manner that prevents waste of oil and gas . . . " and bar operators from "wastefully utiliz[ing] oil or gas or allowing either to leak or escape" from reservoirs, wells and other operating equipment.[87]

In general, the New Mexico Oil and Gas Act requires the New Mexico Oil Conservation Commission (NMOCC) and New Mexico Oil Conservation Division (NMOCD) to prohibit production and oil and gas handling practices which constitute or result in waste. NMSA 1978, § 70-2-2. The concept of "waste" has been statutorily defined by the New Mexico Legislature to include both underground waste and surface waste. NMSA 1978, § 70-2-3. Underground waste can consist of any practice that reduces or tends to reduce the total quantity of crude oil or natural gas ultimately recovered from a reservoir, e.g. shutting in a well; whereas surface waste consists of unnecessary or excessive surface loss or destruction of oil or gas, without beneficial use. Thus, NMOCC and NMOCD are required by statute to encourage the optimum recovery of oil and gas resources. The federal government and other oil and gas producing states similarly prohibit the creation of waste. *See e.g.,* 30 U.S.C. § 187; 30 U.S.C. § 225; WYO. STAT. ANN. § 30-5-101.

For the purpose of limiting venting and flaring, "waste" has historically been defined by the federal government and other oil and gas producing jurisdictions as a "preventable loss of [oil or gas] the value of which exceeds the cost of avoidance." Stephen L. McDonald, Petroleum Conservation in the United States, and Economic Analysis, Johns Hopkins Press, 1971 (Reprinted in 2011 by Resources for the Future) ("Petroleum Conservation Economics"), at 129. NMOCD regulations have likewise allowed flaring in situations where "the flaring or venting casinghead gas appears reasonably necessary to protect correlative rights, prevent waste or prevent undue hardships" on the operator. 19.15.18.12.B NMAC. Indeed, flare may provide environmental benefits in certain situations. The New Mexico Environment Department (NMED) has approved flaring in a variety of situations, and the federal government requires specifically requires flaring in certain situations. *See* NMED, Air Quality Bureau General Construction Permits; 43 C.F.R. § 3179.6(b).

The current NM regulations on casinghead gas also generally bar flaring or venting of casinghead gas, beginning 60 days after the well's completion.[88] In addition to the exemption for the first 60 days of production, these provisions allow for an exception wherever flaring or venting "appears reasonably necessary" to "prevent undue hardships on the applicant."[89] If the application for an exception is not granted in 10 days, it must be referred to the director, who must hold a hearing the matter if the applicant wishes.[90] In effect, this means that to maintain the general prohibition on flaring, the director would have to hold a hearing on and make the decision to reject each individual flaring application. This is simply untenable from an agency workload perspective, and it is no surprise that OCD routinely grants most or almost all flaring exception applications.

Thus, current OCD regulations have not been effective in limiting venting and flaring of associated gas.

WYOMING

Wyoming Oil and Gas Conservation Commission rules (055-3 WYO. CODE R. § 39) impose restrictions on venting and flaring. The Wyoming rules authorize venting and flaring under the following circumstances: (1) emergencies, (2) well purging and evaluation tests, and (3) production tests (for 15 days, unless a longer period is authorized). In addition, the rules authorize the flaring of up to 60 Mcf of gas per day from individual oil wells. (Associated gas may be vented where the rate does not exceed 20 Mcf per day.) An operator may also apply for authorization to flare in other circumstances. An operator's application for authorization to flare must include, among other information, a gas

[86] NMAC 19.15.2.8.
[87] *Id.*
[88] NMAC 19.15.18.12.
[89] *Id.*
[90] *Id.*

capture plan identifying gas gathering and transportation facilities in the area, the name of gas gatherers providing "gas take-away capacity," and information on the gas gathering line to which the operator proposes to connect.

COLORADO

Colorado Oil and Gas Conservation Commission regulations restrict the venting or flaring of natural gas. 2 COLO. CODE REGS. § 404-1-912. Under those regulations, "[t]he unnecessary or excessive venting or flaring of natural gas from a well is prohibited." An operator must obtain prior approval from the Commission for venting or flaring, "[e]xcept for gas flared or vented during an upset condition, well maintenance, well stimulation flowback, purging operations, or a productivity test." Gas flared, vented, or used on the lease must be estimated using a gas-to-oil ratio test or other approved method and reported on a monthly basis.

NORTH DAKOTA

North Dakota's statutory restrictions on the flaring of associated gas are found in North Dakota Century Code section 38-08-06.4.

- Under this statute, operators are allowed to flare associated gas for a period of one year from the date of first production of the well. After that period, the well must be: (1) capped, (2) connected to a gathering line, (3) equipped with an electrical generator that consumes 75% the gas, (4) equipped with an approved process that reduces the volume or intensity of the flare by 60%, or (5) equipped with a system that captures 75% of the gas for consumption by means of use as fuel, transport to processing, production of chemicals/fertilizer, or separating and collecting over 50% of the propane and heavier hydrocarbons. Operators who violate section 38-08-06.4 must pay royalties and taxes on the flared gas.
- An operator may obtain an exemption from section 38-08-06.4 from the North Dakota Industrial Commission by showing "that connection of the well to a natural gas gathering line is economically infeasible at the time of the application or in the foreseeable future or that a market for the gas is not available and that equipping the well with an electrical generator to produce electricity from gas or employing a collection system . . . is economically infeasible."

The North Dakota Industrial Commission has established a special policy for wells in the Bakken, Bakken/Three Forks, and Three Forks Pools. See NDIC Order 24665.

- In those fields, wells are allowed to produce at the maximum efficient rate for the first 90 days, after which the wells may continue to produce at the maximum efficient rate only if the well or operator meets or exceeds Commission approved gas capture goals. (This restriction does not apply to (1) the first horizontal well completed in a non-overlapping spacing unit, or (2) wells that have received an exemption from North Dakota Century Code section 38-08-06.4.) The NDIC has established the following gas capture goals:

  74% October 1, 2014 through December 31, 2014
  77% January 1, 2015 through March 31, 2016
  80% April 1, 2016 through October 31, 2016
  85% November 1, 2016 through October 31, 2018
  88% November 1, 2018 through October 31, 2020
  91 % beginning November 1, 2020

North Dakota Industrial Commission Order 24665 Policy/Guidance Version 102215 (Oct. 22, 2015).

- North Dakota requires that Applications for a Permit to Drill (APD) be accompanied by a Gas Capture Plan containing the following: (1) affidavit indicating coordination with a mid-stream company, (2) a detailed gas gathering pipeline system location map, (3) information on the gathering line to which the operator proposes to connect, (4) the anticipated date of first production and the anticipated production rates, (5) the amount of gas the applicant is flaring, and (6) explanation of alternatives to flaring.

North Dakota

In response to very high flaring rates of associated gas, the North Dakota Industrial Commission adopted in July 2014, Order 24665 to limit flaring.[91] The Commission supplemented this order with guidance and several letters to operators, which the Commission has modified over time. As supplemented, the order provides that operators in the Bakken/Three Forks areas must capture 74% of gas by Oct. 1, 2014; 77% by Jan. 1, 2015; 80% by April 1, 2016; 85% by Nov. 1, 2016; 88% by Nov. 1, 2018, and 91% by Oct. 1, 2020, with potential for 95% capture as attainable.[92]

The guidance requires:
--gas capture plans for increased density and spacing cased and a sworn affidavit that the operator has provided gas production forecast data to midstream gas gathering companies;
--gas capture plans "for all applications for a permit to drill filed by an operator who has failed to meet gas capture goals in any of the most recent three months;"
--meeting the gas capture goals on a monthly basis, statewide, by county, by field, or by well for each operator.[93]

In calculating compliance with the capture goals, operators were initially allowed to remove: the initial 14 days of flowback; flaring due to a force majeure event on the gas gathering system; and the flared remainder after application of a "value-added" process (such as stripping out the NGLs) that reduces flare volume or intensity by over 60%.[94]

If an operator fails to meet the gas capture goals, the guidance states that "well(s) will be restricted to 200 barrels of oil per day if at least 60%" of the gas is captured, or 100 barrels per day otherwise.[95] In practice, however, production restrictions have been applied to very small quantities of production for limited time frames. In part this is because the guidance allows operators to exempt substantial quantities of flared gas from their compliance calculations, and in part this is because even when operators are not in compliance, the Commission appears to have applied production restrictions only rarely.[96]

Initially, it appeared that the new requirements were having some effect – the percentage of produced gas that was flared fell from roughly a third in 2013 to a low of slightly less than 10% in one month in 2015. Since then, however, the percentage of produced gas flared has risen again, rather than continuing to improve, and it has been falling further short of the percentage capture goals.[97] Analysis conducted by Clean Air Task Force on production and flaring in 2017 showed that a number of operators producing oil and gas from the Bakken/Three Forks formations consistently failed to meet the Commission's Gas Capture standard (even considering the provisions allowing operators to exclude certain flared gas volumes when calculating their gas capture percentage), yet they did not suffer any sanction from NDIC.[98] Note that no information is publicly available on why NDIC chose not to sanction operators that fail to meet the Gas Capture standard or on related matters such as declared force majeure events.

[91] Industrial Commission of the State of North Dakota, Order No. 24665 (July 1, 2014);
[92] Industrial Commission of the State of North Dakota, Order No. 24665 (July 1, 2014); North Dakota Industrial Commission Order 24665 Policy/Guidance Version 102215 (Sept. 2015); see also, Reuters, North Dakota postpones deadline for natural gas flaring rules (Sept. 24, 2015) (https://www.reuters.com/article/us-north-dakota-flaring-idUSKCN0RO2KX20150924).
[93] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018 (Nov. 20, 2018).
[94] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 102215 (Sept. 2015).
[95] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018 (Nov. 20, 2018).
[96] See Bismarck Tribune, Oil industry missed October's flaring target, revised numbers show (Jan. 19, 2018) (reporting that in October 2017, 11 companies exceeded the 15% flaring limit, but none were ordered to limit oil production because they met one of the conditions in the policy).
[97] See North Dakota Department of Mineral Resources, Oil & Gas Update (Oct. 25, 2018) (https://www.dmr.nd.gov/oilgas/policies.asp, link to Gas Capture Background Sheet).
[98] See Citizen Groups Commenter's 2018 Comments on BLM's "Waste Prevention, Production Subject to Royalties, and Resource Conservation: Rescission or Revision of Certain Requirements," page 68-75. Available at: https://www.catf.us/wp-content/uploads/2018/09/CATF_Filing_BLMOilsGasDrilling_CitizenGroupComments.pdf.

Given the virtual absence of sanctions for exceedances, it is not surprising that ND's approach has failed to solve the problem.

At the same time, the Commission has softened the requirements, making companies substantially less likely to be in violation, even as the problem has worsened. The current applicable goal is for operators to capture 88% of produced gas. In March 2019, however, operators flared about 20% of the produced gas, and at that time, operators had exceeded the target for the past 13 months in a row.[99]

For the first four years, the guidance stated that the policy goals were to reduce the flaring volume, duration, and number of wells.[100] In November 2018, however, the Commission changed the goals to "increase the volume of captured gas and reduce the percentage of flared gas," and to "incentivize investment in gas capture infrastructure," dropping the goals of reducing the volume and duration of flaring.[101] In addition, in April 2018 and November 2018, the Commission substantially expanded the quantities of flared gas that operators could remove from their compliance calculations.[102] In addition to the exemptions detailed above, operators may now remove: 60 days of flaring during initial production (versus 14 days); flaring where "gas gathering and processing capacity curtailment" is documented; flaring from existing wells bumped off the gathering system by new wells; and flaring under the following documented circumstances:
--landowner, tribal or federal right-of-way delays;
--midstream down-time for upgrades/maintenance;
--federal regulatory restrictions/delays
--safety issues;
--delayed access to electrical power; or
--possible reservoir damage.[103]
Also, outside of the "Bakken core area" or in a previously undrilled township, an operator may apply to designate gas from up to 6 horizontal wells as "stranded gas," which allows the operator to exclude the first year of production from those wells from compliance calculations and bars curtailment of those wells. It is difficult to conceive of situations in which an operator could not plausibly assert that one or more of the broad range exemptions apply.

UTAH
Utah's regulatory restrictions on the flaring of associated gas are found in section R649-3-20 of the Utah Administrative Code. That regulation allows for up to 1,800 Mcf of associated gas to be flared from an individual well on a monthly basis without approval. The regulation also allows for necessary flaring during production tests and for the "unavoidable or short-term" venting or flaring of gas without approval. "Unavoidable or short-term" venting or flaring includes (1) venting from storage tanks (unless the division determines that the recovery of such gas is warranted), and (2) venting or flaring during line failures, equipment failures, blowouts, or other emergencies if shutting in the well would cause waste or an adverse impact on the reservoir. Venting or flaring is allowed during well purging or evaluation tests for a period not to exceed 24 hours or a maximum of 144 hours in a month. If an operator wishes to vent or flare associated gas in circumstances not expressly provided for in the regulation (e.g., where the operator finds conservation of the gas to be not economically viable), then the operator may request approval for such venting or flaring from the state regulatory agency.

[99] Associated Press, North Dakota oil producers are wasting billions of cubic feet of natural gas (May 27, 2019) (https://www.apnews.com/9855f0f8c6f146dbb1ebcc92cca3617a).
[100] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 102215 (Sept. 2015).
[101] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018 (Nov. 20, 2018).
[102] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 041718 (Apr. 17, 2018); North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018 (Nov. 20, 2018).
[103] North Dakota Industrial Commission Order 24665 Policy/Guidance Version 112018 (Nov. 20, 2018).

CALIFORNIA

The California Public Resources Code prohibits the "unreasonable waste of natural gas." CAL. PUB. RES. CODE § 3300. The "blowing, release or escape of gas into the air" is considered prima facie evidence of "unreasonable waste." Upon complaint or petition to the state regulatory agency showing probable cause that the unreasonable waste of gas is occurring or is threatened, the state regulatory agency will order a public hearing to determine whether such waste is in fact occurring or threatened. *Id.* §§ 3302, 3306. If the waste of gas is found to be unreasonable, the state regulatory agency will issue an order directing the waste to be discontinued or curtailed. *Id.* § 3308.

Even in the absence of the hearing process described above, the director of the state regulatory agency may institute an action to enjoin the unreasonable waste of gas when he or she determines that such waste is occurring. *Id.* § 3312.

MONTANA

Montana regulations limit the flaring of associated gas from a well to 100 Mcf per day (after a 60-day well test period). MONT. ADMIN. R. 36.22.1220. However, if the operator finds it necessary to flare more than 100 Mcf a day, it may seek approval for such additional flaring from the state regulatory agency. In order to obtain approval, the operator must submit an application "justifying" the need to flare more than 100 Mcf per day. The regulations identify certain information that must be included in the application (e.g., estimated gas reserves, proximity of the well to market, reinjection potential) and also ask for "any other information pertinent to a determination of whether marketing or not marketing or otherwise conserving the associated gas is economically feasible."

Montana regulations require gas to be flared rather than vented when the volume of gas exceeds 20 Mcf per day for a period in excess of 72 hours. MONT. ADMIN. R. 36.22.1221. An operator may apply for a variance from this requirement. The application for a variance must include information on the potential for human exposure, the relative isolation of the location, restriction of access to the location, low gas volume, and low BTU content.

TEXAS

The Railroad Commission of Texas – the state regulatory agency for oil and gas production in Texas – regulates the venting and flaring of gas pursuant to "Statewide Rule 32" (16 TEX. ADMIN. CODE § 3.32).

In general, Rule 32 requires operators to flare (rather than vent) all gas releases greater than 24 hours in duration. Released gas must be measured (or estimated) and reported to the Commission. Leaks and gas releases associated with storage tanks, well drilling, well completions, and blowdowns are exempted from the requirements of Rule 32. 16 TEX. ADMIN. CODE § 3.32(d). However, Rule 32 provides that the commission may require such releases to be flared for safety reasons.

Rule 32 authorizes the release of gas under the following circumstances: (1) gas may be flared for up to 10 producing days following initial completion, recompletion, or workover; (2) gas may be vented during unloading/clean-up for a period not to exceed 24 hours in a single event or 72 hours in one month; (3) gas may be released for up to 24 hours in the event of a full or partial shutdown of a gas gathering system, compression facility, or gas plant servicing the well (the operator may request an extension of the 24-hour period); and, (4) low pressure separator gas may be released up to 15 Mcf/day/well or 50 Mcf/day/lease. 16 TEX. ADMIN. CODE § 3.32(f)(1).

The Commission may authorize additional venting or flaring when the operator makes a showing of the "necessity of the release." 16 TEX. ADMIN. CODE § 3.32(f)(2). Situations where additional venting or flaring is a "necessity" include: (1) cleaning of well solids or fluids; (2) unloading excess formation fluid buildup; releases of low-pressure gas that cannot be captured due to "mechanical, physical, or economic impracticality"; and (3) (for casinghead gas only) the unavailability of a gas pipeline or other marketing facility.

ALASKA

Alaska regulations place significant restrictions on venting and flaring. 20 ALASKA ADMIN. CODE § 25.235. Under those regulations, gas that is vented or flared constitutes waste, except that: (1) flaring or venting for up to one hour as the result of an emergency or operational upset is authorized for safety purposes; (2) flaring or venting for up to one hour as the result of a planned lease operation is authorized for safety purposes; (3) flaring pilot or purge gas to

test or fuel the safety flare system is authorized for safety, and (4) de minimis venting of gas incidental to normal oil field operations is authorized.

Alaska

In response to high rates of flaring, Alaska adopted regulations in the 1970s that largely prohibit venting or flaring. All flaring or venting is waste except:

(1) flaring or venting for no more than 1 hour needed for safety due to either "an emergency or operational upset," or "a planned lease operation;"
(2) "flaring pilot or purge gas to test or fuel the safety flare system;"
(3) "de minimis venting . . . incidental to normal oil field operations;" and
(4) flaring or venting with approval from the commission for well testing before regular production.

The commission may also authorize flaring or venting for a period of more than 1 hour based on a report describing why the gas was flared or vented, the beginning and ending time, the volume, and actions taken to minimize the volume, if the flaring or venting is:

(1) "necessary for facility operations, repairs, upgrades or testing procedures; "
(2) required by "an emergency that threatens life or property," unless failure to operate in a safe and skillful manner causes the emergency; or
(3) "necessary to prevent loss of ultimate recovery."

In addition, operators are required to act "in accordance with good oil field engineering practices and conservation purposes to minimize the volume of gas released, burned, or permitted to escape in the air."

According to the Alaska Oil and Gas Conservation Commission, the effect of the prohibition on venting and flaring has been widespread reinjection of associated gas for conservation and oil recovery, and Alaska estimates that roughly 0.4 percent of gas production is flared.[104]

It should be noted that the vast majority of gas produced on the north slope of Alaska is stranded because there is no pipeline to take the gas to market, and north slope production exceeds local demand for power generation and petroleum industry needs. Nevertheless, Alaska has effectively banned routing flaring as a means to dispose of gas. Most north slope gas is re-injected (and therefore has some value for maintaining reservoir pressure).

OKLAHOMA

Oklahoma regulations allow an operator to vent or flare up to 50 Mcf/day without a permit where it is not economically feasible to market the gas. OKLA. ADMIN. CODE § 165:10-3-15(b). Operators are allowed to "blow down" a well for up to 72 hours, and operators may vent or flare during initial flowback following completion or recompletion for a 14-day period (which may be extended by up to 30 days) if it is not economically feasible to market the gas. OKLA. ADMIN. CODE § 165:10-3-15(a), (d), (e).

An operator may apply for a permit to vent or flare in excess of 50 Mcf/day where "it is not economically feasible to capture the gas." OKLA. ADMIN. CODE § 165:10-3-15(c). The operator's application for the permit to flare must list the maximum daily volume of gas to be vented or flared.

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

It is important to note that the best solution to flaring is always having a sales pipeline. However, as an industry we continue to investigate new techniques and technologies that reduce flaring. An example is the onsite generation of

[104] BLM, Waste Prevention Rule; proposed rule at 6633 (citing telephone communication with Alaska Oil and Gas Conservation Commission, April 30, 2015); see also, Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference,1640, 1642 (Aug. 25-27, 2014).

power production using produced hydrocarbon vapors as fuel. NM electric power provider's willingness to accept distributed generation from oil and gas sites with stranded gas or limited takeaway capacity could allow the gas to be utilized to support the electrical demands of the state, thus offsetting flaring. Distributed generation could allow for on-site equipment to utilize electricity reducing demand on diesel generators or the grid and supplement the grid with power generated in excess of site demand.

Some operators have pilot programs planned to inject gas for Enhanced Oil Recovery projects. Re-injecting the gas versus putting in the pipeline, could help alleviate some of the pipeline capacity constraints.

Planning the location and timing of the development of new/recompleted wells based on the projected or confirmed present and future availability of takeaway capacity allows operators of such wells to largely avoid routine flaring of associated gas. In making decisions about where to develop the next new wells or set of wells, or in making decisions on whether and when to pursue and sign agreements with midstream companies, the degree to which operators explicitly weigh takeaway capacity availability is unclear. If, however, operators were to optimize their development planning and processes around maximizing capture of associated gas, along with return on capital etc., it appears highly likely that operators would be very successful in increasing gas capture.

For existing wells, operators can add compression to counter the effect of higher pressure new wells pushing lower pressure older wells off the gathering system. While, as noted below, there are limits to the overall pressures and throughputs allowed on gathering systems, adding compression to boost the pressure of gas from lower pressure wells is a reasonable low cost strategy that operators already use at times and might use more frequently if flaring were not an extremely low cost alternative.

Operators providing information on planned development and expected volumes and timing to midstream operators can facilitate midstream investment aligned with future production and minimize any time lag between increased volumes of associated gas production and expansion of takeaway capacity.

When wells are first completed, the pressure into the gas sales line may exceed the gas sales pressure of neighboring well locations. It is not possible to create a system to manipulate well pressures to ensure that all leases connected to a given gas pipeline have access to it. Also, because leases may consist of federal and non-federal leases, where the lateral section of the horizontal well may pass through and drain more than one mineral estate, all royalty owners in that lateral would have an interest in the production. Therefore, it would be an inaccurate assumption that a gas system can be pressure balanced in the form of curtailment of production as a means of preventing loss associated with lack of access to pipeline capacity. Also, the MAOP of gathering lines limits the amount of compression that can be introduced to ensure gas is being produced into the gathering system.

Entering into contractual arrangements with midstream operators that guarantee access to the gathering system and processing facilities would provide far greater certainty regarding available takeaway capacity for both new and existing wells. Alternatively, or in addition, larger operators could directly invest in additional takeaway capacity.

Operators can coordinate with midstream companies regarding planned maintenance and arrange for reduced production or temporary alternative on-site capture technologies, such as CNG trucking, during those periods.

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
		In use or in development		Low Medium High
University of North Dakota's Energy & Environmental Research Center provides a database containing vendor-supplied technical and economic information regarding gas utilization technologies	Database Link Report Link	Varies	Varies	Varies
Department of Energy's funded work with Houston Advanced Research Center is evaluating technologies that address flaring. An update of HARC's 2015 white paper, *'Recommendations to Address Flaring Issues, Solutions and Technologies'* will be published in Fall, 2019.	Link			
Auto igniters for new flares	Link	In use	Feasible	Low
Auto Igniters (including requirements to retrofit older existing flares)	Link	In use in some flare designs, but not all	Feasible for some flare designs, but not all	Medium to high
NGL recovery		In use – e.g., in ND	Scaleable; effective; best for rich gas; reduces only a portion of the associated gas. Well pads designed for hydraulic fracturing equipment will have additional available space when that equipment is removed. Residue gas contains methane, ethane and small amounts of propane; too "rich" for natural gas vehicles. Equipment footprint and spacing requirements often	Low to negative High

			present challenges, especially after interim reclamation Increases product storage and truck traffic at production site.	
Compressed natural gas (CNG) transported to processing plant or other input point on gathering system by truck.		In use Operating at 5 or more well sites in 2015.	Scalable; works for all gas compositions; best for wells within 20-25 miles of gathering system/processing plant access; can address all of the associated gas. CNG marketed for vehicle engines is challenged as infrastructure is lacking and fuel standards require high-purity methane. CNG viability vs. diesel is dependent upon CNG transportation costs.	Low to negative High
Gas to power generation for on-site use		In use	saleable; effective; best with lean gas; can pair with NGL recovery; uses only a portion of the associated gas. Reliability of generation system is critical to ensuring power for production equipment. On well by well basis cannot capture all gas to generate power.	Low to negative High
Gas to power generation for grid		In use	Requires multiple wells for viable scale and location near grid Low price for power makes economics of grid-interconnect challenging at the wellsite. NM electric power provider's	Low to negative High

			willingness to accept distributed generation is not widespread.	
Reinjection of associated gas for EOR		In use At least 5 producers in TX;[105] long-term use in Alaska	Long-established technology for conventional wells. Requires available depleted oil fields or other reservoirs, capital investment, compressors, possibly additional flow lines; effectiveness depends on particular formation.[106]	Low to negative Profitable where effective in boosting oil recovery (e.g., potential for "significant" additional recovery; "30-70% gain in oil output from older wells")[107]
Reinjection of associated gas for storage		Long-term use in AK	Long-established technology. Requires available depleted oil fields or other reservoirs, capital investment, compressors. If reinjected into a different reservoir (salt cavern, aquifer) would require new well.	??
Reinjection solutions that have been presented to NMOCD. These may require development of appropriate permitting procedures.				

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

It is important to note that the best solution to flaring is always having a sales pipeline. Industry proactively employs science, innovation, technology, and collaboration to prevent waste and reduce environmental impacts. Some oil and

[105] Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019).

[106] Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference, 1640, 1645 (Aug. 25-27, 2014); Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019).

[107] Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference, 1640 (Aug. 25-27, 2014); Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019); Carbon Limits, Improving utilization of associated gas in US tight oil fields, Appendix 2, 10 (April 2015).

gas companies have committed to voluntary initiatives to reduce flaring without regulatory requirements. Companies also utilize some of these technology alternatives in the EERC and HARC databases to increase the destruction and removal efficiency of flares and identify beneficial or lease uses of gas in oil and gas operations.

There are a number of technologies in use today that can assist companies with gathering associated gas that might otherwise be flared in the absence of adequate infrastructure. These technologies utilize mobile conditioning and processing equipment to produce a marketable product transportable by truck:

- Natural Gas Liquids (NGL) Skids – liquids (e.g. C3+) are extracted from the gas phase (typically through mechanical refrigeration or JT (Joule-Thompson) effect) and hauled by truck off location, leaving a leaner residue gas phase on site; liquids are delivered to a plant or pipeline for sales.
- Compressed Natural Gas (CNG) – gas is compressed to reduce shipping volume and transported in special trailers where it can be delivered to a plant or used for power generation for production operations or hydraulic fracturing or other gas use.
- Liquefied Natural Gas (LNG) – lean gas is cooled to approximately -260°F to convert to a liquid state so it can be transported in special trailers to a gas plant for sales or to a remote location for power generation or other gas use; the liquid will be re-gasified at these destinations.

Another example is the onsite generation of power production using produced hydrocarbon vapors as fuel mentioned above. See section above for more details.

Auto igniters can also assist in maintaining the pilot. This technology replaces the intermittently or continuously burning flare pilots with electrical sparking pilots similar to a modern gas stove. These sparking pilots require low electrical power that can be supplied from a battery with solar recharge in remote sites. In addition to using electronic flare ignition devices for pilots, facilities may also install sensors to detect the pilot flame and shut off fuel gas if the pilot is extinguished.

What are the pros and cons of the alternatives?

Each technology alternative has its own pros and cons. Featured below are the pros and cons of two specific alternatives.

Natural Gas Liquids Skids

It is only possible to install temporary capture equipment (such as a natural gas liquids (NGL) extraction skid) on locations that are large enough to accommodate the NGL skid, ancillary equipment, and tanks and still meet spacing and safety requirements.

NGL Skids will not operate at very low flows (there is a minimum turndown rate), meaning that these units cannot reasonably be used to process the sometimes small flare volumes occurring when sales lines are at maximum capacity. Gas production may quickly decline to rates much lower than the temporary capture equipment's minimum turndown rate necessary for operation. When the production rate declines, the unit must be moved to a new location, which incurs relocation costs and requires an active drilling program to provide new pads with adequate volumes to justify equipment deployment and operation based on sufficient gas production. Otherwise the equipment would need to be on standby, and operators would be required to pay significant costs to guarantee immediate deployment when the equipment is necessary.

Furthermore, as referenced in the North Dakota's Energy and Environment Research Center study, it has been shown that NGL operations in the Bakken have poor runtime under some operational scenarios.
https://undeerc.org/flaring_solutions/pdf/CW_Tech_Study_April-2013.pdf

Due to high temporary capture equipment cost, economics may be poor, especially during periods of low gas and NGL commodity pricing. Third party companies offering turnkey temporary capture solutions often charge high premiums to cover capital and operating costs that will not be offset by liquids revenue in today's market. Furthermore, pairing two or more technologies such as NGL and CNG for liquids recovery and sales of the gas may compound the economic infeasibility of temporary capture technology. This is a case-by-case assessment for individual operators.

Liquid recovery equipment, including compression and refrigeration hardware for NGL, CNG, or LNG, is not designed to operate as an interruptible service. When employed as a backup to a primary gas gathering pipeline, all inlet gas supply to the temporary capture equipment is interruptible. The equipment will not function properly with an interruptible gas supply and will shut down when the gas supply is interrupted. Most liquid recovery equipment requires an operator onsite to manually restart the equipment following a shutdown of the gas supply, meaning that widespread usage of liquid recovery units as a backup to the primary gas gathering pipeline would require an unreasonable number of operators, which is another factor potentially impacting economics.

In addition to requiring a constant gas supply, liquid recovery equipment also requires a consistent rate of gas supply. Due to fluctuating sales capacity on the gathering pipelines, the gas stream to the liquid recovery equipment is highly variable and would not allow for proper equipment function when temporary capture equipment is used for capturing any excess gas not sold via permanent gas gathering lines. Liquid recovery equipment relies on trucking to remove liquids offsite, which can be unreliable during wintertime. In addition, trucking is an expensive mode of transportation, particularly relative to low liquids prices.

NGL, CNG, or LNG produced would still need to find an end market to absorb the product. For example, NGLs will still have to be fractionated. Gas plants are not normally designed to handle large and frequent truck volumes of NGLs. CNG and LNG will have to find a use or available reinjection point (which then requires further equipment).

Onsite Electrical Power Generation

Onsite electrical power generation, in excess of that required onsite, can only be used where there is acceptance by electrical power providers of electrical power generated by burning hydrocarbon vapors on-site at production facilities. The power produced would help alleviate electrical power supply constraints in areas where crude oil and natural gas production activities place the highest demands on the grid.

NM electric power provider's willingness to accept distributed generation from oil and gas sites with stranded gas or limited takeaway capacity could allow the gas to be utilized to support the electrical demands of the state, thus offsetting flaring. Distributed generation could allow for on-site equipment to utilize electricity, reducing demand on diesel generators or the grid and supplement the grid with power generated in excess of site demand.

<u>Reinjection and on-site capture technologies</u>

Reinjecting associated gas for storage and/or EOR avoids the waste of such gas, except for the small portion that may be released during production using EOR, and EOR can significantly boost oil production.[108] Reinjection for EOR has long been used in conventional oil production, and is currently being used by at least five producers of tight oil in Texas.[109] It requires availability of appropriate oil reservoirs or other reservoirs. Operators would have to incur the capital costs of developing an injection well (or adapting older wells to be used as injection wells), as well as operating costs of

[108] Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference,1640 (Aug. 25-27, 2014); Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019).

[109] Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019).

compressors.[110] For EOR, some make up gas and additional flow lines might also be needed at single well sites.[111] The effectiveness for EOR depends upon the particular formation targeted to enhance oil production.[112] Reinjection for EOR could be profitable where effective in boosting oil recovery. One study found the potential for "significant" additional recovery, a payback period of 7 years, and a 17% rate of return at $55/barrel oil.[113] Recent use in the Eagle Ford has shown a "30-70% gain in oil output from older wells," and that it "can potentially extend crude production volumes in older wells by 18 to 24 months."[114]

Operators can also use alternative on-site capture technologies to beneficially use the gas on-site or reduce the flared volumes. Proven technologies already in use include:
--NGL recovery, which reduces the volume/intensity of the flare, while recovering higher value product for sale;[115]
--Compressed natural gas (CNG) trucking;[116] and
--Gas to power generation, at a local or grid level.[117]
These technologies would not replace traditional gas gathering, but give operators flexibility in finding ways to utilize gas from a pad. For example, if build-out of a gathering system is delayed, these portable approaches could be used to utilize gas in the gap period.

NGL recovery is portable, scalable and low or negative cost. It works best with rich gas. It is only a partial solution, as it eliminates only a portion of the flare (from 5% to 21% depending on the type of NGL system and whether it is a single or multiple wells), but it also works well in combination with other alternative technologies, such as power generation for local load, because the remaining gas is more suitable for engines and compressors. NGL recovery can use a simpler or more complex system. A simpler system is smaller and requires less capital, but also eliminates less of the flaring volume.[118] If allowed, the use of NGL recovery on wells selling gas into gathering systems could also increase the throughput of the gathering system by reducing liquids drop-out in gathering pipelines.

With respect to potential space constraints noted above, the well sites at issue are designed to accommodate fracking equipment at the time of completion/recompletion, which means additional space is available on most sites. However, safety setbacks do impact space constraints for the various equipment types. It is unclear how many sites would be precluded from deploying this option due to space constraints.

With respect to concerns noted above regarding decline rates, NGL skids are designed to be mobile and moved from site-to-site to address that reality, and many or most operators in the Permian do have "active drilling programs," which means that equipment could be moved to new sites if the operator continues to need to reduce flaring volumes.

[110] Carbon Limits, Improving utilization of associated gas in US tight oil fields, Appendix 2, 10 (April 2015) https://www.carbonlimits.no/project/improving-utilization-of-associated-gas-in-us-tight-oil-fields/
[111] Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference,1645 (Aug. 25-27, 2014);
[112] Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference, 1645 (Aug. 25-27, 2014); Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019).
[113] Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference, 1640 (Aug. 25-27, 2014);
[114] Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019);
[115] Carbon Limits, Improving utilization of associated gas in US tight oil fields, 27 (April 2015).
[116] Carbon Limits, Improving utilization of associated gas in US tight oil fields, 33 (April 2015).
[117] Carbon Limits, Improving utilization of associated gas in US tight oil fields, 36 (April 2015).
[118] Carbon Limits, Improving utilization of associated gas in US tight oil fields, 27 (April 2015).

Note that cost of transport can create a significant discount to benchmark prices and negatively impact an already uneconomic technology.[119]

Note that the study cited as support for the previous sentence concludes: "NGL removal will not single-handedly reduce the number of flares, but it will reduce the overall quantity of flared gas and will create a viable secondary revenue stream for wells for which gathering pipelines have not yet been installed. In fact, several companies are now pursuing this business opportunity within the Bakken region."[120]

CNG trucking is portable, scalable and low or negative cost. It works with all gas compositions, and is most feasible at wells that are within 20-25 miles of a processing plant or other point that the gas can be put into the gathering system. It can reduce the flared volume by 91% to 98%, depending on the composition of the gas and whether it is deployed for a single or multiple wells.[121] This option would be most effective not as an intermittent backup for temporary upsets in the gathering system, but rather as a longer term (but not long-term) alternative if a planned capacity increase is delayed for a period.

Gas to power generation for on-site loads is portable, scalable and low or negative cost, with significant cost savings from substitution for diesel. It works best with lean gas, and thus can be coupled with NGL recovery. It can reduce the flare volume by an estimated 18% to 22%, depending on the electricity load of the site, and can use either a reciprocating engine or gas turbine.[122] Generation for use on-site can also support other methane emission reduction efforts such as using electric power rather than pneumatic power to run equipment such as pumps and controllers. In addition, generation for local use might potentially help provide electricity used in gathering systems as well.

Gas to power generation for the grid is low or negative cost (due to electricity generation revenues) where deployable, but requires a larger quantity of gas from multiple wells and proximity to the grid.[123]

Additional alternatives that are less well-proven but have potential include: ammonia production; mini gas-to-liquids – methanol; mini gas-to-liquids – Fischer Tropsch; and mini-liquefied natural gas.[124]

Better development planning, communication with midstream companies, and focus on optimizing the timing of new production with the availability of takeaway capacity offers the potential for substantial reductions in flaring, at potentially low or negative costs. To the extent that this is implemented through better communication with midstream operators and realignment of how the operator prioritizes the next project for development, it could require managerial resources. Where aligning new production with takeaway capacity availability may involve some delays and/or additional investment in gathering systems, there is potential cost to operators. Similarly, entering into contractual arrangements to ensure access to the gathering system would impose some costs. Some of these costs would be recouped by selling rather than flaring the gas.

As discussed above, all of the technological alternatives discussed in detail here use proven technologies that are in use or have been used by some operators. Some technological alternatives work best for rich or lean gas, while others work with all gas compositions. All of the alternatives discussed above (except power generation for the grid) can be deployed at single well sites or scaled up to multiple well sites. Analyses indicate that each of these alternatives have low to negative costs. Some, such as NGL recovery or local power generation are only partial

[119] https://undeerc.org/flaring_solutions/pdf/CW_Tech_Study_April-2013.pdf

[120] EERC, End Use Technology Study – An Assessment of Alternative Uses for Associated Gas, 90-91 (April 2013) (https://undeerc.org/flaring_solutions/pdf/CW_Tech_Study_April-2013.pdf).

[121] Carbon Limits, Improving utilization of associated gas in US tight oil fields, 33 (April 2015).

[122] Carbon Limits, Improving utilization of associated gas in US tight oil fields, 36 (April 2015).

[123] Carbon Limits, Improving utilization of associated gas in US tight oil fields, Appendix 1, 7 (April 2015).

[124] Carbon Limits, Improving utilization of associated gas in US tight oil fields at 11-12 (April 2015).

solutions, but if low cost, that would still be worthwhile, and they would be more effective in combination. Some alternatives are relatively technologically straightforward, such as NGL recovery, CNG trucking, and power generation, while the effectiveness of gas reinjection for EOR in tight oil formations appears to depend upon the specific formation in which it is used and may well improve with additional testing and refinement.

Below is a summary of the 2015 market prices assumed in the Carbon Limits report as compared to current market prices:

	Carbon Limits[125]	U.S. Energy Information Administration
Natural Gas	$4.00/MMBtu	$1.44/MMBtu[126] - Southwest
Natural Gas Liquids	$13/MMBtu	$4.62/MMBtu[127] - July 2019

What is needed and available for new wells?

See Table

What is needed and available for existing wells?

See Table

What technology alternatives exist for this equipment or process itself?

See Table

What are the pros and cons of the alternatives?

See Table

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

As of August 2019, the EERC's Flaring Solutions database contained 33 companies with technologies in the following categories. Approximately 50% of these companies have had units deployed at some point in time.

- NGL recovery
- Power production
- CNG or LNG production
- Gas conversion to chemicals or fuels

Below is a summary of the EERC NGL Liquid Recovery Economics for the Bakken from August 2019. The Key Challenge: Low NGL and ethane value, and large distance from Bakken formation to market (transportation cost)

	August 2019
Total gas treated[1]	1000 mcfd

[125] Carbon Limits, Improving utilization of associated gas in US tight oil fields at 57 (April 2015).
[126] https://www.eia.gov/todayinenergy/prices.php
[127] https://www.eia.gov/dnav/ng/hist/ngm_epg0_plc_nus_dmmbtum.htm

NGL Recovery[2]	3 gal/mcf
NGL Value[3] (net back)	<$0.20/gal
Annual costs[4] (lease, mobilization, royalty)	$569,520
Annual NGL Revenue[5]	$196,800
Net Profit[6] (Loss)	($372,720)

Assumptions:
[1] Larger systems have few locations where 100% capacity is achievable. Smaller systems suffer from economy of scale.
[2] Higher recovery efficiency typically results in higher ethane content and value deduction.
[3] NGL over supply and cost of transport can create a significant discount to benchmark prices.
[4] Annual costs ranging from $0.75-2.00/mcfd capacity ($22,500/mo. - $60,000/mo); three mobilizations/yr at $60k each; and royalty of 15% on NGLs sold.
[5] Annual NGL revenue assumes 90% capacity factor
[6] NGL recovery systems provide challenged economics under the best conditions.
https://undeerc.org/flaring_solutions/pdf/CW_Tech_Study_April-2013.pdf

Note that the scenario presented above (recovery of 3000 gallons of NGL per day for a year, with an annual cost of $373,000, rather than combusting those NGLs if left in the gas sent to the flare) would prevent significant amounts of pollution. Assuming a density of NGLs of ~0.6 (relative to water) and that the NGL is 83% carbon by weight (based on the elemental ratio of butane), flaring 3000 gallons of NGLs a day for one year would emit 7,500 tons of carbon dioxide, assuming perfect combustion. (To the degree combustion is not perfect, the flare is emitting other pollutants aside from CO_2.)

As discussed above, more and better coordination with midstream companies and engaging in development planning to better align the location and timing of new associated gas production with available takeaway capacity are approaches to reducing venting and flaring that operators can use at negative cost. If operators delay production at wells where, for example, projected takeaway capacity has not yet become available, that will impose costs, with the magnitude depending on multiple economic factors regarding the financing of the well, as well as the length of delay. If, however, as a technical matter, operators can deploy other alternative technologies such as NGL recovery, CNG trucking, gas to power generation, or reinjection at a lower cost than the cost imposed by delaying production, those alternative costs, rather than the cost of delay, should be considered the applicable cost of ensuring capture in such situations.

As noted above, for reinjection for EOR, one study found the potential for "significant" additional recovery, a payback period of 7 years, and a 17% rate of return at $55/barrel oil.[128] Recent use in the Eagle Ford has shown a "30-70% gain in oil output from older wells," and that it "can potentially extend crude production volumes in older wells by 18 to 24 months."[129]

Carbon Limits' report on alternatives to flaring for tight oil formations[130] provides extensive cost information for CNG trucking, NGL removal, and on-site electrical generation, where the cost of the measure depends upon many factors such as the amount of gas available at the site, composition of the gas, location and configuration of the sites, etc.

[128] Hoffman et al., The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs, Unconventional Resources Technology Conference, 1640 (Aug. 25-27, 2014);
[129] Energywire, Texas' gas glut is so bad, drillers pump it down wells (June 10, 2019);
[130] http://www.catf.us/wp-content/uploads/2015/04/CATF_Pub_PuttingOuttheFire.pdf

Using data from the Carbon Limits study, MJ Bradley and Associates (MJB&A) calculated the costs of the flaring rule that BLM proposed in early 2016. They concluded that CNG trucking would be an appropriate way for operators to comply with the rule, and calculated that costs of the rule assuming that all capture of gas (relative to current flaring levels at BLM leases) would occur via CNG trucking. This is a conservative assumption, since many operators will get pipelines hooked up to wells under a gas capture standard, and pipeline transport will be more efficient than CNG trucking in many cases. MJB&A also used conservative (high) cost assumptions for CNG trucking. They found that the standards, as BLM proposed them, would have low or negative cost for operators (maximum *nationwide* cost to operators of the BLM gas capture requirement would have been $1.5 million, according to MJB&A). However, we note that MJB&A was using a discounted projection of Henry Hub prices for gas, which are higher than current Waha hub prices. Finally, MJB&A found that when avoided damages from climate pollution were included (i.e., using the social cost of CO_2, the flaring standard BLM proposed would have an overall benefit to society of about $100 million per year.

When BLM finalized the 2016 flaring standard, the agency modeled the costs and benefits of the finalized standard (which was slightly modified from the proposed standard that MJB&A analyzed).[131] BLM's analysis assumed that the predominant response by operators to the flaring standard would be CNG trucking (but unlike MJB&A's analysis, BLM did not assume that 100% of operator response would be CNG trucking). BLM also used costs from the Carbon Limits report for the CNG trucking portion of operator response. Depending on discount rate, and neglecting the societal benefit from reduced pollution, BLM estimated that over a ten year period, the rule would have had a low benefit to operators if CNG trucking costs are low, and would have had a net nationwide cost to operators of ~$250 million over ten years if CNG trucking costs are high.

What would be the implementation cost?
For new wells?
See Technology Alternatives Above

For existing wells?
See Technology Alternatives Above

Are there low-cost solutions available?
See Technology Alternatives Above

If a solution is high-cost, why is that the case?
See Technology Alternatives Above

Are there additional technical analyses needed to refine benefits/costs estimates?

[131] See pages 45-50 of BLM's Regulatory Impact Analysis for 2016 Final Venting and Flaring Rule (available here: https://www.regulations.gov/document?D=BLM-2016-0001-9127).

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

It should be noted that the various technologies are engineered solutions and are site specific with respect to current facility design, economics and technical feasibility.

See Technology Alternatives Above

See discussion of better planning and alternative technologies above, as well as the discussion of the pros and cons of alternatives.

What is the useful life of equipment?

See Technology Alternatives Above

What are the maintenance and repair requirements for equipment required for methane reduction?

See Technology Alternatives Above

How would emissions be detected, reductions verified and reported?

Avoided venting and flaring would reduce reported venting and flaring volumes. There would not be a need to separately report the volumes avoided by specific activities.

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

When reporting of flared volumes (F code) was rolled out, the only guidance given to operators was “The new code “F” is to be used to report the volume of gas that is flared on a well basis, or total volume if flared at a common battery or gathering system and reported under one point of disposition.” There was no formal standard or protocol that detailed what types of flaring to report or how to measure or estimate flared volumes.

Also, C-115s are a requirement for operators of oil and gas wells. Midstream flaring is either permitted or reported to NMED.

Because the aforementioned technology alternatives may not be cost effective in all instances, regulatory incentives should be considered to assist in promoting their use. For example, North Dakota recognizes the following as surplus gas being utilized in a beneficial manner that may be considered as captured gas:

- Equipping the well(s) with an electrical generator that consumes surplus gas
- Equipping the well(s) with a system that intakes the surplus gas and natural gas liquids volume from the well for beneficial consumption by means of compression to liquid for use as fuel, transport to a processing facility, production of petrochemicals or fertilizer, conversion to liquid fuels, separating and collecting the propane and heavier hydrocarbons.
- Equipping the well(s) with other value-added processes as approved by the Director which reduce the volume or intensity of the flare by more than 60%.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

The oil and natural gas industry (industry) and royalty interest owners, including the State of New Mexico have an aligned and vested interest in capturing the natural gas produced. The industry has invested billions of dollars, and continues to invest in infrastructure to capture the gas, gather it from thousands of well sites, and transport it through pipelines to sales. When gas cannot be gathered and transported to market for sales, industry has made further substantial investments in flare and combustion devices and gas capture technology to minimize its impact to the environment.

Since some of the flaring is temporary, if there are air permitting requirements for some of these alternative technologies (NGL Skids, etc.), the timing for NMED air permitting approval may not accommodate timely placement of the equipment.

NM contains approximately 27 million acres of Federal Land. The Bureau of Land Management (BLM) manages all permitting of ROWs on federal land. The NEPA process is triggered when a federal agency develops and/or is presented with a proposal for a federal action (e.g., ROW application). There are different levels and scope of a NEPA Review: Environmental Impact Statement (EIS) is the most rigorous; Environmental Assessment (EA) is the most common, and Categorical Exclusions (CEs). The level of NEPA review required will determine the timeframe for approval, which can vary greatly. Consequently, the timing of ROW approval hinders the construction of infrastructure that is needed to reduce flaring.

NMSLO is proposing a rule for cultural properties on trust land which includes an element of landscape planning at the same time it has implemented a policy related to species surveys.

While the NM statute and regulations prohibit waste of gas, as discussed above, the current regulations allow for almost unlimited exceptions and have failed to adequately control venting and flaring.

In addition, the current regulations do not clearly require operators to flare in lieu of venting in all situations in which flaring is possible (exceptions should be limited to situations such as emergencies, where quantities are too small to route to a flare, or where flaring is prohibited (such as due to wildfire risk)). 19.15.18.12.F. NMAC states that "Pending connection of a well to a gas-gathering facility, or when a well has been excepted from the provisions of Subsection A of 19.15.18.12 NMAC, the operator shall burn all gas produced and not used, and report the estimated volume on form C-115." Additionally, BLM's 2018 rule in §3179.6(b). "The operator must flare, rather than vent, any gas that is not captured, except under certain circumstances."

The current regulations require operators to submit a gas capture plan, but the form provided has failed to generate meaningful or effective plans.[132] It requires a simple statement that the gas will be connected to a gas transporter (who is supposed to be identified) and that the operator believes the system can take the gas, but there is nothing that would require an operator to make a real inquiry or analysis of whether the system is expected to have available capacity at the time the well is to come on line, much less provide any such assurance. There is also a section titled "Alternatives to Reduce Flaring" which lists "alternatives considered from a conceptual standpoint to reduce the amount of gas flared." The form itself lists the alternatives *along with reasons to reject them* (e.g., for NGL Removal the form states "Plants are expensive, residue gas is still flared, and uneconomical to operate when gas volume declines"). Since the operator has to provide no information for that section and the form itself rejects the alternatives, it appears highly unlikely that the requirement to file a Gas Capture Plan has incentivized any operator to consider, let alone seriously evaluate the feasibility and economic implications of, implementing any of the listed alternatives.

Reducing venting and flaring reduces resource waste and air pollution, and where the gas is captured, increases the production of gas resources and the resulting revenues without additional land disturbance. Thus, policies to reduce venting and flaring should be regarded as win-win-win, and there should be no conflicting priorities among these agencies.

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc.?):

All policies to reduce venting and flaring reduce not only methane, but also VOCs, NOx and toxic air pollutants, producing improved air quality and health benefits for nearby residents.

SHUTTING IN A WELL OR CURTAILING PRODUCTION

In general, the New Mexico Oil and Gas Act requires the New Mexico Oil Conservation Commission (NMOCC) and New Mexico Oil Conservation Division (NMOCD) to prohibit production voluntarily to address various conditions including poor price environments and downstream upset conditions. and oil and gas handling practices which constitute or result in waste. NMSA 1978, § 70-2-2. The concept of "waste" has been statutorily defined by the New Mexico Legislature to include both underground waste and surface waste. NMSA 1978, § 70-2-3. Underground waste can consist of any practice that reduces or tends to reduce the total quantity of crude oil or natural gas ultimately recovered from a reservoir, e.g. shutting in a well; whereas surface waste consists of unnecessary or excessive surface loss or destruction of oil or gas, without beneficial use. Thus, NMOCC and NMOCD are required by statute to encourage the optimum recovery of oil and gas resources. The federal government and other oil and gas producing states similarly prohibit the creation of waste. *See e.g.,* 30 U.S.C. § 187; 30 U.S.C. § 225; WYO. STAT. ANN. § 30-5-101.

For the purpose of limiting venting and flaring, "waste" has historically been defined by the federal government and other oil and gas producing jurisdictions as a "preventable loss of [oil or gas] the value of which exceeds the cost of avoidance." Stephen L. McDonald, Petroleum Conservation in the United States, and Economic Analysis, Johns Hopkins Press, 1971 (Reprinted in 2011 by Resources for the Future) ("Petroleum Conservation Economics"), at 129. NMOCD regulations have likewise allowed flaring in situations where "the flaring or venting casinghead gas appears reasonably necessary to protect correlative rights, prevent waste or prevent undue hardships" on the operator. 19.15.18.12.B NMAC. Indeed, flare may provide environmental benefits in certain situations. The New Mexico Environment Department (NMED) has approved

[132] See Gas Capture Plan (ADD LINK TO FORM).

flaring in a variety of situations, and the federal government requires specifically requires flaring in certain situations. *See* NMED, Air Quality Bureau General Construction Permits; 43 C.F.R. § 3179.6(b).

Shutting-in production to avoid flaring would lead to unmanageable gathering system swings. If all operators in the area were to shut-in wells throughout the day to avoid flaring, there would be unmanageable swings on the wells and the pipeline system, with high frequency starts/stops, as all operators shut-in at high pressures, resume production when pressure drops, and immediately back up the pipeline system again when flowing, which again causes all wells in the area to shut-in. This can also lead to frequent trips at the compressor station and additional delays as equipment must be restarted, often manually.

Shutting-in production would affect necessary and routine maintenance operations like pigging. Pigging is the process of launching a malleable or hard plug (called a pig) from an upstream location and allowing pressure to carry the pig to a receiver. The pig sweeps liquid forward and thus reduces liquid in the line. As the pig and liquid front sweep through the system, pressure increases upstream and can thus reduce sales volumes. In areas with rich produced gas (high liquid content), the gas gatherers must frequently pig their lines to manage liquid buildup. Shutting in wells can cause the pig to become stuck because the pressure is too low to drive the pig. Once a pig is stuck, flaring is exacerbated as it is infeasible to override the shut-in valve when pigging occurs with high frequency.

Shutting-in production can also lead to lease default and/or lease maintenance issues. This could ultimately lead to suspended production and the royalties on that production, and wells being shut in (or otherwise cease producing) beyond the term of the lease or leases in question.

Frequent shut-ins can kill a flowing well and lead to premature installation of artificial lift at a significant cost. When a new well is still naturally flowing, artificial lift is unnecessary. Any shutdown poses a risk of liquid loading up in the wellbore and liquid head is greater than available pressure. This is known as "killing" the well. To resume production, a swabbing rig is brought on site to unload the liquids or some means of artificial lift (temporary or permanent) is utilized. If the well has been naturally flowing for a few months, an extended shut-in may require the well be prematurely put on a continuous artificial lift at a cost (gas lift, electric submersible pump, rod pump, etc.). Frequent swabbing increases venting of methane or premature installation of artificial lift again adversely affect well economics. Given lead times and rig schedules, it may take several months to install artificial lift, during which time the well is not producing and may be shut-in or otherwise cease producing.

Shut-in events have the potential to impact the productivity of low permeability hydraulically fractured reservoirs due to various reservoir and mechanical causes. These effects, either individually or combined, have often resulted in a negative effect on productivity of the well and/or an increase in operating costs. It has been well documented in the technical literature that several mechanistic effects associated with shut-in of hydraulically fractured wells can impact productivity and ultimate oil recovery[133]. The damage from repeat shut ins is irreversible and permanent, and is likely to lead to lower ultimate recovery and increased waste. Examples of mechanistic effects include:

[133]S. A. Holditch and D. M. Blakeley, "Flow Characteristics of Hydraulic Fracture Proppants Subjected to Repeated Production Cycles," SPE 19091, 1992.
M. R. Besler, "Bakken Completion Challenges," The Bakken Shale Forum, University of North Dakota Energy and Environmental Research Center, Grand Forks, ND USA. November 6, 2007.
G. R. Coulter, and R. D. Wells, "The Advantage of High Proppant Concentration in Fracture Stimulation," SPE 3298, SPE Journal, June 1972.
J. L. Gidley, G. S. Penny, and R. R. McDaniel, "Effect of Proppant Failure and Fines Migration on Conductivity of Propped Fracture," SPE 24008, 1995.
J. Terracina, "Effects of Proppant Selection on Shale Fracture Treatments," JPT Update, May 2011.

- Mechanical stress cycling on the proppant
- Generation of fines
- Potential damage due to fracture fluids
- Need to restore the productivity of the shut-in well through intervention.

PERCENT GAS CAPTURE REQUIREMENTS

Without a robust dataset and a long term coordinated effort including producers, midstream companies and state agency leadership, percent gas capture goals would have no basis in NM. This is why these data improvement changes, as well as better gas capture planning, are noted below as Paths Forward. Informing an appropriate and achievable percent capture goal requires a robust toolkit in a manner that considers anti-trust laws.

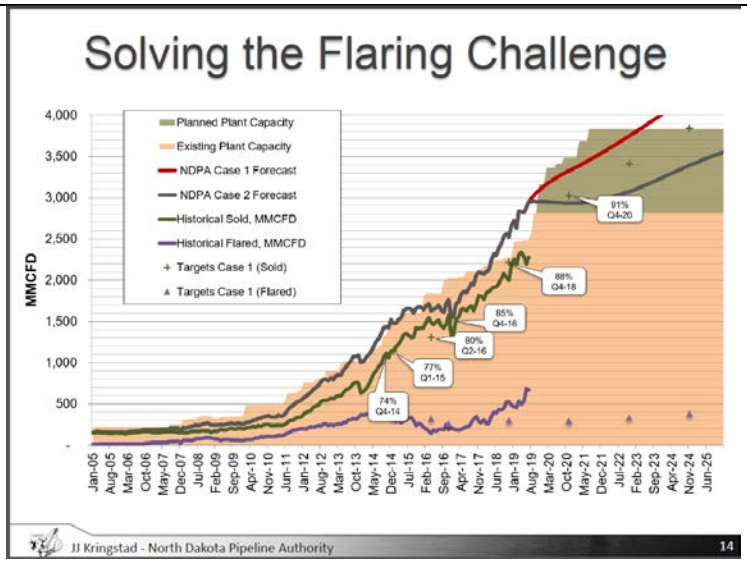
- Comprehensive, accurate, consistent and reason based flare volume reports
- Detailed information on current market, pipeline, compression & plant capacity constraints
- Comprehensive overlay of forecasted infrastructure and production data
- Detailed understanding of compression and electrical grid reliability
- Streamlined right-of-way permitting and execution process
- Comprehensive understanding of gas-to-oil ratios (SE NM has 10+ producing zones)
- Incentives for alternative technologies
- Comprehensive gas capture plans that enable best case scenario gas contracts to prevent as much flaring as possible and a hydraulic analysis by my midstream entity, along with the impact of expected volumes from other operators

It is important to note that BLM and North Dakota are the only entities to have attempted to implement a percent capture goal. The BLM's scheme was stayed by a federal district court, thus, the effectiveness and viability was never tested. As explained below and in the case of North Dakota, there are market, rights-of-way, political and other conditions that have impacted the ability for North Dakota to achieve the established goals.

In the fall of 2013, the North Dakota Petroleum Council formed the Flaring Task Force. Members of the task force sought to pool the knowledge and experience of producers and midstream companies operating in the Bakken to identify solutions to better optimize the resource at the wellhead and increase and improve existing infrastructure to transport gas for processing elsewhere. The Task Force's goals were to offer balanced, effective solutions for policy makers and regulators. The Flaring Task Force addressed the North Dakota Industry Commission on January 29, 2014, which resulted in the first of its kind percent gas capture requirements.

In North Dakota, the Pipeline Authority provides monthly updates to the public. The updates provide an overlay of associated gas forecasts and infrastructure buildout as well as month to month maps of where flaring is occurring. NDPA's purpose is to diversify and expand the North Dakota economy by facilitating development of pipeline facilities to support the production, transportation, and utilization of North Dakota energy-related commodities. NDPA is a non-policy, non-regulatory entity.
https://northdakotapipelines.com/directors-cut/

S. Agrawal and M. Sharma, "Impact of liquid Loading in Hydraulic Fracture on Well Productivity," SPE 163837, 2013.
J. W. Crafton, and S. L. Noe, "Impact of Delays and Shut-Ins on Well Productivity," SPE 165705, 2013.



Despite efforts described above, ND is still struggling with meeting gas capture limits. In addition, the depressed market inhibited investment in gas processing and transmission assets. Also exacerbating the issue were 2 rights-of-way issues that amounted to a total of 6% of the total gas flared in ND. Industry reactivated the Task Force with 6 separate committees to assess infrastructure buildout, right-of-way and tribal regulatory challenges, H2S contamination, remote capture technologies, new operator engagement, and reworking of the gas capture plan requirements. In the fall of 2015, the Flaring Taskforce provided the updated information to the North Dakota Industrial Commission in the fall of 2015, which resulted in the adjustment of the gas capture goals.

Note that the near-absence of any sanctions or penalties for companies that fail to meet the targets, as discussed above, means that the regulation as implemented provides little incentive for companies to expend resources on compliance. Given that compliance is likely to involve some cost, while noncompliance involves little to no cost, a profit-maximizing entity will be acting rationally in failing to comply. NDIC guidance updates indicate their enforcement mechanism is production curtailment but it has only issued an enforcement action a handful of times despite clear violations. Data for voluntary curtailment is not available.

5. VENTING AND FLARING - PATH FORWARD[134]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EFFECTIVENESS OF COST NOW (choose one)	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
6.1	More detailed reporting on C-115 form (production report)	Developing more consistency across the state in how flared gas volumes are reported (i.e., measurement v. estimation, source of gas reported, requirement to report) will benefit the state as it establishes future rules, requirements, and reduction targets.	HIGHLY COST EFFECTIVE	The reporting requirement should include a protocol that establishes consistent reporting, specifies types of flaring that should be reported and an approved standard for measuring flared gas (or accepted methodology for estimating and verifying flared gas volumes).	
	COMMENT: A. Clarify scope of C-115 – This is currently a production report and it would be helpful to keep that scope rather than adding additional scope (tank vapors, etc.) to this specific report. A separate report for NMED would be appropriate for an emissions inventory.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.2	Establishing requirement to submit Gas Capture Plan with APD through rulemaking	Making it a requirement to submit a Gas Capture Plan through rulemaking makes the submittal of the Gas Capture plan enforceable	HIGHLY COST EFFECTIVE	Submittal of Gas Capture Plan	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

[134] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

6.3	Operators do not vent when gas can be flared instead.	See BLM rules. Substantial methane reductions. Consistent with best safety practices, which already strongly discourage venting methane.	Operators do not vent when gas can be flared instead.	See BLM rules. Substantial methane reductions. Consistent with best safety practices, which already strongly discourage venting methane.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.4	Operators engage with midstream in more active development planning [Addressed in MAP infrastructure planning report]				
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.5	Current regulation (19.15.18.12A NMAC) prohibits an operator from flaring or venting casinghead gas produced from a well after 60 days of the well's completion. Provided the exception process is better defined and includes a notice provision, a reduction to 30 days from the 60 days currently authorized is proposed.	Prevention/reduction of waste Consistent with BLM requirement	HIGHLY COST EFFECTIVE	To be reported as a non-transported volume on C-115	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.6	Auto igniters for new flares	Ensures pilots are lit, minimizing venting from unlit flares	HIGHLY COST EFFECTIVE		
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.7	Ensure that all venting and flaring from oil and gas production and gathering upstream of the processing plant is reported on a monthly basis, consistent with clear standards, and made publicly available online. Clarify that C-115 (or another appropriate form) should include venting and flaring that occurs:	Developing more consistency across the state in how flared gas volumes are reported (i.e., measurement v. estimation, source of gas reported, requirement to report) will reduce ambiguity and confusion for industry on what they are required to report, enhance data quality, help the state to develop the most efficient and effective future rules, requirements, and reduction targets, and benefit the public in better understanding how NM's natural resources are	HIGHLY COST EFFECTIVE	The reporting requirement should include a protocol that establishes consistent reporting, specifies types of flaring that should be reported and an approved standard for measuring flared gas (or accepted	

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	--due to lack of connection with a pipeline -- during completions/recompletions, including during initial flowback; -- in response to upsets, disruptions, capacity constraints anywhere in the system; --in the course of maintenance activities; --from operation of pneumatics, tank vapors, and flaring of such vapors (Note that BLM considers these volumes unavoidable lost or beneficial use. Also, low pressure flaring is out of scope for this report.); --each of operator's temporarily abandoned well, if venting occurs; and -- any other sources of venting and flaring that can be measured or estimated. --Adopt third-party audit or verification program to ensure that operators are complying with reporting requirements (given past high levels of non-compliance and also compliance with the exception criteria).	being used, conserved, or wasted. See Norway (monthly reporting and public reporting)		methodology for estimating and verifying flared gas volumes). Reports should be certified by appropriate officers of reporting company. Aggregated reports should be compared to satellite data and any discrepancies investigated promptly. Third-party audit or verification program to ensure that operators are complying with reporting requirements (given past high levels of non-compliance). Regulatory consequences must be strong for inaccurate reporting. Reports should be public.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.8	Include, in reporting specifications, standards for measurement and/or highly reliable estimation approaches based on measurement of other known variables, such as oil production volumes and frequent	Providing industry clear guidance for reporting estimation and measurement methodologies will reduce ambiguity and confusion for industry, enhance data quality, allow the state to better target prevention efforts, and enhance public understanding.	HIGHLY COST EFFECTIVE		

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	(e.g., monthly) measurements of gas-to-oil ratio.				
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.9	Require use of reliable tools for measuring or estimating flared volumes; require regulatory oversight of purchase and calibration of measurement tools (It is important to note that OCD has no authority over purchasing of equipment and BLM requires use of approved equipment under the new measurement rules.)	Norway requires that a regulator is present from the moment the operator places an order to buy instruments (design phase) to calibration of the instruments and tools to decommissioning.	HIGH COST EFFECTIVENESS	Robust recordkeeping and reporting of flared volumes necessary to ensure compliance.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.10	Establish electronic reporting system for all sources of venting and flaring (e.g., including C-129s and C-141s) upstream of processing plants and make results publicly available online. Note that C-129s are submitted by operators as a "just in case" and volumes are estimated. C-141s are after-the-fact and volumes reported as a non-transported disposition code "L" for lost. Therefore, any actual volumes are reported on C-115s. See "enhanced reporting and measurement protocols."	Reporting all venting and flaring information electronically would reduce administrative burdens for industry and the state, greatly facilitate data analysis, and make results accessible to the public	HIGHLY COST EFFECTIVE		
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.11	Condition grant of APD on submission of adequate Gas Capture Plan with APD.	Conditioning grant of APD on submission of an adequate Gas Capture Plan provides operators a strong incentive to submit adequate gas capture plans and makes the submittal of the Gas Capture plan readily enforceable with minimal state effort.	HIGHLY COST EFFECTIVE	Submittal of Gas Capture Plan	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

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6.12	Specify gas capture plan elements to include (items highlighted below are already part of the NM Gas Capture Plan): --well location; expected drilling, completion, and first production date; expected volumes and pressures; --from multiple wells for the above if operator is planning multiple wells in same area within relevant timeframe; --information about the operator's other current production, and venting and flaring, in the vicinity of the proposed well; --identification of intended gathering system and processing facility for gas production, including pipeline size, pressure, and available capacity now and for the period over which the well is projected to produce, and plan for additional compression if needed; --showing/certification that the operator has communicated projected gas volumes and timing for all operations in the vicinity of the destination pipeline to the midstream company, including current venting and flaring; --showing/certification that midstream company projects there will be available capacity to accept the projected gas production from the specified well; --if pipeline capacity not projected to be available, specific plan for alternative gas use/disposal, with demonstration that the operator has	Compliance with comprehensive GCP requirements would greatly improve information available to midstream operators to plan their systems to align with expected gas production in a timely fashion. It would also document for OCD that the producer has obtained transportation and processing capacity for wells that are drilled at the time they go into production. However, the data supplied during this phase of planning is a snapshot in time and may or may not be drilled. See ND, BLM 2016 rules. Expanding the elements required for an adequate GCP would ensure that the operator produces a plan that results in capturing (or disposing through a means other than venting / flaring) the projected volumes of gas over the projected lifetime of the well. For operators seeking APDs for wells without a drilling schedule or sufficient information to forecast production, OCD should consider establishing a process for conditional APD approvals with requirements to update the GCP when required information is available before final drilling approval is granted.	HIGHLY COST EFFECTIVE		

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	the ability to implement such plan (e.g., if plan to reinject gas, show permit applications submitted; if plan to generate for grid, show communications with grid operator, etc.) -measures to prevent waste over the life of the well, including additional compression and operator elected proper plugging and abandonment to avoid the rare instance of orphan well venting scenarios.				
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.13	Define "undue hardships" (e.g. maintenance, emergencies) as per 19.15.18.12.B NMAC while maintaining the ability to apply for an exception.	Provides regulatory certainty on flaring events that establishes a basis for NMOCD to make an inform decision to grant or deny an exception. See: "Describe how the equipment or process is used:" section starting on page 3 that describes "When Flaring is Necessary". Consistent with some NMED exceptions. Note that other recommendations below would move the state away from case-by-case exemptions to reduce administrative burden on the state and industry and boost overall effectiveness of limits on venting and flaring.	HIGHLY COST EFFECTIVE	Documentation and notification of events, record keeping limits	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

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6.14	Prohibit operators from venting whenever gas can be flared instead; i.e., only allow venting when flaring is not possible as a technical matter or where flaring is prohibited due, e.g., to wildfire risk. Note that both the BLM and OCD have rules requiring flaring rather than venting. See page 162 for BLM rule §3179.6(b) and page 163 for NMOCD rule 19.15.18.12.F.	See BLM rules. Substantial methane reductions. Consistent with best safety practices, which already strongly discourage venting methane.	HIGH COST EFFECTIVENESS	Report all venting events, volumes and circumstances allowing (e.g., liquids recovery operation). Continue remote sensing/satellites to track area-wide decreases in methane emissions.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.15	Adopt performance standard for new and existing flares to ensure high destruction removal efficiency (minimum 98%) and continuous burning pilots.	Minimizes excess emissions due to incomplete combustion and improperly operating flares. See CO, WY, ND.	HIGH COST EFFECTIVENESS	Require operators provide manufacturer specification for flares demonstrating compliance with DRE and require operators inspect flares routinely to ensure proper operation	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.16	Set overall limit (with no exceptions for specific activities/circumstances) on the gas flared by each operator. Limit could take the form of a minimum percentage and/or volume of total gas production from the operator in the State that must be captured. If apply sufficiently stringent overall percentage limits, could potentially allow for a limited volume of flaring/well on average over all of an operator's wells (note that C-115s are required to be	See ND and 2016 BLM rules, and specifically 2016 BLM rule set volume of allowed flaring rather than case-by-case exemptions. Allows market to optimize approach rather than requiring the state to select or mandate use of particular technologies or practices. For example, had operators been limited to flaring no more than 1% of their reported associated gas in 2018, this measure would have avoided the waste of 77% or 28 bcf of gas in that year, as well as the associated volumes of CO2, NOx and other pollutants.[135] This approach still recognizes that avoiding flaring in some circumstances, such as emergencies, may	HIGH COST EFFECTIVENESS	Report all flaring volumes, without exceptions. Robust recordkeeping and reporting of flared volumes necessary to ensure compliance.	

[135] Calculation by Clean Air Task Force based on C-115 data.

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	submitted the 15th day of the second month following the month of production, therefore, an average will not be based on most current volumes) that may be deducted from the capture percentage compliance calculation (in lieu of requiring burdensome case-by-case requests and approvals for emergencies, maintenance, and force-majeure events etc.), and ratchet that deductible volume down over time, giving operators an incentive and opportunity to fine-tune operations to reduce such events.	not be cost-effective or even possible, but it does so without requiring industry and OCD to engage in the burdensome process of case-by-case requests for exemptions, reviews, and determinations.			
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.17	Establish automatic consequences for failure to meet capture percentage standards. E.g., set a meaningful fee per mcf gas flared/vented in contravention of applicable capture standard, due upon notice of exceedance; and/or require operator to be in compliance with capture percentage standard as a pre-condition for issuance of any new APD for such operator. Ensure flaring policy is enforceable and penalties sufficient to outweigh financial incentives to flare rather than capture.	Effectiveness of ND rules has been severely undermined by lack of enforcement or even consequences for operators that consistently fail to achieve capture standards. OCD has very limited enforcement resources. Establishing automatic penalties would provide a clear, consistent incentive for operators and minimize implementation burden on OCD. Limiting production as a penalty for failing to meet capture standards may be less effective than (meaningful) financial penalties, as both the state and the industry aim to increase, not reduce, production.	HIGH COST EFFECTIVENESS	Robust recordkeeping and reporting of flared volumes necessary to ensure compliance.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.18	Assess severance tax and royalties on all gas produced rather than only on gas produced or sold	May require legislative fix to change tax and royalty policy.	HIGH COST EFFECTIVENESS	Calculate additional revenues from alternative tax and royalty levels.	

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	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.19	Prohibit flaring unless permitted by OCD. Only permit flaring required for specific delineated circumstances (e.g., safety emergencies, unplanned infrastructure maintenance, upset conditions, etc.). Permit would specify volume and/or time limit. Consider exempting defined de minimis amount of flaring from permit requirement. Monitor to avoid repeat exemptions and long-term flaring.	See Alaska (clear prohibition on flaring other than in narrow circumstances); Norway (extends capture requirements to all phases of production) Ensures any allowable flaring, in particular during emergencies or for safety, is kept to a minimum.	HIGH COST EFFECTIVENESS	Robust recordkeeping and reporting of flared volumes necessary to ensure compliance. System to flag repeat applications to flare.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.20	Create permitting options for some of the more recent reinjection solutions that have been presented to NMOCD.	New EOR projects by injecting produced gas may reduce flaring by not crowding pipeline capacity.		UIC permit application type and requirements.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.21	Approve alternative technology by more streamlined NMED permitting process.	Once alternative technology is proven, permitting process should be expedited to accommodate temporary flaring events.	HIGH COST EFFECTIVENESS	Document proven alternative technologies and make available via NMED website.	
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.22	Clarify the definition of waste in venting/flaring regardless of whether or not it is an authorized exemption.	Identify/define “waste” for the purposes of royalty reporting.	HIGHLY COST EFFECTIVE	Line by line C-115 reporting	
	COMMENT A. Evaluate compatibility with existing statutes/regulations.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
6.23	Ability to amend C-115 by line to ensure accurate reporting/ability to amend reports vs. requiring a company’s statewide C-115 production to be re-submitted.	The benefit would be that agencies could more readily assess line by line modifications and would also minimize production inaccuracies for both the company and the agencies.			
	COMMENT:		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

NMED Exhibit 10 - 0196

	A. Evaluate compatibility with existing statutes/regulations	

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NMED/EMNRD METHANE ADVISORY PANEL

SECTION 7, WORKOVERS/LIQUIDS UNLOADING

Discussion for MAP members on September 12, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

Manual Liquid Unloading:

Managing wellbore liquid build-up in gas wells is fundamental to maintaining production, avoiding early abandonment of wells and maximizing resource recovery. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production declines, wellbore (tubing) velocity goes down, and liquid loading begins to occur in the wellbore. Liquid loading begins when the velocity up the production string is not sufficient to lift liquids up to the surface at a pressure that will allow production to overcome the surface equipment and out of the wellbore. While pressure is a factor, it is generally a lack of velocity, which causes liquids to accumulate in the wellbore (i.e., "to load/load up"). Gas well unloading is a complex field of science and engineering where a large number of different technologies, tools and practices must be matched to an individual well's characteristics at each stage of its lifecycle to most efficiently manage liquids and maintain economic viability of the well. No single technique will be adequate or appropriate across the full lifecycle of a well.

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As a well moves through its lifecycle, the appropriate approach to managing liquids changes. New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and velocity declines and eventually a point is reached where liquids loading begins to be an issue. The time at which liquids loading occurs is dependent on the reservoir characteristics and varies from well to well. At the onset of liquids unloading, techniques that rely on the reservoir energy are typically used. These include:

- **Intermitting:** Shutting in a well for a period of time to allow the reservoir to "refill" the pressure and volume "void" in the near-wellbore reservoir so that when the well is restarted the production rate and velocity are higher and the well can "unload" liquids through the normal production route to sales;
- **Velocity strings:** Installing a smaller diameter tubing string in the well that increases the flow velocity at a given production rate sufficiently to drag liquids up the wellbore and prevent liquid loading;
- **Surfactants and foaming agents**: Introducing surfactants and foaming agents to the bottom of a well (various techniques are used) creating foam with lower specific gravity which enables liquids to be carried up the wellbore at lower velocities.

These techniques can be used individually or in combination to manage wellbore liquids and maintain production.

Eventually a well will reach a point where the reservoir energy is not sufficient to remove the liquids from the well and adding energy to the well is necessary to continue production. Common approaches are to install artificial lift. Two common methods are:

- Installing a plunger lift system that changes the dynamic for removing liquids from velocity to differential pressure between the bottom-hole and the surface/gas collection line; or
- Installing wellhead compression that lowers the surface back-pressure on a well, increases production rate and flowing velocity, and increases the differential pressure between the reservoir and the collection/sales line.

There are a number of different pump types and gas lift systems, each more effective in some respects than others. Installation of a system to add energy to a well is an economic decision based on whether the continuing production will be sufficient to support the costs of installing and operating a pump or gas lift system.

There are some cases where the need to create additional differential pressure is necessary to manually unload accumulated liquids. These cases include onsite or downstream equipment downtime in the gas gathering system.

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NMED Exhibit 10 - 0199

One item of clarification is that deliquification, liquid unloading and venting are not synonymous terms. Liquids can and are routinely removed from gas wells without venting.

Workovers:

Some wells may need to be re-stimulated in a previously completed formation or in a new reservoir in the same wellbore. These operations are called recompletions. Additionally, some wells will require supplementary maintenance to maintain production or minimize the decline in production and are referred to as workovers. Typical workovers include rod, tubing and casing repairs, siphon string or artificial lift installation, paraffin removal, and pump repairs.

Both recompletions and workovers differ from completions in that they are performed on wells that that have previously been completed and have produced some reservoir fluids (water, oil, and/or natural gas). These wells will have to be prepared before recompletion or workover operations can begin. If the well is still producing and/or has pressure, the well will need to be blown down before it is safe to remove the tubing head and install the blowout preventers (BOP's). The well pressure can be decreased by opening the casing to the sales line or the suction of a wellsite compressor. In many cases the fluids in the wellbore will build up to the point the well dies, this is referring to the instance where the hydrostatic pressure of the accumulated fluids is equal to the reservoir pressure. In some cases, it will be necessary to pump water or other fluids in the wellbore to kill the well. As a safety precaution, after the BOP's are installed the well is usually vented to atmosphere via a tank.

In the case of a recompletion, after the well is prepared (well blown down, BOP's installed, and the tubing removed) the stimulation and flow back will be the same as the issues that were presented in the COMPLETIONS/STIMULATIONS Report. A recompletion would be a stimulation of an existing well, in a different horizon, that has already been completed. The preparation of the well for a recompletion is the source covered in this Workovers/Liquids Unloading Report. The preparation of the well, as mentioned above is the process in which the pressure on the wellbore is reduced to atmospheric pressure by venting the well through an atmospheric storage tank. The pressure is relieved to atmosphere to ensure the well can safely be worked on (workover) or recompleted.

Workovers are usually short duration projects that only last a few days or weeks at the most. After the well is prepared (well blown down and the BOP's installed) the workover operations can begin. For the safety of the rig crew, the well is usually allowed to vent to atmosphere via a tank for the duration of the workover. Since these operations are usually performed during daylight hours, the well is shut in or returned to the sales line at the end of the day.

Provide the segment(s) of the industry that the equipment or process is found:

This process is found in the oil and gas production segment of the industry.

NMED Exhibit 10 - 0200

Describe how the equipment or process is used:

The production from the wellbore (tubing and/or casing) is routed to an atmospheric tank to create the differential pressure necessary to manually unload the liquids accumulated in the wellbore or to make the wellbore safe to perform downhole maintenance.

Provide the common process configurations that use this equipment or process:

The liquids unloading process applies primarily to gas wells. The workover operations apply both to oil and gas wells.

What is the distribution of the equipment or process across business segments?

This process primarily relates to the onshore oil and gas production sector.

How has this equipment or process evolved over time?

The technology for gas well deliquification has advanced over time and operators have adopted many wellbore best management practices that have minimized the amount of manual liquids unloading events necessary to keep well production optimized. Advanced planning to reduce the wells pressure prior to blowing the well down have resulted in reduced emissions.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

The source of methane emissions for liquids unloading and workover operations is the venting of a well to an atmospheric tank.[136]

[136] Leaks, upsets and other fugitive emissions are addressed in the leak detection and repair report.

NMED Exhibit 10 - 0201

New Wells:

New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. New wells normally do not require downhole maintenance but if a workover is necessary the process is the same for new and existing wells.

Existing Wells:

The methane emissions for workovers/liquids unloading operations comes from the venting of the well through atmospheric tanks to unload liquids or make the wellbore safe to preform downhole maintenance.

How are the emissions calculated for this equipment or process?

The formulas included below reflect the calculation methodology for estimating emissions from manual liquids unloading events under the EPA Greenhouse Gas Reporting Program (GHGRP). Note that emissions from workovers are combined with completions in the GHGRP program. This calculation methodology contains 3 layers of conservatism in estimating emissions that result in a gross overestimation of emissions. First, the first term of the calculation methodology assumes the full wellbore contains gas only, which does not account for the space occupied by liquid. This asumption over estimates the volume of gas in the column and, therefore, the amount of gas vented. Also, if the tubing or casing were occupied by gas only, a manual liquids unload would not be required. Second, the GHGRP calculation methodology also assumes these activities are no more than 1 hour and 0.5 hour, respectively. After this timeframe, the method assumes the well is venting at the production rate, which leads to another layer of overestimation of emissions. Third, during a manual liquids unloading activity, the valve that allows for flow to the tank may be open for period of time with no liquid/gas movement, therefore, the method assumes flow when there may not be.

Blowdown volumes for wells without plungers (assumes casing)

$$\left(\left\{\begin{matrix}Physical\ Volume\ of\ Casing\\ Being\ Blown\ Down\\ [ft^3]\end{matrix}\right\}\times\left\{\begin{matrix}Convert\ to\ Atmospheric\\ Pressure\end{matrix}\right\}\right)+\left(\left\{\begin{matrix}Avg\ Gas\\ Flowrate\\ \left[\frac{scf}{hr}\right]\end{matrix}\right\}\times\left(\begin{matrix}Blowdown\\ Duration\\ [hrs]\end{matrix}-1\right)\times\left(\begin{matrix}1\ [if\ duration\ longer\ than\ 1\ hr]\\ or\\ 0\ [if\ duration\ shorter\ than\ 1\ hr]\end{matrix}\right)\right)$$

Blowdown volumes for wells with plungers (assumes tubing)

$$\left(\left\{\begin{matrix}Physical\ Volume\ of\ Tubing\\ Being\ Blown\ Down\\ [ft^3]\end{matrix}\right\}\times\left\{\begin{matrix}Convert\ to\ Atmospheric\\ Pressure\end{matrix}\right\}\right)+\left(\left\{\begin{matrix}Avg\ Gas\\ Flowrate\\ \left[\frac{scf}{hr}\right]\end{matrix}\right\}\times\left(\begin{matrix}Blowdown\\ Duration\\ [hrs]\end{matrix}-0.5\right)\times\left(\begin{matrix}1\ [if\ duration\ longer\ than\ 0.5\ hr]\\ or\\ 0\ [if\ duration\ shorter\ than\ 0.5\ hr]\end{matrix}\right)\right)$$

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GHGRP:

(f)**Well venting for liquids unloadings**. Calculate annual volumetric natural gas emissions from well venting for liquids unloading using one of the calculation methods described in paragraphs (f)(1), (2), or (3) of this section. Calculate annual CH4 and CO2 volumetric and mass emissions using the method described in paragraph (f)(4) of this section.

(1)*Calculation Method 1.* Calculate emissions from wells with plunger lifts and wells without plunger lifts separately. For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see § 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, install a recording flow meter on the vent line used to vent gas from the well (*e.g.,* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate the total emissions from well venting to the atmosphere for liquids unloading using Equation W-7A of this section. For any tubing diameter group and pressure group combination in a sub-basin where liquids unloading occurs both with and without plunger lifts, Equation W-7A will be used twice, once for wells with plunger lifts and once for wells without plunger lifts.

Ea=FR∑hp=1Tp(Eq. W-7A)Ea=FR∑p=1hTp(Eq. W-7A)

Where:

Ea = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions, a, in cubic feet. Calculate emission from wells with plunger lifts and wells without plunger lifts separately.

h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin either with or without plunger lifts.

p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.

Tp = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year. If the available venting data do not contain a record of the date of the venting events and data are not available to provide the venting hours for the specific time period of January 1 to December 31, you may calculate an annualized vent time, Tp, using Equation W-7B of this section.

FR = Average flow rate in cubic feet per hour for all measured wells of the same tubing diameter group and pressure group combination in a sub-basin, over the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

Tp=HRpMPp×Dp(Eq. W-7B)Tp=HRpMPp×Dp(Eq. W-7B)

NMED Exhibit 10 - 0203

Where:

HRp = Cumulative amount of time in hours of venting for each well, p, during the monitoring period.

MPp = Time period, in days, of the monitoring period for each well, p. A minimum of 300 days in a calendar year are required. The next period of data collection must start immediately following the end of data collection for the previous reporting year.

Dp = Time period, in days during which the well, p, was in production (365 if the well was in production for the entire year).

(i) Determine the well vent average flow rate ("FR" in Equation W-7A of this section) as specified in paragraphs (f)(1)(i)(A) through (C) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category. Calculate emissions from wells with plunger lifts and wells without plunger lifts separately.

(A) Calculate the average flow rate per hour of venting for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total annual flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) Apply the average hourly flow rate calculated under paragraph (f)(1)(i)(A) of this section to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) Calculate a new average flow rate every other calendar year starting with the first calendar year of data collection. For a new producing sub-basin category, calculate an average flow rate beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2)*Calculation Method 2.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W-8 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-8)}$$

Where:

Es = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

Vp = Total number of unloading events in the monitoring period per well, p.

0.37 × 10−3 = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

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CDp = Casing internal diameter for each well, p, in inches.

WDp = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SPp = For each well, p, shut-in pressure or surface pressure for wells with tubing production, or casing pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure is not available for each well, you may determine the casing pressure by multiplying the tubing pressure of each well with a ratio of casing pressure to tubing pressure from a well in the same sub-basin for which the casing pressure is known. The tubing pressure must be measured during gas flow to a flow-line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading when the well production is impeded by liquids loading or closed to the flow-line by surface valves.

SFRp = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.

HRp,q = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

q = Unloading event.

Zp,q = If HRp,q is less than 1.0 then Zp,q is equal to 0. If HRp,q is greater than or equal to 1.0 then Zp,q is equal to 1.

(3)*Calculation Method 3.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left((0.37\times10^{-3})\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-9)}$$

Where:

Es = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

Vp = Total number of unloading events in the monitoring period for each well, p.

0.37 × 10−3 = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TDp = Tubing internal diameter for each well, p, in inches.

WDp = Tubing depth to plunger bumper for each well, p, in feet.

SPp = Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

SFRp = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section to calculate the average flow-line rate at standard conditions.

HRp,q = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

q = Unloading event.

Zp,q = If HRp,q is less than 0.5 then Zp,q is equal to 0. If HRp,q is greater than or equal to 0.5 then Zp,q is equal to 1.

(4) Calculate CH4 and CO2 volumetric and mass emissions from volumetric gas emissions using calculations in paragraphs (u) and (v) of this section.

EDF Synthesis:

We did not incorporate liquids unloading data from Allen et al 2014b (*) because the GHGRP provided more detailed data on event counts and emission rates; the Allen et al estimate of 2012 national emissions from liquids unloading was within a few percent of the GHGRP estimate.

The data suggest that the central estimate of national emissions from unloadings (270 Gg/yr, 95% confidence range of 190–400 Gg) are within a few percent of the emissions estimated in the EPA 2012 Greenhouse Gas National Emission Inventory (released in 2014), with emissions dominated by wells with high frequencies of unloadings. (*)

(*) *D. T. Allen, D. W. Sullivan, D. Zavala-Araiza, A. P. Pacsi, M. Harrison, K. Keen, M. P. Fraser, A. Daniel Hill, B. K. Lamb, R. F. Sawyer, J. H. Seinfeld, Methane emissions from process equipment at natural gas production sites in the United States: Liquid unloadings. Environ. Sci. Technol. 49, 641–648 (2015). doi:10.1021/es504016r Medline*

What data is available to quantify emissions/waste for this equipment or process?

https://www.epa.gov/ghgreporting

About 85% of the gas wells in the U.S. have production rates low enough to have liquids loading issues, and only about 13% have liquids unloading venting to assist liquid removal in 2012 (gross up of GHGRP data).

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- The frequency and amount of venting to assist liquids unloading is highly skewed, with 10 of the 1991 non-zero datasets reported at the "sub-basin" level (less than 0.5%) datasets accounting for more than 50% of the emissions reported;
- At the facility (basin) and reporter level (251 non-zero data sets) the top 1 (0.4%) accounted for about 37% of the total reported emissions; and
- The top 3 (1.2%) accounted for over 50% of the total methane reported and the top 11 accounted for over 75% of the reported methane emissions.

Methane emissions attributed to LU venting are a fairly small portion of the industry emissions in the GHGI and are trending down

GHGI - 2016 (2018 release) LU Venting
6.1% of Natural Gas Systems E&P CH4
2.0%of Natural Gas Systems CH4
1.6% of Natural Gas + Petroleum Systems CH4

GHGRP, Allen et al 2014b, operator data, etc.

According to the Synthesis* study, EDF estimates about 21,700 metric tons CH4 from unloading in NM in 2017. Better records of unloading process information would provide better estimates of total emissions. Not surprisingly, the majority of these emissions occur in the San Juan Basin.

According to the EDF Synthesis study* data, 8.5% of production CH4 emissions are attributable to LU in NM (excluding abnormal process emissions, for consistency with GHGI) vs. 4.9% nationally (or 6.1% per GHGI for the US). This demonstrates a disproportionately high percentage of LU emissions in NM versus the national rate. On tribal lands in NM, Synthesis* data indicates liquids unloading emissions account for 9.9% of production emissions, even higher than the New Mexico total rate.

*EDF Synthesis study:
https://science.sciencemag.org/content/361/6398/186.full?ijkey=42lcrJ/vdyyZA&keytype=ref&siteid=sci

What are the data gaps in quantifying emissions/waste for this equipment?

Unloading emissions are more often estimated than measured. It is important that operators record process information for better estimates of unloading emissions, such as **number of unloading events and duration of each event**. Operators should also indicate if/how an artificial or plunger lift was utilized.

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Further, the Subpart W Greenhouse Gas Reporting Program (GHGRP) requirements only apply to facilities above the emissions threshold. Therefore, not all unloading events are reported under the program.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

The cost for supervision of manual liquid unloading events is dependent upon each unique situation. Additional labor cost of having a lease operator onsite is variable, which make it very difficult to establish a fixed value or even a range.

What are the annualized operating costs for the equipment or costs associated with the process?

N/A

If the equipment or process is powered, what are the costs?

N/A

What are the maintenance and repair costs for existing or new equipment?

N/A

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

Operators have developed and employed several wellbore best management practices over the life of the well to avoid the need to perform manual liquids unloads. These best management practices include revisiting the application of refined technology in terms of artificial lift. In order to increase gas sales and reduce emissions/waste during these manual liquids unloading activities, operators should monitor manual liquids unloading events onsite, within close proximity or via remote telemetry to return the wells to normal production operation as soon as possible. Advanced planning to reduce pressure prior to blowing the well down has resulted in reduced emissions.

1. Create differential pressure to minimize the need for venting during unloading activities (artificial lift engine/pump jack, electric submersible pump, etc.)
2. Plunger lifts including automated plunger lifts
3. BMPs - Operators onsite to close vents and monitor the unloading events

Between artificial lift engines, plunger lifts, and supervised manual unloading, one option will result in the lowest emissions relative to the others. This lowest emitting option will serve to mitigate emissions

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relative to the others, and should therefore be selected and employed by the operator for liquids unloading at a site.[137]

New Wells:

New wells typically have sufficient production rates and flowing velocity so that manual liquids loading is not required. New wells do not require workovers. Workovers are the downhole maintenance activities performed on existing wells that have previously been capable of producing hydrocarbons.

Existing Wells:

In order to increase gas sales and reduce emissions/waste during manual liquids unloading activities, operators should monitor manual liquids unloading events onsite, within a close proximity or via remote telemetry to return the wells to normal production operation as soon as possible.

How have the emission/waste reductions been measured?

New Mexico Oil and Gas Association report on methane sources and mitigation.

GHGRP 2011-2016 https://www.nmoga.org/methaneroadmap

GHGRP emissions trends data is the most reliable source to establish emission reductions, as described in Section 3 below.

Various studies have measured or modeled emissions from manual liquids unloading events.

Characterizing Regional Methane Emissions from Natural Gas Liquid Unloading

https://pubs.acs.org/doi/abs/10.1021/acs.est.8b05546#

Temporal Variations in Methane Emissions from an Unconventional Well Site

https://pubs.acs.org/doi/pdf/10.1021/acsomega.8b03246

Temporal Variability Largely Explains Difference in Top-down and Bottom-up Estimates of Methane Emissions from a Natural Gas Production Region

https://www.pnas.org/content/115/46/11712

Comparison of methane emission estimates from multiple measurement techniques at natural gas production pads

[137] The application of artificial lift is very dependent on the specific characteristics of each well. The operating parameters of the wells will dictate the appropriate artificial lift application. The misapplication of artificial lift could result in an increase in methane emissions in the case of plunger lift installations.

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https://www.elementascience.org/article/10.1525/elementa.266/

Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially-Resolved Aircraft Measurements

https://pubs.acs.org/doi/10.1021/acs.est.7b01810

Methane Emissions From Process Equipment At Natural Gas Production Sites In The United States: Liquid Unloadings

https://pubs.acs.org/doi/abs/10.1021/es504016r

Measurements Of Methane Emissions At Natural Gas Production Sites In The United States

https://www.pnas.org/content/110/44/17768

If the artificial lift engine operates properly, the only emissions will be combustion. Depending on conditions, plunger lifts can reduce emissions 90% compared to unmitigated venting. (Source: ICF MACC Report, 2014, available at , https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf)

How have other jurisdictions, including state, federal, and tribal, reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

Outside of the initial well preparation the number of activities that can be accomplished under the heading of Recompletions/Workovers is so varied with multiple variables that are well specific, regulating venting and emissions associated with these activities is not feasible. Use of best management practice to manage wellbore pressure makes the most sense because it allows operators to determine the best way to reduce venting on a case by case basis specifically from each well as the situation dictates.

The complexity of liquids unloading is why EPA concluded for NSPS OOOOa that imposing specific regulatory requirements for venting and emissions associated with managing wellbore liquids is not feasible. Requirements for monitoring the activity to manage venting makes the most sense because it allows operators to determine the best way to manage manual unloading on a case by case basis specifically from each well as it changes over time.

BLM's final waste prevention rule requires operators to minimize venting and the need for venting and operators must consider alternatives to manual venting and determine if they are infeasible; if manual venting, operators must remain onsite. BLM, 81 Fed. Reg, 83008 (Nov. 18, 2016)

4. 2016 rule: The final rule requires an operator to: (1) Minimize gas vented to unload liquids, consistent with safe operations; (2) optimize the operation of the plunger lift or automated well

NMED Exhibit 10 - 0210

control system, at wells equipped with such a system, to minimize gas losses from the system to the extent possible; (3) consider other methods for liquids unloading and determine that they are technically infeasible or unduly costly, prior to manually purging a well for the first time; and (4) comply with specified procedures and document venting events when unloading liquids by manual well purging… The operator must notify the BLM by Sundry Notice within 30 days after the first liquids unloading by manual or automated well purging after the effective date of the rule. Additionally, operators must notify the BLM by Sundry Notice within 30 days after the following conditions are met: (1) The cumulative duration of manual well purging events for a well exceeds 24 hours during any production month; or (2) the estimated volume of gas vented in the process of conducting liquids unloading by manual well purging for a well exceeds 75 Mcf during any production month.

5. The requirements to minimize wasted gas remain essentially the same between the two rules. The main difference between the 2016 and 2018 Rules are that the 2016 Rule required recordkeeping and reporting of liquids unloading events, and the 2018 Rule removed those requirements.

Colorado State Regulation to minimize methane emissions in the oil and gas industry:

Colorado, Reg.7, Section XVIII.H.,
https://drive.google.com/file/d/168v7vMsFJtS7D8BWlnMbaXWA6uZUIyj8/view

requires operators to use best management practices to reduce emissions and operators must remain onsite during manual unloading. Colorado is proposing new recordkeeping and reporting requirements to gather better data on emissions and BMPs to reduce emissions.

Wyoming requires operators use BMPs to minimize emissions and operators must remain onsite during manual unloading (see "blowdown and venting" requirements).
http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf (pps. 13, 19, 24)

Pennsylvania requires operators use BMPs to minimize emissions. GP-5A, Section L,
http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=36120

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

Liquids Unloading:

- Create differential pressure to eliminate the need to vent a well to unload liquids.
    - Equalize the well
    - Allow the well to build pressure
- Reduce wellbore pressure as much as possible prior to opening to atmosphere via storage tank.

NMED Exhibit 10 - 0211

        - If possible route the initial volume of gas into the sales line prior to venting. Monitor the pressure and the flowrate to determine the optimal time to vent the well to create the differential pressure to unload the well.
- Monitoring manual liquid unloading events onsite, within a close proximity or via remote telemetry to return the wells to normal production operation as soon as possible.

Recompletions/Workovers:

- Open casing to the sales line or the wellhead compressor to reduce the wellbore pressure prior to venting.
    - Equalize with line pressure or compressor suction pressure prior to blow down operations
    - Route gas flow to sales overnight if possible

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Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
BMP – operator onsite monitoring	Operator	In use	High	Low
Artificial lift engine (rod pump)	https://ediplungerlift.com/products/engine-packages/	In use	Medium-High.[138]	Medium
Plunger Lifts	https://ediplungerlift.com/products/plungers/	In use (common)	High	Low-Medium

It is important to note that artificial lift deployment is a process that operators carry out to maximize production and production value currently. A well may start off with sufficient production rates to lift liquids out of the wellbore but as the wells production declines below the critical rate, artificial lift must be implemented to optimize production. The operator will select the best artificial lift method based on the well parameters and current conditions. The manual liquid unloading events being discussed in this report are primarily related to the action that must be taken due to an abnormal operating condition, such as an increase in the gas sales line pressure. The increased line pressure causes the well to load up with liquid and production to decrease. This applies to both free flowing wells and wells with plunger lift installations. The act of venting the well through an atmospheric storage tank creates the differential pressure necessary to unload the liquids from the well and return the well back to normal operation.

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

Artificial lift engines

[138] The feasibility of installing a rod pumping system on a well depends on a number of variables such as the depth, casing size and production rates.

NMED Exhibit 10 - 0213

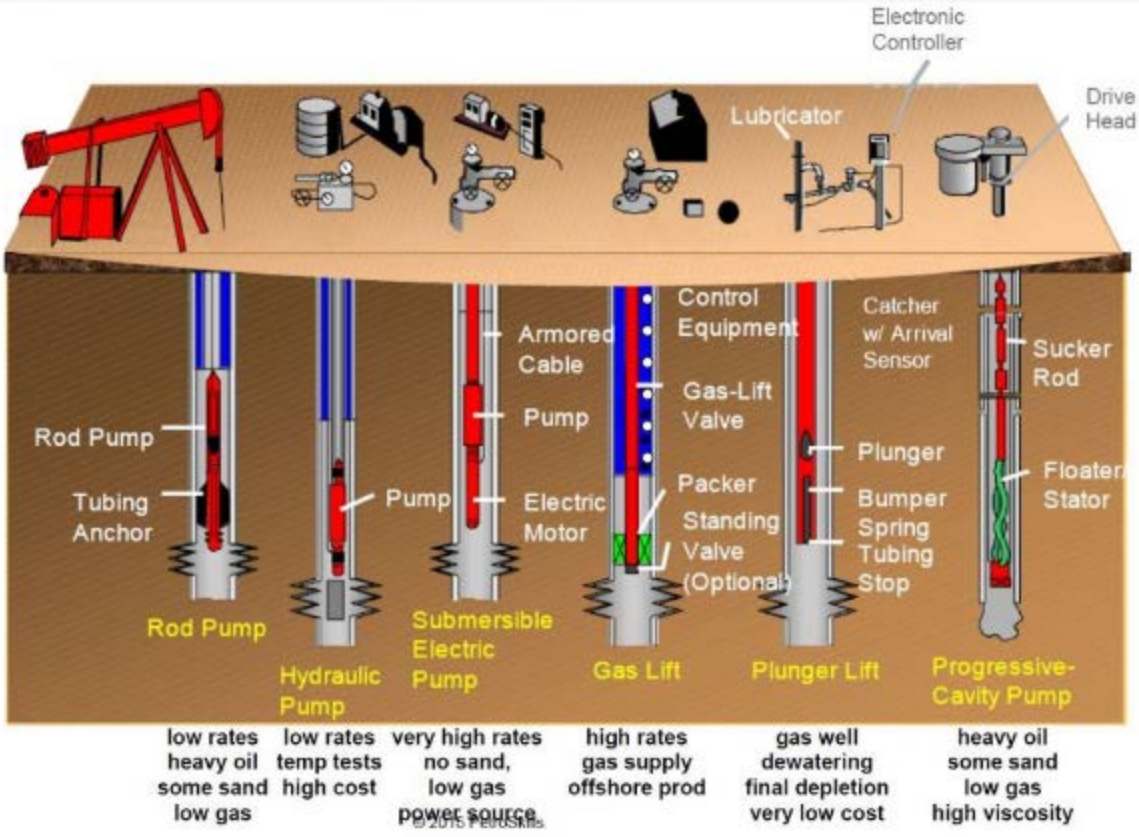


Figure 1-1 *Examples of the primary methods of artificial lift.*

Source: https://www.petroskills.com/blog/entry/00_totm/sept17-sub-totm-artificial-lift?page=5#.XZO2dm9KjIU

As shown above the various artificial lift methods have limitations and drawbacks. It is critically important to consider the application of artificial lift on an individual well basis.

What are the pros and cons of the alternatives?

Pro: The act of liquids unloading increases production. Mitigating unloading emissions increases production and minimizes emissions. Artificial lift engines can prolong the life of a well and operate at lower pressures than plunger lifts (i.e., wider operating range). (*source*: https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-liquids-unloading.pdf)

Con: external power source required, higher cost

What is needed and available for new wells?

See above

What is needed and available for existing wells?

See above

What technology alternatives exist for this equipment or process itself?

Plunger lifts (See above schematic)

There are many artificial lift options available and must be selected based on the well parameters and wellsite conditions.

What are the pros and cons of the alternatives?

See above

Pro: The act of liquids unloading increases production. Mitigating unloading emissions using plunger lifts increases production and minimizes emissions. Estimates indicate production increase of 3 to 300,000 scf/day.

Con: Plunger lifts can operate at low-pressure wells but they do have pressure limits.

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

The cost to achieve methane emission reductions by monitoring the manual venting of a well is tied to the incremental labor cost associated with monitoring each event. The cost to monitor each event is unique in terms of the well configuration, associated pressures (tubing, casing and line).

The cost to reduce the wellbore pressure prior to a workover operation is minimal and is usually offset by the sales proceeds of the gas being sold.

Depends on reduction technology, effectiveness and gas price. Increased productivity in addition to cost benefits of the saved gas can lead to overall savings for artificial lift engines or plunger lift systems.

Table 1 of the "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico" lists per unit costs for installing a plunger lift system in gas wells as $5.03 per mcf of reduced methane ($261.56 per tonne).[139]

[139] "Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico," Erin Camp, PhD, Nate Garner, Asa Hopkins, PhD, Synapse Energy Economics, Inc., September 13,

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What would be the implementation cost?

For new wells?

N/A

Based on results reported by Natural Gas STAR Partners, the cost of implementing artificial lift systems range from $41,000 - $62,000. This is an old report and estimates have likely decreased.[140]

Gas STAR estimates for plunger lift installation range from $2,500 to $10,000 (*Installing Plunger Lift Systems In Gas Wells* http://epa.gov/gasstar/documents/ll_plungerlift.pdf). Some operators estimate $15,000 (ICF 2014).

For existing wells?

The cost of monitoring the manual liquids unloading events depends on how long it takes to unload the well.

Are there low-cost solutions available?

Some BMPs, like having an operator onsite to monitor unloading events, are very low cost.

Other methods (like plunger lifts or lift engines) have higher implementation costs, but are often paid for by the additive benefits of increased productivity and saved gas. In fact, ICF estimates an overall benefit of $0.05/Mcf of methane reduced by installing plunger lifts.

(Source: https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf)

If a solution is high-cost, why is that the case?

Artificial lift engines and plunger lifts require technology implementation.

Are there additional technical analyses needed to refine benefits/costs estimates?

N/A

Can develop cost-benefit estimates with industry input.

2019, page 9, Table 1, http://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf.

[140] The cost of artificial lift installation is highly variable depending on the application. The range provide from the Gas STAR Partners does not reflect the cost of all artificial lift cost. The cost of a rod pump installation could exceed $500,000.00 depending on well depth and production desired pump capacity.

NMED Exhibit 10 - 0216

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

Manual Liquids Unloading:

The lease operators are already deployed in the field to monitor manual liquids unloading events; it is a matter of prioritizing the efforts for monitoring manual liquids unloading events. Recompletion and Workover rig supervisors are experienced and trained in the best ways to minimize venting during the initial well blowdown.

Plunger Lifts and Artificial lift engines:

Many operators already utilize plunger or artificial engine lifts for liquids unloading (deliquification) activities. Indeed, one of these technologies is likely to result in less unloading emissions than manual unloading. In the event that either plunger lifts or artificial lift engines would lead to less methane emissions relative to manual unloading, an operator should verify that the lift option is technically feasible and implement that technology mitigation option for unloading at the facility.[141]

What is the useful life of equipment?

N/A

What are the maintenance and repair requirements for equipment required for methane reduction?

N/A

[141] The application of artificial lift is very dependent on the specific characteristics of each well. The operating parameters of the wells will dictate the appropriate artificial lift application. The misapplication of artificial lift could result in an increase in emissions in the case of plunger lift installations.

How would emissions be detected, reductions verified and reported?

Each venting event is timed and the emission volume calculated and reported to EPA under the GHGRP program and can be trended over time as illustrated below.

As EDF has noted, due to the reporting threshold and fluctuations in well counts, production, location, and age, the GHGRP data does not reflect all facilities or unloading events or trends thereof. Therefore, GHGRP trends should be considered in that context and not relied upon to accurately represent true liquids unloading emissions trends over time.

In addition to current estimation and reporting methods (see section 2), operators can also directly measure unloading event emissions.[142]

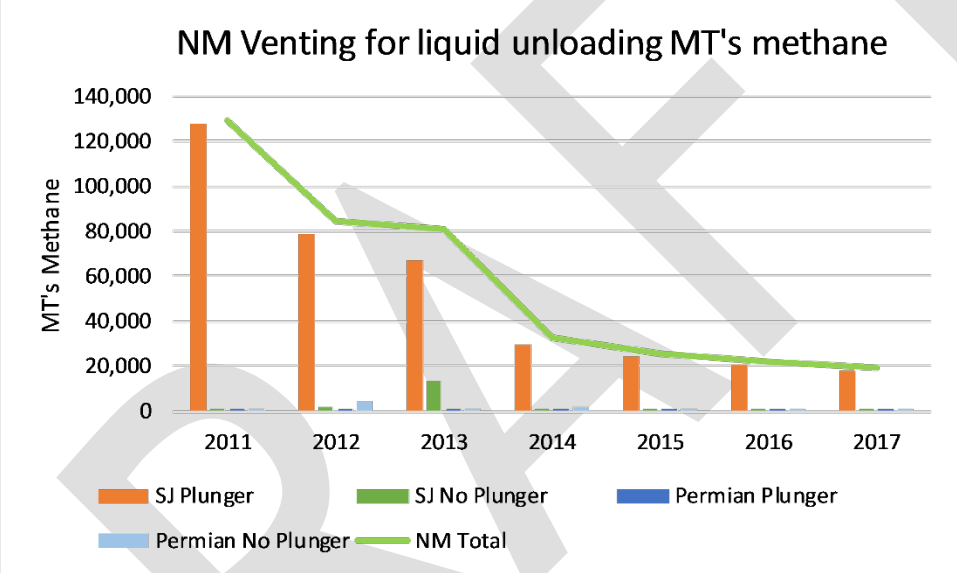


Figure 1: NM LU venting trends

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

[142] Accurate direct measurement is difficult and can result in backpressure that will impede the process of unloading or blowing down a well.

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EPA does not regulate liquids unloading.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

N/A

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

N/A

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc.?):

Safety is a core value for the industry. Being able to safely and effectively unload or blow down a well is a key point to keep in mind with methane reduction efforts during these activities.

DRAFT

5. WORKOVERS AND LIQUID UNLOADING - PATH FORWARD[143]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EMISSIONS REDUCTIONS ARE EASY TO ACHIEVE AND ARE COST EFFECTIVE 1 = EASY 5 = HARD	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
7.1	Create differential pressure to eliminate the need to vent a well to unload liquids.	▪ Equalize the well ▪ Allow the well to build pressure Colorado rule [page 211]	1 2 3 4 5		San Juan Permian Both
	COMMENT A. Explanation of differential pressure [page 201]: The well pressure has to be greater than the pipeline pressure for the well to flow. If the well is also unloading liquids then the well pressure will have to be greater than the pipeline pressure plus the hydrostatic pressure of the liquid plus the friction of the liquids to flow. This differential pressure can be maximized by several methods depending on the wells characteristics. For example, shutting in the well for longer periods, or minimizing the after flow after the liquid slug or plunger arrives at the surface, or tripping the plunger more often are methods of creating the required differential pressure for the well to flow.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
7.2	As a best management practice, minimize volume vented for manual liquid	Route the initial volume of gas to the sales line prior to venting, monitor flow rate and pressures and vent once	1 2 3 4 5		San Juan Permian

[143] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

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	unloading events by lowering the wellhead pressure	the rate or pressure indicate additional differential pressure is necessary to unload.			Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
7.3	As a best management practice, monitor manual venting onsite, in close proximity or via remote telemetry.	Reduce the venting time and emission volume by returning well to normal operation as soon as possible			
	COMMENT A. Place performance standards on monitoring systems to ensure a minimum level of accuracy. [page 208]		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
7.4	As a best management practice, minimize venting for workovers by lowering the wellhead pressure as much as possible prior to blow down.	Open casing to the sales line or the wellhead compressor to reduce the wellbore pressure prior to venting. ▪ Equalize with line pressure or suction pressure prior to blow down operations.			
	COMMENT A. Reduce wellbore pressure as much as possible prior to opening to atmosphere via storage tank. [BMP] [page 211] B. There are not rules that address workovers in other states. [page 202] C. BMPs need to be flexible and not dictated. D. Maybe guidance documents not regulations for BMPs.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
7.5	As a best management practice, consider the lowest-emitting liquids unloading	Select the lowest-emitting, technically feasible option if economically viable.			

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	option between (1) artificial lift, including plunger lifts, and (2) supervised manual unloading. Verify the option is technically feasible and implement that option for liquids unloading at the facility.	The different options available for artificial lift are considered to optimize well production. Well conditions as well as other considerations such as availability of adequate, reliable electricity and well economics are considered prior to installation.			
	COMMENT A. We're focused on liquids unloading and not artificial lift.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
7.6	Establish a liquids unloading emissions limit (e.g., emissions per event, emissions per facility, or some combination thereof)	Operator may choose any of the three unloading options (or others that become/are available) as long as they can demonstrably meet the established emissions limit.			
	COMMENT A. It would be very hard to set a predetermined limit on emissions given all of the different circumstances in the field. [page 210] B. What would be the recourse if a well could not meet a predetermined limit? Premature plugging? C. Given the differences in individual well and reservoir characteristics it would be difficult to have a single emissions limit per event. [page 210] D. Path forward 6.6 is not a control method that operators can take to reduce methane emissions but the goal of our whole process. There are too many variables involved at each wellsite to predetermine what an allowable emission limit should be.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

NMED Exhibit 10 - 0222

SECTION 8, SEPARATORS / HEATERS / STORAGE VESSELS

Discussion for MAP members on October 24, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

There are two primary basins in New Mexico. The San Juan Basin produces primarily natural gas with the possibility of some crude/condensate. The Permian Basin produces primarily oil with associated natural gas. Production facility operators process (separation and treating) the production (oil, gas and water) from the wells to meet pipeline/truck specifications for sales (oil and gas) or disposal/recycling (produced water). Process equipment in use can date back to pre-1940's.

Production facilities can vary based on many factors. Design considerations include, but are not limited to:

1) Rates – Oil, gas, water, gas-to-oil ratio (GOR), decline, etc.
2) Composition – dry gas, heavy oil, light condensate, sweet (low H2S), sour (high H2S), etc.
3) Product Takeaway Specifications – natural gas water content, Reid Vapor Pressure, API gravity, etc.
4) Secondary, Tertiary, etc. Recovery Strategies – Gas Lift, Electric Submersible Pump (ESP), Beam Pumping, etc.
5) Location – Equipment size/count/spacing constraints, automation strategy, storage strategy, etc.
6) Regulatory/Permitting Requirements – recovery, combustion, venting strategies

Common equipment used in production facilities includes:

1) Pressure Vessels ("Separators") – Vertical, horizontal, 2-Phase (vapor/liquid), 3-Phase (vapor/light-liquid/heavy-liquid), heated ("heater treaters" or "production units"), un-heated, etc.
2) Storage Tanks
3) Pumps
4) Compressors
5) Combustion Equipment – flares, enclosed combustors, etc.

6) Fluid loading points

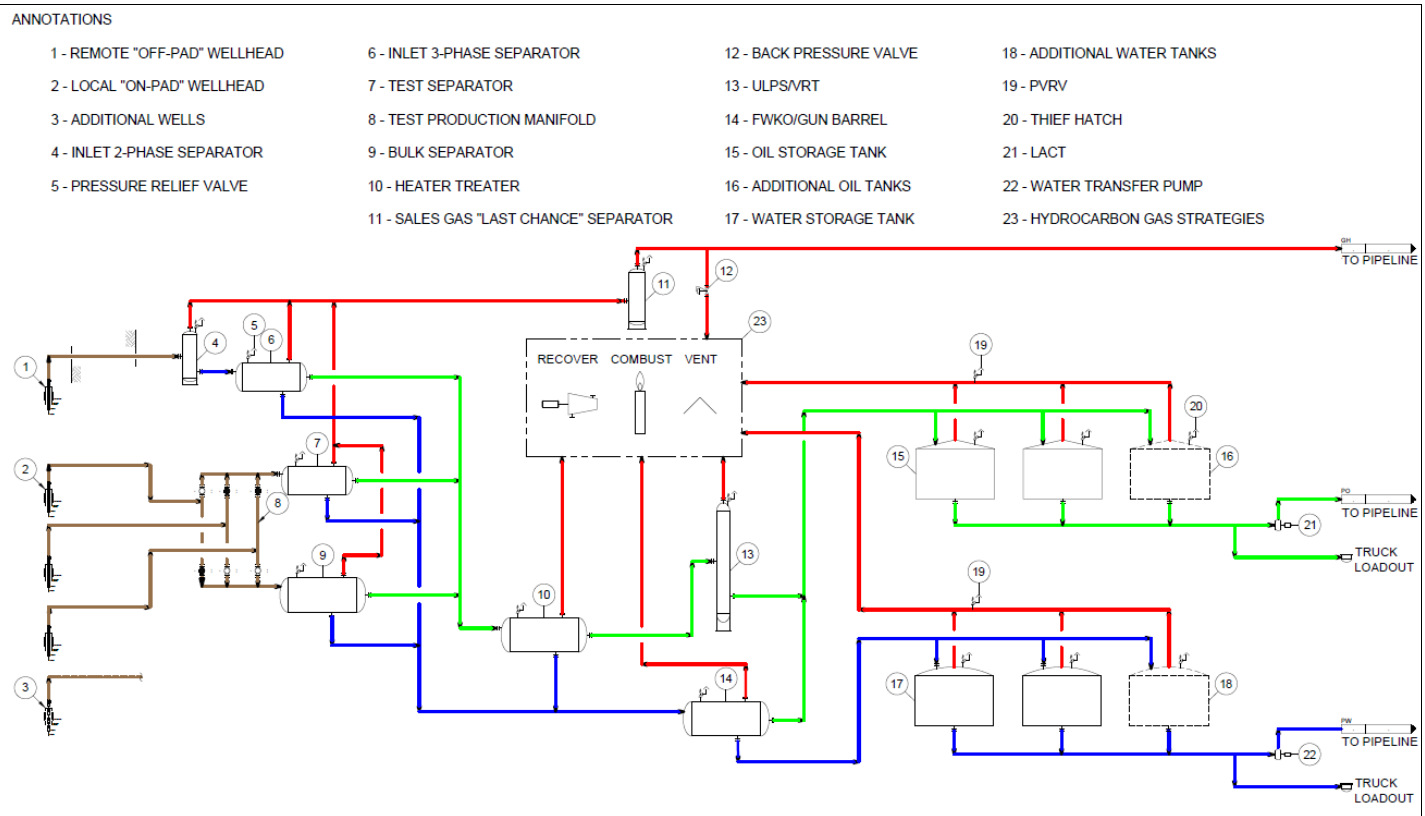
NOTE: Production facilities often contain additional equipment including compressors, pneumatic devices, flares, and vents, which are discussed in separate MAP topic papers. Leak detection and repair (LDAR) for pressure vessels and storage tanks is also discussed in a separate MAP topic paper. Unless otherwise stated, the process descriptions and operational discussions throughout this paper assume a production facility that is properly authorized and operating under normal (non-upset) conditions.

A general process description for production facilities is below. It should be used in conjunction with the below process flow diagram with accompanying annotations. Note: the center box shows the 3 potential ways of managing vent gas: recovery (typically compression to sales or site use), combustion (typically flaring), or venting. See page 22 for further description about the drivers and challenges when determining a particular vent gas management strategy.

From the wellhead, the combined production stream (oil, gas and water) flows to inlet separation processes (i.e. some configuration of 2-Phase and 3-Phase separation) where it is mechanically separated into independent streams. After initial separation, and if necessary, secondary stages of separation are typically applied to

1) oil (e.g. “Heater Treaters”) for further conditioning to meet sales specifications
2) gas (e.g. “Sales Separators”) to prevent inadvertent flow of oil to gas takeaway due to upset conditions (e.g. dump valve malfunction)
3) water (e.g. “Free Water Knockouts” and “Gun Barrels”) to prevent inadvertent flow of oil to water takeaway due to upset conditions (e.g. dump valve malfunction)

Beyond secondary stages of separation, it is common to flow oil to vapor recovery tower (“VRT”) to safely recover as much flash gas as possible prior to storage. Oil will ultimately flow to storage tanks and be sold (typically via Lease Automatic Custody Transfer (LACT) Unit) to pipeline or truck. Water will ultimately flow to storage tanks and be sent to disposal/recycle via pipeline or truck. Under normal operating conditions, associated gas (from inlet separation) is sold via pipeline. Under upset conditions, associated gas must be recovered, combusted or vented. Vapor from all other stages of separation and storage is recovered, combusted or vented.



In its most basic form, a production facility is used to process raw production (oil, gas and water) to meet sales specifications. The goal is to maximize recovery while minimizing cost. The challenge is to do it effectively, safely and within compliance. Our tools are pressure, temperature, gravity, time, chemistry, surface area and agitation.

1 - REMOTE "OFF-PAD" WELLHEAD
Wellheads may be located remotely away from the production facility. This distance can be anywhere from 50’ to 2 miles or longer. Production is delivered to the facility via a “flowline”.
2 - LOCAL "ON-PAD" WELLHEAD
Wellheads and production facilities may even share the same pad. It is also not uncommon for a production facility to have both remote and local wellheads.
3 - ADDITIONAL WELLS
Production facilities are not limited by well count. They can be designed to accommodate ranges from single well applications to an entire section or more.
4 - INLET 2-PHASE SEPARATOR (PRESSURE VESSEL)
Typically used to separator gas from bulk liquids (oil & water). Note that vertical separators are more common in higher GOR applications. It is also important to note that all vessels may be heated or unheated.
5 - PRESSURE RELIEF VALVE
Safety device designed to prevent critical failure during upset conditions. PRV’s used on pressure vessels typically use simple spring-loaded actuators.
6 - INLET 3-PHASE SEPARATOR (PRESSURE VESSEL)
Typically used to separate all three production streams (gas, oil & water). Note that horizontal separators are more common in lower GOR applications.
7 - TEST SEPARATOR (PRESSURE VESSEL)
It is common for operators to employ either a “single well separation” or a “test well separation” strategy. Single well separation strategies utilize an inlet separator for every well (typically for measurement purposes). Test well

separation strategies employ a test separator that cycles wells for a certain period (remaining wells flow to bulk separator when not in testing).
8 - TEST PRODUCTION MANIFOLD
Used in test separation strategies to direct flow of wells to either test separator or bulk separator.
9 - BULK SEPARATOR (PRESSURE VESSEL)
Used in test separation strategies for wells not in their testing cycle.
10 - HEATER TREATER (PRESSURE VESSEL)
Typically employed as a second stage of separation. Its purpose is to further “treat” the oil with heat and additional residence time to ensure it meets sales specifications.
11 - SALES GAS "LAST CHANCE" SEPARATOR (PRESSURE VESSEL)
Used to recover any additional entrained hydrocarbon liquid within the gas stream that may have slipped previous stages of separation.
12 - BACK PRESSURE VALVE
A “BPV” hold processes to a desired pressure for a facility to operate as designed. The illustrated BPV in the diagram is specifically used as a common response to upset (high) sales line pressure conditions.
13 - ULPS/VRT (PRESSURE VESSEL)
A VRT/ULPS is a special type of 2-Phase separator designed to operate at as low of a pressure as possible to minimize flash gas in storage vessels. It is typically used in conjunction with a VRU to deliver flash gas to sales. It was designed out of the need to avoid risks associated with vapor recovery from near atmospheric storage vessels.
14 - FWKO (PRESSURE VESSEL)/GUN BARREL
Used to prevent oil from flowing to water storage due to imperfect separation or upset conditions (e.g. dump valve FAIL-OPEN malfunction).
15 - OIL STORAGE TANK
Oil tanks store product prior to being delivered to sales via truck or pipeline. Their height is used as a driving force (i.e. head pressure) to make delivery easier. They are typically constructed with steel and have a pressure rating between 0-1 PSIG (0-16 OSIG). It is critical to note that this small pressure range yields drastically different operational strategies.
16 - ADDITIONAL OIL TANKS
The quantity of tanks is determined by rate and is a risk-based decision from the operator.
17 - WATER STORAGE TANK
Water tanks store byproduct prior to being delivered to sales via truck or pipeline. They are typically constructed with fiberglass or steel and have a pressure rating between 0-1 PSIG.
18 - ADDITIONAL WATER TANKS
The quantity of tanks is determined by rate and is a risk-based decision from the operator.
19 – PVRV
A Pressure-Vacuum Relief Valve is a safety device designed to prevent critical failure during upset conditions. The illustrated PVRV in the diagram is specifically used on storage vessels. Due to the small design pressure range of storage vessels, small differences in set pressure can yield significantly different operating strategies.
20 - THIEF HATCH (Maintenance hatch)
An opening in the top of a storage tank. Typically used by operators for a variety of reasons, these are sized similar to the storage tank PVRV. The thief hatch allows tank access for a thief or other level measuring device. Opening and closing of a thief hatch is a manual operation by an operator.
21 – LACT
Used to deliver oil to sales via pipeline or truck at required pressures typically higher than atmospheric.
22 - WATER TRANSFER PUMP
Used to deliver water to disposal/recycle via pipeline or truck at required pressures typically higher than atmospheric.
23 - HYDROCARBON GAS STRATEGIES

Gas streams operating below pipeline pressure must either be recovered, destroyed or vented. Each strategy comes with its own benefits and challenges. Examples of engineering considerations can be found in the chart below. Utilization ranges from a single strategy to a combination of all three. As noted in the chart, the design complexity and costs increase as one progresses from venting to recovery of storage tank vents. In general, the more complex combust/recovery installations are at larger surface facilities where there is adequate gas volume for capture, appropriate available infrastructure, such as grid power, and sufficient production to support the installation and operational costs.

	RECOVER	**COMBUST**	**VENT**
STRENGTHS	• Gas to Sales • >95% Efficient • Centralized Production Opportunities • OOOOa Enforceable if Applicable	• Not as complex as recovery - No 3rd Party Maintenance • More reliable than recovery • >95% Efficient • OOOOa Enforceable is Applicable	• Negligible Complexity • Negligible Cost

CHALLENGES	• Requires Compression
	• Requires Power/Fuel
	• Measurement
	• Complexity
	  - Mechanical Design Considerations
	  ▪ Suction Piping Design
	  ▪ Discharge Piping Design
	  ▪ Placement of Equipment
	  - I&E Design Considerations
	  ▪ Installation of Instrumentation
	  ▪ Selection of Instrumentation
	  ▪ PLC
	  ▪ Communications
	  - Vendor/Unit Selection
	  - *(Tanks)* Incorrect Composition
	  ▪ Oxygen
	  ▪ Blanket Gas
	  - *(Tanks)* Set Point Limitations
	  ▪ Retrofit Complications
	• Area Classification
	• Downtime Considerations
	• Maintenance
	  - Service in the area?
	• Operational Deviations
	  - Training
		• Requires Flare/VCU
		  - "Off the shelf"
		  - Custom Design
		• Requires Power/Fuel
		• *(LP Only)* Difficult to Measure
		• Complexity
		  - Mechanical Design Considerations
		  ▪ Vent Header Design (ΔP)
		  ▪ Stack Height
		  - I&E Design Considerations
		  ▪ Installation of Instrumentation
		  ▪ Selection of Instrumentation
		  ▪ PLC
		  ▪ Communications
		  - *(LP Only)* Smokeless Combustion
		• Incorrect Composition
		  - Arrestor Limited Protection
		• Large Radius of Exposure
		• Downtime Considerations
		• Operational Deviations
		  - Training
		  - Thief Hatches
		• Construction Deviations
		  - Equipment Verification
			• 0% Efficient
			• Safety: Risk to Personnel
			  - Toxicity
			  - Asphyxiation
			  - LEL

	- Thief Hatches - Suction Pressure Control Sensitivity ▪ VFD, etc. • Construction Deviations - Equipment Verification		

24 - Vent pipeline-Generally denotes pipelines that allow for pressure equalization for the head space of vessels. Use of the word "vent" does not necessarily imply that the vessel is vented to atmosphere-rather than the vessel utilizes a vent system to manage vapors produced in vessels.

https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry

https://library.e.abb.com/public/34d5b70e18f7d6c8c1257be500438ac3/Oil%20and%20gas%20production%20handbook%20ed3x0_web.pdf

Mid-stream tank configuration description:

On the midstream side, storage tanks are used in a variety of ways. At compressor stations, liquids from inlet scrubbers, compressors and glycol dehydrators can be temporally stored in tanks. Midstream storage tanks can also contain liquids that may accumulate in gathering system lines over time. These liquids from lines can be removed/recovered by "pigging" the line. Pigging is a process involving a plug that is forced through the line, pushing accumulated liquids ahead of it to a pig catching station where it is recovered to tankage. The process of pigging only happens periodically as needed and results in short term emission events, not continuous. These emission events are typically covered by the operating permit for the site where the tank is located. Volume of liquids in the lines removed by pigging varies greatly on the type of product moving through the line and the size of the pipe.

Below are additional technical details.

Pressure Vessels:
The American Society of Mechanical Engineers (ASME) defines pressure vessels as "containers for the containment of pressure, either internal or external." Two common exemptions from this definition are

1) "Vessels having an internal or external pressure not exceeding 15 psi"
2) "Vessels having an inside diameter, width, height, or cross sectional diagonal not exceeding 6 in., with no limitation on length of vessel or pressure"

Based on this definition, it is reasonable to assume that all separators (e.g. Inlet 2Phase, Heater Treaters, Sales Separators, etc.) are pressure vessels. There could be some exception applied to VRT's based on individual design considerations. One glaring clarification to make, however, is that storage tanks are not pressure vessels.

The primary function of pressure vessels in the oil & gas industry is phase separation. The three basic separation principles applied are:

1) Mechanical separation of immiscible fluids using gravity
2) Partial vaporization of a homogenous, single-phase solution using heat transfer
3) Flash vaporization of a homogenous, single-phase solution using pressure reduction

Pressure vessels may be

1) Oriented vertically or horizontally
2) Heated or unheated
3) Configured for 2-Phase (V/L) or 3-Phase (V/L/L) separation
4) Outfitted with internals (plates, weirs, etc.)

5) Etc.

It is common practice to operate pressure vessels at as low of a pressure as possible. The two primary constraints are

1) Having enough pressure to get into the gas sales line (Inlet separation only) and
2) Having enough pressure to dump liquid(s) to the next stage of the process.

Higher pressures yield more flash vaporization downstream in the process. Pressure is typically maintained on the vessel by use of a valve. There are a variety of valves for a variety of applications.

LINK: https://blog.kimray.com/what-does-back-pressure-mean-and-why-is-it-important/

Liquids flow out of the vessel using a liquid level controller in conjunction with a level control ("dump") valve. Once liquid in the vessel reaches a determined set point, the level controller will send a signal to an actuator that will open or close the valve accordingly. Three common types of liquid level controllers are

1) Discrete (1/0) Switch – Sends a command to either open or close. Does not have a range. Can have either a pneumatic or electric signal to a respectively pneumatic or electric actuator. Typically used on scrubber (pressure vessels in low liquid dropout service (e.g. fuel scrubbers)) dumps.
2) Displacer – Sends a ranged command to either open or close. The more the displacer travels, the more the actuator/valve responds. Can have either a pneumatic or electric signal to a respectively pneumatic or electric actuator. It is common for displacers to be configured as either "snap" or "throttle". A snap controller yields a more aggressive actuator response to displacer travel and is useful in applications with lower liquid rates. A throttle controller yields less aggressive actuator response and is useful in applications where it is important to maintain a certain liquid level within a process.
3) Mechanical – Sends a ranged command to either open or close. The more the float travels, the most the valve responds. Mechanical floats are mechanically attached to the valve.

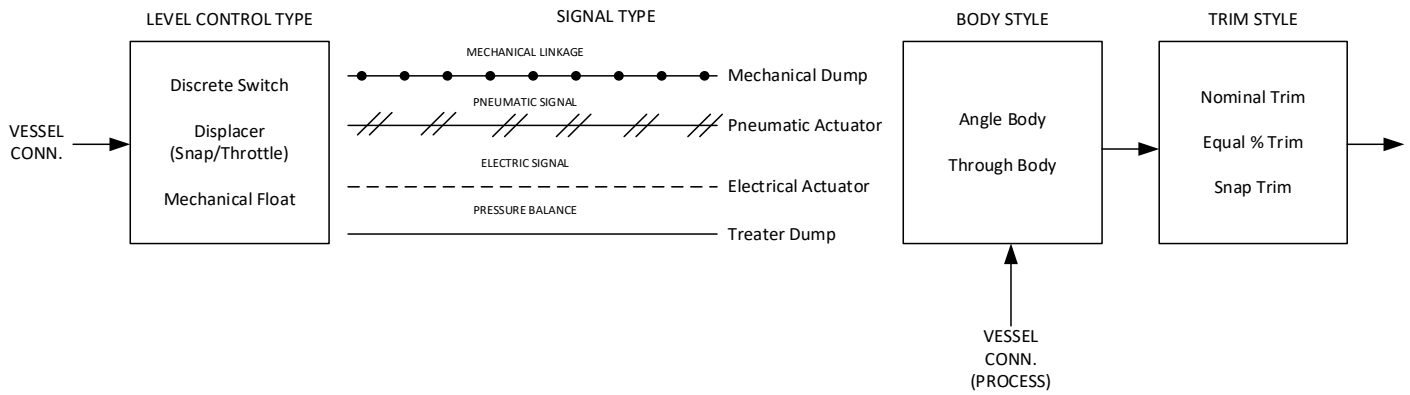
LINK: https://blog.kimray.com/valve-actuator/
LINK: https://blog.kimray.com/how-does-the-kimray-dump-valve-work/
LINK: https://blog.kimray.com/how-to-operate-the-kimray-high-pressure-control-valve/
LINK: https://blog.kimray.com/valve-sizing-3-most-important-factors-selecting-control-valve/

Pneumatic actuators are used to manage the fluids in the separator, heater treater, and storage vessels, and require the use of a gas. Pneumatic operations are discussed in a separate MAP Topic paper.

Trim style is also important to consider and is selected based on how a valve needs to operate as a function of stem travel.

LINK: https://blog.kimray.com/3-types-control-valve-trim/

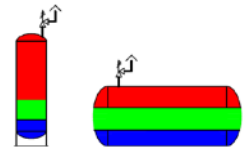
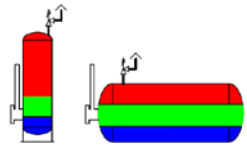
The below flowchart depicts common configurations. Configuration selection considers cost, availability of power/instrument air/instrument gas, reliability, required dump rates, etc. The impact of selection is the instantaneous dump rate yielded. It is important to consider instantaneous rates when designing a facility.



Dump valve failures do occur and typically result in the valves inability to fully close. This can be caused by a stuck debris (plug pieces, sand, etc.) or worn seats, stems and balls. Critical failure (100% Cv) of a dump valve is rare and is considered an upset condition that requires engineered safety controls (i.e. pressure relief valves). Regardless of the extent of the failure, if it is left unattended it will eventually empty the vessel of all liquids, allowing gas to leak or "blow by" to the next stage of the process. If communications are available on site, it is possible to install a level switch that will trip in a low liquid event.

For simplicity, pressure vessels used at production facilities are organized into one of three categories

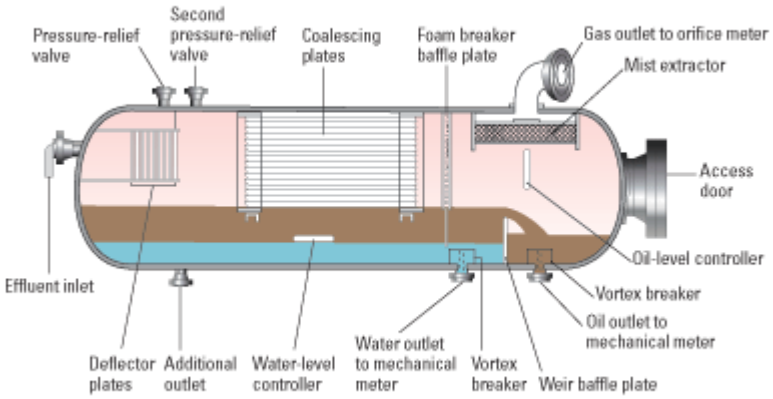
1) Normal Pressure Vessels
2) Heater Treaters
3) VRT's

Category		Pressure	Temperature	Separation Principle(s)	Comment
Normal Pressure Vessels		15-1440 PSIG	Variable	Mechanical Flash Vaporization	Inlet separators, 2Phase, 3Phase, Sales Separators, FWKO, etc.
Heater Treaters		< First Stage	80-140 °F	Mechanical Flash Vaporization Heat Transfer	Uses fuel gas for combustion
VRT's		0-5 PSIG	Variable	Mechanical Flash Vaporization	Gravity feeds to tanks; no dump valve

It is critical to note that the purpose of the VRT is to be used in conjunction with a VRU (where the gas can be sold) to minimize flash vaporization in the tanks. While using a VRU to pull vapors directly from the tanks is theoretically feasible, the potential risk of introducing oxygen into a hydrocarbon rich vapor space adds complexity to the design. If there is inadequate gas produced by flash vaporization in the tanks, the compressor will pull the pressure of the tank below zero (vacuum). The result would be the activation of a PVRD which would allow air to be drawn into the head space of a tank and commingled with the flash gas sent to sales. Introducing oxygen into a hydrocarbon rich vapor space also creates the possibility of an explosive atmosphere. Failure of the PVRD to draw in adequate air to relieve the vacuum may result in tank collapse/failure. In addition, introduction of air/oxygen into the gas stream may result in rejection of the gas due to

composition specification. The result could be flaring of additional gas at the site due to the quality issues. Blanket gas systems can be installed to mitigate the vacuum/introduction of air issue. However, there is disagreement on the use of blanket gas as a viable solution to this challenge. For sites with low production of flash gas and/or limited access to appropriate electrical power other methods may produce more emissions than the alternative. Regardless, the use of a VRT can reduce phase separation VOC's in the tanks by 90+%.

Typical 3-Phase Separator:



https://www.glossary.oilfield.slb.com/en/Terms/s/separator.aspx

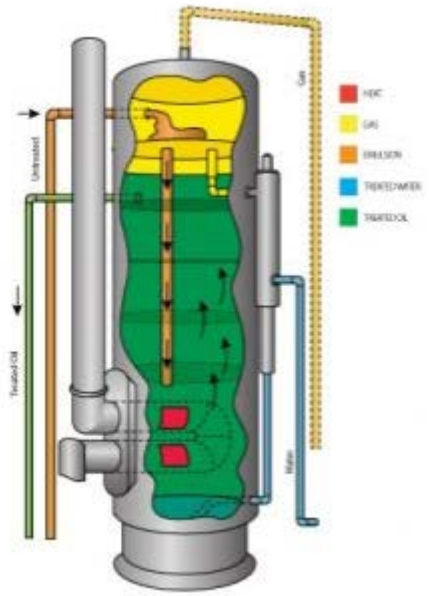
https://hy-bon.com/blog/use-the-power-of-the-vapor-recovery-tower/#targetText=Using%20a%20vapor%20recovery%20tower,a%20crude%20oil%20storage%20tank.

VRT training: https://hy-bon.com/products/vrt/

https://petrowiki.org/Oil_and_gas_separators

Separator design manual: https://pacs.ou.edu/media/filer_public/c9/4a/c94a97ac-9609-4262-ab06-b7b2dda1c4fa/3_oil_and_gas_separation_design_manual_by_c_richard_sivalls.pdf

Figure of Typical Vertical Heater Treater:



(Reference: TCEQ Upstream O&G Heaters and Boilers Final Report, August 30, 2013

https://naturalgasindustryhub.com/what-are-heater-treaters/

Storage Vessels (Tanks):

Tanks are designed to operate at "near atmospheric" pressure. It is common practice to refer to their design rating in ounces of pressure instead of pounds. One (1) pound per square inch gauge (psig) = 16 ounces per square inch gauge (osig).

In the most recent version of API 12F (January 2019), tanks built to the standard have a design pressure of 16 (ounces per square inch gage) osig (with provisions for 24 osig during emergency upset conditions). However, existing tanks throughout New Mexico can have a design pressure ranging from 0-16 osig and be constructed with either carbon steel of fiberglass (only used in water service). 8 osig for carbon steel tanks and 4 osig for fiberglass tanks are likely the most common at existing sites.

Tanks in the production sector of the oil and natural gas industry are used to temporarily store segregated oil and water. Storage vessels can be installed as a single unit or in a grouping of similar or identical vessels, commonly referred to as a "tank battery." The reason for temporary storage is for feasibility of takeaway via pipeline or truck. In cases of pipeline (and pumps in general), it is important to minimize the number of times fluid drivers cycle on and off. There are also net positive suction head requirements to consider when pumping oil. In cases of trucking, it is important to have an appreciable load for takeaway. At sites where multiple tanks are located, tanks are often connected by a manifold. The method of tank operation varies depending on site-specific conditions.

Pipeline is the preferred method of takeaway but requires both a pipeline and available power. Trucking is the other option and has emissions associated with it that are quantified using EPA's AP-42 Emissions Factors (Section 5.2). Vapor balance return lines allow operators to take credit for reduced emission factors and are relatively easy to install. However, the challenge is in finding trucks that are certified in the practice of vapor balance. It is also difficult for operators to enforce the use of vapor balance. There is a perception that truck loading is the primary cause for left open thief hatches, but there is lack of industry data to corroborate.

The industry considers three separation mechanisms from storage tanks:

1) Flash vaporization of a homogenous, single-phase solution using pressure reduction
2) "Working" Losses due to changes in tank levels from filling/emptying
3) "Breathing" Losses due to changes in ambient conditions throughout any given day

Vapors created from this separation must either be recovered, destroyed or vented. For recovery and destruction strategies, it is paramount to adequately maintain pressure on storage tanks by use of thief hatches, pressure/vacuum relief valves and emergency relief valves. Vapor will flow to the path of least resistance. If a storage tank relief device is not properly specified or correctly installed, it can become the path of least resistance. If a storage tank relief device is not properly maintained (i.e. seal failures, worn springs, etc.), it can become the path of least resistance. If a thief hatch is left open after gauging, truck loading, maintenance, etc., it will definitely become the path of least resistance. This is a challenge for storage tanks because the range of control is relatively small and very sensitive to any errors or malfunction. It is especially challenging for existing locations that have even less of a design operating pressure. This plays a pivotal role in NSPS OOOOa compliance determination for closed vent systems if applicable.

Vapor Recovery Units (VRUs) work by using a small compressor to capture and compress the vapor emissions from the oil at low to near atmospheric pressures, reducing the amount of gas that is sent to the vapor combustion device from the storage tanks. They may be operated in conjunction with VRTs, where they compress the flashed gas for sales upstream of the tanks. VRU's can also be tied directly to the tank vent header system or CVS as long as there is an adequate gas blanket system installed to capture emissions directly from the tank and routed to a sales point instead of a combustion device. The VRU compressor is driven by a small natural gas or electric engine. The size is determined by site-specific conditions and production rates. At sites where there is not an adequate and/or reliable electric power source, natural gas engines must be used. VRU's, like all compressors, are rate limited; meaning, available compressors will be too large to run efficiently to control the vapors when emissions are very low. In some cases, VRT/VRU installations may be temporary. Installations would normally occur during the early phase of a well's life when production is highest. This equipment may be removed later when production falls below an economic or operational feasibility threshold. Installation of VRU's on tank headers is generally not recommended due to the safety and gas quality concerns this may introduce to the process (see page 7). In general, for sites authorized under NOI the NMED does not consider different operating strategies. Sites are evaluated for the maximum emissions expected from a site and do not consider the emission reductions/gas capture associated with the use of VRT's/VRU's.

https://www.sciencedirect.com/topics/engineering/oil-storage

https://www.epa.gov/natural-gas-star-program/estimates-methane-emissions-sector-united-states

Provide the segment(s) of the industry that the equipment or process is found:

The equipment/process is found in the upstream, midstream, and transmission segments.

Describe how the equipment or process is used:

Addressed in previous section.

Provide the common process configurations that use this equipment or process:

Addressed in previous section.

What is the distribution of the equipment or process across business segments?

Addressed in previous section.

How has this equipment or process evolved over time?

Tank standards changed to move from 8 oz to 16 oz pressure set points due to a change in API Standard 12F in January 2019 (available by subscription at https://www.monogramwebstore.org/publications/item.cgi?fce92c8f-40c7-4108-90d2-ba38757d174c). An increase in the pressure rating allows operators to set pressure relief devices at a higher setpoint, decreasing the likelihood of triggering relief devices that could vent to atmosphere. However, not all tanks are operated at these higher pressure ranges under normal operating conditions. It is important to note that retrofitting/replacing tanks is a significant economic challenge. Replacing tanks requires existing tanks to be cleaned, tested/treated for naturally occurring radioactive material (NORM), have piping removed, transported, and sold at a price that hardly recovers any value. Installing a new tank is roughly twice the cost of the tank. Retrofitting tanks really only applies when an operator decides to switch a tank from oil service to water service due to hazards associated with fiberglass tanks. The challenge in this is adequately protecting the retrofitted tank from corrosion. Newly constructed tanks are typically internally coated with a protective barrier in between the fluid and the carbon steel wall. This is performed in a controlled environment. Internally coating a tank in the field is much more difficult and commonly results in imperfections that accelerate corrosion. An alternative option is placing sacrificial anodes in the tanks, but this requires constant maintenance. Production decline rarely makes replacing/retrofitting tanks a viable option.

Thief hatch design changes have improved resulting in better seals to prevent tank emissions to atmosphere and better relieving control (closer to tank rating).

There is some recent technology that allows for operators to monitor the open/close status of thief hatches using magnetic switches. However, at this point in its development, reliability is unproven. There is also an economic burden given that it would require installation on every thief hatch. It would also require communications for remote monitoring.

Operators may consider the type of dump valve and the use and its intended service. Snap acting valves and throttling valves can be more appropriate in different settings, and an evaluation of the most appropriate device for the setting can improve dump valve performance. Advancements in communication technology (i.e. internet, email, etc.) have made it easier to right-size valves.

The most significant evolution in upstream has been in the ability to remotely monitor and control processes. Programmable Logic Control (PLC), Supervisory Control and Data Acquisition (SCADA) systems, etc. allow operators to monitor, trend, and control different aspects of their process that are enabled through the use of instrumentation (e.g. Pressure Transmitters, Flow Transmitters, Level Switches, Level Transmitters, etc.). While SCADA is installed for operational purposes, analysis of that data and integration of more SCADA over time can result in lower emissions as facilities are run more efficiently. PLC and SCADA systems require both instrumentation and communication equipment. This poses an economic burden and may not be scalable to smaller operators or many existing locations.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

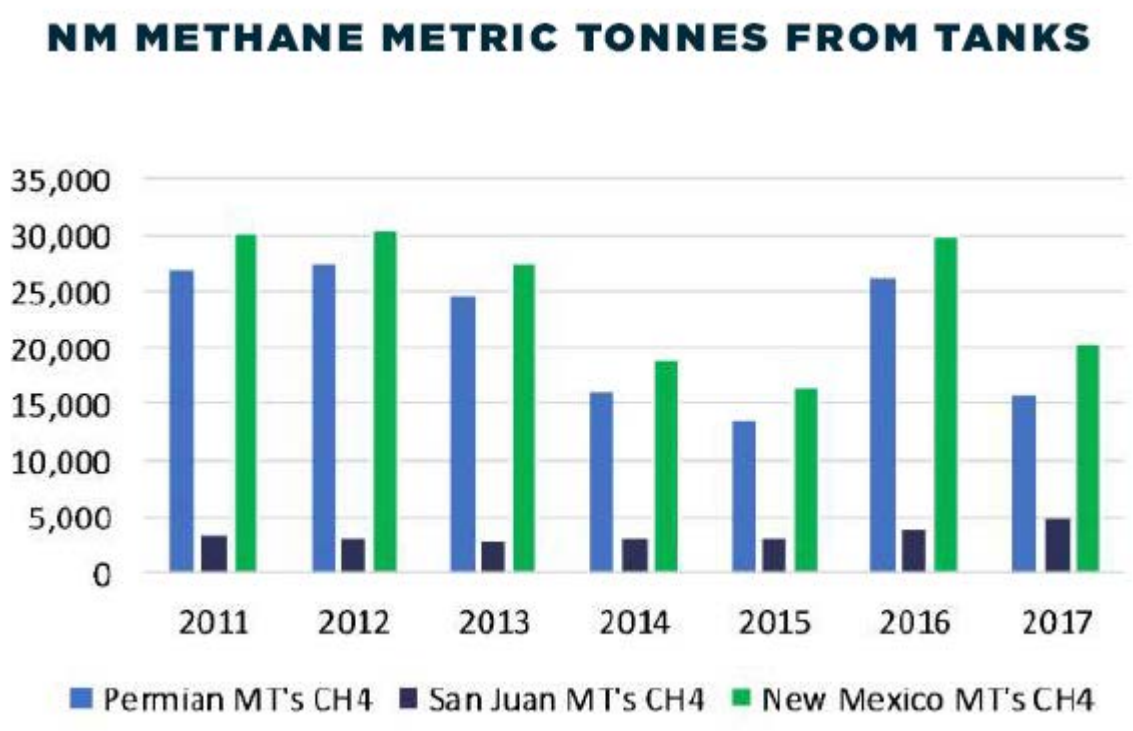
Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

Separator and tank/process flash gas are primarily composed of methane, VOCs, and small amounts of BTEX. In addition to flash emissions previously discussed, storage tanks also have the potential to create working and breathing (or standing) emissions depending upon how tank vents are handled. Working emissions are generated when liquid is added to or removed from the tanks. Turbulence in the liquid may cause vapor to be released from the oil. Breathing or standing emissions occur during the normal expansion and contraction of the tank vapor and is dependent on changes in the ambient temperature.

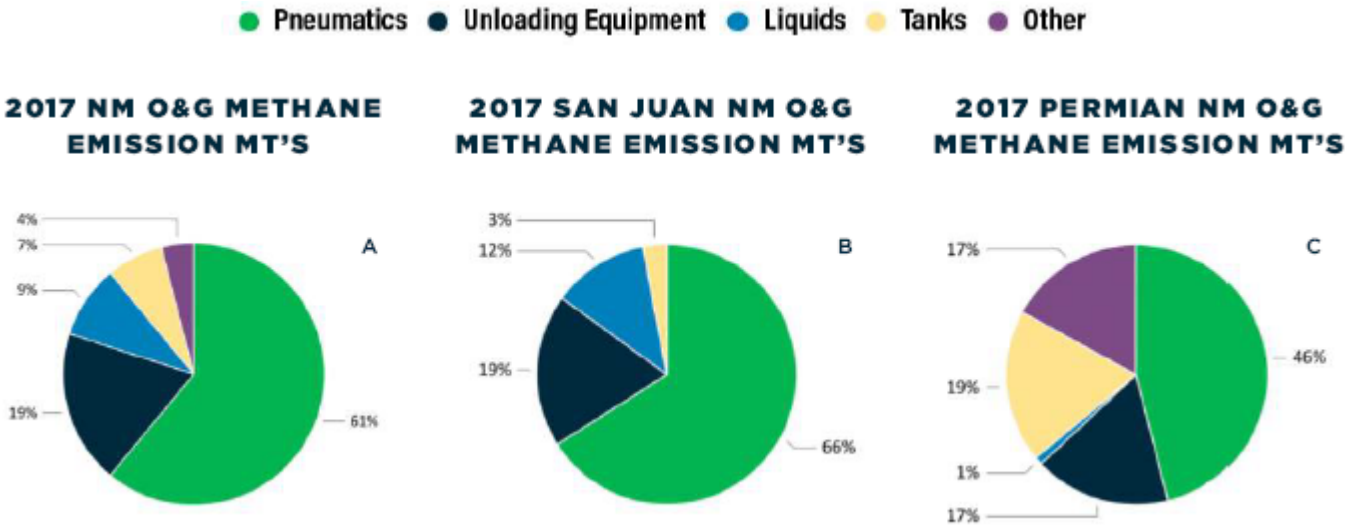
The potential methane emission sources for processing and storage vessels are thief hatches (opening in the top of a tank, which provide access for a thief or level measuring device and also often functions as a pressure/vacuum relief device), pressure vacuum relief valves (PVRV), other safety relief devices (PRV), combustion equipment associated with heater treaters, malfunctioning control equipment such as level controllers/dump valves (fugitive emissions which will be covered in the leak detection paper) and vents. If operating pressures in separators or storage tanks exceed the pressure relief device set point, the device will vent to prevent vessel over-pressure. For thief hatches, worn or dirty gaskets may also prevent a tight seal from forming. Any methane emissions from combustion equipment (e.g. heater treaters, line heaters, and vapor combustion devices/flares) would be very small as combustion efficiency greater than 98% is expected.

In general, emissions in this category come from #2 and #19 in the flow chart on page 2.



https://d3n8a8pro7vhmx.cloudfront.net/nmoga/pages/1008/attachments/original/1563831145/NMOGA_MethaneMitigationRoadmap.pdf

The emissions reported to subpart W include flashing, breathing and working losses, but do not include emissions from tank thief hatches or other system/VRU malfunctions.



Per Synthesis data[144], as reported in the April 11th, 2019 EDF report[145] and associated data platform[146], EDF estimates about 23,000 metric tons of methane from tank vents in New Mexico in 2017 (55% from produced water tanks and 45% from oil/condensate tanks). Additionally, EDF estimates about 650,000 metric tons of methane from all sources that result from abnormal process conditions in NM, https://www.edf.org/energy/explore-new-mexicos-oil-and-gas-pollution There are many observations by researchers and authors of measurement studies which suggest that storage tanks are the likely release point of most large emissions and many of these may be due to abnormal conditions such as tank control system failures and upstream malfunctions such as stuck separator dump valves. "Anecdotal data" is based on or consisting of reports or observations of usually unscientific observers. (https://www.merriam-webster.com/dictionary/anecdotal)

Control System Failures

Tank control system failures can also lead to methane emissions. Common causes of system failure include the following:

- Design Flaws
  - VRUs undersized
  - Separators undersized / dumping very frequently
  - Separator dump valve leakage
  - Liquid pooling
- Mechanical Failures
  - Thief hatch mechanical failure (gasket failure, weak or defective sealing mechanisms, etc.)
  - Pilot flame fuel supply and igniter failures
  - Incomplete combustion
- Operational Failures / Errors
  - Thief hatches open
  - Other issues – intentional bypass, flares unlit
- Leaks in the system

Truck Loading

Truck loading is another source of methane emissions. As discussed in a previous section, pipeline is the preferred method of takeaway, but is only feasible if 1) a pipeline is available, 2) power is available for pumps, and 3) it is economically justifiable. If a pipeline is not available, truck hauling is the only viable option. Loading occurs at atmospheric pressure (after fluid pressure reduction), and losses occur as vapors in empty tank trucks are displaced to the atmosphere by the liquid being loaded into the tanks. These vapors are a composite of 1) vapors formed in the empty tank by evaporation of residual product from previous loads, 2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and 3) vapors generated in the tank as new product is being loaded. Utilizing a vapor balance system can reduce emissions, however, by returning these vapors to the storage vessels.

There are three state jurisdictions currently regulating truck loading, including Wyoming, Utah, and Pennsylvania. Specifically, in Wyoming, loading emissions containing greater than or equal to 6 tpy VOC and HAP emissions must be controlled. Operators of new facilities must utilize a vapor collection system or equivalent device for the truck loading operation that captures a minimum of 70% of the truck loading vapors, and to route the vapors to device with a destruction efficiency of 98%.[147] In Utah, tanker trucks used for intermediate hydrocarbon liquid or produced water must be loaded using bottom filling or a submerged fill pipe. Operators must control VOC emissions during truck

[144] Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 SCIENCE, 186–188 (2018) http://science.sciencemag.org/content/361/6398/186

[145] https://www.edf.org/energy/explore-new-mexicos-oil-and-gas-pollution

[146] https://www.edf.org/nm-oil-gas/

[147] WDEQ Permitting Guidance, at 11.

loading operations at all times using a vapor capture line. The vapor capture line must be connected from the tanker truck to a control device or process, resulting in a minimum 95% VOC destruction efficiency.[148] In Pennsylvania, since August 10, 2013, in accordance with Category 38 of the Air Quality Permit Exemptions document tanker truck load out operations are required to be equipped with controls achieving VOC, and HAP emissions reductions of 95% or greater unless their uncontrolled VOC, single HAP, and total HAP emissions are below the control thresholds of 2.7 tpy, 0.5 tpy, and 1.0 tpy, respectively. Per GP-5 and GP-5A, tanker truck loadout operations that take liquids from storage vessels with emissions above the control thresholds are required to use a vapor balancing system and ensure each truck used to unload liquids has passed an annual leak test.[149] As shown by the initial EIA, these measures will be cost effective.[150]

New Wells:

Surface facility processing and storage vessels are used in both new and existing facilities. On site storage capacity is determined based on expected production of oil and water. NSPS OOOOa requires that new, modified, or reconstructed storage tanks which emit greater than 6 tons per year of VOC reduce emissions by 95% or greater within 60 days after startup. NSPS OOOOa allows storage tanks whose emissions decrease below 4 tpy of VOC for at least 12 consecutive months to operate uncontrolled. EPA provides for removal of controls at 4 tpy as it is no longer cost effective.

Existing Wells:

Surface facility processing and storage vessels are used in both new and existing facilities. On site storage vessels capacity is determined based on expected production of oil and water. As well production rates decline, storage needs may decrease allowing for isolation or removal of some tanks.

Older existing storage tanks may not be equipped with a vapor collection and combustion device to control tank emissions depending on actual production and permitting thresholds. In some situations, it may be technically infeasible to install a control device as there may not be enough gas (volume and pressure) to safely operate a control device.

How are the emissions calculated for this equipment or process?

Emissions from storage vessels are calculated as part of an NMED air permit application, NMED emissions inventories, and EPA GHG reporting. Flash emissions are dependent on a multitude of factors, including oil throughput, oil composition, API gravity, and separator/heater treater temperature and pressure. Due to the complex nature of flash emissions, they are typically estimated using a process simulator such as ProMax and HYSIS using equations of state or by using transient programs such as OLGA, HYSIS DYNAMIC, Ledaflow. Storage tank working and breathing losses may be calculated using AP-42 equations or software built using AP-42 equations (e.g. EPA TANKS, E&P Tanks). Manufacturer's data and state/federal guidance are utilized to determine the control efficiencies of the various types of controls (e.g. VRUs, combustion devices). Typically, multiple storage vessels are connected to a single combustion device through a common header system.

For EPA GHGRP, Basins (Permian and SJ) are broken out into Production and Gathering & Boosting segments. For emission calculation purposes, the total number of oil storage tanks and associated vent management systems (VRT, VCU, uncontrolled) per location are considered along with the volume of oil produced annually utilizing storage at the

[148] EDF_PHS_EX-080, Utah Ann. Code § 307-504-4
[149] Pennsylvania BAQ-GPA/GP-5, § F(1)(a); Pennsylvania BAQ-GPA/GP-5A, § F(1)(a).
[150] Initial EIA, at 29-30.

corresponding site to calculate a methane emission estimate for each facility. Estimated emissions are reported for each segment per county. For pressure relief devices, leaks found during LDAR surveys are reported and quantified/estimated in GHGRP as well using EPA approved emission factors for the type of equipment (e.g. valve) and the type of service the equipment is in (e.g. light oil).

Note that not all storage tank emissions are reported under the Subpart W GHGRP due to the reporting threshold. Additionally, calculated tank emissions figures do not include abnormal process conditions, such as stuck dump valves or open thief hatches, which are responsible for large amounts of methane and VOC emissions.

GHGRP – Calculation tool link:
https://ccdsupport.com/confluence/display/help/Optional+Calculation+Spreadsheet+Instructions

NMED Air Emission Calculation Tool (AECT) link: https://www.env.nm.gov/air-quality/air-emissions-calculation-tool-aect/

What data is available to quantify emissions/waste for this equipment or process?

The US EPA publishes most of the emission information and activity data that it receives as part of the US GHG Reporting Program annually (https://ghgdata.epa.gov/ghgp/main.do?site_preference=normal#). By March 31st of each year, operators upload their emission information to the EPA website for the previous year (i.e. 2018 emission information was reported in March 2019), EPA undertakes a quality assurance process, and uploads the information in October to a publicly accessible website. Care should be taken in estimating emissions from this inventory for New Mexico since both the Permian and San Juan Basins span multiple states and are challenging to separate emissions between states for all source categories.

https://www.epa.gov/ghgreporting

NMED currently conducts annual emission inventories for permitted major sources. NMED will also be conducting an emission inventory for calendar year 2020 which will include emissions from all sources with an air quality construction permit (including general construction permits such as the GCP-O&G) or notice of intent (NOI). The emissions inventory will be reported to NMED by April 1, 2021.

In addition to the above-mentioned inventories, companies are required to report emissions in excess of the quantity, rate, opacity, or concentration specified by an air quality regulation or permit condition. Therefore, emissions in excess of a limit or rate established by an air permit (including the GCP-O&G, NSR, or other air permit) are reported to NMED through excess emission reports per 20.2.7 NMAC.

Various studies and information indicate tank emissions are higher than estimated and likely account for many of the largest emissions releases. Relevant studies include the following:

EDF Synthesis study: Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 SCIENCE, 186–188 (2018) http://science.sciencemag.org/content/361/6398/186

Lyon, D.R., Alvarez, R.A., Zavala-Araiza, D., Brandt, A.R., Jackson, R.B. and Hamburg, S.P., 2016. Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites. Environmental science & technology, 50(9), pp.4877-4886, https://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705

US EPA Compliance Alert: EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities, September 2015, available at https://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf

Englander, J.G., et al, Aerial Interyear Comparison and Quantification of Methane Emissions Persistence in the Bakken Formation of North Dakota, USA, E*nviron. Sci. Technol.*201852158947-8953, available at https://pubs.acs.org/doi/abs/10.1021/acs.est.8b01665

Clean Air Task Force (CATF) analysis of emissions from controlled tank systems in the helicopter study is available here: https://www.epa.gov/sites/production/files/2017-11/documents/5._catf_tank_presentation_for_inventory_workshop_final.pdf

What are the data gaps in quantifying emissions/waste for this equipment?

There are gaps in quantifying emissions at sites that do not have remote monitoring or control, and it may not be reasonable to retrofit these existing facilities.

There are also gaps in direct measurement of emissions from storage tanks regardless of whether they are destroyed or vented. In low-pressure conditions, such as storage tank vent headers, technical feasibility issues exist with measurement of these low flow, low energy flows. To improve accuracy at low volumes sent to a flare, a smaller orifice size is required but such a restriction in the flare piping introduces intolerable safety concerns when flow increases. Furthermore, an orifice meter will restrict the line to the flare such that when large volumes are flared for emergency purposes, it will result in an explosion. Other meter options such as ultrasonic or thermal mass can be more costly, and depending on technology, can be very sensitive to operating and ambient conditions at low flow conditions (e.g., thermal mass meter). In most situations, the only economically feasible form of measurement is using a thermal mass meter, which is too dependent on calibration to be considered reliably accurate. In lieu of direct measurement, process modeling or metering downstream of the compressors is a more viable option to quantify emissions.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

Costs vary widely based upon design, materials of construction, and capacity. Because the operation of VRUs is not always economical or feasible, VRUs are often leased rather than purchased by an operator.

What are the annualized operating costs for the equipment or costs associated with the process?

Costs vary widely based capacity and service conditions. VRUs are often leased and operators will be charged as long as the VRU is on site. There typically comes a point at which the operation of the VRU is no longer economic due to low volumes of gas being recovered or low gas prices.

Note that a VRU can be used to capture emissions streams in addition to tank emissions, such as dehydrators and pneumatics. This makes the economics of the VRU more attractive to an operator.

If the equipment or process is powered, what are the costs?

Generally, the processing vessels and tanks are not powered. The control equipment (controllers, actuators, process indicators) for the vessels consume power. The exception is heater treaters, which are generally use field gas to generate heat through combustion. VRUs require a powered driver for the compressor (electric or natural gas engine).

The availability of reliable and adequate voltage electrical grid power is a determining factor on control strategy. In addition to cost of power, reliability is an important consideration for control devices as interruption will result in controllers going to a fail-safe condition. If an electric VRU is on site and power fails, gas will go to flare or potentially be vented from tank pressure relief devices.

What are the maintenance and repair costs for existing or new equipment?

Costs vary widely based upon size, age, and configuration.

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

Pursuant to 20.2.72 NMAC and 20.2.74 NMAC. oil and gas companies that wish to build or modify facilities must obtain an air quality permit from NMED prior to construction based on the potential air emission rate or potential to emit (PER or PTE) of the entire facility. Air permits are required for any facility with potential emissions greater than 10 pounds per hour or 25 tons per year of pollutants with a national or state ambient air quality standard. The NMED has issued several General Construction Permits (GCP) specifically for the oil and gas industry. GCP-Oil & Gas (issued 4/27/2018) may be obtained for a variety of oil and gas facilities, and GCP-6 (issued 1/14/2014) authorizes voluntary controls for storage vessels. Both permits are relevant to current emissions concerns and aim to reduce emissions.

Smaller well pad facilities may quality to operate under a Notice of Intent (NOI) registration if potential emissions are more than 10 tons per year of any regulated pollutant, but less than the threshold required to obtain a minor construction permit such as the GCP-Oil & Gas.

The rapid growth in crude oil production in southeast New Mexico began in 2011, which corresponds with the initial NSPS OOOO applicability date. As such, many existing storage vessels are currently subject to controls under NSPS OOOO/OOOOa. In New Mexico, the enforceable state program (GCP-Oil & Gas) allows operators to account for emissions reductions processes when calculating potential emission rate (PER) to determine NSPS OOOO/OOOOa applicability for new and modified storage vessels. EPA expressly allows for operators to account for enforceable limitations under state programs to prevent operators from being subject to duplicative requirements under state and federal law. To avoid duplication, storage vessels should only be required to comply with either NSPS OOOO/OOOOa or the state program, not both. It is estimated that more than 59% of oil production in New Mexico is either subject to the control requirements of NSPS OOOO/OOOOa, subject to the control requirements of the enforceable state program, or utilizes process equipment which results in emission rates that allow for registration under the NOI.

According to DrillingInfo[151] data, EDF estimates that **only 15% of well sites** in New Mexico are new/modified after August 23, 2011 and are therefore subject to the NSPS standards. As such, the remaining 85% of existing sources (the large majority of facilities) are not currently subject to OOOOa tank standards unless there have been modifications to the tanks

151 https://www.enverus.com/?utm_source=google&utm_medium=cpc&utm_term=drillinginfo&utm_campaign=DrillingInfo_Brand&utm_adgroup=DI_Generic_Brand_Match&_bt=341635638623&_bm=e&_bn=g&_bk=drillinginfo&gclid=CjwKCAiA_MPuBRB5EiwAHTTvMUwsPpq8U3RAVQxq9gYqyMw74CrIsimx5htzAbI_jZ_kJBVUT4Jh7BoCUF8QAvD_BwE?utm_source=google&utm_medium=cpc&utm_term=drillinginfo&utm_campaign=DrillingInfo_Brand&utm_adgroup=DI_Generic_Brand_Match&_bt=341635638623&_bm=e&_bn=g&_bk=drillinginfo&gclid=CjwKCAiA_MPuBRB5EiwAHTTvMUwsPpq8U3RAVQxq9gYqyMw74CrIsimx5htzAbI_jZ_kJBVUT4Jh7BoCUF8QAvD_BwE

at the site. Using the same DrillingInfo data, EDF calculates that the existing facilities are responsible for 87% of total cumulative production since August 2011 in New Mexico, illustrating that the majority of wells and production are not subject to the NSPS.

Tank modifications, such as adding a new oil and gas well's production to the tank battery, tank modifications, etc. result in the tank becoming subject to OOOOa regulations. These newer wells (15%) added 129 million barrels of annual oil production (180% increase) over the time period, bringing total current annual oil production to 200 million barrels. The remaining 85% of well sites account for 71 million barrels, or 1/3, of current annual oil production. (http://www.emnrd.state.nm.us/ADMIN/publications.html)

Tank replacement or retrofits of old storage tanks ~~have~~ can been employed to allow tank emissions to be routed to a control device when needed on a case-by-case. Replacement or retrofits of old tanks are usually required because many existing storage vessels at older facilities were not designed to employ vent control devices and are subject to new emission reduction needs. The additional back pressure on the tank from an improperly designed controlled vent header may pose a safety risk by compromising tank integrity from over-pressurization. However, the economics and technical feasibility of this option is predicated on various factors. Costs, estimated useful equipment life, product value, production type and volume (well life), and geographic issues and logistical constraints are all factors in the determination. Additionally, in the San Juan Basin, tank retrofit is not a technically feasible option for the open-top tanks that are commonly used.

Storage tank equipment control requirements for existing facilities, not already subject to NSPS OOOO/OOOOa, should be based on appropriate thresholds (e.g., low production facilities that cannot support new technology controls). Existing source engineered retrofits are more costly than controls on a new source. The throughput impacts the ability of the control equipment to function effectively, so for existing storage tanks, the control threshold should be even higher due to the additional cost to retrofit the equipment.
Retrofit engineering analysis requires collection of facility and production data, an engineering review of the entire system (including retrofit or tank replacement), and economic considerations.

Facility Data/Information Collection (inlet to outlet) needs:

1. Vessel/tank(s)/piping/valves/connections inspection (integrity), maintenance, and operational condition
    a. Tanks
        i. Roof and sides (shell)
        ii. Foundation
        iii. As-builts including controls/automation
        iv. Internal inspection
        v. Specification sheet
    b. Vessels (separator) /Piping
        i. Pressurized fluids analysis
        ii. Shell vessel inspection (welds, thickness, penetrations, mechanical function)
        iii. As-built (piping size, connections, valves), metallurgy, and automation
        iv. Specification sheet
    c. Mechanical Integrity (MI)
        i. Non-destructive examination (NDE)
        ii. Metal thickness
        iii. Brittle fracture
        iv. Joints (welds)
        v. Penetrations
    d. Maintenance
        i. Inspections records
        ii. Equipment maintenance records (vessels, tanks, piping, PRVs, Thief Hatches)

iii. Releases (spills, LDAR, etc.)

e. Operations
   i. Placement of equipment (spacing)
   ii. Suitability for Service
   iii. Automation
   iv. Air permit/Regulatory requirements
   v. Marginal production facility / GIS-remote location
   vi. Operational changes over time

2. Oil/Gas throughput, pressure, temperature, liquids analysis, and extended gas analysis (VOCs, methane)
3. Power source (electricity, generator, solar)
4. Oil and gas pipeline/infrastructure (e.g., collection system, LACT, meter, etc.) in place

Engineering Review (retrofit verses remove/replace separators/storage vessels):

1. Process model/simulations e.g., Promax, Hysys, Pipesim
2. Process results … system flowrate, pressure, equipment specs
3. Compare process results to existing equipment/facility data
4. Process optimization
   a. Vessels – (e.g., pressure, corrosion (internal), wall thickness)
   b. Tanks – (e.g., pressure, corrosion (internal, top), wall thickness, compatible materials)
   c. Piping/Valves/Connections (e.g., size, corrosion, wall thickness, compatible materials)
5. Tanks/vessels out of service to complete the retrofit (PVRV/thief hatch condition).

Economic Considerations -- Technical Feasibility / Costs / Remaining Useful Life of Equipment:

Based on the above engineering analysis, operators can then decide the most feasible methane control based on technical feasibility, costs (e.g., rate-of-return/return of capital/or payback standpoint), and remaining useful life of equipment (e.g., mechanical integrity and replacement costs). In many cases, the production rate of older stripper[1] oil and gas wells will not support facility retrofits. In addition, due to the low well production rates the emissions from these tanks may be low resulting in a high cost/benefit ratio.

There are 57,868 oil and gas wells in the state of New Mexico of which 11,670 oil wells produce 10 BOPD or less, and average 2.5 BOPD per well. There are 26,282 natural gas wells that average 23 mcfd per well. Combined, these oil and natural gas stripper wells make up 66% of all wells in New Mexico and produce 12.4 million barrels of oil and 225 billion cubic feet of natural gas annually. (https://www.eia.gov/petroleum/wells/pdf/full_report.pdf)

By their very nature of marginal producing rates this class of well is cost sensitive. Frequently, these wells and facilities may be shut in or plugged and abandoned rather than retrofitted resulting in underground waste from unrecovered hydrocarbons. The reservoirs that stripper wells access are not necessarily depleted, in many cases they still hold two thirds of its potential value, however due to the low operating margin of a stripper well they are at risk of premature abandonment, leaving large quantities of oil and gas reserves behind.
(http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/MarginalWell-2015.pdf)

Any storage vessels not currently subject to OOOO/OOOOa, which are replaced due to state regulations or due to reaching the end of useful life, will be subject to OOOO/OOOOa, which would provide additional emission reductions. At very low levels of gas, in order to run a combustion device, operators would need to bring out supplemental fuel.

[1]Stripper Well: An oil well that produces 10 BOPD or less, and a gas well that produces 60 Mcfd or less as defined by the Interstate Oil & Gas Compact Commission.

Remaining useful like of equipment include wells and tank settings. For discussion purposes:

- Technical Feasibility: For retrofitting a tank setting, the operator must have adequate Q (including production decline), P, and tank integrity to address delta P operations with a control device to be technically feasible. If the tank integrity is in question, then tank modifications or replacement (along with tank cleanout) is required.

- Costs: Cost comes in several different ways, one being monthly lease operating expense (LOE), and others coming as deductions from product income streams such as lease burdens (State & Federal royalty, ORRI, production payments, etc.), production taxes, and product price deductions for items such as gathering and transportation, dehydration, processing, and compression.

- Cash flow: Revenue minus lease burden (expenses, taxes, etc.).

- Cash Flow Deferral – Time when well and facility operates at a loss.

- Useful life of a well/facility: Generally, if the cash flow deferral is greater than 3 years, the well/facility may be considered no more useful resulting in waste of resources in the oil and gas reservoir.

STRIPPER OR MARGINAL WELL CASE:

- Avg stripper (also referred to as marginal) oil well 2.5 BOPD, average stripper gas well 23 MCFD
- Monthly Revenue at $50/BO and $2/MCF is $3,800 and $1,400 respectively.
- Monthly Income (deducting lease burden and taxes) $2,800 and $1,030 respectively.
- Monthly Cash Flow (deducting LOE) $1,200 and $530 respectively.
- This case for a stripper well operating near the current product pricing level above illustrates the annual cash flow to be $14,400 for oil and $6,360 for gas. From these cash flow numbers, it can be easily seen that stripper (marginal) wells are extremely cost sensitive and any one time expense of $14,400 for a stripper oil well or $6,360 for a stripper gas well would render the well uneconomic for an entire year. An annually reoccurring expense of the same magnitude would render the well permanently uneconomic to operate, production would cease, and the well would be plugged and abandoned (P&A). This case also illustrates even fractional increases in operating expense have a significant impact on profitability and subsequently a significant impact on the companies that operate stripper or marginal wells.

As noted previously on page 7, connection of a tank vent header to a VRU requires a more complex design/installation to manage the potential failure consequences. The potential to draw tank pressure down below 0 osig in the condition of 1) inadequate flash gas from the influent, 2) no/inadequate blanket gas system, 3) inadequate/malfunctioning PVRV can result in tank failure/collapse. Blanket gas systems, if present, are normally installed on newer and/or larger facilities due to cost and complexity. Without blanket gas systems, air/oxygen can be drawn into the tanks through the PVRV producing a potentially combustible mixture and/or gas that does not meet midstream specifications. The mixture imposes a safety risk and also may result in curtailment of the gas sales line which leads to flaring.

New Wells:

In newer high producing wells, there are more opportunities to control emissions via vapor recovery. Newer sources are also covered by NSPS OOOO/OOOOa.

Existing Wells:

N/A

How have the emission/waste reductions been measured?

NMED emissions calculations for the permitting process and process simulation prior to the development of a facility to ensure emissions are in compliance with required permitted limits. Additionally, tank methane and GHG emissions are reported under the GHG Reporting Rule.

How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

The NMED General Construction Permit (GCP) requires controls reducing VOCs and HAPs, which also reduce methane. Moreover, the NMED permits require conditions to ensure that the controls remain effective. For example, the GCP Oil and Gas requires inspection of controls, periodic gas sampling of the gas routed to the separator/tanks, and other requirements. The requirements (conditions) are intended to ensure the emissions from the tanks remain below permit allowances.

CO: https://www.colorado.gov/pacific/cdphe/air-oilandgas-storagetankguidelines

EPA: https://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf

In Colorado, state rules require 95% control efficiency of hydrocarbons from individual new storage tanks with the PTE 6 tpy of VOCs.[152] Colorado is also proposing new rules for storage tanks which would lower the threshold at which an owner or operator must control storage tank emissions on a state-wide basis from 6 tpy to 2 tpy.[153] In addition, Colorado is proposing operators install automatic tank gauging on storage tanks to monitor the liquid level.[154] Finally, Colorado is proposing operators of storage tanks with uncontrolled actual VOC emissions greater than or equal to 2 tpy must control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles by using submerged fill and a vapor collection and return system and/or air pollution control equipment.[155]

Colorado's proposed 2-tpy threshold for installing storage tank controls is not supported by the cost data and will not result in cost-effective emission reductions. Of perhaps most importance, Colorado's economic analysis utilizes a 15 year period over which to annualize the costs associated with hydrocarbon liquid and produced water tanks. With respect to at least a subset of these storage tanks, historic evidence and current plans demonstrate that those tanks will not be in existence within 15 years and thus annualizing the cost out over the life of the equipment – as opposed to over the remaining life of the well is inappropriate. Colorado also incorrectly assumes that the emissions reductions remain steady year over year. The reality is that a number of wells operating today within the 2 to 4 tpy framework, will not be operational within five years. Even for those low-emitting storage tanks that are not expected to be plugged and abandoned in the next several years, the production is continuing to decline and thus, so are the emissions – limiting the value of emission reduced each year. Of significance as well, cost-effectiveness is not the only metric that is of importance – and frankly is not the metric utilized by operators. Rather, operators evaluate the production from the well, the operating costs of the wells, the continued life of the well, and the taxes and other expenses of the wells in determining its path

[152] Colorado Air Quality Control Commission, 5 C.C.R. 1001-9, CO Reg. 7 §XVII.C.1.b. (Feb. 24, 2014). Available at https://drive.google.com/file/d/168v7vMsFJtS7D8BWlnMbaXWA6uZUIyj8/view

[153] Colorado Air Quality Control Commission, proposed revisions to Regulation 7, available at https://drive.google.com/drive/folders/14fvt4C0Tzl79to4c2tVuLDKucksk5uaB

[154] *Id*.

[155] *Id*.

forward with respect to any given well. Expenses such as those proposed in in Colorado will come at the outset and at considerable cost. As a result, operators may be forced to evaluate if they can continue operating wells and whether there remains sufficient value in a particular well to justify the costs of compliance (and for how long). Ignoring these considerations is not appropriate.

Colorado has proposed to require operators of storage tanks with 2 tpy of VOCs to use submerged fill and either a vapor collection and return system, air pollution control equipment, or both to reduce tank loadout emissions.[156]

https://doc-0o-68-docs.googleusercontent.com/docs/securesc/ha0ro937gcuc7l7deffksulhg5h7mbp1/v7vu3oupcqapualargdbcm4uedb202ac/1573596000000/09887998073533830170/*/1ot2dCFpgp18S8cqQWMHlZGQ_uz0VYKHy?e=download

Wyoming regulations specific to the Upper Green River Basin require new and existing tanks control flash emissions by at least 98%. Removal of flashing emissions control devices is allowed after 1 year if VOC flashing emissions have declined to less than, and are reasonably expected to remain below, 4 tpy. Statewide, Wyoming requires 98% control for tanks with 6 tpy of VOCs.[157] The Wyoming threshold is applied to the cumulative emissions from all tanks located at a well production facility. Accordingly, if there is more than one manifolded storage vessel onsite, operators must apply controls if the sum of all emissions from both manifolded vessels are 4 tons per year or greater.

Utah similarly requires 95% control of storage tank emissions if emissions are at least 4 tpy of VOCs.[158] Utah, similarly, requires operators to aggregate tanks and glycol dehydrators emissions, in order to calculate emissions for purposes of determining whether controls are required.[159]

In California, tanks with 10 metric tons of CH_4 or more must route emissions to a vapor collection system. Combustion using a low-NOx flare is only allowed if capture is demonstrated to be infeasible.[160] Pennsylvania general permit and exemption requirements mandate 95% control if emissions are 200 tpy of CH_4, or 2.7 tpy of VOC.[161]

Mexico adopted the same 10 metric tons of CH_4 threshold as CARB, recently, in its adoption of country-wide methane rules.[162] Mexico also requires operators capture emissions and route to vapor recovery unless it is infeasible to do so.[163]

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[156] Colorado Air Quality Control Commission, proposed revisions to Regulation 7, available at https://drive.google.com/drive/folders/14fvt4C0Tzl79to4c2tVuLDKucksk5uaB

[157] WDEQ, Oil and Gas Production Facilities Ch. 6, Section 2 Permitting Guidance for the UGRB (2016), available at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf

[158] U.A.C. § 307-506.

[159] U.A.C. § 307-506.

[160] 17 C.C.R. Section 95668(a) (March 24, 2006), available at https://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20Appx%20A%20Regulation%20Text.pdf

[161] Department of Environmental Protection, Air Quality Permit Exemption 38, available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf

[162] SEMARNAT, ASEA, Secretaria de Medio Ambiente y Recursos Naturales, Title III, Ch. VI, Article 49, http://www.dof.gob.mx/nota_detalle.php?codigo=5543033&fecha=06/11/2018.

[163] Id., Article 50.

Pennsylvania has required new storage tanks located at unconventional well sites to limit VOC emissions to 2.7 tons per year since 2013.[164] Recently the state retained this requirement in its general permits, GP-5 and GP-5A. GP-5 applies to midstream compression, gas processing, and gas transmission facilities. GP-5A applies to new or modified unconventional natural gas well site operations and remote pigging stations.[165] The Pennsylvania Department of Environmental Protection has proposed to require existing storage tanks installed at unconventional well sites on or after August 10, 2013, with potential to emit 2.7 tpy of VOCs to control emissions by 95% as part of its implementation of the EPA Control Techniques Guidelines.[166]

Canadian operators are subject to a facility venting limit of 15,000 standard cubic meters per year. Rules also require operators to reduce venting by 95% if produced and received gas amounts to 60,000 cubic meters per year (PTE threshold).[167] In British Columbia, new tanks which begin operations after Jan. 1, 2022, are subject to an emissions limit of 1,250 m3 per month. Existing tanks that begin operations before Jan. 1, 2022, are subject to an emissions limit of 9,000 m3 per month. Operators must retain records of emissions from uncontrolled storage tanks on a monthly basis.[168]

Various jurisdictions require operators control vapors when unloading liquids from storage tanks. Specifically, in Wyoming, loading emissions containing greater than or equal to 6 tpy VOC and HAP emissions must be controlled. Operators of new facilities must utilize a vapor collection system or equivalent device for the truck loading operation that captures a minimum of 70% of the truck loading vapors, and to route the vapors to device with a destruction efficiency of 98%.[169] In Utah, tanker trucks used for intermediate hydrocarbon liquid or produced water must be loaded using bottom filling or a submerged fill pipe. Operators must control VOC emissions during truck loading operations at all times using a vapor capture line. The vapor capture line must be connected from the tanker truck to a control device or process, resulting in a minimum 95% VOC destruction efficiency.[170] In Pennsylvania, since August 10, 2013, in accordance with Category 38 of the Air Quality Permit Exemptions document tanker truck load out operations are required to be equipped with controls achieving VOC, and HAP emissions reductions of 95% or greater unless their uncontrolled VOC, single HAP, and total HAP emissions are below the control thresholds of 2.7 tpy, 0.5 tpy, and 1.0 tpy, respectively. Per GP-5 and GP-5A, tanker truck load-out operations that take liquids from storage vessels with emissions above the control thresholds are required to use a vapor balancing system and ensure each truck used to unload liquids has passed an annual leak test.[171]

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

The addition of the controls and/or practices outlined above can reduce methane emissions from tanks. These strategies are widely utilized and required by permit.

[164] Pennsylvania Dept. of Environmental Protection, Air Quality Permit Exemption Category No. 38 (Aug. 8, 2018).
[165] Department of Environmental Protection, Air Quality Permit Exemption 38, available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf
[166] Pennsylvania Draft Proposed RACT Rulemaking for Control of VOC Emissions from Oil and Natural Gas Sources Annex, available at, http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Advisory%20Committees/smallbiz/2019/4-17-19/7_ONG_PRN_Annex_A_AQTAC_4-11-2019.pdf
[167] Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (July 2019). Available at https://laws-lois.justice.gc.ca/PDF/SOR-2018-66.pdf
[168] British Columbia Oil & Gas Commission Regulation (2018), available at http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018
[169] WDEQ, Oil and Gas Production Facilities Ch. 6, Section 2 Permitting Guidance for the UGRB (2016), available at http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/5-12-2016%20Oil%20and%20Gas%20Guidance.pdf.
[170] U.A.C. § 307-504.
[171] Pennsylvania GP-5, GP-5A, Section F(1)(a).

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
Low production threshold / Vent	Need emissions inventory and remaining useful equipment analysis.	In use or in development		**Low** Medium High
VCU / Flare		In use or in development		Low **Medium** High
VRU / Gas Sales	https://hy-bon.com/blog/faq-about-vapor-recovery-units/	In use or in development		Low Medium High
Equipment (VRT) / Separator operating Practices	https://greasebook.com/blog/separators-heater-treaters-pressure/	In use or in development		Low Medium High
Heater Treater operating practices		In use or in development	Region specific	Low Medium High
Relief devices and thief hatches operating practices		In use or in development		Low Medium High
Solar Heating for Site Located Oil Storage or Separation	Utilizes solar power to supplement fired combustors in heating oil to improve separation. Patent No: US 9,394,780 B2	In use or in development		Low Medium High
SCADA		In use	Typically used to monitor/control larger facilities due to high installation costs	
Secondary Vapor Capture				

What technology alternatives exist to reduce or detect emissions? Please list all alternatives identified along with contact information for further investigation of this technology or process.

Radiant heat transmitted to stored hydrocarbons can affect product vaporization and increase vent flows from storage. In hot climates, lighter colors were chosen to reduce evaporative product losses in tanks which would route to vent or flare depending on the configuration of the tank battery. As noted in the Khark island study (citation below) the impact of paint color (dark versus light) can impact the amount of product lost due to evaporation by

250%. Currently, storage tank paint color may be dictated through BLM, landowner agreement, etc. with the intent to minimize the aesthetic impact of facilities on the landscape. Flexibility in the choice of storage tank paint colors on new installations could reduce venting in cases where tank vents are not controlled and low pressure flaring on controlled installations.

		Solar Absorptance (α) (dimensionless) Surface Condition	
Surface Color	Shade or Type	Good	Poor
Aluminum	Specular	0.39	0.49
Aluminum	Diffuse	0.60	0.68
Beige/Cream		0.35	0.49
Brown		0.58	0.67
Gray	Light	0.54	0.63
Gray	Medium	0.68	0.74
Green	Dark	0.89	0.91
Red	Primer	0.89	0.91
Rust	Red iron oxide	0.38	0.50
Tan		0.43	0.55
White	—	0.17	0.34
Aluminum	Mill finish, unpainted	0.10	0.15

Figure 5. Solar Absorptance for Selected Tank Surfaces

https://www.technokontrol.com/pdf/evaporation/evaporation-loss-measurement.pdf

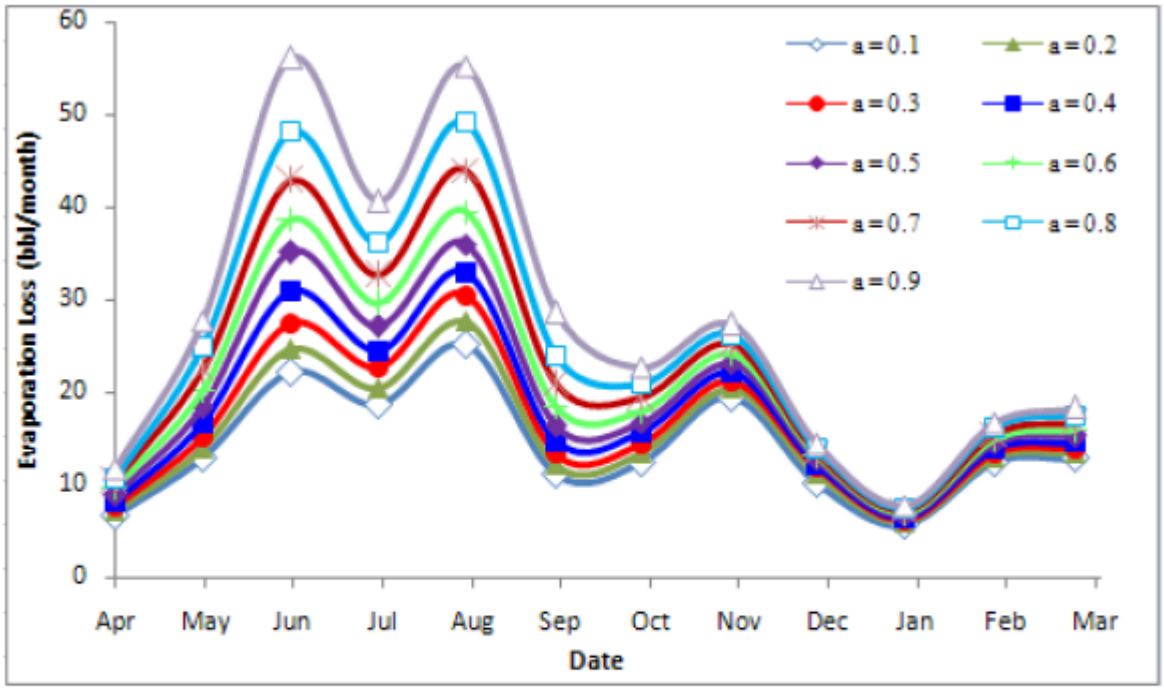


Figure 14. Surface paint absorptivity effects on monthly variations of the evaporative losses.

https://www.researchgate.net/publication/271227741_Effects_of_outer_surface_paint_color_on_crude_oil_evaporative_loss_from_the_Khark_Island_storage_tanks

NOTE: See other topic papers for LDAR, flaring, venting, compressors, and pneumatics.

What are the pros and cons of the alternatives?

This is discussed above in the table. Many of them are already in use per best practice and regulation.

What is needed and available for new wells?

Discussed above in table.

What is needed and available for existing wells?

Discussed above in table.

What technology alternatives exist for this equipment or process itself?

Discussed above in table

What are the pros and cons of the alternatives?

Discussed above in table.

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

No new controls are necessary due to current control mechanisms and efficiency of process.

A 2014 ICF International Report analyzed the cost of vapor recovery units (VRUs), which collect and compress gas, which can then be re-directed to a sales line, used on-site for fuel, or flared. The report states, "[B]ased on Gas STAR and industry data, the capital cost of this measure is assumed to be $100,000 with an operating cost (electricity) of $7,500 per year and a reduction of 13,410 Mcf per year. This yields a reduction cost of -$0.51/Mcf if the gas is recovered for sale or $4.57/Mcf if it is flared."[172] The recently released Synapse report estimates the unit cost ($/mcf of reduced methane) of adding VRUs to oil and condensate tanks to be $4.18 and the unit cost ($/tonne of reduced methane) to be $217.36.[173]

In connection with Colorado's proposed rule for lowering the control threshold for tanks from 6 tpy to 2 tpy, the Colorado AQCC estimated the annualized cumulative cost of installing 65 flare control devices in the Denver Metro Front Range North (DMFRN) area to be about $421,700 dollars, with an average cost effectiveness of about $2,232 per ton of VOC reduced. For the smallest category of tanks (2-3 tpy) the incremental cost of controls on 36 tanks is estimated at $2,843 per ton of VOC reduced.[174] For crude oil and water tanks in the remainder of the state, the AQCC estimates the annualized cost of installing 202 flare control devices at about $1.31 million dollars with an average cost effectiveness of about $1,512 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 80 tanks is estimated at $2,688 per ton of VOC reduced.[175] For condensate tanks outside the DMFRN, the estimated annualized cost of installing 444 flare control devices is about $2.88 million dollars with an average cost effectiveness of about $1,679 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 175 tanks is estimated at $2,817 per ton of VOC reduced.[176] Colorado estimates the cost of a vapor collection and return system to control tank loadout emissions to be $12,000-$15,0000 for initial set-up. Per the Colorado Initial Economic Impact, "Emission reductions will depend on how frequently the storage tank is unloaded. EPA estimates the cost purchasing additional connections to route a transport vehicle vent to a useful outlet at $1,000 (estimated implementation cost) and additional operating costs to connect the lines at $200 (incremental operating cost). EPA also estimates that recovering these vapors can payback in two years depending on the frequency of loading, load volumes, and the value of the gas.27 In most cases, the storage tank will already be controlled as required by the Regulation Number 7 storage tank control programs; therefore, the additional costs to control the transport vehicle emissions are related only to the installation of

[172] ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (Mar. 2014), available at https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf
[173] Synapse, Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico (Sept. 2019), available at http://blogs.edf.org/energyexchange/files/2019/09/Synapse-Methane-Cost-Benefit-Report.pdf
[174] Economic Impact Analysis (Initial Analysis), Proposed Revisions to ACQQ Reg. 7(Sept. 19, 2019), available at https://drive.google.com/drive/folders/14fvt4C0Tzl79to4c2tVuLDKucksk5uaB
[175] *Id*.
[176] *Id*.

vapor return lines to the storage tank such that transport vehicle emissions are then routed to the existing control device."[177]

The California Air Resources Board estimates the cost of installing VRUs for tanks at $4,700,000 annually, with annual savings of $500,000. CARB estimates reductions from the installation of VRUs of 540,000 MT CO2e, with a cost per ton of $9 per MT CO2e reduced (using the 20 year GWP). The Cost per Ton is estimated at $25 per MT CO2e reduced using the 100 year GWP.[178]

What would be the implementation cost?
For new wells?

N/A

For existing wells?

N/A

Are there low-cost solutions available?

N/A

If a solution is high-cost, why is that the case?

N/A

Are there additional technical analyses needed to refine benefits/costs estimates?

N/A

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

See above section on economic and technical analysis of replacements/retrofits.

What is the useful life of equipment?

[177] CO APCD, Economic Impact Analysis (Initial Analysis), Sept. 19, 2019, p. 29, available at https://drive.google.com/drive/folders/14fvt4C0Tzl79to4c2tVuLDKucksk5uaB

[178] 17 C.C.R. §§95665 et seq., Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, Attachment 2: Summary of Cost, Emissions, and Cost per Ton using the 20 year and 100 year GWP, respectively, available at https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf

Standard life of control equipment. Processing and storage vessels generally have long useful lives, 20 to 30 years is common.

What are the maintenance and repair requirements for equipment required for methane reduction?

Discussed in table

How would emissions be detected, reductions verified and reported?

Emissions from storage vessels are calculated as part of an NMED air permit application and reported to NMED as part of any required emission inventories. This includes emissions that result from the volume of tank vapors routed at low pressure to an enclosed combustor or flare used as a control device.

No direct measurement; calculate pre and post-actual/PER for the control technology.

Remote monitoring of control equipment.

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

None.

Where do conflicting priorities exist between NMED, EMNRD, and NMSLO? Are there opportunities for coordination between these agencies?

None

Are there existing regulations related to methane that do not address the intended purpose? Identify any unintended barriers to methane reductions/capture that may hinder proposed processes.

No

Other considerations or comments (e.g. particular design or technological challenges/opportunities, co-benefits, non-air environmental impacts, etc.?):

None

5. SEPARATORS - PATH FORWARD[179]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EFFECTIVENESS OF COST NOW (choose one)	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
8.1	Applicability threshold	Storage tank equipment control requirements for existing facilities, not already subject to NSPS OOOO/OOOOa, should be based on appropriate thresholds. American Petroleum Institute's December 4, 2015 comments to EPA on the draft Control Techniques Guidelines suggests that a 15 tons per year VOC threshold is appropriate as existing source retrofits are more costly than controls on a new source. The throughput impacts the ability of the control equipment to function effectively. As noted in EPA's OOOO/OOOOa, requiring controls for new storage tanks below a certain VOC threshold may not be effective. For existing storage tanks, the control threshold will be even higher due to the additional cost to retrofit the equipment.	**LOW** MODERATE HIGH	Covered in NMED permit conditions	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.2	Controls – VCUs and VRUs: Consider incorporating VCUs and VRUs into facility design to capture additional "flash		LOW **MODERATE** HIGH	Covered in NMED permit conditions	San Juan Permian

[179] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

	gas" not captured by separator, especially early in the well life when production is highest.				Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.3	Separators / VRTs: Optimize separator design/operating parameters to maximize gas separation. Consider use of VRT after the separator as a second opportunity to minimize "flashing" in the storage tanks.	The facility should be designed and operated to safely recover as much flash gas as possible prior to storage.	**LOW** MODERATE HIGH	Covered in NMED permit conditions	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.4	Inclusion of controlled tanks and relief devices in site specific LDAR	Minimize leaks from controlled tanks and relief devices through their inclusion in the existing site specific LDAR program (at the same frequency as the existing program).			San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.5	Control storage tanks with emissions above specified threshold (e.g., 10 tpy of CH4 or 2 tpy of VOCs) by 98%	See discussion above of CARB and Colorado proposed requirements in section discussing existing reduction strategies.	**Cost effective**	Robust recordkeeping and reporting requirements essential for compliance monitoring	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

8.6	Require operators route tank emissions to VRU unless technically infeasible.	See discussion above of CARB requirements in section discussing existing reduction strategies.	**Cost effective**	Robust recordkeeping and reporting requirements essential for compliance monitoring	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.7	Require operators use automated tank gauges to reduce fugitive emissions from thief hatches	See discussion above of Colorado proposed requirements in section discussing existing reduction strategies.	**Cost effective**	Robust recordkeeping and reporting requirements essential for compliance monitoring	San Juan Permian Both
	COMMENT A. Require operators to install vapor balance return lines. Delay effective date of regulations (by 1 year) to allow truck drivers to receive training and certification in operation. Require monitoring and reporting.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.8	Require operators control emissions during unloading of emissions from tanks into trucks	See discussion above of Colorado proposed requirements in section discussing existing reduction strategies.	**Cost effective**	Robust recordkeeping and reporting requirements essential for compliance monitoring	San Juan Permian Both
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.9	Convert Water Tank Blanket from Natural Gas to Produced CO2 Gas	https://www.epa.gov/sites/production/files/2016-06/documents/convertwatertank.pdf Natural Gas STAR Partner has switched water tank blanket from natural gas to CO2-rich produced gas, saving 32,600 Mcf per year of methane.	$1,000-$10,000		San Juan Permian Both

	COMMENT A. There is an applicability restraint for this option: "This practice can be implemented where there is a source of CO2-rich produced gas or a nearby gas processing plant with acid gas removal."		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.10	Recover Gas During Condensate Loading	https://www.epa.gov/sites/production/files/2016-06/documents/recyclelinerecovers.pdf Natural Gas STAR: "Lease condensate production, when transferred from storage into tank trucks, can generate significant volumes of methane vapor due to pressure and temperature changes and evaporation. This methane is typically vented to the atmosphere to prevent the internal tank pressure from rising. One [Natural Gas STAR] Partner reported capturing methane that would otherwise be vented by connecting the tank truck vent to the condensate storage tank, or to a vapor recovery line… Partners have reported reducing methane emissions by 6,500 Mcf to 39,000 Mcf per year, which includes flashing loses.	< $1,000		San Juan Permian Both
	COMMENT Applicability "This technology applies to all condensate production operations using tank trucks or railroad tanks."		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.11	Install Pressurized Storage of Condensate	https://www.epa.gov/sites/production/files/2016-06/documents/installpressurized.pdf Natural Gas STAR: "When transferred to atmospheric storage tanks, a pressure drop occurs causing the methane to flash out. Operators often vent this gas to the atmosphere. Interstage knockout in multi-stage compressors with interstage cooling also contains raw natural gas liquids (NGL) saturated in methane. If transferred to atmospheric storage, nearly all the methane will flash and vent to the atmosphere	$10,000-$50,000		San Juan Permian Both

		One [Natural Gas STAR] partner reported installing pressurized storage, requiring pressurized transport of condensate to a gas plant for economic recovery of gas liquids and associated methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) emissions reductions…Total partner reported methane emissions savings were 27,992 Mcf per year for 4 installations of pressurized storage tanks."			
	COMMENT A. Applicability: This technology is applicable on all gas well and gathering/booster compressors.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.12	Apply control threshold to tank emissions from all tanks located at a facility, rather than individual tanks or individual tanks manifolded together.	See discussion above about Wyoming and Utah approaches.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.13	Consider installation of remote monitoring to notify/control critical controllers or components, such as malfunctioning dump valves or open thief hatches	Programmable Logic Control (PLC), Supervisory Control and Data Acquisition (SCADA) systems, etc. allow operators to monitor, trend, and control different aspects of their process that are enabled through the use of instrumentation (e.g. Pressure Transmitters, Flow Transmitters, Level Switches, Level Transmitters, etc.). While SCADA is installed for operational purposes, analysis of that data and integration of more SCADA over time can result in lower emissions as facilities are run more efficiently. PLC and SCADA systems require both instrumentation and communication equipment. This poses an economic burden and may not be scalable to smaller operators or many existing locations.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

8.14	Consideration of a control credit similar to TCEQ program	See page 12 of Enhanced Vapor Recovery presentation. The addition of additional control equipment can result in an increased percent emission reduction credit.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
8.15	Install enhanced vapor recovery in addition to a VRU system.	See Enhanced Vapor Recovery presentation. This (or similar) enhanced gas recovery technology allows operators to capture up to 100% of flash gas for sale. https://www.ecovaporrs.com/	Cost-effective (often economically beneficial)		
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

Natural Gas "Recommended Technologies"

https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions

NMED/EMNRD METHANE ADVISORY PANEL

SECTION 9, COMPLETIONS/ RECOMPLETIONS AND STIMULATIONS

Discussion for MAP members on August 30, 2019

NOTE: The focus of this report is processes, and the associated equipment, directly related to the release or capture of methane gas. We are not requesting information on processes/equipment that are not related to the release or capture of methane gas.

1. DESCRIPTION OF PROCESS AND EQUIPMENT

Provide a description of the processes and/or equipment used in oil and/or gas extraction for this topic. Note that this report template will be used for all topics of the MAP review and, thus, not all questions or information may be relevant for each topic. If information is not relevant, indicate N/A. Note any differences expected for differing well types, industry sector, or basin location.

Technical description of the process or equipment:

A typical oil or gas well goes through several phases during its life. The first phase is the actual drilling of well. Drilling is followed by completions. After a well is completed the well can produce hydrocarbons for several years or decades. For an existing well, it may be necessary to complete a well stimulation to increase production in case of production decline. In any case, the emissions during completions/stimulations are associated with a relatively short period in a decades-long well life cycle.

All oil and natural gas wells must be “completed” after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations but can vary between wells in the same formation. Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and potentially hydraulically fracturing one or more zones in the reservoir to stimulate production.

Well stimulation is a well intervention performed on an oil or gas well to increase production by improving the flow of hydrocarbons from the reservoir into the well bore. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract hydrocarbons.

In the process of hydraulic fracturing, high-pressure fluid typically water emulsion, or inert gas, with a proppant (sand) is injected into the formation resulting in fractures of the formation rock. Typically, truck mounted pumps are used to inject the high-pressure fluid into the formation. The fracturing process is often carried out in stages on sections of the well tubing or casing. After each section of the well and formation is hydraulically fractured, plugs are inserted in the well prior to fracturing the next section. This process is repeated many times over the length of the wellbore.

Once the fracturing is completed, a workover/completion rig or coil tubing unit is used to drill through the plugs and begin the well cleaning process.

After a new or existing well has been hydraulically fractured and the plugs have been cleaned out, the well begins its flowback process which is primarily water (with additives) or inert gas and proppants. This material has to be evacuated to prepare the well for production. When flowback is initiated, various forces act on the fluid in the well tubing. These include the weight of frac fluid column itself, formation pressure, back pressure from the gas gathering line of the flowback gas and the surface equipment connected to the well. These forces have to be overcome in order for the fluids in the wellbore to come to the surface.

During the flowback, the fracturing fluid or a mix of hydrocarbons and fracturing fluid from the formation come to the surface. As the fracturing fluid flows to the surface, reservoir hydrocarbons and produced water replace the fracturing fluid in the well tubing. Thus, initially the amount of hydrocarbons coming to the surface is very limited. Initial flowback is discussed in the preamble to NSPS Subpart OOOOa regulations and can be found on Page 56630 of the following document:

https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-21023.pdf. As the fracturing fluid reach the surface, they are processed per New Source Performance Standards (NSPS) regulations, 40 CFR Part 60, Subpart OOOOa which govern the managing of fluids during flowback. In most cases, NSPS OOOOa requires Reduced Emission Completions (RECs) as discussed later. The regulations are available at https://ecfr.io/Title-40/sp40.8.60.oooo_0a .The regulations related to well completions are at 40 CFR §60.5375a.

Useful information on RECs can be found at http://www.ipieca.org/resources/energy-efficiency-solutions/units-and-plants-practices/green-completions/ .

Provide the segment(s) of the industry that the equipment or process is found:

NMED Exhibit 10 - 0261

This process is found in the oil and gas production segment of the industry.

Describe how the equipment or process is used:

Reduced emission completions are mandated by NSPS Subpart OOOOa regulations for both gas and oil wells with some exceptions for certain well types. In many cases, the flowback is first routed to a solids separator (often called a sand trap). This is necessary since some of the sand that is injected in the hydraulic fracturing process comes back to the surface along with the injected water. Removal of solids is needed to prevent damage to downstream equipment. From the solids separator the fluid can be routed to additional separators where gas, oil, and water can be separated. Once gas quality is such that it can meet specifications for gas sales, it is typically routed to a sales line unless it is technically infeasible to do so. In that case, gas must be combusted until there is a fire hazard or a negative impact to tundra, permafrost or waterways.

Provide the common process configurations that use this equipment or process:

Typical equipment used in flowback can include sand separator, two or three phase separators, frac tanks, tanks, completion combustion device, or permanent production-phase equipment. Depending upon the amount of flowback expected and the availability of equipment to be used during production, flowback can be routed to temporary equipment or the permanent equipment. The flowback period typically lasts for days or a few weeks following which the well transitions to a production phase. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. NSPS Subpart OOOOa has different gas capture requirements for initial flowback and separator flowback. During initial flowback, gas may be vented if it is technically infeasible for a separator to function (i.e., any gas present in the initial flowback stage is not subject to control under NSPS OOOOa). During separator flowback all gas must be recovered and sold or rescued if technically feasible to do so. If not technically feasible, it must be routed for combustion. NSPS Subpart OOOOa hydraulic fracturing requirements are now in place for all hydraulic fracturing operations onshore in the U.S.

What is the distribution of the equipment or process across business segments?

This process primarily relates to the onshore oil and gas production sector.

How has this equipment or process evolved over time?

Hydraulic fracturing itself has used since the 1940's in the industry.

There are many reported instances where industry started voluntarily using reduced emission completions (REC). EPA's Natural Gas STAR program has reports of RECs since the 2004. These

NMED Exhibit 10 - 0262

voluntary activities resulted in reduced emissions as reported by various operators. Additional information about the Natural Gas STAR program and reduced emission completions can be found at https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf https://www.epa.gov/sites/production/files/2017-09/documents/greencompletions.pdf

Federal regulations first addressed emission associated with completions in the 2012 NSPS regulations at 40 C.F.R. Part 60 Subpart OOOO: https://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.oooo . These regulations require the use of RECs to completions at gas wells following hydraulic fracturing. NSPS Subpart OOOOa, finalized in 2016, requires RECs for oil wells as well.

2. INFORMATION ON EQUIPMENT OR PROCESS COSTS, SOURCES OF METHANE EMISSIONS, AND REDUCTION OR CONTROL OPTIONS

Identify the capital and operating costs for the equipment or the process. Identify how methane is emitted or could be leaked into the air. Please **prioritize** the list to identify first the largest source of methane from the process or equipment and where there is **potential** for the greatest reduction of methane emissions. Note any differences expected for differing well types, industry sector, or basin location.

Sources of Methane:

Provide an overview of the sources of methane from this equipment or process:

During the hydraulic fracturing process itself, injection of water, or inert gas, and proppant is handled by pumps powered by engines. This process itself lasts only a few days per well depending upon the well stimulation design. The emissions during the actual hydraulic fracturing are combustion emissions associated with diesel usage.

The flowback period involves the return to surface of the fracking fluids, or inert gas, as well as some formation hydrocarbons. This is the primary source of methane emissions for completions activity. NSPS Subpart OOOOa requires that, when feasible, hydrocarbons are captured and sent to sales or combusted if sales are not technically feasible.

New Wells:

New wells that fall into the category of wildcat or delineation, wells or low-pressure wells are allowed to route the recovered gases during flowback to a completion combustion device. In this case, the emissions of methane are due to uncombusted methane from the combustion device.

NMED Exhibit 10 - 0263

Low pressure wells may also be exempted from sending entrained gas to sales instead sending the full stream of production to a well completion vessel or frac tank.

New wells that do not fall into the wildcat or delineation, category are required to route gas emissions of saleable gas to a gas sales line unless it is technically infeasible to do so, in which case the gas must be sent to a completion combustion device.

Existing Wells:

The same requirements apply to refracturing at existing wells as for new wells. It is however, less likely that existing wells will meet the definitions of a wildcat well. Note there may be technical infeasibility due to reservoir low pressure to operate control equipment on the surface.

The Grant Schreiber study (below), based on Gas Capture Plans submitted by operators in San Juan and Rio Arriba Counties in November 2018, found that 100% of Gas Capture Plans provided for either venting or flaring of recompletions—with 68.5% of recompletions vented and 31.5% of recompletions flared.

Grant-Schreiber Study

Grant Schreiber Summary of OCD Gas Capture Plans San Juan/Rio Arriba recompletions. November, 2018
Government source: OCD online/Dist. 3 office Reports of data: OCD Gas Capture Plans example attached
Published peer review: NA
Published non-peer: NA
Unpublished: NA

Date	MCF Rio Arriba / Day	MCF San Juan / Day	Vented or Flared
1/11/18	686		V
	500		F
	500		F
	500		F
	356		V
	431		V
	686		V
	500		F
	500		F
	500		F
		390	V
	502		V
	245		V

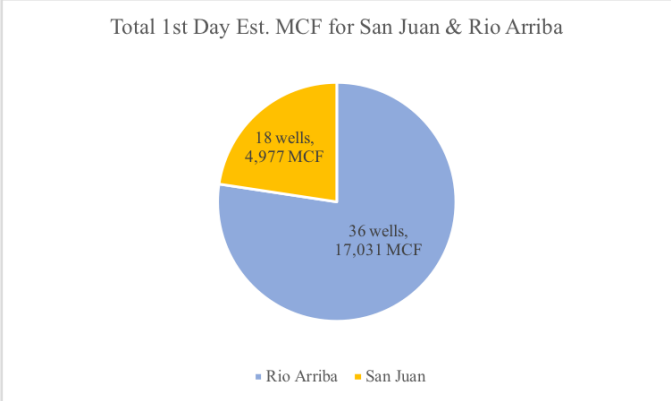
NMED Exhibit 10 - 0264

1/25/18	500		F
	500		F
2/8/18	500		F
	500		F
	500		F
	500		F
	450		F
	302		V
	234		V
	200		V
	347		V
		162	V
3/8/18	302		V
	500		F
	300		V
	180		V
	500		F
	360		V
5/3/18		300	V
	500		V
	500		V
	500		V
	500		V
	500		V
		310	V
5/17/18	500		V
	500		V
		310	F
		300	V
		300	V
		340	V
		290	V
	450		V
	500		V
		295	V
		310	F
7/12/18		290	V
		310	V
8/23/18		310	V
		310	V
11/15/18		450	V
Total MCF	(36 wells) 17,031	(18 wells) 4,977	* ** ***

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*68.5% of recompletions (37 wells) are vented

**31.5% of recompletions (17 wells) are flared



Note on the study [from non-participants]: During the Methane Advisory Panel's discussion about data located in OCD Gas Capture Plans, it was suggested that Gas Capture Plan data should not be used to characterize emissions that may occur after recompletions. Data entered into the Gas Capture Plans reflect estimates made prior to the project taking place and are merely estimated volumes of what could happen to produced gas. Accordingly, vented and flared volumes represented in Gas Capture Plans are estimates of what could be potentially vented or flared if there isn't a gathering or sales pipeline in place for the pipeline quality gas and are not accurate. It was instead suggested that information on production accounting reports from the OCD be used when discussing green completion emissions. The data from the production accounting reports reflects actual data points following completion and are far more accurate. In addition, the data from the Grant Schreiber study as described contains no context or other explanation regarding controls, volumes, timing or whether the venting or flaring was conducted pursuant to regulation.

How are the emissions calculated for this equipment or process?

Emissions from this source can be calculated using the EPA GHG reporting rule (Subpart W) or at https://ecfr.io/Title-40/sp40.23.98.w. These are reported to EPA in accordance with the GHG reporting rule. Equations for estimating emissions from well venting during completions and workovers with hydraulic fracturing are given at 40 CFR 98.233(g), Equations W-10A and W-10B.

What data is available to quantify emissions/waste for this equipment?

EPA has discussed emissions from this source in Section 1 of the Technical Support Document for the NSPS OOOO regulation found here: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4550 .

In 2017, the total methane emissions reported from Petroleum and Natural Gas Systems for the entire country were 88 million metric tons CO2e. The onshore production sector reported approximately half or 44 million metric tons CO2e. Of these, well completion and workovers with hydraulic fracturing reported approximately 1 million metric tons CO2e. This number is an approximation from the sector summary. Thus, the methane emissions from the well completions sector are approximately 2% of total methane emissions from the onshore production sector or approximately 1% of total methane emissions from the Petroleum and Natural Gas Systems sector.

https://www.epa.gov/sites/production/files/2018-10/documents/subpart_w_2017_industrial_profile.pdf

Allen et al (2013), University of Texas and Environmental Defense Fund (EDF) study did actual measurements from 27 completions in various areas of the country. The study can be found here: https://www.pnas.org/content/110/44/17768

The duration of the flowbacks in their study ranged from 5 hours to 2 weeks. Measured emissions of methane over an entire completion averaged to be about 1.7 metric tons methane with a range of 0.01 to 17 metric tons. They extrapolated these values to come up with estimates of national methane emissions from completions ranging from 0.125 million metric tons of CO2e to 0.675 million metric tons of CO2e with an average of 0.45 million metric tons of CO2e. These are less than the EPA GHG reported number of approximately 1 million metric tons CO2e for 2017.

What are the data gaps in quantifying emissions/waste for this equipment?

These emissions are estimated and reported in accordance with the GHG reporting rule.

Economic Description of the Process or Equipment:

What is the per unit cost of the equipment or the costs associated with the process?

The total cost of completion events including hydraulic fracturing greatly varies depending upon the well, hydraulic fracturing setup, length of flowback, availability of permanent equipment, sales line availability and quality of gas.

The cost of RECs with and without combustion has been discussed in detail in the Technical Support Documents to the EPA NSPS Subparts OOOO and OOOOa regulations. The costs are with and without any anticipated savings from sale of recovered gas. Note that the Technical Support Documents provide economic date that is generalized across the Onshore industry for both gas (2012) and oil (2015) wells, and that this data is not specific to New Mexico.

The Technical Support Document for NSPS OOOO regulations discusses emissions and control options in Sections 1 through 4 of

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https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4550

The Technical Support Document for NSPS OOOOa regulations discusses emissions and control options in Section 3 of https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-7646&attachmentNumber=6&contentType=pdf

Detail spreadsheet about the costs associated with the controls is found in this attachment to the Technical Support Document: https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-7646&attachmentNumber=14&contentType=excel12book

Note that in certain circumstances that the Technical Support Documents are no longer representative in that the economic data is not always reflective of current design, but they do have the best data we have thus far. The oil and gas completions and stimulation industry is regularly evolving. While traditional stimulation activities and equipment exist, the data does not take into account permanent facility utilization.

What are the annualized operating costs for the equipment or costs associated with the process?

See above

If the equipment or process is powered, what are the costs?

See above

What is the useful life of the equipment?

The REC and rig/stimulation equipment is used for several hours or weeks during the completion, stimulation and flowback operations. Well servicing, coil tubing and stimulation equipment have a useful life primarily based upon the power unit, but is also limited based upon technological advances requiring a different tool for the job.

What are the maintenance and repair requirements for existing or new equipment?

Maintenance costs are included in the cost of the equipment above.

Existing Reduction Strategies:

How has industry reduced emissions/waste from this equipment or process historically?

NSPS requirements have been applicable to completions following hydraulic fracturing for gas wells since 2012 and for oil wells since 2016. Prior to 2012, while many operators practiced voluntary RECs,

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various configurations were prevalent including allowing the flowback to flow into frac tanks with the gas being vented or combusted.

Voluntary reductions from completions with hydraulic fracturing are also discussed in Section 5.0 of the NSPS OOOO Technical Support Document at: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4550

There are many reported instances where industry started voluntarily using reduced emission completions. EPA's Natural Gas STAR program has reports of RECs since the 2004. These voluntary activities resulted in reduced emissions as reported by various operators. Additional information about the Natural Gas STAR program and reduced emission completions can be found at https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf https://www.epa.gov/sites/production/files/2017-09/documents/greencompletions.pdf

New Wells:

Existing Wells:

How have the emission/waste reductions been measured?

Emissions from completions are reported annually to EPA's GHG reporting program. Based on industry sector summaries of Petroleum and Natural Gas systems, the methane emissions from completions have decreased from approximately 7 million metric tons CO2e in 2012 to approximately 1 million metric ton CO2e in 2017. References for the above estimates are found on Pages 7 and 9 respectively of the following documents:
https://www.epa.gov/sites/production/files/2015-07/documents/petroleumandnaturalgassystemsector2012.pdf

https://www.epa.gov/sites/production/files/2018-10/documents/subpart_w_2017_industrial_profile.pdf

EPA's GHG Emissions database EnviroFacts allows for download and additional analysis of reported GHG emissions. The database can be accessed here:
https://www.epa.gov/enviro/greenhouse-gas-customized-search

While nationally emissions have decreased, in the Permian Basin, total GHG emissions (including both CO2 and methane) from completions have increased from approximately 82,481 million metric tons CO2e in 2015 to approximately 615,096 million metric tons CO2e in 2016 and 974,877 million metric tonnes in 2017. Further, the CO2e figures are converted from raw methane at a GWP of 25 rather than the current 100-year GWP recognized by the IPCC of 36 suggesting that, along with the 25,000 metric ton GHGRP reporting threshold, the EPA figures represent a potentially significant underestimation of completion emissions.

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In 2017, as reported to EPA and downloaded from EPA's EnviroFacts database, emissions associated with completions and workovers in the Permian basin are 7,773 metric tons of methane relative to 184,941 metric tons of methane from all sources in the onshore petroleum and natural gas production sector for Permian basin. Thus, the emissions are approximately 4% of the total onshore production sector emissions.

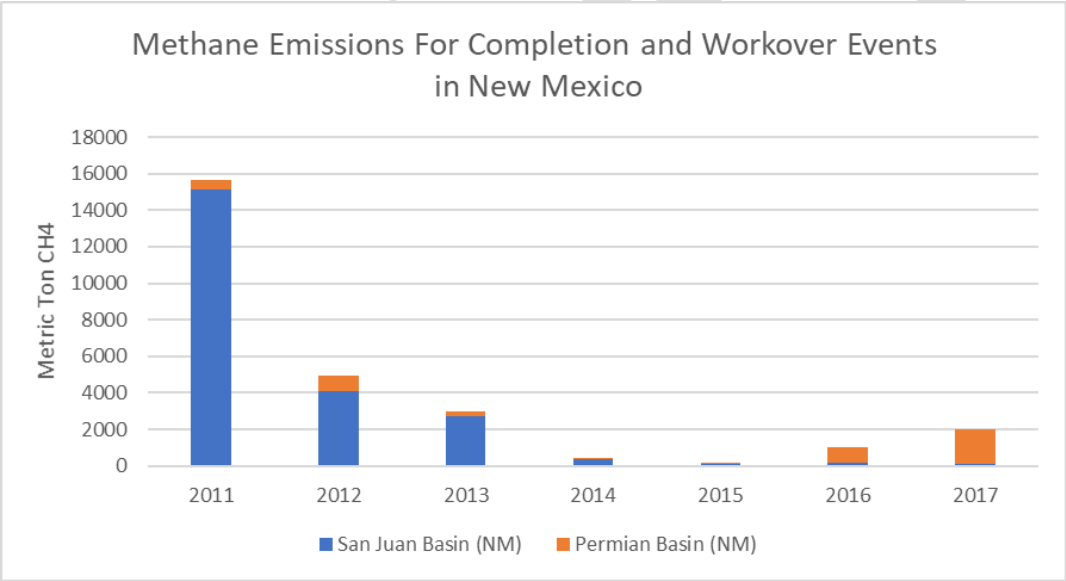
Completion and workover emissions with hydraulic fracturing for New Mexico for 2017 were downloaded from the EnviroFacts Database and are as follows.

San Juan Basin (NM only)– 124 metric tons methane

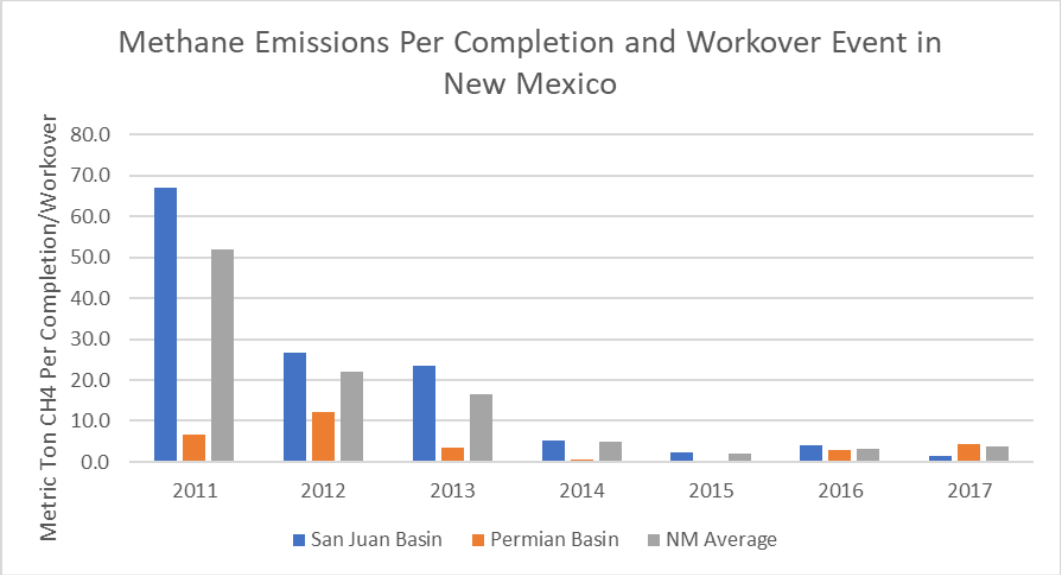
Permian Basin (NM only) - 1867 metric tons methane

NM emissions for both basins – 1994 metric tons methane

The trend from methane emissions associated with completions and workover emissions with hydraulic fracturing is shown in the chart



On a per-completion basis, methane emissions are as follows:



Further analysis of the data indicated an operator had relatively elevated emissions compared to the number of completions. When contacted, the operator revealed that some of the reported emissions were in error and that corrected data has been submitted to EPA. However, the EPA database has not been updated with the corrected data as of September 2017.

Using the corrected data, the emissions are as follows:

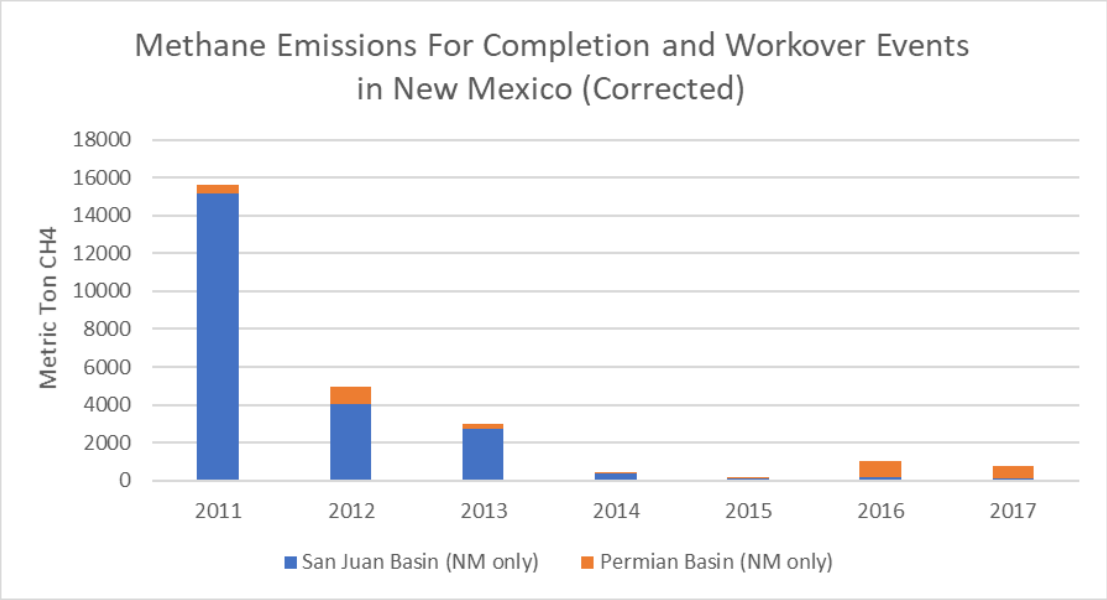
San Juan Basin (NM only)– 124 metric tons methane

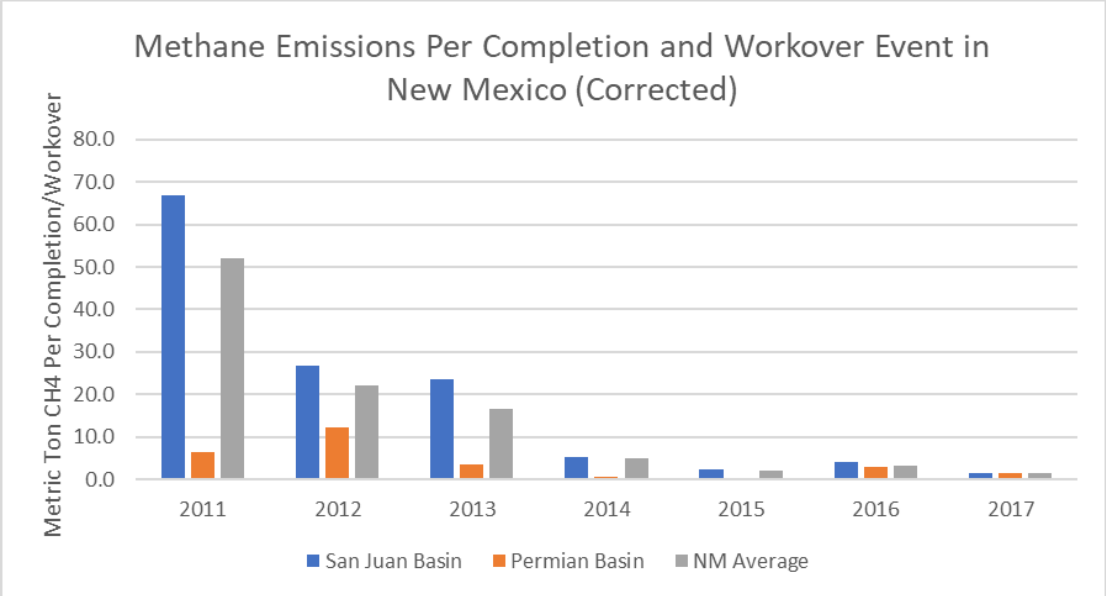
Permian Basin (NM only) - 645 metric tons methane (instead of 1867 metric tons methane)

Total NM for both basins – 769 metric tons methane (instead of 1994 metric tons methane)

The revised charts are presented below:

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How have states and the federal government reduced emissions/waste from this equipment or process historically? In addition, please identify voluntary reductions achieved whether or not they were in response to a regulatory action/requirement.

Voluntary reductions were achieved by operators as reported to EPA's Natural Gas Star program and have been discussed earlier in this document.

Completions following hydraulic fracturing have to meet the emission standards outlined in federal NSPS regulations. NSPS OOOO regulations (2012) addressed emissions from gas wells. NSPS OOOOa regulations (2015) added oil well requirements for completions beginning November 2016.

The requirements for completions in the NSPS OOOOa regulations can be found at https://ecfr.io/Title-40/sp40.8.60.oooo_0a.

The regulations related to well completions are at 40 CFR §60.5375a. In addition, the federal register notice contains information about the requirements for completions. https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-21023.pdf

In general, the regulations classify completions at four categories of wells:

1. Nonwildcat and non-delineation wells
2. Wildcat and delineation wells
3. Low pressure wells
4. Low gas-oil ratio (GOR) wells

Non-wildcat and non-delineation wells

For these wells, the flowback period of a well completion has been defined as consisting of two distinct stages, the ‘‘initial flowback stage’’ and the ‘‘separation flowback stage.’’ The initial flowback stage begins with the onset of flowback and ends when the flowback is routed to a separator. Routing of the flowback to a separator is required as soon as a separator is able to function (i.e., the operator must route the flowback to a separator unless it is technically infeasible for a separator to function). Any gas in the flowback prior to the point at which a separator begins functioning is not subject to control. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must do the following, unless technically infeasible to do so as discussed below: (1) Route all salable quality gas from the separator to a gas flow line or collection system; (2) re-inject the gas into the well or another well; (3) use the gas as an onsite fuel source; or (4) use the gas for another useful purpose that a purchased fuel or raw material would serve. If the operator assesses all four options for use of recovered gas, and still finds it technically infeasible to route the gas as described, the operator must route the gas to a completion combustion device with a continuous pilot flame and document the technical infeasibility assessment. No direct venting of gas is allowed during the separation flowback stage unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways.

Wildcat and Delineation wells

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A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or is the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

For these wells regulations require either (1) routing all flowback directly to a completion combustion device with a continuous pilot flame (which can include a pit flare) or, at the option of the operator, (2) routing the flowback to a well completion vessel and sending the flowback to a separator as soon as a separator will function and then directing the separated gas to a completion combustion device with a continuous pilot flame. For option 2, any gas in the flowback prior to the point when the separator will function is not subject to control. In either case, combustion is not required if combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways.

Low Pressure wells

Low pressure well means a well that satisfies at least one of the following conditions: (1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure at the sales meter; (2) The pressure of flowback fluid immediately before it enters the flow line, is less than the flow line pressure at the sales meter; or (3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Regulatory standards for low pressure wells are the same as that for a wildcat well.

Low GOR wells

While subject to the rule, wells with a GOR of less than 300 scf of gas per stock tank barrel of oil produced have no well completion requirements. The reason for the proposed threshold GOR of 300 is that based on industry experience separators typically do not operate at a GOR less than 300. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field.

A majority of the wells in New Mexico that are undergoing completions at this time fall into the non-wildcat and non-delineation wells and the full requirements of the NSPS regulations, i.e., REC and combustion devices apply to these wells.

Use of combustion devices

On Pages 56628 and 56629 of the Federal Register notice (see reference below) EPA has discussed the infeasibility of traditional combustion devices such as flares or enclosed combustion devices because the flowback following hydraulic fracturing consists of liquids, gases and sand in a high-volume, multiphase slug flow.
https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-21023.pdf

NMED Exhibit 10 - 0274

What are examples of process changes/modifications that reduce or eliminate emissions/waste from this equipment or process?

Some operators have been voluntarily practicing reduced-emission completions for this source over the past several years. These reductions have been reported to the EPA Natural Gas Star program:
https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf
https://www.epa.gov/sites/production/files/2017-09/documents/greencompletions.pdf

Furthermore, federal requirements apply to all new completions. While there are exemptions from the full REC requirements for some types of completions it would be technically infeasible to extend the full REC requirements to exploratory, low-pressure, or low GOR wells.

Technology Alternatives:

List of technology alternatives with link to information or contact information for the company/developers.

Name/Description of Technology	Link (and contact info for company if available)	Availability	Feasibility	Cost Range (choose one)
		In use or in development		Low Medium High

Would new technology or equipment be needed to reduce methane emissions?

As discussed earlier most well completions are subject to the NSPS REC requirements. Additional control requirement for non-wildcat and non-exploratory wells are not easily identifiable. In addition, at this stage, it is not evident that there are technology options available to extend the full REC requirements to exploratory, low-pressure, or low-GOR wells.

What technology alternatives exist to reduce or detect emissions?

At this stage, it is not clear what additional technology alternatives exist to reduce emissions further from these wells.

What are the pros and cons of the alternatives?

NA

What is needed and available for new wells?

NA

What is needed and available for existing wells?

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NA

What technology alternatives exist for this equipment or process itself?

NA

What are the pros and cons of the alternatives?

NA

Costs of Methane Reductions:

What is the cost to achieve methane emission reductions?

NA

What would be the implementation cost?

For new wells?

NA

For existing wells?

NA

Are there low-cost solutions available?

NA

If a solution is high-cost, why is that the case?

NA

Are there additional technical analyses needed to refine benefits/costs estimates?

NA

3. IMPLEMENTATION

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

Implementation Feasibility:

What is the feasibility of implementation (availability of required technology or contractors, potential permitting requirements, potential for innovation)?

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Reduced emission completion technology has been required for all gas completions since 2012 and for all completions since 2016 with limited exceptions outlined in the regulations. This is an accepted process and is readily available for most completions across the country.

What is the useful life of equipment?

Completion activities typically last from several days to several weeks. Depending upon the specific circumstances, operators have the option of using either (permanent) equipment installed for production purposes or rental equipment. If rental, operators source this equipment for the expected duration of completion activities.

What are the maintenance and repair requirements for equipment required for methane reduction?

The separators and any temporary equipment including frac tanks is sourced by the operator prior to the commencement of flowback following completion activities. Perhaps the most critical aspect of the flowback period is the necessity to remove sand using an effective sand separator to prevent damage to downstream equipment.

How would emissions be detected, reductions verified and reported?

Operators continue to report emissions from flowback activities in accordance with EPA GHG reporting program.

4. CHALLENGES AND OPPORTUNITIES TO ACHIEVE METHANE REDUCTION IN NEW MEXICO

For each piece of equipment or process, please consider the following questions and add other relevant information. If relevant, please identify if the answers are different for large company and small company requirements or are different for well type or basin.

What regulatory gaps exist for this equipment or process? Are there regulatory gaps filled by the proposed implementation?

As discussed earlier, NSPS standards apply to essentially all completions across the country. Due to technical considerations, wildcat, low-pressure, and low-GOR wells are not required to meet the same standards as non-wildcat and non-delineation wells. For technical feasibility reasons, it is important to have these different standards for completions at these special categories of wells. EPA considered and ultimately did not require prior approval for the technical feasibility exemptions for reasons discussed in the previously referenced preamble to the NSPS OOOOa regulations.

EPA requires operators to record the basis for a claim of technical infeasibility to comply with the reduced emission completion requirement, and to provide the recorded information to EPA in an annual

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compliance report. 40 C.F.R. Section 60.5420a(c). There is no requirement that operators notify EPA, or the delegated state agency, prior to claiming an exception. One potential improvement to the federal requirements would be for the state to require operators to notify the state prior to claiming an exception from the reduced emission completion requirement. The notice could require the same information EPA currently requires operators record as the basis for the exception claim. The state could require approval of an exception claim prior to completions commencing. This would provide more information to the state as to how many operators are claiming exceptions, and the reasons for such claims. Additional oversight as to the grounds for exception requests could lead to additional emission reductions were the state to find that some exception requests are not warranted (e.g., increased coordination between upstream and midstream operators prior to drilling may lead to the availability of gas pipeline infrastructure being in place prior to completions, thereby making reduced emission completions technically feasible).

Other considerations or comments (e.g. particular design or technological challenges/opportunities, non-air environmental impacts, etc.?):

NA

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5. COMPLETIONS, RECOMPLETIONS AND STIMULATIONS - PATH FORWARD[180]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EMISSIONS REDUCTIONS ARE EASY TO ACHIEVE AND ARE COST EFFECTIVE 1 = EASY 5 = HARD	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
9.1	Existing federal NSPS requirements adequately address the completion activities in NM.	Federal regulations create a set of common standards that are applicable for completion activities in New Mexico where both producing basins (Permian and San Juan) each straddle two states.	1 2 3 4 5	Continue with the requirement to report emissions in accordance with EPA's GHG reporting program.	San Juan Permian Both
	COMMENT A. As indicated in the Completions document, emissions from this activity are a small percent of total methane emissions. In order to get the necessary reduction, it would be more practical to focus on sources contributing more to the methane emissions. [page 267] B. Continue to allow flaring when technically infeasible to conduct a Reduced Emission Completion. [page 262] C. Data from operator's failure to capture methane emissions [page 263] in completions/recompletions are unknown—therefore comment A. above is unfounded [page 267]. Every effort is being made to capture emissions from		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

[180] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

	smaller sources of methane emissions through the LDAR process. However, completions/recompletions may very well be in excess of volumes we are actively seeking to stop with LDAR; and we should pursue completions/recompletions as a significant source of methane pollution. More complete methane emission data regarding completions/recompletions must be collected before reaching the conclusion that the current NSPS regulations are adequate. In fact, Expert Presentation by Dr. Robert Balch suggests that methane emission data reported by operators is underestimated and incomplete https://www.env.nm.gov/wp-content/uploads/sites/15/2019/08/Flaring-and-Venting-Stats-by-District-9-27-19.pdf.				
9.2	Codify existing federal regulations to protect against possible roll-back.	NMED should not rely on any existing federal regulations, given uncertainty as to what might be repealed. We should codify existing federal regulations and take steps that go beyond OOOOa to further cut emissions.	1 2 3 4 5		San Juan Permian Both
	COMMENT A. There is no indication that OOOOa regulations are being rolled back for oil and gas production sources in general and for completions in particular. B. Federal environmental protections including those for methane emission reductions are actively being rolled back at this time—continuing a federal record since 2017 of dismantling both EPA and BLM regulations. There is no indication that current federal policies to eliminate methane regulations will cease.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
9.3	Eliminate "Technical Infeasibility" Exemption where infeasibility could have been recognized in advance.	NSPS Subpart OOOOa allows operators to obtain an exemption from green completion requirements on technical infeasibility grounds even when the grounds for the exemption (e.g., lack of gathering lines) are known in advance. See 81 FR 35852. In adopting this rule, EPA considered but rejected comments urging the agency to disallow technical infeasibility exemptions in these cases. Id. The agency also considered but rejected comments suggesting that the agency require advanced	1 2 3 4 5		San Juan Permian Both

		notification of an operator's decision to invoke the technical infeasibility. Id. As EPA's discussion indicates, in many cases operators know in advance that it is not feasible to comply with EPA's green completion requirements due to lack of gathering lines, right of way issues, or similar factors. In these cases, there is a technically feasible alternative to wasting the gas: delay drilling until it is technically feasible to perform a green completion.			
	COMMENT A. Wells may be connected to pipeline but may still need to flare due to capacity or pressure issues. There are technical infeasibilities that arise even when capture options have been planned, making the need to flare difficult to predict ahead of time. Abrupt shut-ins or restricted well flow can cause formation damage to wells and result in underground waste. [page 274] B. Sometimes technical infeasibility issues can come up very late in the process despite operator plans (GCP submittal for example) to connect to a gathering line and to route the gas to sales. For example, pipeline may have operational issues on the day of the completion activity. Or there may be a right of way issue that prevents a connection at the last minute. Or the gas quality may prevent routing the gas into the gas pipeline. [page 262] There can be unforeseen circumstances which cannot be predicted in "advance". The option needs to make provisions for unforeseen and unpredictable circumstances despite advanced planning. C. The comment B. (above) misinterprets the scope of 8.3 PATH FORWARD. To discredit the PATH FORWARD, the Comment cites instances of flaring that are "difficult to predict ahead of time" while this PATH FORWARD specifically refers to instances where infeasibility could have been recognized "in *advance*."		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

NMED Exhibit 10 - 0281

	D. Comment B. (above) fails to consider that flaring events will be easier to predict with increase of data research and multiple options to flaring exist as outlined in detail in Expert Presentations. E. Comment B. (above) assumes that state agency resources will not increase in the future. This assumption is contrary to recent political climate justice trends in New Mexico, and also to consistent historical evidence of technological and process solutions to existing problems after regulations have been put in place, i.e., D.D.T. 1950's https://www.epa.gov/ingredients-used-pesticide-products/ddt-brief-history-and-status and lead in gasoline 1975 https://archive.epa.gov/epa/aboutepa/epa-takes-final-step-phaseout-leaded-gasoline.html				
9.4	NM state rule that contains the following components for all completions, re-completions, and stimulations: Provide notice prior to completion/re-completion/stimulation (required)	*If operator <u>has</u> monitoring equipment with data recording on site*, notice must be made **two (2) days** prior to completion/re-completion/stimulation. Data must be submitted within 48 hours. OR *If operator <u>does not</u> have monitoring equipment with data recording on site*, notice must be provided **fifteen (15) days** prior to completion/re-completion/stimulation	**2**	Monitoring required using portable combined FID/PID toxic vapor analyzer with data logging technologies or another technology capable of measurement within acceptable parameters such as FTIR/laser or other innovative and	Both

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				emerging technologies.[181]. Cost for a TVA2020 FID/PID unit starts at $10,300.[182]	
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE: C. Mirror notice requirements already used for drilling operations which would provide for		

Table 1: Summary of the technologies participating in the Stanford/EDF Mobile Monitoring Challenge. DOI: https://doi.org/10.1525/elementa.373.t1

Company	Platform Type	Sensor Type/Species Measured	Survey Method	Survey Speed[a] (mph)	Survey Height (m)
ABB/ULC Robotics	Drone	Cavity-enhanced laser absorption spectroscopy – Methane	Modified raster scan (wind responsive)	2–5	5–10 m
Advisian	Helicopter	Laser absorption spectroscopy – methane/ethane	Upwind/Downwind transects with sample tube	2–5	15–20 m
Aeris Technologies	Vehicle	Laser absorption spectroscopy – methane, ethane, water-vapor	Fence-line around equipment groups, facility	~10	1–2 m
Baker Hughes (GE)	Drone	Laser absorption spectroscopy – methane	Concentric circles around equipment	~5	5–10 m
Ball Aerospace	Plane	Airborne differential LIDAR – methane	Fly-overs (multiple passes)	~115	~1000 m
Heath Consultants Inc.	Vehicle	Off-axis integrated cavity output spectroscopy – methane, ethane	Fence-line around equipment groups, facility	~10	~1–2 m
Picarro	Drone and Vehicle	Cavity ringdown spectroscopy – methane, ethane, water-vapor	Upwind/Downwind transects	2–5	5–10 m
Seek Ops Inc.	Drone	Laser absorption spectroscopy – methane	Raster scan, with flux plane mapping	2–5	1–3 m
U Calgary	Vehicle	Open-path laser spectroscopy – methane	Fence-line and highway-based screening	~10 (fence-line) 30–50 (highway)	2–3 m
U Calgary and Ventus Geospatial	Drone (fixed-wing)	Open-path laser spectroscopy – methane	Multiple downwind plume transects	30–40	28–124 m

[a]Some technologies were limited in their speed due to speed-limits at the METEC test-site (10 mph).

181 https://doi.org/10.1525/elementa.373.t1

182 This price quote is from one commercial vendor, LDAR Solutions. Most distributors of this technology only offer quotes directly to a purchasing company, which generally results in a lower per-unit price.

	A. It is not clear how this would actually reduce emissions. It will be helpful to have emission reductions quantified to warrant changing the existing notification requirements. [page 275] B. At this time, actual methane emissions from completions/recompletion amounts have not been quantified or made public. The Colorado notification requirement encourages operators to have methane detection equipment in place as shown in Table 1 (DOI link).for the purpose of determining pollution volumes. Until such time that volumes have been established, emission reductions will be impossible to quantify. (See 8.1 above). Nonetheless, this PATH FORWARD encourages a methane-reducing practice. A lack of complete data does not justify the failure to promote gas-capture practices. Expert Presentation by Dr. Robert Balch suggests that methane emission data reported by operators is underestimated and incomplete https://www.env.nm.gov/wp-content/uploads/sites/15/2019/08/Flaring-and-Venting-Stats-by-District-9-27-19.pdf.		consistency in regulations, familiarity for both operating and OCD field personnel, and reduced paperwork. Requirements are verbal notice to the appropriate OCD District Office prior to spud, then prior to cementing operations with minimum time frames. Same could be done for verbal notice prior to moving in on completion operations and prior verbal notice before stimulation work. Verbal notice dates and times are referenced on appropriate C-103 forms. [page 278]		
9.5	NM state rule that contains the following components for all completions, re-completions, and stimulations: No venting exceptions during completion/re-completion/stimulation	Multiple additional options are available to operators during completions/re-completions/stimulation of a well that make any venting unnecessary: CNG in a box; Capture and conversion to NGL (mobile refrigeration skid); reduced emissions completions.	**3 - 4**	*See* innovative and emerging technologies	Both
	COMMENT A. Generally, there is not a large amount of gas production during the completions phase. [page 267] Conversion to sales options (CNG, NGL) require both an adequate supply of gas and sales quality gas which may not be present during completions. [page 262] Capture of the gas as CNG/NGL would be prohibitively expensive given the short deployment and small amount of captured gas. Equipment availability is also very limited. B. The comment A. above incorrectly asserts that completions are not a significant source of methane emissions (See comments in 8.1 and 8.4). Conversion of		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

	flowback to sales have an established record of success. Many options exist (Natural Gas STAR program studies: (1) https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf (2) https://www.epa.gov/sites/production/files/2017-09/documents/greencompletions.pdf (3) http://www.ipieca.org/resources/energy-efficiency-solutions/units-and-plants-practices/green-completions/ Existing affordable capture technology exists and will be brought to market when regulations require it. [page 267] Equipment was once available, can be again, and at presumed improved function, cost, and availability.				
9.6	NM state rule that contains the following components for all completions, re-completions, and stimulations: Limit technical feasibility exceptions for flaring within volumetric limitation	Requests for flaring within volumetric limitations must provide detailed data and costs to be considered. This cost information must include actual equipment costs and estimated operational costs of both capture and flaring for comparison, as well as percentage of expected net yield lost to these costs.	**2**	Requests could be submitted electronically under a confidential procedure managed by the regulating agency.	Permian
	COMMENT A. Wells may be connected to pipeline but may still need to flare due to capacity or pressure issues. There are technical infeasibilities that arise even when capture options have been planned, making the need to flare difficult to predict ahead of time. Agency resources may be too limited to process requests in a timely manner. Abrupt shut-ins or restricted well flow can cause formation damage to wells and result in underground waste. [page 274] B. NSPS OOOOa requires operators to comply with REC requirements with exemptions for certain wells such as wild cat wells. [page 275] This suggestion would be feasible in those cases where the operator knows "in advance" that it is technically infeasible to route the gas to a pipeline. It is not practical for unforeseen circumstances.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

	C. Comments A. and B. [above] do not address the fact that increasing the amount of data that industry provides to state agencies is beneficial for the purpose of reducing methane emissions. [page 278] D. Comments A. and B. [above] unwarrantedly rely heavily on a minority of cases (i.e. "capacity or pressure", instances that are "difficult to predict ahead of time") that do not represent the majority of flaring requests that the agency processes. E. Comment A. [above] fails to distinguish between a flaring event being "difficult" to predict from a flaring event being impossible to predict; and, additionally, fails to justify why "difficulty" of a methane-reducing measure grants operators a pass on taking precautionary measures. F. Comments A. and B. [above] fail to consider that flaring events will be easier to predict with increase of data research and that multiple options to flaring exist as outlined in detail in Expert Presentations. G. Comment A. [above] assumes that state agency resources will not increase in the future. This assumption is contrary to recent political climate justice trends in New Mexico, and also to consistent historical evidence of technological and process solutions to existing problems after regulations have been put in place, i.e., D.D.T. 1950's https://www.epa.gov/ingredients-used-pesticide-products/ddt-brief-history-and-status and lead in gasoline 1975 https://archive.epa.gov/epa/aboutepa/epa-takes-final-step-phaseout-leaded-gasoline.html H. We have ample evidence that not only [are operators] failing to capture methane and avoid emitting it during completions/recompletions, they are also venting it (see: Grant-Schreiber study [page 264] "2. Sources of Methane Emissions"—"Existing wells"). NSPS OOOOa says that green completions/R.E.C. will not be vented or flared (40 C.F.R §60.5375a https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf). Extensive evidence of methane emission capture and successful sales line access is listed in comment 8.4 above.	

SECTION 10, CROSS-CUTTING PATH FORWARD REPORT

Discussion for MAP members on October 11, 2019

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1. NARRATIVE INTRODUCING THE CROSS- CUTTING PATH FORWARD

The MAP members determined that several Path Forward concepts would apply to more than one piece of equipment or were more over-arching ideas. This report collects those over-arching ideas.

2. CROSS-CUTTING - PATH FORWARD[183]

	OPTIONS	DESCRIPTION AND LINK TO INFORMATION IF AVAILABLE. PLEASE LIST THE BENEFIT THAT COULD BE ACHIEVED THROUGH THIS OPTION AND ANY DRAWBACKS OR CHALLENGES TO IMPLEMENTATION	EMISSIONS REDUCTIONS ARE EASY TO ACHIEVE AND ARE COST EFFECTIVE 1 = EASY 5 = HARD	REPORTING, MONITORING AND RECORDING OPTIONS, INCLUDING REMOTE DATA COLLECTION	IS THIS OPTION HELPFUL IN THE SAN JUAN BASIN, PERMIAN BASIN OR BOTH
10.1	Comprehensively Improve Methane Emissions Reporting	Use multiple reporting and monitoring tools to create a comprehensive structure for reporting of methane emissions in the state, tracking emissions reductions, and supporting compliance and enforcement. This system could include: • Clearer guidance for OCD C115 reporting on venting and flaring, including venting during completions and recompletions, and data from those forms; • Improvements to OCD Form 129 and Gas Capture Plan data requirements; • Data from NMED's 2020 Minor Source Emission Inventory (and future year inventories); • U.S. GHGRP data; • Satellite Data from Descartes' Labs Data Refinery https://www.currentargus.com/story/news/local/2019/09/30/new-mexico-works-data-firm-track-oil-and-gas-methane-emissions/3819579002/); and • Data from third parties, such as the newly announced EDF/ Pennsylvania State University/ University of Wyoming/ and Scientific Aviation Permian Basin	2		BOTH

[183] The format of the Path Forward table evolved over the course of the meetings as the group tried to identify the best method for capturing the most useful information. As a result, there is some variation in the table headers from topic to topic in the final consolidated report.

		methane emissions mapping and monitoring initiative. https://www.edf.org/media/new-initiative-will-map-and-measure-methane-emissions-across-permian-basin The system should incorporate mechanisms for using data from satellite, tower, or mobile monitoring sources to identify potential gaps or shortfalls in bottom-up reporting through OCD, NMED, or US GHGRP.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.2	Consider co-benefits in evaluating methane control mechanisms and work processes	Many control mechanisms and work processes for reducing methane emissions in oil and gas development provide co-benefits, or can be implemented in ways that provide co-benefits. When considering the methane reduction potential of these control strategies and work processes, agencies should also consider co-benefits. These co-benefits can include: • Reducing emissions of Volatile Organic Compounds and Hazardous Air Pollutants, which cause adverse health impacts for nearby communities. *See* OOOOa Rulemaking: https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf; John L. Adgate et al., *Potential Public Health Hazards, Exposures and Health Effects from Unconventional Natural Gas Development,* 48 Environ. Sci. Technol. 8307–8320 (2014), https://pubs.acs.org/doi/10.1021/es404621d; Clean Air Task Force, Fossil Fumes: A Public Health Analysis of Toxic Air Pollution from the Oil and Gas Industry, https://www.catf.us/resource/fossil-fumes-public-health-analysis. Using a multi-pollutant approach to regulation has also been widely supported in public policy literature. *See e.g.,*	3		BOTH

		National Research Council, *Air Quality Management in the United States* (2004) https://doi.org/10.17226/10728. Using setback requirements can also prevent localized health harms; an October 2019 Colorado Health Impacts Assessment found that "there is a possibility of negative health impacts at distances from 300 feet out to 2000 feet" near oil and gas facilities. (CPDHE Press Release, https://www.colorado.gov/pacific/cdphe/news/oil-and-gas-health-risk-study; Chris Holder et al., *Evaluating potential human health risks from modeled inhalation exposures to volatile organic compounds emitted from oil and gas operations*, J. AIR & WASTE MANAGEMENT ASSOC., DOI: 10.1080/10962247.2019.1680459 (2019). • Reducing noise pollution, for example by using electric power instead of a combustion engine. • Potential reduced surface impacts such as dust, noise, water contamination, and truck traffic, as well as impact to Tribal Cultural Properties, for example where infrastructure planning processes that require pipelines can be used to reduce surface impacts from truck traffic. *See* Mark Squillace, Managing Unconventional Oil and Gas Development as if Communities Mattered, 40 VT. L.REV. 525 (2016), https://scholar.law.colorado.edu/articles/22. • Creation of local jobs, for example through leak detection and repair requirements. Marie Veyrier, Datu Research, Find and Fix: Job Creation in the Emerging Leak Detection and Repair Industry (2017), https://www.edf.org/how-reducing-methane-emissions-creates-jobs Effective methane mitigation, in particular relative to infrastructure planning, can, if done right, induce these			

		positive co-benefits to environmental, cultural, and community resources (or, if done wrong, cause negative impacts to these resources).			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.3	Consider history of technology innovation and deployment to meet regulatory requirements	Historically, innovation and technology deployment has outpaced predictions to meet regulatory requirements. For example, the Clean Air Act's implementing regulations required electric utilities to control SO2 from power plant smokestacks. Despite industry predictions that the new regulatory requirements would induce high costs, innovation yielded inexpensive scrubbers to satisfy the CAA requirements. Margaret R. Taylor et al., *Control of SO2 emissions from power plants: A case of induced technological innovation in the U.S.*, 72 TECH. FORECASTING & SOC'L CHANGE 697 (2005), https://doi.org/10.1016/j.techfore.2004.11.001. In another case, a study found that performance-based, technology forcing car standards induced substantial innovation in vehicle pollution control technologies. Jaegul Lee et al, *Linking Induced Technological Change, and Environmental Regulation: Evidence from Patenting in the U.S. Auto Industry*, 40 Research Policy 1240 (2011), https://www.sciencedirect.com/science/article/pii/S0048733311001193. At least one study documents how methane control requirements create jobs. "Companies have already experienced 5–30% business growth in states with methane regulations." Marie Veyrier, Datu Research, Find and Fix: Job Creation in the Emerging Leak Detection and Repair Industry (2017), https://www.edf.org/how-reducing-methane-emissions-creates-jobs.	2		BOTH
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

10.4	Well Site Electrification: Incentives for Utility Co-ops	Providing a well site with electricity allows operators to implement methane-reducing technologies such as zero-emission dehydrators, electric pumps, and heater treaters. This would require the expansion of service territories for Utility Co-ops surrounding the Permian Basin and San Juan. Expanding utility service territories requires substantial infrastructure investment. But with the right market conditions (i.e. State regulations, financial incentives), this expansion could be economically and environmentally beneficial--especially considering the potential for methane reduction with well site electrification. In the case that the agency would decide to contact utilities regarding this topic, the following is a link with contact information for electric companies relevant to San Juan or Permian Basin: [184]			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.5	Require Large Operators to Submit Biennial Progress Reports Detailing Steps Taken to Achieve Net Zero Emission Target	In order to prevent warming in excess of 1.5°C, global net anthropogenic CO2 emissions must fall to zero by around 2050. Intergovernmental Panel on Climate Change, Global Warming of 1.5 ºC, Summary for Policymakers at 12. Methane emissions must also be reduced dramatically during the same time-frame. *Id.* In order to be viable in a carbon constrained world, the oil-and-gas industry must eliminate net GHG emissions within a matter of decades. Large oil and gas operators could be required to submit to NMED a comprehensive status report every 2 years, updating the agency on their progress towards this zero emission target.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

[184] https://docs.google.com/spreadsheets/d/10_IOLsuWtE6hEzFe5Tfgcfa8BdcZ3qckMLbr224_WT4/edit?usp=sharing

10.6	Utilize Flexible Policy Instruments (Including Market-Based Policies) to Incentivize Continuous Emission Reduction	There are a variety of policy instruments that have been developed to address situations where significant emission reductions from an industry are possible, but it is difficult to mandate the use of specific techniques to achieve these reductions. Examples include company-wide emission reduction targets, fleet-wide averages for particular equipment, cap-and-trade, and emission fees. These instruments can operate in conjunction with equipment, design, and operational standards that are more prescriptive. The agencies should consider combining flexible policy instruments that drive continuous emissions reductions with more prescriptive measures that establish a baseline level of performance for the entire industry.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.7	Exempt stripper wells	Exempt all identified emissions reduction options (column 1) and be specific to stripper well production. As defined by the Interstate Oil & Gas Compact Commission (IOGCC), a stripper oil well produces 10 BOPD or less, or 60 Mcf/day or less if a gas well. This is an important segment of the oil and gas industry in New Mexico that should not be overlooked, as 66% of the total 57,868 wells (EIA) in this state fall under the IOGCC definition. The majority of wells in New Mexico are marginal wells yet will have the lowest emissions profile and stand to generate the largest increase in emissions generated by mandating quarterly LDAR.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.8	MOU between state agencies to 1) speed the development of electrical infrastructure to the oilfield	*Electricity reliability and voltage requirements-Oilfield equipment power requirements are quite varied ranging from instrumentation at a single well pad needing approximately 35W to operate up to approximately 2,000 kW (note unit change) to operate a single frac/stimulation pump. The power demand required to operate equipment determines if*		Metering of gas used for generation (would royalties be due since the gas utilized would alternately be flared).	BOTH

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	2) willingness of electrical utilities to accept and manage distributed generation put onto the grid from oilfield sites Impacts suggestions: Conversion of pneumatic controllers, compressors, etc. to electrical power. Use of available associated gas for onsite generation	*single phase power (household) is adequate or if three phase power (industrial) is necessary. See Infrastructure planning paper for a further detailed description of the status of electrification in the field and needs of the oilfield.* *Due to the challenges around the development of adequate power supply to remote locations and the temporary nature of some areas of oilfield demand, many sites are supplied by onsite generation.* *Solar or wind installations typically require a back-up power source for reliability purposes. This necessary back-up significantly impacts the economic feasibility of the solutions and may also result in emissions dampening some of the benefit of alternate installation.* *Management of distributed oilfield generated power on the grid would offset the load on the existing system, reduce generation from existing power plants, and convert a source of stranded energy.* *Management and stability of the grid are critical considerations when considering adding distributed sources of power.* *Collection of produced gas in "mini" gathering systems may be necessary to provide a stable source of gas to generators.* *Determination of gas royalties and/or payment for power generated would need to be sorted out to maximize economic options.* *Expedited right of way for electrical lines would be necessary to maximize generation capability and minimize associated gas flaring.*		Metering of electrical production.	However, the lack of supporting electrical infrastructure is more predominant in the Permian due to growth in remote locations.
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.9	Consider where methane reduction strategies and	Native communities experience unique and disproportionate harms from Oil and Gas production. For example, Oil and Gas Production has impacted Diné society, it structures			

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	processes have the potential to reduce negative impacts to native communities, native lifeways, or tribal cultural properties, including through consultation with the NM Department of Indian Affairs	relationships with family, community and ecosystems, and that fracking caused a significant perturbation of practice and reverence of Hozhoo. The NM Health Impact Assessment Report, *A Cultural, Spiritual, and Health Impact Assessment of Oil Drilling Operations in the Navajo Nation Areas of Counselor, Torreon, and Ojo Encino Chapters*. 2019. Herbert Benally, PhD, and Moroni Benally, MPP, MSPPA. *Spatial Justice and Indigenous People' Protection of Sacred Places: Adding Indigenous Dimensions to the Conversation*. March, 2017. June L. Lorenzo, PhD, NM Attorney. Moreover, as sovereign nations, Tribal communities are owed government-to-government consultation under federal and state laws and policies. See New Mexico State-Tribal Collaboration Act, NMSA 11-18-1 et seq; Consultation and Coordination with Indian Tribal Governments, Exec. Order 13175 (Nov. 6, 2000). Tribal communities, lifeways, and cultural properties are also protected by numerous federal and state laws. See e.g., New Mexico Cultural Properties Act, NMSA 18-6-1 et seq.; National Historic Preservation Act, 54 U.S.C. § 302706. A number of promising methane reduction technologies and work processes can either harm or benefit Tribal communities, lifeways, and cultural properties. In the process of rulemaking, agencies should consider how regulatory options could harm or benefit Tribal communities, lifeways, and cultural processes, and where possible should require options to be implemented in ways that will reduce harmful effects or secure co-benefits for Tribal Communities, lifeways, and cultural properties. Agencies should consult with Tribes and with the NM Indian Affairs Department to identify potential co-benefits and harms.			

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	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.10	Federal Regulations that may affect some path forwards. Section 106 Tribal consultation. Regional Haze.	https://www.npi.org/nepa-and-section-106-national-historic-preservation-act This may affect infrastructure. https://www.epa.gov/visibility/regional-haze-program			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.11	Navajo Nation Regulations need to be considered regarding paths forward	Proposed Navajo Nation Environmental Protection Agency proposed minor new source regulations. These rules will be a unitary permit. This follows 76. FED. Reg. 38784 (July 1, 2011), 40 CFR sections 49.151-161 Navajo EPA will have proposed rule out for comment in the near future.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.12	Navajo Nation Aquifer Protection Act affect multiple path forward sections	This regulation needs consideration on Checkerboarded lands. http://www.navajopublicwater.org/26_NPDWR-2600_Aquifer_Protection-Regulations_Rev.pdf			
	COMMENT A. Adjustable regulations: Do not pass the point of regulatory diminishing returns. Energy expended and greenhouse gases emitted chasing down small leaks are greater than the environmental impact of the leaks themselves. Repetitive monitoring makes little sense as the percentage of leaking components decreases. This calls for a fresh look at regulatory regimens in light of current sealing and monitoring technologies.		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE		
10.13	Consider incentives / recognition of companies that are meeting / exceeding expectations – differentiate through public recognition	Adjusting behavior in any organization requires application of both positive recognition for those reflecting the behaviors expected as well as negative influence with others who aren't moving quickly enough to meet the new behavioral expectations. Studies show that positive recognition has a greater influence on behavior than negative.	**1**	It is recommended that a report or portal be created to allow a company that is striving to meet or exceed NM expectations can answer voluntary questions regarding their	BOTH

				proactive work (i.e. more frequent FLIR studies, complete changeout to Viton gaskets, etc.) which is auditable. If those companies achieve a score of X or higher against proactive and voluntary reporting, they would be incentivized through Governor or other governmental recognition of their company in order to promote great behavior and motivate others to strive for this recognition. It would also be good to incentivize this verified good behavior to reduce reporting or other regulatory burdens.	
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.14	Add more detail to the New Mexico Civil Penalty Policy – Appendix D (https://www.env.nm.gov/air-quality/civil-penalty-policy/)	The Texas EHS Audit Privilege Act (https://crgtexas.com/2018/03/05/texas-environmental-health-safety-audit-privilege-act/) is extremely detailed in its design and would allow NMED, OCD and the company to enter an agreement in a much more protected manner. Highly recommend emulating this structure in NM. It is important to note that the Texas RRC has adopted this EHS	**1**	The Texas Audit Privilege Act has strong guidance which would help NM in objective communication of expectations and also provide clear gates through which a	BOTH

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	using the Texas Environmental, Health and Safety Audit Privilege Act (both TCEQ and RRC have adopted this program) as a foundation.	Audit Privilege program in recent years – it was founded within TCEQ.		company must follow to meet its expectations. This would lead to more use of the system.	
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.15	Temporary (< 1 year on site) gen set power allowed to be placed on site in the event line power is not available without forcing NMED permitting staff to write permit for this temporary requirement and requires company to wait up to 120 for this permit modification – with this timing sometimes forcing flaring while waiting on gen set power.	Many states allow the placement of temporary gen set power on a site in the event there are delays in getting line power to a site. This minimizes flaring in the event line power is delayed. Most states allow this and it would have an immediate impact on improving methane capture in New Mexico.	1	Company would be obligated to remove temporary power by end of year. Companies would always prefer to use line power versus gen set power so the financial benefits of getting line power ASAP is the primary driver to get away from gen sets.	BOTH
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.16	Adjustable regulations	Do not pass the point of regulatory diminishing returns. Energy expended and greenhouse gases emitted chasing down small leaks are greater than the environmental impact of the leaks themselves. Repetitive monitoring makes little sense as the percentage of leaking components decreases. The majority of wells in New Mexico are marginal wells yet will have the lowest emissions profile and stand to generate			

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		the largest increase in emissions generated by mandating quarterly LDAR. This calls for a fresh look at regulatory regimens in light of current sealing and monitoring technologies.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.17	Incorporating the Social Cost of Methane	When state agencies are considering cost-benefit analyses to determine the "economic feasibility" of a certain methane reducing technology, the social cost of methane (SCM) should be taken into account. Methane emissions have externality costs (i.e. perpetuating the climate crisis, damaging public health, harming agriculture yields) that industry does not internalize. Scholarship on this issue suggests that "quantifying these damages to the planetary commons by calculating the social cost of methane (SCM) facilitates more comprehensive cost-benefit analyses of methane emissions control measures and is the first step to potentially incorporating them into the marketplace." Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (February 2010) (IWG (2010)). Interagency Working Group on Social Cost of Carbon, United States Government, *Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (August 2016)* (IWG (2016))	2		

		Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (August 2016) (IWG (2016)). Hindell, D. T., Fuglestvedt, J. S. and Collins, W. J. (2017) The social cost of methane: theory and applications. Faraday Discussions, 200. pp. 429-451. ISSN 1364-5498 (http://centaur.reading.ac.uk/72181/)			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.18	Require consideration of ambient constant noise level dBA regulation/policy for mechanical, hydraulic, pneumatic, compressors or other devices in sites that are close to residential areas.				
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		
10.19	Increase FTE count and funding at OCD and NMED AQB in order to more effectively implement and enforce methane reduction regulations.	As underlined by the consensus industry, environmental organizations, and state regulators in the 2019 State Review of Oil and Natural Gas Environmental Regulations (STRONGER) New Mexico State Review Report key recommendations 10.2.6 (AQB) and 10.2.6a (OCD), both agencies require increases in full time employee (FTE) counts and funding from the Governor and State Legislature in order to accomplish their statutory duties including the implementation and enforcement of methane waste and pollution reduction regulations. Therefore, effectuating these	3		BOTH

	"Community Ombudsman"	increases will be key to realizing these methane reductions going forward. There is a body of existing knowledge on the effect of oil and gas development/production on rural and indigenous communities. An opportunity exists to create additional reference for people who are either impacted by oil and gas development initially or are otherwise challenged by oil and gas production to get advice and references that will help give access to pertinent agencies, speed up response times and help orient them to the challenges ahead. For example, organizations like Earthworks' Oil & Gas Accountability Project and San Juan Citizens Alliance have been providing support to individuals and communities throughout New Mexico living with oil and gas development for over 30 years. These organizations and groups like them could help inform a neutral "community ombudsman" office established by the state to work with those directly affected by oil and gas development to better understand their rights and best practices available to prevent and reduce the impacts caused by development.			
	COMMENT		SUGGESTION TO MAKE THIS OPTION MORE WORKABLE:		

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New Mexico Environment Department

Ozone Attainment Initiative
Air Quality Bureau, Control Strategies
September 26, 2019



New Mexico Ozone Attainment Initiative Development

Our mission is to protect the inhabitants and natural beauty of New Mexico by preventing the deterioration of air quality.

The NMED will use the following during the development of the Ozone Attainment Initiative (OAI):

- Science: We will use the best available science to inform our decision-making.
- Innovation: We will employ creative engineering and technological solutions.
- Collaboration: We will engage with communities and interested stakeholders in our OAI development strategy.
- Compliance: We will ensure compliance with National Ambient Air Quality Standards and state regulations.

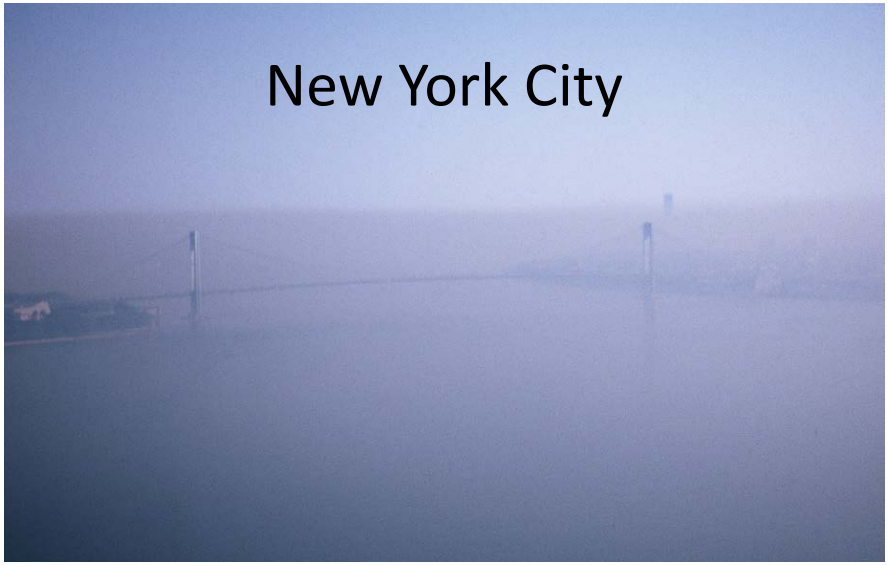
Outline

- What is Ozone?
- What are the health effects of ground level ozone?
- What is the Ozone Attainment Initiative?
- Why do we need the OAI?
- How will NMED implement the OAI?
- Where are the focus areas?
- What is the projected timeline?
- How can stakeholders get involved?

Smog


Denver Colorado

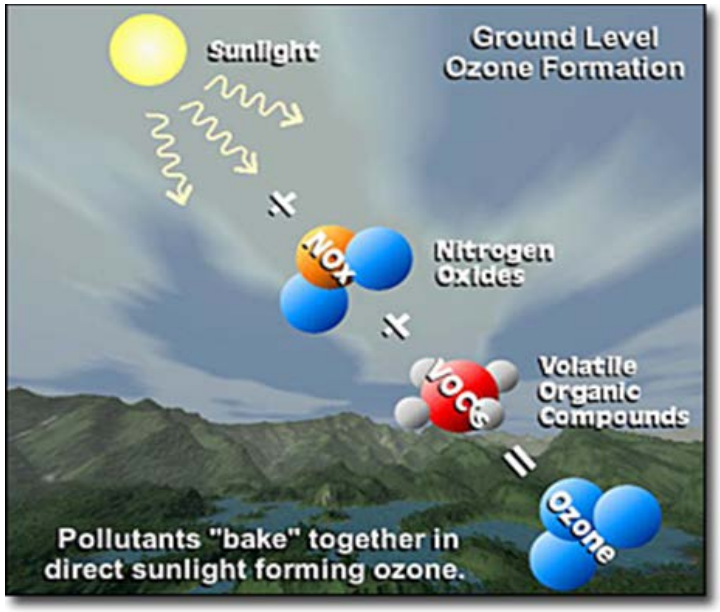

A layer of smog hovers over Los Angeles

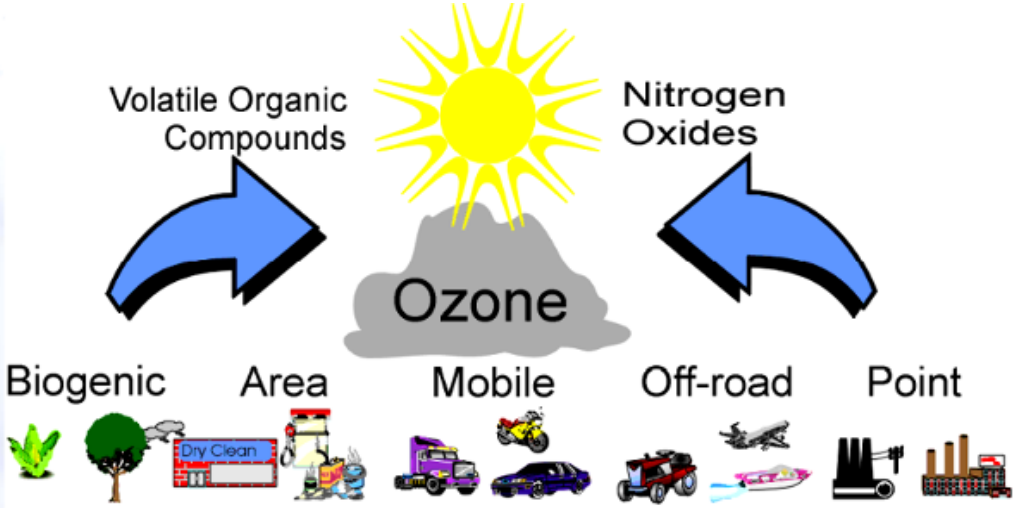

New York City

Ground-level Ozone Formation

The main pollutants that form ozone are oxides of nitrogen (NOx) and volatile organic compounds (VOC).

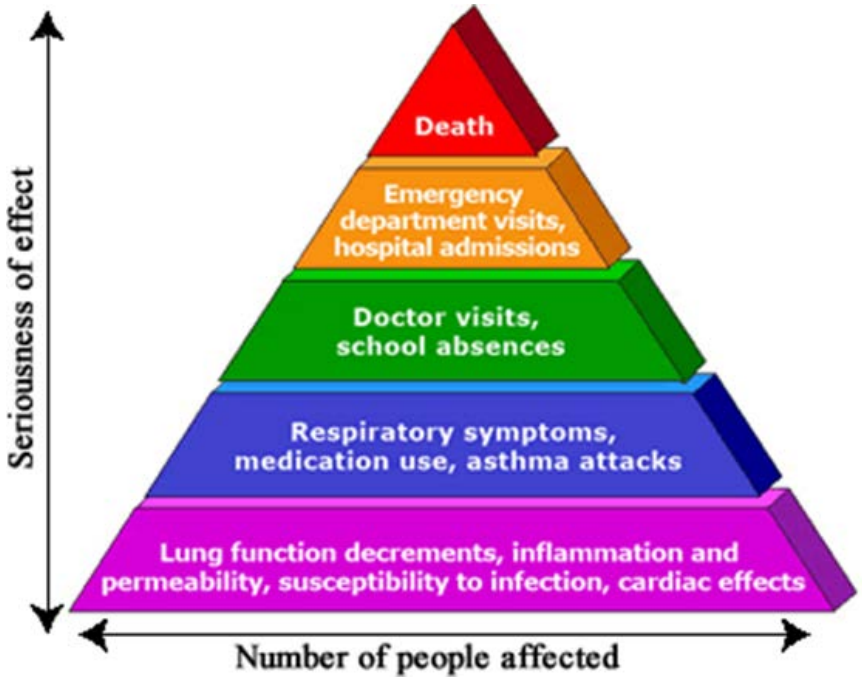
Ground level ozone, is not emitted directly into the air, but is created by chemical reactions between the "precursor" pollutants of nitrogen oxides (NOx) and volatile organic compounds (VOC) in the presence of sunlight.





Ozone Pollution Health Effects

- Effects seen across a wide range of health outcomes
- Sensitive groups include:
  - Asthmatic children and other people with lung disease
  - All children and older adults, especially people active outdoors
  - Outdoor workers



https://www.epa.gov/ozone-pollution-and-your-patients-health/health-effects-ozone-patients-asthma-and-other-chronic

NAAQS and Nonattainment

National Ambient Air Quality Standards (NAAQS)

- Standards for criteria pollutants
- Established by the U.S. Environmental Protection Agency (EPA)
- Nonattainment Area= Can be an area that violates/exceeds one of the NAAQS

Pollutant	Type	Standard	Averaging	Form
Ozone (O_3)	Primary and Secondary	0.070 ppm (70 ppb)	8-hour	Annual 4th high daily maximum 8-hr. avg., averaged over 3 yrs.*

*EPA's calculation methodology can be found at:
https://www.epa.gov/air-trends/air-quality-design-values

What is the Ozone Attainment Initiative (OAI)?

Monitoring data show several areas in the State approaching the level of the National Ambient Air Quality Standard (NAAQS) for Ozone

The OAI aims to:

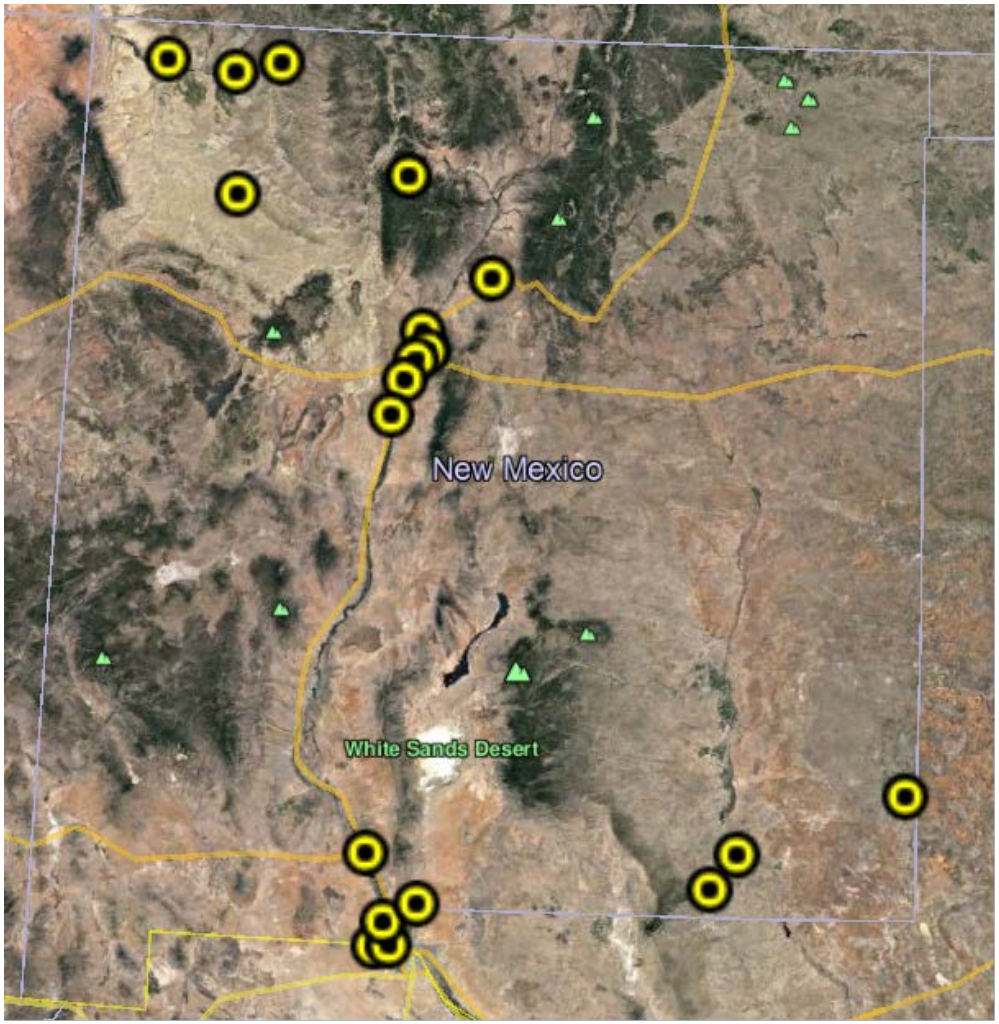
- Protect the attainment/unclassifiable status of all areas in the state
- Ensure the health and welfare of the residents of the state for future generations

Why do we need the OAI?

74-2-5.3 NMSA 1978

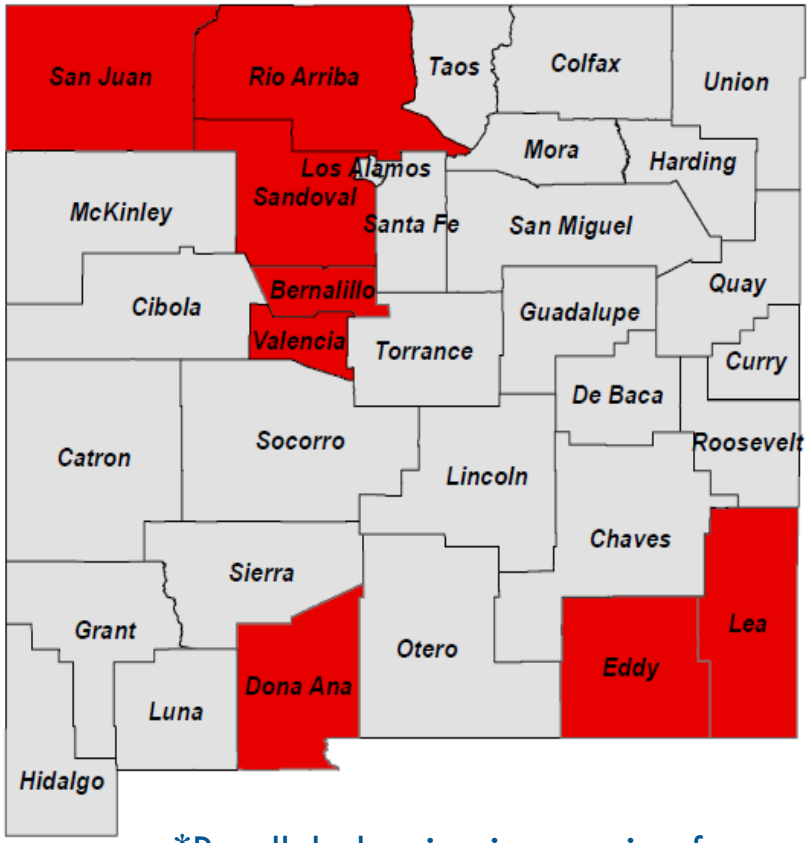
- If the EIB finds that sources cause or contribute to ozone concentrations in excess of ninety-five percent of a national ambient air quality standard for ozone, then
- NMED shall adopt a plan to control oxides of nitrogen and volatile organic compounds.

Affected Monitoring Stations*



- Includes CABQ/EHD O_3 monitoring sites. Each monitoring station includes several air monitors that each monitor a different pollutant.

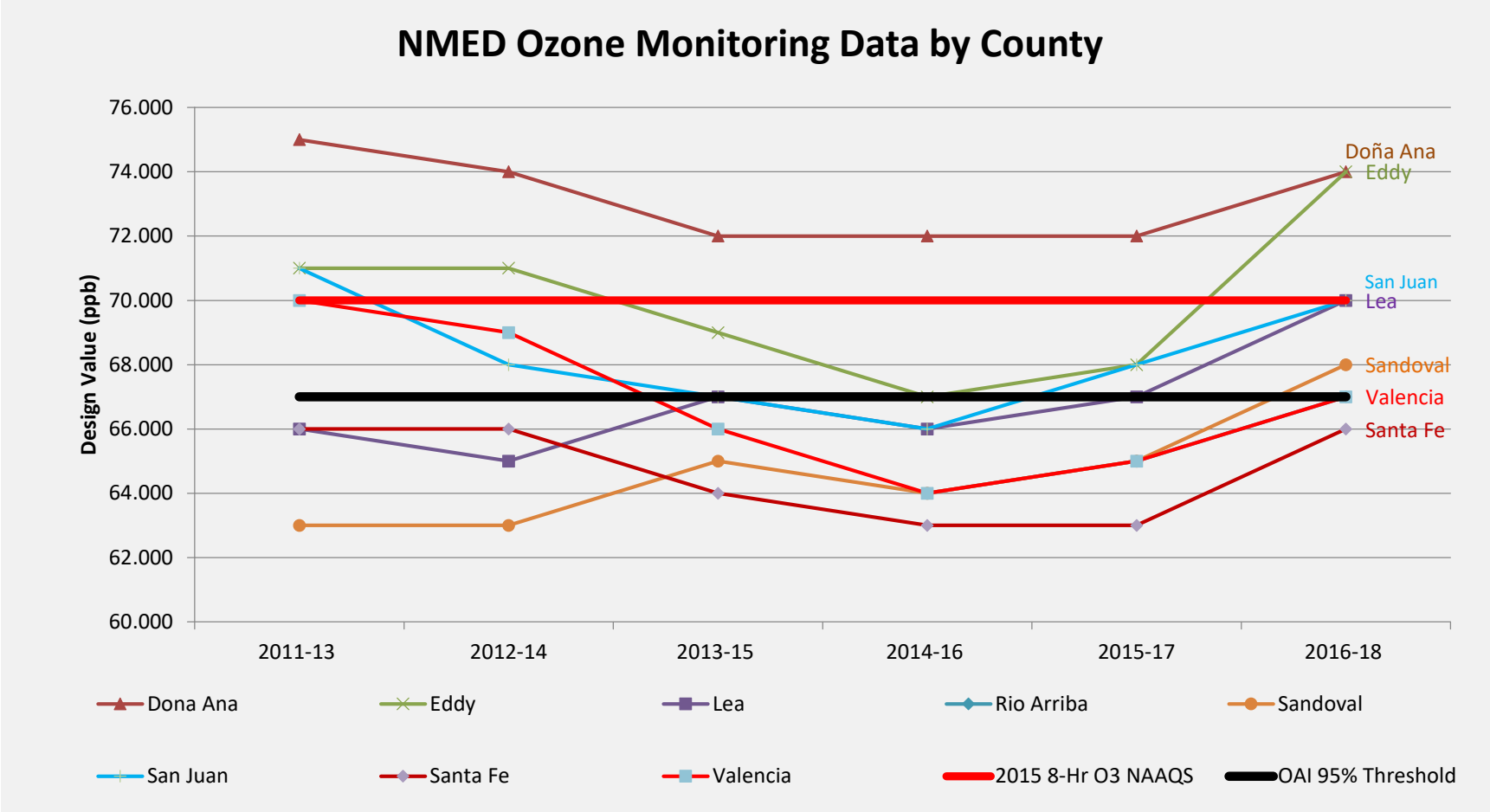
Focus Areas



*Parallel planning is occurring for Bernalillo County through the Albuquerque/Bernalillo County Department of Environmental Health

- Counties within 95% of the standard:
  - San Juan (Navajo Lake, 70 ppb)
  - Doña Ana (several monitors, 74 ppb)
  - Eddy (Carlsbad, 74 ppb)
  - Lea (Hobbs, 70 ppb)
  - Rio Arriba (Coyote, 67 ppb)
  - Sandoval (Bernalillo, 68 ppb)
  - Valencia (Los Lunas, 67 ppb)

NMED Ozone Monitoring Data by County

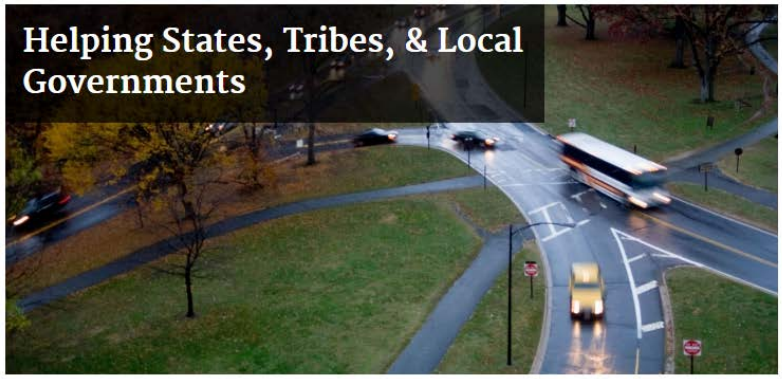


95% of the 70 ppb standard ≥ 67 ppb

How Will NMED Implement the OAI?

- Data Gathering
  - Emissions Inventories, Modeling and Continued Monitoring
    - O_3 and NOx Concentrations
    - Source sector contributions
    - Ozone formation and its transport
- Mandatory and/or Voluntary Measures
  - Normal NMED rulemaking process
  - EPA's Ozone Advance Program
- Robust stakeholder involvement
  - Stay informed through the OAI Listserv!

Ozone Advance



Currently, 38 areas are actively participating in Advance. These areas are located in 21 states and 9 of the 10 EPA Regions. They include 21 Ozone Advance areas, 7 PM Advance areas, and 10 areas that are participating in both Ozone and PM Advance.

- Is a collaborative effort by EPA, states, tribes and local governments to encourage emission reductions to help them continue to meet the NAAQS
- Take near-term steps to improve local air quality and ensure continued health protection
- Flexibility, participant determine their own goals and the measures
- Actions taken could better position an area to handle nonattainment requirements.

https://www.epa.gov/advance

Why are Early Efforts Important

- Local steps to reduce air pollution voluntarily, before becomes a requirement
- Improving air quality to ensure continued health protection
- Proactive efforts could better position areas to stay in attainment.
- Areas working voluntarily to reduce air pollution have more flexibility to choose measures that make sense to them
  - Once a nonattainment designation has occurred, less flexibility is available

Projected Timeline*

- **2018**
  - **Spring**
    - Kick off OAI planning meeting; and
    - Development of outreach and educational materials.
- **2019**
  - **Summer**
    - Initial public outreach including education and initial input request.
  - **Fall/Winter**
    - Conduct modeling;
    - Research and review mandatory or voluntary control measures; and
    - Additional public outreach.
- **2020**
  - **Winter/Spring**
    - Gather input; and
    - More public comment opportunities.
  - **Summer**
    - Analyze input;
    - Develop rules; and
    - Other measures for inclusion in programs.
  - **Fall/Winter**
    - OAI Plan drafted and released with formal comment period; and
    - EIB hearing to adopt proposed plan/rules.

*Note that NMED is in the initial stages of planning, which only includes the educational component and planning for public outreach. No rules/programs have yet been discussed.

Path Forward and Next Steps

Path Forward



- Modeling and Data Analyses
  - Identify source categories causing elevated ozone
  - Predict effectiveness of a proposed strategy or control measure
- Control and pollution reduction measures
  - Once sources and types are identified, a list of potential air quality improvements and/or emission reduction options can be developed

How can stakeholders get involved?

- NMED is committed to a robust, transparent process where feedback and suggestions are encouraged.
- Provide input!
  - Attend public meetings
  - Share comments and suggestions
- Stay current
  - OAI Listserv: public.govdelivery.com/accounts/NMED/subscriber/new
  - OAI webpage: www.env.nm.gov/air-quality/o3-initiative/
  - Air Monitoring Network: https://www.env.nm.gov/air-quality/air-monitoring-network-2/

Questions or comments?

Thank you. We look forward to working with our stakeholders.

OAI Project Manager and Permian Basin Contact
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OAI Four Corners Area Contact
Mark Jones, mark.jones@state.nm.us, (505) 566-9746

OAI Doña Ana County Contact
Armando Paz, Armando.Paz@state.nm.us, (575) 449-2983

Rule Preamble: The New Mexico Environment Department has developed the following draft regulation pursuant to the directives of Section 74-2-5.3 of the New Mexico Air Quality Control Act. The objective of the proposed rule is to establish emissions standards for volatile organic compounds (VOC) and nitrogen oxides (NOx) for oil and gas production and processing sources located in areas of the State within the Environmental Improvement Board's jurisdiction where ozone concentrations are exceeding 95% of the national ambient air quality standard.

This is a preliminary draft being released for public input in advance of the Department filing a formal rulemaking petition with the Board and requesting a public hearing. The purpose of this initial, pre-petition comment period is to foster transparency and facilitate continued engagement from stakeholders, members of the public, and other interested parties. Specifically, the Department is seeking public input on the proposed rule language to assist in identifying potential regulatory and technical issues, and areas that require additional clarification or modification. Additional opportunities for public input and changes to the draft rule will occur through the formal rule-making process following the filing of the rulemaking petition. This initial, pre-petition process will help ensure that major issues or problematic areas are identified and can be addressed prior to the initiation of the formal process.

NMED is soliciting specific review and public input on a number of proposed provisions and concepts in the draft rule. In particular, for the equipment standards section, NMED requests feedback on the following:

1. The proposed definitions of stripper wells and marginal wells under the draft rule and the regulatory requirements that would apply to those wells under Section 20.2.50.25 NMAC;
2. Examples of technologies or regulatory programs utilizing non-combustion emission control technologies, like fuel cells, as a means of reducing or eliminating emissions for inclusion in Section 20.2.50.15 NMAC;
3. Specific regulatory language regarding criteria necessary to demonstrate equivalency of alternative equipment leak monitoring plans in Section 20.2.50.16(C) NMAC;
4. Specific regulatory language to establish a pre-approved equipment leak monitoring plan in 20.2.50.16(C) NMAC;
5. For leak detection and repair requirements under Section 20.2.50.16 NMAC, specific standards to be used by NMED to determine if certain new or existing technologies (real-time remote fence line and aerial surveillance, for example) or proposals are enforceable, effective, and equivalent. Specific feedback on data capture requirements, quality assurance, error rates, calibration requirements, training and certification, interference issues, quantification methods, and pollutant identification will assist the Department in exploring this option further;
6. Regulatory requirements for oil and gas evaporative ponds in Section 20.2.50.26 NMAC, including whether to establish emission standards based on the pond's potential to emit or throughput; and
7. Opportunities for greater transparency.

Comments or input on the draft rules may be submitted electronically to nm.methanestrategy@state.nm.us or via hardcopy to Liz Bisbey-Kuehn, NMED Air Quality Bureau, 525 Camino de los Marquez, Santa Fe, NM 87505 by 5 p.m. Aug. 20, 2020.

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TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND NATURAL GAS REGULATION FOR OZONE PRECURSORS

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TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND NATURAL GAS REGULATION FOR OZONE PRECURSORS

20.2.50.1 ISSUING AGENCY:
New Mexico Environmental Improvement Board.

20.2.50.2 SCOPE:
This rule applies to sources located within counties that have areas with ambient ozone concentrations in excess of ninety-five percent of the national ambient air quality standard for ozone, including but not limited to Chaves, Eddy, Lea, Rio Arriba, Sandoval, and San Juan. Sources located in Bernalillo County, on Tribal Lands, and in other areas that are not within the Board's jurisdiction are excluded.

20.2.50.3 STATUTORY AUTHORITY: NMSA 1978, § 74-2-5.3

20.2.50.4 DURATION: Permanent.

20.2.50.5 EFFECTIVE DATE:
[To be determined], except where a later date is cited in a section or paragraph.

20.2.50.6 APPLICABILITY:
A. Except as provided in paragraph (B), Part 50 applies to crude oil production and natural gas production equipment and operations that extract, collect, store, transport, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other form of transportation. Natural gas production, processing, transmission, and storage includes the well and extends to, but does not include, the local distribution company custody transfer station.
B. Oil refineries are not subject to this Part.
C. Equipment located at stripper wells, as defined in 20.2.50.8 NMAC, is exempt from the requirements of this Part 50, except as specified in 20.2.50.25 NMAC.
D. Individual facilities with a site-wide total annual potential to emit less than 15 tons per year (tpy) of volatile organic compounds (VOC) are exempt from the requirements of this Part, except as specified in 20.2.50.25 NMAC.

20.2.50.7 OBJECTIVE:
The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and nitrogen oxides (NO_x) for oil and gas production and processing sources.

20.2.50.8 DEFINITIONS:
In addition to the terms defined in 20.2.2 NMAC (Definitions), as used in this Part:
A. "Air Pollution Control Equipment" means open flares, enclosed combustion devices, thermal oxidizers, vapor recovery units, fuel cells, condensers, other combustion devices, air fuel ratio controllers, oxidative catalytic converters, selective and non-selective catalytic converters, or emission reduction equipment or technologies used to

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comply with emission standards and emission reduction requirements in 20.2.50 NMAC that are approved by the Department.

B. "Approved Instrument Monitoring Method" means an infra-red camera, U.S. EPA Method 21, or other instrument-based monitoring method or program approved by the Department in advance and in accordance with 20.2.50 NMAC.

C. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

D. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas and VOC is continuously vented (bleeds) from a pneumatic controller.

E. "Calendar Year" means a year beginning January 1 and ending December 31.

F. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

G. "Commencement of operation" means for oil and natural gas wellheads, the date any permanent production equipment is in use and product is flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than the end of well completion operations.

H. "Compressor station" means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations.

I. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

J. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

K. "Custody Transfer" means the transfer of oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

L. "Department" means the New Mexico Environment Department.

M. "Downtime" means the period of time when equipment is not operational or a well is producing and the air pollution control equipment is not in operation.

N. "Enclosed Combustion Device" means any combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to enclosed flares, boilers, re-boilers, and heaters.

O. "Existing" means any piece of equipment regulated by this Part that began operation prior to the effective date of the rule and has not since been modified or reconstructed.

P. "Gas processing plant" means equipment assembled for the extraction of natural gas liquids from natural gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit

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can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Q. "Gathering and boosting site" means any permanent combination of equipment that collect or move natural gas, crude oil, condensate, or produced water between the wellhead site and midstream oil and natural gas collection or distribution facilities such as tank batteries or compressor stations, or into or out of storage.

R. "Glycol Dehydrator" means any device in which a liquid glycol absorbent (including, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream and absorbs water.

S. "Hydrocarbon liquids" means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, produced water, and intermediate hydrocarbons.

T. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

U. "Liquids Unloading" means the removal of accumulated liquids from the wellbore that reduce or stop natural gas production.

V. "Liquid Transfers" means the loading and unloading of hydrocarbon liquids or produced water between storage tanks and tanker trucks or tanker rail cars for transport.

W. "Modification" means any physical change in, or change in the method of operation of, a stationary source which results in an increase in the potential emission rate of any regulated air contaminant emitted by the source or which results in the emission of any regulated air contaminant not previously emitted, but does not include:

- **(1)** a change in ownership of the source;
- **(2)** routine maintenance, repair or replacement;
- **(3)** installation of air pollution control equipment, and all related process equipment and materials necessary for its operation, undertaken for the purpose of complying with regulations adopted by the board or pursuant to the federal act; or
- **(4)** unless previously limited by enforceable permit conditions:
  - **(a)** an increase in the production rate, if such increase does not exceed the operating design capacity of the source;
  - **(b)** an increase in the hours of operation; or
  - **(c)** use of an alternative fuel or raw material if, prior to January 6, l975, the source was capable of accommodating such fuel or raw material, or if use of an alternate fuel or raw material is caused by any natural gas curtailment or emergency allocation or any other lack of supply of natural gas.

X. "Natural Gas Compressor Station" means one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline.

Y. "Natural Gas-Fired Heater" means an enclosed device using controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

Z. "Natural Gas Processing Plant" means any processing equipment engaged in the extraction of natural gas liquids from natural gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point

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depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

AA. "New" means any piece of equipment regulated by this Part that began operation on or after the effective date.

BB. "Optical gas imaging" means an imaging technology that utilizes high-sensitivity infra-red cameras designed for and capable of detecting hydrocarbons.

CC. "Pneumatic Controller" means an automated instrument used for maintaining a process condition such as liquid level, pressure, flow volume, delta-pressure and temperature.

DD. "Pneumatic Pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

EE. "Potential to Emit" means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is federally enforceable. The potential to emit for nitrogen dioxide shall be based on total oxides of nitrogen.

FF. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

GG. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

HH. "Responsible Official" means one of the following:

(1) For a corporation: a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating.

(2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively.

(3) For a municipality, state, federal or other public agency: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a regional administrator of US EPA).

II. "Startup" means the setting into operation of any air pollution control equipment or process equipment.

JJ. "Storage tank" means any process vessel, or fixed roof storage vessel or series of storage vessels that are connected together via a liquid line.

KK. "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquids or produced water and is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which

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provide structural support, or a process vessel such as surge control vessels, bottom receivers, or knockout vessels. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. A storage vessel does not include: vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships); are located at the site for less than 180 consecutive days; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

LL. "Stripper well" means an oil well with a maximum daily average oil production not exceeding 10 barrels of oil per day, or a natural gas well with a maximum daily average natural gas production not exceeding 60,000 standard cubic feet per day, or a well with a maximum daily average combined oil and natural gas production not exceeding 10 barrels of oil equivalent per day during any 12-month consecutive time period.

MM. "Wellhead site" means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

20.2.50.9 AMENDMENT AND SUPERSESSION OF PRIOR REGULATIONS [PLACEHOLDER]

20.2.50.10 DOCUMENTS:

Documents incorporated and cited in this Part may be viewed at the New Mexico Environment Department, Air Quality Bureau, Harold Runnels Building, 1190 St. Francis Dr., or 2048 Galisteo St., Santa Fe, NM 87502 [87505].

20.2.50.11 PLACEHOLDER

20.2.50.12 GENERAL PROVISIONS

A. General Requirements

(1) All equipment subject to requirements under 20.2.50 NMAC shall be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the Department.

(2) Owners and operators of equipment subject to requirements under 20.2.50 NMAC shall establish and implement a plan to minimize emissions during routine or predictable startup, shutdown, and scheduled maintenance through work practice standards and good air pollution control practices. [20.2.7.14 NMAC]

(3) The emission of an air contaminant in excess of the quantity, rate, opacity, or concentration specified in 20.2.50 NMAC that results in an excess emission is a violation of 20.2.50 NMAC.

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(4) The owner or operator of equipment having an excess emission shall comply with 20.2.7 NMAC and, to the extent practicable, operate the equipment, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.
(5) The owner or operator of equipment that has an excess emission may claim an affirmative defense for the excess emission pursuant to 20.2.7.111, 20.2.7.112, and 20.2.7.113 NMAC.
(6) Within one year of the effective date of this rule, owners and operators of equipment requiring an Equipment Monitoring Information and Tracking Tag (EMITT) shall physically tag the unit with an EMITT that is scannable with a hand held scanner (RFID or QR) that uniquely identifies the unit to which it is assigned and the EMITT shall be maintained by the owner or operator. Data in the EMITT shall be scannable by state inspectors to provide at a minimum, the following information:
    (a) Unique unit identification number;
    (b) UTM coordinates of the facility;
    (c) Type of unit (tank, VRU, dehydrator, pneumatic controller, etc.);
    (d) For equipment, the VOC (and NOx, if applicable) potential to emit in pounds per hour and tons per year; and
    (e) For control equipment, the controlled VOC (and NOx, if applicable) potential to emit in pounds per hour and tons per year and the design control efficiency in percent.
(7) The EMITT shall be linked to an EMITT Database accessible to state inspectors that at a minimum supplies the data required by Section 20.2.50.12 NMAC and any other data required for that equipment under this Part.

B. Monitoring Requirements
(1) All equipment subject to control or monitoring requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different inspection schedule is specified in the section below applicable to that particular type equipment. If the emission unit is shutdown at the time when periodic monitoring or inspections are due to be accomplished, the owner or operator is not required to restart the unit for the sole purpose of performing the monitoring or inspection but shall so note in the equipment or controller's records.
(2) All periodic monitoring events shall be conducted at 90% or greater of the unit's capacity. If the 90% capacity cannot be achieved, the monitoring will be conducted at the maximum achievable load under prevailing operating conditions.
(3) In order to allow for equivalent new and alternate monitoring technologies that satisfy the requirements of this regulation, prior to implementing, owners and operators may request an equally effective, enforceable, and equivalent alternative monitoring strategy to the Department for approval.
    (a) Each request shall be made on application forms provided by the Department. Upon approval of a request, the Department will issue an Alternative Monitoring Approval Letter. All Alternative Monitoring Approval Letters will

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be published on a link on the Department's webpage to provide authorization for the use of the approved alternative monitoring method.

(b) Each owner or operator will need to request and receive approval from the Department in order to operate under an approved Alternative Monitoring Strategy.

(4) Each EMITT shall be initially scanned and the required monitoring data shall be electronically captured during the monitoring event. The captured data shall be uploaded (either live or subsequently) into the database. At a minimum, the uploaded data shall include:

(a) Date and time of the monitoring event;
(b) The name of the monitoring personnel;
(c) Unique unit identification number;
(d) Type of unit;
(e) A description of any maintenance or repair activities conducted; and
(f) Required results of any monitoring required by 20.2.50 NMAC.

C. Recordkeeping Requirements

(1) Owners and operators shall keep records of any inspections and/or maintenance required under this Part. Records shall include:

(a) Date and time of the monitoring event;
(b) The name of the monitoring personnel;
(c) Unique unit identification number;
(d) Type of unit;
(e) Required results of any monitoring required by 20.2.50 NMAC;
(f) Equipment make, model and serial number;
(g) A copy of the equipment manufacturer's maintenance or repair recommendations;
(h) A description of any maintenance or repair activities conducted; and
(i) All results of any required parameter readings.

(2) Owners and operators shall keep records required this Part for a period of five years. The records shall be retained electronically. The Department may treat any loss of data or failure to maintain records (including failure to transfer records upon sale or transfer or ownership or operating authority) as a failure to collect the data.

(3) Owners and operators shall keep records of emissions from equipment malfunctions and routine or predictable emissions during startup, shutdown, and scheduled maintenance.

(4) Owners and operators of equipment having an excess emission shall record the following information no later than ten (10) days after the end of the excess emission event:

(a) The equipment type and identification number;
(b) The location, date, and time;
(c) The emission limit or air quality regulation that was exceeded;
(d) The air contaminant and the magnitude of the excess emission expressed in the units of the limit or air quality regulation;

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(e) The cause of the excess emission and any steps taken to limit the magnitude and duration of the excess emissions;
(f) The corrective action(s) taken to eliminate the cause of the excess emission and prevent a recurrence, if required; and
(g) Whether the owner or operator attributes the excess emission to malfunction, startup, or shutdown.

(5) Records of each EMITT monitoring event required by 20.2.50.12.B NMAC shall be electronically uploaded (either in real time or subsequently) into the EMITT database. At a minimum, the uploaded data shall include the data required in 20.2.50.12.B(4) and 20.2.50.12.C(4) NMAC.

(6) Prior to the transfer of ownership of any equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of all equipment subject to the rule. The documentation shall indicate whether or not each piece of equipment subject to requirements under this Part is currently complying with those requirements. The compliance determination shall be conducted no earlier than one year prior to the transfer.

D. Reporting Requirements

(1) Owners and operators shall submit reports upon the request of the Department. Any reports requested by the Department shall be submitted electronically via the Department's Secure Extranet Portal (SEP) at https://sep.net.env.nm.gov/sep/login-form.

(2) Owner and operators of a source having an excess emission shall submit a Root Cause and Corrective Action Analysis, as directed in 20.2.7.114 NMAC, upon the request of the department.

20.2.50.13 STANDARDS FOR ENGINES AND TURBINES

A. Applicability

(1) New and existing portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellheads, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.13 NMAC.

(2) Existing sources that were subject to federal standards of performance under 40 CFR Part 60 and Part 63 between March 25, 2004 and January 1, 2009 are exempt from the requirements of 20.2.50.13 NMAC.

B. Emission Standards

(1) Owners and operators of each portable or stationary natural gas-fired spark ignition engine, compression ignition engine, and natural gas-fired combustion turbine shall ensure compliance with the emission standards in 20.2.50.13.B NMAC by the dates specified in 20.2.50.13.B NMAC.

(2) Each natural gas-fired spark ignition engine shall comply with the applicable emission standards in Table 1 of 20.2.50.13 NMAC.

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(3) By January 1, 2022, owners and operators of existing engines shall complete an inventory of all existing engines and shall prepare a schedule for each existing engine to ensure that all existing engines comply with these requirements and meet or exceed the emission standards in Table 1 by January 1, 2028. The schedule shall meet the following requirements:

(a) By January 1, 2024, owners and operators shall ensure 30% of the company's fleet of existing engines meet the requirements of Table 1.

(b) By January 1, 2026, owners and operators shall ensure an additional 35% of the company's fleet of existing engines meet the requirements of Table 1.

(c) By January 1, 2028, owners and operators shall ensure that the remaining 35% of the company's fleet of existing engines meet the requirements of Table 1.

Table 1 - Emission Standards for Natural Gas-Fired Spark-Ignition Engines

For each natural gas-fired spark-ignition engine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the existing engine(s) does not exceed the following emission standards as determined by the compliance schedule required in 20.2.50.13.B(3) NMAC:				
Engine Type	Rated bhp	NOx	CO	NMNEHC (as propane)
Lean-burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-
Lean-burn	>100 - ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h
Lean-burn	>500	0.50 g/bhp-h	47 ppmvd @ 15% O2 or 93% reduction	0.30 g/bhp-h
Rich-burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-
Rich-burn	>100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h
Rich-burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h
For each natural gas-fired spark-ignition engine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the engine does not exceed the following emission standards upon startup:				
Engine Type	Rated bhp	NOx	CO	NMNEHC (as propane)
Lean-burn	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h
Lean-burn	>100 - ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h
Lean-burn	>500 - <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.30 g/bhp-h
Lean-burn	≥2,370	0.30 g/bhp-h Uncontrolled or 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.30 g/bhp-h
Rich-burn	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h
Rich-burn	>100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h
Rich-burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h

(4) Owners and operators of natural gas-fired spark ignition engines that control NOx emissions with a control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to

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15 percent oxygen.

(5) Owners and operators of each compression ignition engine shall ensure compliance with the applicable emission standards in 20.2.50.13.B(5)(a) NMAC and 20.2.50.13.B(5)(b) NMAC.

(a) Stationary compression ignition engines that are subject to and complying with standards in 40 CFR Part 60, subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, are exempt from the requirements of this paragraph.

(b) Portable and stationary compression ignition engines with a maximum design power output equal to or greater than 500 horsepower that are not subject to the emission standards under 20.2.50.13.B(5)(a) NMAC shall limit NOx emissions to no more than 9 g/bhp-h. For each compression-ignition engine constructed or reconstructed and installed before the effective date of this Part, the owner or operator shall ensure compliance no later than one year from the effective date. For each compression-ignition engine constructed or reconstructed and installed on or after the effective date of this Part, the owner or operator shall ensure compliance upon startup.

(6) Owners and operators of portable or stationary compression ignition engines that control NOx emissions with a control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15 percent oxygen.

(7) Owners and operators of stationary natural gas-fired combustion turbines with a maximum design rating equal to or greater than 1,000 bhp (or a maximum heat input capacity equal to or greater than 2.54 MMBtu/hr) shall comply with the applicable emission standards for existing, new, or reconstructed turbines listed in Table 2 of 20.2.50.13 NMAC.

Table 2 - Emission Standards for Stationary Combustion Turbines

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than one year from the effective date:				
Turbine Rating (bhp)	Turbine Rating (MMBtu/hr)	NOx (ppmvd @15% O2)	CO (ppmvd @ 15% O2)	NMNEHC (as propane, ppmvd @15% O2)
≥1,000 and <5,000	≥2.54 and <12.7	25	25	9
≥5,000 and <15,000	≥12.7 and <38.2	15	25	9
≥15,000	≥38.2	15	10 or 93% reduction	5 or 50% reduction
For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:				
Turbine Rating (bhp)	Turbine Rating (MMBtu/hr)	NOx (ppmvd @15% O2)	CO (ppmvd @ 15% O2)	NMNEHC (as propane, ppmvd @15% O2)

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≥1,000 and <5,000	≥2.54 and <12.7	25	25	9
≥5,000 and <15,900	≥12.7 and <40.4	15	10	9
≥15,900	≥40.4	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) Owners and operators of stationary natural gas-fired combustion turbines that control NOx emissions with a control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to 15% oxygen.

(9) Owners and operators of new or existing engines or turbines shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each engine or turbine in accordance with 20.2.50.12 NMAC.

C. Monitoring Requirements

(1) Maintenance and repair for all spark ignition engines, compression ignition engines, and stationary combustion turbines shall meet the minimum engine or turbine manufacturer's recommended maintenance schedule. Activities that involve engine or turbine maintenance, adjustment, replacement, or repair of functional components with the potential to affect the operation of an emission unit shall be documented as they occur for the following events:

(a) Routine maintenance that takes a unit out of service for more than two hours during any 24-hour period.

(b) Unscheduled repairs that require a unit to be taken out of service for more than two hours in any 24-hour period.

(2) Oxidation catalytic converters, selective and non-selective catalytic converters, and air-fuel ratio (AFR) controllers shall be maintained according to manufacturer's or supplier's recommended maintenance, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalyst or AFR controller maintenance, the owner or operator shall shut down the engine(s) or turbine(s) until the catalyst or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to remain in operation.

(3) Compliance with the emission standards in 20.2.50.13.B NMAC shall be demonstrated by performing an initial and annual test for NOx, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or EPA Reference Methods. For units with g/hp-hr emission standards, the engine load shall be calculated by using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scfh) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

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Where:
LVH = lower heating value, btu/scf, or btu/gal, as appropriate
BSCF = brake specific fuel consumption

(a) Periodic monitoring utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. However, if a facility has met a previously approved Department criterion for portable analyzers, the analyzer may be operated in accordance with that criterion until it is replaced.
(b) The default time period for each test run shall be at least 20 minutes.
(c) Each performance test shall consist of three separate runs. The arithmetic mean of results of the three runs shall be used to determine compliance with the applicable emission standard.
(d) For all periodic monitoring events, three test runs shall be conducted at 90% or greater of the unit's capacity. If the 90% capacity cannot be achieved, the monitoring will be conducted at the maximum achievable load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions and shall be included with the monitoring test report.
(e) During emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing EPA Reference Method 19. This information shall be included with the monitoring test report.
(f) Stack gas flow rate shall be calculated in accordance with EPA Reference Method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months prior to the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using EPA Reference Methods 1 through 4.
(g) The owner or operator shall submit a notification and protocol for periodic emissions tests upon the request of the Department.

(4) Testing shall be conducted once per calendar year. Performance testing required by 40 CFR 60, Subparts GG, IIII, JJJJ, or KKKK, or 40 CFR 63, Subpart ZZZZ may be used to satisfy these periodic testing requirements if they meet the requirements of this section and are completed once per calendar year.
(5) Each monitoring, testing, inspection, or tune-up of an engine or turbine shall include the initial scanning of the EMITT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.12 NMAC.

D. Recordkeeping Requirements
(1) The owner or operator of spark ignition engines, compression ignition engines, or stationary combustion turbines shall maintain records in accordance with 20.2.50.12 NMAC for each engine or turbine of:

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(a) The make, model, serial number, and equipment identification number for each engine, turbine, and any control equipment,
(b) A copy of the engine or turbine manufacturer's or control equipment manufacturer's recommended maintenance and repair schedule,
(c) Inspections, maintenance and repairs activities on all engines, turbines, and control equipment, including:
(i) Date(s) and time(s) of inspection, maintenance, and/or repair;
(ii) Date(s) any subsequent analyses were performed (if applicable);
(iii) Name of the person or qualified entity conducting the inspection, maintenance, and/or repair;
(iv) A description of the physical condition of the equipment as found during any required inspection;
(v) Description of maintenance or repair activities conducted; and
(vi) Results of required equipment inspections including a description of any condition which required adjustment to bring the equipment back into compliance and a description of the required adjustments.
(d) Results of any required parameter readings.

(2) The owner or operator of spark ignition engines, compression ignition engines, or stationary combustion turbines shall maintain records of initial and annual performance testing in accordance with 20.2.50.12 NMAC for each engine or turbine, including:
(a) The make, model, serial number, and equipment identification number for all tested engines, turbines, and emission control equipment);
(b) Date(s) and time(s) of sampling or measurements;
(c) Date(s) analyses were performed;
(d) The qualified entity that performed the analyses;
(e) Analytical or test methods used;
(f) Results of analyses or tests; and
(g) Operating conditions existing at the time of sampling or measurement.

(3) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.14 STANDARDS FOR COMPRESSOR SEALS

A. Applicability

(1) All new and existing centrifugal compressors using wet seals located at tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.14 NMAC. Any new or existing centrifugal compressor located at a wellhead is not subject to the requirements of 20.2.50.14 NMAC.

(2) All new and existing reciprocating compressors located at tank batteries,

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gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.14 NMAC. Any new or existing reciprocating compressor located at a wellhead is not subject to the requirements of 20.2.50.14 NMAC.

B. Emission Standards

(1) Owners and operators of existing centrifugal compressors shall control VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95%, beginning on the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

(2) Owners and operators of existing reciprocating compressors shall, either:

(a) Replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours and months of compressor operation toward the first replacement of the rod packing beginning no later than one year from the effective date; OR

(b) Beginning no later than one year from the effective date, collect emissions from the rod packing under negative pressure and route via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

(3) Owners and operators of new centrifugal compressors shall control VOC emissions from each centrifugal compressor wet seal fluid degassing system by 98% upon startup. Emissions shall be captured and routed via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

(4) Owners and operators of new reciprocating compressors shall, upon startup, either:

(a) Replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; OR

(b) Collect emissions from the rod packing under negative pressure and route via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

(5) Owners and operators of new and existing centrifugal and reciprocating compressors shall install an Equipment Monitoring Information Tracking Tag (EMITT) on each compressor in accordance with 20.2.50.12 NMAC.

(6) Owners and operators complying with the control requirements in 20.2.50.14.B NMAC through use of a control device shall comply with the control device requirements in 20.2.50.15 NMAC.

(7) Owners and operators with an air permit shall incorporate these requirements in their permit during their next scheduled or requested permit or permit revision.

C. Monitoring Requirements

(1) The owner or operator of a centrifugal compressor complying with 20.2.50.14.B(1) NMAC or 20.2.50.14.B(3) NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.15 NMAC.

(2) The owner or operator of a reciprocating compressor complying with

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20.2.50.14.B(2)(a) NMAC or 20.2.50.14.B(4)(a) NMAC shall continuously monitor the number of hours of operation with a non-resettable hour meter and track the number of months since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with 20.2.50.14.B(2)(b) NMAC or 20.2.50.14.B(4)(b) NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device.

(4) Owners and operators complying with the requirements in 20.2.50.14.B NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.

(5) Owners and operators of new and existing centrifugal and reciprocating compressors, during each required monitoring activity, shall scan the compressor EMITT and perform monitoring data entry in accordance with the requirements of 20.2.50.12 NMAC.

(6) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) The owner or operator of a centrifugal compressor shall maintain records of:

(a) The identification number and location of each centrifugal compressor using a wet seal system,

(b) The date of construction, reconstruction, or modification of each centrifugal compressor,

(c) The records of the monitoring and inspections required in 20.2.50.14.C NMAC. The records shall include the time and date of the inspection, the person conducting the inspection, a notation of which checks required in 20.2.50.12.C NMAC were completed, a description of any problems observed during the inspection, and a description and date of any corrective actions taken, and

(d) The location, type, make, model and unique identification number of any control equipment, recovery system, fuel cell, or process used to comply with the control requirements in 20.2.50.14.B NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain records of the following:

(a) The identification number and location of each reciprocating compressor;

(b) The date of construction, reconstruction, or modification of each reciprocating compressor; and

(c) The records of the monitoring and inspections required in 20.2.50.14.C NMAC. The records shall meet the requirements of 20.2.50.14.C NMAC and shall include:

(i) The number of hours of operation and the number of months of operation since initial startup or the last rod packing replacement;

(ii) The records of pressure in the rod packing emissions collection system; and

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(iii) The time and date of the inspection, the person conducting the inspection, a notation of which checks required in 20.2.50.14.C NMAC were completed, a description of any problems observed during the inspection, and a description and date of any corrective actions taken.

(3) Owners and operators complying with the requirements in 20.2.50.14.B NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.

(4) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

(1) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.15 STANDARDS FOR CONTROL DEVICES

A. Applicability

(1) These requirements apply to open flares, enclosed combustors, thermal oxidizers, vapor recovery units, condensers, closed vent collection systems, other combustion devices, or emissions reduction equipment or technologies used to comply with the emission standards and emission reduction requirements in this Part.

B. General Requirements

(1) All air pollution control equipment used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications and good engineering and maintenance practices.

(2) All air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NOx.

(3) Owners and operators of a flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device used to comply with the emission standards in this Part shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device in accordance with 20.2.50.12 NMAC.

(4) Owners and operators shall inspect all air pollution control equipment used to control emissions from equipment subject to emission standards under this Part at least monthly to ensure proper maintenance and operation. Each EMITT inspection or monitoring event shall be initially scanned and the required monitoring data shall be electronically captured during the monitoring event.

(5) Owners and operators shall ensure that any flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device used to comply with emission standards in this Part shall at all times operate as a closed vent system that captures and routes all VOC emissions from equipment

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subject to regulation under this Part to the control or vapor recovery device and that un-combusted gas is not vented to the atmosphere.

(6) Owners and operators shall keep manufacturer specifications for all control or vapor recovery equipment on file. The information shall include:
   (a) Manufacturer's name, control device name and model;
   (b) Maximum heating value for open flares, enclosed combustors, and thermal oxidizers;
   (c) Fuel gas flow range for open flares, enclosed combustors, and thermal oxidizers; and
   (d) Designed destruction or vapor recovery efficiency.

(7) Owners and operators shall keep records of any stack testing or control or vapor recovery efficiency testing for all control equipment. The records shall be kept in accordance with 20.2.50.12 NMAC for each flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device and shall include:
   (a) Control device type, name and model;
   (b) Location;
   (c) Date of the stack test; and
   (d) A summary of the stack test results.

C. Requirements for Open Flares

(1) Emission Standards
   (a) The flare shall combust all gas sent to the flare. Owners and operators shall not send gas to the flare in excess of the flare's maximum rated capacity.
   (b) Owners and operators shall equip all flares with a continuous pilot flame, an auto-igniter, or require manual ignition.
      (i) Flares with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times that gas is being sent to the flare.
      (ii) Owners and operators of flares with manual ignition shall inspect and ensure a flame is present upon initiating each flaring event.
      (iii) Any new flare constructed or re-constructed after the effective date of this Part shall be equipped with an auto-igniter. The auto-igniter shall be installed and operational upon startup.
      (iv) Any existing flare constructed prior to the effective date of this Part shall be equipped with an auto-igniter no later than one year after the effective date.
   (c) Owners and operators shall operate any flare used for controlling VOC emissions to comply with this Part with no visible emissions, except for periods not to exceed a total of sixty (60) seconds during any fifteen (15) consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare, or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring Requirements

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(a) Owners and operators of flares with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. Owners and operators may use any other equivalent device that fulfills the same purpose.
(b) Owners and operators of manually ignited flares shall monitor the presence of a flame using continual visual observation during each flaring event.
(c) Owners and operators, at least quarterly, and upon observing any visible emissions, shall perform a U.S. EPA Method 22 observation while the flare pilot flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of fifteen (15) consecutive minutes.
(d) Each EMITT inspection or monitoring event shall be initially scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.12 NMAC.

(3) Recordkeeping Requirements

(a) The owner or operator of open flares subject to regulation under 20.2.50.15.A NMAC shall keep records for each flare in accordance with 20.2.50.12 NMAC of the following:
(i) All instances of alarm activation, including the date and cause of alarm activation, actions taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;
(ii) The results of the U.S. EPA Method 22 observations and flame inspection for manual flares and
(iii) The results of any gas analysis for the gas being flared, including VOC content and heating value.

(4) Reporting Requirements

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

D. Requirements for Enclosed Combustion Devices (ECD) and Thermal Oxidizers (TO)

(1) Emission Standards

(a) The ECD/TO shall combust all gas sent to the ECD/TO. Owners and operators shall not send gas to the ECD/TO in excess of the ECD/TO's maximum rated capacity.
(b) Owners and operators shall equip all ECDs/TOs with a continuous pilot flame or an operational auto-igniter. ECDs/TOs constructed or re-constructed prior to the effective date of this Part shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. ECDs/TOs constructed or re-constructed on or after the effective date shall be equipped with a continuous pilot flame or an operational auto-igniter upon startup.
(c) ECDs/TOs with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at

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all times that gas is being sent the ECD/TO. Combustion shall be maintained for the duration of time that gas is being sent to the ECD/TO.

(d) Owners and operators shall operate ECDs/TOs used to control VOC emissions to comply with the emission standards in this Part with no visible emissions, except for periods not to exceed a total of sixty (60) seconds during any fifteen (15) consecutive minutes. The combustion device shall be designed so that an observer can, by means of visual observation from the outside of the combustion device, or by other means, such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring Requirements

(a) Owners and operators of ECDs/TOs with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. Owners and operators may use any other equivalent device that fulfills the same purpose.

(b) Owners and operators, at least quarterly, and upon observing any visible emissions, shall perform a Method 22 observation while the ECD/TO pilot flame is present to certify compliance with the visible emission requirements. The observation shall be a minimum of fifteen minutes.

(c) Each EMITT inspection or monitoring event shall be initially scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.12 NMAC.

(3) Recordkeeping Requirements

(a) The owner or operator of an ECD/TO subject to regulation under 20.2.50.15.A NMAC shall keep records in accordance with 20.2.50.12 NMAC for each ECD/TO of:

(i) All instances of alarm activation, including the date and cause of alarm activation, actions taken to bring the ECD/TO into normal operating conditions, the name of the personnel conducting the inspection, and any maintenance activities performed;

(ii) The results of the Method 22 observations; and

(iii)The results of any gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting Requirements

(a) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

E. Requirements for Vapor Recovery Units (VRU)

(1) Emission Standards

(a) Owners and operators shall operate the VRU as a closed vent system that captures and routes all VOC emissions from units back to the process stream or to a sales pipeline and does not vent to the atmosphere.

(b) Owners and operators shall control emissions during startup, shutdown, and maintenance (SSM) or other VRU downtime with a backup control device (flare/ECD/TO) or redundant VRU.

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(2) Monitoring Requirements
  (a) Owners and operators shall comply with the standards for equipment leaks in 20.2.50.16 NMAC, or, alternatively, shall implement a program that meets the requirements of NSPS Subpart OOOOa (40 CFR 60.5416a).
  (b) Each VRU EMITT inspection or monitoring event shall be initially scanned and the required monitoring data shall be electronically captured during the monitoring event requirements of 20.2.50.12 NMAC.
(3) Recordkeeping Requirements
  (a) For each VRU inspection or monitoring event, the owner or operator shall record the results of the VRU inspections in accordance with 20.2.50.12 NMAC, including the name of the personnel conducting the inspection, and noting any maintenance or repairs that are required.
(4) Reporting Requirements
  Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.16 STANDARDS FOR EQUIPMENT LEAKS

A. Applicability
  All new and existing wellheads, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations and associated piping are subject to the requirements of 20.2.50.16 NMAC.

B. Emission Standards
  Each owner and operator of oil and gas production and processing equipment located at a site identified in 20.2.50.16.A NMAC shall demonstrate compliance with 20.2.50.16 NMAC by performing the monitoring, recordkeeping, and reporting requirements specified in this Section.

C. Monitoring Requirements
  (1) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.
  (2) Default Equipment Leak Monitoring Requirements:
    (a) Owners or operators shall conduct an audible, visual, and olfactory (AVO) inspection of each thief hatch, closed vent system, pump, compressor, pressure relief device, open-ended valve or line, valve, flange, connector, piping, and any associated equipment to identify defects and leaking components at least weekly as follows:
      (i) Visually inspect for cracks, holes or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure devices;
      (ii) Listen for pressure leaks or liquid leaks.
      (iii) Smell for unusual or strong odors.

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(iv) Any positive audible, visual, or odorous indication shall be considered a leak. All AVO leaks shall be tagged with a visible tag and reported to management or designee within three calendar days.

(b) Owners or operators shall conduct an inspection using EPA Reference Method 21 (40 CFR 60, Appendix B) (RM 21) or optical gas imaging (OGI) with infrared cameras of each thief hatch, closed vent system, pump, compressor, pressure relief device, open-ended valve or line, valve, flange, connector, piping, and any associated equipment to identify leaking components at a frequency determined according to the following schedule:

(i) For well production and tank battery facilities:

(A) Annually at facilities with a potential to emit less than 2 tpy VOC.

(B) Semi-annually at facilities with a potential to emit equal to or greater than 2 tpy and less than 5 tpy VOC.

(C) Quarterly at facilities with a potential to emit equal to or greater than 5 tpy VOC.

(ii) For gathering and boosting sites, gas processing plants, and transmission compressor stations:

(A) Quarterly at facilities with a potential to emit less than 25 tpy VOC.

(B) Monthly at facilities with a potential to emit equal to or greater than 25 tpy VOC.

(c) The inspections required under 20.2.50.16.C(2)(b) NMAC shall be conducted using RM 21 or OGI with infrared cameras.

(i) For leaks determined using RM 21:

(A) The instrument shall be calibrated before each day of its use by the procedures specified in RM 21.

(B) The instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air); and a mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(C) A leak is detected if an instrument reading of 500 ppm or greater of hydrocarbon is measured that is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(ii) For leaks determined using OGI:

(A) The instrument must comply with the specifications, the daily instrument checks, and the leak survey requirements at 40 CFR 60.18(i)(1) through (3).

(B) A leak is detected if any emissions are imaged by the OGI instrument that are not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(d) If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to inspect the component until it becomes feasible to do so.

(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters

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above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

(iii) Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

(3) Alternative Equipment Leak Monitoring Plans

(a) As an equivalent means of compliance with 20.2.50.16 NMAC, owners or operators may comply with the equipment leak requirements through an individual alternative monitoring plan approved by the Department, subject to the following requirements:

(i) Upon the Department's approval of an alternative monitoring plan, the owner or operator shall comply with the terms and conditions of the approved alternative monitoring plan.

(ii) A responsible official shall certify compliance with the approved alternative monitoring plan on behalf of the owner or operator on an annual basis.

(iii) The Department may terminate an approved alternative monitoring plan if the Department finds that the owner or operator failed to comply with any provision of the plan and failed to correct and disclose the violation(s) to the Department within 15 calendar days of identifying the violation.

(iv) Upon the Department's denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under 20.2.50.16.C(2) NMAC within 30 days.

(b) As an equivalent means of compliance with 20.2.50.16 NMAC, owners or operators may comply with equipment leak requirements through one of the pre-approved monitoring plans maintained by the Department, subject to the following requirements:

(i) The owner or operator shall notify the Department of the pre-approved monitoring plan that the owner or operator will follow and shall comply with the terms and conditions of the pre-approved monitoring plan.

(ii) A responsible official shall certify compliance with the pre-approved monitoring plan on behalf of the owner or operator on an annual basis.

(iii) The Department may terminate the use of a pre-approved monitoring plan by the owner or operator if the Department finds that the owner or operator failed to comply with any provision of the plan and failed to correct and disclose the violation(s) to the Department within 15 calendar days of identifying the violation.

(iv) Upon the Department terminating the use of an approved monitoring plan by an owner or operator, the owner or operator shall comply with the

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default monitoring requirements under 20.2.50.16.C(2) NMAC within 30 days.

D. Repair Requirements
   (1) For any leaks detected in 20.2.50.16(C) NMAC:
      (a) The owner or operator shall place a visible tag on the leaking component until the component has been repaired;
      (b) All leaks detected using optical gas imaging shall be repaired within 7 days of discovery, all other leaks shall be repaired within 15 days of discovery;
      (c) The equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and
      (d) If the leak cannot be repaired within 7 days for leaks detected using optical gas imaging and within 14 days for all other leaks without a process unit shutdown, it may be designated "Repair delayed," and must be repaired before the end of the next process unit shutdown.

E. Recordkeeping Requirements
   (1) Owners or operators shall keep records of all monitoring under 20.2.50.16.C NMAC and provide such records to the Department upon request.
   (2) Owners or operators subject to 20.2.50.16.C NMAC shall keep records of the following for all AVO, RM21, and OGI inspections conducted as required under 20.2.50.16.C NMAC:
      (a) The facility location and unique inventory control number or name;
      (b) The date of inspection;
      (c) The monitoring method (AVO, RM 21, or OGI);
      (d) The name of the operator(s) performing the inspection;
      (e) A list of the leaks requiring repair or a statement that no leaks were found; and
      (f) Whether a visible flag was placed on the leak or not;
   (3) Owners or operators shall keep the following records for any leak detected:
      (a) Date the leak is detected;
      (b) Dates of attempts to repair;
      (c) For leaks with a designation of "repair delayed" keep the following:
         (i) The reason for delay if the leak is not repaired within 30 days of leak discovery;
         (ii) The signature of the authorized representative whose decision it was that the repair could not be implemented without a process shutdown;
      (d) The date of successful leak repair;
      (e) The date the leak was monitored after the repair and the results of the monitoring; and
      (f) A list of components that are designated as unsafe, difficult, or inaccessible to monitor, an explanation stating why the component is so designated, and the schedule for monitoring such component(s).
   (4) For leaks determined using optical gas imaging with infrared cameras, owners or operators shall keep the records of the specifications, the daily instrument checks and the leak survey requirements specified at 40 CFR §60.18(i)(1) – (3).
   (5) Owners or operators shall comply with the recordkeeping requirements in

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20.2.50.12 NMAC.

F. Reporting Requirements
   (1) Owners and operators shall report the certifications required under 20.2.50.16.C(3)(a)(ii) and (b)(ii) NMAC to the Department annually.
   (2) Owners or operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.17 STANDARDS FOR NATURAL GAS WELL LIQUIDS UNLOADING

A. Applicability
   (1) All manual liquids unloading, including those associated with down-hole well maintenance events, performed at natural gas wells are subject to the requirements of 20.2.50.17 NMAC.
   (2) Owners and operators shall comply with these requirements for any manual liquids unloading performed after the effective date of this Part.

B. Emission Standards
   (1) Owners and operators of natural gas wells shall use best management practices during the life of the well to avoid the need for manual liquids unloading.
   (2) Owners and operators of natural gas wells shall use the following best management practices during manual liquids unloading to minimize emissions, consistent with well site conditions and good engineering practices:
      (a) Reduce wellhead pressure prior to blowdown;
      (b) Monitor manual liquids unloading in close proximity to the well or via remote telemetry; and
      (c) Close all well head vents to the atmosphere and return the well to normal production operation as soon as practicable.
   (3) Owners and operators of a natural gas well shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each natural gas well in accordance with 20.2.50.12 NMAC.

C. Monitoring Requirements
   (1) Owners and operators subject to 20.2.50.17 NMAC shall monitor the following parameters during manual liquids unloading:
      (a) Wellhead pressure;
      (b) Flow rate of the vented natural gas (to the extent feasible); and
      (c) Duration of venting to the storage tank/atmosphere.
   (2) Owners and operators shall calculate the volume and mass of VOC vented during each manual liquids unloading event.
   (3) Each manual liquids unloading event shall include the scanning of the EMITT and monitoring data entry in accordance with the requirements of 20.2.50.12 NMAC.
   (4) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

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(1) Owners and operators subject to 20.2.50.17 NMAC shall keep the following records for each manual liquids unloading:
  (a) The identification number and location of the well;
  (b) The date(s) the manual liquids unloading was performed;
  (c) Wellhead pressure;
  (d) Flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);
  (e) Duration of venting to the storage tank/atmosphere;
  (f) A description of the management practices used to minimize release of VOC prior to and during the manual liquids unloading; and
  (g) A calculation of the VOC emissions vented during the manual liquids unloading based on the duration, volume, and mass of VOC.
(2) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.18 STANDARDS FOR GLYCOL DEHYDRATORS

A. Applicability

(1) All new and existing glycol dehydrators with a potential to emit equal to or greater than 2 tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.18 NMAC.

B. Emission Standards

(1) Owners and operators of an existing glycol dehydrator constructed on or before the effective date of this Part with a potential to emit equal to or greater than 2 tpy of VOC shall have a minimum combined capture and control efficiency of 95 percent of VOC emissions from the still vent and flash tank, no later than one year after the effective date. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of 98 percent.
(2) Owners and operators of a new glycol dehydrator constructed after the effective date of this Part with a potential to emit equal to or greater than 2 tpy of VOC shall have a combined capture and control efficiency of 95 percent of VOC emissions from the still vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of 98 percent.
(3) Owners and operators of a new or existing glycol dehydrator subject to control requirements under 20.2.50.18 NMAC shall comply with the following equipment requirements:
  (a) The still vent and flash tank emissions shall be routed at all times to the

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reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a vapor recovery unit (VRU) that reinjects the VRU VOC emissions back into the process stream or natural gas gathering pipeline.

(b) If a VRU is used, it shall consist of a closed loop system of seals, ducts, and a compressor that will reinject the natural gas into the process stream or the natural gas gathering pipeline. The VRU shall be operational at least 95 percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of 95 percent. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications.

(c) The still vent and flash tank emissions shall not be vented to the atmosphere.

(d) Owners and operators of a glycol dehydrator shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each glycol dehydrator in accordance with 20.2.50.12 NMAC.

(4) Any new or existing glycol dehydrator subject to control requirements under 20.2.50.18 NMAC will become exempt from these requirements when its uncontrolled actual annual VOC emissions decreases to an amount less than 2 tpy.

(5) Owners and operators complying with the control requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

C. Monitoring Requirements

(1) The owner or operator of a glycol dehydrator subject to control requirements in 20.2.50.18 NMAC shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled VOC emissions (tpy) and controlled VOC emissions (tpy).

(2) The owner or operator of any glycol dehydrator subject to control requirements shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control equipment semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer's recommended procedures.

(3) Owners and operators complying with the requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) Owners and operators subject to control requirements in 20.2.50.18 NMAC shall maintain records of the following for each glycol dehydrator, in accordance with 20.2.50.12 NMAC:

(a) The dehydrator's location and unique inventory control number or name;

(b) Glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) The data and methodology used to estimate the potential to emit of VOC (the method must be a Department approved calculation methodology);

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(d) The controlled and uncontrolled VOC emissions (tpy);
(e) The location, type, make, model and unique identification number of any control equipment;
(f) The date and the results of all equipment inspections, including any maintenance or repairs needed to bring the glycol dehydrator into compliance; and
(g) Copies of the glycol dehydrator manufacturer's operation and maintenance recommendations.

(2) Owners and operators complying with the requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.

(3) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.

(1) Owners and operators complying with the requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.19 STANDARDS FOR HEATERS

A. Applicability

(1) All new and existing natural gas-fired heater units with a rated heat input equal to or greater than 10 MMBtu/hr including, but not limited to, heater treaters, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.19 NMAC.

B. Emission Standards

(1) In order to ensure compliance with good combustion engineering practices, the owner or operator of a natural gas-fired heater units shall ensure compliance with the emission limits in Table 1 of 20.2.50.19 NMAC.

Table 1 - Emission Standards for NO_x and CO

Date of Construction:	NO_x (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

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(2) Natural gas-fired heater units constructed or reconstructed prior to the effective date of this Part shall come into compliance with the requirements of 20.2.50.19 NMAC beginning no later than one year after the effective date.
(3) Natural gas-fired heater units that are constructed or reconstructed on or after the effective date of this Part shall be in compliance with the requirements of this section upon startup.
(4) Owners and operators of a natural gas-fired heater unit shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each combustion unit in accordance with 20.2.50.12 NMAC.

C. Monitoring Requirements
(1) Owners and operators of natural gas-fired heater units with a rated heat input of greater than or equal to 10 MMBtu/hr shall:
(a) Conduct the monitoring for NOx and CO specified in paragraph C(2) of this section within 180 days of the compliance date specified in the relevant paragraph B(2) or B(3) of this section and every 2 years thereafter.
(b) inspect, maintain, and repair each combustion unit consistent with the manufacturers specifications at least once every 2 years following the compliance date specified in the relevant paragraph B(2) or B(3) of this section. The inspection, maintenance, and repair shall include, at a minimum:
(i) Inspecting the burner and cleaning or replacing any components of the burner as necessary;
(ii) Inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer's specifications or good combustion engineering practices;
(iii) Inspecting the system air-to-fuel ratio controller and ensuring it is calibrated and functioning properly;
(iv) Optimizing total emissions of CO consistent with the NO_x requirement and the manufacturer's specifications or good combustion engineering practices; and
(v) Measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with paragraph C(2)(a) of this section.
(2) Owners and operators of combustion units shall comply with the following combustion unit periodic monitoring requirements:
(a) Conduct three test runs of at least 20-minutes duration within 10% of 100% peak (or the highest achievable) load;
(b) Determine NO_X and CO emissions and O_2 concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522;
(c) If the measured NO_X or CO emissions concentrations are exceeding the emissions limits of Table 1 of this section, the owner or operator shall repeat the inspection and tune-up in paragraph C(1)(b) of this section within 180 days of the periodic monitoring; and

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(d) If at any time the owner or operator operates the combustion unit in excess of the highest achievable load plus 10%, the owner or operator shall perform the monitoring specified in paragraph C(2)(a) within 180 days from the anomalous operation.

(3) When conducting periodic monitoring on a combustion unit, the owner or operator shall follow the procedures in paragraph C(2) of this section. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternative procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure to the satisfaction of the Department.

(4) The owner or operator of any combustion unit subject to periodic monitoring, inspections, and/or tune-up shall monitor, inspect, maintain, and repair as required under 20.2.50.19.C NMAC. Each monitoring, inspection, maintenance or repair event shall include the scanning of the EMITT and the simultaneous monitoring data entry in accordance with the requirements of 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) For each combustion unit with a rated heat input of greater than or equal to 10 MMBtu/h, the owner or operator shall maintain the following records in accordance with 20.2.50.12 NMAC:

(a) The location of the combustion unit;

(b) Either the summary for each complete test report described in paragraph C(2) of this section, or the results of each periodic monitoring described in paragraph C(3) this section;

(c) The records of the inspection/maintenance/repair described in paragraph C(1)(c) of this section, which shall include at a minimum:

(i) The date the inspection/maintenance/repair was conducted;

(ii) The concentrations in the effluent stream of CO in ppmv and O_2 in volume percent as determined in paragraph C(2)(a) of this section; and

(iii) A description of any corrective actions taken as part of the inspection/maintenance/repair.

E. Reporting Requirements

Owners or operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.20 STANDARDS FOR HYDROCARBON LIQUID TRANSFERS

A. Applicability

(1) All new and existing hydrocarbon liquid transfer operations located at wellheads, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.20 NMAC, beginning on the effective date of this Part.

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B. Emission Standards

(1) Owners and operators of all existing and new liquid transfer operations subject to 20.2.50.20 NMAC shall use vapor balance, vapor recovery, or control VOC emissions by 98% or greater using vapor combustion when transferring liquids from storage tanks to transfer vessels, or when transferring liquids from transfer vessels to storage tanks.

(2) Owners and operators using vapor balance during liquid transfer operations shall:
(i) Transfer the vapors displaced from the vessel being loaded back to the vessel being emptied via pipes and/or hoses connected prior to the start of transfer operations;
(ii) Ensure that the transfer does not begin until the vapor collection and return system is connected;
(iii) Maintain connector pipes, hoses, couplers, valves, and pressure relief devices in a condition that prevents leaks;
(iv) Check all liquid and vapor line connections for proper connection prior to commencing transfer operations; and
(v) Operate all transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage tank.

(3) Bottom loading or submerged filling shall be used for all liquids transfers.

(4) Connector pipes and couplers shall be maintained in a condition that prevents leaks.

(5) All connections of hoses or piping used during liquid transfer operations shall be supported on a drip tray that collects any leaks, and any material collected shall be returned to the process or disposed of in a manner compliant with the state law.

(6) Any liquid leaks that occur shall be cleaned and disposed of in a manner that prevents emissions to the atmosphere, and any material collected shall be returned to the process or disposed of in a manner compliant with the state law.

(7) All owners and operators complying with the control requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

C. Monitoring Requirements

(1) All transfer equipment must be visually inspected during transfer operations to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. All leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of any liquid transfer operations controlled by air pollution control equipment must follow manufacturer's recommended operation and maintenance procedures.

(3) All tanker trucks or tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:

(i) Method 27, appendix A, 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H_2O (18 in. H_2O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H_2O

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(6 in. H_2O), gauge. The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in Table 1 of this section.

Table 1 - Allowable Cargo Tank Test Pressure or Vacuum Change

Cargo tank or compartment capacity, liters (gal)	Allowable vacuum change (Δv) in 5 minutes, mm H_2O (in. H_2O)	Allowable pressure change (Δp) in 5 minutes, mm H_2O (in. H_2O)
less than 3,785 (less than 1,000)	64 (2.5)	102 (4.0)
3,785 to less than 5,678 (1,000 to less than 1,500)	51 (2.0)	89 (3.5)
5,678 less than 9,464 (1,500 to less than 2,500)	38 (1.5)	76 (3.0)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)

(ii) Pressure test of the cargo tank's internal vapor valve as follows:
(*A*) After completing the tests under 20.2.50.20.C(3)(i) NMAC, use the procedures in Method 27 to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge. Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.
(*B*) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

(4) Owners or operators complying with the requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.
(5) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements
(1) For each liquid transfer operation, the owner or operator shall maintain records of:
(a) The tank's location and the tank's unique inventory control number or name and,
(b) The location, type, make, and model of any control equipment.
(2) Each owner or operator shall maintain records of the inspections required in 20.2.50.20.C NMAC. These records shall include the following:
(i) the time and date of the inspection;
(ii) the person conducting the inspection;
(iii) a notation that each of the checks required under 20.2.50.20.C NMAC were completed;
(iv) a description of any problems observed during the inspection; and
(v) a description and date of any repairs and corrective actions taken.
(3) Owners and operators shall create and maintain a calendar year record for each site summarizing, calculating, recording, and totaling the liquid loading operation

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liquids and associated VOC emissions. Each calendar year, the owners and operators shall create a company-wide record summarizing the liquid transfer total calculated emissions for the company.

(4) Owners and operators complying with the requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.

(5) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

(1) Owners and operators complying with the requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.21 STANDARDS FOR PIG LAUNCHING AND RECEIVING

A. Applicability

(1) All new and existing pipeline pig launching and receiving operations located within the property boundary at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.21 NMAC.

B. Emission Standards

(1) The owner or operator of new and existing pipeline pig launching and receiving operations with a potential to emit equal to or greater than 1.0 tpy of VOC shall capture and reduce VOC emissions by at least 98%, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operations shall:

(a) Employ best management practices to minimize the liquids present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and prior to opening the receiving chamber to the atmosphere;

(b) Employ methods to prevent emissions including, but not limited to, installing liquids ramps, installing liquid drains, routing high-pressure chambers to a low-pressure line or vessel, using ball valve type chambers, or using multiple pig chambers;

(c) Recover and dispose of all receiver liquids in a manner that prevents emissions to the atmosphere; and

(d) Ensure that any material collected is returned to the process or disposed of in a manner compliant with the state law.

(3) Owners and operators of a pig launching and receiving operation shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each pig launcher and each pig receiver in accordance with 20.2.50.12 NMAC.

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(4) Any existing pipeline pig launching and receiving operation subject to control requirements may become exempt from those requirements when its actual annual emissions of VOC decreases to an amount less than 0.5 tpy of VOC.
(5) Owners and operators complying with the control requirements in 20.2.50.21.B(2) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

C. Monitoring Requirements
(1) The owner or operator of any pig launching and receiving equipment shall monitor the type and volume of liquids cleared.
(2) The owner or operator of any pig launching and receiving equipment subject to control requirements shall inspect the equipment for leaks using RM 21 or OGI with infrared cameras immediately prior to the commencement and immediately after the conclusion of each pig launching or receiving operation, and according to the requirements in 20.2.50.16 NMAC.
(3) Owners and operators complying with the requirements in 20.2.50.21.B(1) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.
(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements
(1) Owners and operators shall maintain the following records in accordance with 20.2.50.12.C NMAC for each pig launching and receiving operation or event:
(a) Records of each pigging operation including the date and time of the pigging operation, and the type and volume of liquids cleared;
(b) The data and methodology used to estimate the actual emissions to the atmosphere;
(c) The data and methodology used to estimate the potential to emit; and
(d) The type of control(s), location, make, model and, if applicable, the unique identification number of the control equipment.
(2) Owners and operators complying with the requirements in 20.2.50.21.B(1) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.
(3) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements
(1) Owners and operators complying with the requirements in 20.2.50.21.B(1) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.
(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

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20.2.50.22 STANDARDS FOR PNEUMATIC CONTROLLERS AND PUMPS

A. Applicability

(1) All new and existing natural gas-driven pneumatic controllers and pumps located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.22 NMAC.

B. Emission Standards

(1) Natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps constructed on or after the effective date of this Part shall comply with the requirements of 20.2.50.22 NMAC upon startup.

(2) Natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps constructed before the effective date of this Part shall comply with the requirements of 20.2.50.22 NMAC within one year of the effective date of this Part.

(3) Standards for natural gas-driven pneumatic controllers.

(a) Owners and operators of each pneumatic controller located at a natural gas processing plant shall ensure the pneumatic controller has a VOC emission rate of zero.

(b) Owners and operators of each pneumatic controller located at a wellhead site, tank battery, gathering and boosting site, or transmission compressor station with access to electrical power shall ensure the pneumatic controller has a VOC emission rate of zero.

(c) Owners and operators of each pneumatic controller located at a wellhead site, tank battery, gathering and boosting site, or transmission compressor station without access to electrical power shall ensure the pneumatic controller has a bleed rate of less than or equal to 6 standard cubic feet per hour.

(d) Pneumatic controllers with a bleed rate greater than 6 standard cubic feet per hour are permitted where the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including but not limited to response time, safety, and positive actuation.

(4) Standards for natural gas-driven pneumatic pumps.

(a) Owners and operators of each pneumatic pump located at a natural gas processing plant shall ensure the pneumatic pump has a VOC emission rate of zero.

(b) Owners and operators of each pneumatic pump located at a wellhead site, tank battery, gathering and boosting site, or transmission compressor station with access to electrical power shall ensure the pump has a VOC emission rate of zero.

(c) Owners and operators of each pneumatic pump located at a wellhead site, tank battery, gathering and boosting site, or transmission compressor station without access to electrical power shall reduce VOC emissions from the pneumatic pump by 95% if it is technically feasible to route emissions to a control device, fuel cell, or process.

(d) If there is a control device available onsite, but it is unable to achieve a 95%

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emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process this section, the owner or operator shall route the pneumatic pump emissions to this control device.

C. Monitoring Requirements

(1) Owners and operators of pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the requirements of this section.

(2) Owners and operators of pneumatic controllers with a natural gas bleed rate greater than zero shall on a monthly basis scan each controller and, considering the EMITT specified design continuous or intermittent bleed rate, conduct an audible, visual, and olfactory (AVO) inspection and shall also inspect each pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

(3) Each EMITT shall be linked to a database allowing the state inspectors to, at a minimum, identify:

(a) unique pneumatic controller and pneumatic pump identification number;
(b) type of controller (continuous or intermittent);
(c) if continuous, design continuous bleed rate in standard cubic feet per hour;
(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and
(e) design annual bleed in standard cubic feet per year.

(4) Owners and operators of natural gas-driven a pneumatic pump with a natural gas bleed rate greater than zero shall on a monthly basis scan each pump or actuator and, considering the EMITT specified design pump rate or actuation volume, conduct an audible, visual, and olfactory (AVO) inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the pump's natural gas emissions are minimized.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) Owners and operators of pneumatic controllers, pumps with a natural gas bleed rate equal to zero are not subject to the requirements of this section.

(2) Owners and operators shall maintain an electronic pneumatic controller inspection log for each pneumatic controller with a natural gas bleed rate greater than zero at each facility, including for each inspection:

(a) Unique pneumatic controller ID number;
(b) EMITT scanned inspection dates;
(c) Name of the inspector;
(d) AVO inspection results;
(e) Any AVO level discrepancy in continuous or intermittent bleed rate;
(f) Maintenance dates; and
(g) Maintenance activities.

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(3) Owners and operators who determine that the use of a natural gas-driven pneumatic controller with a bleed rate greater than 6 standard cubic feet per hour is required shall maintain a record in the EMITT database of each such pneumatic controller documenting why a bleed rate greater than 6 standard cubic feet per hour is required per the requirements in 20.2.50.22.B NMAC.

(4) Owners and operators shall maintain records in the EMITT database of natural gas-driven pneumatic pumps with an emission rate greater than zero and their associated pump numbers at each facility, including:

(a) For natural gas-driven pneumatic pumps in operation less than 90 days per calendar year, records of the days of operation each calendar year.

(b) Records of control devices designed to achieve less than 95% emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) Records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(5) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.23 STANDARDS FOR STORAGE TANKS

A. Applicability

(1) All new and existing hydrocarbon storage tanks with an uncontrolled potential to emit equal to or greater than 2 tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to regulation under 20.2.50.23 NMAC.

B. Emission Standards

(1) All existing storage tanks with a potential to emit equal to or greater than 2 tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions by at least 95 percent no later than one year after the effective date of this Part.

(2) All existing storage tanks with a potential to emit equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions by at least 98 percent, no later than one year after the effective date of this Part.

(3) All new storage tanks constructed after the effective date of this part with a potential to emit equal to or greater than 2 tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions by at least 95 percent upon startup.

(4) All new storage tanks constructed after the effective date of this Part with a

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potential to emit equal to or greater than 10 tpy of VOC shall have a combined capture and control and control of VOC emissions by at least 98 percent upon startup.

(5) Any new or existing storage tank subject to control requirements under 20.2.50.23 NMAC becomes exempt from those requirements when its uncontrolled actual annual VOC emissions decreases to less than 2 tpy.

(6) If air pollution control equipment is not installed by the applicable date specified in 20.2.50.23.B(1) through 20.2.50.23.B(4) NMAC, compliance with 20.2.50.23.B(1) through 20.2.50.23.B(4) NMAC may be demonstrated by shutting in all wells producing into that storage tank by that applicable date and so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

(7) Owners and operators of an existing or new tank with a thief hatch shall install a control device on the thief hatch which allows the thief hatch to open sufficiently to relieve overpressure in the tank and to automatically close once the tank overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device will only be engaged during in the presence of owner or operator staff and during active ingress activities.

(8) Owners and operators of a new or existing hydrocarbon storage tank(s) shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each storage tank in accordance with 20.2.50.12 NMAC.

(9) Owners and operators complying with the control requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

(10) After the compliance deadlines established in the rule, it is a violation to operate any tank not complying with the requirements of this section.

C. Monitoring Requirements

(1) The owner or operator of any storage tank subject to control requirements shall monitor the total monthly liquid throughput (barrels) and the upstream separator pressure (psig) on a monthly basis. Any time the storage tank is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted prior to the storage tank being unloaded.

(2) The owner or operator of any storage tank subject to control requirements shall conduct an auditory, visual, and olfactory (AVO) inspection on a weekly basis. Any time the storage tank is unloaded less frequently than weekly, the AVO inspections shall be conducted prior to the storage tank being unloaded.

(3) The owner or operator of any storage tank subject to control requirements shall inspect the tanks monthly to ensure compliance with the requirements of 20.2.50.23 NMAC. Inspections shall include a check to ensure the tanks have no leaks, that all hatches are closed, the pressure relief valves are properly seated, and all vent lines are closed.

(4) Each monitoring or inspection shall include the scanning of the EMITT and the simultaneous entry of the required monitoring data in accordance with the requirements of 20.2.50.12 NMAC.

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(5) Owners and operators complying with the requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.
(6) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements
(1) Owners and operators subject to control requirements under 20.2.50.23 NMAC shall, on a monthly basis, maintain records in accordance with 20.2.50.12 NMAC for each storage tank of:
(a) The tank's location and unique inventory control number or name;
(b) Monthly liquid throughput and the most recent date of measurement;
(c) The average monthly upstream separator pressure;
(d) The data and methodology used to calculate the potential to emit of VOC (the calculation methodology must be a Department approved methodology);
(e) The controlled and uncontrolled VOC emissions (tpy); and
(f) The location, type, make, model and unique identification number of any control equipment.
(2) Records of liquid throughput required in 20.2.50.23.D(1) NMAC shall be verified by dated delivery receipts from the purchaser of the hydrocarbon liquids, or metered volumes of hydrocarbon liquids sent downstream, or other proof of transfer.
(3) Records of the inspections required in 20.2.50.23.C NMAC shall include the time and date of the inspection, the person conducting the inspection, a notation that each check required under 20.2.50.23.C NMAC was completed, a description of any problems observed during the inspection, and a description and date of any corrective actions taken in accordance with 20.2.50.12 NMAC.
(4) Owners and operators complying with the requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.
(5) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.
(1) Owners and operators complying with the requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.
(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.24 STANDARDS FOR WORKOVERS

A. Applicability
(1) All workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.24 NMAC for any workovers performed after the effective date of this Part.

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B. Emission Standards
   (1) Owners and operators of oil or natural gas wells shall use the following best management practices during workovers to minimize emissions, consistent with well site conditions and good engineering practices:
      (a) Reduce wellhead pressure prior to blowdown to minimize the volume of natural gas vented;
      (b) Monitor manual venting in close proximity to the well or via remote telemetry; and
      (c) Route natural gas flow to the sales line, if possible.

C. Monitoring Requirements
   (1) Owners and operators subject to 20.2.50.24 NMAC shall monitor the following parameters during workovers:
      (a) Wellhead pressure;
      (b) Flow rate of the vented natural gas (to the extent feasible); and
      (c) Duration of venting to the atmosphere.
   (2) Owners and operators shall calculate the volume and mass of VOC vented during each workover.
   (3) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements
   (1) Owners and operators subject to 20.2.50.24 NMAC shall keep the following records for each workover:
      (a) The identification number and location of the well;
      (b) The date(s) the workover was performed;
      (c) Wellhead pressure;
      (d) Flow rate of the vented natural gas (to the extent feasible. If measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);
      (e) Duration of venting to the atmosphere;
      (f) A description of the management practices used to minimize release of VOC prior to and during the workover; and
      (g) A calculation of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.
   (2) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements
   (1) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.
   (2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from any workover event, the owner or operator shall notify all residents by certified mail located within 0.25 miles of the well of the planned workover at least three (3) calendar days prior to the workover event.

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20.2.50.25 STANDARDS FOR OIL AND NATURAL GAS STRIPPER WELLS AND FACILITIES WITH SITE-WIDE VOC POTENTIAL TO EMIT LESS THAN 15 TPY

A. Applicability
   (1) Stripper wells, defined as any oil and natural gas well producing less than 10 barrels of oil per day or less than 60 thousand standard cubic feet of natural gas per day, are subject to the requirements of 20.2.50.25 NMAC.
   (2) Owners or operators of stripper wells shall comply with these requirements no later than one year after the effective date of this Part.
   (3) Facilities with a site-wide annual PTE of less than 15 tons per year of VOC are subject to the requirements of 20.2.50.25 NMAC.
   (4) Owners or operators of facilities with a site-wide annual PTE of less than 15 tons per year of VOC shall comply with these requirements no later than one year after the effective date of this Part.
   (5) If at any time a facility identified in 20.2.50.25.A(1) or (3) NMAC exceeds the daily production limit or PTE threshold of 15 tpy of VOC, the owner or operator shall conduct semi-annual LDAR monitoring as required by 20.2.50.16.C(2)(b) NMAC for a period of two years.

B. Emission Standards
   (1) Owners or operators shall ensure that all equipment located at a stripper well or low-PTE facility shall be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the Department.
   (2) Owners or operators of an oil or natural gas stripper well or individual facility with a site-wide PTE less than 15 tpy of VOC shall, within the first calendar quarter of the year, use actual production volumes to calculate the VOC and NOx emissions from the stripper well site.
   (3) Owners or operators of an oil or natural gas stripper well(s) or facility(s) with a site-wide PTE less than 15 tpy of VOC shall maintain a database of company-wide calculated VOC and NOx emissions estimates for each site and must update the database annually.

C. Monitoring Requirements
   (1) Owners or operators complying with 20.2.50.25 NMAC shall monitor the following for each stripper well or facility with a site-wide PTE of VOC less than 15 tpy:
      (a) the unique identifier of the stripper well or facility (number and name, as applicable);
      (b) the UTM coordinates of the stripper well or facility and its county of location;
      (c) the annual total well production rate in barrels of oil per year and natural gas production in thousand standard cubic feet per year; and
      (d) Dates, duration, and VOC emission estimates of any venting or flaring event longer than eight (8) hours.

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(2) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) Owners or operators complying with 20.2.50.25 NMAC shall:

(a) maintain electronic records of the following for each stripper well and low-PTE facility:

(i) the unique identifier of the stripper well and low-PTE facility (number and name, as applicable);

(ii) the UTM coordinates of the stripper well and low-PTE facility and its county of location;

(iii) the total annual well production in barrels of oil per year and natural gas production in thousand standard cubic feet; and

(iv) Dates, duration, and VOC emission calculation of any venting or flaring event lasting longer than eight (8) hours, and the cause of the event.

(2) Within the first calendar quarter of the year, record the calculated total annual emissions of VOC and NOx from each stripper well site and low-PTE facility in tons, and the company-wide total VOC and NOx emissions from stripper wells and low-PTE facilities in tons. All venting and flaring emissions shall be included in the calculated total annual emissions.

(3) Within the first calendar quarter of the year, provide a description of the management practices used to minimize and prevent the release of VOC and NOx at each stripper well and low-PTE facility.

(4) Owners or operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

Owners or operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.26 STANDARDS FOR EVAPORATION PONDS

A. Applicability

(1) All new and existing oil and natural gas evaporation ponds with pond capacity equal to or greater than [TBD barrels] or a potential to emit greater than [10 lbs/day VOC] and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, transmission compressor stations, or not associated with a facility but located in San Juan, Lea, Eddy, Rio Arriba, Sandoval counties are subject to the requirements of 20.2.50.26 NMAC.

(2) Owners or operators of oil and natural gas evaporation ponds shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission Standards

(1) Owners or operators of an oil or natural gas evaporation pond shall use best management practices to minimize emissions of VOC, consistent with good engineering practices.

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(2) Prior to unloading into a pond(s), all liquids shall be first loaded into a 20.2.50.23 NMAC compliant liquid storage tank designed to minimize subsequent VOC emissions from the pond.
(3) Owners or operators shall install an impermeable continuous barrier or cover over the entire surface area of the liquid, which prevents VOC emissions from being emitted to the atmosphere. Owners and operators shall ensure that VOC emissions are collected and routed to a control device for destruction.

C. Monitoring Requirements
(1) For each oil or natural gas evaporation pond, the owners or operators subject to 20.2.50.26 NMAC shall:
(a) on a monthly basis, perform an inspection to ensure that the barrier is an impermeable continuous barrier or cover that covers the entire surface area of liquid;
(b) on a monthly basis, ensure that all VOC emissions are being captured and routed to a control device; and
(c) monitor the monthly total and annual total oil and natural gas evaporation pond throughput in thousands of gallons of liquids.
(2) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements
(1) Owners or operators subject to 20.2.50.26 NMAC shall maintain electronic records of the following for each evaporation pond:
(a) the unique identifier of the evaporation pond (number and name, as applicable);
(b) the UTM coordinates of the evaporation pond site and its county of location;
(c) the results of the barrier or cover inspection, including the date, time, and name of the personnel performing the inspection;
(d) the results of the VOC capture and control device inspection, including the date, time, and name of the personnel performing the inspection; and
(e) the total calculated VOC emissions in tons per year.
(2) Owners or operators of an oil or natural gas evaporation pond shall, within the first calendar quarter of the year, record the calculated emission estimates of VOC from the evaporation pond in tons per year.
(3) Owners or operators of an oil or natural gas evaporation pond shall record a description of the management practices used to minimize release of VOC at the evaporation pond, and the company-wide total VOC emissions from evaporation ponds in tons per year.
(4) Owners or operators of an oil or natural gas evaporation pond shall, within the first calendar quarter of the year, use actual volumes of liquid loaded into each site's pond(s) to calculate total site-wide VOC emissions from all evaporation ponds.
(5) Owners or operators of an oil or natural gas evaporation pond(s) shall maintain a database of company-wide calculated annual total VOC emissions estimates in tons per year from each pond.

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(6) Owners or operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

Owners or operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.27 PROHIBITED ACTIVITIES AND CREDIBLE INFORMATION PRESUMPTIONS

A. Failure to comply with any of the emissions standards, recordkeeping, reporting, or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 of the Act.

B. If credible information obtained by the Department indicates that a source is not in compliance with any provision of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.

C. If credible information provided to the Department by a member of the public indicates that a source is not in compliance with any provision of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.

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STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF ANGELA RASO

My name is Angel Raso, and I am a dispersion modeler for the New Mexico Environment Department's ("Department" or "NMED") Air Quality Bureau ("Bureau"). I am presenting this written testimony on behalf of the Department in this proceeding on proposed new air quality regulations at 20.2.50 NMAC ("Part 50"). My testimony will address the chemistry of ozone in the atmosphere, and NMED's review of the photochemical modeling performed by Ramboll for this rulemaking.

I. QUALIFICATIONS

I have been a dispersion modeler for the Bureau for 3 years. As a dispersion modeler, I routinely evaluate the air quality impacts of complex facilities. I hold a PhD in chemistry from Purdue University, and a BA in chemistry from Whitman College. My PhD research focused on the chemistry and interactions of ozone in the atmospheric boundary layer.

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 14.

II. TROPOSPHERIC OZONE FORMATION

Dry air in the atmosphere is composed of 78.08% molecular nitrogen (N_2), 20.95% molecular oxygen (O_2), 0.93% Argon, and 0.04% other trace gases by volume. In many respects the most important trace gas in the atmosphere is ozone. The impacts of ozone depend on where in the atmosphere it exists. In the upper atmosphere, stratospheric ozone absorbs biologically

harmful solar ultraviolet light, protecting living organisms. At the surface, high ozone concentrations can be detrimental to human and plant health.

Rather than being directly emitted by sources ozone is produced by a set of chemical reactions between Nitrous Oxides (NO_x) and Volatile Organic Compounds (VOCs). Therefore, reductions in ozone concentration must be achieved through regulation of these precursor pollutants. Nitric Oxide (NO) is formed when N_2 and O_2 combine under high heat. This occurs both naturally (such as during lightning strikes), and due to human (anthropogenic) activities, such as fossil fuel combustion. More than 90% of the NO released to the atmosphere is anthropogenic [EPA 456/F-99-006R, 1999]. In the presence of ozone (O_3) and sunlight, NO and NO_2 are rapidly interconverted. The sum of NO and NO_2 are referred to as NO_x. VOCs are a subset of hydrocarbons that are volatile enough to evaporate and enter the atmosphere to undergo photochemical (light dependent) chemical reactions. Most VOCs in the atmosphere are emitted by plant life. In some areas with large anthropogenic emissions, such as densely populated cities, VOC emissions from anthropogenic activities can be nearly equal to emissions from plants.

In the presence of sunlight, NOx and VOCs react to form ozone. This cycle of radical photochemical (involving light) reactions begins with ozone separating (undergoing photolysis) to form a hydroxyl radical (OH). Hydroxyl radicals rapidly oxidize VOCs (shown in the reactions below as hydrocarbons, RH). Oxidation of VOCs in the atmosphere causes them to become more water soluble, and ultimately facilitates the removal of VOCs from the atmosphere. However, in the presence of NO, each oxidized VOC produces two O_3 molecules without the net removal of NO_x from the atmosphere.

$$OH^{\cdot} + RH + O_2 \rightarrow H_2O + RO_2^{\cdot}$$

$$RO_2^{\cdot} + NO^{\cdot} \rightarrow NO_2^{\cdot} + RO^{\cdot}$$

$$RO^{\cdot} + O_2 \rightarrow HO_2^{\cdot} + carbonyl\ compound$$

$$HO_2^{\cdot} + NO^{\cdot} \rightarrow NO_2^{\cdot} + OH^{\cdot}$$

$$2NO_2^{\cdot} + 2O_2 + light \rightarrow 2NO^{\cdot} + 2O_3$$

$$NET: RH + 4O_2 + light \rightarrow H_2O + carbonyl\ compound + 2O_3$$

The formation of OH and subsequent oxidation reactions to form O_3 are highly dependent on light and temperature. The dependence of these reactions on light and heat leads to the largest O_3 concentrations occurring on warm, sunny days during the summer.

Ozone has been regulated in the U.S. as a pollutant since the establishment of the National Ambient Air Quality Standards ("NAAQS") under the Clean Air Act in 1971. Since 1979, the U.S. Environmental Protection Agency ("EPA") has been incrementally decreasing the ozone NAAQS as more evidence emerges on the public health and environmental consequences of ozone. Most recently, EPA decreased the ozone NAAQS from 0.75 ppm (parts per million) to 0.70 ppm in 2015. Regulation has successfully reduced mean ozone concentrations in the U.S. by 33% since 1980, as shown in Figure 1.

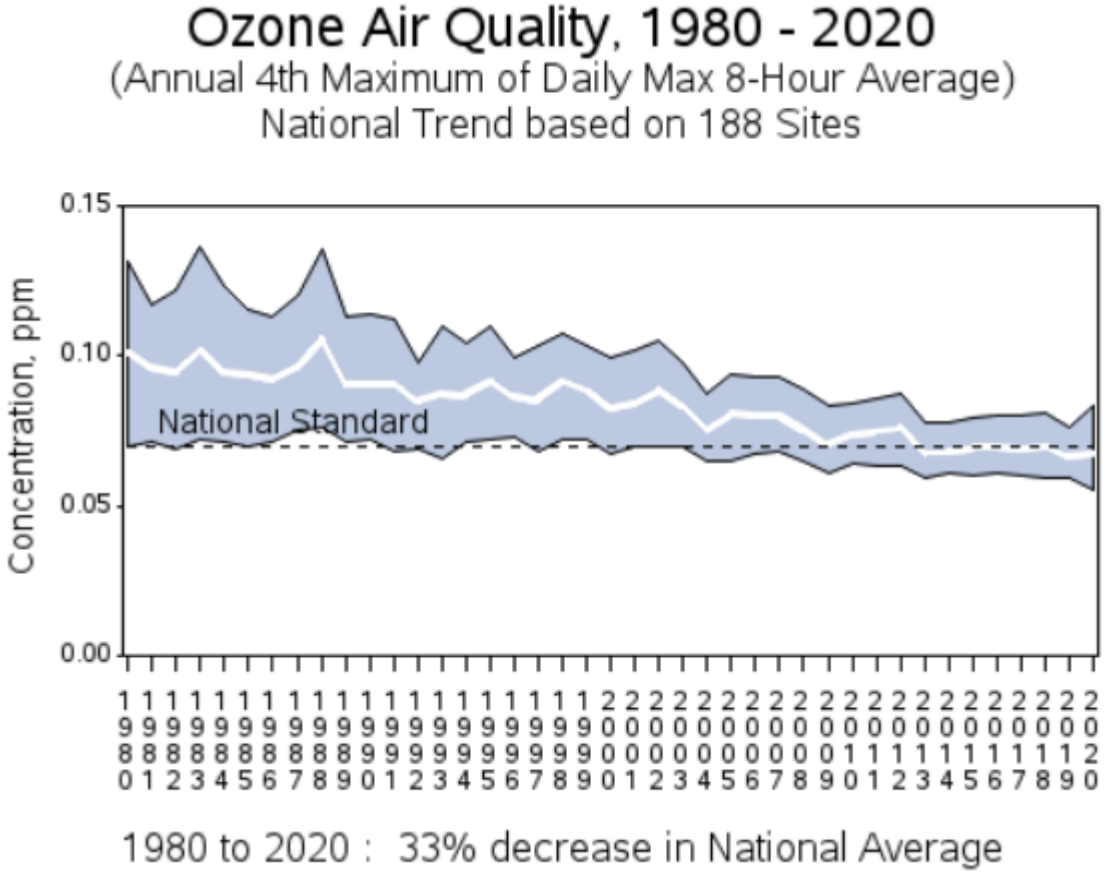


Figure 1: Mean (white line) and 10%-90% ozone daily values nationally for the U.S. from 1980-2020.[1]

The photochemical cycle that leads to the formation of ozone is comprised of a complex series of emissions, chemical reactions, and physical processes and is dependent on the time of day, sunlight, temperature, and other meteorological conditions. Understanding the potential reductions in ozone concentrations from reductions in emissions of anthropogenic precursors requires an integrated assessment of these factors. In order to conduct this assessment, a photochemical model is utilized. Testimony on the photochemical modeling performed for this rulemaking will be presented by Ralph Morris of Ramboll.

[1] *See* https://www.epa.gov/air-trends/ozone-trends.

IV. NMED REVIEW OF RAMBOLL PHOTOCHEMICAL MODELING

On behalf of the Bureau, I reviewed the photochemical work products that were produced by Ramboll. A table of photochemical modeling products produced by Ramboll and reviewed by the Bureau is included below.

Product	Topics
NMED Exhibit 15 - Photochemical Modeling Protocol	Planning and Communication Document Describing Proposed Modeling Strategy
NMED Exhibit 16 - 2014 Modeling Platform Development and Model Evaluation	Work Product Document Describing Development of the Base Case Modeling and Evaluation of Modeling Performance
NMED Exhibit 17 - Air Quality Technical Support Document	Work Product Document Containing Technical Specifications of Modeling Performed
NMED Exhibit 18 - New Mexico OAI Study Photochemical First Monthly Webinar May 2020	• Existing Meteorological Modeling • Evaluation of Boundary Conditions • Modeling Protocol Overview • 2014 and Future Year Emissions
NMED Exhibit 19 - New Mexico OAI Study Photochemical Monthly Webinar June 2020	• 2014 and Future Year Emissions • Meteorological Modeling
NMED Exhibit 20 - 2014 and 2023 Emissions, CAMx WRF Sensitivity Tests and Final Model Configuration	• 2014 and Future Year Emissions, Quality Assurance and Processing • Photochemical Modeling, Sensitivity Tests, and Base Case Configuration
NMED Exhibit 21 - Emissions, CAMx, Base and Model Performance, 2023 CAMx Model Status	• 2014 and Future Year Emissions, Natural Sources and Processing • Photochemical Modeling, Base Case Configuration and Model Performance Evaluation
NMED Exhibit 22 - 2014 and 2028 Emissions Development	• Development of 2014 and Future Year Emissions Sources • Processing of Emissions for Modeling
NMED Exhibit 23 - Revised 2014v2 Base Case, 2028 Base Case	• 2014 Modeling • Future Year (2028) Base Case Modeling • Future Year (2028) Control Strategy Modeling

Modeling and 2028 NM O&G Control Strategy (Feb 2021)	• Design of Source Apportionment Modeling
NMED Exhibit 24 - Sensitivity of 2028 Ozone Projections to Current Year Ozone, Draft TSD	• Summary of Future Year (2028) modeling Design Value Projections • Sensitivity of Future Year Design Values to Current Year Design Values • Status of Ozone Source Apportionment Modeling
NMED Exhibit 25 - 2028 Source Sector APCA Ozone Source Apportionment Modeling, Revised Draft TSD (April 2021)	• Summary of Future Year Design Value Projections and Sensitivity • Future Year Source Sector Apportionment Modeling Results (APCA Modeling) • Status of Source Apportionment Results for VOC/NOx Sensitivity (OSAT Modeling)
NMED Exhibit 26 - 2028 VOC and NOx Sensitivity OSAT Ozone Source Apportionment Modeling and Draft Final TSD (April 2021)	• Overview of OSAT Modeling for VOC/NOx Sensitivity • Summary of Source Sector Apportionment Modeling (APCA modeling) • Future Year (2028) VOC/NOx Sensitivity OSAT Ozone Source Apportionment Modeling Results

A full discussion of the modeling and the deliverables produced by Ramboll is provided in the testimony of NMED witness Ralph Morris.

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Education

Purdue University, West Lafayette, IN **December 2018**
Doctor of Philosophy, Analytical chemistry
Dissertation: "Halogen Photochemistry and Emissions from the Arctic Snowpack"
Advisor Dr. Paul B. Shepson, Dr. Kerri A. Pratt (University of Michigan)

Whitman College, Walla Walla, WA **May 2012**
Bachelor of Arts, Chemistry. Mathematics minor.
Undergraduate Thesis: "Determining the Presence of Dense Non-Aqueous Phase Liquid (DNAPL) Pollutants in River Sediments"
Advisor Dr. Frank M. Dunnivant

Professional Experience

Dispersion Modeler, New Mexico Environment Department, Air Quality Bureau September 2018 - Present

- Evaluate facilities emissions for compliance with Ambient Air Quality Standards using dispersion models
- Assist with data analysis and evaluation related to emissions inventories
- Assist with special projects involving modeling and emissions inventories including; preparation for photochemical modeling, modeling for state implementation plans

Research Experience

Research Assistant, Purdue University **Fall 2012 – August 2018**

- Lead field work based research on gas phase oxidation processes in the Arctic to understand a complex environmental system
- Collaboratively design and perform atmospheric chemistry experiments in the Arctic including eddy covariance flux measurements
- Full process responsibility for analytical measurements in a remote Arctic environment
- Coordinate logistical needs to ensure successful Arctic fieldwork in Barrow, Alaska
- Manage instrumentation including a homebuilt chemical ionization mass spectrometer, and an ion chromatography / liquid chromatography system
- Mentor and train students to safely and effectively use instrumentation
- Conduct zero- and one- dimensional photochemical modeling to understand and contextualize the importance of measurements

Visiting Research Assistant, University of Michigan **Fall & Winter 2015**

- Collaboratively planned for a spring 2016 field study in Barrow, Alaska

User, Environmental Molecular Sciences Laboratory, **October 2015**
Pacific Northwest National Laboratory

- Acquired first ever measurements of iodide in Arctic snow using ion chromatography coupled with inductively coupled plasma mass spectrometry (IC-ICPMS)

Undergraduate Research Assistant, Whitman College **Fall 2010 –Spring 2012**

- Conducted research on dense non-aqueous phase liquids in mixed stream-bed media for detection at highly polluted sites using gas chromatography – electron capture detection

Teaching Experience

General Chemistry Adjunct, Santa Fe Community College **Spring & Fall 2019**

- Instructed General Chemistry Laboratories

Analytical Chemistry TA, Purdue Chemistry Department **Fall 2013**

- Instructed laboratory sessions for upper division chemistry students in a major required course

- Wrote and graded exam questions and graded written lab reports, giving important feedback to students

Fundamental General Chemistry TA, Purdue Chemistry Department **Spring 2013**

- Instructed laboratory and recitation for students with no previous chemistry courses to give a gentle introduction to important laboratory and scientific skills

General Chemistry for Engineers TA, Purdue Chemistry Department **Fall 2012**

- Instructed laboratory and recitation sessions to introduce freshman engineers and scientists to college level science courses.

Chemistry Tutor, Whitman Chemistry Department **2010 -2012**

- Demonstrated concepts and problem solving techniques for students from general, organic and analytical chemistry classes in an open "drop in" environment using a variety of teaching methods

Organic Chemistry Laboratory Assistant, Whitman Chemistry Department **Fall 2011**

- Supported students in an organic chemistry laboratory to ensure safe, time effective, and comprehensive completion of experiments

Quantitative Analysis Lab. Assistant, Whitman Chemistry Department **Fall 2011**

- Supported students in a data rich laboratory to introduce analytical methods to chemistry majors
- Corrected spreadsheet style lab reports to give important feedback to students

Tutor, Whitman College Academic Resource Center **2010-2012**

- Tutored general chemistry, organic chemistry, calculus I, calculus II and differential equations to support student understanding and grades

Publications and Presentations

- "Active Molecular Iodine Photochemistry in the Arctic" December 11, 2017. Oral Presentation, American Geophysical Union Meeting. New Orleans, La
- "Surface fluxes and recycling of molecular halogens above the snowpack" December 11, 2017. Poster, American Geophysical Union Meeting. New Orleans, La
- Raso, A. R. W., K. D. Custard, N. W. May, D. J. Tanner, M. K. Newburn, L. Walker, R. Moor, L. G. Huey, M. L. Alexander, P. B. Shepson, K. A. Pratt "Active Molecular Iodine Photochemistry in the Arctic" *Proceedings of the National Academy of Sciences 114(38) 10053-10058*
- Custard, K. D., A. R. W. Raso, K. A. Pratt, R. M. Staebler, and P. B. Shepson (2017) "Molecular halogen production in and flux measurements from tundra snow" *ACS earth and space chem. 1(3), 142-151*
- Raso, A.R.W., B. Elstrott, and F. M. Dunnivant, (2012) Envirolab: Simulations of Laboratory experiments in environmental chemistry [Computer Program]
- Available at http://people.whitman.edu/~dunnivfm/software.html
- "Mass transport and recycling of molecular halogens near the snowpack surface in Barrow (Utqiaġvik), Alaska" December 12, 2016. American Geophysical Union Fall Meeting. San Francisco, Ca.
- "The impact of Molecular iodine photochemistry in the Arctic" December 17, 2014. Poster, American Geophysical Union Fall Meeting. San Francisco, Ca.
- "Determining the presence of dense non-aqueous phase liquid (DNAPL) pollutants in river sediments" March 26, 2012. Poster, National Spring Meeting of the American Chemical Society. San Diego, Ca.

May 2020

NEW MEXICO OZONE ATTAINMENT INITIATIVE PHOTOCHEMICAL MODELING STUDY - DRAFT MODELING PROTOCOL



RAMBOLL

WESTAR
Western States Air Resources Council

NMED Exhibit 15

NEW MEXICO OZONE ATTAINMENT INITIATIVE PHOTOCHEMICAL MODELING STUDY - DRAFT MODELING PROTOCOL

Project name	**New Mexico Environmental Division**
Project no.	**1690017454**
Recipient	**New Mexico Environmental Division**
Document type	**Modeling Protocol**
Version	**V5.0**
Date	**May 19, 2020**
Prepared by	**Ralph Morris, Marco Rodriguez, Tejas Shah, Jeremiah Johnson, Fiona Jiang, Tom Moore, Mary Uhl**

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ACRONYMS AND ABBREVIATIONS

3SAQS	Three-State Air Quality Study
AIRS	Aerometric Information Retrieval System
AMET	Atmospheric Model Evaluation Tool
APCA	Anthropogenic Precursor Culpability Assessment
AQ	Air Quality
AQS	Air Quality System
BC	Boundary Condition
BLM	Bureau of Land Management
CAMx	Comprehensive Air-quality Model with extensions
CARB	California Air Resources Board
CASTNet	Clean Air Status and Trends Network
CB6r2	Carbon Bond mechanism version 6, revision 2
CMAQ	Community Multiscale Air Quality modeling system
CONUS	Continental United States
CPC	Center for Prediction of Climate
CSAPR	Cross State Air Pollution Rule
CSN	Chemical Speciation Network
EC	Elemental Carbon Fine Particulate Matter
ECMWF	European Center for Medium Range Weather Forecasting
EGU	Electrical Generating Units
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
FB	Fractional Bias
FE	Fractional Error
FRM	Federal Reference Method
GCM	Global Chemistry Model
GEOS-Chem	Goddard Earth Observing System (GEOS) global chemistry model
GIRAS	Geographic Information Retrieval and Analysis System
IMPROVE	Interagency Monitoring of PROtected Visual Environments
IWDW	Intermountain West Data Warehouse
LCP	Lambert Conformal Projection
LSM	Land Surface Model
MADIS	Meteorological Assimilation Data Ingest System
MATS	Modeled Attainment Test Software
MCIP	Meteorology-Chemistry Interface Processor
MEGAN	Model of Emissions of Gases and Aerosols in Nature
MNGE	Mean Normalized Gross Error
MNB	Mean Normalized Bias
MNE	Mean Normalized Error
MOVES	Motor Vehicle Emissions Simulator
MOZART	Model for OZone And Related chemical Tracers
MPE	Model Performance Evaluation
MSKF	Multi-Scale Kain-Fritsch Cumulus Parameterization
NAAQS	National Ambient Air Quality Standard
NAM	North American Mesoscale Forecast System

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NCAR	National Center for Atmospheric Research
NCEP	National Center for Environmental Prediction
NCDC	National Climatic Data Center
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NH_4	Ammonium Fine Particulate Matter
NMB	Normalized Mean Bias
NME	Normalized Mean Error
NMED	New Mexico Environmental Division
NO_2	Nitrogen Dioxide
NO_3	Nitrate Fine Particulate Matter
NOAA	National Oceanic and Atmospheric Administration
OA	Organic Aerosol Fine Particulate Matter
OAI	Ozone Attainment Initiative
OC	Organic Carbon Fine Particulate Matter
OSAT	Ozone Source Apportionment Technology
PAVE	Package for Analysis and Visualization
PBL	Planetary Boundary Layer
PGM	Photochemical Grid Model
PM	Particulate Matter
PPB	Parts Per Billion
PPM	Piecewise Parabolic Method
QA	Quality Assurance
QC	Quality Control
RMP	Resource Management Plan
RRF	Relative Response Factor
SCC	Source Classification Code
SIP	State Implementation Plan
SMOKE	Sparse Matrix Kernel Emissions modeling system
SNMOS	Southern New Mexico Ozone Study
SOA	Secondary Organic Aerosol
SO_2	Sulfur Dioxide
SO_4	Sulfate Fine Particulate Matter
TCEQ	Texas Commission on Environmental Quality
UNC-IE	University of North Carolina Institute for the Environment
USFS	United States Forest Service
VERDI	Visualization Environment for Rich Data Interpretation
VMT	Vehicle Miles Traveled
WBD	Wind Blown Dust model
WAQS	Western Air Quality Study
WESTAR	Western States Air Resources Council
WestJumpAQMS	West-Wide Jump-Start Air Quality Modeling Study
WESTUS	Western United States
WRAP	Western Regional Air Partnership
WGA	Western Governors' Association
WRF	Weather Research Forecast model

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1. INTRODUCTION

This document is a Modeling Protocol and an informal Quality Assurance Project Plan (QAPP) for the New Mexico (NM) Ozone Attainment Initiative (OAI) Photochemical Modeling Study ("NM OAI Study"). The New Mexico Environmental Division (NMED) has contracted with a team consisting of Western States Air Resources Council (WESTAR) and Ramboll US Corporation to conduct the NM OAI Study. The NM OAI Study leverages the 2014 photochemical grid model (PGM) modeling platform developed by the Western Regional Air Partnership (WRAP) in the Western Air Quality Study (WAQS) and enhances it by adding a 4-km grid resolution modeling domain over New Mexico. 2023 future year modeling, source apportionment and control measure evaluation will be performed to assist the NMED in ozone air quality planning for the state.

1.1 NM OAI Project Genesis

The NMED Air Quality Bureau has authority over air quality management activities throughout the state of New Mexico, with the exception Bernalillo County and Tribal Lands. The City of Albuquerque/Air Quality Division has authority in Bernalillo County and, except for where Tribal Implementation Plans have been approved, EPA oversees air quality issues in Tribal Lands. The New Mexico Air Quality Control Act (NMAQCA) requires the NMED to develop a plan to address elevated ozone levels when air quality is within 95% of the ozone NAAQS (74-3-5.3, NMSA 1978[1]). The ozone NAAQS was revised in 2015 with a threshold of 0.070 ppm (70 ppb) with the relevant metric being the ozone Design Value (DV) that is expressed as the three-year average of the fourth highest Daily Maximum Average 8-hour (DMAX8) ozone concentrations. Figure 1-1 displays the trends in observed ozone DVs at 8 New Mexico monitoring sites from 2013 to 2018 and compares them with the 70 ppb 2015 ozone NAAQS (red line) and 95% of the 70 ppb NAAQS (i.e., ≥ 67 ppb; black line). This results in 7[2] counties in New Mexico under NMED jurisdiction with measured 2016-2018 ozone DVs at or exceeding 95% of the 70 ppb ozone NAAQS, as shown in Figure 1-1.

[1] https://law.justia.com/codes/new-mexico/2017/chapter-74/article-2/section-74-2-5.3/

[2] 8 total counties in New Mexico if you also include Bernalillo County whose air quality is under the jurisdiction of the City of Albuquerque.

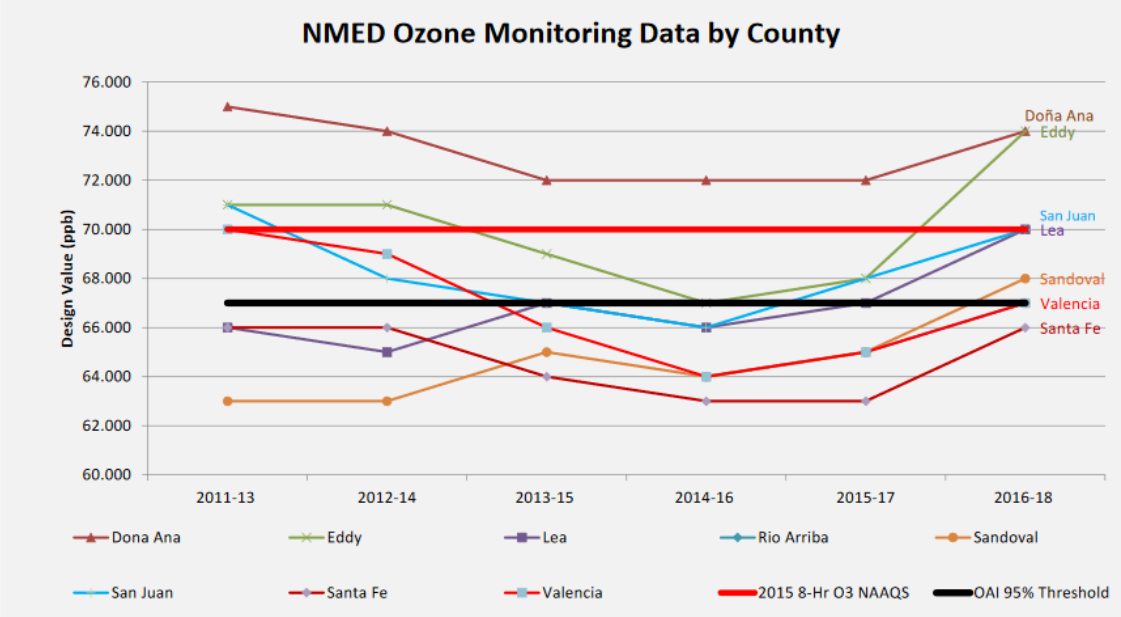
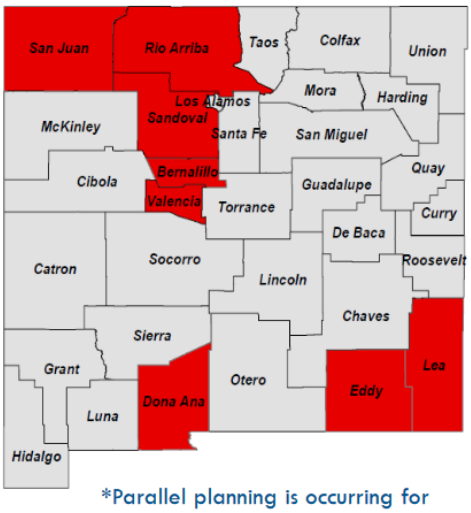


Figure 1-1. Trends in observed ozone DVs between 2013 and 2018 at 7 monitoring sites in New Mexico (Source: https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2019/10/OAI_Presentation_09262019.pdf).



- Counties within 95% of the standard:
  - San Juan (Navajo Lake, 70 ppb)
  - Doña Ana (several monitors, 74 ppb)
  - Eddy (Carlsbad, 74 ppb)
  - Lea (Hobbs, 70 ppb)
  - Rio Arriba (Coyote, 67 ppb)
  - Sandoval (Bernalillo, 68 ppb)
  - Valencia (Los Lunas, 67 ppb)

Figure 1-2. 7 counties in New Mexico under the jurisdiction of the NMED whose observed 2016-2018 ozone DVs are at or exceed 95% of the 2015 ozone NAAQS (70 ppb) (Source: https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2019/10/OAI_Presentation_09262019.pdf).

To address the high observed ozone concentrations in New Mexico, the NMED has embarked on an Ozone Attainment Initiative (OAI[3]) to protect the ozone attainment status of the state and ensure health and welfare of the residents of the state for future generations. The OAI was initiated in Spring 2018. As part of the OAI, NMED released a Request for Proposal (RFP#20 667 4040 0001) the NM OAI Study. The NM OAI Study PGM modeling was awarded to a contracting team of WESTAR and Ramboll. This Modeling Protocol is the first major deliverable under that contract.

1.2 Overview of NM OAI Study Modeling Approach

This Modeling Protocol describes the modeling activities to be performed under the NM OAI Study. The NM OAI Study will conduct PGM modeling by enhancing the WRAP/WAQS 2014 modeling platform[4] to use a 4-km grid resolution domain covering New Mexico and surrounding areas, especially the oil and gas (O&G) production regions in the Permian and San Juan Basins. The NM OAI Study PGM modeling will conduct 2014 base year modeling and model performance evaluation as well as 2023 future year modeling. The 2023 future year modeling will include ozone source apportionment and control measure sensitivity modeling. The NM OAI Study PGM modeling will be conducted in accordance with EPA's guidance for ozone State Implementation Plan (SIP) attainment demonstration modeling.

1.2.1 EPA Guidance for Ozone Attainment Demonstration Modeling Protocols

A comprehensive Modeling Protocol for an 8-hour ozone SIP attainment demonstration study consists of many elements. Its main function is to serve as a roadmap for planning and communicating how a modeled attainment demonstration will be performed before it occurs. The protocol guides the technical details of a modeling study and provides a formal framework within which the scientific assumptions, operational details, commitments and expectations of the various participants can be set forth explicitly.

On November 28, 2018 EPA released a final 8-hour ozone modeling guidance (EPA, 2018d) that replaces the previous final guidance (EPA, 2007) and draft guidance (EPA, 2014d). The EPA 2018 ozone modeling guidance is similar to the draft 2014 guidance with updates (e.g., slight modification to the recommended ozone DV projection approach). As stated in EPA's latest modeling guidance (EPA, 2018d, pp. 15):

> "The most important function of the modeling protocol is to serve as a blueprint for planning how the modeled demonstration will be performed. The protocol should be a valuable communication device by which air agencies, EPA, and other stakeholders can assess the applicability of default recommendations and develop area-specific alternatives, where needed, prior to conducting the work to build the modeling system. A suitable protocol should lead to extensive participation by stakeholders in developing the demonstration. It should also reduce the risk of spending time and resources on efforts that are unproductive or inconsistent with EPA rules, policy, and guidance. While the modeling protocol

[3] https://www.env.nm.gov/air-quality/o3-initiative/

[4] http://views.cira.colostate.edu/wiki#WAQS-2014-Modeling-Platform

is initially developed at the beginning of a modeling exercise to foster communication, it is advisable to modify the document as needed throughout the modeling process when alterations from the original modeling plan are necessary. Again, any changes to the protocol should be fully communicated between affected air agencies, stakeholders, and the EPA."

1.2.1.1 Contents of the Modeling Protocol

EPA's 8-hour ozone SIP modeling guidance identifies specific "core elements" that should be part of any ozone SIP Modeling Protocol. These "core elements" are repeated below along with where they are addressed in this NM OAI Study Modeling Protocol (EPA, 2018d, pp. 15-16):

- Overview of the air quality issue being considered including historical background: Chapter 1 provides an overview of ozone issues in New Mexico including past and related ozone modeling studies for the region.
- List of the planned participants in the analysis and their expected roles: The principal participants in the NM OAI Study are listed in Table 1-1 at the end of Chapter 1.
- Schedule for completion of key steps in the analysis and final documentation: The current schedule is presented in Tables 1-2 and 1-3 at the end of Chapter 1.
- Description of the conceptual model for the area: The Conceptual Model of ozone formation in the NM OAI Study is provided in Section 1.4.
- Description of periods to be modeled, how they comport with the conceptual model, and why they are sufficient: Chapter 3 presents the Episode Selection and justifies the selection of the summer of 2014 modeling period for the NM OAI Study.
- Models to be used in the demonstration and why they are appropriate: Model selection and justification is presented in Chapter 2.
- Description of model inputs and their expected sources (e.g., emissions, meteorology, etc.): The source of data and description of the model inputs are given in Chapters 4, 5 and 6.
- Description and justification of the domain to be modeled (expanse and resolution): Domain selection and justification is provided in Chapter 4.
- Process for evaluating base year model performance (meteorology, emissions, and air quality) and demonstrating that the model is an appropriate tool for the intended use: The procedures for conducting the 2014 base case photochemical modeling and model performance evaluation is given in Chapter 7. Procedures for conducting the meteorological modeling and evaluation are provided in Chapter 5. Emission inputs are discussed in Chapter 6.
- Description of the future years to be modeled and how projection inputs will be prepared: Future year modeling procedures are provided in Chapter 8.
- Description of the NAAQS attainment test procedures and (if known) planned weight of evidence, and/or description of the procedures for calculating RPGs from the modeling outputs, as applicable: The ozone attainment demonstration procedures for the 2023 future years are described in Chapter 9 along with

potential additional weight of evidence (WOE) analysis to support the modeled attainment demonstration.

- Expected diagnostic or supplemental analyses needed to develop weight of evidence analyses: Potential WOE analysis are described in Chapter 9.
- Commitment to specific deliverables fully documenting the completed analysis: Deliverables to support the modeling component of the NM OAI Study are listed at the end of Chapter 9 with schedule for the deliverables listed in Tables 1-2 and 1-3.
- Quality Assurance Project Plan (QAPP): Although not part of EPA's guidance Modeling Protocol. Elements of a QAPP are contained throughout the Modeling Protocol and in each process of the PGM database development. Chapter 10 discusses the contents of a QAPP and where they can be found in this Modeling Protocol.

1.3 Related Studies

There are numerous other studies related to the NM OAI Study whose results may provide insight or provide data useful to the study that are summarized below.

1.3.1 Historic EPA and More Recent EPA-MJO-States Modeling Platforms

EPA routinely develops national PGM modeling platforms that are used to evaluate the air quality impacts of national rules, make transport assessments, such as the Cross-State Air Pollution Rule (CSAPR[5]), or other regional air quality analysis, such as the recent 2028 national regional haze modeling.[6] The national PGM modeling platforms typically coincide with the triennial National Emission Inventory (NEI[7]) years (e.g., 2008, 2011, 2014). Below we discuss the current (May 2020) status of EPA's more recent national PGM modeling platforms.

2011v6.3 Modeling Platform: The EPA 2011v6.3[8] PGM modeling platform is the result of many years of development and refinements (e.g., v6.0, v6.1 and v6.2[9]). It consists of a base year 2011 meteorological conditions and emissions and three future year emission scenarios: 2017, 2023 and 2028. It has been used in numerous EPA rulemakings (e.g., CSAPR Update). As with the other recent EPA modeling platforms, the 2011v6.3 modeling platform uses a 12-km grid resolution continental U.S. (12US2) modeling domain that is the red domain shown in Figure 1-3.

2014v7.1 Modeling Platform: The EPA 2014v7.1[10] PGM modeling platform was used in the 2014 National Air Toxics Assessment (NATA[11]) modeling. It also uses the 12-km 12US2 modeling (Figure 1-3, red domain). 2014 was a relatively low ozone year in the eastern U.S. so EPA did not pursue using the 2014 platform for national rulemakings

[5] https://www.epa.gov/csapr
[6] https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling
[7] https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei
[8] https://www.epa.gov/air-emissions-modeling/2011-version-63-platform
[9] https://www.epa.gov/air-emissions-modeling/2011-version-6-air-emissions-modeling-platforms
[10] https://www.epa.gov/air-emissions-modeling/2014-version-71-platform
[11] https://www.epa.gov/national-air-toxics-assessment

(except for the NATA) developed a 2016 modeling platform for ozone, $PM_{2.5}$ and regional haze modeling.

2015 Alpha Modeling Platform: EPA has made data available to model 2015 using data based on the 2014v7.1 platform. However, a full 2015 PGM modeling platform was never developed.

2016 Modeling Platform: The EPA, Multi-Jurisdictional Organizations (MJOs), and states conducted a collaborative national emissions modeling platform[12] (2016 EMP) to develop a 2016 emissions inventory of comparable or better quality than the NEI, with projections to 2023 and 2028. Separately, EPA developed a 2016 PGM modeling platform that used the same 12-km grid resolution continental U.S. domain used in previous EPA PGM platforms (e.g., 2011) but added an expanded 36-km grid resolution 36US3 domain as shown in Figure 1-3. EPA has released several versions of their 2016 36/12-km PGM modeling platforms as follows:

- 2016v7.1 Alpha[13] PGM platform was available in June 2019 and uses the 2016 EMP Alpha version emissions, which were based mainly on the 2014 NEIv7.1 emissions (called the 2016fd emissions scenario by EPA).
- The 2016v7.2 Beta (called 2016ff by EPA) PGM platform uses the 2016 EMP Beta version emissions[14] from the EPA/MJO/states emissions collaborative study. The original 2016v7.2 Beta PGM platform was released in March 2019 through the Intermountain West Data Warehouse (IWDW[15]). EPA made some updates to the 2016v7.2 PGM platform and used the 2016v7.2 Beta Prime (called 2016fg by EPA) modeling platform for their preliminary 2028 regional haze modeling. Details on EPA's 2016v7.2 modeling platform are contained in a Technical Support Document (TSD; EPA, 2019).
- The final EPA 2016v1[16] (called 2016fh by EPA) PGM modeling platform uses the 2016 EMP version 1 emissions[17] from the EPA/MJO/states emissions collaborative study. It was released in November 2019 with updates to Commercial Marine Vessels (CMV) occurring in February 2020 and WRAP region O&G data, and is also available on the IWDW. The 2016v1 inventory included emission projections for 2023 and 2028.

[12] http://views.cira.colostate.edu/wiki/wiki/9169
[13] https://www.epa.gov/air-emissions-modeling/2016-alpha-platform
[14] http://views.cira.colostate.edu/wiki/wiki/10197
[15] http://views.cira.colostate.edu/iwdw/
[16] https://www.epa.gov/air-emissions-modeling/2016v1-platform
[17] http://views.cira.colostate.edu/wiki/wiki/10202

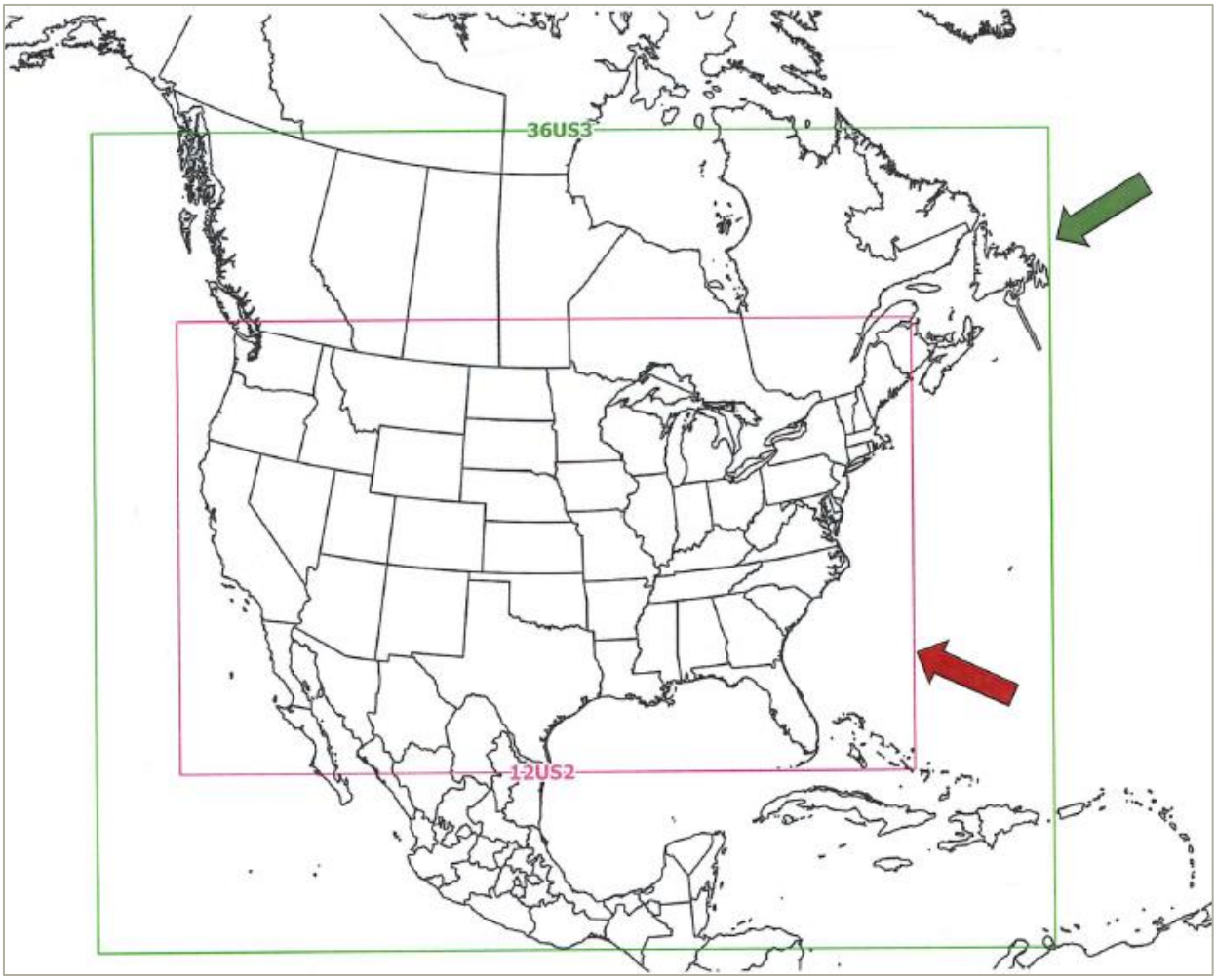


Figure 1-3. 36-km grid resolution 36US3 domain (green) and 12-km grid resolution 12US2 domain (red) used in EPA's 2016 modeling platform.

1.3.2 Denver Ozone SIP Modeling and Analysis

The Denver Metropolitan (DM) and North Front Range (NFR) ozone nonattainment area (NAA) has undergone several rounds of ozone SIPs to address attainment of a series of ozone NAAQSs.

Denver 2003 EAC SIP: The 2003 Denver Early Action Compact (EAC) SIP modeling performed 36/12/4/1.33 km photochemical modeling of the DM/NFR NAA for a summer 2002 period using the meteorological based on the MM5 model (McNally, Tesche and Morris, 2003), EPS3 emissions and CAMx photochemical grid models. The 1.33-km fine grid was ultimately not used because of little improvement in model performance over using a 4-km resolution grid at the expense of high additional computational requirements. The Denver EAC SIP developed an Ozone Action Plan[18] and

[18] http://www.colorado.gov/airquality/tech_doc_repository.aspx?action=open&file=EAC_SIP_031104-aqcc_DRAFT.pdf

demonstrated that the region would attain the 1997 ozone NAAQS by 2007 (Morris et al., 2004a,b,c,d).

Denver 2008 Ozone SIP: The 2008 Denver ozone SIP[19] modeling used the MM5 meteorological, SMOKE/CONCEPT emissions and CAMx photochemical grid models (Morris et al., 2007). The CONCEPT model was interfaced with link-based Vehicle Miles Traveled (VMT) and other mobile source activity data (e.g., speeds, fleet mix, temporal variations, etc.) from a Traffic Demand Model (TDM) operated by DRCOG, on-road emission factors from the MOBILE6 model and hourly meteorological data from MM5 to generate detailed on-road mobile source emissions for the DMA. Other emission inputs were generated using SMOKE. The MM5/SMOKE/CONCEPT/CAMx modeling system was applied to the June-July 2006 period and used to demonstrate that the DMA/NFR region would attain the 1997 8-hour ozone NAAQS by 2010 (Morris et al., 2008a,b,c; 2009a,b).

The 2008 ozone SIP 2006 modeling platform was also used to investigate improvements to the modeling system (Morris et al., 2011) and evaluate the VOC/NOx emissions inventory that suggested 2006 oil and gas emissions in Weld County were understated (Morris, Tai and Sturtz, 2011).

Denver 2016 Ozone SIP: The 2016 Denver ozone SIP[20] modeling addressed the 2017 attainment of the DM/NFR Moderate NAA under the 2008 ozone NAAQS (RAQC and CDPHE, 2016). The 2016 ozone SIP used a 2011 36/12/4-km modeling platform based on the WRAP/WAQS modeling platform available on the IWDW and adding a 4-km domain focused on Colorado (Ramboll and Alpine, 2015; 2016a,b; 2017).

The 2016 Denver ozone SIP 2011 36/12/4-km modeling platform was used to conduct additional future-year sensitivity modeling and other analysis in anticipation of the requirements needed to attain the 2015 ozone NAAQS. These results were presented at a November 2, 2017 Modeling Forum[21] and included the following:

- 2017 local source contributions to ozone concentrations in the DM/NFR NAA;
- Contributions of international anthropogenic emissions to 2011 ozone concentrations in the DM/NFR NAA; and
- Preliminary 2023 ozone projections and sensitivity to VOC/NOx anthropogenic emissions reductions.

Current Denver Ozone SIP 2020 and 2023 Attainment Demonstration Modeling: Current Denver ozone SIP efforts are using a 2016 36/12/4-km CAMx modeling platform based in part on EPA's 2016v1 modeling platform with new WRF meteorological modeling and a 4-km domain covering Colorado added. The new Denver 2016 36/12/4-km CAMx platform will be used to demonstrated attainment in 2020 to address the area as a

[19] https://www.colorado.gov/airquality/documents/deno308/

[20] https://raqc.org/sip/moderate-area-2008-8-hour-ozone-standard-state-implementation-plan/

[21] https://raqc.org/reports/?titlePost=Modeling+Forum

Serious NAA under the 2008 ozone NAAQS and in 2023 to address the area as a Moderate NAA under the 2015 ozone NAAQS.

1.3.3 West-wide Jumpstart Air Quality Modeling Study

The Western Regional Air Partnership (WRAP) initiated a new round of regional ozone, particulate matter, visibility and deposition modeling for the western U.S. starting with the West-wide Jumpstart Air Quality Modeling Study (WestJumpAQMS[22]; ENVIRON, 2013). WestJumpAQMS performed 36/12/4-km modeling for the 2008 calendar year with the 12-km domain focused on the western U.S., and the 4-km domain focused on the states of CO, NM, UT and WY (ENVIRON and Alpine, 2012). The WestJumpAQMS was completed in September 2013 and calculated, among other things, the contributions of transport to ozone in the Denver area and contributions of emissions from Colorado (including Denver) to downwind ozone and $PM_{2.5}$ concentrations (ENVIRON, Alpine and UNC, 2013). The 2008 base year from the WestJumpAQMS platform was used in the development of the 3-State Data Warehouse and Air Quality Study, the predecessor to the Intermountain West Data Warehouse and Western Air Quality Study, described next.

1.3.4 Intermountain West Data Warehouse and Western Air Quality Study

The WRAP Intermountain West Data Warehouse (IWDW[23]) was developed to be a repository and source of ambient air quality and modeling data that can be used by the western states. The Western Air Quality Study (WAQS) developed 2011 PGM modeling platforms to assess air quality, visibility and deposition in the western states and was used to populate the IWDW. The WAQS started by enhancing the WestJumpAQMS 2008 WRF/SMOKE/CAMx/CMAQ 36/12 km database and making it available through the IWDW. WAQS then developed new 2011 WRF/SMOKE/CAMx/CMAQ modeling platforms (Adelman, Shankar, Yang and Morris, 2014; 2016; Adelman and Baek, 2015) that was also made available through the IWDW. IWDW is not only a source of modeling data, but also includes data analysis and visualization tools and is a repository of data from other modeling studies.

1.3.5 Southern New Mexico Ozone Study (SNMOS)

The Southern New Mexico Ozone Study (SNMOS[24]) conducted WRF meteorological, SMOKE emissions and CAMx ozone modeling for a 2011 base and 2025 future year using a 12/4-km modeling domain, as shown in the right panel of Figure 1-4. SNMOS found that a vast majority of ozone in Southwestern New Mexico is due to ozone transport from outside of New Mexico. For example, Figure 1-4 (left panel) displays the 2011 and 2025 ozone contributions to the ozone Design Value (DV) at the Desert View monitoring site in Dona Ana County by geographic regions within the 12/4-km PGM modeling domain also shown in Figure 1-4. Only 3 percent of the 2011 ozone DV at Desert View is due to anthropogenic emissions from New Mexico, and New Mexico

[22] http://www.wrapair2.org/pdf/WestJumpAQMS_FinRpt_Finalv2.pdf

[23] http://views.cira.colostate.edu/iwdw/

[24] https://www.wrapair2.org/SNMOS.aspx

emissions contribute less than 2 percent of the projected 2025 ozone DV at Desert View.

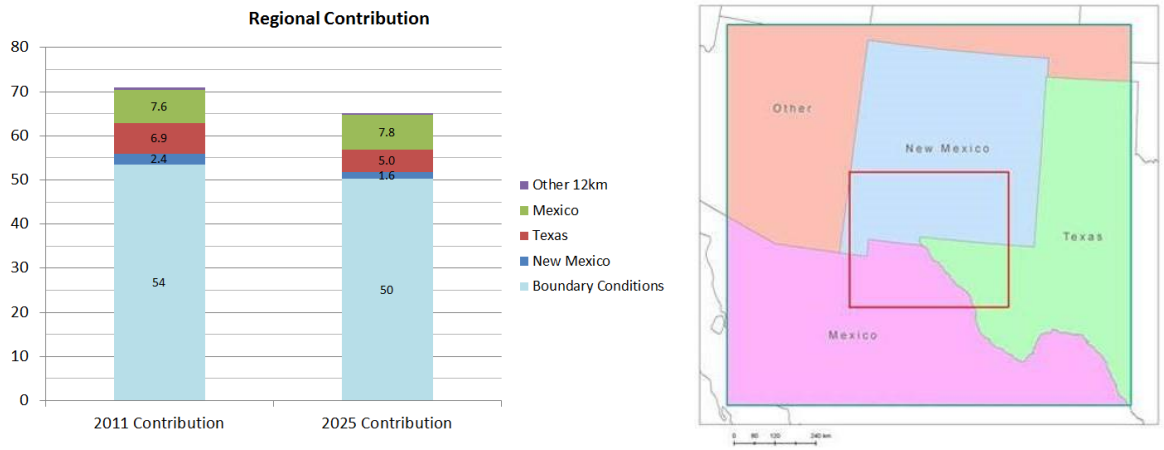


Figure 1-4. Contributions of geographic regions (including Boundary Conditions) to the 2011 and 2025 ozone Design Values at Desert View monitoring site in Dona Ana County in Southwestern New Mexico.

The SNMOS 2011 and 2025 ozone source apportionment modeling also obtained contributions by Source Sector in addition to the four Source Regions depicted in the left panel of Figure 1-4. Figure 1-5 displays the Source Sector contributions to the 2011 and 2025 ozone DV at Desert View monitor as well as the 10 highest Source Groups (i.e., Source Sector emissions from Source Regions) contributions. On-road mobile sources has the highest contribution to ozone DVs in both 2011 and 2025 (Figure 1-5, top panel), but that is mainly due to on-road mobile source emissions in Texas and Mexico that are the two highest contributing Source Groups (Figure 1-5, bottom panel).

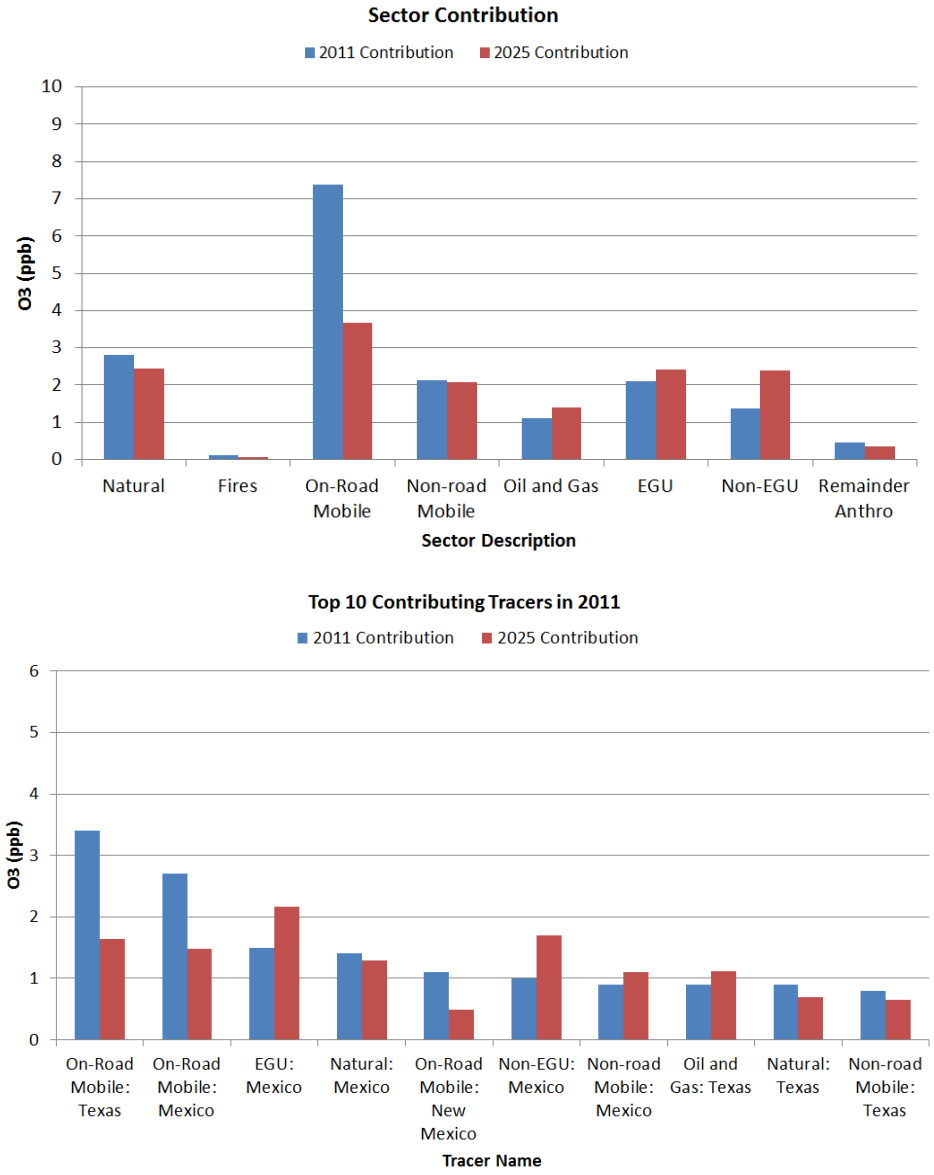


Figure 1-5. Contributions of Source Sector emissions within the 12/4-km modeling domain to the 2011 and 2025 ozone Design Value at Desert View monitoring site (top) and top ten Source Group contributions (bottom).

Figure 1-6 examines the contributions of emissions from New Mexico to 2011 and 2025 ozone DVs at nine monitoring sites in Southeast New Mexico. With one exception, on-road mobile source emissions are the largest contributing Source Sector in New Mexico to 2011 ozone DVs in southeastern New Mexico with the contribution at the Solano monitoring site being higher than the others. The one exception is the Carlsbad monitoring site in Eddy County where O&G emissions is the largest contributing Source Sector in New Mexico due to its close proximity to the Permian Basin. Although on-road mobile source emissions are the largest contributor in 2011, it is also the Source

Sector whose New Mexico ozone contribution is reduced the most in 2025, by over a factor of two. This is in contrast to O&G whose contribution at the Carlsbad monitoring site is projected to increase between 2011 and 2025, although future year projections of O&G emissions are highly uncertain. In any event, by 2025 the SNMOS estimate that on-road mobile, non-road mobile and O&G Source Sectors in New Mexico will contribute the most, with New Mexico EGU and non-EGU point sources and other anthropogenic emission Source Sectors having relatively lower ozone contributions.

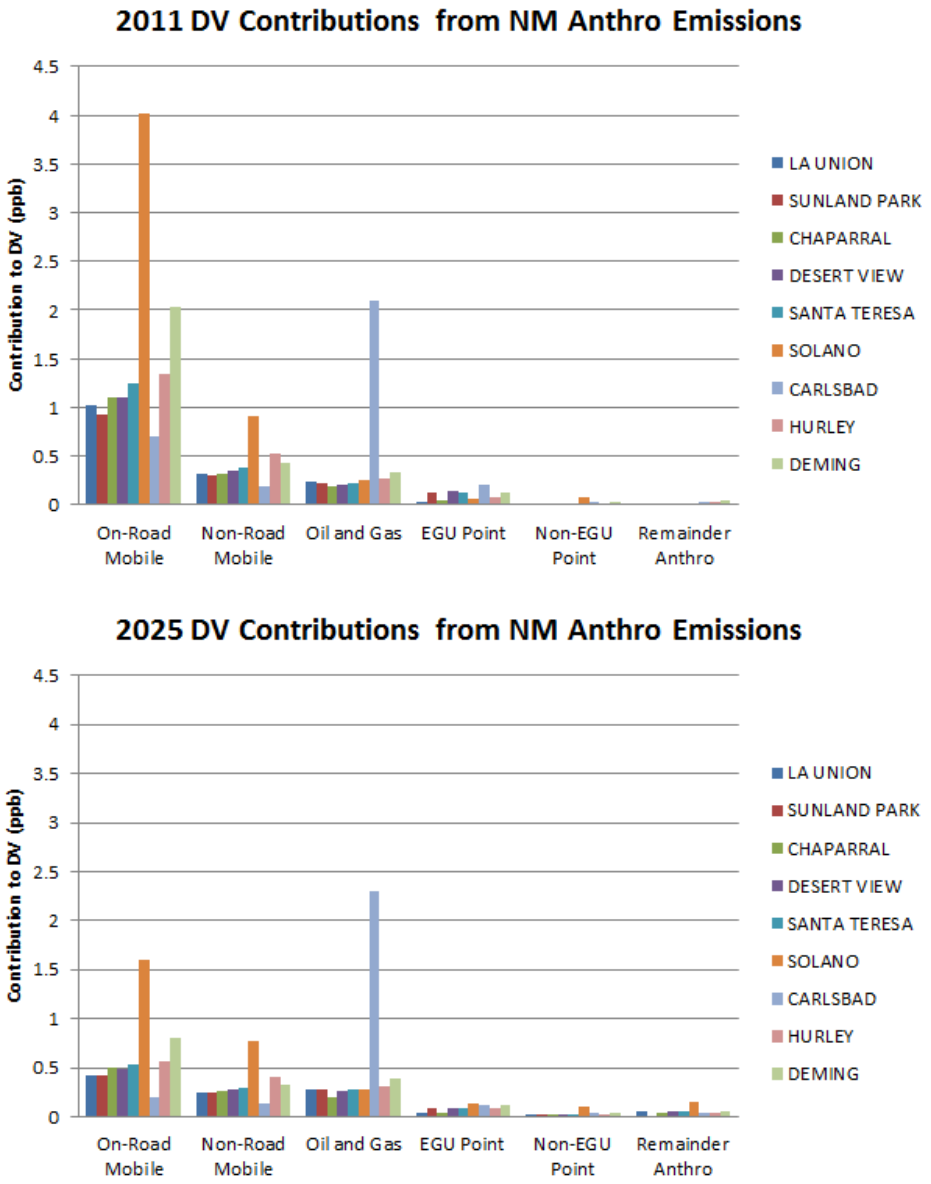


Figure 1-6. Contributions of major Source Sectors in New Mexico to 2011 (top) and 2025 (bottom) ozone DVs at nine monitoring sites in Southwestern New Mexico.

1.3.6 City of Albuquerque Ozone Modeling Study

The City of Albuquerque conducted an ozone modeling study[25] for two episodes in 2017: June 12-16, 2017 and July 3-14, 2017. The purpose of the study was to better understand the source of high ozone concentrations in Bernalillo County and what types of control strategies, if needed, would be most effective at reducing ozone concentrations in the County.

Figure 1-7 displays the maximum ozone DVs in Albuquerque from 2013 to 2018 and their relationship with the 80, 75 and 70 ppb ozone NAAQS. 2016 is a low point in the ozone DV trend (~65 ppb) followed by increases so by 2018 the maximum Bernalillo County ozone DV is at the 2015 ozone NAAQS.

The City of Albuquerque Ozone Modeling Study conducted WRF meteorological and SMOKE emissions modeling using a 12/4-km CAMx ozone modeling database, with the 4-km domain covering New Mexico and the 12-km domain covering the western states (Figure 1-7, right panel).

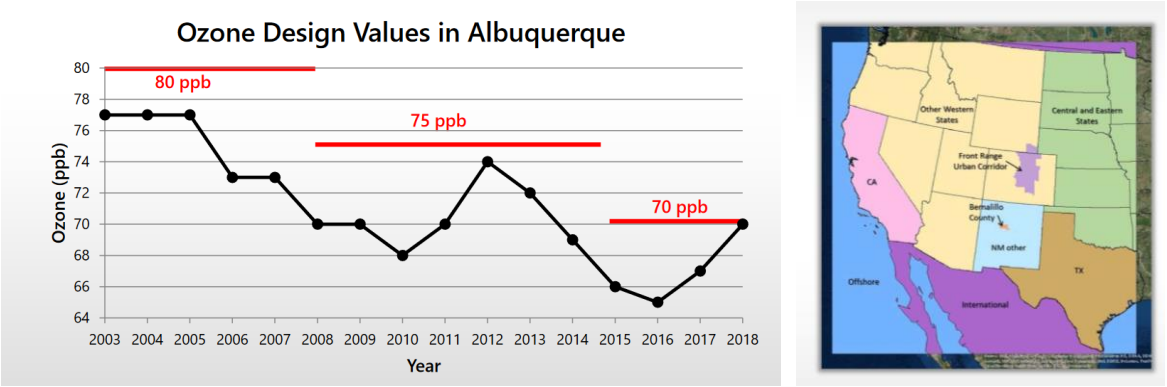


Figure 1-7. Trends in maximum ozone Design Values in Albuquerque from 2013 to 2018 (left) and 12-km modeling domain and source apportionment geographic regions (right).

Ozone source apportionment was performed to determine the geographic regions (Figure 1-7, right) that contributed to elevated ozone concentrations in Albuquerque. Figure 1-8 displays the contributions to ozone concentrations in Albuquerque for the June and July episodes. Anthropogenic emissions from New Mexico contributed 14% and 24% to ozone in Albuquerque during the, respectively, June and July 2017 episodes. And anthropogenic emissions from Bernalillo County accounted for up to 75% of the New Mexico contribution.

[25] https://www.cabq.gov/airquality/documents/06-ken-craig-sonoma-technology-inc-ozone-modeling-presentation-10-17-2018-aqcb-meeting.pdf

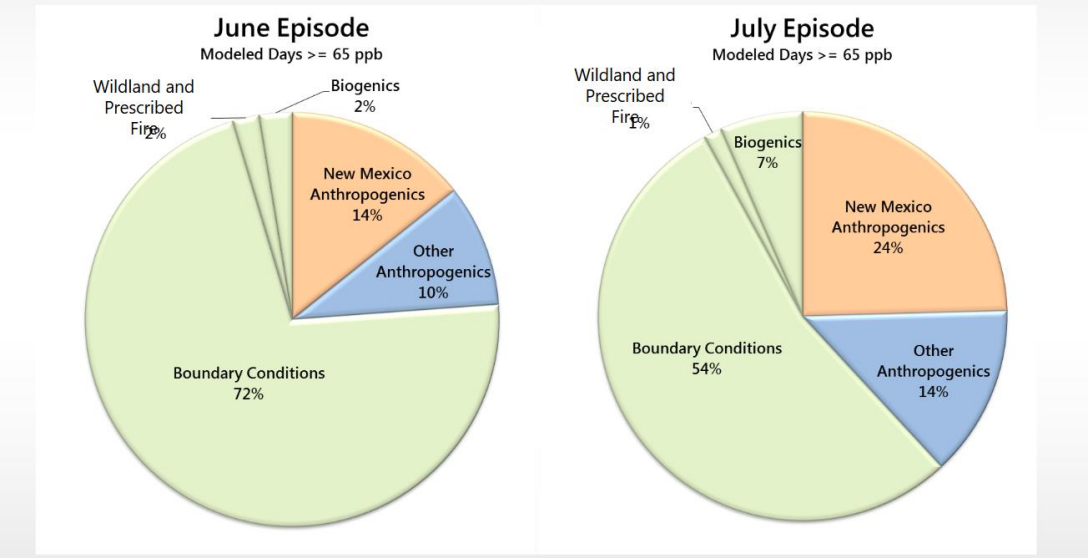


Figure 1-8. Contributions to ozone in Albuquerque during the June and July 2017 modeling episodes.

Although only two short episodes were modeled, so any conclusions are limited to those conditions, the City of Albuquerque Ozone Modeling Study concluded as follows:

- Transport from outside of New Mexico is always important and accounts for over half of the ozone in Albuquerque.
- Local emissions in Albuquerque and Bernalillo County are also important with half of the locally generated ozone due to on-road mobile sources in 2017.
- On high ozone days for the two modeled episodes, contributions from major power plants in northern New Mexico were small at sites in Albuquerque.
- Impacts from man-made emissions in western states, including California, are non-negligible.
- Ozone contributions from wildfire smoke were important for both episodes.
- As on-road mobile source emissions are reduced, emissions from non-road and non-mobile sources are becoming increasingly important. NOx emission controls are more effective at reducing high ozone concentrations in Albuquerque than VOC controls.
- Ozone in Albuquerque is sensitive to emissions from O&G sources throughout New Mexico.

1.3.7 Relationship Between Meteorology and Ozone in the Intermountain West Region

Reddy and Pfister (2016) and CDPHE and RAQC (2016c) analyzed meteorological factors that contributed to the interannual variability in midsummer ozone concentrations focusing mainly on Utah and Colorado. They analyzed ozone and

meteorology for July during 1995-2013 and found several meteorological variables that were able to explain the years with higher ozone formation conditions. The most powerful meteorological variable for describing high ozone formation potential conditions (i.e. ozone conducive conditions) was the height of the 500 hPa[26] pressure level. The current Denver ozone SIP modeling study extended the analysis of meteorology conducive to ozone formation and observed ozone trends analysis of Reddy and Pfister (2016) and CDPHE and RAQC (2016c) to include the most recent years (through 2018) and for summer-average conditions. Figure 1-9 shows the relationship between summer-average 500 hPa heights and summer-average ozone at the Rocky Flats North (RFNO) monitoring site northwest of downtown Denver and the years 1995-2018, results for the other sites are similar.

Figure 1-10 displays the correlation between elevated ozone concentrations and 500 hPa heights in the western U.S. and some of the sites in New Mexico are also weakly to moderately correlated to the 500 hPa heights like the sites in Denver and Utah. Elevated ozone at sites in northwestern New Mexico show less correlation with 500 hPa heights as it is believed that the large point source NOx and oil and gas NOx and VOC emissions in the region swamp the signal.

[26] hPa is100 Pa where Pa is short for Pascal that is a unit of pressure where 500 hPa = 500 mb.

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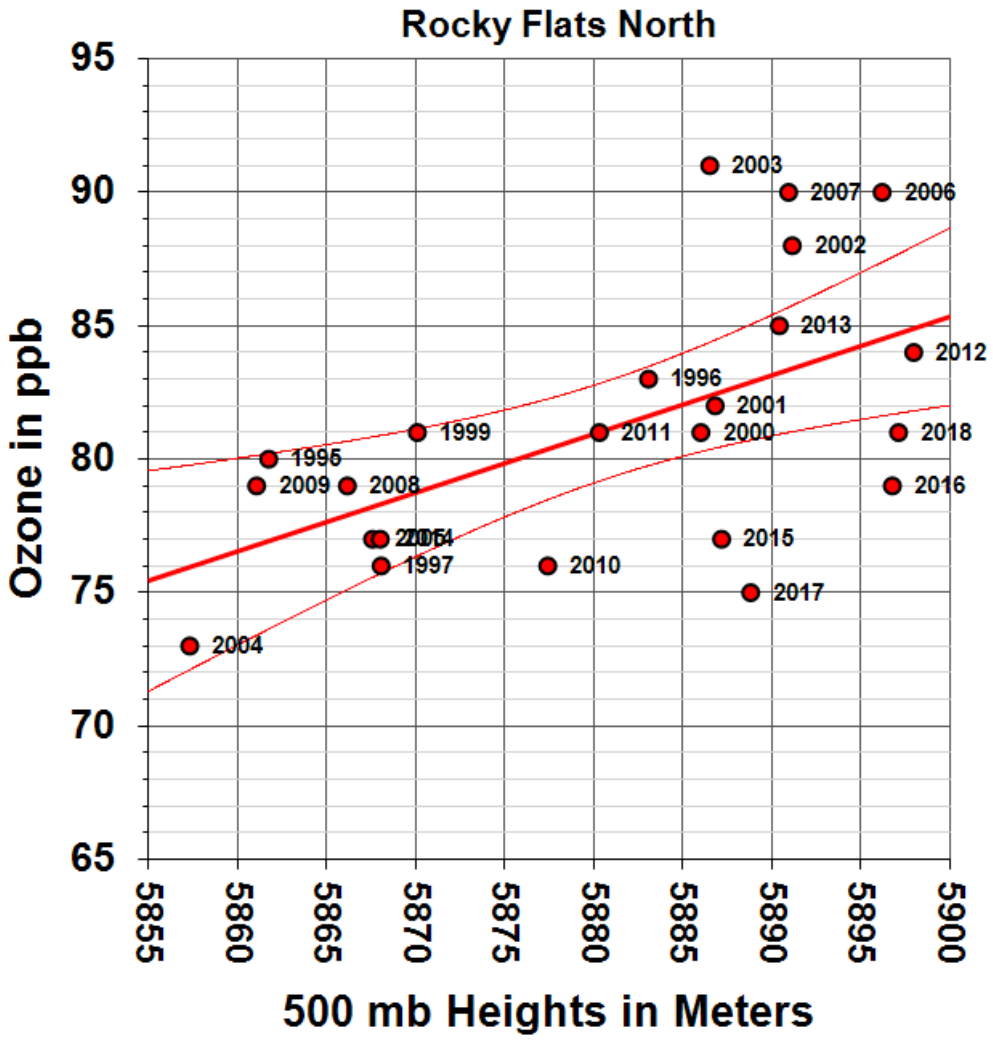


Figure 1-9. Linear regression of the annual 4th highest MDA8 ozone concentrations and mean July through August NCEP/NCAR Reanalysis 500 hPa (or 500 mb) heights for the DM/NFR NAA region at the Rocky Flats North (RFNO) monitoring site for the years 1995 to 2018.

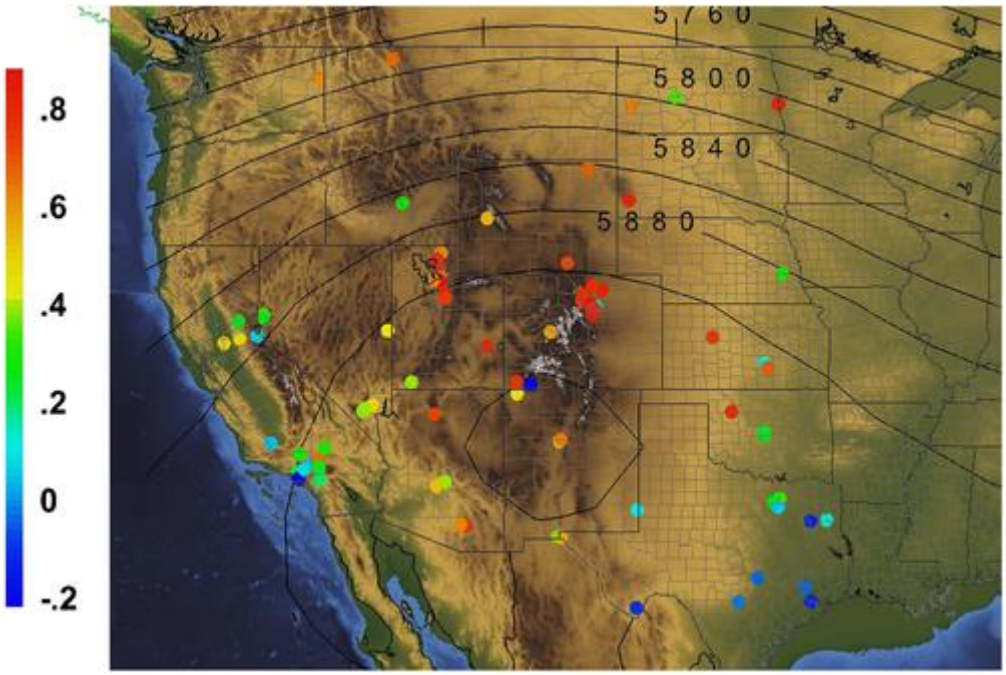


Figure 1-10. Correlation between 500 hPa heights and elevated ozone concentrations for monitoring sites in the western U.S.[27]

1.3.8 The Four Corners Air Quality Task Force

The Four Corners Air Quality Task Force (FCAQTF) was convened by the states of New Mexico and Colorado in 2005 and comprised of over 100 members and over 150 of interested parties. Its goals were to address air quality issues in the Four Corners region and consider mitigation options to reduce air pollution and acid deposition and improve visibility in the region. They found that transport from outside of the region was the largest contributor to ozone concentrations. Several large power plants and O&G production in the San Juan Basin, as well as mobile sources, also contributed to ozone in the region. The FCAQTF was completed in November 2007 with the release of a report[28] that contained over 100 potential mitigation measures for reducing emissions in the Four Corners region. The FCAQTF has been replaced by the Four Corners Air Quality Group (FCAQG[29]).

1.3.9 Other Studies

There are numerous other studies that may also be relevant to the NM OAI Study.

- Summary of State Regulations Applicable to Oil and Gas Sources in the WESTAR-WRAP Region (PDF) and companion spreadsheet (XLS)
- Final Work Products - Low and High Emissions Scenarios

[27] https://agupubs.onlinelibrary.wiley.com/cms/asset/192a6975-cd1c-4bce-a20a-a2a049ca4df6/jgrd52767-fig-0001-m.png
[28] https://www.env.nm.gov/wp-content/uploads/sites/2/2016/11/4CAQTF_Report_FINAL.pdf
[29] https://www.env.nm.gov/air-quality/fcaqg/

I. WESTAR-WRAP region Future Year Oil and Gas Emission Inventories for Two Additional Scenarios: Declined Vertical Wells and Increased Horizontal Wells Memorandum
II. Future Year Lower Scenario Inventory Spreadsheet
III. Future Year Higher Scenario Inventory Spreadsheet

- OGWG Projected Emissions from Baseline Year Emissions Inventory – October 11, 2019
  I. Final Report (revised version of March 5, 2020) and Inventory Spreadsheet for the "Continuation of Historical Trends" projection inventory. These data will be used in modeling and control analyses for Regional Haze planning.
  II. State of Colorado projections methodology (PDF) (January 2, 2020, data are included in Final Report and Inventory Spreadsheet above).
- OGWG Baseline Year Alaska and Intermountain Region Emissions Inventory revised final deliverables – Sept. 2019
  I. The Revised Final Report and Inventory Spreadsheet were completed in mid-Sept. and posted on Sept. 23, 2019. These files completely replace the previously posted July 2019 report and spreadsheet, while the gas profile information posted in July is unchanged. The July report and spreadsheet files have been removed to avoid confusion. The Revised Final Report includes updates from the July postings to include the: 1) Colorado O&G emissions based on new inventories provided by Colorado Department of Public Health and Environment and Southern Ute Indian Tribe and 2) Williston Basin casinghead gas emission inventory to correct emissions that were biased low based on EPA O&G Tool inputs.
- OGWG Emissions Survey for State Air Agencies and O&G Operators
  I. Complete survey (January 2019)
  II. Fleet turnover and controls-focused survey (January 2019)

San Juan & Permian Basins' O&G 2014 Emission Inventory Project

The National Park Service (NPS) has conducted studies of visibility impairment and nitrogen/sulfur deposition at National Parks throughout the U.S. For example, the Rocky Mountain Atmospheric Nitrogen and Sulfur Study (ROMANS) studied nitrogen deposition and potential mitigation scenarios at Rocky Mountains National Park (RMNP). RMNP studies have included data collection, data analysis, modeling and the development of a nitrogen deposition reduction plan. Details on these activities can be found at:

https://www.colorado.gov/pacific/cdphe/rocky-mountain-national-park-initiative

http://www.nature.nps.gov/air/studies/romans.cfm

The Bureau of Land Management (BLM) has conducted several iterations of the Colorado Air Resource Management Modeling Study (CARMMS) using a CAMx 4-km modeling database with a 4-km grid resolution domain covering Colorado and northwest New Mexico. Future year source apportionment modeling was conducted to assess the ozone, $PM_{2.5}$, visibility and sulfur and nitrogen deposition impacts at Class I

and sensitive Class II Area due to oil and gas and mining development on Federal lands in Colorado and northern New Mexico.

https://www.blm.gov/sites/blm.gov/files/documents/files/program_natural%20resources_soil%20air%20water_airco_quicklins_CARMMS2.0.pdf

1.4 New Mexico Conceptual Models for High Ozone Concentrations

There are three interrelated but distinct Conceptual Models of ozone formation within New Mexico: southeastern New Mexico, Albuquerque and surrounding areas, and northwestern New Mexico. They share the attribute that ozone transport dominates ozone concentrations on all days. Days with the highest local ozone formation are typically hot summer days with slow winds and without an excessive amount of precipitation (summer monsoon).

1.4.1 Southeastern New Mexico

Ozone at monitoring sites in southeastern New Mexico, including Dona Ana, Eddy and Lea Counties, is dominated by ozone transport from outside of New Mexico. This transport includes long-range transport from the remainder of U.S. and global sources (e.g., Asia) as well as medium-range transport from Texas and Mexico. Current year on-road mobile source emissions tend to be the largest contributing Source Sector within southwestern New Mexico and nearby areas, with non-road mobile and O&G sources also contributing. With the exception of emissions from Mexico, the contributions of Electrical Generating Units (EGU) and other large industrial point sources tends to be smaller than the other Source Sectors.

The SNMOS discussed in Section 1.3.5 provides more details on the sources that contribute to elevated ozone concentrations in southeastern New Mexico. It found only 3% of the 2011 ozone Design Value was due to emissions from New Mexico. Emissions from nearby areas in Mexico and Texas contribute the most after long-range transport of ozone.

1.4.2 City of Albuquerque

Ozone transport also dominates elevated ozone concentrations in and near the City of Albuquerque. The Albuquerque modeling study discussed in Section 1.3.6 provides details on source contributions, but sources within New Mexico contributed a large fraction (e.g., 14% and 24%) to elevated ozone in Albuquerque with emissions from Albuquerque contributing up to 75% of the New Mexico contribution. Emissions from on-road and non-road mobile and state-wide O&G also have substantial contributions.

1.4.3 Northwest New Mexico

Although ozone transport dominates ozone in the New Mexico Four Corners region, there are significant contributions due to local power plants and O&G production in the San Juan Basin. The FCAQTF identified numerous local control measures that could mitigate elevated ozone concentrations in the region (see Section 1.3.7).

1.5 Overview of the Modeling Approach

The NM OAI Study will conduct photochemical modeling for a 2014 base and 2023 future year and perform 2023 ozone source apportionment and control strategy sensitivity modeling.

1.5.1 Episode Selection

The May-August 2014 modeling period was selected as it has a high quality emissions inventory with western state updates and has a PGM platform already developed from the WRAP/WAQS regional haze modeling (see Chapter 3 for more details).

1.5.2 Model Selection

Details on the rationale for model selection are provided in Chapter 2. The Weather Research Forecast (WRF) prognostic meteorological model was selected with the 4-km grid covering New Mexico. Emissions modeling will be performed using the Sparse Matric Operator Kernel Emissions (SMOKE) model for most source categories. The Model of Emissions of Gases and Aerosols from Nature (MEGAN) will be used for biogenic emissions and there are special processors for fires, windblown dust (WBD), lightning NOx (LNOx) and oceanic sea salt (NaCl) and Dimethyl Sulfide (DMS) emissions. The 2014 version of the MOtor Vehicle Emissions Simulator (MOVES2014b) on-road mobile source emissions model will be used with SMOKE-MOVES and WRF meteorological data to generate on-road mobile source emissions for the 4-km New Mexico and 12-km western U.S. modeling domains.

The Comprehensive Air-quality Model (CAMx) photochemical grid model (PGM) will be used because it supports two-way grid nesting, includes a subgrid-scale Plume-in-Grid module, contains a well-vetted ozone source apportionment tool and has a rich and successful history of application to the region.

1.5.3 Domain Selection

The same 36-km 36US and 12-km 12WUS2 modeling domains as used in the WRAP/WAQS 2014 modeling will be used in the NM OAI Study modeling. A higher resolution 4-km domain will be added covering New Mexico and adjacent areas. New 2014 36/12/4-km WRF meteorological modeling will be conducted to provide the higher resolution meteorological fields needed for the 4-km New Mexico domain. Details on the domain definition are presented in Chapter 4.

1.5.4 Base and Future Year Emissions Data

The 2014 base year emissions data will be based on the WRAP/WAQS 2014v2 emissions that was in turn based on the 2014NEIv2 with updates from western states. New emissions will be generated for natural emission sources (e.g., biogenic and LNOx) as needed. 2023 future year emissions will be mostly based on the EPA 2016v1 emissions (2023fh inventories). 2023 mobile source emissions will be created using SMOKE-MOVES modeling with 2023 MOVES emission factor look-up table and 2014 WRF meteorology. 2023 O&G emissions for the WRAP states will be based on the WRAP 2023 O&G emissions. The 2014 and 2023 emissions for New Mexico will be reviewed by NMED and updated as needed.

1.5.5 Emissions Input Preparation and QA/QC

Quality assurance (QA) and quality control (QC) of the emissions datasets are some of the most critical steps in performing air quality modeling studies. Because emissions processing is tedious, time consuming and involves complex manipulation of many different types of large databases, rigorous QA measures are a necessity to prevent errors in emissions processing from occurring. The NM OAI Study modeling study will perform a multistep emissions QA/QC approach as developed for the WRAP 2002 modeling (Adelman, 2004) and following the procedures in EPA's latest ozone modeling guidance (EPA, 2018a, pp. 60) and Section 2.20 of the SMOKE User's Manuel (UNC, 2018, pp. 94). This includes the initial emissions QA/QC by the NMED of their emissions for New Mexico as well as QA/QC by the WESTAR/Ramboll team.

1.5.6 Meteorology Input Preparation and QA/QC

The CAMx 2014 36/12/4-km meteorological inputs will be based on a new 2014 WRF meteorological modeling conducted by the Ramboll. The new WRF 2014 36/12/4-km modeling will be evaluated against measured meteorological parameters in a model performance evaluation. The 2014 36/12/4-km WRF output will be processed by WRFCAMx processors to generate meteorological inputs for CAMx. Details on the NM OAI Study 2014 36/12/4-km WRF modeling are provided in Chapter 5.

1.5.7 Initial and Boundary Conditions Development

Initial concentrations (IC) and Boundary Conditions (BCs) are important inputs to PGMs. We intend to run approximately the first two-weeks of May on the 36/12/4-km domains to spin-up the model before the first high ozone day in New Mexico (68 ppb on May 17). This will "wash out" the influence of the ICs before elevated ozone concentrations occur in New Mexico.

BCs for the 36-km 36US domain will be based on a 2014 simulation of the GEOS-Chem global chemistry model conducted by WRAP processed by the GC2CAMx converter. The result is day-specific diurnally varying BCs for the lateral boundaries around the 36-km 36US modeling domain (i.e., GCBC). The top BC (TopCon) will be based on a zero-gradient assumption where concentrations above the top of the model (at 50 mb, or ~19-km above sea level) are assumed to be the same as in the top vertical layer of the model.

1.5.8 Air Quality Modeling Input Preparation and QA/QC

Each step of the air quality modeling will be subjected to QA/QC procedures. These procedures include verification of model configurations, confirmation that the correct data were used and were processed correctly and other procedures. Visualization of model inputs are a critical component of the QA/QC process.

1.5.9 Model Performance Evaluation

The Model Performance Evaluation (MPE) will follow EPA's MPE recommendations in their ozone modeling guidance (EPA, 2007; 2014d; 2018a) and other sources (e.g., Simon, Baker and Phillips, 2012; Emery et al., 2016) and use many elements in EPA Region 8's MPE checklist (EPA, 2015a). The CAMx 2014 36/12/4-km base case

simulation will focus on ozone and precursor model performance within the 4-km New Mexico domain. Details on the MPE are provided in Chapter 7.

1.5.10 Diagnostic Sensitivity Analyses

Depending on the results of the CAMx 2014 base case modeling and MPE, diagnostic sensitivity tests may be conducted to try and improve model performance. The definition of these diagnostic sensitivity tests will depend on the results of the initial MPE. The WRAP/WAQS development of the CAMx 2014 36/12-km modeling database conducted numerous sensitivity tests[30] leading to the final 2014v2 base case.

Under the NM OAI Study we expect most of the sensitivity tests to be conducted for the 2023 future-year where both emissions control strategy sensitivity and ozone source apportionment modeling is planned.

1.5.11 Future Year Control Strategy Modeling

Future year modeling for ozone will be performed for the 2023 future year. A CAMx 2023 36/12/4-km base case simulation will be conducted and projected 2023 ozone DVs calculated. The procedures to calculate projected 2023 ozone DVs will follow EPA's latest guidance (EPA, 2018d). These procedures use the modeling results in a relative fashion to scale the current year observed 8-hour ozone Design Values (DVCs) to project future year ozone Design Values (DVFs). The scaling factors are called Relative Response Factors (RRFs) and are the ratio of the future-year to current-year modeling results for the 10 highest base year modeled MDA8 ozone days near the monitoring site. EPA has developed the Speciated Modeled Attainment Test (SMAT[31]) tool that includes the recommended procedures in the latest EPA guidance for projecting ozone DVFs.

2023 future year control strategy sensitivity modeling will be performed. The future year controls will be defined by the NMED.

1.5.12 Future Year Source Apportionment Modeling

2023 future year ozone source apportionment modeling will be conducted using the CAMx Anthropogenic Precursor Culpability Assessment (APCA) ozone source apportionment tool. The WRAP 2014 GEOS-Chem global chemistry base case, ZROW and NAT simulation will be processed to isolate the contributions of U.S. anthropogenic, International anthropogenic and natural sources to the BCs. Within New Mexico, contributions will be obtained for the major Source Sectors. A NM OAI Study 2023 ozone source apportionment plan will be developed and discussed with NMED.

1.6 Project Participants and Contacts

The NMED is leading the NM OAI Study that is being carried out by the contracting team of WESTAR and Ramboll. Key participants in the NM OAI Study and their contact information are provided in Table 1-1.

[30] http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx
[31] https://www.epa.gov/scram/photochemical-modeling-tools

NMED Exhibit 15

Table 1-1. Key participants and contact information for the NM OAI Study.

Organization	Individual(s) [Roll]	Address	Contact Information
New Mexico Environmental Division (NMED) Air Quality Bureau (AQB)			
NMED	Kerwin Singleton	Planning Section Chief NMED/AQB 525 Camino de los Marquez, Suite 1 Santa Fe, NM 87505	Bus: (505) 476-4350 Cell: (505) 669-3371 kerwin.singleton@state.nm.us
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1.7 Communication

Frequent communication between the NMED and the WESTAR and Ramboll modeling team and other potentially participants is anticipated. These communications will include e-mails, conference calls and potentially face-to-face meetings.

1.8 Schedule

The task structure and schedule for the NM OAI Study key deliverables are shown in Table 1-2. The study will be continuously documented with PowerPoint presentations and other documents that will be presented to the NMED each month in a webinar whose current schedule and topics are shown in Table 1-3. After each webinar, and with approval of the NMED, the presentations will be posted to a NM OAI Study webpage that will be hosted on the WRAP website. There are two formal reports for the study: (1) a 2014 base case modeling and model performance evaluation report prepared under Task 5, with a draft report currently scheduled for delivery in September 2020; and (2) an Air Quality Technical Support Document (AQTSD) that documents the entire study including the 2023 modeling prepared under Task 7, with a draft report currently scheduled for delivery in November 2020..

Table 1-2. Current schedule for NM OAI Study.

Task	Deliverable	Date
1. Formal Modeling Protocol/QAPP and Work Plan		
	Kick-Off Conference Call	Apr 2020
	Draft Modeling Protocol/QAPP and Work Plan	May 2020
	Webinar PPT on final approach and project plan	May 2020
	Final Modeling Protocol/QAPP and Work Plan	May2020
	Response-to-Comments (RTC) Document	May 2020
2. Base Year Meteorological Modeling (Met)		
2.1 Evaluate Met Modeling	*Webinar PPT on WAQS 12-km WRF MPE and WAQS 12-km PGM ozone performance in New Mexico*	May 2020
2.2 Additional Met Modeling	*Webinar PPT on WRF 4-km MPE in New Mexico and Comparison with WAQS 12-km WRF*	Jun 2020
2.3 Process Met Data	PGM summer 2014 36/12/4-km meteorological inputs	Jun 2020
3. Boundary Conditions (BC)		
3.1 Evaluate BC Data	*Webinar PPT on WRAP/WAQS 2014 GEOS-Chem BCs and latest updates to GEOS-Chem*	Jun 2020
4. Base Year (2014) and Future Year (2023) Emissions		
4.1 & 4.3. 2014 and 2023 Emissions for 4-km New Mexico Domain	*Webinar PPT on recommended sources for 2014 and 2023 emissions in the 4-km New Mexico domain*	May 2020

Task	Deliverable	Date
	Webinar PPT and tile plots/excel spreadsheets for selected 2014 and 2023 emissions for sources in the 4-km NM domain	Jun 2020
4.2 Mobile Sources		
4.2.1 Evaluate Mobile Emissions	*Webinar PPT on options for 2014 & 2023 mobile source emission inputs and advantages/disadvantages*	Jun 2020
	Webinar PPT on final 2014 & 2023 selected mobile source emissions options	Jun 2020
4.2.3 Prepare Mobile Source Emission Inputs	*Webinar PPT on SMOKE-MOVES modeling to generate 2014 and 2023 mobile source emission inputs for 4-km NM domain*	Aug 2020
	Model-ready 2014/2023 mobile source emissions inputs	Aug 2020
4.4 Biogenic/Natural Emissions	*Webinar PPT on biogenic and natural emission modeling*	Jul 2020
	Model-ready 2014 natural emissions inputs (Bio, LNOx, Fires)	Jul 2020
4.5 SMOKE Modeling	*Webinar PPT on SMOKE modeling 2014/2023 anthropogenic emissions*	Aug 2020
	Model-ready 2014/2023 anthropogenic emissions inputs	Aug 2020
4.6 FY Emissions Strategies	*Webinar PPT on FY 2023 SMOKE control/strategies*	Aug 2020
	Summary tables and tile plots of emissions for 2023 scenarios	Aug 2020
5. 2014 Base Year (2014) Air Quality Modeling		
	Webinar PPT on final 2014 base case and MPE	Sep 2020
	Draft report on 2014 base case, MPE and Tasks 2-5	Sep 2020
	Final Report on 2014 base case, MPE & Tasks 2-5	Oct 2020
	RtC on 2014 base case and MPE report	Oct 2020
6. Future Year (2023) Air Quality Modeling		
6.1 FY PGM Modeling	*Webinar PPT on FY 2023 PGM Modeling*	Oct 2020
	Difference plots of FY-BY Ozone Concentrations	Oct 2020
6.2 Modeled Attainment Test	*Webinar PPT on FY ozone DV projections*	Oct 2020

Task	Deliverable	Date
6.4 FY Source Apportionment	*Webinar PPT on FY Source Apportionment Modeling*	Nov 2020
	Interactive Excel spreadsheets with Source Apportionment modeling Results	Nov 2020
6.3 FY Controls Modeling	*Webinar PPT on FT control strategy/sensitivity*	Nov 2020
	Excel Spreadsheet of 2023 ozone DV projections	Nov 2020
7. Air Quality Technical Support Document and Data Transfer		
	Draft Air Quality Technical Support Document (AQTSD)	Nov 2020
	Final Air Quality Technical Support Document (AQTSD)	Dec 2020
	RtC document on AQTSD comments	Dec 2020
	Data Transfer of BY and FY modeling databases and results	Dec 2020

Table 1-3. Current schedule for monthly webinars for the NM OAI Study.

Webinar No.	Webinar Topics by Task	Date
1.	1. Modeling Protocol and Work Plan 2.1 Evaluate Existing Met 4.1 Recommend 2014 and 2023 Emissions 4.2.1 Recommend 2014 & 2023 Mobile Source Emissions	May 2020
2.	2.2 Additional Met Modeling 3.1 Evaluate BC Data 4.1 Summary of 2014 and 2023 Emissions	Jun 2020
3.	4.2.1 Summary of 2014 and 2023 Mobile Source Emissions 4.4 2014 Natural Emissions Results (e.g., Biogenic and LNOx)	Jul 2020
4.	4.2.3 2014 & 2023 SMOKE-MOVES Results for 4-km NM Domain 4.5 2014 & 2023 SMOKE Emissions Modeling Results	Aug 2020
5.	4.6 FY Emissions Strategy Results 5. 2014 CAMx Base Case Modeling and MPE	Sep 2020
6.	6.1 2023 CAMx Modeling Results 6.2 2023 Ozone Design Value Projections	Oct 2020
7.	6.3 2023 Control Strategy Results 6.4 2023 Source Apportionment Modeling Results	Nov 2020

2. MODEL SELECTION

This section introduces the models to be used in the NM OAI Study. The selection methodology presented follows EPA's guidance for regulatory modeling in support of ozone attainment demonstrations (EPA, 2007; 2014d; 2018d). Unlike some of EPA's previous ozone modeling guidance that specified a particular ozone model to be used (e.g., EPA's 1991 ozone modeling guidance that specified the Urban Airshed Model [UAM; Morris and Myers, 1990]), the EPA now recommends that models be selected for ozone, $PM_{2.5}$ and regional haze SIP modeling on a case-by-case basis (EPA, 2018d). The latest EPA ozone guidance (EPA, 2018d) explicitly mentions the CMAQ and CAMx PGMs as the most commonly used PGMs that would satisfy EPA's selection criteria but notes that this is not an exhaustive list and does not imply that they are "preferred" over other PGMs that could also be considered and used with appropriate justification. EPA's ozone modeling guidance lists several criteria for model selection that are paraphrased as follows (EPA, 2018d, pp. 24-27):

- It should not be proprietary;
- It should have received a scientific peer review;
- It should be demonstrated to be applicable to the problem on a theoretical basis;
- It should be used with data bases which are available and adequate to support its application;
- It should be shown to have performed well in past modeling applications;
- It should be applied consistently with an established protocol on methods and procedures;
- It should have a user's guide and technical description;
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable; and
- When other criteria are satisfied, resource considerations may be important and are a legitimate concern.

For the NM OAI Study, we will use the same WRF/SMOKE/MOVES2014/MEGAN/CAMx modeling system as used in many recent studies and satisfies all the selection criteria above. The CAMx modeling system was used in the Western Regional Air Partnership (WRAP) West-wide Jump Start Air Quality Modeling Study (WestJumpAQMS; ENVIRON, 2011; ENVIRON and Alpine, 2012; ENVIRON, Alpine and UNC, 2013), Western Air Quality Study (WAQS; Adelman, Shankar, Yang and Morris, 2014; 2016), EPA's September 2019 Regional Haze modeling (EPA, 2019) and transport (CSAPR) modeling, and for a series of Denver ozone SIP modeling [e.g., 2003 EAC SIP (Morris et al., 2004c,b,c,d), 2008 SIP (Morris et al., 2007; 2008a,b,c) and 2016 SIP (Ramboll and Alpine, 2016a,b; 2017a; RAQC and CDPHE, 2017)] so has a long history of demonstrated success for simulating ozone concentrations in the western U.S.

2.1 Meteorological Model

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs (Skamarock, 2004; 2006; Skamarock et al., 2005; 2008; 2019). The Advanced Research WRF (ARW) version of WRF will be used in the NM OAI Study. It features multiple dynamical cores, sophisticated data assimilation system, and a software architecture allowing for computational parallelism and system extensibility. WRF is suitable for a broad spectrum of applications across scales ranging from meters to thousands of kilometers. The effort to develop WRF has been a collaborative partnership, principally among the National Center for Atmospheric Research (NCAR), the National Oceanic and Atmospheric Administration (NOAA), the National Centers for Environmental Prediction (NCEP) and the Forecast Systems Laboratory (FSL), the Air Force Weather Agency (AFWA), the Naval Research Laboratory, the University of Oklahoma, and the Federal Aviation Administration (FAA). WRF allows researchers the ability to conduct simulations reflecting either real data or idealized configurations. WRF provides operational forecasting a model that is flexible and efficient computationally, while offering the advances in physics, numerics, and data assimilation contributed by the research community.

WRF is publicly available, has full documentation and has demonstrated success in simulating meteorological conditions in New Mexico and Intermountain West (IMW) to support PGM modeling efforts in numerous studies (e.g., SNOMS, WRAP WestJumpAQMS and WAQS, EPA national studies and more recent Denver ozone SIPs).

2.2 Emissions Models

2.2.1 Sparse Matrix Operator Kernel Emissions (SMOKE)

The Sparse Matrix Operator Kernel Emissions (SMOKE) is an emissions modeling system that generates hourly gridded speciated emission inputs of mobile, non-road, area, point, fire and biogenic emission sources for PGMs (Coats, 1995; Houyoux and Vukovich, 1999; UNC, 2019). As with most "emissions models," SMOKE is principally an emission processing system and not a true emissions modeling system in which emissions estimates are simulated from "first principles." This means that, except for mobile sources, its purpose is to provide an efficient, modern tool for converting an existing base emissions inventory data that is typically at the county or point source level into the hourly gridded speciated formatted emission files required by a PGM. SMOKE will be used to prepare emission inputs for non-road mobile, non-point (area) and point sources. SMOKE performs three main functions to convert emissions to the hourly gridded emission inputs for a PGM: (1) spatial allocation, spatial allocates county-level emissions to the PGM model grid cells typically using a surrogate distribution (e.g., population); (2) temporal allocation, allocates annual emissions to time of year (e.g., monthly or seasonally) and day-of-week (typically weekday, Saturday and Sunday); and (3) chemical speciation, maps the emissions to the species in the chemical mechanism used by the PGM, most important for VOC and $PM_{2.5}$ emissions.

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2.2.2 MOtor Vehicle Emissions Simulator (MOVES)

The MOtor Vehicle Emissions Simulator (MOVES2014b) is EPA's latest on-road mobile source emissions model that was first released in July 2014 (EPA, 2014a,b,c). MOVES2014 includes the latest on-road mobile source emissions factor information. The NM OAI Study will use a version 2014b of MOVES (MOVES2014b[32]) with CB6 species that was released in August 2018.

2.2.3 SMOKE-MOVES

SMOKE-MOVES uses an Emissions Factor (EF) Look-Up Table from MOVES, vehicle miles travelled (VMT) and other activity data and hourly gridded meteorological data (typically from WRF) for the base modeling year and generates hourly gridded speciated on-road mobile source emissions inputs. SMOKE-MOVES will be used to generate on-road mobile source emissions for the 4-km New Mexico domain using the 4-km WRF data developed in this study. It will also be used to generate mobile source emissions inputs for the 12-km western U.S. domain.

2.2.4 Model of Emissions of Gases and Aerosols from Nature (MEGAN)

Biogenic emissions will be generated using version 3.1 of the Model of Emissions of Gases and Aerosols from Nature (MEGAN). MEGAN is the latest biogenic emissions model that was originally developed by researchers from the National Center for Atmospheric Research (NCAR) and is currently supported by the University of California at Irvine. MEGAN includes the full range of ozone and PM precursor species from biogenic sources (Guenther and Wiedinmyer, 2004; Wiedinmyer, Sakulyanontvittaya and Guenther, 2007). The NM OAI Study will use the latest version of MEGAN v3.1 that includes more western states plant emissions data that were implemented by WRAP (Sakulyanontvittaya, Yarwood and Guenther, 2012).

2.3 Photochemical Grid Model

2.3.1 Comprehensive Air-quality Model with extensions (CAMx)

The Comprehensive Air-quality Model with Extensions (CAMx; Ramboll, 2018a) is a state-of-science "One-Atmosphere" multi-scale photochemical grid model capable of addressing ozone, particulate matter (PM), visibility and acid deposition at regional, urban and local scale typically for periods of a year. CAMx is a publicly available open-source computer modeling system for the integrated assessment of gaseous and particulate air pollution. Built on today's understanding that air quality issues are complex, interrelated, and reach beyond the urban scale, CAMx is designed to (a) simulate air quality over many geographic scales, (b) treat a wide variety of inert and chemically active pollutants including ozone, inorganic and organic $PM_{2.5}$ and PM_{10} and mercury and toxics, (c) provide source-receptor, sensitivity, and process analyses and (d) be computationally efficient and easy to use.

The U.S. EPA has approved the use of CAMx for numerous ozone and PM State Implementation Plans throughout the U.S. (including the Denver 2003, 2008 and 2016 ozone SIPs) and has used this model to evaluate regional mitigation strategies

[32] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100V7H1.pdf

including those for most recent national transport rules, such as the Cross-State Air Pollution Rule (CSAPR) and CSAPR Update. The most recent version of CAMx is Version 7.0 that was used in the WRAP/WAQS 2014v2 modeling and EPA's recent national Regional Haze modeling (EPA, 2019). The latest EPA ozone guidance (EPA, 2018d, pp. 24) explicitly mentions the CMAQ and CAMx PGMs as the most commonly used PGMs that would satisfy EPA's selection criteria but notes that this is not an exhaustive list and does not imply that they are "preferred" over other PGMs that could also be considered and used with appropriate justification. EPA has conducted an analysis of the appropriateness for using CAMx and CMAQ for single-source ozone and secondary $PM_{2.5}$ modeling justifying their use (EPA, 2017c).

2.4 Final Justification for Model Selection

At the beginning of this Chapter we presented EPA's criteria for model selection (EPA, 2018d). The proposed WRF/SMOKE/MOVES/CAMx modeling system satisfies all of these criteria as follows:

- It should not be proprietary: The WRF[33], SMOKE[34], MOVES[35], MEGAN[36] and CAMx[37] models are all publicly available at no cost and can be downloaded from their websites.
- It should have received a scientific peer review: All the models considered have been published in 100s of peer-review journal articles. The CAMx model has been subject to their own peer-review reports[38] and an assessment by EPA that they are suitable for ozone SIP modeling (EPA, 2018d).
- It should be appropriate for the specific application on a theoretical basis: The WRF model was designed to simulate time varying three-dimensional meteorological fields and provide all the meteorological information necessary for ozone modeling. The SMOKE, MOVES and MEGAN models provide the hourly gridded speciated emissions information required for ozone modeling. And the CAMx model was designed to have all the processes necessary to simulate ozone formation in the troposphere.
- It should be used with data bases which are available and adequate to support its application: The procedures outlined for the development of the 2014 modeling platform to support ozone modeling of New Mexico use databases that are adequate to support the meteorological, emission and photochemical model applications.
- It should be shown to have performed well in past modeling applications: The WRF/SMOKE/CAMx modeling system has a demonstrated history in simulating ozone formation in the western U.S. in general and New Mexico in particular. CAMx was used in the New Mexico EAC SIP, FCAQTF, CARMMS, WRAP WAQS[39]

[33] https://www.mmm.ucar.edu/weather-research-and-forecasting-model
[34] https://www.cmascenter.org/smoke/
[35] https://www.epa.gov/moves
[36] http://lar.wsu.edu/megan/
[37] http://www.camx.com/
[38] https://hero.epa.gov/hero/index.cfm/reference/details/reference_id/1399874
[39] http://views.cira.colostate.edu/tsdw/

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and WestJumpAQMS[40], and Denver ozone SIP modeling, including the 2008[41] and 2016[42] Denver ozone SIPs.

- It should be applied consistently with an established protocol on methods and procedures: The NM OAI Study WRF/SMOKE/CAMx application methodology follows the established procedures used in the past (e.g., see studies discussed above) with enhancements (i.e., 4-km New Mexico domain and use of latest model versions).
- It should have a user's guide and technical description: Each of the models cited has a technical description and procedures for application (see websites in footnotes). The CAMx model has an up-to-date and comprehensive user's guide (Ramboll, 2018a) that has a detailed technical description and procedures for application.
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable: One of the reasons for selecting CAMx is due to the availability of advanced features such as the Plume-in-Grid module and Ozone Source Apportionment Technology (OSAT/APCA) in addition to latest science updates (e.g., CB6 chemistry and Decoupled Direct Method).
- When other criteria are satisfied, resource considerations may be important and are a legitimate concern: CAMx is computationally efficient and supports both MPI and OpenMP multi-processing approaches and allows for layer collapsing. CMAQ does not support OpenMP or allow for layer collapsing so runs over 1.5 times slower than CAMx.

[40] http://wrapair2.org/WestJumpAQMS.aspx

[41] https://www.colorado.gov/airquality/documents/deno308/

[42] https://raqc.org/sip/moderate-area-2008-8-hour-ozone-standard-state-implementation-plan/

3. EPISODE SELECTION

EPA's current and past 8-hour ozone modeling guidance (EPA, 2007; 2014d; 2018d) contains recommended procedures for selecting modeling episodes for demonstrating attainment of the ozone NAAQS. The NM OAI Study modeling will use the summer of 2014 as the base year modeling period because it is representative of high ozone conditions and has available modeling databases to leverage for the analysis.

3.1 Candidate Year for Modeling Episodes

Given the need to leverage an existing photochemical grid model (PGM) modeling platform for the NM OAI Study, there are only two candidate years for episode selection, 2014 and 2016. The WRAP/WAQS has developed a PGM modeling platform for the 2014 year and the EPA/MJO collaborative emissions study and EPA have built a PGM modeling platform for 2016. EPA's previous PGM modeling platform was for 2011, which is too old. And EPA is working on a new PGM modeling platform for 2017 that is not yet available.

3.2 EPA Episode Selection Criteria

EPA's 8-hour ozone SIP modeling guidance (EPA, 2018d) identifies specific criteria to consider when selecting one or more episodes for use in demonstrating attainment of the 8-hour ozone NAAQS. This guidance builds off the 1-hour ozone modeling guidance (EPA, 1991) and the original (EPA, 2007) and revised draft (EPA, 2014d) 8-hour ozone modeling guidance that recommends selecting multiple episodes representing diverse meteorological conditions that lead to exceedances of the ozone NAAQS in the region under study. For the NM OAI Study, an entire summer ozone season will be modeled to capture a wide range of different types of meteorological and emission conditions that lead to observed ozone high ozone concentrations at monitoring sites in New Mexico.

Below we address each of EPA's episode selection criteria (EPA, 2018a, pp. 19) and the justification for using the summer 2014 modeling period for the NM OAI Study.

3.2.1 Model a Time Period that Corresponds to a Year with an Available National Emissions Inventory (NEI) and has Air Quality and Meteorological Data Available

NEI's are prepared every three years. The most recent currently available NEIs are for the 2011 and 2014 years. The 2017 NEI is in preparation and a usable version is not yet available. Thus, the 2014NEI is the latest NEI available.

3.2.2 Model Time Periods in which Observed Ozone Concentrations are Close to the Appropriate Base Year Ozone Design Values*.*

Appendix A presents the observed MDA8 ozone concentrations at monitoring sites within the proposed 4-km New Mexico domain including those in New Mexico (FIP State Code = 35). Observed DMAX8 ozone concentrations that exceed the 2015 ozone NAAQS are colored red. And ozone values that are above approximately 95% of the 2015 ozone NAAQS but below the ozone NAAQS (i.e., 67 ppb ≤ ozone < 70 ppb) are

colored yellow. The number of 2015 ozone NAAQS exceedances (i/e/., 71 ppb or higher) and between 67 and 71 ppb in the three main geographic regions in New Mexico are shown in Table 3-1.

For southeast New Mexico (e.g., Dona Ana County), the peak ozone in 2016 (79 ppb) is higher than in 2014 (76 ppb), but there are many more ozone exceedances days in 2014 (8) than 2016 (3). Both potential candidate modeling years have comparable levels to the observed highest 2014-2016 ozone DV in southeast New Mexico (74 ppb).The highest 2014-2016 ozone DV in northwest New Mexico is 70 ppb in San Juan County. Both candidate modeling years have a highest observed MDA8 ozone in 2014 and 2016 of 69 ppb and two days per year with ozone between 67 and 71 ppb.

Finally, for Bernalillo and Valencia Counties 2016 has a higher peak ozone than 2014 (70 vs. 68 ppb) and more days per year between 67 and 71 ppb (5 vs. 3 days per year).

Table 3-1. Maximum observed DMAX8 ozone concentrations and number of days ozone is above the 2015 ozone NAAQS or between 67 and 71 ppb in the three geographic regions of New Mexico and the 2014 and 2016 candidate modeling years.

NM Region	Max Ozone		Days ≥ 71 ppb		Days ≥ 67 ppb	
	2014	2016	2014	2016	2014	2016
NM All Sites	76	79	8	3	24	27
Albuquerque[a]	68	70	0	0	3	5
Southeast NM	76	79	8	3	21	22
Northwest NM	69	69	0	0	2	2

[a] The Albuquerque geographic region in this table included Bernalillo and Valencia Counties.

3.3 Episode Selection Conclusions

Based on the above analysis, the May-August summer season of 2014 was selected for modeling, because:

- 2014 has a PGM modeling database developed by the WRAP/WAQS.
- It corresponds with a NEI emissions year.
- The 2014 emissions have been reviewed and updated by the western states.
- The ozone air quality is comparable to current ozone DVs.
- It has more ozone exceedance days (8) than the other candidate year (3).

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4. MODELING DOMAIN SELECTION AND DATA AVAILABILITY

This Chapter summarizes the definition of the horizontal modeling domains for the NM OAI Study PGM modeling. This includes the map projection, domain coverage, grid resolution and grid nesting. As the vertical structure of the PGM model will be defined based on the vertical structure of the WRF meteorological model, it is discussed in Chapter 5. This Chapter also discusses emissions, aerometric and other data available for use in model input preparation and performance testing.

4.1 Horizontal Domain

The NM OAI Study modeling will use the same 36-km 36US and 12-km 12WUS2 domains as used in the WRAP/WAQS 2014 modeling platform. A 4-km New Mexico domain will be added to the 36/12-km domain structure. Figure 4-1 displays the 36/12/4-km domain structure with Figure 4-2 showing the 4-km New Mexico domain. New WRF 2014 36/12/4-km meteorological modeling will be conducted to generate finer scale 4-km meteorological conditions for the New Mexico domain and consistent meteorology among the 36/12/4-km domains.

CAMx will be run using the 36/12/4-km domain structure shown in Figure 4-1 using two-way interactive grid nesting.

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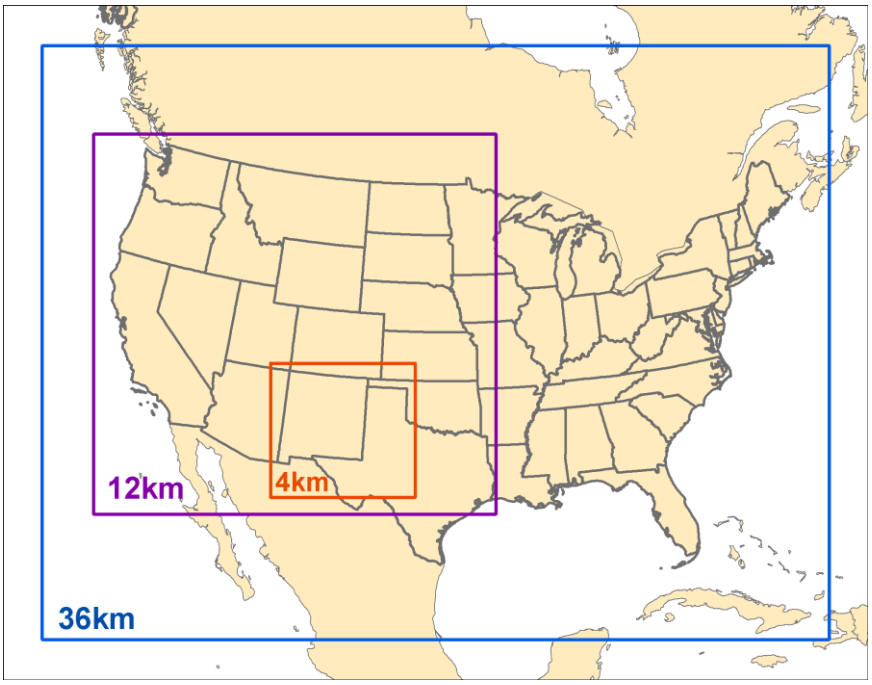


Figure 4-1. NM OAI Study modeling 2014 36/12/4-km PGM and emissions modeling domains.

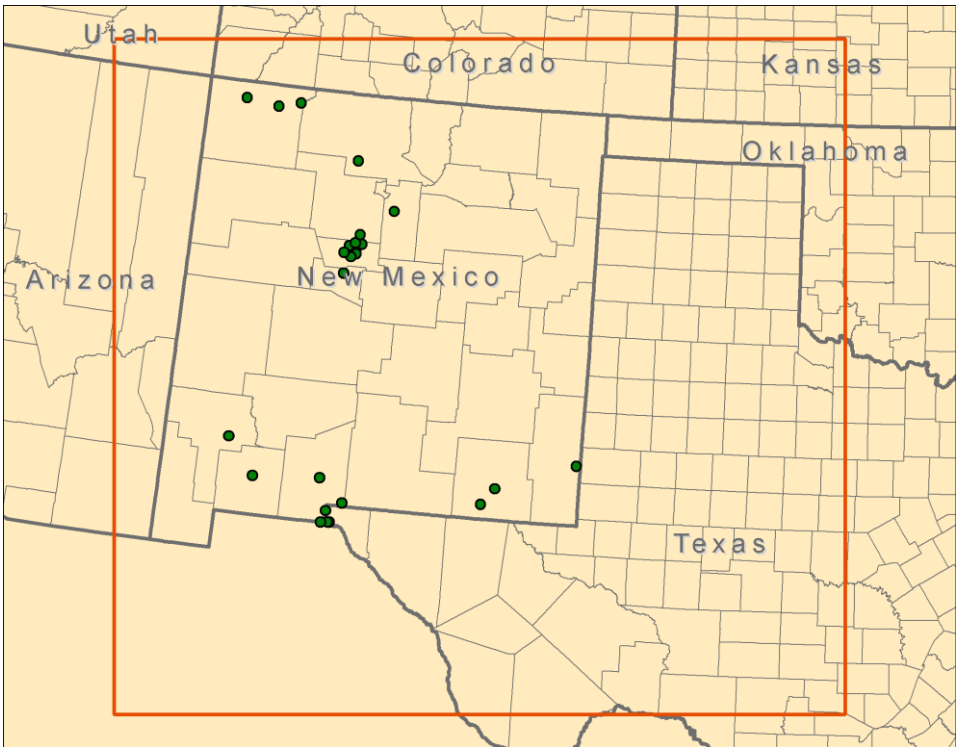


Figure 4-2. 4-km New Mexico modeling domain for PGM and emissions modeling, with locations of ozone monitors that were operating during some portion of 2014.

Table 4-1. Lambert Conformal Conic (LCC) projection parameters for the NM OAI Study 36/12/4 modeling domains.

Parameter	Value
Projection	Lambert-Conformal
1st True Latitude	33 degrees N
2nd True Latitude	45 degrees N
Central Longitude	-97 degrees W
Central Latitude	40 degrees N

Table 4-2. Grid definitions for CAMx NM OAI Study 2014 36/12/4-km modeling domains.

Grid	Origin (SW) (km)	Extent (NE) (km)	NX	NY
36-km	(-2736, -2088)	(2592, 1944)	148	112
12-km*	(-2388, -1236)	(336, 1344)	227	215
4-km*	(-1192, -1120)	(-212, -212)	245	227

*Definition includes outer row/column of buffer cells required by CAMx for nested domains

4.2 Data Availability

The CAMx modeling system requires emissions, meteorology, surface characteristics, initial and boundary conditions (IC/BC), and ozone column data for defining the inputs.

4.2.1 Emissions Data

Except for on-road mobile source emissions for the 4-km domain, the 2014 base year anthropogenic emissions inventory for New Mexico will be based on the WAQS 2014v2 emissions. The NMED will review the WAQS 2014v2 emissions for New Mexico and provide updates as needed. The sources of the 2014 emissions data are as follows.

- Major point source SO_2 and NO_x emissions will be based off measured Continuous Emissions Monitor (CEM) data that are available online from the EPA Clean Air Markets Division (CAMD[43]) website. These data are hour-specific for SO_2, NO_x, and heat input. The temporal variability of other pollutant emissions (e.g., PM) from the CEM sources will be simulated using the hourly CEM heat input data using the annual emissions from the WAQS 2014v2 emissions inventory.
- WRAP developed new 2014 oil and gas emissions for WRAP states that includes New Mexico that will be used. Outside of the WRAP states the EPA 2014NEI will be used.
- On-road mobile sources will be based on the EPA's MOVES2014 on-road emissions model (EPA, 2014a,b,c). The WAQS 36/12-km 2014v2 emissions will be used as is. Within the New Mexico 4-km domain, SMOKE-MOVES will be used

[43] http://www.epa.gov/AIRMARKETS/

with EPA's MOVES2014 2014 emission factor (EF) table and county-level vehicle activity data and 2014 hourly 4-km WRF meteorology developed in this study.

- The 2014 fire emissions developed for the 2014NEI and then updated by the WRAP Fire and Smoke Work Group will be used.
- 2014 biogenic emissions will be generated for the 36/12/4-km domains using version 3.1 of the Model of Emissions of Gases and Aerosols in Nature (MEGAN[44]) that was updated by WRAP[45] to include western U.S. plant types.
- Mexico and Canada emissions will be based on the EPA 2014 modeling platform.

4.2.2 Air Quality Data

Data from ambient air quality monitoring networks for gaseous species are used in the model performance evaluation. Table 4-3 summarizes routine ambient gaseous and PM monitoring networks available in the U.S. For this project only the routine ozone monitoring sites within the New Mexico 4-km modeling domain operating during 2014 (Figure 4-2) will be used to perform an operational evaluation of the CAMx 2014 4-km base case simulation.

[44] http://acd.ucar.edu/~guenther/MEGAN/MEGAN.htm

[45] http://www.wrapair2.org/pdf/WGA_BiogEmisInv_FinalReport_March20_2012.pdf

Table 4-3. Overview of routine ambient data monitoring networks.

Monitoring Network	Chemical Species Measured	Sampling Period	Data Availability/Source
The Interagency Monitoring of Protected Visual Environments (IMPROVE)	Speciated PM25 and PM10 (see species mappings)	1 in 3 days; 24 hr average	http://vista.cira.colostate.edu/improve/Data/IMPROVE/improve_data.htm
Clean Air Status and Trends Network (CASTNET)	Speciated PM25, Ozone (see species mappings)	Approximately 1-week average	http://www.epa.gov/castnet/data.html
National Atmospheric Deposition Program (NADP)	Wet deposition (hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium)), Mercury	1-week average	http://nadp.sws.uiuc.edu/
Air Quality System (AQS) or Aerometric Information Retrieval System (AIRS)	CO, NO2, O3, SO2, PM25, PM10, Pb	Typically, hourly average	http://www.epa.gov/air/data/
Chemical Speciation Network (CSN)	Speciated PM	24-hour average	http://www.epa.gov/ttn/amtic/amticpm.html
Photochemical Assessment Monitoring Stations (PAMS)	Varies for each of 4 station types.		http://www.epa.gov/ttn/amtic/pamsmain.html
National Park Service Gaseous Pollutant Monitoring Network	Acid deposition (Dry; SO4, NO3, HNO3, NH4, SO2), O3, meteorological data	Hourly	http://www2.nature.nps.gov/ard/gas/netdata1.htm

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4.2.3 Ozone Column Data

Additional data used in the air quality modeling include ozone column data from the Ozone Monitoring Instrument (OMI) which continues the Total Ozone Mapping Spectrometer (TOMS) record for total ozone and other atmospheric parameters related to ozone chemistry (OMI officially replaced the TOMS ozone column satellite data on January 1, 2006). OMI data are available every 24-hours and are obtained from the TOMS ftp site.[46] The CAMx o3map program reads the OMI ozone column txt file data and interpolates to fill gaps and generated gridded daily ozone column input data. The OMI data are used in the CAMx (TUV) radiation models to calculate photolysis rates. The CAMx o3map processor also allows for the use of episode and monthly average data, although in this study daily data are used. Note that a new ozone column satellite product is available (OMPS) that may be used if appropriate.

4.2.4 Meteorological Data

Meteorological data for PGM modeling will be obtained from the WRF meteorological model as described in Chapter 5.

4.2.5 Initial and Boundary Conditions Data

Boundary conditions (BCs) for the 36-km 36US domain for both the base and future years will be derived from the output from a 2014 simulation of the GEOS-Chem global chemistry model conducted by WRAP.

[46] ftp://toms.gsfc.nasa.gov/pub/omi/data/

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5. WRF METEOROLOGICAL MODELING

This chapter describes how the Weather Research Forecasting (WRF) meteorological model will be used to generate 2014 36/12/4-km meteorological inputs for CAMx photochemical grid modeling. The WRF model contains separate modules to compute different physical processes, such as surface energy budgets and soil interactions, turbulence, cloud microphysics, and atmospheric radiation. Within WRF, the user has many options for selecting the different schemes for each type of physical process. The WRF Pre-processing System (WPS) generates the initial conditions (ICs) and boundary conditions (BCs) and analysis fields used by WRF, based on topographic datasets, land use information, and larger-scale atmospheric and oceanic models.

5.1 Description of WRF

WRF's research and operational application ensures state-of-the-science physics and adaptability to a wide range of environments, through a broad selection of physics options, allowing us to develop the best-performing configuration for simulating meteorology in the region.

The non-hydrostatic version of the Advanced Research version of the Weather Research and Forecast (WRF-ARW) model (Skamarock et al., 2005; 2008; 2019) is a three-dimensional, limited-area, primitive equation, prognostic model that has been used widely in regional air quality model applications. WRF is a next-generation mesoscale prognostic meteorological model routinely used in urban- and regional-scale photochemical, fine particulate and regional haze regulatory modeling studies. Developed jointly by the National Center for Atmospheric Research (NCAR) and NCEP, WRF is maintained and supported as a community model by researchers and practitioners around the globe. It is suitable for use in a broad spectrum of applications across scales ranging from hundreds of meters to thousands of kilometers.

5.2 WRF Model Domain

The PGM (CAMx) 2014 36/12/4-km modeling domains were shown in Figure 4-1 in the previous Chapter. The WRF 2014 36/12/4-km modeling domains are defined slightly larger than the PGM 36/12/4-km domains so that any modeling artifacts that occur near the WRF boundaries as the BCs come into dynamic balance with the WRF numerical algorithms are not present in the PGM meteorological inputs.

5.3 WRF Model Configuration

Below we summarized the proposed WRF configuration and input to be used to generate 2014 36/12/4-km meteorological inputs for the PGM 2014 photochemical modeling. WPS and WRF version 4.2 are used for this modeling analysis. Previous studies utilizing WRF at high resolution over New Mexico, such as the WRAP WestJumpAQMS, WAQS, Southern New Mexico Ozone Study (SNMOS) and EPA modeling platform development, have evaluated different configurations of WRF. Table 5-1 below summarizes the WRF configurations used in the WAQS 2014 and EPA 2014/2015/2016 WRF modeling. Preliminary analysis of WAQS 12 km model performance in New Mexico shows superior summertime precipitation performance

compared to EPA 2014 WRF modeling. Therefore, we propose that the NM OAI Study match the WRF physics configuration options used by 2014 WAQS modeling, except where noted below.

We propose to match the NM OAI 36/12-km WRF/PGM grid configuration (e.g., horizontal domains and vertical layer structure) with the WAQS 2014 WRF/PGM grid configuration in order the facilitate the use of data between the two studies. The following paragraphs describe the proposed WRF configuration for the NM OAI 2014 photochemical modeling.

5.3.1 Model Vertical Resolution

The WAQS 2011/2014 WRF modeling used 36 vertical levels (35 vertical layers) from the surface to a 50 mb (hPa) height (approximately 19-km above sea level). The EPA 2014 and 2015 WRF modeling used 35 vertical layers also up to a 50 mb height. Table 5-1 displays the 36-vertical layer structure used in the WAQS 2011/2014 WRF modeling that will be the layer structure proposed for our WRF 2014 NM OAI 36/12/4-km modeling.

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Table 5-1. WRF 36 level vertical layer structure for the NM OAI study. This is the same WRF layer structure as used in WAQS 2011/2014 WRF modeling.

WRF Layer	Sigma	Pressure (mb)	Height (m)	Thickness (m)
36	0.0000	50.00	19260	2055
35	0.0270	75.65	17205	1850
34	0.0600	107.00	15355	1725
33	0.1000	145.00	13630	1701
32	0.1500	192.50	11930	1389
31	0.2000	240.00	10541	1181
30	0.2500	287.50	9360	1032
29	0.3000	335.00	8328	920
28	0.3500	382.50	7408	832
27	0.4000	430.00	6576	760
26	0.4500	477.50	5816	701
25	0.5000	525.00	5115	652
24	0.5500	572.50	4463	609
23	0.6000	620.00	3854	461
22	0.6400	658.00	3393	440
21	0.6800	696.00	2954	421
20	0.7200	734.00	2533	403
19	0.7600	772.00	2130	388
18	0.8000	810.00	1742	373
17	0.8400	848.00	1369	271
16	0.8700	876.50	1098	177
15	0.8900	895.50	921	174
14	0.9100	914.50	747	171
13	0.9300	933.50	577	84
12	0.9400	943.00	492	84
11	0.9500	952.50	409	83
10	0.9600	962.00	326	82
9	0.9700	971.50	243	82
8	0.9800	981.00	162	41
7	0.9850	985.75	121	24
6	0.9880	988.60	97	24
5	0.9910	991.45	72	16
4	0.9930	993.35	56	16
3	0.9950	995.25	40	16
2	0.9970	997.15	24	12
1	0.9985	998.58	12	12
0	1.0000	1000.00	0	

5.3.2 Vertical Coordinate

Since its inception, WRF has used the eta (sometimes called sigma or "terrain-following") vertical coordinate system. One weakness of the eta coordinate is that

variations in terrain (especially steep topography) can increase numerical errors in the model. To reduce these errors, Park et al., (2018) developed a hybrid sigma–pressure coordinate that is now included as the default vertical coordinate system for the WRF model (Skamarock et al., 2019).

In Figure 5-1, we present vertical cross sections of layer interface heights over the Rocky Mountains during a strong near-surface wind event (Park et al., 2018). The left panel shows the results using the eta or terrain-following vertical coordinate and the right panel shows the same results but using the hybrid vertical coordinate. The eta coordinate cross-sections show the influence of terrain extending high into the stratosphere. This is a representation of numerical noise and results in erroneous vertical motion in the model. Park et al., (2018) found that the simulation using the eta vertical coordinate produced high turbulence forecasts aloft which were not observed by pilots or soundings. In CAMx, erroneous vertical motion can help transport stratospheric ozone toward the surface. In contrast, the same simulation using the hybrid vertical coordinate produced lower turbulence forecasts that agreed more closely with observations. The hybrid vertical coordinate cross-sections show a gradual damping of terrain effects with increasing altitude until the layer interfaces are flat aloft. The purpose of using the hybrid vertical coordinate in the CAMx is to better represent ozone in the upper troposphere and lower stratosphere. Eliminating this source of numerical noise reduces spurious downward transport of stratospheric ozone.

We will use a new version of the WRFCAMx processor that has been updated to use WRF's hybrid vertical coordinate.

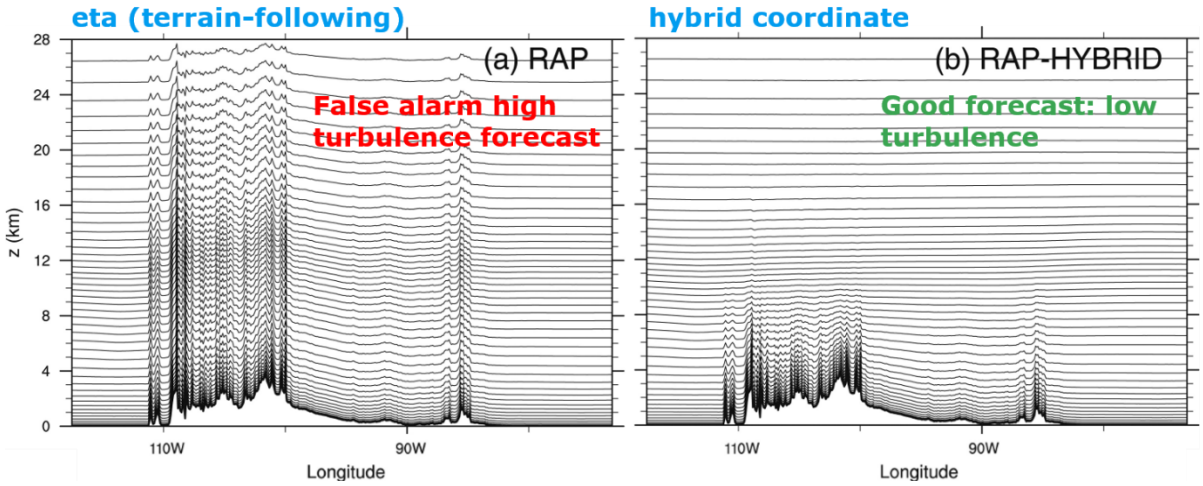


Figure 5-1. Cross-sections of layer interface heights over the Rocky Mountains for the eta (left panel) and hybrid (right panel) vertical coordinates for the WRF-Based Rapid Refresh (RAP) model. Adapted from Park et al., (2018).

5.3.3 Topographic Inputs

Topographic information for WRF will be based on a combination of the standard WRF terrain databases and high-resolution terrain. The 36-km 36US domain will use the 10-minute global data, the 12-km 12WUS2 domain will use the 2-minute data, and the 4-km New Mexico domain will use the 30 second data.

5.3.4 Vegetation Type and Land Use Inputs

Vegetation type and land use information will use the United States Geological Survey (USGS) land use databases from the most recently released WRF databases provided with the WRF distribution. Standard WRF surface characteristics corresponding to each land use category will be employed.

5.3.5 Atmospheric Data Inputs

WRF relies on other model or re-analysis output meteorological fields to provide initial and boundary conditions (IC/BC) and fields for the four-dimensional data assimilation (FDDA). FDDA refers to the nudging of the WRF meteorological fields to observed analysis fields so that the WRF meteorological fields better represent what was observed and prevent the model from drifting away from the observed meteorology. As seen in Table 5-2, both the WAQS 2014 and EPA 2014/2015/2016 12-km WRF modeling used the 12-km resolution North American (NAM) analysis fields for IC/BC and analysis nudging.

We propose to use both NAM and the ~30 km European Center for Medium-Range Weather Forecasting (ECMWF) Re-Analysis (ERA5[47]) dataset analysis fields for IC/BC and FDDA. We have found from previous work that the ERA-Interim (lower resolution predecessor to ERA5) dataset has lower humidity near the surface and higher humidity aloft, leading to lower convective available potential energy (CAPE), which lowers overall precipitation rates, especially during the summer Monsoon season. Many WRF simulations of the southwest U.S. summer Monsoon have featured an over-prediction of summertime (convective) precipitation when the NAM analysis fields are used. The Southern New Mexico Ozone Study (SNMOS) conducted PGM ozone sensitivity modeling using meteorological fields based on WRF simulations using the NAM and ERA analysis fields and found that the PGM ozone performance using the WRF/ERA meteorological inputs produced superior ozone performance than when WRF/NAM inputs were used.[48]

The ERA5 is a fairly new analysis fields product that has not been used in WRF modeling as extensively as the ERA fields. We will conduct WRF and PGM sensitivity modeling using the NAM and ERA5 analysis fields to determine which configuration provides the best meteorological inputs and potentially resultant ozone model performance. The ERA5 fields will be objectively re-analyzed using meteorological observational data to the higher resolution for the 36-km and 12-km grid domains using the OBSGRID program. These fields are used both to initialize the model and used with analysis nudging (on selected domains) to guide the model to best match the observations. The initialization dataset with the best WRF performance will be chosen for the final PGM configuration.

[47] https://www.ecmwf.int/en/forecasts/datasets/archive-datasets/reanalysis-datasets/era5

[48] https://www.wrapair2.org/SNMOS.aspx

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5.3.6 Time Integration

Third-order Runge-Kutta integration will be used (rk_ord = 3). The maximum time step, defined for the outer-most domain (36 km) only, should be set by evaluating the following equation:

$$dt = \frac{6dx}{F_{map}}$$

Where dx is the grid cell size in km, Fmap is the maximum map factor (which can be found in the output from REAL.EXE), and dt is the resulting time-step in seconds. For the case of the 36 km RPO domain, dx = 36 and Fmap = 1.08, so *dt* should be taken to be less than 200 seconds. Longer time steps risk CFL errors, associated with large values of vertical velocity, which tend to occur in areas of steep terrain (especially during stable conditions typical of winter). For this WRF run, adaptive time-stepping will be used with a maximum timestep of 180s.

5.3.7 Diffusion Options

Horizontal Smagorinsky first-order closure (km_opt=4) with sixth-order numerical diffusion and suppressed up-gradient diffusion (diff_6th_opt=2) will be used.

5.3.8 Lateral Boundary Conditions

Lateral boundary conditions will be specified from the initialization dataset on the 36-km WRF domain with continuous updates nested from each "parent" domain to its "child" domain, using one-way nesting (feedback=0).

5.3.9 Top and Bottom Boundary Conditions

The implicit Rayleigh dampening for the vertical velocity will be used for the top boundary conditions. Consistent with the model application for non-idealized cases, the bottom boundary condition was selected as physical, not free-slip.

5.3.10 Sea Surface Temperature Inputs

The water temperature data for the refined WRF configurations will be taken from the Fleet Numerical Meteorology and Oceanography Center (FNMOC)[49]. The FNMOC product has horizontal resolution of about 9-km in the mid-latitudes but is produced *four* times per day using AVHRR satellite sensors and in-situ observations.

5.3.11 Four Dimensional Data Assimilation (FDDA)

Analysis nudging will be used for winds, temperature, and humidity on the 36-km and 12-km domains. Both surface and aloft nudging will be used but nudging for temperature and mixing ratio will not be not performed within the boundary layer. Observation nudging will not be performed even on the 4-km domain.

[49] http://www.usgodae.org/cgi-bin/datalist.pl?summary=Go&dset=fnmoc_ghrsst

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5.3.12 New Lightning Data Assimilation

More recently, the assimilation of lightning data in WRF simulations has been shown to improve the locations and amounts of convective precipitation. The use of lighting detection networks, such as the National Lightning Detection Network (NLDN), have been used in WRF simulations and used to force deep convection (thunderstorms) when lightning is observed and only allow shallow convection when lightning is not present. The use of the new lightning assimilation approach has been demonstrated to improve both WRF convective precipitation as well as PGM concentration and deposition performance (Heath et al., 2016). The new lightning data assimilation algorithms will not be used in the 2014 WRF modeling for the NM OAI Study for the following reasons: (1) it would have to be tested and evaluated and there is insufficient time in the schedule to conduct such diagnostic testing; (2) the NLDN data used to date with the WRF lightning assimilation is a commercial product that is expensive and not in the budget; and (3) the implementation of the lightning detection data assimilation in WRF has a flaw that it doesn't distinguish between no lightning detects and missing data and suppresses convection in areas with missing data (e.g., over the Gulf of Mexico).

5.3.13 PBL and LSM Physics Options

The YSU Planetary Boundary Layer (PBL) and Noah Land Surface Model (LSM) physics options will be used in the NM OAI Study 2014 36/12/4-km modeling. Previous WRF sensitivity modeling for the IMW region found the YSU/Noah PBL/LSM schemes produces the most realistic meteorological fields. Note that EPA's 2014/2015/2016 WRF modeling uses the ACM2 PBL and Pleim-Xiu (PX) LSM schemes (Table 5-2). The WAQS tried to evaluate WRF using the ACM2/PX PBL/LSM and found it more difficult to implement and didn't always run so that annual fields could not be generated. Furthermore, the PX LSM scheme requires each run segment of a WRF run soil moisture inputs to be initialized using the previous WRF run segment PX output so that an annual WRF simulations must be run in series. This contrasts with the Noah LSM scheme that initializes soil moisture based on observations with some spin-up time (typically 12-hours) that allows annual WRF runs to be performed using parallel run segments (e.g., 5.5 day run segments). Thus, annual WRF simulations using the YSU/NOAH PBL/LSM physics options can be completed much faster than when ACM2/PX is used.

5.3.14 Remaining WRF Physics Options

Table 5-2 lists the remaining WRF physics options for the NM OAI Study 2014 36/12/4-km WRF application. These are standard WRF physics options and consistent with the WRF options used in the WAQS 2014 and EPA 2014/2015/2016 WRF modeling. Our preliminary comparison of 2014 WAQS and 2014 EPA WRF modeling for summertime precipitation performance in New Mexico finds that WAQS WRF outperformed EPA WRF modeling. Therefore, we propose to use the same microphysics and cumulus schemes for the NM OAI Study as used in 2014 WAQS (Thompson and Multi-Scale Kain-Fritsch, respectively).

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Table 5-2. Proposed NM OAI 2014 WRF model configuration and comparison with the WRF configuration used in the WAQS 2014 and EPA 2014/2015 WRF modeling.

WRF Option	Proposed NM OAI	2014 WAQS	2014/2015 EPA
Domains run	36/12/4-km	36/12/4-km	12-km
Microphysics	Thompson	Thompson	Morrison 2
LW Radiation	RRTMG	RRTMG	RRTMG
SW Radiation	RRTMG	RRTMG	RRTMG
Sfc Layer Physics	MM5 similarity	MM5 similarity	MM5 similarity
LSM	Noah	Noah	Pleim-Xiu
PBL scheme	Yonsei University (YSU)	YSU	ACM2
Cumulus	36/12/4-km Multi-scale Kain Fritsch	36/12-km Multi-scale_Kain Fritsch; 4-km None	Kain-Fritsch
BC, IC Analysis Nudging Source	12-km NAM/ERA5	12-km NAM	12-km NAM
Analysis Nudging Grids	36/12-km	36/12-km	12-km
Obs Nudging	None	4-km	None
Sea Sfc Temp	FNMOC	FNMOC	FNMOC

5.3.15 Application Methodology

The WRF model will be executed in 5.5-day blocks initialized at 12Z every five days. Model results will be output every 60 minutes, split at twelve (12) hour intervals. Twelve (12) hours of spin-up is included in each 5-day block before the data is used in the subsequent evaluation and PGM meteorological inputs.

5.4 WRF Model Evaluation

Quantitative and qualitative evaluations of the NM OAI Study 2014 WRF 36/12/4-km simulation will be conducted. The quantitative evaluations compare integrated surface hourly meteorological observations with WRF predictions matched by time and location. The qualitative evaluations compared time series plots of modeled wind speed and wind direction to the observations at specific sites. The evaluation is conducted for meteorological observation sites across the western U.S., with particular focus on sites within the 4-km New Mexico domain.

5.4.1 Quantitative Evaluation Using METSTAT

A quantitative model performance evaluation of the NM OAI Study 2014 WRF modeling will be performed using the publicly-available METSTAT software (Ramboll Environ, 2015) evaluation tool. Output from the WRF meteorological model will be compared

against meteorological observations from the various networks operating in the study area. This is carried out both graphically and statistically to evaluate model performance for surface winds, temperatures, humidity, and the placement, intensity, and evolution of key weather phenomena. The purpose of these evaluations is to establish a first-order acceptance/rejection of the simulation in adequately replicating the weather phenomena in the study area. Thus, this approach screens for obvious model flaws and errors.

5.4.1.1 Quantitative Statistics

The quantitative analysis will be conducted using METSTAT. Statistical measures calculated by METSTAT include observation and prediction means, prediction bias, and prediction error that are given as follows.

Mean Observation (M_o) is calculated using values from all sites for a given time period by Eq. **(5-1)**:

$$M_o = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I} O_j^i \qquad (5\text{-}1)$$

where O^i_j is the individual observed quantity at site i and time j, and the summations are over all sites (I) and over time periods (J).

Mean Prediction (M_p) is calculated from simulation results that are interpolated to each observation used to calculate the mean observation for a given time period by Eq. **(5-2)**:

$$M_p = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I} P_j^i \qquad (5\text{-}2)$$

where P^i_j is the individual predicted quantity at site i and time j. Note the predicted mean wind speed and mean resultant direction are derived from the vector-average (for east-west component u and north-south component v), from which the

Bias (B) is calculated as the mean difference in prediction-observation pairings with valid data within a given analysis region and for a given time period by Eq. **(5-3)**:

$$B = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right) \qquad (5\text{-}3)$$

Gross Error (E) is calculated as the mean *absolute* difference in prediction-observation pairings with valid data within a given analysis region and for a given time period by Eq. **(5-4)**:

$$E = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - O_j^i\right| \qquad (5\text{-}4)$$

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Note that the bias and gross error for winds are calculated from the predicted-observed residuals in speed and direction (not from vector components *u* and *v*). The direction error for a given prediction-observation pairing is limited to range from 0 to ±180°.

Root Mean Square Error (RMSE) is calculated as the square root of the mean squared difference in prediction-observation pairings with valid data within a given analysis region and for a given time period by Eq **(5-5)**:

$$RMSE = \left[\frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right)^2\right]^{\frac{1}{2}} \quad (5\text{-}5)$$

The RMSE, as with the gross error, is a good overall measure of model performance. However, since large errors are weighted heavily (due to squaring), large errors in a small sub-region may produce a large RMSE even though the errors may be small and quite acceptable elsewhere.

5.4.1.2 METSTAT Processing

METSTAT was developed to calculate and graphically present statistics associated with temporally paired meteorological model predictions and observations. The horizontal analysis range can be given for an entire output grid, by a coordinate box, or as a list of specific site identifiers (such as WBAN or AIRS numbers), as labeled on the observational file. This allows for an evaluation at a single site, a subset of specific sites (e.g., within a state) or over an entire regional domain. The program then proceeds to calculate statistics for each hour and for each day of the time window.

The process involves statistical comparisons of model data from the WRF grid cells to observational measurements located with each grid cell. METSTAT evaluates wind speed and direction, air temperature, and air humidity using both bias and error statistics. METSTAT has been widely applied to WRF runs for many years, across many modeling domains. Using a consistent definition of the statistical quantities to be calculated and a consistent methodology for pairing observations in time, METSTAT allows for more straightforward comparisons between model applications in widely different regions and time periods.

5.4.2 Statistical Benchmarks

METSTAT calculates statistical performance metrics for bias, error and correlation for surface winds, temperature, and mixing ratio (i.e., water vapor or humidity). To evaluate the performance of a meteorological model simulation for air quality model applications, a number of performance benchmarks for comparison are typically used. Table 5-3 lists the meteorological model performance benchmarks for simple (Emery et al., 2001) and complex (Kemball-Cook et al., 2005) situations. The simple benchmarks were developed by analyzing well-performing meteorological model evaluation results for simple, mostly flat terrain conditions and simple meteorological conditions (e.g., stationary high pressure) that were mostly conducted to support air quality modeling studies (e.g., ozone SIP modeling). The complex benchmarks were developed during the Western Regional Air Partnership (WRAP) regional haze modeling and are

performance benchmarks for more complex conditions, such as the complex terrain of the Rocky Mountains and Alaska (Kemball-Cook et al., 2005). McNally (2009) analyzed multiple annual runs that included complex terrain conditions and suggested an alternative set of benchmarks for temperature under more complex conditions. The purpose of the benchmarks is to understand how good or poor the results are relative to other model applications run for the U.S.

The NM OAI Study 2014 WRF application will compare the WRF meteorological variables to the benchmarks as an indication of WRF model performance. These benchmarks include bias and error in temperature, wind direction and mixing ratio as well as the wind speed bias and Root Mean Squared Error (RMSE) between the models and databases.

Table 5-3. Meteorological model performance benchmarks for simple and complex conditions.

Parameter	Emery et al. (2001)	Kemball-Cook et al. (2005)	McNally (2009)	Resulting Criteria
Conditions	Simple	Complex	Complex	Complex
Temperature Bias	≤ ±0.5 K	≤ ±2.0 K	≤ ±1.0 K	≤ ±1.0 K
Temperature Error	≤ 2.0 K	≤ 3.5 K	≤ 3.0 K	≤ 3.0 K
Temperature IOA	≥ 0.8	(not addressed)	(not addressed)	≥ 0.8
Humidity Bias	≤ ±1.0 g/kg	≤ ±0.8 g/kg	≤ ±1.0 g/kg	≤ ±1.0 g/kg
Humidity Error	≤ 2.0 g/kg	≤ 2.0 g/kg	≤ 2.0 g/kg	≤ 2.0 g/kg
Humidity IOA	≥ 0.6	(not addressed)	(not addressed)	≥ 0.6
Wind Speed Bias	≤ ±0.5 m/s	≤ ±1.5 m/s	(not addressed)	≤ ±1.5 m/s
Wind Speed RMSE	≤ 2.0 m/s	≤ 2.5 m/s	(not addressed)	≤ 2.5 m/s
Wind Speed IOA	≥ 0.6	(not addressed)	(not addressed)	≥ 0.6
Wind Dir. Bias	≤ ±10 degrees	(not addressed)	(not addressed)	≤ ±10 degrees
Wind Dir. Error	≤ 30 degrees	≤ 55 degrees	(not addressed)	≤ 55 degrees

The output from the 2014 36/12/4-km WRF simulations will be compared against meteorological data obtained from the National Climate Data Center's (NCDC) global-scale, quality-controlled DS3505 integrated surface hourly observational (ISHO) data (NOAA-NCDC, 2015) as verification data. Global hourly and synoptic observations are compiled from numerous sources into a single common ASCII format and common data model. The DS3505 database contains records of most official surface meteorological stations from airports, military bases, reservoirs/dams, agricultural sites, and other sources dating from 1901 to the present.

A standard set of statistical metrics from the METSTAT package will be used. These metrics will be calculated on hourly, daily and monthly time frames for wind speed, wind direction, temperature, and humidity at the surface, using all available observational weather data. The WRF surface meteorological model performance metrics will be compared against the simple and complex model performance goals using "soccer plots." Soccer plots use two WRF performance metrics as X-axis and Y-axis values (e.g., temperature bias as X, and temperature error as Y) along with the

performance benchmarks. The closer the symbols are to the zero origin, the better the model performance. It is also easy to see when the two WRF performance metrics fall within the benchmark lines. Figure 5-2 displays an example WRF monthly temperature soccer plot from the 2011 WRF simulations used in the 2017 Denver ozone SIP modeling. We will present WRF 2014 monthly-averaged surface meteorological model performance from the 4-km New Mexico domain with additional performance products produced for the 12-km 12WUS2 and 36-km 36US domains.

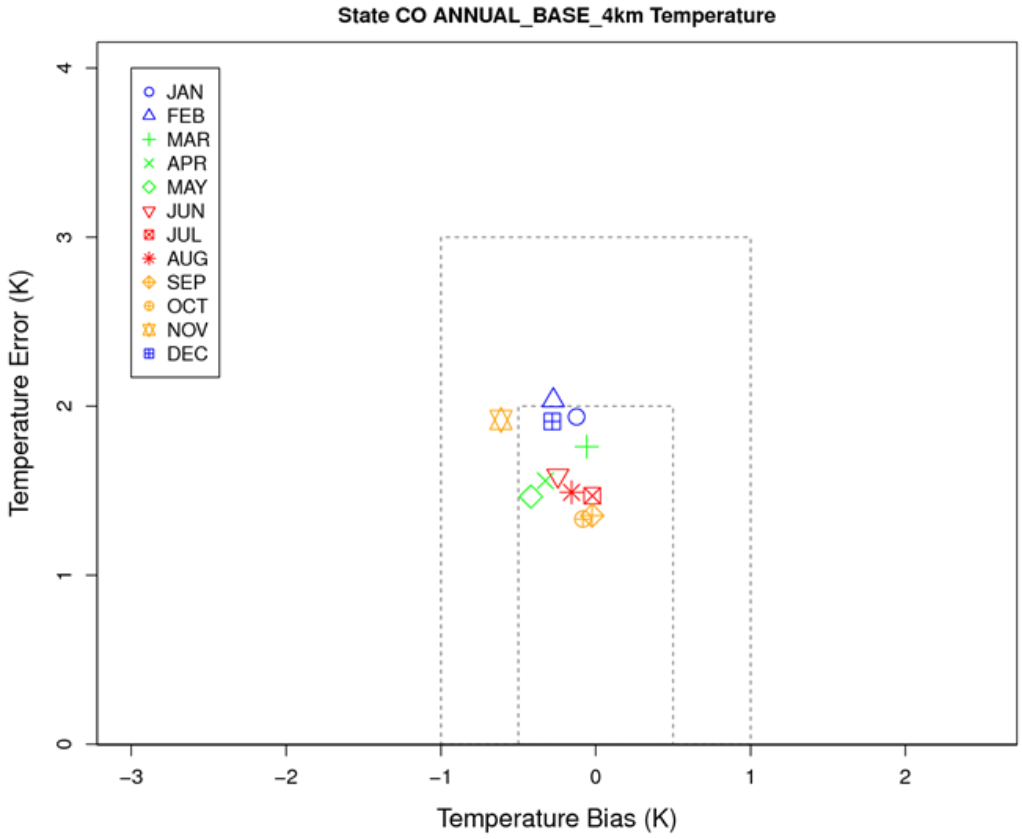


Figure 5-2. Example Soccer plot of monthly temperature error and bias (K) for 4-km domain.

5.4.3 Qualitative Evaluations Using PRISM Data

Oregon State University (OSU) publishes precipitation analysis fields based on observations that can be used to qualitatively evaluate the WRF precipitation fields. The Parameter-elevation Relationships on Independent Slopes Model (PRISM[50]) is used to generate the precipitation analysis fields (Daly et al., 2008). The PRISM interpolation method was used to develop data sets that reflected, as closely as possible, the current state of knowledge of spatial climate patterns in the United States. PRISM calculates a climate – elevation regression for each digital elevation model

[50] http://prism.oregonstate.edu/

(DEM) grid cell, and stations entering the regression are assigned weights based primarily on the physiographic similarity of the station to the grid cell. Factors considered are location, elevation, coastal proximity, topographic facet orientation, vertical atmospheric layer, topographic position, and orographic effectiveness of the terrain.

Spatial plots of the WRF monthly precipitation fields will be compared with the PRISM spatial maps for the 12-km 12WUS2 and 4-km New Mexico modeling domains in a qualitative model evaluation (note that PRISM does not include any analysis fields outside of the U.S.). Daily PRISM precipitation fields will be compared against the WRF daily spatial maps within the 12WUS2 domain and the New Mexico 4-km domain. The WRF performance for daily convective precipitations will be analyzed in particular as overstated summer convective precipitation can suppress ozone formation and its correct simulation is critically important for ozone modeling in New Mexico during the summer monsoon season. In the past WRF has had difficulty in accurately predicting the spatial extent and magnitude of the summer convective precipitation in the IMW region. Note that the PRISM precipitation interpolation scheme works better for synoptic weather systems than for convective showers that can be spotty and intermittent. So even though quantitative statistics can be calculated using the PRISM and WRF precipitation data, the evaluation will still be qualitative in nature as the PRISM interpolation scheme has greater uncertainties for convective precipitation.

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6. PGM BASE YEAR INPUT PREPARATION PROCEDURES

This section summarizes the procedures to be used for developing the base case meteorological, emissions, and air quality inputs for the CAMx photochemical grid model and the summer 2014 modeling period. The modeling procedures used in the NM OAI Study modeling are consistent with almost 30 years of EPA ozone modeling guidance documents (e.g., EPA, 1991; 1999; 2005a; 2007; 2014d; 2018d), past modeling studies of the western U.S. conducted by WRAP and others (see, for example, Morris et al., 2004a,b, 2005a,b; 2007; 2008a,b,c; Tesche et al., 2005a,b; Stoeckenius et al., 2009; ENVIRON, Alpine and UNC, 2013; Adelman, Shankar, Yang and Morris, 2014; 2016), Denver 8-hour ozone SIP modeling (Morris and Mansell, 2003a; Morris et al., 2004d; Morris et al., 2008a,b; Ramboll and Alpine, 2016a,b; 2017a; RAQC and CDPHE, 2017) as well as the methods used by EPA in support of their recent Transport analysis (EPA, 2010; 2015b, EPA, 2016c) and national regional haze modeling (EPA, 2019).

6.1 Meteorological Inputs

Procedures for WRF meteorological modeling for the NM OAI Study 2014 36/12/4-km applications were described in Chapter 5. The WRF meteorological model output data will be processed to provide inputs for the CAMx photochemical grid model.

6.1.1 WRFCAMx Processing of 2014 WRF Output

The WRFCAMx processor maps WRF meteorological fields to the format required by CAMx. It also calculates turbulent vertical exchange coefficients (Kz) that define the rate and depth of vertical mixing in CAMx. Steps in the WRFCAMx processing include:

- Reading in meteorological model output files;
- Extracting meteorological data for PGM domain;
- Collapsing meteorological data if coarser vertical resolution data is requested in the PGMs than used in WRF;
- Computing vertical diffusivities (Kz); and
- Output the meteorological fields in the formats used by CAMx.

Several options are available to derive vertical turbulent exchange coefficient (also known as: Kv, Kz or vertical diffusivity) fields from WRF output in WRFCAMx. When TKE (turbulent kinetic energy) is not available from the WRF output (as is the case with the YSU PBL selected WRF physics options), Kv fields are diagnosed from wind, temperature, and Planetary Boundary Layer (PBL) parameters in WRFCAMx. For this application the CMAQ-like Kv profile option was selected in WRFCAMx, although the YSU Kv profile options will also be investigated.

6.1.2 Treatment of Minimum Kv

The CAMx Kv_patch pre-processor program sets the minimum Kv value to 0.1 to 1.0 m^2/s depending on the amount urban land use category in grid cell in the lowest 100 m

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of the atmosphere. This is done to account for the urban heat island effect that enhances vertical mixing through-out the day.

6.2 Emission Inputs

6.2.1 Available Emissions Inventory Datasets

The emissions inventories developed for the CAMx 2014 36/2/4-km base case modeling will be based on the WRAP/WAQS 2014v2 emissions inventory. Within the 36-km 36US North American and 12-km 12WUS2 western U.S. domains, the 2014v2 base case emissions developed by WRAP/WAQS will be used as is.

For the 4-km New Mexico domain, the WRAP/WAQS 2014v2 emissions will be reviewed by the NMED, who will provide updates as needed. For on-road mobile sources, the 4-km domain emissions will be based on MOVES2014 model, 2014 activity data and day-specific hourly gridded 2014 WRF meteorology run through SMOKE-MOVES.

6.2.2 Development of CAMx Emission Inputs

CAMx emission inputs will be generated mainly by the SMOKE and MEGAN emissions models. CAMx requires two emission input files for each day: (1) low level gridded emissions that are emitted directly into the first layer of the model from sources whose emissions are released at the surface with little or no plume rise; and (2) elevated point sources (stacks) with plume rise calculated from stack parameters and meteorological conditions. CAMx will be operated using version 6 revision 4 of the Carbon Bond chemical mechanism (CB6r4) (Yarwood et al., 2010).

A 2014 base case 4-km New Mexico domain emission inputs for CAMx and the May to August 2014 modeling period will be based on the WRAP/WAQS 2014v2 emissions that were based on the 2014NEIv2 with updates provide by the western states. The New Mexico emissions from the 2014v2 database will be reviewed by the NMED who will provide updates as needed. The 2014v2 emissions for New Mexico and portions of surrounding states within the 4-km New Mexico domain will be processed by the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system (UNC, 2015). SMOKE version 4.7 is the current version of SMOKE that was released in October 2019.[51]

6.2.2.1 Day-Specific On-Road Mobile Source Emissions

The 2014 on-road mobile source emission inputs for the 4-km New Mexico domain will be generated using the SMOKE-MOVES emissions model. SMOKE-MOVES will use a 2014 mobile source emission factor (EF) lookup table generated by the Motor Vehicle Emission Simulator (MOVES2014[52]) model (EPA, 2014a,b,c). The SMOKE-MOVES default county-level 2014 vehicle activity data for New Mexico will be reviewed by NMED and updated as needed. SMOKE-MOVES uses the 2014 MOVES EF lookup table, hourly gridded 4-km meteorological data from the 2014 WRF simulation conducted in this study and 2014 county-level activity data (e.g., vehicle miles travelled [VMT],

[51] https://www.cmascenter.org/smoke/

[52] http://www.epa.gov/oms/models/moves/#user

speed, etc.) to generate 2014 day-specific hourly gridded on-road mobile source emission inputs for CAMx and the 4-km New Mexico domain.

6.2.2.2 Point Source Emissions

2014 point source emissions will be based on the WRAP/WAQS 2014v2 emissions inventory. The 2014v2 New Mexico point source emissions will be reviewed by NMED and updated a needed. Point sources will be processed in two streams: (1) major point sources with Continuous Emissions Monitoring (CEM) devices, which are primarily fossil-fueled Electrical Generating Units (EGU) with capacity of 25 MW or greater; and (2) point sources without CEMs. For point sources with CEM data, day-specific hourly NO_X and SO_2 emissions will be used for the 2014 base case emissions scenario. The VOC, CO and PM emissions for point sources with CEM data will be based on the annual data in the 2014v2 inventory temporally allocated to each hour of the year using the CEM hourly heat input. The hourly CEM data available in the Acid Rain database on the EPA Clean Air Market Division (CAMD) website fills hours with missing CEM data with maximum potential to emit (PTE) emission rates and flags the data. This is because the purpose of the Acid Rain database is to assure that the source is not emitting higher emissions than its cap. Using PTE emissions rates is inappropriate for PGM modeling since the goal is to be accurate. Thus, a data filling program is used that uses the missing data flags to identify hours when the data filled PTE emissions occur, and they are replaced with typical emission rates.

For all point sources the locations of the point sources will be converted to the LCC coordinate system used in the modeling. Non-CEM point sources will be processed by SMOKE to generate the temporally varying (i.e., seasonal, day-of-week and hour-of-day) speciated emissions needed by CAMx. The 2014 point source emissions without CEM data will be processed using SMOKE using the default temporal (e.g., monthly, day-of-week and hourly) and speciation profiles.

6.2.2.3 Area and Non-Road Source Emissions

The 2014v2 area and non-road sources will be spatially allocated to the 4-km New Mexico grid using an appropriate surrogate distribution (e.g., population for home heating, etc.). The area sources will be temporally allocated by month and by hour of day using the SMOKE source-specific temporal allocation factors. The SMOKE source-specific CB6r4 speciation allocation profiles will also be used.

6.2.2.4 Episodic Biogenic Emissions

Biogenic emissions will be generated using Version 3.1 of the MEGAN biogenic emissions model. MEGAN uses high resolution GIS data on plant types and biomass loadings and the 2014 WRF surface temperature fields, and solar radiation to develop hourly emissions for biogenic species on the 36/12/4-km grids. MEGAN generates gridded, speciated, temporally allocated emission files. The MEGAN biogenic emissions will be used for the 36-km 36US, 12-km 12WUS2 and 4-km New Mexico modeling domains. Note that the BEIS biogenic emissions were used in the WRAP/WAQS 2014v2 modeling platform. WRAP/WAQS conducted sensitivity tests using MEGAN v3.0 and BEIS biogenic emissions and found they produced comparable ozone estimates (because the isoprene emissions were similar), but CAMx with BEIS has better Organic

Aerosol (OA) performance[53] than CAMx with MEGAN v3.0 biogenic emissions so WAQS selected BEIS. Since then MEGAN has been updated to version 3.1 and the CAMx OA performance is now similar using MEGAN v3.1 and BEIS.

6.2.2.5 Wildfires, Prescribed Burns, Agricultural Burns

2014 emissions from open-land burning including wildfires, prescribed burns and agricultural burning will be based on the WRAP/WAQS 2014v2 emissions inventory. The WRAP Fire and Smoke Work Group (FSWG[54]) processed the 2014NEIv2 Bluesky/SMARTFIRE fire emissions for the U.S. and classified them as either wildfires (WF), prescribed burns (Rx) or agricultural burning (Ag) and made other updates for the 2014v2 inventory. The 2014NEIv2 fire emissions for Mexico and Canada will be used as is.

6.2.2.6 Other Natural Emissions

Lightning NO_x (LNOx), oceanic sea salt (SSA) and dimethyl sulphide (DMS) and windblown dust (WBD) emissions will be generated using special CAMx processors and WRF 2014 meteorological data.

6.2.2.7 QA/QC and Emissions Merging

The emissions for the 4-km New Mexico domain will be processed by major source category in several different "streams", including area sources, on-road mobile sources, non-road mobile sources, biogenic sources, non-CEM point sources, CEM point sources using day-specific hourly emissions, and emissions from fires. Separate Quality Assurance (QA) and Quality Control (QC) will be performed for each stream of emissions processing and in each step following the procedures developed by WRAP (Adelman, 2004). SMOKE includes advanced quality assurance features that include error logs when emissions are dropped or added. In addition, we will generate visual displays that include:

- Spatial plots of the hourly emissions for each major species (e.g., NO_X, VOC, and CO).
- Summary tables of emissions for major species for each grid and by major source category.
- This QA information will be examined against the original point and area source data and summarized in an overall QA/QC assessment.

Scripts to perform the emissions merging of the appropriate biogenic, on-road, non-road, area and low-level point sources (i.e., point sources with little or no plume rise so they are released into the first layer of the PGM) emission files will be written to generate the CAMx-ready two-dimensional day and domain-specific hourly speciated gridded emission inputs. The point source and fire, emissions would be processed into the day-specific hourly speciated emissions in the CAMx-ready point source format.

[53] http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx

[54] https://www.wrapair2.org/FSWG.aspx

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For the 36/12-km domains we plan on using the model-ready emissions from the WRAP/WAQS 2014v2 modeling platform, with the exception of biogenic emissions where we would replace the BEIS biogenic emissions with those from MEGAN.

The resultant CAMx model-ready emissions will be subjected to a final QA using spatial maps to: (1) assure that the emissions were merged properly and CAMx inputs contain the same total emissions; and (2) provide additional QA/QC information.

6.2.2.8 Use of the Plume-in-Grid (PiG) Subgrid-Scale Plume Treatment

CAMx includes a Plume-in-Grid (PiG) sub-model treats the early plume chemistry and dynamics of emissions from point sources and then releases the emissions into the grid model farther downwind at such time that the plume is adequately resolved by the grid. Large NO_X emissions point sources within the 4-km New Mexico domain will be selected for treatment by the subgrid-scale PiG module. The selection of which sources to be treated by the PiG module will be made after a review of the inventory.

6.2.2.9 QA/QC of Model-Ready Emissions

In addition to the CAMx-ready emission input files generated for each hour of all days modeled in the May-August 2014 modeling period, a number of quality assurance (QA) files will be prepared and used to check for gross errors in the emissions inputs. Importing the model-ready emissions into PAVE or VERDI and examine both the spatial and temporal distribution of the emission to investigate the quality and accuracy of the emissions inputs.

- Visualizing the model-ready emissions with the scale of the plots set to a very low value, we can determine whether there are areas omitted from the raw inventory or if emissions sources are erroneously located in water cells;
- Spot-checking the holiday emissions files to confirm that they are temporally allocated like Sundays;
- Producing pie charts emission summaries that highlight the contribution of each emissions source component (e.g. non-road mobile);
- Normalizing the emissions by population for each state will illustrate where the inventories may be deficient and provide a reality check of the inventories.

State inventory summaries prepared prior to the emissions processing will be used to compare against SMOKE output report totals generated after each major step of the emissions generation process. To check the chemical speciation of the emissions to CB6 species, we will compare reports generated with SMOKE to target these specific areas of the processing. For speciation, the inventory state import totals will be compared against the same state totals with the speciation matrix applied.

The quantitative QA analyses often reveal significant deficiencies in the input data or the model setup. It may become necessary to tailor these procedures to track down the source of each major problem. As such, one can only outline the basic quantitative QA steps that we will perform in an attempt to reveal the underlying problems with the inventories or processing.

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6.3 Photochemical Model Inputs

6.3.1 PGM Science Configuration and Input Configuration

This section describes the CAMx configuration and science options to be used in the NM OAI Study ozone modeling. Table 6-1 summarizes the CAMx configuration to be used, with more details provided below.

6.3.1.1 PGM Model Versions

The latest version 7.0 (v7.0) of CAMx will be used in the NM OAI Study. This is the same version as used in the WRAP/WAQS 2014v2, Representative Baseline and 2028 On-the-Books (OTB) modeling as well as EPA in their national Regional Haze modeling (EPA, 2019). The model will be configured to predict both ozone and PM species.

6.3.1.2 PGM Grid Nesting Strategy

CAMx will be operated using the 36/12/4-km nested grid structure using two-way grid nesting for all simulations.

6.3.1.3 Initial and Boundary Conditions

Boundary Conditions for the CAMx most outer 36-km 36US modeling domain will be based on output from a 2014 simulation of the GEOS-Chem global chemistry conducted by WRAP for their 2014v2 modeling platform. For their 2014v1 modeling platform WRAP used BCs based on EPA's 2014 GEOS-Chem simulation. EPA's 2014 modeling platform was used in the 2014 National Air Toxics Assessment (NATA[55]). However, EPA's 2014 BCs produced a large sulfate overestimation bias in June and July and a year-round ozone overestimation bias. So, WRAP conducted their own 2014 GEOS-Chem modeling to generate new BCs that did not have those problems.

CAMx will be started on May 1, 2016 using the 36/12/4-km domains that will give it over two-weeks to initialize the model before the first high ozone day on May 17, 2014.

6.3.1.4 Other PGM Model Options

The CAMx model options and setup are defined in Table 6-1. The PPM advection solver (Colella and Woodward, 1984) will be used for horizontal transport along with the spatially varying (Smagorinsky) horizontal diffusion approach. K-theory will be used for vertical diffusion. The CB6r4 gas-phase chemical mechanism is selected because it includes the very latest chemical kinetic rates with halogen chemistry that affects ozone levels over the ocean. The latest aerosol mechanism will be used in CAMx along with the standard wet and dry deposition schemes. The Plume-in-Grid module will be used to treat the near-source chemistry and dispersion of major NO_X emissions sources in the New Mexico 4-km domain. For the future year modeling the same point sources will be selected for the plume-in-grid treatment, if they are still operating.

[55] https://www.epa.gov/national-air-toxics-assessment

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Table 6-1. CAMx model configuration for the NM OAI Study.

Science Options	CAMx	Comment
Model Codes	CAMx v7.0	Latest version of CAMx used in WRAP/WAQS 2014v2 and EPA Regional Haze modeling
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes buffer cells
4-km grid	245 x 227 cells	New Mexico 4-km domain. Includes buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 thickness ~20 m. Model top at 50 mb (~19 km)
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 17, 2014
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain
Emissions		
Baseline Emissions Processing	SMOKE, SMOKE-MOVES2014, MEGAN	WRAP/WAQS 2014v2 emissions and EPA 2023fh for future year
Sub-grid-scale Plumes	Plume-in-Grid for major NO_X sources in New Mexico	Keep same PiG sources in 2014 and 2023 emission years
Chemistry		
Gas Phase Chemistry	CB6r4	Latest chemical reactions and kinetic rates with halogen chemistry (Yarwood et al., 2010)
Meteorological Processor	WRFCAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh grid size dependence
Vertical Diffusion	CMAQ-like Kv	Evaluate YSU Kv scheme
Diffusivity Lower Limit	Kv-min = 0.1 to 1.0 m^2/s in lowest 100 m	Depends on urban land use fraction
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	rain/snow/graupel
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative(EBI)	EBI fast and accurate solver
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update	Emery et al., (2009a,b; 2011)
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	Colella and Woodward (1984)
Integration Time Step	Wind speed dependent	~0.5-1 min (4-km), 1-5 min (12-km), 5-15 min (36-km)

7. 2014 BASE CASE MODELING AND MODEL PERFORMANCE EVALUATION

This Chapter describes the CAMx 2014 base case simulations and procedures for model performance evaluation (MPE). The primary purposes of the MPE is to establish the reliability of the CAMx 2014 base case modeling for predicting maximum daily average 8-hour (MDA8) ozone and related concentrations in New Mexico to have confidence that the modeled ozone responses to changes in emissions within New Mexico are accurate enough for air quality planning. The CAMx 2014 base case model estimates are compared against the observed ambient ozone and other concentrations to establish that the model is able to reproduce the current year observed concentrations, so it is likely a reliable tool for estimating future year ozone levels. The model performance evaluation will include many types of graphical and statistical comparisons of the predicted and observed ozone concentrations including spatial plots, scatter plots and time series analysis.

7.1 2014 Base Case Modeling

A CAMx 2014 May-August 36/12/4-km base case simulation will be performed following the procedures outlined in the previous Chapters. The CAMx 2014 base case simulations will then be subjected to a model performance evaluation following the procedures outlined in this Chapter.

7.2 EPA Model Performance Evaluation Recommendations

7.2.1 Overview of EPA Model Performance Evaluation Recommendations

EPA's ozone modeling guidance (EPA, 2018d) describes a MPE framework that has four components:

- Operation Evaluation: The Operation Evaluation compares the modeled concentration estimates against concurrent observations using statistical and graphical analysis aimed at determining how well the model simulates the base year observed concentrations (i.e., does the model get the right answer).
- Diagnostic Evaluation: The Diagnostic Evaluation evaluates various components of the modeling system. It focuses on process-oriented evaluation and whether the model simulates the important processes for the air quality problem being studied (i.e., does the model get the right answer for the right reason).
- Dynamic Evaluation: The ability of the model's air quality predictions to correctly respond to changes in emissions and meteorology is part of the Dynamic Evaluation. This can include running the model for historical years to see whether the model's predictions match the changes in observations; comparison of model performance on weekdays versus weekend days can also help elucidate whether the model response to changes in emissions correctly.
- Probabilistic Evaluation: The Probabilistic Evaluation assess the level of confidence in the model predictions and estimates model uncertainty through techniques such as ensemble model simulations.

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EPA's guidance recommends that "At a minimum, a model used for air quality planning should include a complete operational MPE using all available ambient monitoring data for the base case model simulations period" (EPA, 2018d, pg. 68). And goes on to say, "Where practical, the MPE should also include some level of diagnostic evaluation." EPA notes that there is no single definite test for evaluating model performance, but instead there are a series of statistical and graphical MPE elements to examine model performance in as many ways as possible while building a "weight of evidence" (WOE) that the model is performing sufficiently well for the air quality problem being studied.

7.2.2 WRAP/WAQS Companion Model Performance Evaluation

The WRAP/WAQS has conducted CAMx 2014v2 36/12-km base case modeling and MPE. The MPE of the WRAP/WAQS 2014v2 platform results will be used to help interpret the NM OAI Study MPE and put it into context.

7.3 Overview of Evaluation of CAMx 2014 Base Case Procedures

This section describes the procedures for evaluating the performance of the CAMx model focusing on ozone and related species in New Mexico.

7.3.1 Photochemical Model Evaluation Methodology

The CAMx performance evaluations will follow the procedures recommended in the EPA photochemical modeling guidance documents (EPA, 1991; 1999; 2005a; 2007; 2014d; 2018d), EPA MPE Checklist (EPA, 2015a,b), procedures discussed by Boylan and Russell (2006), Simon, Baker and Phillips (2012) and Emery and co-workers (2016). The NM OAI Study CAMx 2014 MPE will be conducted in a series of levels with each level diving more deeply into the MPE. An initial performance would focus on ozone performance at key monitors in New Mexico in 2014 to identify systematic problems that would require immediate corrective action. The MPE would then be expanded to ozone and ozone precursors across New Mexico and nearby states, especially those portions within the 4-km New Mexico domain. Finally, a broad-brush evaluation would be conducted across the western U.S. for ozone and where available its precursors.

7.3.2 Model Performance Goals and Benchmarks

EPA first proposed the use of ozone model performance goals in their 1991 ozone modeling guidance (EPA, 1991) with goals for bias (≤±15%) and error (≤35%). Since then, EPA has de-emphasized the use model performance goals as some users were focusing on achieving the model performance goals not on whether the model was accurately simulating atmospheric processes that led to the high ozone concentrations. However, model performance goals are still useful for interpreting model performance and putting the model performance into context. Since the EPA 1991 ozone guidance performance goals, Boylan and Russell (2006) extended the performance goals to PM species and visibility. Simon, Baker and Phillips (2012) summarized the model performance statistics from 69 PGM applications from 2006 to 2012 and found lots of variability but were able to isolate model performance statistical levels for the best performing models.

Emery et al., (2016) built off the work of Simon, Baker and Phillips (2012) adding additional PGM model applications and coming up with a set of PGM model performance

goals and criteria based on the variability in the past PGM model performance. "Goals" indicate statistical values that about a third of the top performance past PGM applications have met and should be viewed as the best a model can be expected to achieve. "Criteria" indicates statistics values that about two thirds of past PGM applications have met and should be viewed as what a majority of the models have achieved. We will compare the CAMx 2014 base case simulations model performance statistics for normalized mean bias (NMB), normalized mean error (NME) and correlation coefficient (r) against the model performance goals and criteria summarized by Emery et al., (2016) that are given in Table 7-1.

Table 7-1. Recommended benchmarks for photochemical model statistics (Source: Emery et al., 2016).

Species	NMB		NME		r	
	Goal	Criteria	Goal	Criteria	Goal	Criteria
1-hr & MDA8 Ozone	<±5%	<±15%	<15%	<25%	>0.75	>0.50
24-hr $PM_{2.5}$, SO_4, NH_4	<±10%	<±30%	<35%	<50%	>0.70	>0.40
24-hr NO_3	<±15%	<±65%	<65%	<115%	NA	NA
24-hr OC	<±15%	<±50%	<45%	<65%	NA	NA
24-hr EC	<±20%	<±40%	<55%	<75%	NA	NA

7.3.3 Available Aerometric Data for the Evaluations

The following monitoring networks were operating in 2014 so these data that can be used in the MPE.

EPA AQS Surface Air Quality Data: Data files containing hourly-averaged concentration measurements at a wide variety of state and EPA monitoring networks are available in the Air Quality System (AQS[56]) database throughout the U.S. Typical surface measurements at the ground level routine AIRS monitoring stations include ozone, NO_2, NO_X and CO.

IMPROVE Monitoring Network: The Interagency Monitoring of Protected Visual Environments (IMPROVE[57]) network collects 24-hour average $PM_{2.5}$ and PM_{10} mass and speciated $PM_{2.5}$ concentrations at many sites across the U.S. on a 1:3 day sampling frequency, including most Class I areas.

CSN Monitoring Network: The Chemical Speciation Network (CSN[58]) collects 24-hour average speciated $PM_{2.5}$ components on a 1:3 or 1:6-day sampling frequency. CSN monitoring sites tend to be urban oriented as compared to IMPROVE sites that are typically rural.

[56] http://www.epa.gov/ttn/airs/airsaqs/aqsweb/
[57] http://vista.cira.colostate.edu/IMPROVE/
[58] http://www.epa.gov/ttnamti1/speciepg.html

FRM Monitoring Network: 24-hour total $PM_{2.5}$ mass is collected using the federal Reference Method (FRM[59]) on a 1:3-day sampling schedule.

CASTNet Monitoring Network: The Clean Air Status and Trends Network (CASTNet[60]) operates approximately 80 monitoring sites in mainly rural areas across the U.S. CASTNet sites typically collect hourly ozone and weekly speciated $PM_{2.5}$, including HNO3. There is one CASTNet site located in the northwest corner of New Mexico (Chaco Culture NHP), although there are several more within the 4-km New Mexico modeling domain in neighboring states (i.e., Colorado and Arizona).

NADP Network: The National Acid Deposition Program (NADP[61]) collects weekly samples of SO_4, NO_3 and NH_4 in precipitation (wet deposition). There are also some sites that collect daily samples as well as mercury.

7.4 Operational Evaluation

As noted above, the Operational Evaluation compares the modeled concentrations with concurrent observations. Various tools and graphical displays and statistical methods are used as part of the Operational Evaluation as discussed below.

7.4.1 Atmospheric Model Evaluation Tool (AMET)

The Atmospheric Model Evaluation Tool (AMET[62]) (Appel et al., 2011) is a suite of software designed to facilitate the analysis and evaluation of predictions from meteorological and air quality models. AMET matches the model output for grid cells with observations from monitoring site locations from one or more networks of monitors. AMET also does species mappings to map the modeled species to the corresponding observations. These pairings of values (model and observation) are then used to statistically and graphically analyze the model's performance using a variety of techniques, many of which will be used in the CAMx 2014 base case MPE. The latest version of AMET is version 1.4, but AMET website doesn't have any information on its release date or documentation so we assume the documentation for AMET v1.3[63] is pertinent for AMET v1.4.

7.4.2 Example Operational Model Performance Evaluation Products

Below we use the results from the 2016 Denver ozone SIP (RAQC and CDPHE, 2016) modeling MPE (Ramboll and Alpine, 2017) for the 2011 CAMx ozone modeling platform to illustrate the type of MPE products that will be produced in the NM OAI Study. Summary tables of ozone statistical model performance metrics across sites in New Mexico will be produced. Such ozone performance statistics can be calculated with and without observed cut-off concentrations as illustrated in the next section. AMET comes pre-loaded with observation data from multiple networks that were described previously:

[59] http://www.epa.gov/ttn/airs/airsaqs/detaildata/downloadaqsdata.htm
[60] http://java.epa.gov/castnet/
[61] http://nadp.sws.uiuc.edu/NADP/
[62] https://www.cmascenter.org/amet/
[63] https://www.cmascenter.org/help/documentation.cfm

- Air Quality System (AQS) network
- Clean Air Status and Trends Network (CASTNET)
- Interagency Monitoring of PROtected Visual Environments (IMPROVE)
- Mercury Deposition Network (MDN)
- National Atmospheric Deposition Program (NADP)
- South-Eastern Aerosol Research and Characterization Study (SEARCH)
- Chemical Speciation Network (CSN; formerly STN)

AMET will be the primary MPE tool used in the CAMx 2014 base case simulations augmented by other MPE tools as necessary. Some example MPE displays are described in the following sections.

7.4.2.1 Soccer Plots for Comparing Performance Statistics with Goals and Criteria

Soccer Plots display ozone (or other species) model performance statistics against model performance goals and/or criteria using a scatter plot, such as bias on the x-axis and error on the y-axis. When the statistics achieves the goal, it falls within the box outlined by the goals. For example, Figure 7-1 shows ozone monthly fractional bias and error (FB and FE) performance statistics against a 15% and 35% performance goal, respectively, for the 2011 CAMx base case from the 2016 Denver ozone SIP. The Soccer Plots are for hourly (right) and MDA8 (left) ozone using no (top) and a 60 ppb (bottom) cut-off concentration. Using Soccer Plots, it is easy to determine when the performance statistics are achieving the goals and as the symbols approach the (0,0) origin that indicates better model performance. Although the example in Figure 7-1 is for monthly performance, the different symbols could be for different monitoring sites, specific modeling days with ozone exceedance days, stratified by observed ozone concentrations or stratified by any other variable that provides insight into the MPE.

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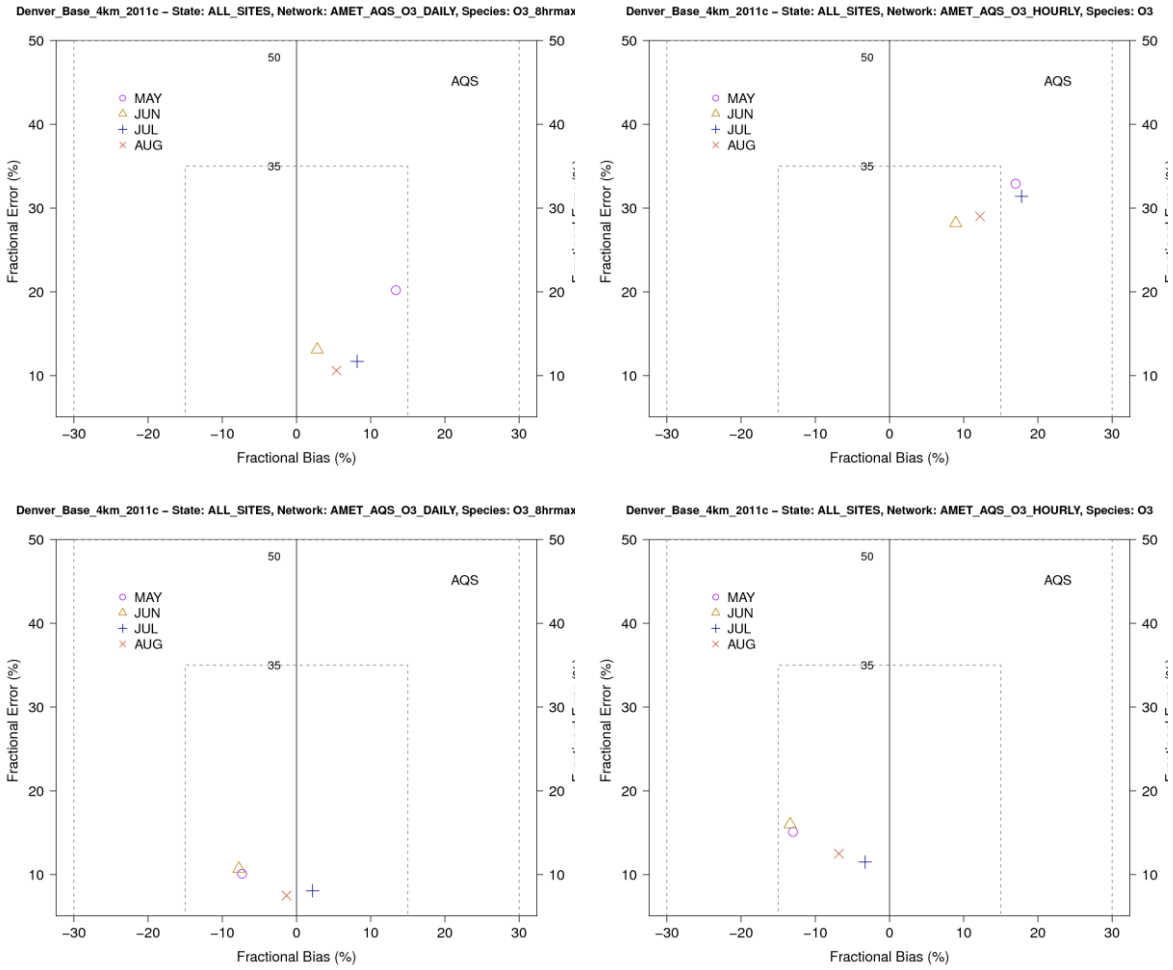


Figure 7-1. Example Soccer Plots of MDA8 (left) and hourly (right) ozone bias (FB) and error (FE) performance using no (top) and 60 ppb (bottom) observed ozone cut-off concentration (Source: Ramboll and Alpine, 2017).

7.4.2.2 Spatial Maps of Statistical Model Performance

AMET can generate spatial maps of different statistical performance metrics where the different colored symbols at the locations of monitoring sites allows an assessment of performance by geographic location. For example, Figure 7-2 displays the MDA8 ozone monthly bias (NMB) spatial plot from the CAMx 2011 base case simulation and shows an overestimation bias in May at many sites (yellow) with most of the sites achieving the <±15% performance goal for the other three months. The exception is the DMAS site in downtown Denver and the FTCO site in Fort Collins that are located close to mobile NOx emissions that titrate the ozone that is not reproduced by the model due to dilution of the local NOx emissions across a 4-km grid cell.

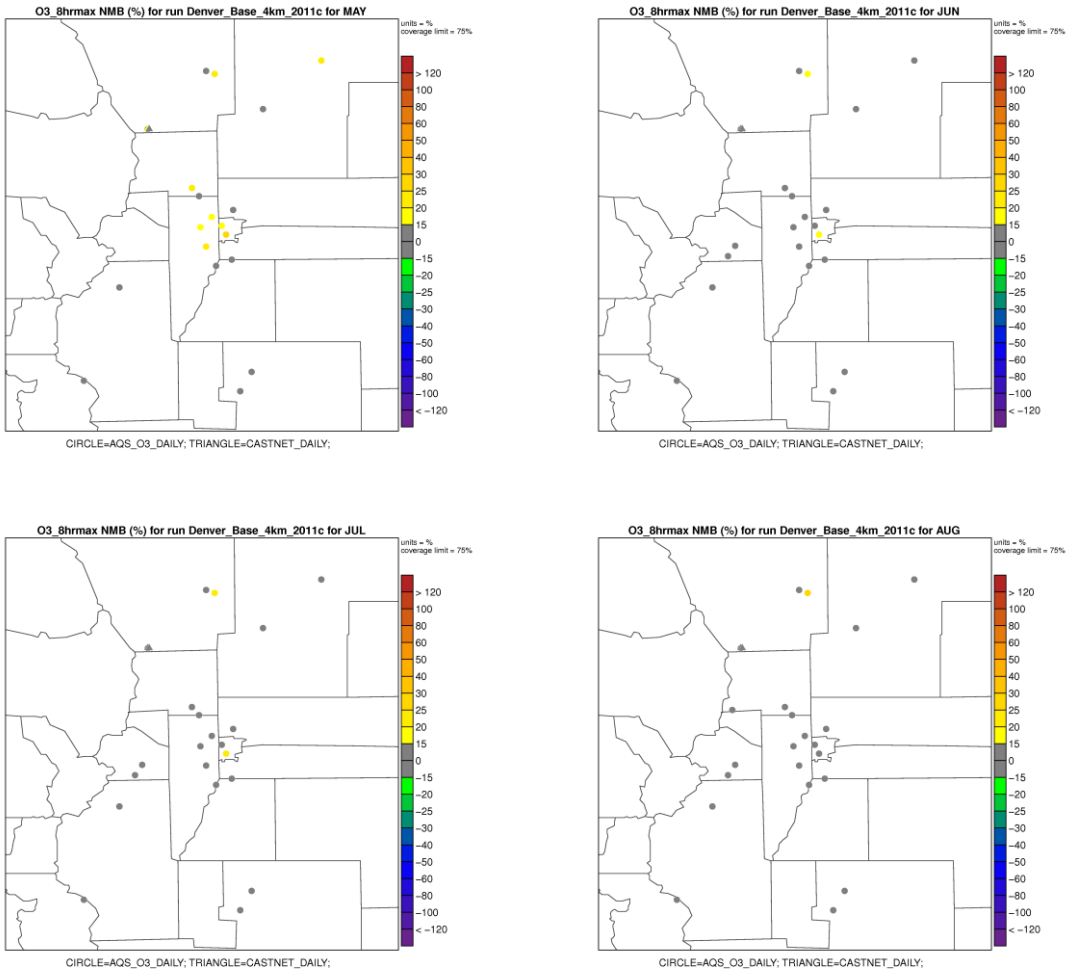


Figure 7-2. Spatial statistics plot of MDA8 monthly ozone model performance for Normalized Mean Bias (NMB), AQS sites in the Denver Metro/NFR NAA using no observed ozone cut-off concentration and May (top left), June (top right), July (bottom left) and August (bottom right) (Source: Ramboll and Alpine, 2017).

7.4.3 Scatter Plots of Model Performance

Scatter Plots are a main stay of MPE as they allow you to directly see the point-by-point comparison of predicted and observed concentrations. Figure 7-3 shows example MDA8 (left) and hourly (right) ozone scatter plots for July without (top) and with a 60 ppb observed ozone cut-off concentration from the CAMx 2011 base case simulations. In this case ozone performance for two different CAMX base cases are shown (red and blue symbols) and summary performance statistics are also displayed. The model has difficulty in predicting the lowest observed hourly ozone concentrations (see comment above on DMAS and FTCO ozone over-prediction bias), which appears to have little effect on MDA8 ozone MPE or hourly ozone performance when a 60 ppb observed ozone cut-off is used.

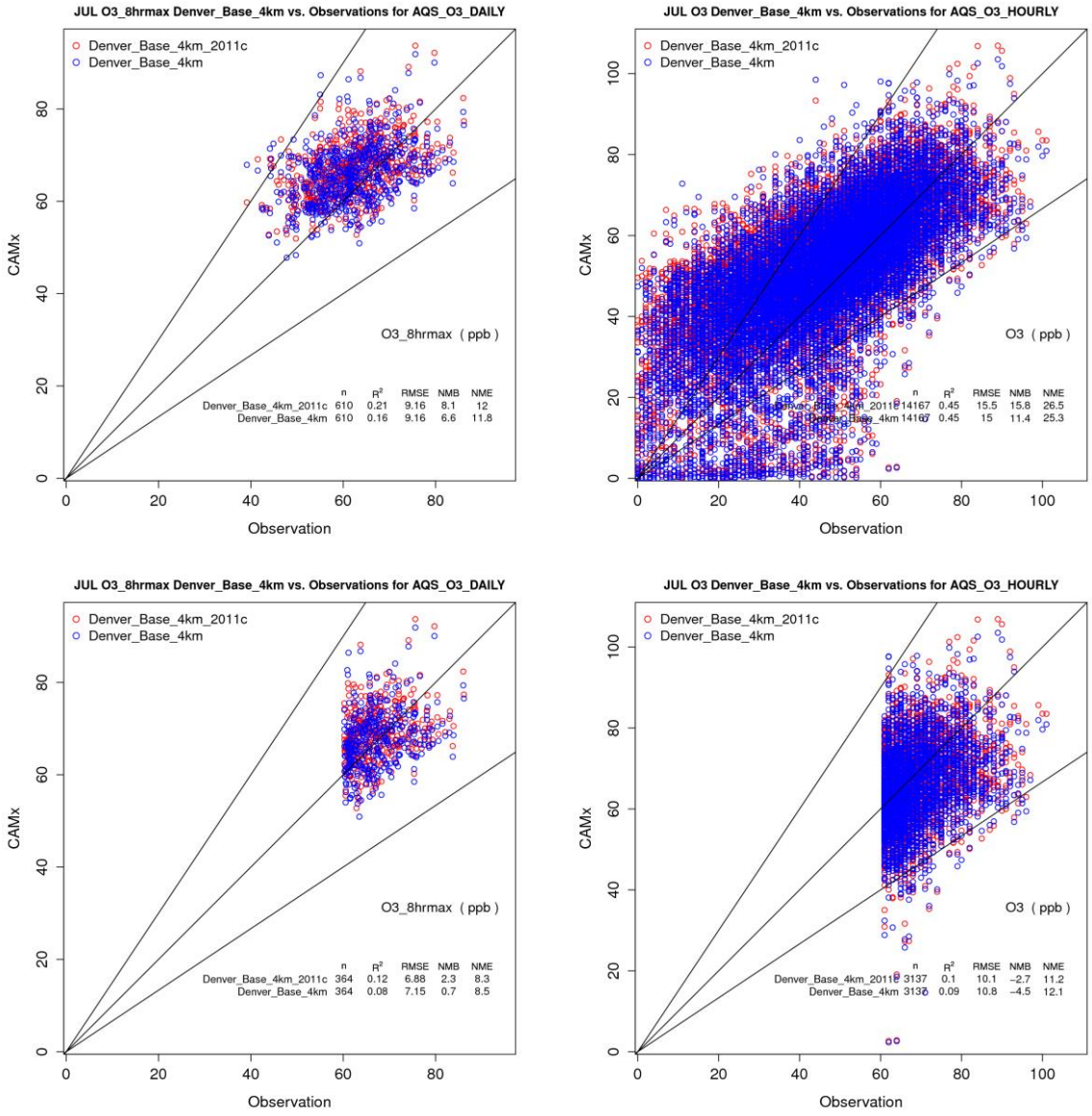


Figure 7-3. Scatter plots and model performance statistics for MDA8 (left) and hourly (right) ozone concentrations using no (top) and 60 ppb (bottom) observed ozone cut-off concentrations during the month of July (Source: Ramboll and Alpine, 2017).

7.4.4 Time Series of Predicted and Observed Concentrations

Time series of predicted and observed concentrations is another main stay of a MPE and focuses of the temporal evaluation of model performance at particular sites. For example, Figure 7-4 displays time series of predicted and observed July and August MDA8 ozone concentrations at the RFNO monitoring site for two CAMx 2011 base case simulations from 2016 Denver ozone SIP. These displays not only include the MDA8 ozone concentrations levels but the daily bias (i.e., different in the predicted and observed MDA8 ozone.

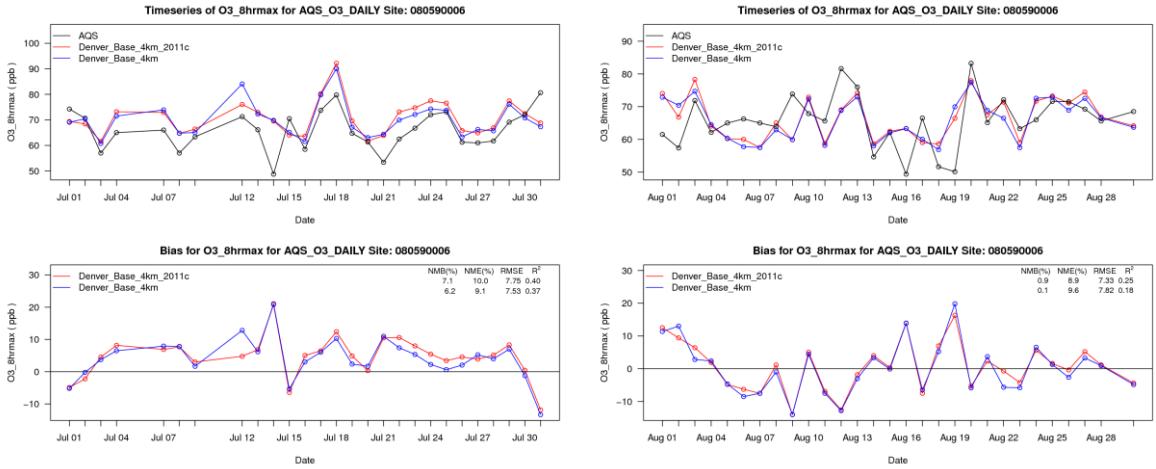


Figure 7-4. Time series of predicted and observed (black) MDA8 ozone concentrations (top panel) and bias (bottom panel) at Rocky Flats North (RFNO) for the preliminary 2011b1 (blue) and final 2011c (red) CAMx 4 km base case simulations and the months of July (left) and August (right) (Source: Ramboll and Alpine, 2017).

7.4.5 Evaluation for the Modeled MDA8 Ozone Concentrations

An important component of a PGM MPE is to evaluate the model for how well it predicts the modeled 10 highest MDA8 ozone concentrations because of the way the base and future year modeling results are used to project future year ozone DVs. The relative change in the base and future modeling results are used to project the current year observed ozone DVs to the future year. EPA's modeling guidance (EPA, 2018d) describes how to use the PGM modeling results to make the future year ozone DV projections with details presented in Chapter 8. The 10 highest base year modeled MDA8 ozone concentrations near a monitoring site are used to make the future year DV projections. It is desirable for the modeled MDA8 ozone concentrations on these 10 highest modeled base year ozone concentrations to match the observed MDA8 ozone concentrations on the same day sufficiently well. Thus, the model performance for the days used in the future year ozone DV projections are evaluated. As discussed in more detai8l in Chapter 8, alternative ozone DV projection techniques use the 10 highest modeled MDA8 ozone concentrations near a monitor just on those days in which the

modeled MDA8 ozone reproduces the observed MDA8 ozone with some performance criteria (e.g., < 10%. < 15%, < 20%).

7.5 Diagnostic Evaluation

The goal of the diagnostic evaluation is to assure that the model is simulating the correct physical and chemical processes that control the formation of ozone from the precursor emissions. Such processes include transport, dispersion, deposition and chemical transformation. The diagnostic evaluation investigates the processes that determine the ambient concentrations of ozone and related pollutants to develop confidence that the model's ozone response to changes in emissions will be accurate.

7.5.1 Base Year Base Case Diagnostic Sensitivity Tests

When developing a PGM base year base case model configuration, diagnostic sensitivity tests are frequently used to evaluate the sensitivity of the model to alternative inputs or model options in an effort to obtain a better performing base year base case simulation. For example, if two WRF base year simulations are available, the PGM could be run with both sets of WRF meteorological inputs to determine which one produces better performing PGM simulations. However, care must be taken that compensatory errors are not introduced.[64] For the NM OAI Study that is leveraging the WRAP/WAQS 2014v2 modeling platform, many diagnostic tests have already been performed so additional diagnostic sensitivity tests are likely not needed unless performance issues arise. The WRAP/WAQS modeling conducted the following diagnostic sensitivity tests that led to the 2014v2 base case CAMx configuration.

- Boundary Conditions (BC) Sensitivity: WRAP/WAQS initially used BCs based on EPA's 2014 GEOS-Chem simulation and found them inadequate so WRAP conducted their own 2014 GEOS-Chem simulation and generated BCs that greatly improved model performance.
- Vertical Mixing Sensitivity: This is a frequent sensitivity test to analyze alternative formulation of vertical mixing (Kz) formulations and the treatment of the minimum Kz near the surface that is especially important for cities where the urban heat island affects vertical mixing.
- Other Meteorological Sensitivity: The WRAP/WAQS evaluated the EPA's 2014 WRF meteorological simulations as input to CAMx and selected the WAQS 12-km data due to better precipitation model performance.
- Emissions Sensitivity: Increases or decreases in emissions (e.g., VOC and/or NO_x) from specific source categories or other emissions perturbation:
  - Top down studies have suggested oil and gas emissions may be under- or over-estimated.
  - Some studies have suggested MOVES mobile source NOx emissions may be overestimated, particularly in urban areas.
  - NO_x emissions are almost always produced by combustion so typically are hotter than ambient air so have some buoyancy and plume rise even if

[64] Compensatory errors can occur when two incorrect inputs compensate for each other so the PGM achieves seemingly good model performance, but for the wrong reason. For example, PGM modeling of Los Angeles in the late 1970s and early 1980s had a deficient VOC emissions inventory that was compensated for by overstated the Boundary Conditions.

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emitted at the surface (e.g., mobile sources). By trapping them in the lowest layer (20-m in this case) it may overstate surface NO_x emissions. Emitting some of the NO_x in layer 2 may alleviate this condition, alternative the surface minimum Kz mixing parameter may also address this issue.

- Biogenic and lightning NO_x emissions are uncertain and the sensitivity to their estimates could be investigated.

- Other Sensitivity: In the development of the CAMx 2014 base case modeling platform we may find inputs or parameterizations that are uncertain how to define so warrant further investigation.

When the initial results of the CAMx 2014 base year base case MPE are obtained, they will be shared with NMED to determine a path forward and if additional sensitivity tests may be needed and as time and resource constraints allow.

7.5.2 Additional Diagnostic Evaluation Approaches

Diagnostic Evaluation of a PGM can use several different techniques to diagnose features regarding model performance, such as evaluation of how the model responds to changes in inputs or simulates specific processes important for simulating the air quality issue being studied. The CAMx is instrumented with "probing tools" that can explore attributes of the model during a simulation, including ozone and particulate source apportionment (OSAT/PSAT), Decoupled Direct Method (DDM) sensitivity and Process Analysis. The most common type of diagnostic evaluation involves using the Brute Force (BF) approach where a model base case and model perturbation case is performed, and the sensitivity of the model estimates are the differences in the output concentrations between the two BF runs.

The comparison of modeling results with observations for key indicator species can also be a useful diagnostic evaluation technique. Section 3.4.2 of EPA's PGM modeling guidance list several species indicator ratios that suggest whether the atmosphere and/or model ozone formation is more VOC-limited or NO_x-limited (EPA, 2018a, pp. 92-95). However, many of these indicator ratios involve species not routinely measured and may require more precision than typically obtained.

Although a comprehensive diagnostic sensitivity analysis may not be possible given resource and time constraints, some elements of a Diagnostic Evaluation is expected to occur.

7.6 Dynamic Evaluation

The Dynamic Evaluation evaluates a PGM for the way it is primary used in an ozone SIP as it evaluates how well the modeled ozone response to emissions changes with observed responses. The most comprehensive dynamic evaluation is to compare model responses to observed historical changes in ozone concentrations in a retrospective analysis. Because differences in meteorology between years can have as much or even more effect on observed ozone concentrations, such dynamic evaluation could include not only running with different historical years of emissions, but also running with different historical years of meteorology. Thus, this kind of retrospective analysis dynamic evaluation can be quite resource and time intensive. The WRAP/WAQS is

conducting a Dynamic Evaluation of their 2014v2/RepBase modeling platform by back casting 2014v2 emissions to 2002 and comparing the changes in observed and modeled concentrations form a past year (2002), to a current year (2014 and RepBase) that can be potentially used as a Dynamic Evaluation in the NM OAI Study.

Another dynamic evaluation approach that is not as resource intensive as a retrospective modeling analysis is to stratify the operational model performance under varying conditions, such as day-of-week (e.g., weekday vs. weekend day), by season or by region. When the model shows the same ozone response as observed across these different chemical regimes, it supports the assertion that the modeled ozone concentrations would respond correctly to changes in emissions over time.

7.6.1 Probabilistic Evaluation

The probabilistic evaluation attempts to assess the level of confidence in the model predictions through techniques such as ensemble of model simulations. At this time, there are no plans to incorporate the probabilistic evaluation as part of the NM OAI Study.

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8. FUTURE YEAR MODELING

This Chapter describes the 2023 future year modeling to evaluate source contributions to ozone concentrations in New Mexico and potential control strategies designed to reduce ozone.

8.1 Future Year to be Modeled

There is no Federal regulation guiding the NM OAI Study future year modeling. Thus, we selected the 2023 future year due to the available of EPA's 2023fh emissions inventories developed as part of the EPA 2016v1 modeling platform. EPA also developed a 2028fh emissions that is too far out in the future and portions of a 2020 emissions inventory that is too current. Thus, the 2023 future year seemed an ideal choice for the NM OAI Study.

8.2 Future Year Emissions

2023 future year anthropogenic emissions will be used in the future year modeling. The following natural emission sources will be assumed to remain unchanged from 2014 base year base case levels:

- Biogenic emissions.
- Lighting NOx emissions.
- Ocean Sea Salt and DMS emissions.
- Windblown Dust.
- Open Land Fires (Wildfires, Prescribed Burns and Agricultural Burning).

8.2.1 2023 Future Year Anthropogenic Emissions

The primary source of the 2023 future year anthropogenic emissions is the 2023fh emission projections from the joint EPA/MJO 2016 emissions inventory collaborative development study. EPA's 2016v1 modeling platform included model-ready 2023 emissions for the 36/12-km domains that can be used "as is" for the NM OAI Study except for on-road mobile source emissions that were developed using SMOKE-MOVES and the 2016 meteorological conditions. For the 12-km 12WUS2 domain we will run SMOKE-MOVES using the 2023 MOVES EF Look-Up table, 2023 vehicle activity and the 2014 WRF meteorological conditions.

For the 4-km New Mexico domain, the EPA 2023fh New Mexico emissions will be reviewed and updated by NMED as needed and processed with SMOKE to generate 4-km resolution emission inputs for the 4-km New Mexico domain. The 2023 MOVES inputs and 2023 vehicle activity data will also be reviewed and updated by NMED as needed and SMOKE-MOVES run using the 2023 MOVES EF Look-Up table, 2023 vehicle activity and 4-km hourly gridded WRF data to generate 2023 on-road mobile emission inputs.

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8.2.2 Future Year Emissions Quality Assurance

Similar QA/QC procedures (e.g., as described in Adelman, 2004; UNC, 2018; EPA, 2018a) will be performed on the future year model-ready emissions inventories as were utilized in checking the base year datasets described previously. Standard inventory assessment methods will be employed to generate the future year emissions data including, but not limited to: (a) visualizing the model-ready emissions graphically, (b) spot-checking the holiday emissions files to confirm that they are temporally allocated like Sundays, (c) producing pie charts emission summaries for each source category, and (d) normalizing the emissions by population for each state to reveal where the future year inventories may be suspect. Of particular importance will be the comparison of the 2014 base year and 2023 future year emissions by source category and region to make sure the expected changes occurred in the modeling inventories.

8.3 Future Year CAMx Modeling

The 2023 future year CAMx base case modeling will be performed the same way that the 2024 base year base case modeling was performed only using the 2023 future year anthropogenic emissions. The CAMx PGM will be applied on the 36/12/4-km nested grid domain structure using two-way grid nesting. Due to uncertainties in global emissions, the BCs based on the WRAP 2014 GEOS-Chem simulation will also be used for 2023.

Future year ozone DV projections will be made using the 2014 base case and 2023 future year CAMx simulation outputs following the procedures given in Chapter 9 that use EPA's latest 8-hour ozone modeling guidance (EPA, 2018d).

8.3.1 Future Year Ozone Source Apportionment Modeling

The CAMx Anthropogenic Precursor Culpability Assessment (APCA) version of the Ozone Source Apportionment Technology (OSAT) will be used to estimate 2023 future year contributions of emissions from U.S. and international anthropogenic emissions and natural emissions from different geographic regions on ozone concentrations in New Mexico. A 2023 future year CAMx 36/12/4-km nested grid simulations will be conducted using geographic source regions defined by New Mexico and other nearby state boundaries and separating anthropogenic sources from natural sources. Fires would also be treated as a separate source category. The CAMx 2023 future year ozone source apportionment modeling will also provide separate contributions by Source sector for emissions in New Mexico and outside New Mexico as follows:

- Upstream Oil and Gas.
- Midstream Oil and Gas.
- EGU Point.
- Non-EGU Point.
- On-Road Mobile.
- Non-Road Mobile.
- Other Anthropogenic.

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- Fires (WF, Rx and Ag).
- Natural
- BC from International Anthropogenic Emissions.
- BC from US Anthropogenic Emissions.
- BC from Natural Sources.
- Initial Concentrations.

The exact definition of the 2023 ozone source apportionment modeling will be documented and provided to NMED for review and refinements later in the NM OAI Study.

8.3.2 Future Year Sensitivity and Control Strategy Simulations

2023 future year control strategy sensitivity simulations will be conducted. The definitions for the 2023 control strategy sensitivity scenarios will be provided by NMED at a later date,

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9. FUTURE YEAR OZONE PROJECTIONS

EPA's latest ozone State Implementation Plan (SIP) modeling guidance (EPA, 2018d) contains detailed procedures for how to use base year and future year photochemical grid model (PGM) modeling results to make future year ozone Design Value (DV) projections. The EPA-recommended ozone attainment demonstration includes a model attainment test for projecting base year ozone DVs to the future year and a weight of evidence (WOE) analysis used to confirm and corroborate the modeled attainment demonstration test. EPA has developed the Speciated Modeled Attainment Test (SMAT[65]) tool that includes the EPA (2018d) recommended procedures for projecting ozone DVFs.

9.1 EPA Recommended Future Year Ozone DV Projection Procedures

The procedures for making future year ozone DV projections are outlined in Chapter 4 of EPA's latest ozone modeling guidance (EPA, 2018d, pp. 99-110). EPA recommends using PGM modeling results in a relative fashion the scale base year ozone DV (DVB) to estimate the future year ozone DV (DVF). The model derived scaling factors are called Relative Response Factors (RRF) and are the ratio of future to base year ozone modeling results.

$$DVF = DVB \times RRF$$

Below we highlight the key elements in EPA's recommended ozone DV projection approach, more details and justification for the approach are provided in EPA's modeling guidance (EPA, 2018d).

9.1.1 Base Year Ozone Design Value (DVB)

The DVB is defined as the average of three-years of ozone DVs centered on the base modeling year. As an ozone DV is defined as the three-year average of the 4th highest MDA8 ozone concentrations at a monitor, the DVB is based on 5 years of 4th highest MDA8 ozone concentrations centered on the base year so the highest weight (3x) is on the 4th highest MDA8 ozone for the base year with less weights in the 2 years before and after the base year (i.e., weighting factors of 1, 2, 3, 2, 1).

For the NM OAI Study modeling, the base year is 2014 so that the DVB at each site will be defined from three years of ozone DVs as follows:

$$DVB_{2014} = (DV_{2012\text{-}2014} + DV_{2013\text{-}2015} + DV_{2014\text{-}2016}) / 3$$

9.1.2 Calculation of Relative Response Factors (RRFs)

The RRF is defined as the ratio of the average of the PGM future year (FY) to base year (BY) MDA8 ozone concentrations near the monitor for the 10 days with the -highest base year modeled MDA8 ozone concentrations near the monitoring site.

[65] https://www.epa.gov/scram/photochemical-modeling-tools

$$RRF = \sum MDA8\ Ozone_{FY} / \sum MDA8\ Ozone_{BY}$$

Near the Monitor: By near the monitor, the highest modeled base year MDA8 ozone is selected in a 3x3 array of grid cells centered on the monitor is used. For the future year, the future year MDA8 ozone is selected from the same grid cell in the 3x3 array centered on the monitor as used in the base year.

10 Highest Base Year MDA8 Ozone Days: The RRF is based on the 10 days with the highest base year modeled MDA8 ozone concentrations near the monitor, provided the base year MDA8 ozone is greater or equal to 60 ppb. If there are less than 10 days with base year MDA8 ≥ 60 ppb, then just the days ≥ 60 ppb are used provided there are at least 5 days. If there are less than 5 days with base year MDA8 ozone ≥ 60 ppb EPA recommends that RRFs not be calculated for that site.

9.1.3 Flexibility in RRF Calculations

EPA's modeling guidance includes the flexibility to modify the recommended ozone DV projection procedure. For example, there may be a reason that grid cells in the 3x3 array centered on the monitor may not be representative of conditions at the monitor. For example, if a grid cell is dominated by water so has different mixing characteristics or the monitor is in an area with sharp terrain gradients.

There may be also reasons that one of the highest 10 base year MDA8 ozone days should not be used in the RRF. For example, if the modeled base year MDA8 ozone is highly influenced by emissions from wildfires it could be excluded and then the next highest modeled MDA8 ozone included so that 10 modeled days are still used in the RRF.

The PGM model performance on the 10 highest modeled MDA8 ozone days may also be considered in selected the top 10 modeled MDA8 ozone days to use in the RRFs.

9.2 Unmonitored Area Analysis (UAA)

An unmonitored area analysis (UAA) will be conducted using the SMAT tool. The UAA first interpolates the ozone DVB to each 4-km grid cell in the New Mexico 4-km domain. The interpolation will be done with and without accounting for modeled concentration gradients. Once a gridded field of ozone DVB is obtained, the ozone DVB are projected to the future using the same procedures as used in the modeled attainment test only the modeling results at the grid cell containing the monitor is used and there is typically some relaxation of the requirement for MDA8 ozone to be above 60 ppb since the UAA is making projections in fairly clean ozone concentrations regions. The gridded future year ozone DVFs are then analyzed to determine locations with grid cells that exceed the ozone NAAQS. Note that estimate locations of ozone DVFs above the ozone NAAQS in the UAA does not necessarily imply a failure to demonstrate attainment. For example, when modeled concentration fields are used in the UAA ozone DVB interpolation frequently at locations of wildfires the ozone DVB and DVF are above the NAAQS. But any UAA ozone DVF exceedances of the NAAQS should be identified and explained in the analysis.

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9.3 Weight of Evidence (WOE) Attainment Demonstration

The Weight of Evidence (WOE) is a necessary and critically important component of the ozone attainment demonstration. As stated in EPA's modeling guidance, "By definition, models are simplistic approximations of complex phenomena" (EPA, 2018a, pp. 169). EPA guidance recommends three types of supplemental analysis to support a modeled attainment demonstration:

1. Additional modeling analysis.
2. Analysis of trends in ambient concentrations and emissions.
3. Additional emission controls.

As the NM OAI Study is not a formal regulatory SIP ozone attainment demonstration study, then a formal WOE is not needed. However, the concept of a WOE should be integrated into the NM OAI Study.

9.4 Documentation of the PGM Modeling

Results of the NM OAI Study will be documented in PowerPoint (PPT) presentations and other documents that will be presented to the NMED in monthly webinars following the schedule in Tables 1-2 and 1-3. After each webinar presentations and with approval from NMED, the documents will be posted to a webpage on the WRAP website, like we did for the Southern New Mexico Ozone Study (SNMOS[66]). Two formal reports will be generated, one on the developed of the NM OAI Study 2014 36/12/4-km CAMx modeling platform and model performance evaluation and an Air Quality Technical Support Document (AQTSD) that documents the entire study including the 2023 future year modeling, ozone design Value projections, source apportionment modeling and control strategy sensitivity modeling.

[66] https://www.wrapair2.org/SNMOS.aspx

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10. QUALITY ASSURANCE PROJECT PLAN (QAPP)

This Modeling Protocol also serves as an informal Quality Assurance Project Plan (QAPP) for the NM OAI Study. A formal QAPP is a stand-alone document that discusses the Quality Assurance (QA) and Quality Control (QC) aspects of a study. QAPPs are typically required for Federal studies and are designed to assure that data are collected in the most rigorous ways possible, subjected to detailed QA/QC and have a chain of custodia review of data to preserve the quality. QAPPs are particularly important for measurement studies where the study must assure that the data collected meet a level of QA/QC as, unlike a modeling study where one can go back and rerun the model, if data collected at a certain time and place is ruled invalid there is no way to collect the measurement data under the same circumstances. This is not to say QA/QC is not important for modeling studies and, as shown below, this Modeling Protocol is full of QA/QC processes in each step of the modeling.

EPA has developed a template for developing a formal QAPP.[67] EPA has also developed a document that describes the elements of a QAPP.[68] Below we go through each of the seven elements EPA recommends be part of a QAPP and discuss where they can be found in this Modeling Protocol.

10.1 Title Page And Approval Page

As this is not a formal QAPP , there is no Approval Page. However, we have a list of Project Participants in Table 1-1 that are responsible for reviewing and accepting the Modeling Protocol/QAPP.

10.2 Quality System Components

This section of a QAPP describes the study's quality assurance program and procedures and who has responsibility for the QA/QC. Below we point to sections in this Modeling Protocol where rigorous QA/QC procedures are put in place for the NM OAI Study.

10.2.1 Roles of Personal for QA/QC of the NM OAI Study

The two Co-Principal Investigators, Tom Moore of WESTAR and Ralph Morris of Ramboll, have overall responsibility for the QA/QC of the NM OAI Study. Together they have over 50 years' experience in managing large air quality studies including instituting comprehensive QA/QC procedures. In Table 1-1 we also list the leads for each major component of the modeling study (emissions, meteorological and photochemical modeling) who will oversee the QA/QC of each component of the database development. Also listed in Table 1-1 is the NM OAI Study Project Manager and staff at NMED who will review and comment on each phase of the study. Each month during the NM OAI Study we will have a Webinar and present elements of the study to the NMED for their review and comment following the schedule in Table 1-3.

[67] https://www.epa.gov/quality/quality-assurance-project-plan-development-tool

[68] https://www.epa.gov/sites/production/files/2015-05/documents/assess4.pdf

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10.2.2 QA/QC of the 2014 Base Year and 2023 Future Year Emissions Data

The QA/QC of the base and future year emissions data is described in Section 1.5.4. The 2014 base year emissions were based on the 2014NEIv2 that have gone through several rounds of review and updates by EPA and the states. The WRAP states then conducted further review and updates of the 2014NEIv2 emissions in two phases to develop the WRAP/WAQ 2014v1 and final 2014v2 emissions used in the WRAP/WAQS 2014v2 modeling platform. Finally, under the NM OAI Study, the NMED will make further review of the New Mexico emissions in the 2014v2 inventory and make updates as needed.

The 2023 future year emissions used in the study are part of EPA's 2016v1 modeling platform (2023fh inventory). They are the result of several iterations of EPA making future year emission projections and represent their current best estimate of future year emissions. The NMED will also review the 2023 emissions for New Mexico and make updates as needed.

10.2.3 QA/QC of 2014 and 2023 Emissions Processing

Section 1.5.5 describes the process that will be used in processing the 2014 and 2023 emissions into the gridded, hourly and speciated emissions inputs needed for the CAMx PGM. The NM OAI Study modeling study will perform a multistep emissions QA/QC approach as developed for the WRAP 2002 modeling (Adelman, 2004) and following the procedures in EPA's latest ozone modeling guidance (EPA, 2018a, pp. 60) and Section 2.20 of the SMOKE User's Manuel (UNC, 2018, pp. 94). These steps include making sure that the mass input to the emissions models is consistent with the output and generation numerous QA/QC visualization graphics, including spatial maps and time series plots. Sections 6.2.2.7 and 6.2.2.9 provide more details on the QA/QC process for the emissions modeling. The QA/QC of the 2023 emissions processing is discussed in Section 8.2.2.

10.2.4 QA/QC of the Meteorological Modeling

The QA/QC of the meteorological modeling is briefly discussed in Section 1.5.6 with a more detailed discussions contained in Chapter 5. The NM OAI Study has separate work elements to evaluate the performance of the current WRAP/WAQS 2014 WRF simulation in New Mexico as well as a more detailed evaluation of the 36/12/4-km WRF simulation being conducted under the NM OAI Study that is described in Section 5.4.

10.2.5 QA/QC of the Boundary Conditions

The WRAP/WAQS study did a detailed QA/QC of EPA's 2014 GEOS-Chem modeling that was used in the initial BCs in the 2014v1 platform and found the ozone BCs to be inadequate, so WRAP ended up doing their own 2014 GEOS-Chem modeling that improved the 2014 BCs. The NM OAI Study will conduct a QA/QC of the WRAP 2014 GEOS-Chem BCs for sites in New Mexico

10.2.6 QA/QC of the Air Quality Modeling

The QA/QC of the CAMx air quality modeling will included independent review of the run scripts against the Modeling Protocol to make sure that the model configuration is

correct, as discussed in Section1.5.7. The NM OAI Study CAMx 36/12/4-km base case simulation will be subjected to a model performance evaluation (MPE) to assure that the model is replicating 2014 observed ozone concentrations sufficiently well that it can be used for making future year ozone projections (Section 1.5.9). Chapter 7 goes into details on how the CAMx Operational MPE will be conducted that includes statistical performance measures that are compared against Goals and Criteria and graphical MPE products. Elements of Diagnostic MPE being conducted are discussed in Section 1.5.10 with details of the diagnostic model performance evaluation provided in Section 7.5.

10.3 Project Definition and Background

Section 1-1 provides the impetus for the NM OAI Study with an overview of the study provided in Section 1-2. The background on related studies in provided in Section 1.3.

10.4 Data Quality Objectives

The data quality objectives for the meteorological, emissions and photochemical modeling are contained in Chapters 5, 6 and 7 respectively. Of particular note are meteorological model performance benchmarks listed in Table 5-3 that the NM OAI Study WRF 22014 36/12/4-km simulation will be compared against as part of the assessment of the meteorological data quality. Similarly, Table 7-1 contains model Performance Goals and Criteria that the CAMx 2014 base case simulation model performance will be compared against as part of the assessment of the data quality of the photochemical model simulation.

10.5 Project Organization and Responsibilities of the Researchers

Table 1-2 lists the organization of the NM OAI Study by task with schedule. The responsibilities of the NM OAI Study project participants are given in Table 1-1.

10.6 Project Description, Documentation and Reporting

This Modeling Protocol has a complete description of how the NM OAI Study will be carried. A description of the documentation and how the study will be reported is given in Section 1.8. And a summary of the documentation is also provided at the end of Chapter 9.

10.7 Reconcile with Data Quality Objectives

This Modeling Protocol provides a roadmap for how the NM OAI Study will be conducted. However, it is a living document that can be modified as issues or new information comes up. During the course of the study, WESTAR/Ramboll will have regular webinars that are scheduled monthly to go over progress and results for the previous month. If issues come up or problems are encountered, the WESTAR/Ramboll team will discuss them with the NMED and develop corrective action to reconcile any issues/difficulties.

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NMED Exhibit 15

APPENDIX A

Observed MDA8 Ozone Concentrations during 2014. Red indicates ozone ≥71 ppb and yellow indicates ozone between 67 and 71 ppb.

NMED Exhibit 15

Observed MDA8 Ozone Concentrations during 2014. Red indicates ozone ≥71 ppb and yellow indicates ozone between 67 and 71 ppb.

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Montezuma	Bernalillo	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
1-Jan	36	28	43	38	43	39	36	32	39	36	38		37	47	42	39	32	36	37	34	32	33		47	43	47	42
2-Jan	42	34		28	32	30	35	29	37	32	37		33	47	46	31	29	26	39	36	34	35		47	35	47	46
3-Jan	47	32		26	30	28	33	23	32	30	35		30	47	48	29	31	27	41	28	29	36		48	33	47	48
4-Jan	44	42		40	44	40	40	33	42	37	43		34	51	44	41	40	40	36	37	41	31		51	44	51	44
5-Jan	45	41		38	43	42	38	33	43	36	35		35	50	42	40	38	39	34	38	39	38		50	43	50	42
6-Jan	42	35		34	38	35	35	28	37	27	34		32	50	42	38	32	33	33	34	34	35		50	38	50	42
7-Jan	34	27		19	28	24	26	21	31	26	28		28	47	39	29	26	25	30	24	26	33		47	28	47	39
8-Jan	39	23		22	28	25	30	32	39	37	40		32	49	40	27	18	10	32	27	37	24		49	30	49	40
9-Jan	43	35		24	24	22	29	28	37	33	26		27	48	43	24	28	16	31	28	34	33		48	29	48	43
10-Jan	42	39		38	42	40	38	36	43	40	44		38	52	43	39	37	40	40	36	41	43		52	42	52	43
11-Jan	41	36		35	36	36	33	31	35	35	39		36	49	39	35	29	30	39	32	29	40		49	36	49	39
12-Jan	45	42		38	44	41	38	33	42	38	42		36	50	43	41	40	43	38	35	40	36		50	44	50	43
13-Jan	41	32	44	37	42	38	37	32	40	35	41		36	48	42	39	36	34	44	31	28	41		48	42	48	42
14-Jan	42	39	46	38	44	41	38	26	43	33	44		40	51	44	41	38	37	46	28	30	40		51	44	51	44
15-Jan	40	30	47	36	40	34	37	30	40	38	41		36	49	42	39	35	32	41	32	35	38		49	40	49	42
16-Jan	40	31	47	38	43	36	38	29	44	33	40		40	53	42	40	30	34	44	32	34	41		53	43	53	42
17-Jan	44	31	45	27	16	31	35	31	44	38	43		37	53	42	36	31	29	50	37	36	37		53	35	53	42
18-Jan	41	34	42	33	36	34	36	33	41	37	41		37	51	41	37	28	33	47	34	37	43		51	36	51	41
19-Jan	39	33	42	28	31	34	32	27	43	35	44		43	53	44	34	29	27	48	37	39	40		53	34	53	44
20-Jan	36	30	43	34	38	31	36	31		34	42		38	50	42	37	21	32	44	27	34	40		50	38	50	42
21-Jan	35	33	40	30	33	32	32	32		36	42		39	52	45	34	30	31	45	38	38	39		52	33	52	45
22-Jan	31	18	39	18	25	26	28	23		29	34		27	52	40	27	23	22	42	22	3	40		52	28	52	40
23-Jan	40	36	33	32	30	32	34	29			35		31	42	37	32	35	32	35	35	32	34		42	34	42	37
24-Jan	39	30	31	17	25	23	25	22			34		33	44	42	28	25	28	35	25	27	35		44	28	44	42
25-Jan	44	25	45	26	29	30	36	23			31		25	47	44	35	21	32	36	31	30	38		47	36	47	44
26-Jan	47	30	43	37	38	39	38	29			32		26	51	44	40	28	37	35	37	40	37		51	39	51	44
27-Jan	45	38	42	26	32	30	29	20			36		33	47	41	31	30	29	35	31	30	35		47	32	47	41
28-Jan	45	50	52	43	40	32	41	21			33		31	53	50	37	47	32	33	32	31	35		53	43	53	50
29-Jan	48	35	48	35	33	37	39	18		33	32		27	49	47	35	31	32	36	32	25	37		49	39	49	47

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Nav-ajo	La Plata	Monte-zuma	Berna-lillo	Berna-lillo	Berna-lillo	Berna-lillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sand-oval	San Juan	Val-encia	Brew-ster	El Paso	El Paso	Lamp-asas	San Juan	Maxi-mum	Maxi-mum	Maxi-mum	Maxi-mum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
30-Jan	45	29	37	30	33	30	32	29		38	39		29	52	37	33	30	33	42	33	40	35		52	33	52	37
31-Jan	45	39	44	39	37	39	36	29	36	36	43		34	48	46	38	37	35	38	35	38	28		48	39	48	46
1-Feb	45	41	43	41	45	43	38	27	35	34	42		36	48	44	41	36	45	39	35	36	31		48	45	48	44
2-Feb	46	40	42	42	42	42	39	25	37	37	32		33	56	46	41	38	38	34	34	38	38		56	42	56	46
3-Feb	47	42	39	39	43	41	39	26	39	36	27		28	53	45	42	41	40	31	41	40	35		53	43	53	45
4-Feb	48	41	42	36	42	40	37	32	44	39	44		38	54	44	40	38	45	45	40	41	29		54	45	54	44
5-Feb	48	35	41	22	27	26	23	20	28	24	33		33	46	42	29	37	27	33	29	28	38		46	27	46	42
6-Feb	44	38	43	18	22	20	24		33	24	32		33	44	44	24	38	24	31	34	33	39		44	24	44	44
7-Feb	45	35	43	31	37	35	34	44	43		38		28	53	45	37	35	39	37	38	42	33		53	39	53	45
8-Feb	47	38	44	37	36	39	37	46	45		44		40	54	46	39	32	39	43	40	43	41		54	39	54	46
9-Feb	40	34	36	34	36	36	34	40	39		40		40	47	40	36	28	35	42	35	37	28		47	36	47	40
10-Feb	46	36	41	36	40	35	35	41	39		21		24	45	39	37	33		35	34	38	35		45	40	45	39
11-Feb	47	41	44	34	38	37	36	30	32		22		33	49	43	37	35		32	30	31	35		49	38	49	43
12-Feb	46	32	46	38	42	41	38	31	47		45		33	41	46	40	34	30	40	39	41	43		47	42	47	46
13-Feb	37	32	36	27	31	33	31	34	36		37		37	32	37	32	28	32	41	29	32	41		37	33	37	37
14-Feb	35	33	35	28	33	33	31	33	35	29	25		37	34	36	31	29	34	38	31	31	44		37	34	37	36
15-Feb	39	28	35	29	27	30	28	32	32	33	22		32	33	33	28	26	31	37	27	30	32		33	31	33	33
16-Feb	45	32	45	36	40	38	36	38	40	39	25		37	38	41	37	23	40	40	34	38	41		41	40	40	41
17-Feb	45	44	45	42	42	43	41	31	38	28	28		38	38	48	42	38	43	45	32	35	43		48	43	38	48
18-Feb	48	29	46	38	42	41	41	37	40	29	28		40	40	47	31	32	44	46	33	37	49		47	44	40	47
19-Feb	52	45	45	44	48	46	44	36	42	40	32		39	40	48	45	44	48	45	32	44	41		48	48	42	48
20-Feb	49	43	43	40	44	43	39	46	45	47	34		45	34	44	41	41	44	53	42	40	44		47	44	47	44
21-Feb	47	42	42	38	41	40	40	39	46	42	31		41	46	45	39	33	38	46	33	47	44		46	41	46	45
22-Feb	50	42	45	42	44	45	42	47	53	49	38		50	51	44	40	39	43	45	43	50	44		53	45	53	44
23-Feb	54	41	46	43	44	46	44	49	53	50	32		46	51	47	42	38	43	44	46	49	43		53	46	53	47
24-Feb	53	43	49	41	46	47	45	39	42	40	35		43	42	50	41	41	36	47	38	38	44		50	47	43	50
25-Feb	45	48	51	35	37	35	38	34	38	35	26		31	38	48	37	45	37	38	31	34	35		48	38	38	48
26-Feb	47	40	45	37	41	41	41	36	41		19		31	39	49	39	39	41	26	38	37	33		49	41	41	49
27-Feb	42	37	44	38	41	40	39	36	37		25		39	38	43	38	34	41	34	33	33	40		43	41	39	43
28-Feb	40	40	40	41	43	43	43	32	35		29		45	33	46	42	39	42	39	30	31	47		46	43	45	46
1-Mar	38	34	39	33	28	32	32	26	27		22		33	25	28	34	32	28	37	25	25	37		34	33	33	34
2-Mar	49	42	45	40	46	45	43	44	45		21		33	44	45	42	44	45	35	43	44	36		46	46	45	45
3-Mar	51	43	46	43	44	45	43	32	39		21		31	44	47	42	39	44	38	34	38	39		47	45	44	47
4-Mar	38	41	43	39	42	42	41	41	42		29		38	43	48	41	37	43	38	41	43	45		48	43	43	48

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Montezuma	Bernalillo	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
5-Mar	52	35	50	43	48	46	42	46	46		35		38	46	48	44	38	47	49	43	43	35		48	48	46	48
6-Mar	49	44	50	41	41	44	41	43	51		33		47	48	52	41	40	41	51	46	48	47		52	44	51	52
7-Mar	52	44	43	43	49	48	45	50	54		40		53	51	48	45	44	50	51	47	49	49		54	50	54	48
8-Mar	48	44	43	40	40	42	38	38	39		33		40	41	46	39	44	40	42	38	37	41		46	42	41	46
9-Mar	52	41	41	44	45	46	39	42	41		33		43	42	46	44	41	47	46	42	40	44		47	47	43	46
10-Mar	51	11	47	41	42	45	38	45	47		35		46	46	47	39	35	43	42	44	45	50		47	45	47	47
11-Mar	56	29	47	46	49	49	46	51	54	52	37		49	52	54	45	48	50	50	47	49	46		54	50	54	54
12-Mar	54	50	52	44	47	47	40	42	42	42	27		41	44	46	43	46	44	45	42	41	49		47	47	44	46
13-Mar	49	49	51	43	46	45	42	42	46	44	34		43	45	47	44	48	43	47	42	43	47		48	46	46	48
14-Mar	51	44	49	43	43	43	40	47	50	49	36		44	50	47	42	46	43	50	46	46	50		50	43	50	47
15-Mar	55	55	52	46	47	47	45	48	49	49	39		48	51	48	44	52	47	53	46	45	51		52	47	51	52
16-Mar	52	46	49	50	50	51	46	50	52	52	36		42	51	52	47	46	49	47	49	48	42		52	51	52	52
17-Mar	56	50	52	49	51	46	47	46	49	48	35		46	48	53	48	50	51	48	43	48	46		53	51	49	53
18-Mar	56	44	43	44	48	50	43	52	54	52	39		48	52	47	43	43	51	54	48	49	47		54	51	54	47
19-Mar	54	51	50	47	48	47	43	43	44	45	37		45	48	53	44	44	45	46	42	42	47		53	48	48	53
20-Mar	55	52	53	46	48	50	45	41	47	43	33		46	47	55	46	50	47	50	41	41	49		55	50	47	55
21-Mar	56	51	51	50	53	51	48	48	51	50	38		52	50	54	50	48	52	51	44	47	48		54	53	52	54
22-Mar	56	54	53	44	49	49	44	43	45	44	38		44	45	56	47	55	48	45	42	41	43		56	49	45	56
23-Mar	59	52	52	50	51	51	46	44	43	45	36		42	46	53	49	52	48	41	41	41	42		53	51	46	53
24-Mar	56	45	54	50	54	52	49	48	50	51	39		50	52	56	49	50	54	43	51	47	45		56	54	52	56
25-Mar	52	53	54	46	49	51	46	44	45	45	37		48	50	52	46	52	47	43	43	43	46		52	51	50	52
26-Mar	56	50	52	46	48	45	46	44	47	46	32		44	45	52	46	52	46	42	40	43	45		52	48	47	52
27-Mar	54	49	51	47	52	50	49	43	47	45	34		44	46	49	48	47	51	50	40	45	48		52	52	47	49
28-Mar	53	49	47	44	48	47	46	46	50	48	35		48	49	51	44	47	48	49	43	44	49		51	48	50	51
29-Mar	56	53	52	50	53	54	50	52	53	54	39		53	49	51	50	50	48	54	49	49	50		54	54	54	51
30-Mar	57	51	54	51		54	51	51	55	53	35		50	54	56	51	53	53	52	47	50	54		56	54	55	56
31-Mar	54	50	49	52	53	53	49	49	52	50	38	47	51	50	52	49	50	53	55	46	46	51		53	53	52	52
1-Apr	57	54	58	46		48	47	49	47	51	39	56	50	51	52	45	54	48	51	46	48	49		56	48	56	54
2-Apr	59	54	56	53		57	53	50	53	51	39	52	50	52	57	51	55	54	53	45	50	54		57	57	53	57
3-Apr	53	54	52	49		53	50	55	58	55	46	57	57	53	54	49	51	53	53	53	53	52		58	53	58	54
4-Apr	59	57	56	53		56	52	48	51	50	40	52	52	50	55	51	55	51	51	47	47	53		56	56	52	55
5-Apr	58	60	57	55		57	53	54	56	56	39	53	50	58	56	53	59	56	53	51	54	49		59	57	58	59
6-Apr	53	53	50	49		52	50	52	54	53	41	54	50	51	54	48	51	52	58	51	50	45		54	52	54	54
7-Apr	55	47	50	52		55	51	52		52	40	51		52	55	50	51	54	52	49	41	48		55	55	52	55

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Nav-ajo	La Plata	Monte-zuma	Berna-lillo	Berna-lillo	Berna-lillo	Berna-lillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sand-oval	San Juan	Val-encia	Brew-ster	El Paso	El Paso	Lamp-asas	San Juan	Maxi-mum	Maxi-mum	Maxi-mum	Maxi-mum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
8-Apr	50	44	48	47		49	47	50	53	53	33	48		43	54	45	46	51	53	55	49	49		54	51	53	54
9-Apr	54	51	50	49		49	48	46	50	49	35	53	49	49	53	46	48	48	54	46	44	53		53	49	53	53
10-Apr	51	54	54	53		57	52	49	54	51	37	51	48	51	57	50	53	59	56	47	47	53		59	59	54	57
11-Apr	56	55	55	51		54	52	47	52	50		55		48	58	50	50	53	53	44	45	68		58	54	55	58
12-Apr	55	56	56	46		50	46	41	44	43		45		46	54	46	54	48	47	40	42	51		54	50	46	54
13-Apr	59	56	54	54		55	53	49	52	51		55		52	53	52	54	56	56	45	49	50		56	56	55	54
14-Apr	52	54	57	44		45	43	40	41	41	36	41	44	55	49	43	48	43	45	38	38	47		55	45	55	49
15-Apr	53	51	53	48		51	47	47	53	50	36	50	49	49	53	47	46	46	50	47	47	53		53	51	53	53
16-Apr	58	50	52	50		54	49	53	57	56	40	60	51	56	53	48	49	54	52	50	54	55		60	54	60	53
17-Apr	54	57	52	56		57	53	56	54	60	40	53	50	55	59	51	51	55	56	52	50	37		60	57	60	59
18-Apr	56	59	59	55		58	54	53	54	56	34	50	51	53	58	55	57	52	47	50	50	52		58	58	56	58
19-Apr	52	59	57	47		50	43	44	45	47	26	43	41	48	54	47	60	43	44	42	42	47		60	50	48	60
20-Apr	55	55	53	50		51	48	49	54	52	33	55	54	55	55	49	52	49	47	53	48	53		55	51	55	55
21-Apr	59	64	61	59		60	56	61	55	64	38	55	57	54	64	54	60	57	51	59	54	61		64	60	64	64
22-Apr	61	60	61	56		59	56	54	59	59	36	59	68	54	59	56	58	54	59	53	52	66		68	59	68	59
23-Apr	61	60	60	54		56	55	50	55	54	38	61	56	53	59	54	58	56	53	48	51	61		61	56	61	59
24-Apr	62	55	58	55		58	52	58	60	61	37	58	56	57	62	51	53	55	58	59	55	56		62	58	61	62
25-Apr	53	65	64	52		55	52	49	55	52	35	56	56	56	60	51	60	50	59	46	48	62		60	55	56	60
26-Apr	53	46	53	50		51	50	49	51	51	38	51	52	46	56	49	51	49	52	47	47	53		56	51	52	56
27-Apr	59	55	54	52		56	51	54	57	57	42	56	55	53	55	50	53	55	50	53	52	47		57	56	57	55
28-Apr	57	59	58	54		55	55	54	57	55	41	57	55	54	59	53	57	53	52	52	50	54		59	55	57	59
29-Apr	56	53	49	57		59	54	62	63	61	44	60	55	58	53	52	52	54	58	58	56	44		63	59	63	53
30-Apr	56	56	49	54		58	49	45	48	48	34	47	45	50	50	47	47	55	48	46	44	50		58	58	50	50
1-May	56	54	55	52		53	49	47	49	51		53	51	52	53	48	51	49	56	48	46	49		53	53	53	53
2-May	51	51	51	48		51	48	49	55	52		49	52	52	54	47	49	47	59	54	48	53		55	51	55	54
3-May	52	59	59	50		52	48	48	54	52		53	51	49	55	46	53	45	54	52	48	53		55	52	54	55
4-May	59	56	56	57		59	55	53	58	57		59	55	55	57	51	54	54	56	51	50	57		59	59	59	57
5-May	59	56	55	54		56	56	46	52	50		58	58	48	59	51	52	51	54	45	46	57		59	56	58	59
6-May	55	57	56	53		56	53	40	46	43		53	53	42	59	50	53	49	47	37	40	56		59	56	53	59
7-May	60	58	58	53		56	54	47	53	51	53	57	45	52	50	51	57	54	43	46	52	46		57	56	57	57
8-May	60	48	48	51		53	51	54	56	57	61	61	55	54	49	50	47	53	49	52	52	57		61	53	61	50
9-May	59	56	58	56		58	56	54	59	58	64	63	58	55	58	55	54	55	57	53	54	55	56	64	58	64	58
10-May	56	57	56	57		60	56	52	56	56	57	56	54	51	56	58	55	51	54	51	49	62	57	60	60	57	58
11-May	65	59	61	58		61	57	50	52	53	58	57	56	50	61	57	58	58	59	48	50	57	50	61	61	58	61

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Montezuma	Bernalillo	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
12-May	50	32	40	45		46	42	55	57	58	49	47	48	56	43	44	40	42	53	55	53	43	45	58	46	58	44
13-May	55	49	51	46		46	41	42	44	45	47	44	45	42	46	43	48	42	47	42	40	42	51	48	46	47	48
14-May	58	53	51	54		55	50	50	49	53	57	54	52	52	54	51	53	54	52	49	45	57	52	57	55	57	54
15-May	55	53	50	52		52	52	57	63	59	57	57	55	51	59	52	49	51	64	56	58	57	51	63	52	63	59
16-May	56	52	51	49		52	51	54	58	57	62	58	57	53	57	49	51	53	60	54	51	56	50	62	53	62	57
17-May	68	52	55	55		55	55	58	63	62	68		60	58	57	54	56	51	62	63	56	60	54	68	55	68	57
18-May	61	68	65	61		61	62	55	59	58	70	62	61	54	66	60	62	57	62	53	51	58	61	70	62	70	66
19-May	61	62	59	58		58	59	53	56	57	64	61	58	55	63	57	57	55	55	49	53	61	58	64	59	64	63
20-May	53	58	56	55		56	56	51	55	54	62	61	60	49	61	54	53	52	54	49	48	63	56	62	56	62	61
21-May	51	47	48	51		52	52	50	56	55	62	57	52	47	57	52	44	50	49	50	49	56	51	62	52	62	57
22-May	46	49	49	46		46	48	44	48	48	45	42	34	38	49	47	45	45	47	43	42	43	48	49	48	48	49
23-May	48	43	47	43		45	44	43	51	47	52	51	47	36	42	45	40	42	55	47	47	43	49	52	45	52	45
24-May	61	50	53	44		44	46	46	50	52	55	54	47	52	48	43	56	44	53	43	44	49	60	56	46	55	56
25-May	58	58	51	56		55	56	54	58	58	59	55	57	56	59	55	51	55	48	55	51	57	47	59	56	59	59
26-May	55	60	62	62		62	59	53	55	56	56	55	55	52	63	58	59	62	51	53	49	55	60	63	62	56	63
27-May	59	54	53	63		63	58	60	61	64	67	65	65	55	55	57	55	61	61	61	55	66	53	67	63	67	57
28-May	59	59	57	62		58	62	65	63	72	75	74	68	59	58	61	52	59	65	60	58	65	59	75	62	75	61
29-May	52	61	58	63		61	64	67	66	72	72	69	65	57	57	64	59	58	60	64	62	63	55	72	64	72	64
30-May	56	47	57	56		53	57	59	66	63	69	60	69	52	55	54	58	56	65	59	60	66	50	69	57	69	58
31-May	56	57	54	56		55	56	57	63	61	72	63	73	51	55	57	51	55	65	54	55	62	55	73	56	73	57
1-Jun	51	55	56	49		49	51	45	49	49	60	53	60	44	55	48	53	50	63	44		66	67	60	51	60	55
2-Jun	46	66	61	59		55	58	53	54	55	62	56	64	40	54	55	56	47	52	57	54	52	64	64	59	64	56
3-Jun	46	41	53	53		51	54	49	57	54	54	51	53	47	49	52	39	52	38	44	46	52	69	57	54	57	52
4-Jun	57	59	64	51		52	52	49	54	53	57	49	50	46	57	46	54	54	45	56	46	60	69	57	54	57	57
5-Jun	65	71	68	60		59	59	52	53	55	60	52	56	53	64	60	66	60	41	55	51	63	65	66	60	60	66
6-Jun	71	70	67	62		62	58	52	57	57	47	42	40	57	68	60	69	63	32	54	63	47	45	69	63	57	69
7-Jun	71	67	67	51		50	47	62	67	66	51	49	40	59	56	52	61	53	31	61	63	54	61	67	53	67	61
8-Jun	67	59	57	61		63	58	52	59	56	45	43	46	58	62	59	60	65	35	52	59	59	62	65	65	59	62
9-Jun	63	61	56	62		64	57	65	65	69	58	56	51	60	67	57	52	67	53	64	65	47	59	69	67	69	67
10-Jun	67	42	61	64		65	60	72	70	76	74		66	65	63	62	60	64	60	70	71	61	64	76	65	76	63
11-Jun	54	59	61	43		44	45	44	48	47	62		61	43	53	43	54	48	52	41	44	67	65	62	48	62	54
12-Jun	55	65	58	62		61	59	41	46	44	60	59	57	43	56	60	60	61	44	45	46	50	56	62	62	60	60
13-Jun	46	46	47	41		43	41	51	42	55	58	52	58	38	42	45	42	44	46	46	54	56	60	58	44	58	45
14-Jun	69	61	63	52		52	55	39	43	43	46	43	49	42	64	54	61	52	48	38	39	61	59	64	55	49	64

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Montezuma	Bernalillo	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
15-Jun	66	62	63	57		57	55	35	38	38	50	43	50	37	61	56	56	53	44	34	38	58	60	61	57	50	61
16-Jun	48	53	56	41		42	40	40	44	43	52		46	42	46	40	46	44	43	37	39	45	55	52	44	52	46
17-Jun	42	45	42	40		40	40	36	40	39	47	47	49	40	47	38	43	44	42	39	39	49	41	49	44	49	47
18-Jun	44	34	47	32		32	32	35	40	38	41	40	52	28	39	32	40	35	43	36	36	43	49	52	35	52	40
19-Jun	45	57	56	48		47	46	37	40	40	44	45	55	31	57	47	55	45	43	45	41	38	50	57	48	55	57
20-Jun	49	56	51	41		42	40	48	43	53	39	42	42	39	52	43	55	44	33	41	43	39	51	55	44	53	55
21-Jun	41	50	51	47		48	45	63	53	64	42		43	44	47	45	49	49	39	52	57	36	49	64	49	64	49
22-Jun	43	54	50	41		42	40	41	43	44	50		57	38	45	41	51	42	45	42	39	46	49	57	42	57	51
23-Jun	47	53	47	47		48	47	45	46	47	53	51	54	42	47	47	50	49	41	52	46	51	42	54	49	54	50
24-Jun	47	58	55	46		46	45	42	46	45	55		72	39	55	45	55	45	50	46	43	55	45	72	46	72	55
25-Jun	49	59	53	53		50	50	42	46	46	48		46	42	54	51	52	49	42	43	44	45	51	54	53	48	54
26-Jun	51	49	48	47		46	46	41	44	45	56	60	48	40	53	46	47	45	44	41	42	48	48	60	47	60	53
27-Jun	50	47	45	50		53	49	36	42	40	42		44	43	48	51	43	53	47	35	42	50	45	53	53	44	51
28-Jun	62	60	57	56		59	54	44	54	47	51		54	48	65	54	56	59	46	42	47	51	48	65	59	54	65
29-Jun	50	56	53	60		59	56	41	48	45			51	43	55	54	57	60	43	40	43	50	59	60	60	51	57
30-Jun	49	47	44	51		51	48	37	44	41	45		44	39	51	45	45	48	37	35	38	45	51	51	51	45	51
1-Jul	47	49	46	46		45	39	41	43	44	47	51	39	45	47	50	42	47	41	42	42	46	60	51	47	51	50
2-Jul	47	49	50	51		52	46	47	49	52	47	42	43	35	45	53	49	53	34	44	48	41	41	53	53	52	53
3-Jul	49	52	50	55		55	50	46	43	51	47		44	48	45	58	51	56	35	42	43	38	41	58	56	51	58
4-Jul	50	51	52	55		53	49	43	41	47	41	41	36	40	48	54	52	53	31	39	41	37	47	55	55	47	54
5-Jul	53	48	46	60		57	55	47	50	49	43	43	40	47	44	54	50	57	36	42	51	43	49	60	60	50	54
6-Jul	54	60	53	60		61	52	39	43	43	40	45	40	48	59	54	61	57	39	37	40	44		61	61	48	61
7-Jul	56	60	63	64		59	59	58	55	63	54	56	43	52	52	63	62	59	34	50	57	52		64	64	63	63
8-Jul	54	56	59	51		49	43	55	51	61	51		53	55	47	48	56	52	33	49	51	43	46	61	52	61	56
9-Jul	56	50	56	56		57	52	50	47	55	43		41	51	44	51	54	59	34	45	48	41	52	59	59	55	54
10-Jul	56	60	59	60		58	54	51	44	57	41		40	49	52	57	58	58	40	43	47	44	38	60	60	57	58
11-Jul	55	62	55	63		64	56	42	41	44	39		39	45	57	59	59	61	35	38	40	38	39	64	64	45	59
12-Jul	58	55	52	65		60	60	41	39	46	41		37	48	55	59	57	63	39	36	40	39		65	65	48	59
13-Jul	62	56	59	43		45	40	42	39	46	48		39	46	45	43	51	49	34	38	38	49	39	51	49	48	51
14-Jul	54	51	55	60		68	52	41	45	46	47	44	43	48	45	48	54	61	36	43	47	45	45	68	68	48	54
15-Jul	53	36	50	50		51	42	67	60	72	53		50	61	42	43	49	50	38	57	62	50	52	72	51	72	49
16-Jul	47	47	47	51		54	43	48	56	54	59		58	53	44	45	47	53	43	53	53	50		59	54	59	47
17-Jul	57	55	57	60		58	54	47	52	52	52		43	47	58	56	54	59	52	58	51	42	44	60	60	52	58
18-Jul	54	57	59	61		65	57	50	68	56	56		63	44	58	57	58	63	42	57	73	47		68	65	68	58

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Montezuma	Bernalillo	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
19-Jul	49	58	57	52		64	61	46	53	52	52		56	51	57	59	59	68	49	50	50	51		68	68	56	59
20-Jul	47	52	50	55		60	48	47	55	52	58		55	48	52	47	49	56	51	52		57	31	60	60	58	52
21-Jul	41	49	41	56		53	48	48	54	53	59		59	49	54	48	39	51	48	66	55	55	34	59	56	59	54
22-Jul	51	48	45	54		55	47	67	59	71	52		52	55	48	48	51	57	45	58	62	46	38	71	57	71	51
23-Jul	58	51	57	54		54	48	45	48	51	57		58	56	52	52	48	52	47	43	45	54	46	58	54	58	52
24-Jul	55	58	59	57		55	52	56	54	51	65		64	52	52	55	51	51	54	51	56	61		65	57	65	55
25-Jul	57	51	59	62		58	53	65	67	69	61	61	58	54	62	56	52	57	52	51	63	63	40	69	62	69	62
26-Jul	61	57	58	64		64	54	59	61	61	55	48	55	56	56	55	48	60	50	53	60	54	39	64	64	61	56
27-Jul	63	59	57	56		59	50	58		61	53	53	51	54	56	51	52	61	45	51	55	66		61	61	61	56
28-Jul	60	55	60	57		56	50	52		57	53		48	55	41	58	44	55	39	47	51	51	38	58	57	57	58
29-Jul	60	58	59	58		54	50	55		59	56	52	50	57	46	56	55	53	43	59	65	45	46	59	58	59	56
30-Jul	54	56	55	66		63	54	57		59	55	51		57	59	60	45	61	48	66	54	50		66	66	59	60
31-Jul	54	48	54	53		52	48	62		67	43			55	46	54	46	50	49	53	58	56		67	53	67	54
1-Aug	56	48	54	56		54	48	49		52	46		55	52	43	54	46	55	41	49	51	56		56	56	55	54
2-Aug	54	49	53	56		52	50	54		56	57		52	57	46	50	41	53	49	50	49	56		57	56	57	50
3-Aug	51	51	56	57		58	48	54		58	63		58	57	51	58	42	58	51	51	52	56	41	63	58	63	58
4-Aug	50	52	54	57		56	49	56		60	61		60	51	45	54	51	49	57	51	55	59		61	57	61	54
5-Aug	51	56	55	59		57	50	59	63	66	64		58	60	52		51	56	59	62	70	61		66	59	66	52
6-Aug	55	53	56	55		52	51	61	74	62	62		61	58	51	47	52	55	54	56	70	55		74	55	74	52
7-Aug	59	59	55	43		43	42	53	57	58	54		59	52	45	43	53	39	48	57	59	56	32	59	43	59	53
8-Aug	57	51	52	60		57	56	58	55	61	52		48	55	50	60	52	57	44	73	58	53	38	61	60	61	60
9-Aug	58	54	56	59		56	51	48	48	53	49		43	49	57	56	54	57	42	46	49	43		59	59	53	57
10-Aug	56	53	56	53		50	47	41	41	46	48		45	47	52	51	56	52	46	43	43	51		56	53	48	56
11-Aug	52	55	56	58		55	48	44	43	48			45	50	51	51	53	57	37	42	43	57		58	58	50	53
12-Aug	48	53	57	48		60	53	42	39	45			59	46	50	46	54	57	36	36	39	55		60	60	59	54
13-Aug	47	39	47	41		41	36	48	45	50			61	47	40	45	36	42	52	40	45	58		61	42	61	45
14-Aug	52	44	48	53		51	43	41	49	47			53	50	49	52	46	51	55	41	48	56		53	53	53	52
15-Aug	52	45	51	52		52	47	52	56	54			51	50	52	53	49	49	49	57	54	54		56	52	56	53
16-Aug	55	45	46	49		54	37	51	53	54			53	53	44	49	46	58	43	61	54	57		58	58	54	49
17-Aug	51	44	49	53		54	42	52	57	55			59	51	39		49	56	44	57	65	59		59	56	59	49
18-Aug	51	51	50	59		55	53	63	57	69			61	56	43	63	51	57	45	58	57	55	38	69	59	69	63
19-Aug	42	48	52	52		50	48	46	54	51	55	42	60	50	51	55	48	54	45	49	51	48	40	60	54	60	55
20-Aug	49	52	52	47		48	42	43	47	47	49	56	47	43	55	47	48	51	42	46	45	55		56	51	56	55
21-Aug	46	49	49	54		53	51	39	45	44	40	54	47	45	48	55	44	54	50	46	43	50		55	54	54	55

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Nav-ajo	La Plata	Monte-zuma	Berna-lillo	Berna-lillo	Berna-lillo	Berna-lillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sand-oval	San Juan	Val-encia	Brew-ster	El Paso	El Paso	Lamp-asas	San Juan	Maxi-mum	Maxi-mum	Maxi-mum	Maxi-mum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
22-Aug	46	43	48	41		40	36	46	60	50	46	56	52	43	39		41	43	43	48	58	53		60	43	60	41
23-Aug	48	53	54	51		49	47	38	42	43	49	59	59	40	54		51	48	42	44	43	52	44	59	51	59	54
24-Aug	45	61	59	56		55	49	47	53	48	43	55	50	41	52		53	55	38	45	50	48		56	56	55	53
25-Aug	42	55	52	50		50	46	43	51	45	45	42	45	43	45		45	49	40	44	52	47		51	50	51	45
26-Aug	37	43	48	41		41	40	42	45	43	47	51	51	39	34		41	42	44	49	44	39		51	42	51	41
27-Aug	40	54	53	39		41	35	56	51	59	36	46	52	46	44		46	43	50	60	52	51		59	43	59	46
28-Aug	55	48	49	52		52	38	47	46	48	47	63	51	44	55		44	55		62	46	48		63	55	63	55
29-Aug	56	54	51	62		58	57	62	54	64	51	68	59	53	49		56	57		57	56	55		68	62	68	56
30-Aug	52	54	54	54		55	49	67	67	68	54	70	55	50	51		50	55		55	67	55		70	55	70	51
31-Aug	49	49	51	55		53	51	46	50	49	51	60	52	48	56		46	54		50	48	51		60	55	60	56
1-Sep	45	47	49	52		50	46	45	47	47	45	55		46	50		43	50		46	43	58		55	52	55	50
2-Sep	47	54	48	50		51	46	48	55	50	49	56		44	49		45	53		57	56	51		56	53	56	49
3-Sep	47	51	48	51		50	48	52	51	56	39	49		43	46		43	52		41	50	40		56	52	56	46
4-Sep	42	41	41	47		44	42	36	37	39	37	39		36	44		38	46		34	35	37		47	47	39	44
5-Sep	45	47	47	51		45	44	28	34	33	37	39		43	41		49	51		30	33	32		51	51	43	49
6-Sep	45	46	48	40		36	42	31	31	32	20	24		39	38		49	41		29	30	28		49	42	39	49
7-Sep	47	47	47	45		43	40	25	26	28	35	33		31	39		44	42		27	24	35		45	45	35	44
8-Sep	33	49	42	35		32	32	39	50	41	47	42		34	38		40	35	36	34	52	46		50	35	50	40
9-Sep	35	31	37	36		36	35	33	39	36	35	50		39	36		30	39	36	34	36	47		50	39	50	36
10-Sep	55	48	48	49		50		36	39	38	38	51		35	54		42	55	40	41	36	41		55	55	51	54
11-Sep	58	58	60	55		52	56	33	40	36	40	45		38	62		56	55	34	35	35	38		62	56	45	62
12-Sep	58	52	52	28		25	38	33	36	36	21	23		44	48		54	35	31	34	34	17		54	38	44	54
13-Sep	48	48	51	33		34	37	30	30	33	25	27		32	43		46	35	22	27	30	30		46	37	33	46
14-Sep	41	49	55	34		33	38	29	28	32	32	28	17	33	42		47	33	20	27	28	27		47	38	33	47
15-Sep	44	49	51	38		35	42	24	26	25	29	32	26	34	46		50	38	25	21	25	26		50	42	34	50
16-Sep	33	48	48	28		27	32	32	26	34	38	38		24	38	29	45	29	32	32	25	32		45	32	38	45
17-Sep	30	43	44	21		25	28	38		42	44	40		31	35	27	38	31	37	32	34	37		44	31	44	38
18-Sep	34	47	52	45		39	48	24		29	32	38		29	46	48	47	42	32	25	25	35		48	48	38	48
19-Sep	44	47	43	40		41	42	28	29	31	27	27		32	42	45	47	38	33	33	28	33		47	42	32	47
20-Sep	45	48	50	41		43	41	43	31	47	28	27		42	47	41	47	44	32	56	41	29	34	47	44	47	47
21-Sep	39	41	41	34		34	37	34	30	38	27	31		33	40	35	37	34	30	30	31	39	38	40	37	38	40
22-Sep	39	38	43	30		32	35	22	27	24	37	46	34	32	31	33	35	33	48	25	27	43	42	46	35	46	35
23-Sep	44	33	46	40		42	45	52	32	55	40	45	52	36	51	46	42	44	50	38	50	51	45	55	45	55	51
24-Sep	50	49	52	51		50	52	42	40	48	47	45	49	45	44	48	48	51	47	38	40	51	46	52	52	49	48

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Montezuma	Bernalillo	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
25-Sep	47	50	53	48		50	50	52	48	56	59	57	52	46	45	51	49	49	50	48	49	45	50	59	50	59	51
26-Sep	51	49	48	44		47	48	59	54	63	60	53	59	50	45	50	51	47	48	51	55	57	48	63	48	63	51
27-Sep	46	50	51	47		51	51	52	46	57	42	41	41	46	46	53	46	51	37	46	46	45	48	57	51	57	53
28-Sep	42	36	40	34		38	37	36	43	37	40	41	49	28	39	39	34	38	34	43	44	46	44	49	38	49	39
29-Sep	49	41	51	38		41	47	31	39	35	42	43	47	22	42	42	40	40	37	32	36	42	51	47	47	47	42
30-Sep	54	48	51	49		36	54	29	36	33	40	54	36	41	54	53	48	52	36	30	38	46	47	54	54	54	54
1-Oct	57	45	47	47		51	53	44	54	50	53		50	54	51	52	44	54	36	43	49	52	48	54	54	54	52
2-Oct	52	47	48	45		43	51	51	48	54	45		42	53	49	50	39	54	51	50	47	45	50	54	54	54	50
3-Oct	46	30	47	44		42	48	50	50	54	47		55	50	49	46	37	52	49	48	47	44	52	55	52	55	49
4-Oct	45	39	43	41		39	44	52	57	55			52	52	45	43	36	47	47	56	54	50	43	57	47	57	45
5-Oct	46	41	45	40		39	45	47	46	49			43	50		46	36	46	48	46	43	54	44	50	46	50	46
6-Oct	47	47	51	46		40	53	39	42	42			50	43	58	52	41	50	45	40	40	54	53	58	53	50	58
7-Oct	48	52	52	45		41	51	43	37	46			49	46	55	48	38	47	46	42	41	52	52	55	51	49	55
8-Oct	38	45	51	32		27	38	42	49	45			45	35	46	38	42	36	47	45	48	53	45	49	38	49	46
9-Oct	41	34	35	28		27	36	28	32	31	30		36	32	31	35	34	33	46	27	36	44	44	36	36	36	35
10-Oct	50	33	40	30		31	35	38	40	41	35		33	41	36	33	35	37	36	41	39	29	51	41	37	41	36
11-Oct	50	41	48	42		39	49	47	46	54	40		37	42	45	47	45	43	35	40	48	42	44	54	49	54	47
12-Oct	51	43	44	45		47	49	49	51	51	48		47	48	47	49	41	51	46	48	50	45	42	51	51	51	49
13-Oct	42	39	42	36		35	42	43	43	45	41		40	42	44	41	34	41	44	45	42	39	43	45	42	45	44
14-Oct	42	43	45	36		37	42	15	49	47	50		44	47	43	38	34	42	44	43	46	44	38	50	42	50	43
15-Oct	42	37	47	31		34	44	50	50	56	56		46	45	42	41	40	42	43	48	49	48	44	56	44	56	42
16-Oct	40	49	54	45		42	53	40	48	35	54		37	44	53	48	46	46	45	43	43	49	45	54	53	54	53
17-Oct	38	40	50	44		45	49	39	44	41	55		54	43	45	41	37	43	42	46	38	50	46	55	49	55	45
18-Oct	34	43	45	46		48	51	54	50	54	55		40	50	40	53	39	51	47	56	53	42	42	55	51	55	53
19-Oct	42	40	42	42		45	47	42	40	44	47		36	41	39	46	42	42	36	43	41	42	43	47	47	47	46
20-Oct	44	25	43	31		34	35	34	36	35	42		46	39	41	37	35	37	34	35	36	41	41	46	37	46	41
21-Oct	41	23	41			39	42	38	38	41	39		44	36	36	41	34	40	35	37	39	48	37	44	42	44	41
22-Oct	44	38	48			38	42	38	40	42	41		41	38	44	39	37	42	35	38	42	44	46	44	42	42	44
23-Oct	43	41	49			40	47	42	50	48	35		35	43	47	44	37	45	30	54	48	41	43	50	47	50	47
24-Oct	43	42	47			44	48	43	49	45	51		41	42	45	44	38	45	35	56	47	48	44	51	48	51	45
25-Oct	38	43	47			43	46	39	44	42	48		38	37	44	43	43	45	36	46	44	44	43	48	46	48	44
26-Oct	37	35	42			35	39	33	38	36	39		38	34	41	36	32	36	36	37	35		42	41	39	39	41
27-Oct	44	45	49			41	46	31	35	33	33		29	33	47	43	41	43	38	29	33		45	47	46	35	47
28-Oct	46	41	47			38	43	42	43	41	42		41	37	50	14	36	45	46	39	41		44	50	45	43	50

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Montezuma	Bernalillo	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
29-Oct	44	38	45			40	48	40	43	43	56		50	40	50	43	33	44	41	39	42	45		56	48	56	50
30-Oct	46	39	42			44	50	41	42	38	44		48	43	46	45	32	46	38	40	39	45		50	50	48	46
31-Oct	45	47	51			47	48	45	47	47	48		36	50	48	49	44	47	45	46	47	39		50	48	50	49
1-Nov	38	39	42			40	41	36	40	37	43		41	36	42	40	36	40	45	37	38	41		43	41	43	42
2-Nov	46	30	50			33	35	40	41	41	39		37		33	30	31	36	46	41	42	42		41	36	41	33
3-Nov	45	44	44			49	51	28	31	29	34		31	34	48	48	40	53	41	32	31	34		53	53	34	48
4-Nov	44	41	42			38	41	33	34	33	27		26	35	45	39	30	27	33	31	32	26		45	41	35	45
5-Nov	40	32	41			37	41	32	35	30	35		34	39	48	38	29	39	37	32	36	41		48	41	39	48
6-Nov	45	28	47	34		35	40	25	40	31	34		39	41	43	37	32	39	39	34	37	42		43	40	41	43
7-Nov	44	31	45	33		37	37	39	44	40	40		30	39	48	41	30	37	35	37	41	44		48	37	44	48
8-Nov	41	40	46	40		43	44	37	39	38	40		29	38	42	43	36	43	44	36	38	39		44	44	40	43
9-Nov	44	40	46	37		40	42	39	46	41	44		32	41	49	40	40	37	39	44	47	38		49	42	46	49
10-Nov	48	40	52	39		42	45	39	44	41	45		29	44	47	45	38	44	38	36	42	40		47	45	45	47
11-Nov	43	45	51	30		37	41	37	42	39	35		28	39	50	36	42	39	32	37	40	36		50	41	42	50
12-Nov	41	40	47	24		29	29	31	35	31	35		27	34	40	31	38	29	35	34	35	32		40	29	35	40
13-Nov	37	31	37	27		28	32	29	34	30	30		22	35	29	26	32	30	35	32	33	30		35	32	35	32
14-Nov	37	28	41	31		33	37	28	31	31	31		23	34	40	34	17	33	28	31	30	31		40	37	34	40
15-Nov	45	40	47	42		47	47	35	42	36	42		24	41	46	45		45	30	32	40	42		47	47	42	46
16-Nov	46	43	46	39		45	43	36	38	37	31		25	44	43	43		43	35	36	37	36		45	45	44	43
17-Nov	40	31	48	38		39	43	34	41	35	41		30	41	44	30	25	39	42	40	40	42		44	43	41	44
18-Nov	41	31	44	36		35	44	34	42	36	36		27	43	44	38	26	38	38	30	35	41		44	44	43	44
19-Nov	42	30		26		32	39	35	24	37	43		26	40	44	33	27	33	37	31	31	41		44	39	43	44
20-Nov	44	31		28		33	39	35	41	34	44		26	30	45	33	26	33	38	32	36	40		45	39	44	45
21-Nov	42	34		19		23	33	27	38	32	39		25		38	29	29	30	38	27	34	44		39	33	39	38
22-Nov	44	36		28		42	41	39	44	41	42		23		47	37	31	36	42	38	43	42		47	42	44	47
23-Nov	44	42		40		44	43	46	49	47	45		27		43	42	39	43	42	45	47	38		49	44	49	43
24-Nov	42	40		36		41	41	37	41	38	40		22		42	39	37	40	43	33	38	40		42	41	41	42
25-Nov	41	36		35		36	41	36	41	38	40		20		43	37	31	33	43	33	39	37		43	41	41	43
26-Nov	35	26		26		33	36	32	37	35	36		24		36	33	24	32	41	23	27	39		37	36	37	36
27-Nov	33	27		26		34	32	25	38	27	44		26		39	29	23	32	40	32	35	37		44	34	44	39
28-Nov	38	30		25		31	39	28	35	38	44		25		44	30	27	28	47	32	32	36		44	39	44	44
29-Nov	38	34		32		37	41	34	41	38	43		28		41	33	28	33	43	33	36	35		43	41	43	41
30-Nov	41	28		26		32	39	37	43	40	43		27		40	30	22	31	43	36	40	34		43	39	43	40
1-Dec	39	31		24		24	37	25	36	26	25		15		37	29	28	27	31	28	32	31		37	37	36	37

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Nav-ajo	La Plata	Monte-zuma	Berna-lillo	Berna-lillo	Berna-lillo	Berna-lillo	Dona Ana	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Luna	Rio Arriba	Sand-oval	San Juan	Val-encia	Brew-ster	El Paso	El Paso	Lamp-asas	San Juan	Maxi-mum	Maxi-mum	Maxi-mum	Maxi-mum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	001	013	013	013	015	015	025	029	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0027	0029	1012	0017	0020	0021	1005	3001	0008	0003	0026	1001	0009	0008	0101	0057	0058	9991	0004				
2-Dec	32	23		1		19	35	22	33	22	26		15		37	22	28	12	34	27	30	28		37	35	33	37
3-Dec	22	35		17		25	27	28	16	31	40		23		31	25	21	29	31	27	27	29		40	29	40	31
4-Dec	41	20		20		16	31	19	25	22	15		9		34	29	13	13	28	21	30	18		34	31	25	34
5-Dec	39	27		24		6	37	28	37	33	36		21		30	25	20	31	33	30	34	39		37	37	37	30
6-Dec	25	26		25		26	34	42	42	41	44		26		33	29	22	26	40	41	41	34		44	34	44	33
7-Dec	20	30		33		38	38	38	42	42	35		15		41	36	18	34	32	38	41	36		42	38	42	41
8-Dec	26	26	39	17		21	29	32	39	32	33		25		34	24	22	24	29	32	39	41		39	29	39	34
9-Dec	22	31	40	13		18	28	30	34	31	24		17		35	22	24	26	27	32	32	44		35	28	34	35
10-Dec	24	29	35	27		28	34	19	32		23		17		34	27	10	31	24	28	28	25		34	34	32	34
11-Dec	17	28	37	17		22	30	27	39	34	25		15		37	24	17	27	30	30	36	25		39	30	39	37
12-Dec	37	27	40	14		22	37	31	41	35	23		12		35	21	28	24	34	18	32	31		41	37	41	35
13-Dec	42	42	45	34		39	44	35	25	36	34		19		47	41	28	39	42	38	44	32		47	44	36	47
14-Dec	38	38	39	38		44	41	41		42	45		26		41	40	34	41	40	40	44	37		45	44	45	41
15-Dec	36	32	43	34		25	40	33	33	35	38		23		41	37	27	36	41	24	24	31		41	40	38	41
16-Dec	35	32	43	17		15	26	35	40	36	31		20		37	25	29	15	37	35	39	36		40	26	40	37
17-Dec	36	29	38	20		27	31	39	43	41	43		22		36	18	20	24	36	37	42	22		43	31	43	36
18-Dec	41	32	39	27		33	36	34	34	38	39		24		41	32	24	35	40	32	36	17		41	36	39	41
19-Dec	39	34	42	32		39	38	30	36	34	37		16		43	36	18	37	42	24	35	21		43	39	37	43
20-Dec	35	27	40	23		29	34	33	40	37	36		17		43	23	17	32	36	30	36	32		43	34	40	43
21-Dec	33	30	37	31		29	38	38	40	39	41		24		38	35	23	28	40	36	41	36		41	38	41	38
22-Dec	36	38	43	32		36	38	34	36	36	34		21		42	35	35	36	37	33	35	42		42	38	36	42
23-Dec	42	46	44	36		42	44	39	44	40	39		26		46	41	39	41	39	40	41	36		46	44	44	46
24-Dec	41	38	40	34		37	40	34	37	39	41		23		42	35	25	37	42	36	37	39		42	40	41	42
25-Dec	42	36	44	39		41	43	36	44	40	34		19		41	40	34	39	43	34	44	34		44	43	44	41
26-Dec	37	37	39	36		42	41	30	38	34	42		23		43	39	26	39	40	34	40	23		43	42	42	43
27-Dec	39	32	40	32		35	37	32	38	33	15		17		39	35	21	31	37	37	37	32		39	37	38	39
28-Dec	39	28	38	31		36	36	35	40	39	36		20		43	33	24	31	36	35	36	34		43	36	40	43
29-Dec	43	33	41	28		28	37	35	41	38	42		21		43	30	28	29	35	33	38	29		43	37	42	43
30-Dec	43	34	39	21		27	23	27	31	27	21		20		29	21	27	24	14	25	29	30		31	27	31	29
31-Dec	32	31	35	14		22	20	17	22	18	28		17		32	24	26	20	16	19	19	28		32	22	28	32

APPENDIX B

Observed MDA8 Ozone Concentrations during 2016. Red indicates ozone ≥71 ppb and yellow indicates ozone between 67 and 71 ppb.

NMED Exhibit 15

Observed MDA8 Ozone Concentrations during 2016. Red indicates ozone ≥71 ppb and yellow indicates ozone between 67 and 71 ppb.

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
1-Jan	29	40	46	29	40	33	25	26	33		38	34	34	35	32	21	26	25	36		40	40	38	35
2-Jan	31	35	48	34	38	37	29	27	37		30	40	33	35	34	28	27	27	38		40	38	37	40
3-Jan	32	35	48	28	37	28	35	32	41		40	40	30	33	29	21	34	31	41		41	37	41	40
4-Jan	32	36	47	30	34	41	31	27	40		33	41	38	35	27	26	29	29	39		41	41	40	41
5-Jan		37	40	25	30	32	27	14	29		22	41	30	32	28	26	15	21	28		41	32	29	41
6-Jan		36	41	31	40	37	39	40	39		28	42	35	18	33	40	34	40	20		42	40	40	42
7-Jan		37	43	33	38	39	40	41	43		38	44	36	33	37	43	38	41	32		44	39	43	44
8-Jan		39	44	37	45	44	43	43	44		38	46	40	32	44	45	37	42	21		46	45	44	46
9-Jan		38	45	36	43	41	40	41	26		26	43	38	31	40	43	36	39	34		43	43	41	43
10-Jan		41	44	35	41	42	34	38	28		33	46	40	33	39	38	33	37	25		46	42	38	46
11-Jan	37	35	43		40	41	40	40	40		36	45	38	29	37	39	35	37	42		45	41	40	45
12-Jan	41	32	39	31	29	40	34	36	37		39	44	35	32	25	40	29	23	32		44	40	39	44
13-Jan	37	37	46	34	33	43	37	38	39		37	49	37	28	33	39	24	28	37		49	43	39	49
14-Jan	41	42	50	38	45	46	42	44	43		40	47	43	33	37	46	34	43	41		47	46	44	47
15-Jan	40	37	46	38	41	41	44	44	46		41	47	38	31	38	43	39	43	41		47	41	46	47
16-Jan	41	38	50	43	47	48	43	42	44		35	49	44	38	44	46	37	38	34		49	48	44	49
17-Jan	39	36	49	40	45	46	41	40	42		42	45	41	38	43	42	35	37	19		46	46	42	45
18-Jan	37	40	47	36	36	42	38	39	25		31	44	31	35	35	41	32	36	26		44	42	39	44
19-Jan	41	36	42	38	39	42	40	42	40		40	47	39	31	39	41	33	37	35		47	42	42	47
20-Jan	41	44	48	40	45	44	43	41	43		34	45	42	40	43	43	36	41	38		45	45	43	45
21-Jan	42	38	46	39	44	45	44	44	43		41	46	42	32	43	46	40	41	40		46	45	44	46
22-Jan	40	41	48	32	36	45	38	40	41		39	47	36	36	38	42	34	33	39		47	45	41	47
23-Jan	46	44	55	27	38	43	38	43	39		39	49	32	41	34	43	34	34	37		49	43	43	49
24-Jan	46	45	45	45	51	49	45	44	47		44	47	45	39	46	52	38	47	40		51	51	47	47
25-Jan	42	40	45	40	46	46	46	45	44		43	44	42	32	44	43	38	43	41		46	46	46	44
26-Jan	41	41	45	35	35	41	38	39	30		34	47	36	36	38	36	35	36	38		47	41	39	47
27-Jan	40	39	45	36	35	44	37	40	40		38	48	40	33	37	40	37		42		48	44	40	48
28-Jan	43	43	46	34	36	42	36	40	41		38	49	34	32	37	40	36		41		49	42	41	49
29-Jan	41	41	46	36	40	41	36	40	45		41	48	40	29	41	41	31	31	40		48	41	45	48
30-Jan	45	40	45	39	45	42	42	43	47		42	44	39	34	41	44	35	41	35		47	45	47	44

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
31-Jan	42	35	43	44	49	46	43	44	46		42	46	44	38	45	46	39	42	39		49	49	46	46
1-Feb	43	44	46	41	46	45	43	44	46		43	48	44	39	44	43	39	42	36		48	46	46	48
2-Feb	41	41	45	37	43	41	37	44	44		40	42	40	39	41		40	41	40		44	43	44	42
3-Feb	41	38	45	38	44	42	39	43	43		41	43	40	39	42	45	36	40	41		44	44	43	43
4-Feb	41	39	45	38	39	44	40	38	42		42	46	40	33	41	45	39	38	41		46	44	42	46
5-Feb	42	38	46	40	44	43	44	43	45		42	47	41	35	43	45	40	40	41		47	44	45	47
6-Feb	42	44	48	43	46	46	42	42	45		43	48	44	33	42	44	34	38	44		48	46	45	48
7-Feb	40	45	50	42	47	45	41	42	45		43	51	42	30	43	40	33	36	44		51	47	45	51
8-Feb	40	53	49	42	45	45	41	39	47		43	50	44	35	42	43	35	42	43		50	45	47	50
9-Feb	40	53	55	41	44	44	42	38	48		46	51	41	35	43	43	39	40	43		51	44	48	51
10-Feb	44	46	57	39	44	45	42	40	47		42	56	42	41	41	41	36	37	44		56	45	47	56
11-Feb	42	51	50	42	42	43	43	46	47		45	51	43	35	42	46	40	34	43		51	43	47	51
12-Feb	40	49	52	43	42	45	41	47	44		53	50	42	38	43	48	35	39	44		53	45	53	50
13-Feb	45	51	52	37	47	45	46	45	64		52	48	41	45	42	50	39	43	50		64	47	64	48
14-Feb	41	42	47	41	47	42	46	46	46		44	45	42	35	44	50	41	43	40		47	47	46	45
15-Feb	41	39	44	38	42	39	43	42	47		43	42	38	37	41	45	38	39	42		47	42	47	42
16-Feb	39	41	43	35	38	39	39	41	42		35	42	29	30	38	46	36	37	41		42	39	42	42
17-Feb	42		48	33	41	44	45	60	56		46	43	36	38	39	50	42	42	44		60	44	60	43
18-Feb	42	28	51	40	47	43	51	53	58		48	44	41	35	43	54	48	48	42		58	47	58	44
19-Feb	38	42	48	34	35	40	48	47	48		38	39	37	36	36	47	41	45	42		48	40	48	39
20-Feb	40	46	50	39	45	47	47	46	51		44	46	39	40	42	47	43	41	50		51	47	51	46
21-Feb	44	49	49	46	49	46	42	45	44		42	47	44	43	46	34	41	41	44		49	49	45	47
22-Feb	44	40	48	43	49	46	51	52	43		34	48	45	41	44	44	46	49	41		52	49	52	48
23-Feb	46	45	44	37	42	34	44	49	32		37	45	37	38	43	49	44	43	35		49	43	49	45
24-Feb	48	44	46	33	44	47	40	45	45		44	49	42	34	44	43	43	40	45		49	47	45	49
25-Feb	49	45	45	45	46	44	44	45	43		40	49	45	20	47	45	45	43	43		49	47	45	49
26-Feb	47	49	47	43	46	46	51	53	51		45	50	45	41	47	51	48	51	47		53	47	53	50
27-Feb	49	46	48	45	49	49	50	51	53		50	49	44	42	50	50	45	46	49		53	50	53	49
28-Feb	45	42	45	45	46	46	53	53	49		45	45	44	36	49	52	50	48	43		53	49	53	45
29-Feb	44	44	45	39	42	44	48	49	52		47	47	41	37	44	50	41	44	46		52	44	52	47
1-Mar	44	38	38	39	40	42	46	48	50		46	45	37	36	42	47	42	43	46		50	42	50	45
2-Mar	53	48	50	43	44	47	47	50	51		44	49	46	41	47	49	42	46	44		51	47	51	49
3-Mar	51	49	52	48	48	52	48	55	52		48	54	45	41	49	54	43	45	49		55	52	55	54
4-Mar	52	50	53	53	50	53	50	52	55		46	52	49	43	49	52	46	47	49		55	53	55	52

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
5-Mar	50	51	50	49	52	52	50	51	45		57	54	50	47	51	52	45	46	51		57	52	57	54
6-Mar	42	40	47	41	43	42	47	49	39		43	43	40	38	42	44	42	45	38		49	43	49	43
7-Mar	50	47	47	49	47	49	41	44	47		41	50	49	44	47	49	40	41	40		50	49	47	50
8-Mar	48	48	49	45	45	46	48	49	48		47	49	45	44	47	47	45	46	42		49	47	49	49
9-Mar	47	42	50	48	47	49	45	47	46		43	49	47	44	51	46	43	42	42		51	51	47	49
10-Mar	49	48	44	49	51	51	49	51	48		45	41	51	43	52	47	47	45	47		52	52	51	51
11-Mar	47	48	46	45	48	47	57	62	53		53	44	45	46	49	46	52	54	52		62	49	62	46
12-Mar	53	49	53	50	52	53	52	51	55		51	51	51	51	56	48	52	55	40		56	56	55	51
13-Mar	48	47	45	49	49	49	50	51	53		48	47	47	43	48	49	47	47	47		53	49	53	47
14-Mar	46	47	47	46	47	47	46	48	48		45	48	46	44	47	56	42	45	44		48	47	48	48
15-Mar	50	51	50	48	49	49	49	52	52		50	52	48	48	51	49	49	47	50		52	51	52	52
16-Mar	47	51	48	47	47	48	49	50	56		52	51	47	46	49	52	45	44	50		56	49	56	51
17-Mar	47	37	46	46	46	47	48	50	51		49	49	45	43	47	50	45	45	51		51	47	51	49
18-Mar	48	44	48	44	45	45	49	51	44		42	48	44	41	49	52	45	46	39		51	49	51	48
19-Mar	43	43	46	44	46	45	41	45	47		42	44	43	41	45	41	42	40	44		47	46	47	44
20-Mar	50	46	47	45	46	45	42	49	46		48	48	44	44	44	41	44	42	46		49	46	49	48
21-Mar	53	53	55	53	52	54	49	51	50		45	56	53	52	51	45	46	48	46		56	54	51	56
22-Mar	53	52	54	52	49	51	55	56	58		51	52	49	51	50	52	49	55	50		58	52	58	52
23-Mar	43	40	44	44	45	44	57	57	55		50	43	42	39	48	55		53	53		57	48	57	43
24-Mar	50	48	46	48	48	49	45	48	48		43	51	47	46	50	47	49	43	46		51	50	48	51
25-Mar	51	50	53	44	50		52	56	55		52	51	47	48	51	47	51	51	50		56	51	56	51
26-Mar	55	54	52	51	53		53	55	56		51	55	50	51	53	52	50	50	48		56	53	56	55
27-Mar	56	56	52	56	56	50	53	58	47		45	54	52	51	55	41	49	50	48		58	56	58	54
28-Mar	47	50	51	49	49	50	47	48	53		47	50	48	46	49	48	43	45	45		53	50	53	50
29-Mar	51	48	50	51	48	51	48	50	53		51	48	50	48	48	53	45	46	51		53	51	53	50
30-Mar	51	48	47	50	52	51	47	46	45		45	50	51	45	53	58	43	49	48		53	53	47	51
31-Mar	47	47	46	49	51	49	48	49	50		49	49	47	43	52	57	49	47	51		52	52	50	49
1-Apr	44	49	47	46	46	44	43	50	33		38	47	46	47	46	48	48	42	45		50	46	50	47
2-Apr	49	52	50	51	51	50	47	50	50		40	46	49	46	52	46	46	44	49		52	52	50	49
3-Apr	47	47	44	47	47	46	51	50	43		44	50	45	42	48	51	50	46	50		51	48	51	50
4-Apr	56	47	44	47	43	47	55	56	54		45	46	47	41	47	55	53	51	56		56	47	56	47
5-Apr	55	53	52	54	50	53	58	59	58		51	54	52	51	57	55	54	55	55		59	57	59	54
6-Apr	53	50	51	50	51	48	54	62	52		49	53	49	47	49	55	55	51	51		62	51	62	53
7-Apr	48	54	48	50	49	50	51	42	48		49	50	47	50	49	50	39	47	44		51	50	51	50

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
8-Apr	46	45	46	44	41	43	44	50	54		48	41	41	40	45	47	48	41	49		54	45	54	41
9-Apr	50	49	48	51	49	50	52	51	55		55	52	50	48	51	47	50	47	56		55	51	55	52
10-Apr	43	54	49	54	53	54	45	46	49		47	53	53	48	54	44	43	42	51		54	54	49	53
11-Apr	45	46	43	50	46	50	49	48	45		43	45	48	42	50	49	46	45	29		50	50	49	48
12-Apr	50	48	47	45	43	45	44	44	27		28	44	43	47	47	36	39	40	41		47	47	44	47
13-Apr	48	49	47	49	46	49	53	52	52		48	49	47	45	49	51	52	49	46		53	49	53	49
14-Apr	53	52	51	55	52	54	55	54	58		51	50	54	48	55	50	51	51	57		58	55	58	54
15-Apr	55	55	53	53	53	53	52	53	53	53	51	54	50	51	56	55	49	52	43		56	56	53	54
16-Apr	42	64	62	49	47	49	52	53	63	64	59	59	49	44	48	55	49	49	41		64	49	64	59
17-Apr	39	48	42	44	41	43	51	52	46	47	47	42	40	41	45	57	52	50	32		52	45	52	42
18-Apr	53	45	46	38	36	40	47	54	46	46	46	39	39	37	43	32	48	47	47		54	43	54	39
19-Apr	55	42	51	52	49	51	56	56	49	51	47	55	49	47	53	39	56	51	34		56	53	56	55
20-Apr	57	50	53	50	49	53	59	59	59	64	53	55	49	50	53	53	54	55	52		64	53	64	55
21-Apr	58	59	56	59	53	56	59	67	53	53	57	55	53	55	58	51	54	53	56		67	59	67	55
22-Apr	57	59	59	57	54	59	57	57	62	59	60	57	58	55	56	53	55	52	62		62	59	62	58
23-Apr	56	55	65	53	49	53	55	50	56	57	57	53	53	58	53	57	51	49	61		58	53	57	58
24-Apr	63	58	59	64	62	61	53	51	53	57	52	61	60	57	64	50	47	48	74		64	64	57	61
25-Apr	61	62	64	59	56	59	58	56	55	60	57	60	56	59	57	52	50	53	61		60	59	60	60
26-Apr	52	53	53	55	52	46	61	61	60	60	59	56	54	50	55	58	56	56	57		61	55	61	56
27-Apr	54	50	47	47	45	48	57	58	60	64	59	49	47	44	49	60	55	52	50		64	49	64	49
28-Apr	60	60	59	59	57	58	52	50	48	51	56	58	58	53	60	56	50	53	56		60	60	56	58
29-Apr	49	63	60	58	50	57	62	60	63	63	62	60	58	57	56	59	59	56	36		63	58	63	60
30-Apr	51	52	48	48	45	47	58	59	59	61	56	49	45	46	48	60	57	54	42		61	48	61	49
1-May	57	46	46	45	40	43	42	44	33	33	35	42	45	37	44	53	39	39	35		45	45	44	45
2-May	57	54	51	56	52	56	47	48	44	49	47	48	53	52	54	37	43	42	52		56	56	49	53
3-May	60	61	49	57	54	54	53	60	58	59	54	53	52	56	61	44	51	49	56		61	61	60	56
4-May	59	63	61	59	55	61	63	66	63	69	59	56	60	57	61	61	59	58	50		69	61	69	60
5-May	61	64	62	62	59	62	61	61	64	61	58	60	62	57	61	61	55	55	65		64	62	64	62
6-May	54	62	58	60	58	58	61	60	57	53	57	62	59	53	60	57	52	54	57		62	60	61	62
7-May	51	62	57	60	58	58	66	67	51	65	49	57	58	55	61	51	60	62	57		67	61	67	58
8-May	53	56	54	57	54	56	63	62	59	64	60	56	56	53	56	54	59	57	61		64	57	64	56
9-May	50	49	50	47	46	48	55	53	53	55	55	48	46	45	51	60	49	51	53		55	51	55	48
10-May	52	54	52	56	52	55	59	60	60	70	63	56	53	51	56	58	56	55	58		70	56	70	56
11-May	55	49	55	55	52	55	63	63	57	68	58	56	54	52	55	54	57	57	55		68	55	68	56

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
12-May	56	66	61	64	59	60	54	61	49	50	50	61	56	61	59	42	51	50	54		64	64	61	61
13-May	60	61	60	60	55	57	64	71	54	54	52	62	57	58	60	51	53	58	61		71	60	71	62
14-May	53	62	62	54	50	53	55	59	47	52	42	52	53	54	50	57	55	52	45		59	54	59	54
15-May	58	51	51	53	50	52	54	51	43	54	37	55	52	48	53	55	47	47	36		55	53	54	55
16-May	55	59	56	55	55	56	37	39	36	43	45	56	55	52	60	45	34	39	44		60	60	45	56
17-May	53	59	55	39	36	39	39	49	24	27	31	44	44	53	40	50	44	44	35		53	40	49	53
18-May	58	41	41	35	36	39	31	37	30	30	34	40	36	38	42	28	34	35	50		42	42	37	40
19-May	56	56	56	44	50	53	52	58	49	46	43	53	50	55	53	36	56	56	45		58	53	58	55
20-May	57	63	60	57	57	52	55	56	55	54	58	59	59	55	59	46	52	55	64		59	59	58	59
21-May	57	67	61	58	60	59	53	56	53	50	50	64	61	58	61	49	52	50	45		64	61	56	64
22-May	47	54	57	56	55	57	52	54	56	66	58	55	57	49	59	51	51	54			66	59	66	57
23-May	59	67	66	52	53	54	50	53	52	63	56	49	52	58	58	49	50	48			63	58	63	58
24-May	59	63	64	55	58	58	56	60	58	69	57	60	57	55	61	42	56	56	49		69	61	69	60
25-May	54	75	67	60	57	60	50	50	46	50	49	64	61	65	60	33	46	52	63		65	60	50	65
26-May	61	67	66	62	62	65	54	57	54	62	53	65	64	64	67	51	54	59	59		67	67	62	65
27-May	56	59	58	57	58	58	60	63	58	69	61	61	59	56	64	65	62	60	64		69	64	69	61
28-May	63	63	55	58	57	60	67	66	63	65	69	54	59	55	60	53	61	63	62		69	60	69	59
29-May	58	72	67	55	53	53	47	51	41	43	48	63	57	65	57	41	50	46	57		65	57	51	65
30-May	49	63	56	54	51	53	37	41	50	49	42	54	55	53	52	37	42	40	52		55	54	50	55
31-May	54	61	55	52	54	53	47	48	46	50	52	53	52	55	52	42	44	46	55		55	54	52	55
1-Jun	53	56	55	56	54	56	46	53	50	53	51	48	60	54	55	52	50	47	46	45	60	56	53	60
2-Jun	56	57	52	58	53	55	55	61	49	51	50	52	54	54	58	55	68	57	46	49	61	58	61	54
3-Jun	49	52	50	51	50	55	55	67	54	55	55	51	50	49	56	53	55	52	45	49	67	56	67	51
4-Jun	48	43	48	56	53	53	52	60	50	51	50	37	56	40	57	49	48	50	52	28	60	57	60	56
5-Jun	56	56	54	54	50	53	57	65	54	61	55	49	56	55	54	55	52	54	60	47	65	54	65	56
6-Jun	67	57	61	61	56	61	64	79	63	62	63	50	61	54	61	61	55	63	56	55	79	61	79	61
7-Jun	54	59	57	58	54	60	69	64	61	62	64	56	60	49	58	64	53	60	57	52	69	60	69	60
8-Jun	59	57	54	56	52	58	55	55	65	66	66	59	60	56	56	60	54	52	64	53	66	58	66	60
9-Jun	58	54	53	54	48	52	57	58	57	56	56	51	52	52	56	49	55	51	55	50	58	56	58	52
10-Jun	54	50	48	49	49	48	56	57	56	60	49	44	46	47	54	46	59	56	55	42	60	54	60	47
11-Jun	52	56	48	50	47	52	58	59	56	57	51	48	52	50	53	50	55	54	46	48	59	53	59	52
12-Jun	58	63	54	55	52	54	59	60	58	60	58	55	52	56	57	50	55	53	59	44	60	57	60	56
13-Jun	53	57	50	55	48	56	51	53	60	60	65	56	58	48	53	47	43	50	45	45	65	56	65	58
14-Jun	63	62	57	60	54	61	53	54	55	60	52	56	59	52	62	46	46	48	51	50	62	62	60	59

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
15-Jun	56	69	66	61	59	63	54	52	55	56	55	61	64	58	63	45	49	47	59	60	64	63	56	64
16-Jun	55	71	54	55	50	57	52	54	51	57	65	60	57	56	57	44	45	48	63	49	65	57	65	60
17-Jun	52	66	55	60	54	57	60	61	56	51	59	55	55	53	57	48	57	54	62	49	61	60	61	55
18-Jun	58	71	69	69	66	70	55	68	62	60	61	56	67	64	69	50	60	49	47	49	70	70	68	67
19-Jun	55	62	57	62	59	60	52	63	52	53	53	57	59	62	65	42	46	49	49	48	65	65	63	62
20-Jun	55	54	53	59	54	58	54	59	51	54	52	48	60	52	56	40	48	50	50	44	60	59	59	60
21-Jun	57	61	62	58	53	59	55	70	47	45	33	49	65	56	57	30	52	56	47	56	70	59	70	65
22-Jun	55	59	64	62	57	63	58	59	44	48	43	57	63	58	61	33	59	53	48	55	63	63	59	63
23-Jun	54	48	63	65	59	66	66	65	45	50	48	57	62	56	63	41	62	77	48	54	66	66	66	62
24-Jun	49	58	55	59	57	62	59	69	50	56	53	56	59	56	56	45	61	63	51	50	69	62	69	59
25-Jun	56	59	59	54	53	54	56	61	49	54	43	53	53	57	54	45	69	56	45	51	61	54	61	57
26-Jun	52	59	57	55	52	53	46	59	47	51	52	50	55	52	58	40	51	48	37	55	59	58	59	55
27-Jun	55	60	57	60	52	57	51	54	30	42	40	51	60	59	56	32	45	47		51	60	60	54	60
28-Jun	49	52	53	44	40	44	34	37	38	38	40	47	46	47	42	39	29	33		48	47	44	40	47
29-Jun	48	49	52	48	42	51	41	49	52	54	52	40	53	43	44	40	37	38		40	54	51	54	53
30-Jun	45	50	53	50	49	39	48	57	55	57	57	38	49	48	51	48	43	45		43	57	51	57	49
1-Jul	41	38	41	40	41	39	46	47	53	48	53	38	42	34	43	45	43	44		39	53	43	53	42
2-Jul	49	48	50	52	52	51	57	59	48	53	52	51	52	45	55	52	41	52		46	59	55	59	52
3-Jul	54	58	61	54	53	54	55	58	54	56	58	63	54	57	57	52	47	51		58	63	57	58	63
4-Jul	45	58	54	54	51	51	56	57	51	53	58	54	50	52	53	51	59	53		51	58	54	58	54
5-Jul	48	55	52	50	46	49	54	55	52	53	59	48	51	51	50	51	62	48		48	59	50	59	51
6-Jul	45	48	47	50	46	49	55	53	48	52	52	51	50	48	51	43	50	47	52	52	55	51	55	51
7-Jul	47	38	51	52	51	53	55	52	52	54	53	47	52	47	54	45	50	48		49	55	54	55	52
8-Jul	46	51	45	52	48	50	60	55	53	57	63	56	48	54	53	49	55	51		39	63	53	63	56
9-Jul	48	57	54	57	52	52	58	56	62	60	55	58	54	59	57	51	64	53		49	62	57	62	59
10-Jul	50	59	54	51	46	50	54	52	53	54	53	53	51	52	52	50	52	45		55	54	52	54	53
11-Jul	45	55	58	45	40	43	52	48	50	51	54	46	45	48	48	49	41	45	56	57	54	48	54	48
12-Jul	52	60	58	46	41	48	48	46	46	50	49	56	48	59	45	42	42	40	58	52	59	48	50	59
13-Jul	52	57	55	53	52	49	49	51	48	47	53	59	51	56	54	40	51	42	61	56	59	54	53	59
14-Jul	49	61	58	57	56	56	53	52	51	50	47	62	57	60	58	44	48	43	58	54	62	58	53	62
15-Jul	46	66	61	67	58	61	51	61	54	57	57	59	60	61	58	43	46	46	58	57	67	67	61	61
16-Jul	43	61	59	52	47	49	68	65	58	58	48	48	51	53	49	38	55	67	53	55	68	52	68	53
17-Jul	42	48	44	44	44	41	60	56	52	52	44	45	42	48	48	39	56	53	49	45	60	48	60	48
18-Jul	46	59	52	54	48	51	60	61	47	50	44	45	51	48	53	36	57	60	42	34	61	54	61	51

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
19-Jul	43	61	58	63	53	59	59	70	46	47	47	43	61	61	56	39	54	56	46	39	70	63	70	61
20-Jul	60	68	60	60	55	60	54	61	47	48	42	53	59	65	61	40	41	49	45	44	65	61	61	65
21-Jul	55	68	62	62	57	61	44	55	48	51	48	56	62	65	61	45	39	41	52	52	65	62	55	65
22-Jul	58	68	64	65	59	64	48	62	49	53	51	60	62	69	63	40	44	44	51	48	69	65	62	69
23-Jul	55	48	51	60	60	58	55	69	55	60	46	53	57	53	64	39	47	51	54	48	69	64	69	57
24-Jul	54	48	49	65	59	61	51	64	52	53	48	49	60	56	62	37	48	49	50	46	65	65	64	60
25-Jul	56	54	53	70	63	60	50	54	48	50	50	49	63	60	65	43	47	46	47	49	70	70	54	63
26-Jul	56	52	51	62	62	59	50	66	51		54	51	58	57	63	47	47	47	65	44	66	63	66	58
27-Jul	54	56	52	68	66	63	58	60	63		61	49	58	61	66	52	52	52	53	50	68	68	63	61
28-Jul	52	41	58	65	63	61	63	66	63		62	54	58	56	64	43	58	56	61	50	66	65	66	58
29-Jul	54	57	56	54	55	54	51	53	52		50	56	57	60	54	39	46	47	54	52	60	55	53	60
30-Jul	55	58	56	56	54	56	49	56	53		45	51	59	58	53	44	47	47	51	48	59	56	56	59
31-Jul	55	64	61	64	60	60	57	57	51		47	57	62	62	62	45	48	53	49	51	64	64	57	62
1-Aug	57	49	55	64	59	60	64	50	48		50	46	58	59	63	42	48	59	51	57	64	64	64	59
2-Aug	54	55	56	60	54	55	59	54	53	49	51	48	58	55	54	38	53	58	47	48	60	60	59	58
3-Aug	53	61	66	49	45	49	65	49	52	49	47	40	51	64	49	39	56	59	53	51	65	49	65	64
4-Aug	58	49	53	50	49	50	68	58	56	52	55	40	53	51	50	40	63	63	50	44	68	50	68	53
5-Aug	48	43	50	53	52	53	66	58	56	53	52	39	54	43	54	41	57	65	51	49	66	54	66	54
6-Aug	47	60	56	59	56	61	60	67	51	50	50	42	59	63	57	38	57	55	49	44	67	61	67	63
7-Aug	53	58	57	63	61	64	55	56	49	52	38	47	62	58	61	31	48	53	50	46	64	64	56	62
8-Aug	55	62	57	54	51	57	64	64	50	50	44	48	55	59	56	32	54	68	41	47	64	57	64	59
9-Aug	44	56	53	56	50	58	57	53	51	49	49	46	56	57	56	33	51	52	53	45	58	58	57	57
10-Aug	48	43	50	53	49	53	62	46	53	46	48	42	56	57	49	35	52	57	53	45	62	53	62	57
11-Aug	58	51	50	50	50	54	54	52	40	41	52	52	50	48	52	40	54	49	54	48	54	54	54	52
12-Aug	53	41	54	56	56	55	48	54	49	52	54	56	52	52	58	42	52	47	56	46	58	58	54	56
13-Aug	55	52	51	56	57	57	48	49	48	52	58	42	55	55	56	51	44	48	54	48	58	57	58	55
14-Aug	55	57	58	56	55	56	50	54	50	51	45	48	54	56	57	47	49	49	47	47	57	57	54	56
15-Aug	55	57	56	62	57	62	61	64	55	57	52	47	56	57	58	52	52	54	52	47	64	62	64	57
16-Aug	53	54	57	55	55	56	59	64	58	58	57	50	49	53	56	52	55	54	52	49	64	56	64	53
17-Aug	53	56	53	55	53	58	54	56	52	52	50	43	58	58	54	36	47	47	49	48	58	58	56	58
18-Aug	52	54	52	51	51	56	54	65	49	46	38	46	53	50	54	25	54	52	46	43	65	56	65	53
19-Aug	51	51	53	53	52	54	60	56	47	42	42	43	52	55	52	28	58	58	44	51	60	54	60	55
20-Aug	54	57	50	60	54	58	48	47	51	49	45	41	56	53	56	30	41	42	37	44	60	60	51	56
21-Aug	54	55	53	51	51	52	45	49	43	46	51	45	53	51	48	34	42	42	49	49	53	52	51	53

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
22-Aug	56	52	51	53	50	54	71	61	48	44	40	48	53	50	51	34	44	66	47	45	71	54	71	53
23-Aug	47	48	51	50	44	49	57	47	40	39	41	48	51	48	51	38	46	54	45	36	57	51	57	51
24-Aug	54	32	50	51	48	52	55	51	42	40	39	41	49	47	50	45	46	47	50	44	55	52	55	49
25-Aug	50	43	55	58	52	56	56	63	39	39	41	43	52	53	53	42	47	54	47	51	63	58	63	53
26-Aug	49	61	56	49	46	51	58	63	57	47	44	49	49	53	48	40	45	53	44	46	63	51	63	53
27-Aug	45	53	50	48	47	49	60	55	51	44	45	43	49	46	48	32	42	58	48	46	60	49	60	49
28-Aug	50	54	45	48	46	49	54	59	48	44	46	43	46	48	47	35	53	49	44	45	59	49	59	48
29-Aug	50	49	47	50	44	51	46	48	50	50	38	46	47	50	47	38	41	41	39	46	51	51	50	50
30-Aug	48	50	51	42	42	42	39	37	37	36	32	44	46	51	45	36	32	35	38	44	51	45	39	51
31-Aug	48	52	49	46	42	45	39	45	35	34	34	40	46	48	44	36	35	35	38	46	48	46	45	48
1-Sep	43	47	51	54	46	50	44	49	44	42	42	36	44	45	47	37	36	41	40	46	54	54	49	45
2-Sep	44	46	47	43	39	46	50	60	53	49	51	35	45	49	40	40	40	47	40	40	60	46	60	49
3-Sep	44	47	48	45	43	48	58	49	46	43	46	35	47	46	44	44	40	51	46	36	58	48	58	47
4-Sep	39	44	42	42	42	46	58	44	47	40	41	42	44	39	43	44	40	52	44	38	58	46	58	44
5-Sep	40	46	43	42	42	46	45	46	42	39	34	41	43	42	43	33	36	39	38	39	46	46	46	43
6-Sep	35	46	40	42	41	47	37	35	31	26	30	39	44	40	42	27	28	29	32	42	47	47	37	44
7-Sep	37	46	47	31	30	35	35	33	28	23	32	29	32	38	31	33	24	31	29	46	38	35	35	38
8-Sep	39	48	47	46	41	51	37	35	34	39	34	50	48	42	44	30	32	32	31	43	51	51	39	50
9-Sep	45	42	47	43	44	45	50	47	49	46	48	46	44	40	49	32	51	48	46	42	50	49	50	46
10-Sep	45	51	51	40	39	42	39	39	32	30	37	42	44	43	41	26	33	34	40	46	44	42	39	44
11-Sep	45	48	47	45	41	48	61	68	38	34	36	46	45	48	43	32	46	59	38	44	68	48	68	48
12-Sep	38	43	40	40	37	44	48	43	45	41	39	37	40	37	39	32	42	41	42	38	48	44	48	40
13-Sep	34	41	38	42	40	45	43	40	49	45	45	39	42	36	41	38	41	38	30	30	49	45	49	42
14-Sep	37	35	47	34	33	38	51	47	43	42	42	35	37	33	34	34	38	45	29	35	51	38	51	37
15-Sep	37	49	52	40	37	43	51	45	39	39	35	38	41	41	36	34	38	44	39	45	51	43	51	41
16-Sep	45	49	48	41	40	42	39	36	42	41		39	43	48	40	35	37	31	44	46	48	42	42	48
17-Sep	45	50	49	48	44	49	50	47	42	41		47	46	48	45	32	68	48	37	47	50	49	50	48
18-Sep	50	51	52	48	46	51	45	45	39	45		54	48	48	51	30	53	42	43	48	54	51	45	54
19-Sep	44	57	54	55	52	59	51	47	43	47	45	52	54	52	55	29	50	47	50	48	59	59	51	54
20-Sep	33	46	45	39	39	35	50	39	42	46	34	46	42	47	41	32	30	42	43	35	50	41	50	47
21-Sep	36	37	36	42	40	40	47	38	40	44	37	32	44	37	41	38	37	42	40	35	47	42	47	44
22-Sep	42	26	43	34	34	33	45	39	44	46	42	33	38	35	34	44	33	39	44	43	46	34	46	38
23-Sep	50	45	49	41	39	42	42	41	44	37	44	42	44	45	43	42	35	39	43	45	45	43	44	45
24-Sep	43	40	42	39	39	40	46	44	42	42	44	46	40	39	42	36	42	41	47	37	46	42	46	46

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
25-Sep	42	47	43	42	40	40	43	45	32	35	34	44	41	46	42	34	43	42	38	40	46	42	45	46
26-Sep	44	35	46	44	42	45	40	38	31	39	37	38	41	47	44	34	34	36	43	39	47	45	40	47
27-Sep	38	51	54	46	44	46	43	51	54	48	55	40	47	48	46	36	44	42	47	44	55	46	55	48
28-Sep	32	45	50	49	42	48	39	47	41	48	53	41	48	43	43	29	32	37	49	46	53	49	53	48
29-Sep	31	35	38	49	39	45	55	55	54	58	43	41	50	27	42	38	47	50	38	31	58	49	58	50
30-Sep	34	45	40	40	40	36	57	48	49	40	45	37	38	34	44	39	39	49	46	27	57	44	57	38
1-Oct	39	43	42	40		38	45	44	50		42	43	40	39	40	37	40	39	45	29	50	40	50	43
2-Oct	33	45	44	42		41	47	43	51		47	41	42	40	42	34	37	38	41	39	51	42	51	42
3-Oct	53	48	54	46	43	47	38	33	39		37	48	45	46	48	33	28	40	42	49	48	48	39	48
4-Oct	46	49	46	47	44	45	49	48	48		45	47	46	42	49	31	38	42	47	42	49	49	49	47
5-Oct	49	48	53	44	41	45	45	44	50		46	51	47	46	42	33		38	50	48	51	45	50	51
6-Oct	54	47	49	51	49	52	44	42	50		41	52	51	47	51	34		36	46	43	52	52	50	52
7-Oct	47	48	53	45	36	46	43	42	40		36	44	49	45	47	28	34	37	45	43	49	47	43	49
8-Oct	41	43	48	26	31	30	32	33	30		35	37	30	40	37	27	27	28	44		40	37	35	40
9-Oct	41	32	42	37	36	39	35	38	40		40	35	38	34	36	40	28	32	32		40	39	40	38
10-Oct	34	36	44	37	34	38	43	54	40		37	40	39	41	40	38	36	46	39		54	40	54	41
11-Oct	33	37	43	36	31	36	39	37	40		38	36	37	35	33	33	31	33	37		40	36	40	37
12-Oct	36	39	45	38	35	39	41	37	42		33	41	37	36	37	35	36	33	28		42	39	42	41
13-Oct	41	43	46	35	34	37	56	54	36		29	42	37	38	37	34	36	48	28		56	37	56	42
14-Oct	41	43	47	37	35	41	46	45	55		41	44	41	38	39	32	37	42	34		55	41	55	44
15-Oct	43	45	50	44	40	43	45	43	45		42	46	43	44	42	40	35	36	43		46	44	45	46
16-Oct	42	41	42	43		42	45	43	50		47	47	43	40	41	41	36	38	43		50	43	50	47
17-Oct	39	31	44	39	31	40	43	41	46		46	41	40	39	38	42	33	38	41		46	40	46	41
18-Oct	43	43	46	41	38	41	46	43	45		43	46	41	39	40	40	33	39	45		46	41	46	46
19-Oct	45	47	49	43	35	47	44	43	46		40	50	47	44	46	41	33	35	53		50	47	46	50
20-Oct	47	47	52	44	44	46	46	48	47		46	44	46	44	47	44	40	42	44		48	47	48	46
21-Oct	47	50	53	41	41	47	51	52	54		49	49	44	47	46	44	43	50	48		54	47	54	49
22-Oct	43	46	49	47	42	50	59	46	49		44	45	46	44	46	42	44	59	49		59	50	59	46
23-Oct	45	43	45	43	37	43	45	60	54		50	43	42	40	43	39	51	44	50		60	43	60	43
24-Oct	41	39	44	34	34	40	45	49	51		46	40	38	38	37	38	45	47	51		51	40	51	40
25-Oct	35	32	35	33	33	33	45	44	48		42	33	33	33	38	37	37	39	39		48	38	48	33
26-Oct	38	35	39	35	32	37	37	38	41		43	37	35	34	36	37	33	30	43		43	37	43	37
27-Oct	41	37	43	33	34	44	46	52	48		43	38	34	39	35	37	38	44	43		52	44	52	39
28-Oct	41	37	43	43	41	48	46	41	37		39	40	43	39	40	40	33	39	44		48	48	46	43

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
29-Oct	29	30	32	30	31	33	47	48	49		41	33	30	28	34	42	44	40	44		49	34	49	33
30-Oct	36	30	36	32	32	38	51	55	42		41	35	35	29	33	42	37	45	36		55	38	55	35
31-Oct	31	35	39	33	8	37	39	39	46		40	38	34	34	35	41	35	34	42		46	37	46	38
1-Nov	41	37	42	23	19	33	37	37	39		38	39	23	37	21	44	29	32	36		39	33	39	39
2-Nov	42	42	46	37	34	37	31	31	27		29	44	39	40	35	41	23	27	26		44	37	31	44
3-Nov	34	28	41	40	35	40	34	34	18		33	40	38	31	35	30	32	30	41		40	40	34	40
4-Nov	38	27	40	35	31	40	33	33	35		38	32	33	29	32	28	28	30	44		40	40	38	33
5-Nov	35	33	37	29	28	32	23	29	25		29	28	30	29	31	28	23	20	33		32	32	29	30
6-Nov	39	30	39	39	36	42	41	40	35		32	39	41	31	37	30	36	36	24		42	42	41	41
7-Nov	39	34	41	31	29	39	40	38	37		34	37	32	33	32	43	31	35	22		40	39	40	37
8-Nov	42	26	44	35	32	37	41	41	39		40	36	37	37	38	35	33	36	40		41	38	41	37
9-Nov	43	39	40	39	38	42	42	42	36		28	40	37	36	39	28	36	38	38		42	42	42	40
10-Nov	42	35	37	34	32	37	33	33	34		29	39	35	33	35	28	29	30	39		39	37	34	39
11-Nov	43	39	44	34	33	39	35	36	32		29	41	30	35	36	27	31	33	35		41	39	36	41
12-Nov	43	40	46	37	36	41	37	40	37		36	42	37	35	37	29	32	34	38		42	41	40	42
13-Nov	42	39	47	38	38	43	43	40	39		40	45	39	37	36	32	35	38	39		45	43	43	45
14-Nov	46	37	49	39		44	44	41	42		43	46	37	29	39	40	31	36	44		46	44	44	46
15-Nov	42	36	45	32		40	41	41	47		41	45	30	35	38	42	31	35	45		47	40	47	45
16-Nov	46	40	45	34		40	39	38	45		46	44	31	39	31	42	32	37	48		46	40	46	44
17-Nov	44	41	43	45		41	44	41	43		39	45	46	40	46	38	33	42	42		46	46	44	46
18-Nov	40	36	39	35		39	42	41	36		35	45	39	32	38	45	35	39	40		45	39	42	45
19-Nov	39	40	44	31		36	39	38	41		41	37	35	40	35	37	34	37	40		41	36	41	40
20-Nov	35	36	40	34		37	40	38			39	39	36	35	34	38	32	37	40		40	37	40	39
21-Nov	41	30	34	33		35	33	32			30	38	31	28	35	39	25	38	33		38	35	33	38
22-Nov	37	31	32	27		29	45	44	42		40	32	30	30	35	39	37	42	37		45	35	45	32
23-Nov	38	32	41	26		35	39	36	42		38	33	28	32	31	39	34	36	39		42	35	42	33
24-Nov	41	37	42	44	43	42	47	40	42		42	45	41	37	44	37	40	41	41		47	44	47	45
25-Nov	38	39	45	34	35	40	39	38	35		33	39	37	37	38	30	34	36	40		40	40	39	39
26-Nov	41	39	44	20	19	32	33	30	31		26	38	30	35	26	29	28	32	34		38	32	33	38
27-Nov	43	43	44	45	43	44	45	44	45		39	46	44	43	45	41	38	44	41		46	45	45	46
28-Nov	39	35	39	36	37	33	46	45	50		44	40	37	36	39	48	38	47	41		50	39	50	40
29-Nov	37	34	39	34	33	34	43	42	42		38	39	36	34	37	45	34	40	40		43	37	43	39
30-Nov	39	33	40	33	34	38	40	37	39		39	41	36	30	36	42	26	33	39		41	38	40	41
1-Dec	37	34	38	30	25	30	34	28	39		41	43	33	28	33	38	27	31	39		43	33	41	43

State	AZ	CO	CO	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	TX	TX	TX	TX	UT	NM	NM	NM	NM
County	Navajo	La Plata	Monte-zuma	Bernalillo	Bernalillo	Bernalillo	Dona Ana	Dona Ana	Eddy	Eddy	Lea	Rio Arriba	Sandoval	San Juan	Valencia	Brewster	El Paso	El Paso	Lampasas	San Juan	Maximum	Maximum	Maximum	Maximum
State Code	04	08	08	35	35	35	35	35	35	35	35	35	35	35	35	48	48	48	48	49	Sites			
County Code	017	067	083	001	001	001	013	013	015	015	025	039	043	045	061	043	141	141	381	037				
Site ID	0119	7001	0101	0023	0029	1012	0020	0021	1005	3001	0008	0026	1001	0009	0008	0101	0057	0058	9991	0004				
2-Dec	35	41	44	38	36	41	40	33	29		25	38	38	38	38	37	30	36	38		41	41	40	38
3-Dec	36	36	42	33	34	37	28	28	23		29	45	35	28	37	17	21	25	34		45	37	29	45
4-Dec	38	33	36	38	35	39	40	36	24		29	45	39	30	34	25	35	36	40		45	39	40	45
5-Dec	42	38	41	25	26	39	44	40	42		37	43	31	33	33	32	30	43	36		44	39	44	43
6-Dec	44	33	40	28	22	36	44	41	37		38	44	24	32	35	38	33	39	37		44	36	44	44
7-Dec	41	45	44	36	31	40	41	31	22		22	43	38	40	37	33	22	38	24		43	40	41	43
8-Dec	37	36	40	20	21	25	25	22	26		27	33	24	38	26	25	22	24	29		38	26	27	38
9-Dec	38	36	39	9	22	28	26	18	19		21	41	24	30	26	23	20	22	24		41	28	26	41
10-Dec	40	32	38	26	25	35	28	30	32		27	42	29	30	29	29	26	27	32		42	35	32	42
11-Dec	35	31	34	32	24	36	41	39	38		35	35	33	24	32	33	31	38	36		41	36	41	35
12-Dec	36	22	34	20	17	35	38	35	32		29	38	15	27	28	36	24	35	31		38	35	38	38
13-Dec	36	30	37	32	27	38	34	30	38		31	40	31	21	34	31	26	31	36		40	38	38	40
14-Dec	33	27	34	27	26	34	34	33	32		29	37	30	24	28	30	26	29	26		37	34	34	37
15-Dec	29	19	29	20	15	31	30	31	23		16	36	19	19	20	25	22	31	26		36	31	31	36
16-Dec	35	36	40	29	29	31	35	31	33		28	35	30	35	28	54	22	33	28		35	31	35	35
17-Dec	42	44	43	42	43	44	47	46	35		31	47	43	41	44	38	43	48	35		47	44	47	47
18-Dec	41	39	48	41	38	46	39	34	32		33	46	42	33	38	31	30	35	35		46	46	39	46
19-Dec	34	35	41	35	32	44	35	27	31		32	43	37	26	29	36	28	30	37		44	44	35	43
20-Dec	28	32	35	29	23	36	34	29	31		29	42	32	30	31	31	22	20	42		42	36	34	42
21-Dec	28	35	36	23	32	34	21	25	25		31	40	27	29	27	31	14	11	38		40	34	31	40
22-Dec	30	19	31	13	19	26	28	24	41		38	39	22	26	23	43	25	26	35		41	26	41	39
23-Dec	34	22	27	24	22	33	37	33	36		35	34	23	22	25	39	25	29	33		37	33	37	34
24-Dec	43	41	45	38	36	41	41	40	41		35	47	38	42	37	33	37	42	38		47	41	41	47
25-Dec	43	43	42	43	44	46	41	40	47		46	47	43	39	45	37	36	40	42		47	46	47	47
26-Dec	40	41	40	39	33	43	36	35	41		44	44	41	40	40	34	28	30	45		44	43	44	44
27-Dec	28	45	35	33	31	36	36	33	34		35	41	38	42	34	30	22	30	37		42	36	36	42
28-Dec	27	34	39	20	11	38	33	31	36		35	43	34	30	18	34	20	25	41		43	38	36	43
29-Dec	23	34	34	22	19	24	35	30	40		39	39	33	26	22	40	31	33	41		40	24	40	39
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September 2020

NEW MEXICO OZONE ATTAINMENT INITIATIVE PHOTOCHEMICAL MODELING STUDY – 2014 MODELING PLATFORM DEVELOPMENT AND MODEL EVALUATION



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NEW MEXICO OZONE ATTAINMENT INITIATIVE PHOTOCHEMICAL MODELING STUDY – 2014 MODELING PLATFORM DEVELOPMENT AND MODEL EVALUATION

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ACRONYMS AND ABBREVIATIONS

3SAQS	Three-State Air Quality Study
AIRS	Aerometric Information Retrieval System
AMET	Atmospheric Model Evaluation Tool
APCA	Anthropogenic Precursor Culpability Assessment
AQ	Air Quality
AQS	Air Quality System
BC	Boundary Condition
BLM	Bureau of Land Management
CAMx	Comprehensive Air-quality Model with extensions
CARB	California Air Resources Board
CASTNet	Clean Air Status and Trends Network
CB6r2	Carbon Bond mechanism version 6, revision 2
CMAQ	Community Multiscale Air Quality modeling system
CONUS	Continental United States
CPC	Center for Prediction of Climate
CSAPR	Cross State Air Pollution Rule
CSN	Chemical Speciation Network
EC	Elemental Carbon Fine Particulate Matter
ECMWF	European Center for Medium Range Weather Forecasting
EGU	Electrical Generating Units
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
ERA5	ECMWF global hourly meteorological forecasts at 30-km
FB	Fractional Bias
FE	Fractional Error
FRM	Federal Reference Method
GCM	Global Chemistry Model
GEOS-Chem	Goddard Earth Observing System (GEOS) global chemistry model
GIRAS	Geographic Information Retrieval and Analysis System
IMPROVE	Interagency Monitoring of PROtected Visual Environments
IWDW	Intermountain West Data Warehouse
LCC	Lambert Conformal Conic projection
LSM	Land Surface Model
MADIS	Meteorological Assimilation Data Ingest System
MATS	Modeled Attainment Test Software
MCIP	Meteorology-Chemistry Interface Processor
MEGAN	Model of Emissions of Gases and Aerosols in Nature
MNGE	Mean Normalized Gross Error
MNB	Mean Normalized Bias
MNE	Mean Normalized Error
MOVES	Motor Vehicle Emissions Simulator
MOZART	Model for OZone And Related chemical Tracers
MPE	Model Performance Evaluation
MSKF	Multi-Scale Kain-Fritsch Cumulus Parameterization
NAAQS	National Ambient Air Quality Standard

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NAM	North American Mesoscale Forecast System
NCAR	National Center for Atmospheric Research
NCEP	National Center for Environmental Prediction
NCDC	National Climatic Data Center
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NH_4	Ammonium Fine Particulate Matter
NMB	Normalized Mean Bias
NME	Normalized Mean Error
NMED	New Mexico Environmental Division
NO_2	Nitrogen Dioxide
NO_3	Nitrate Fine Particulate Matter
NOAA	National Oceanic and Atmospheric Administration
OA	Organic Aerosol Fine Particulate Matter
OAI	Ozone Attainment Initiative
OC	Organic Carbon Fine Particulate Matter
OSAT	Ozone Source Apportionment Technology
PAVE	Package for Analysis and Visualization
PBL	Planetary Boundary Layer
PGM	Photochemical Grid Model
PM	Particulate Matter
PPB	Parts Per Billion
PPM	Piecewise Parabolic Method
QA	Quality Assurance
QC	Quality Control
RMP	Resource Management Plan
RRF	Relative Response Factor
SCC	Source Classification Code
SIP	State Implementation Plan
SMOKE	Sparse Matrix Kernel Emissions modeling system
SNMOS	Southern New Mexico Ozone Study
SOA	Secondary Organic Aerosol
SO_2	Sulfur Dioxide
SO_4	Sulfate Fine Particulate Matter
TCEQ	Texas Commission on Environmental Quality
UNC-IE	University of North Carolina Institute for the Environment
USFS	United States Forest Service
VERDI	Visualization Environment for Rich Data Interpretation
VMT	Vehicle Miles Traveled
WBD	Wind Blown Dust model
WAQS	Western Air Quality Study
WESTAR	Western States Air Resources Council
WestJumpAQMS	West-Wide Jump-Start Air Quality Modeling Study
WESTUS	Western United States
WRAP	Western Regional Air Partnership
WGA	Western Governors' Association
WRF	Weather Research Forecast model

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1. INTRODUCTION

This document presents the development and evaluation of a photochemical grid model (PGM) modeling platform for the New Mexico (NM) Ozone Attainment Initiative (OAI) Photochemical Modeling Study ("NM OAI Study"). The New Mexico Environmental Division (NMED) has contracted with a team consisting of Western States Air Resources Council (WESTAR) and Ramboll US Corporation to conduct the NM OAI Study. The NM OAI Study leverages the 2014 PGM modeling platform developed by the Western Regional Air Partnership (WRAP) in the Western Air Quality Study (WAQS) and enhances it by adding a 4-km grid resolution modeling domain covering New Mexico and adjacent regions. Future year modeling, source apportionment and control measure evaluation are planned to assist the NMED in ozone air quality planning for the state.

1.1 NM OAI Project Genesis

The NMED Air Quality Bureau has authority over air quality management activities throughout the state of New Mexico, with the exception Bernalillo County and Tribal Lands. The City of Albuquerque/Air Quality Division has authority in Bernalillo County and, except for where Tribal Implementation Plans have been approved, EPA oversees air quality issues in Tribal Lands. The New Mexico Air Quality Control Act (NMAQCA) requires the NMED to develop a plan to address elevated ozone levels when air quality is within 95% of the ozone NAAQS (74-3-5.3, NMSA 1978[1]). The ozone NAAQS was revised in 2015 with a threshold of 0.070 ppm (70 ppb) with the relevant metric being the ozone Design Value (DV) that is expressed as the three-year average of the fourth highest Maximum Daily Average 8-hour (MDA8) ozone concentrations. Figure 1-1 displays the trends in observed ozone DVs at 8 New Mexico monitoring sites from 2013 to 2018 and compares them with the 70 ppb 2015 ozone NAAQS (red line) and 95% of the 70 ppb NAAQS (i.e., ≥ 67 ppb; black line). This results in 7[2] counties in New Mexico under NMED jurisdiction with measured 2016-2018 ozone DVs at or exceeding 95% of the 70 ppb ozone NAAQS, as shown in Figure 1-1.

[1] https://law.justia.com/codes/new-mexico/2017/chapter-74/article-2/section-74-2-5.3/

[2] 8 total counties in New Mexico if you also include Bernalillo County whose air quality is under the jurisdiction of the City of Albuquerque.

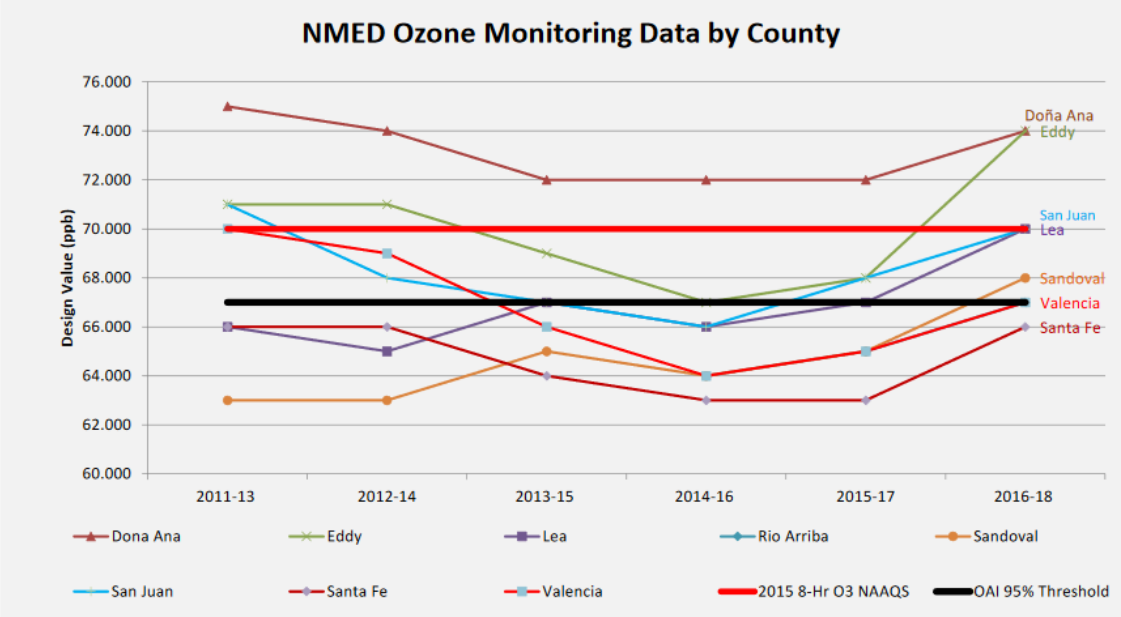


Figure 1-1. Trends in observed ozone DVs between 2013 and 2018 at 7 monitoring sites in New Mexico (Source: https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2019/10/OAI_Presentation_09262019.pdf).

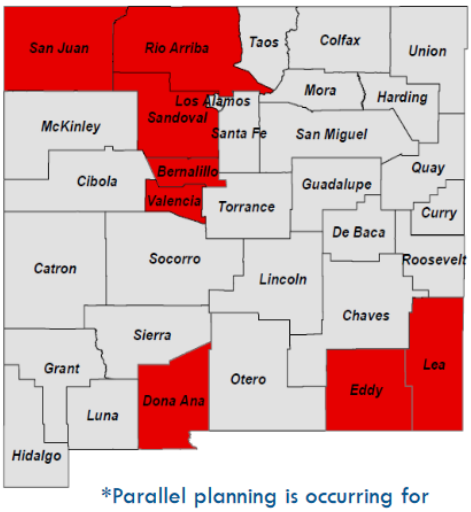


Figure 1-2. 7 counties in New Mexico under the jurisdiction of the NMED whose observed 2016-2018 ozone DVs are at or exceed 95% of the 2015 ozone NAAQS (70 ppb) (Source: https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2019/10/OAI_Presentation_09262019.pdf).

To address the high observed ozone concentrations in New Mexico, the NMED has embarked on an Ozone Attainment Initiative (OAI[3]) to protect the ozone attainment status of the state and ensure health and welfare of the residents of the state for future generations. The OAI was initiated in Spring 2018. As part of the OAI, NMED released a Request for Proposal (RFP#20 667 4040 0001) for the NM OAI Study and the NM OAI Study PGM modeling was awarded to a contracting team of WESTAR and Ramboll. .

1.2 Conceptual Model for High Ozone Concentrations in New Mexico

There are three interrelated but distinct Conceptual Models of ozone formation within New Mexico: southern New Mexico, Bernalillo County and surrounding areas, and northern New Mexico. All three regions share the attribute that ozone transport dominates ozone concentrations on all days. Days with the highest local ozone formation are typically hot summer days with slow winds and without an excessive amount of precipitation (summer monsoon).

1.2.1 Southern New Mexico

Ozone at monitoring sites in southern New Mexico, including Dona Ana, Eddy and Lea Counties, is dominated by ozone transport from outside of New Mexico. This transport includes long-range transport from the remainder of U.S. and global sources (e.g., Central America and Asia) as well as medium-range transport from Texas and Mexico. Current year on-road mobile source emissions tend to be the largest contributing Source Sector within southern New Mexico and nearby areas, with non-road mobile and O&G sources also contributing. With the exception of emissions from Mexico, the contributions of Electrical Generating Units (EGU) and other large industrial point sources tends to be smaller than the other Source Sectors.

The Southern New Mexico Ozone Study (SNMOS[4]) conducted CAMx ozone modeling for a 2011 base and 2025 future year using a 12/4-km modeling domain, as shown in the right panel of Figure 1-3. SNMOS found that a vast majority of ozone in southern New Mexico is due to ozone transport from outside of New Mexico. For example, the left panel in Figure 1-3 displays the 2011 and 2025 ozone contributions to the ozone Design Value (DV) at the Desert View monitoring site in Dona Ana County by geographic regions within the 12/4-km PGM modeling domain shown in the right panel in Figure 1-3. Only 3 percent of the 2011 ozone DV at the Desert View monitor in Dona Ana County is due to anthropogenic emissions from New Mexico, and New Mexico emissions contribute less than 2 percent of the projected 2025 ozone DV at Desert View (not shown).

[3] https://www.env.nm.gov/air-quality/o3-initiative/

[4] https://www.wrapair2.org/SNMOS.aspx

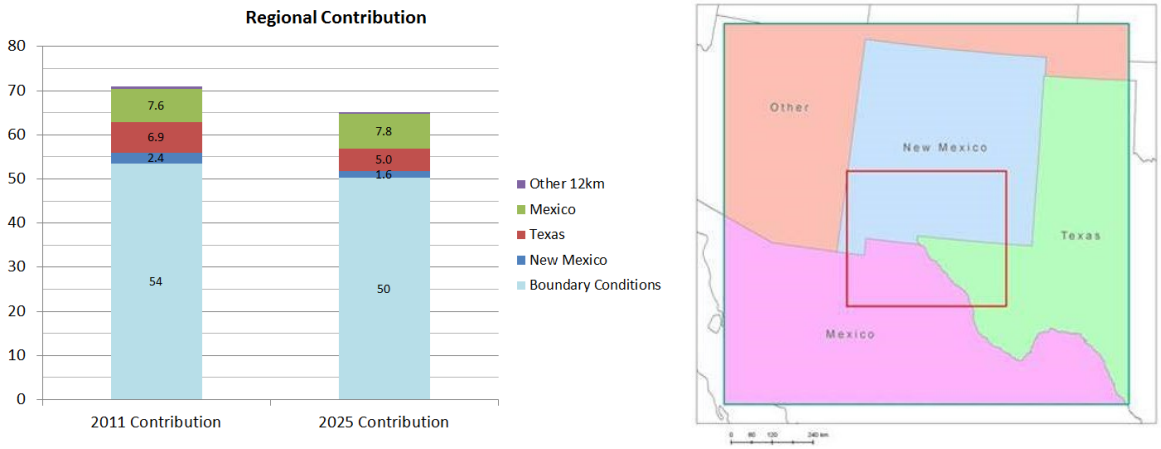


Figure 1-3. Contributions of geographic regions (including Boundary Conditions) to the 2011 and 2025 ozone Design Values at Desert View monitoring site in Dona Ana County in southern New Mexico (left) and 12/4-km modeling domain and definition of source regions (right).

The SNMOS 2011 and 2025 ozone source apportionment modeling also obtained contributions by Source Sector in addition to the four Source Regions depicted in the right panel of Figure 1-3. Figure 1-4 displays the Source Sector contributions to the 2011 and 2025 ozone DV at the Desert View monitor as well as the 10 highest Source Groups (i.e., Source Sector emissions from Source Regions) contributions. On-road mobile sources has the highest contribution to ozone DVs in both 2011 and 2025 (Figure 1-4, top panel), but that is mainly due to on-road mobile source emissions in Texas and Mexico that are the two highest contributing Source Groups (Figure 1-4, bottom panel).

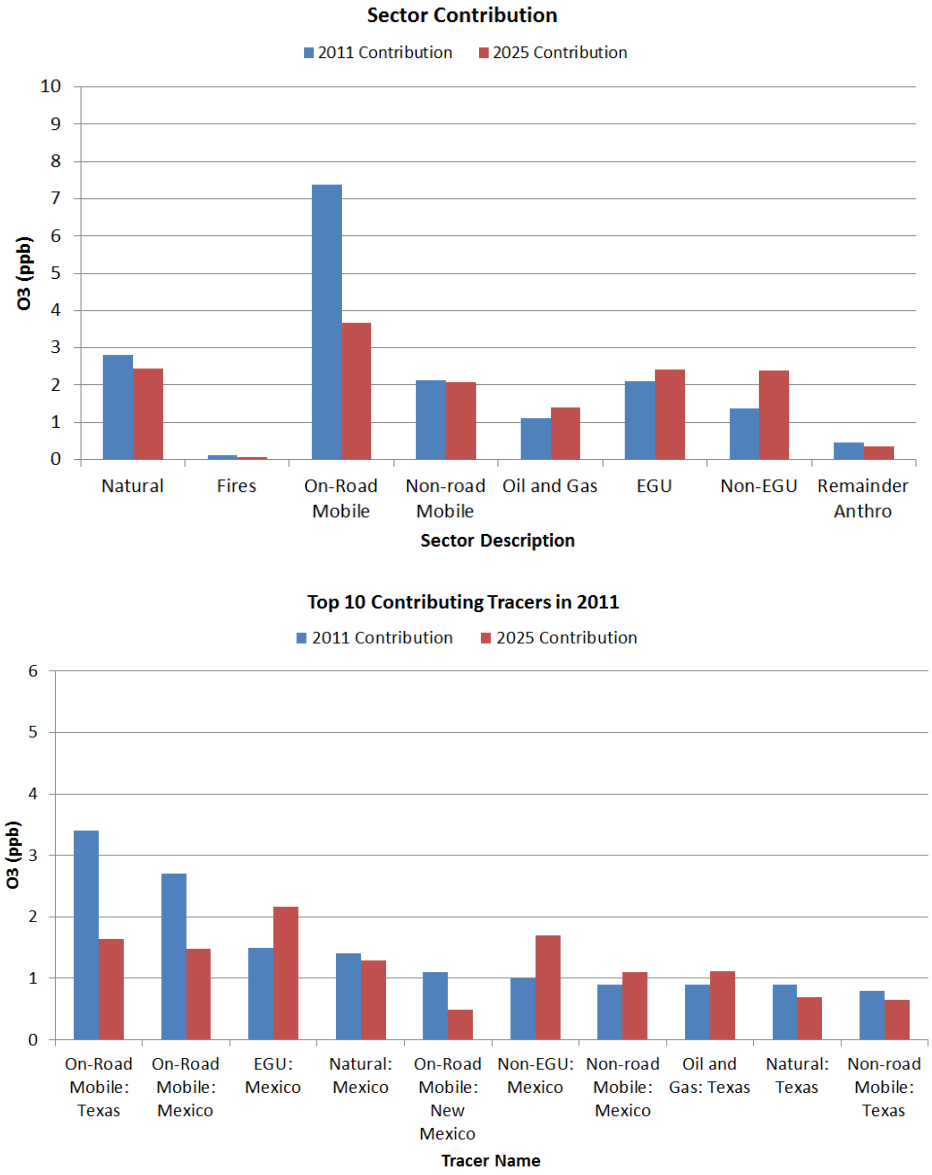


Figure 1-4. Contributions of Source Sector emissions within the 12/4-km modeling domain to the 2011 and 2025 ozone Design Value at Desert View monitoring site (top) and top ten Source Group contributions (bottom).

Figure 1-5 examines the contributions of emissions from New Mexico to 2011 and 2025 ozone DVs at nine monitoring sites in southern New Mexico. With one exception, on-road mobile source emissions are the largest contributing Source Sector in New Mexico to 2011 ozone DVs in southern New Mexico with the on-road mobile contribution at the Solano monitoring site being higher than the others. The one exception is the furthest east Carlsbad monitoring site in Eddy County where O&G emissions are the largest contributing Source Sector in New Mexico due to being within the Permian Basin O&G development region. Although on-road mobile source emissions are the largest

contributor in 2011, it is also the Source Sector whose New Mexico ozone contribution is reduced the most in 2025, by over a factor of two. This is in contrast to O&G whose contribution at the Carlsbad monitoring site is projected to increase between 2011 and 2025, although future year projections of O&G emissions are highly uncertain. In any event, by 2025 the SNMOS estimate that on-road mobile, non-road mobile and O&G Source Sectors in New Mexico will contribute the most, with New Mexico EGU and non-EGU point sources and other anthropogenic emission Source Sectors having relatively lower ozone contributions.

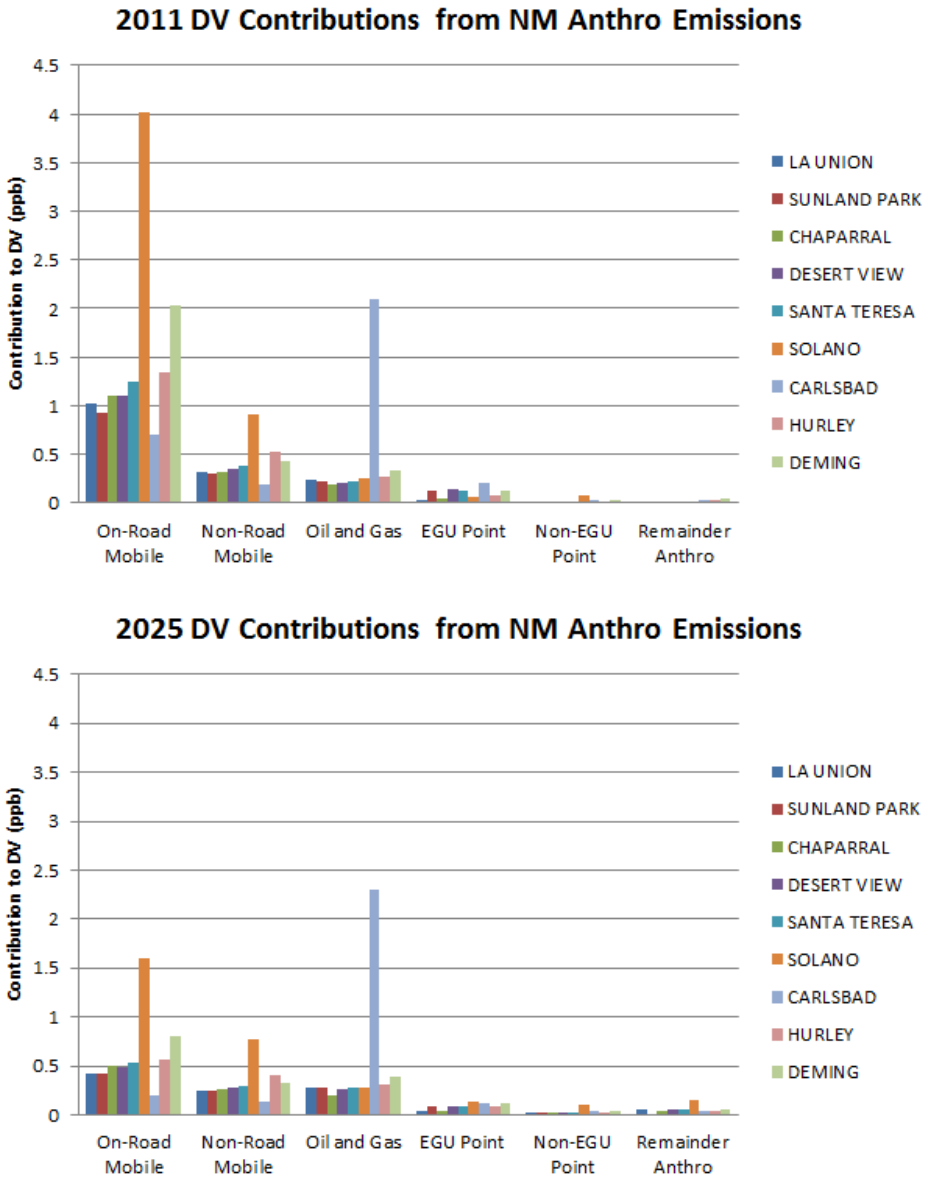


Figure 1-5. Contributions of major Source Sectors in New Mexico to 2011 (top) and 2025 (bottom) ozone DVs at nine monitoring sites in Southwestern New Mexico.

1.2.2 Bernalillo County and Vicinity

High ozone in Bernalillo County and nearby areas is dominated by ozone transport and shares some of same ozone Conceptual Model attributes as northern New Mexico, with the addition of local contributions from a major city (Albuquerque). The City of Albuquerque conducted an ozone modeling study[5] for two episodes in 2017: June 12-16, 2017 and July 3-14, 2017. The purpose of the study was to better understand the source of high ozone concentrations in Bernalillo County and what types of control strategies, if needed, would be most effective at reducing ozone concentrations in the County. Ozone source apportionment was performed to determine the geographic regions that contributed to elevated ozone concentrations in Albuquerque. Figure 1-6 displays the contributions to ozone concentrations in Albuquerque for the June and July episodes. Anthropogenic emissions from New Mexico contributed 14% and 24% to ozone in Albuquerque during the, respectively, June and July 2017 episodes. And anthropogenic emissions from Bernalillo County accounted for up to 75% of the New Mexico contribution. But sources other than New Mexico anthropogenic emissions (e.g., natural sources and sources outside of New Mexico) were the largest contributor accounting for 86% and 76% of the ozone during the, respectively, June and July episodes.

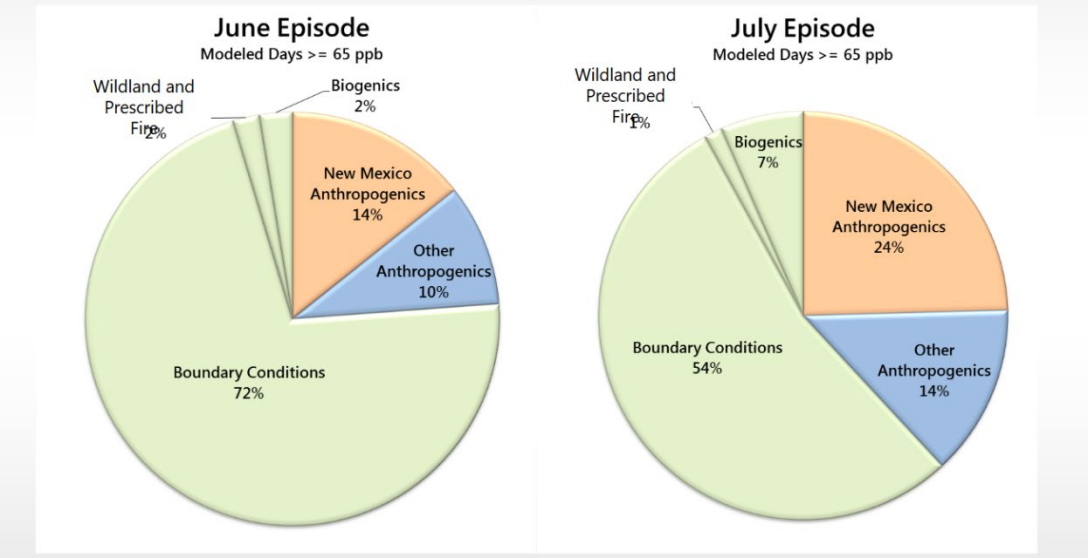


Figure 1-6. Contributions to ozone in Albuquerque during the June and July 2017 modeling episodes.

Although only two short episodes were modeled so any conclusions are limited to those conditions, the City of Albuquerque Ozone Modeling Study concluded as follows:

- Transport from outside of New Mexico is always important and accounts for over half of the ozone in Albuquerque.

[5] https://www.cabq.gov/airquality/documents/06-ken-craig-sonoma-technology-inc-ozone-modeling-presentation-10-17-2018-aqcb-meeting.pdf

- Local emissions in Albuquerque and Bernalillo County are also important with half of the locally generated ozone due to on-road mobile sources in 2017.
- On high ozone days for the two modeled episodes, contributions from major power plants in northern New Mexico were small at sites in Albuquerque.
- Impacts from man-made emissions in western states, including California, are non-negligible.
- Ozone contributions from wildfire smoke were important for both episodes.
- As on-road mobile source emissions are reduced, emissions from non-road and non-mobile sources are becoming increasingly more important.
- NOx emission controls are more effective at reducing high ozone concentrations in Albuquerque than VOC controls.
- Ozone in Albuquerque is sensitive to emissions from O&G sources throughout New Mexico.

1.2.3 Northern New Mexico

The Four Corners Air Quality Task Force (FCAQTF) conducted a comprehensive modeling study of the region and found, although there are significant contributions due to local power plants and O&G production in the San Juan Basin, ozone transport was by far the largest contributor. The FCAQTF identified numerous local control measures that could help mitigate elevated ozone concentrations in the region.

Reddy and Pfister (2016) and CDPHE and RAQC (2016c) analyzed meteorological factors that contributed to the interannual variability in midsummer ozone concentrations focusing mainly on Utah and Colorado that is also relevant to northern New Mexico. Reddy and Pfister analyzed ozone and meteorology for July during 1995-2013 and found several meteorological variables that were able to explain the years with higher ozone formation conditions. The most powerful meteorological variable for describing high ozone formation potential conditions (i.e. ozone conducive conditions) was the height of the 500 hPa[6] pressure level. The Denver 2017 ozone SIP modeling study (CDPHE and RAQC, 2016c) extended the analysis to include more recent years and for summer-average conditions. Figure 1-7 shows the relationship between summer-average 500 hPa heights and summer-average ozone at the Rocky Flats North (RFNO) monitoring site northwest of downtown Denver and the years 1995-2018 that shows years with higher 500 hPa heights tend to have higher ozone, and vice versa.

Figure 1-8 displays the correlation between elevated ozone concentrations and 500 hPa heights in the western U.S. Some of the sites in New Mexico are also weakly to moderately correlated to the 500 hPa heights, like the sites in Denver and Utah. Elevated ozone at sites in northern New Mexico show less correlation with 500 hPa heights as it is believed that the large point source NOx and oil and gas NOx and VOC emissions in the region swamp the signal. But the presence of a large high pressure over the region, which results in slow winds and hot temperatures, is corelated with high ozone concentrations in northern New Mexico.

[6] hPa is100 Pa where Pa is short for Pascal that is a unit of pressure where 500 hPa = 500 mb.

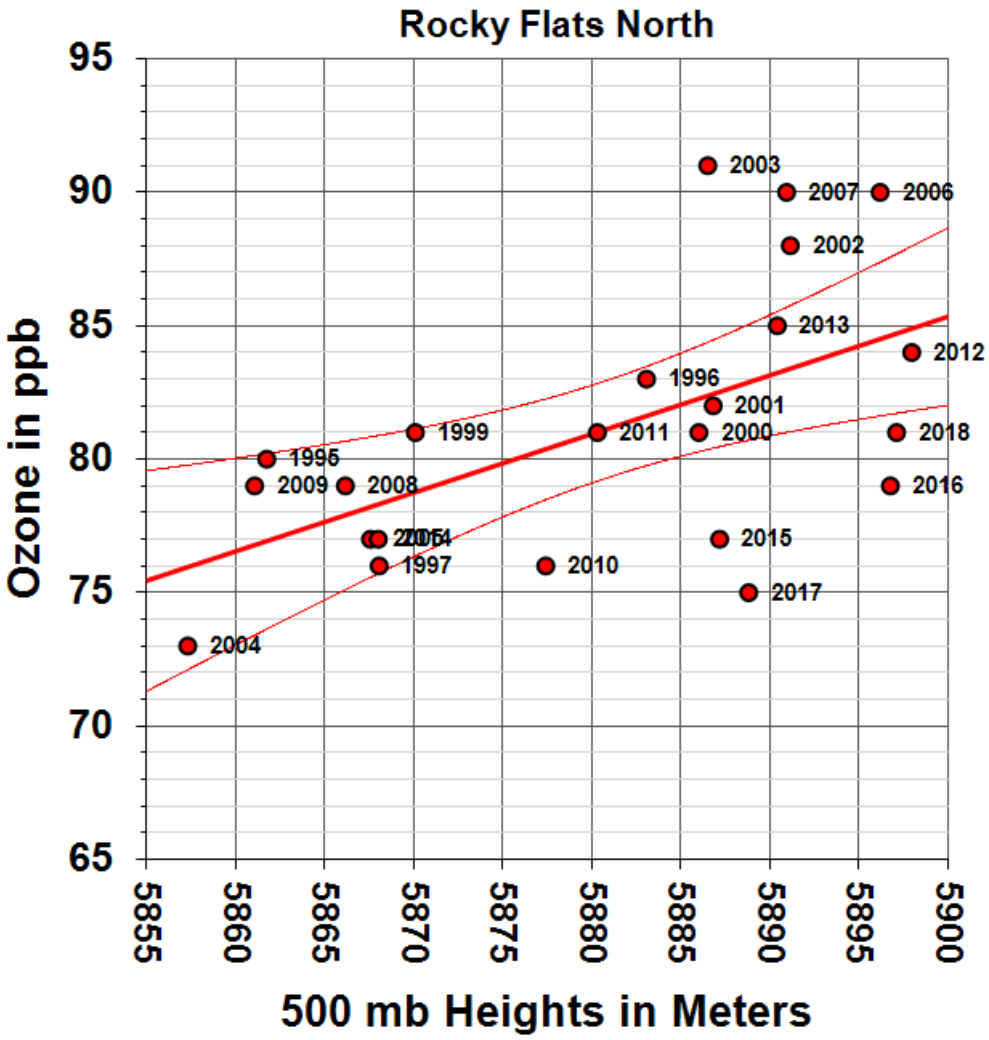


Figure 1-7. Linear regression of the annual 4th highest MDA8 ozone concentrations and mean July through August NCEP/NCAR Reanalysis 500 hPa (or 500 mb) heights for the DM/NFR NAA region at the Rocky Flats North (RFNO) monitoring site for the years 1995 to 2018.

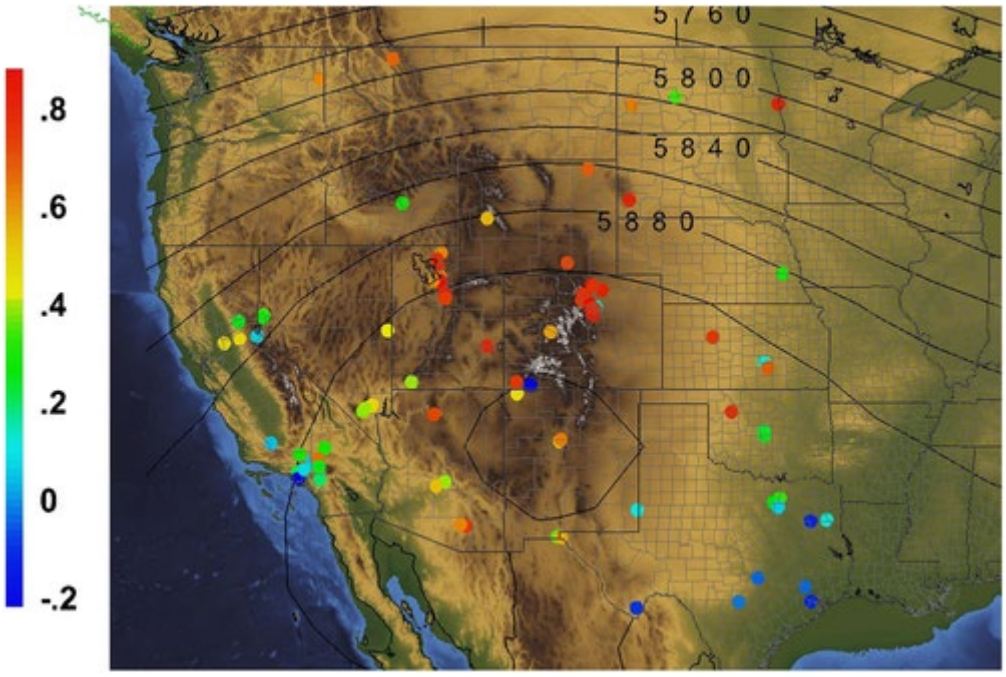


Figure 1-8. Correlation between 500 hPa heights and elevated ozone concentrations for monitoring sites in the western U.S.[7]

1.3 Overview of NM OAI Study Modeling Approach

The procedures used for the NM OAI Study photochemical modeling were described in a detailed Modeling Protocol dated May 19, 2020 (Ramboll and WESTAR, 2020a[8]). A description of the tasks and schedule for completing the NM OAI Study is contained in a Work Plan (Ramboll and WESTAR, 2020b[9]) with presentations, results and reports posted to the NM OAI Study webpage[10] as they are produced.

The NM OAI Study is conducting PGM modeling by enhancing the WRAP-WAQS 2014v2 36/12-km PGM modeling platform[11] with the addition of a new 4-km grid resolution domain covering New Mexico and surrounding areas, especially the oil and gas (O&G) production regions in the Permian and San Juan Basins. The NM OAI Study PGM modeling is performing 2014 base year modeling and model performance evaluation. Future year modeling will also be conducted. The NM OAI Study PGM modeling is being conducted in accordance with EPA's guidance for ozone State Implementation Plan (SIP) attainment demonstration modeling (EPA, 2018d).

[7] https://agupubs.onlinelibrary.wiley.com/cms/asset/192a6975-cd1c-4bce-a20a-a2a049ca4df6/jgrd52767-fig-0001-m.png
[8] https://www.wrapair2.org/pdf/NM_OAI_Modeling_Protocol_v5.pdf
[9] https://www.wrapair2.org/pdf/NM_OAI_Work_Plan_v2.pdf
[10] https://www.wrapair2.org/NMOAI.aspx
[11] http://views.cira.colostate.edu/wiki#WAQS-2014-Modeling-Platform

The two main studies that the NM OAI Study modeling is leveraging off of to cost-effectively develop a PGM modeling platform for analyzing ozone issues in New Mexico are discussed below.

1.3.1 WRAP-WAQS 2014 PGM Platform Development Study

The WRAP-WAQS developed an annual 2014 PGM modeling platform to address air quality issues in the western states. The initial use of the WRAP-WAQS 2014 PGM modeling platform is to address the western state technical needs for their Regional Haze SIPs that are scheduled to be submitted to EPA by July 2021. But the platform is designed so it can be used to address visibility, ozone, particulate matter, deposition and other air quality and air quality related values issues in the western states.

An initial WRAP-WAQS 2014v1 PGM modeling platform was developed in 2019 for the CAMx and CMAQ PGMs that is documented in a webpage[12] on the Intermountain West Data Warehouse (IWDW). Additional diagnostic sensitivity tests were conducted to address several model performance issues culminating in the WRAP-WAQS 2014v2 36/12-km CAMx modeling database that was used as the starting point for the NM OAI Study CAMx summer of 2014 36/12/4-km modeling database. The develop of the WRAP-WAQS 2014v2 PGM database and model performance evaluation is available in a webpage[13] on the IWDW.

The WRAP-WAQS 2014v2 CAMx platform used a 36/12-km grid resolution domains structure as shown in Figure 1-9. Meteorological inputs were based on the WAQS 2014 36/12/4-km WRF meteorological model simulation (Bowden, Talgo and Adelman, 2016[14]). The 2014 emissions were based on the 2014 National Emissions Inventory (2014NEI[15]) with updates from western states[16]. Boundary Condition (BC) inputs were based on a WRAP 2014 GEOS-Chem model simulation.

Because the NM OAI Study requires a 4-km modeling domain for New Mexico, new summer of 2014 36/12/4-km WRF meteorological modeling was conducted that was used to develop 36/12/4-km meteorological inputs for CAMx. The NM OAI Study defined their 36/12-km domains to match WRAP-WAQS 2014v2 36/12-km domains so the WRAP-WAQS 2014v2 36/12-km emission and some other inputs (e.g., BCs) can be directly used in the NM OAI Study PGM modeling.

[12] http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx

[13] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

[14] http://views.cira.colostate.edu/wiki/Attachments/Modeling/WAQS_2014_WRF_MPE_January2016.pdf

[15] https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data

[16] https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf

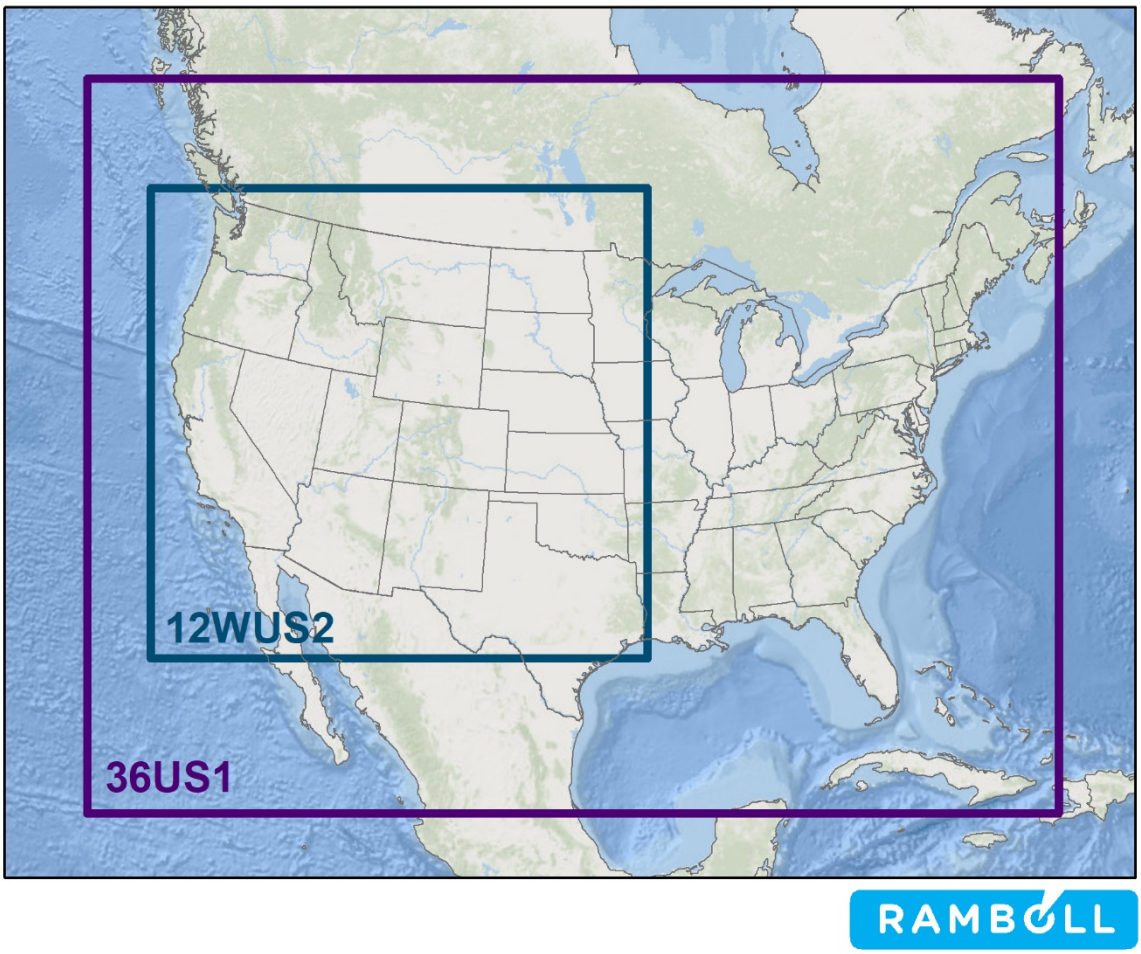


Figure 1-9. 36-km continental U.S. (36US1) and 12-km western U.S. (12WUS2) modeling domains used in the WRAP-WAQS CAMx 2014v2 modeling platform.

1.3.2 EPA 2016v1 Modeling Platform

The EPA, Multi-Jurisdictional Organizations (MJOs), and states conducted a collaborative national 2016 emissions modeling platform[17] (2016 EMP) study to develop a 2016 emissions inventory of comparable quality to the NEI. Separately, EPA developed a 2016 PGM modeling platform that used a 12-km grid resolution continental U.S. domain and an expanded 36-km grid resolution 36US3 domain. EPA has released several versions of their 2016 36/12-km PGM modeling platform with version 1 being the latest version (2016v1).

EPA's 2016v1[18] PGM modeling platform uses the 2016 EMP version 1 emissions[19] from the EPA/MJO/states emissions collaborative study (called 2016fh). It was released in

[17] http://views.cira.colostate.edu/wiki/wiki/9169

[18] https://www.epa.gov/air-emissions-modeling/2016v1-platform

[19] http://views.cira.colostate.edu/wiki/wiki/10202

October 2019 with future year emissions for 2023 and 2028 (2023fh and 2028fh inventories). Since the release of the EPA 2016v1 modeling platform in October 2019, there have been several updates to the emissions, as follows:

1. Updates to 2023 and 2028 EGU emissions to address the accidental dropping of NOx and SO2 emissions for a few EGU sources (January 2020). EPA found that source/hour where the heat input, steam load, and gross load are all zero in the hourly CEMs data, SMOKE will set all emissions to zero for that source/hour, even if the CEMs NO_X or SO2 for that source/hour is not zero.[20]
2. The 2023 and 2028 Commercial Marine Vessel (CMV) emissions were updated to address hoteling and to match the 2016 days-of-week (February 2020).[21]
3. The WRAP 2016 and 2023 O&G emissions were added as an option to EPA's 2016 and 2023 O&G estimates (April 2020). This resulted in double counting as EPA incorrectly had O&G emissions in files that were not supposed to include O&G emissions (i.e., non-EGU point) so corrections have to be made if the WRAP 2023 O&G emissions are used.
4. New 2016, 2023 and 2028 airport emissions for all airports to correct an error that resulted in airport emissions that are a little more than half of the airport emissions in the initial release of the 2016v1 inventories.
5. The SMOKE processing of the 2016 EGU emissions dropped some EGUs as duplicates when they were not. This appears to be a minor issues for EGUs in the western states (August 2020).

The NM OAI Study plans to use the EPA 2016v1 emission projections in their future year modeling.

1.3.3 Episode Selection

The May-August 2014 modeling period was selected as it has a high quality emissions inventory with western state updates and has a PGM platform already developed from the WRAP-WAQS regional haze modeling that can be leveraged for the NM OAI Study. Details on the episode selection are contained in Chapter 3 of the NM OAI Study Modeling Protocol (Ramboll and WESTAR, 2020a).

1.3.4 Model Selection

Details on the rationale for model selection are provided in Chapter 2 of the NM OAI Study Modeling Protocol (Ramboll and WESTAR, 2020a). The Weather Research Forecast (WRF) prognostic meteorological model was selected. Emissions modeling will be performed using the Sparse Matric Operator Kernel Emissions (SMOKE) model for most source categories. The Model of Emissions of Gases and Aerosols from Nature (MEGAN v3.1) will be used for biogenic emissions. There are special processors for fires, windblown dust (WBD), lightning NOx (LNOx) and oceanic sea salt (NaCl) and Dimethyl Sulfide (DMS) emissions that were used. The 2014 version of the MOtor Vehicle Emissions Simulator (MOVES2014b) on-road mobile source emissions model

[20] ftp://newftp.epa.gov/Air/emismod/2016/v1/2023fh1_2028fh1_addendum/README_2023fh1_2028fh1_ptegu_addendum.txt

[21] http://views.cira.colostate.edu/wiki/wiki/11205

will be used with SMOKE-MOVES and WRF meteorological data to generate on-road mobile source emissions for the 4-km New Mexico modeling domain.

The Comprehensive Air-quality Model with extensions (CAMx) photochemical grid model (PGM) was used because it supports two-way grid nesting, was used in the WRAP-WAQS regional haze modeling, contains a well-vetted ozone source apportionment tool and has a rich and successful history of application to the region.

1.3.5 Domain Selection

The NM OAI Study modeling is using the same 36-km 36US and 12-km 12WUS2 domains as used in the WRAP-WAQS 2014 modeling platform (Figure 1-9). A new 4-km New Mexico domain was added to the 36/12-km domain structure. Figure 1-10 displays the 36/12/4-km domain structure with Figure 1-11 showing the 4-km New Mexico domain. New WRF 2014 36/12/4-km meteorological modeling was conducted to generate finer scale 4-km meteorological conditions for the New Mexico domain and consistent meteorology among the 36/12/4-km domains. The domains use a Lambert Conformal Conic (LCC) projection using the parameters given in Table 1-1 with the definitions of the extent of the 36/12/4-km domains given in Table 1-2. CAMx will be run using the 36/12/4-km domain structure shown in Figure 1-10 using two-way interactive grid nesting.

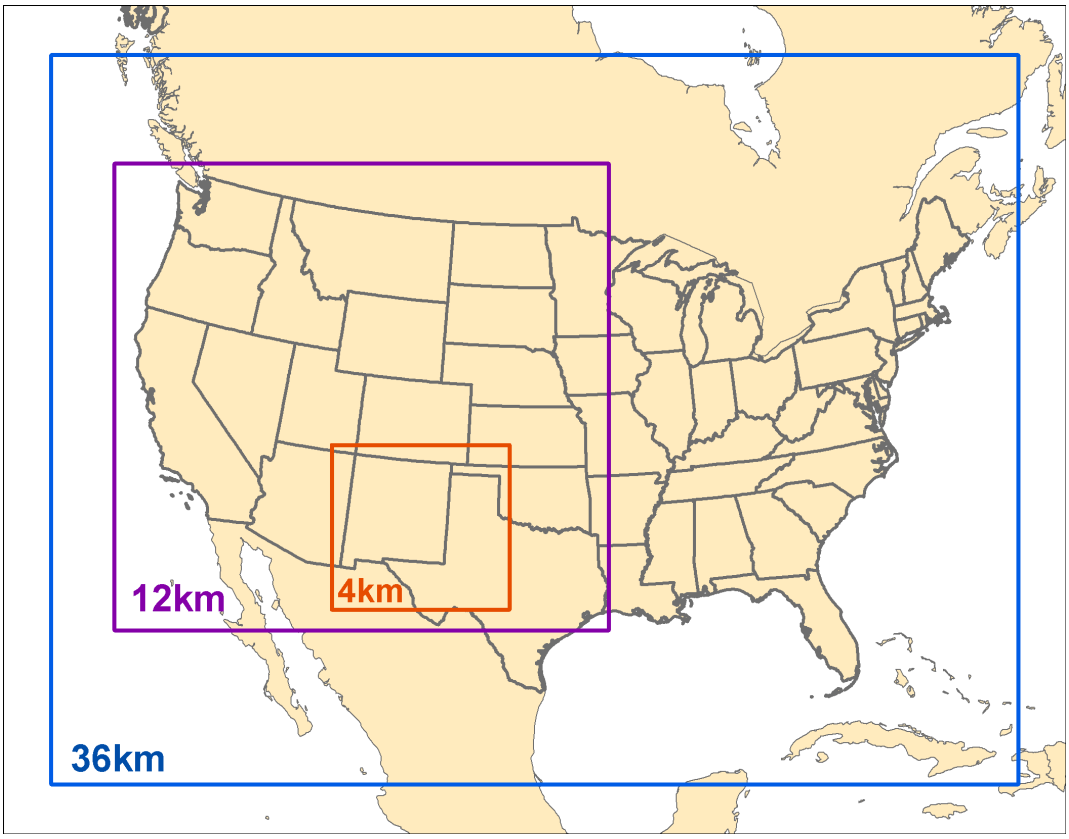


Figure 1-10. NM OAI Study 2014 36/12/4-km PGM and emissions modeling domains.

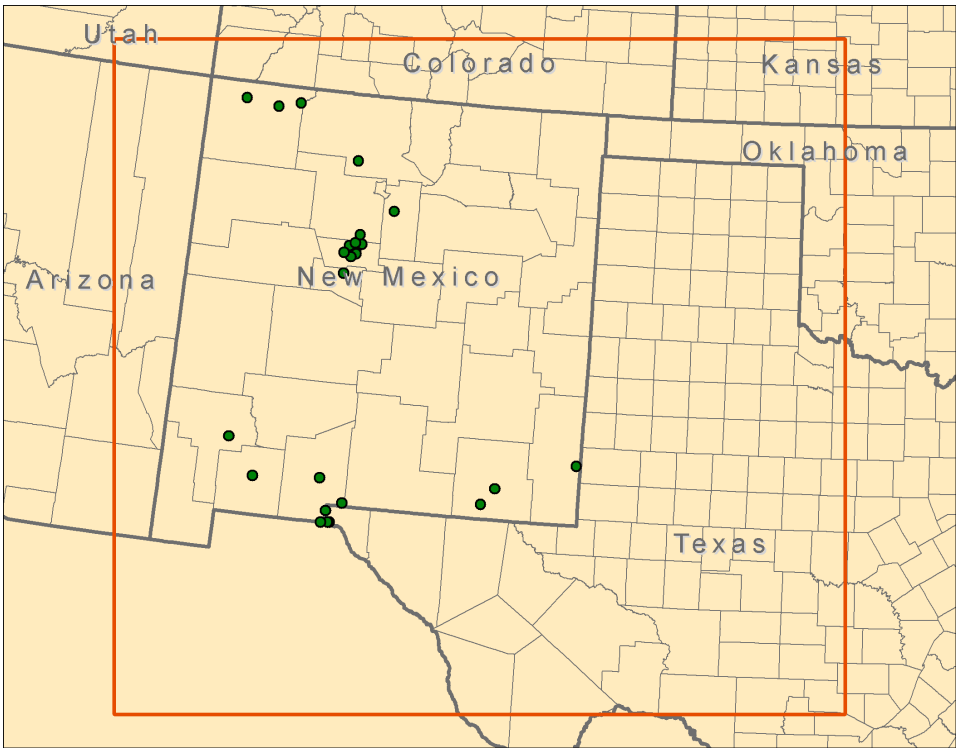


Figure 1-11. 4-km New Mexico modeling domain for PGM and emissions modeling, with locations of New Mexico ozone monitors that were operating during some portion of 2014.

Table 1-1. Lambert Conformal Conic (LCC) projection parameters for the NM OAI Study 36/12/4 modeling domains.

Parameter	Value
Projection	Lambert-Conformal
1st True Latitude	33 degrees N
2nd True Latitude	45 degrees N
Central Longitude	-97 degrees W
Central Latitude	40 degrees N

Table 1-2. Grid definitions for CAMx NM OAI Study 2014 36/12/4-km modeling domains.

Grid	Origin (SW) (km)	Extent (NE) (km)	NX	NY
36-km	(-2736, -2088)	(2592, 1944)	148	112
12-km*	(-2388, -1236)	(336, 1344)	227	215
4-km*	(-1192, -1120)	(-212, -212)	245	227

*Definition includes outer row/column of buffer cells required by CAMx for nested domains

1.3.6 Base and Future Year Emissions Data

The 2014 base year emissions data were based on the WRAP-WAQS 2014v2 emissions that were in turn based on the 2014NEIv2 with updates from western states. New emissions were generated for natural emission sources (e.g., biogenic and LNOx). Future year emissions are based on the EPA 2016v1 modeling platform. The 2014, 2023 and 2028 emissions for New Mexico were reviewed by NMED and updated to address their comments.

1.3.7 Initial and Boundary Conditions Development

The first two-weeks of May were run on the 36/12/4-km domains to spin-up the model before the first high ozone day in New Mexico (68 ppb on May 17). This washes out the influence of the initial concentrations (IC) before elevated ozone concentrations occur in New Mexico.

Boundary conditions (BC) for the outer 36-km 36US domain were based on a 2014 simulation of the GEOS-Chem global chemistry model conducted by WRAP processed by the GC2CAMx converter. The result is day-specific diurnally varying BCs for the lateral boundaries around the 36-km 36US modeling domain. The top BC (TopCon) was based on a zero-gradient assumption where concentrations above the top of the model (above 50 mb, or ~19-km above sea level) are assumed to be the same as in the top vertical layer of CAMx.

Chapter 3 has more details on the development of the 2014 CAMx BC inputs. Because of uncertainties in international emissions and their projections, the 2014 BCs will be held constant for the future year modeling.

1.3.8 Diagnostic Sensitivity Analyses

The NM OAI Study conducted four diagnostic sensitivity tests for the CAMx 2014 36/12/4-km base case that compared the CAMx ozone performance for four alternative meteorological inputs. The NM OAI Study conducted two WRF 2014 36/12/4-km WRF simulations that used different analysis fields as input. The two 2014 36/12/4-km WRF outputs were processed with WRFCAMx using two different options for vertical turbulent exchange (i.e., vertical mixing) coefficients (Kv or Kz). This resulted in four different CAMx meteorological inputs that were evaluated using CAMx diagnostic sensitivity tests that are described in Chapter 5.

1.3.9 Model Performance Evaluation

The NM OAI Study CAMx 2014 36/12/4-km base case simulation Model Performance Evaluation (MPE) followed EPA's MPE recommendations in their ozone modeling guidance (EPA, 2018a) and other sources (e.g., Simon, Baker and Phillips, 2012; Emery et al., 2016). The CAMx 2014 36/12/4-km base case simulation MPE focuses on ozone model performance within the 4-km New Mexico domain, and especially within New Mexico. The CAMx 2014 MPE is presented in Chapter 7.

1.3.10 Future Year Base and Control Strategy Modeling

Future year modeling for ozone will be performed using the EPA 2016v1 platform 2028 emission projections. A CAMx future year 36/12/4-km base case simulation will be conducted and used to project future year ozone design values (DVs). The procedures to calculate projected ozone DVs will follow EPA's latest guidance (EPA, 2018d). These procedures use the modeling results in a relative fashion to scale the current year observed 8-hour ozone Design Values (DVCs) to project future year ozone Design Values (DVFs). The scaling factors are called Relative Response Factors (RRFs) and are the ratio of the future-year to current-year modeling results for the 10 highest base year modeled MDA8 ozone days near the monitoring site. EPA has developed the Speciated Modeled Attainment Test (SMAT[22]) tool that includes the recommended procedures in the latest EPA guidance for projecting ozone DVFs.

The current NM OAI Study also plans to conduct future year emission reduction control strategy sensitivity modeling. The future year modeling will be discussed in a separate report at a later date.

1.3.11 Future Year Source Apportionment Modeling

The current NM OAI Study has plans to conduct future year ozone source apportionment modeling using the CAMx Anthropogenic Precursor Culpability Assessment (APCA) ozone source apportionment tool. The WRAP 2014 GEOS-Chem global chemistry base case, ZROW and NAT simulation will be processed to isolate the contributions of U.S. anthropogenic, International anthropogenic and natural sources to the BCs. Within New Mexico, contributions will be obtained for the major Source Sectors. A NM OAI Study future year ozone source apportionment plan will be developed and discussed with NMED prior to conducting the source apportionment modeling.

[22] https://www.epa.gov/scram/photochemical-modeling-tools

2. 2014 WRF METEOROLOGICAL MODELING

The NM OAI Study conducted 2014 36/12/4-km WRF meteorological modeling to generate CAMx meteorological inputs for the summer of 2014 and the 36/12/4-km domain structure shown in Figure 1-10.

2.1 WRF Meteorological Model

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs (Skamarock, 2004; 2006; Skamarock et al., 2005; 2008; 2019). The Advanced Research WRF (ARW) version of WRF was used in the NM OAI Study.

This chapter describes the application and evaluation of the WRF meteorological model to generate 2014 36/12/4-km meteorological inputs for CAMx photochemical grid modeling. The WRF model contains separate modules to compute different physical processes, such as surface energy budgets and soil interactions, turbulence, cloud microphysics, and atmospheric radiation. Within WRF, the user has many options for selecting the different schemes for each type of physical process. The WRF Pre-processing System (WPS) generates the initial conditions (ICs) and boundary conditions (BCs) and analysis fields used by WRF, based on topographic datasets, land use information, and larger-scale atmospheric and oceanic models.

2.2 WRF Horizontal Modeling Domain

The PGM (CAMx) 2014 36/12/4-km modeling domains were shown in Figure 1-10 in the previous Chapter. The WRF 2014 36/12/4-km modeling domains are shown in Figure 2-1 and were defined slightly larger than the PGM 36/12/4-km domains so that any modeling artifacts that occur near the WRF boundaries as the BCs come into dynamic balance with the WRF numerical algorithms are not present in the PGM meteorological inputs.

NMED Exhibit 16

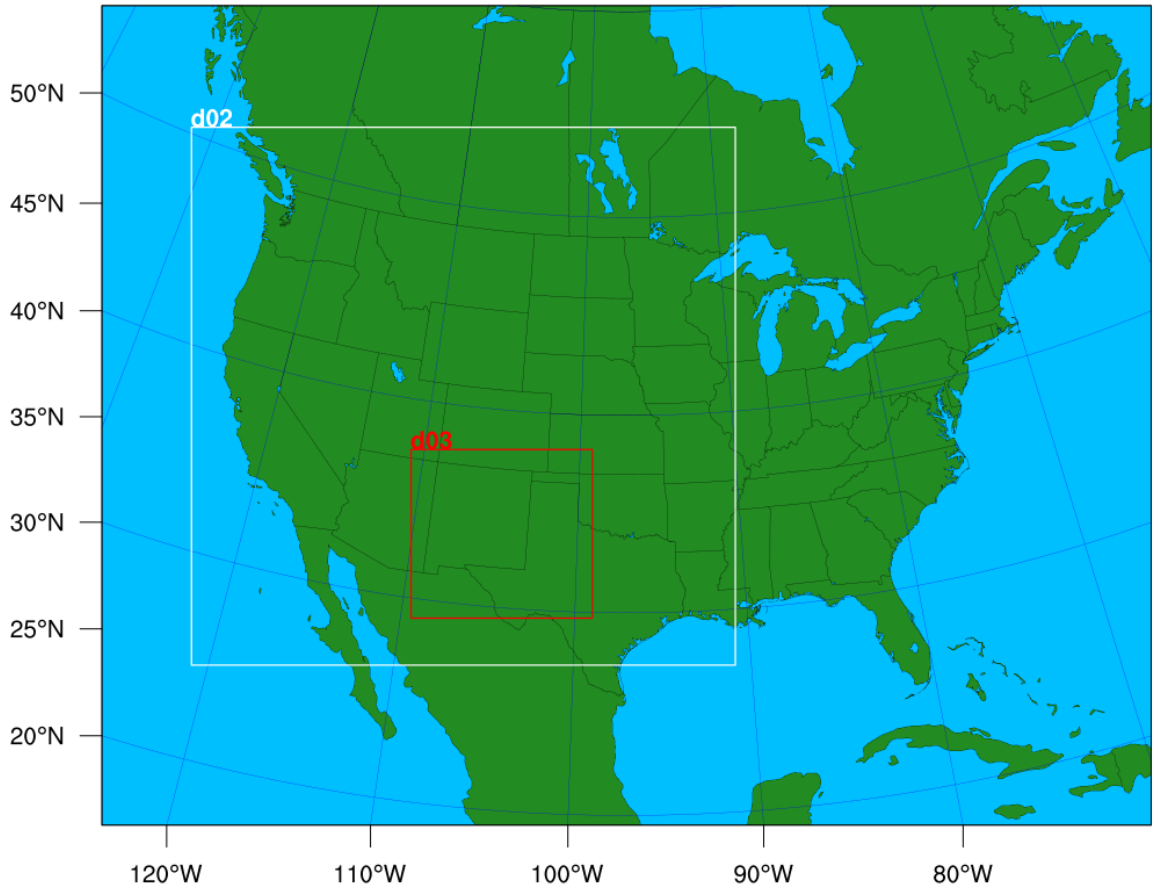


Figure 2-1. WRF 36-km (outer extent), 12-km (d02) and 4-km (d03) modeling domains used in the NM OAI Study.

2.3 WRF Model Configuration

WPS and WRF version 4.2 were used for this modeling analysis. Previous studies utilizing WRF at high resolution over New Mexico, such as the WRAP WestJumpAQMS, WAQS, SNMOS and EPA modeling platform development, have evaluated different configurations of WRF. Table 2-2 presented later in this section summarizes the WRF configurations used in the NM OAI Study and compares it to the WRF configuration used in the WRAP-WAQS 2014 and EPA 2014/2015/2016 WRF modeling. Preliminary analysis of WRAP-WAQS 2014 WRF 12 km model performance in New Mexico showed superior summertime precipitation performance compared to EPA's 2014 WRF modeling.[23] Therefore, the NM OAI Study WRF application was set to match the WRF physics configuration options used by WRAP-WAQS 2014 WRF modeling, except where noted below.

The NM OAI Study 36/12-km WRF/PGM grid configuration (e.g., horizontal domains and vertical layer structure) was designed to be identical to the WRAP-WAQS 2014

[23] https://www.wrapair2.org/pdf/NM_OAI_Study_Webinar1_2020-05-28.pdf

WRF/PGM grid configuration in order the facilitate the use of data between the two studies.

2.3.1 Model Vertical Resolution

The WAQS 2011/2014 WRF modeling used 36 vertical levels (35 vertical layers) from the surface to a 50 mb (hPa) height (approximately 19-km above sea level). The EPA 2014, 2015 and 2016 WRF modeling also used 35 vertical layers up to a 50 mb height. Table 2-1 displays the 36-vertical layer structure used in the WRAP-WAQS 2011/2014 WRF modeling that was also adopted for the NM OAI Study WRF 2014 36/12/4-km modeling.

2.3.2 Vertical Coordinate

Since its inception, WRF has used the eta (sometimes called sigma or "terrain-following") vertical coordinate system. One weakness of the eta coordinate is that variations in terrain (especially steep topography) can increase numerical errors in the model. To reduce these errors, Park et al., (2018) developed a hybrid sigma–pressure coordinate that is now included as the default vertical coordinate system for the WRF model (Skamarock et al., 2019).

Figure 2-2 shows vertical cross sections of layer interface heights over the Rocky Mountains during a strong near-surface wind event (Park et al., 2018). The left panel shows the results using the eta or terrain-following vertical coordinate and the right panel shows the same results but using the new hybrid vertical coordinate. The eta coordinate cross-sections show the influence of terrain extending high into the stratosphere. This is a representation of numerical noise and results in erroneous vertical motion in the model. Park et al., (2018) found that the simulation using the eta vertical coordinate produced high turbulence forecasts aloft which were not observed by pilots or soundings. In CAMx, erroneous vertical motion can help transport stratospheric ozone toward the surface. In contrast, the same simulation using the hybrid vertical coordinate produced lower turbulence forecasts that agreed more closely with observations. The hybrid vertical coordinate cross-sections show a gradual damping of terrain effects with increasing altitude until the layer interfaces are flat aloft. The purpose of using the hybrid vertical coordinate in the CAMx is to better represent ozone in the upper troposphere and lower stratosphere. Eliminating this source of numerical noise reduces spurious downward transport of stratospheric ozone.

For the NM OAI Study 2014 36/12/4-km WRF modeling, we used the new hybrid vertical coordinate system and a new version of the WRFCAMx processor that has been updated to use WRF's hybrid vertical coordinate. The hybrid vertical coordinate system and use of 4-km New Mexico domain are the two biggest differences between the NM OAI Study and WRAP-WAQS 2014 WRF modeling. The WRAP-WAQS 2014 WRF/CAMx modeling did not use the hybrid vertical coordinate system in WRF because at the time it was not supported in the WRFCAMx processor.

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Table 2-1. WRF 36 level vertical layer structure for the NM OAI study. This is the same WRF layer structure as used in WAQS 2011/2014/2016 and EPA 2016 WRF modeling.

WRF Layer	Sigma	Pressure (mb)	Height (m)	Thickness (m)
36	0.0000	50.00	19260	2055
35	0.0270	75.65	17205	1850
34	0.0600	107.00	15355	1725
33	0.1000	145.00	13630	1701
32	0.1500	192.50	11930	1389
31	0.2000	240.00	10541	1181
30	0.2500	287.50	9360	1032
29	0.3000	335.00	8328	920
28	0.3500	382.50	7408	832
27	0.4000	430.00	6576	760
26	0.4500	477.50	5816	701
25	0.5000	525.00	5115	652
24	0.5500	572.50	4463	609
23	0.6000	620.00	3854	461
22	0.6400	658.00	3393	440
21	0.6800	696.00	2954	421
20	0.7200	734.00	2533	403
19	0.7600	772.00	2130	388
18	0.8000	810.00	1742	373
17	0.8400	848.00	1369	271
16	0.8700	876.50	1098	177
15	0.8900	895.50	921	174
14	0.9100	914.50	747	171
13	0.9300	933.50	577	84
12	0.9400	943.00	492	84
11	0.9500	952.50	409	83
10	0.9600	962.00	326	82
9	0.9700	971.50	243	82
8	0.9800	981.00	162	41
7	0.9850	985.75	121	24
6	0.9880	988.60	97	24
5	0.9910	991.45	72	16
4	0.9930	993.35	56	16
3	0.9950	995.25	40	16
2	0.9970	997.15	24	12
1	0.9985	998.58	12	12
0	1.0000	1000.00	0	

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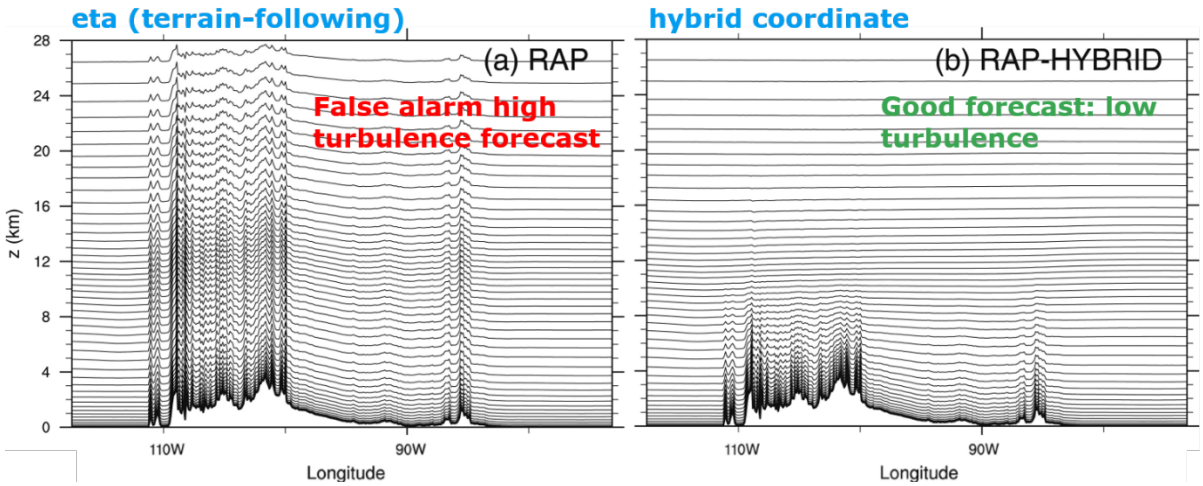


Figure 2-2. Cross-sections of layer interface heights over the Rocky Mountains for the eta (left panel) and hybrid (right panel) vertical coordinates for the WRF-Based Rapid Refresh (RAP) model. Adapted from Park et al., (2018).

2.3.3 Topographic Inputs

Topographic information for WRF was based on a combination of the standard WRF terrain databases and high-resolution terrain. The 36-km 36US domain used the 10-minute global data, the 12-km 12WUS2 domain used the 2-minute data, and the 4-km New Mexico domain used the 30 second data.

2.3.4 Vegetation Type and Land Use Inputs

Vegetation type and land use information used the United States Geological Survey (USGS) land use databases from the most recently released WRF databases provided with the WRF distribution. Standard WRF surface characteristics corresponding to each land use category was employed.

2.3.5 Atmospheric Data Inputs

WRF relies on other model or re-analysis output meteorological fields to provide initial and boundary conditions (IC/BC) and fields for the four-dimensional data assimilation (FDDA). FDDA refers to the nudging of the WRF meteorological fields to observed analysis fields so that the WRF meteorological fields better represent what was observed and prevent the model from drifting away from the observed meteorology. As seen in Table 2-2, both the WRAP-WAQS 2014 and EPA 2014/2015/2016 12-km WRF modeling used the 12-km resolution North American Mesoscale Forecast System (NAM[24]) analysis fields for IC/BC and analysis nudging (i.e., FDDA).

The NM OAI Study applied WRF with two different analysis fields that were evaluated for their performance against meteorological variables as well as their effect on CAMx ozone model performance. Both the NAM and the ~30-km resolution European Center for Medium-Range Weather Forecasting (ECMWF) Re-Analysis (ERA5[25]) dataset analysis

[24] https://www.ncdc.noaa.gov/data-access/model-data/model-datasets/north-american-mesoscale-forecast-system-nam

[25] https://www.ecmwf.int/en/forecasts/datasets/archive-datasets/reanalysis-datasets/era5

fields were used for IC/BC and FDDA in the two NM OAI Study WRF sensitivity simulations. We have found from previous work that the ERA-Interim (lower resolution predecessor to ERA5) dataset has lower humidity near the surface and higher humidity aloft leading to lower convective available potential energy (CAPE), which lowers overall precipitation rates, especially during the summer Monsoon season that is important for ozone modeling in New Mexico. Many WRF simulations of the southwest U.S. summer Monsoon have featured an over-prediction of summertime (convective) precipitation when the NAM analysis fields are used. The Southern New Mexico Ozone Study (SNMOS) conducted PGM ozone sensitivity modeling using meteorological fields based on WRF simulations using the NAM and ERA analysis fields and found that the PGM results using the WRF/ERA meteorological inputs produced superior ozone performance than when WRF/NAM inputs were used so the SNOMS ended up using the WRF/ERA meteorological inputs.[26]

The ERA5 is a fairly new analysis fields product that has not been used in WRF modeling as extensively as the ERA fields. We conducted WRF and PGM sensitivity modeling using the NAM and ERA5 analysis fields to determine which configuration provides the best meteorological inputs and best ozone model performance. The ERA5 fields were objectively re-analyzed using meteorological observational data to the higher resolution for the 36-km and 12-km grid domains using the OBSGRID program. These fields are used both to initialize the model and used with analysis nudging FDDA (on the 36/12-km domains) to guide the model to better match the observations.

2.3.6 Time Integration

Third-order Runge-Kutta integration was used (rk_ord = 3). The maximum time step, defined for the outer-most domain (36 km) only, is set by evaluating the following equation:

$$dt = \frac{6dx}{F_{map}}$$

Where dx is the grid cell size in km, Fmap is the maximum map factor (which can be found in the output from REAL.EXE), and dt is the resulting time-step in seconds. For the case of the 36 km RPO domain, dx = 36 and Fmap = 1.08, so *dt* should be taken to be less than 200 seconds. Longer time steps risk CFL errors, associated with large values of vertical velocity, which tend to occur in areas of steep terrain (especially during stable conditions typical of winter). For this WRF run, adaptive time-stepping was used with a maximum timestep of 180s.

2.3.7 Diffusion Options

Horizontal Smagorinsky first-order closure (km_opt=4) with sixth-order numerical diffusion and suppressed up-gradient diffusion (diff_6th_opt=2) was used.

[26] https://www.wrapair2.org/SNMOS.aspx

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2.3.8 Lateral Boundary Conditions

Lateral boundary conditions was specified from the initialization dataset (i.e., either NAM or ERA5) on the 36-km WRF domain with continuous updates nested from each "parent" domain to its "child" domain, using one-way nesting (feedback=0).

2.3.9 Top and Bottom Boundary Conditions

The implicit Rayleigh dampening for the vertical velocity was used for the top boundary conditions. Consistent with the model application for non-idealized cases, the bottom boundary condition was selected as physical, not free-slip.

2.3.10 Sea Surface Temperature Inputs

The water temperature data for the WRF application was taken from the Fleet Numerical Meteorology and Oceanography Center (FNMOC)[27]. The FNMOC product has horizontal resolution of about 9-km in the mid-latitudes but is produced *four* times per day using AVHRR satellite sensors and in-situ observations.

2.3.11 Four Dimensional Data Assimilation (FDDA)

Analysis nudging was used for winds, temperature, and humidity on the 36-km and 12-km domains. Both surface and aloft nudging was used but nudging for temperature and mixing ratio was not performed within the boundary layer. Observation nudging was not used, even on the 4-km domain.

2.3.12 New Lightning Data Assimilation

More recently, the assimilation of lightning data in WRF simulations has shown to improve the locations and amounts of convective precipitation. The use of lighting detection networks, such as the National Lightning Detection Network (NLDN), have been used in WRF simulations and used to force deep convection (thunderstorms) when lightning is observed and only allow shallow convection when lightning is not present. The use of the new lightning assimilation approach has been demonstrated to improve both WRF convective precipitation as well as PGM concentration and deposition performance (Heath et al., 2016). The new lightning data assimilation algorithms was not used in the NM OAI Study 2014 WRF modeling for several reasons: (1) it would have to be tested and evaluated and there is insufficient time in the schedule to conduct such diagnostic testing; (2) the NLDN data used to date with the WRF lightning assimilation is a commercial product that is expensive and not within the budget; (3) the implementation of the lightning detection data assimilation in WRF has a flaw that it doesn't distinguish between no lightning detects and missing data and suppresses convection in areas with missing data (e.g., over the Gulf of Mexico); and (4) the lightning detection data assimilation algorithm has not been implemented in the latest versions of WRF so its use would limit the use of other model options.

2.3.13 PBL and LSM Physics Options

As used in the WRAP-WAQS 2014 WRF modeling, the YSU Planetary Boundary Layer (PBL) and Noah Land Surface Model (LSM) physics options were used in the NM OAI

[27] https://www.usno.navy.mil/FNMOC

Study 2014 36/12/4-km WRF modeling. Previous WRF sensitivity modeling for the intermountain west region found the YSU/Noah PBL/LSM schemes produces the most realistic meteorological fields. Note that EPA's 2014/2015/2016 WRF modeling uses the ACM2 PBL and Pleim-Xiu (PX) LSM schemes (Table 2-2). The WRAP-WAQS tried to evaluate WRF using the ACM2/PX PBL/LSM and found it more difficult to implement and didn't always run so that annual fields could not be generated. Furthermore, the PX LSM scheme requires each run segment of a WRF run soil moisture inputs to be initialized using the previous WRF run segment PX output so that an annual WRF simulations must be run in series. This contrasts with the Noah LSM scheme that initializes soil moisture based on observations with some spin-up time (typically 12-hours) that allows annual WRF runs to be performed using parallel run segments (e.g., 5.5 day run segments). Thus, annual WRF simulations using the YSU/NOAH PBL/LSM physics options can be completed much faster than when ACM2/PX is used.

2.3.14 Remaining WRF Physics Options

Table 2-2 lists the remaining WRF physics options for the NM OAI Study 2014 36/12/4-km WRF application. These are standard WRF physics options and consistent with the WRF options used in the WRAP-WAQS 2014 and EPA 2014/2015/2016 WRF modeling. Our comparison of 2014 WRAP-WAQS and 2014 EPA WRF modeling for summertime precipitation performance in New Mexico found that the WRAP-WAQS WRF meteorological model performance was better than EPA WRF for most variables. Therefore, we used the same microphysics and cumulus schemes for the NM OAI Study as used in 2014 WRAP-WAQS (Thompson and Multi-Scale Kain-Fritsch, respectively) and most of the same other physics options (Table 2-2).

Table 2-2. NM OAI Study 2014 WRF model configuration and comparison with the WRF configuration used in the WRAP-WAQS 2014 and EPA 2014/2015/2016 WRF modeling.

WRF Option	NM OAI Study	2014 WRAP-WAQS	2014 EPA
Horizontal Domains	36/12/4-km	36/12/4-km	12-km
Vertical Coordinate	Hybrid Sigma	Sigma	Sigma
Microphysics	Thompson	Thompson	Morrison 2
LW Radiation	RRTMG	RRTMG	RRTMG
SW Radiation	RRTMG	RRTMG	RRTMG
Sfc Layer Physics	MM5 similarity	MM5 similarity	MM5 similarity
LSM	Noah	Noah	Pleim-Xiu
PBL scheme	Yonsei University (YSU)	YSU	ACM2
Cumulus	36/12/4-km Multi-scale Kain Fritsch	36/12-km Multi-scale_Kain Fritsch; 4-km None	Kain-Fritsch
BC, IC Analysis Nudging Source	36/12-km NAM & ERA5	36/12-km NAM	12-km NAM
Analysis Nudging Grids	36/12-km	36/12-km	12-km
Obs Nudging	None	4-km	None
Sea Sfc Temp	FNMOC	FNMOC	FNMOC

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2.3.15 Application Methodology

The WRF model was executed in 5.5-day blocks initialized at 12Z every five days. Model results were output every 60 minutes, split at twelve (12) hour intervals. Twelve (12) hours of spin-up is included in each 5-day block before the data is used in the subsequent evaluation and PGM meteorological inputs.

2.4 WRF Model Evaluation

Quantitative and qualitative evaluations of the NM OAI Study 2014 WRF 36/12/4-km simulation meteorological performance was conducted for both the WRF/NAM and WRF/ERA5 applications. The quantitative evaluations compare integrated surface hourly meteorological observations with WRF predictions matched by time and location and included the calculation of model performance statistical metrics that were compared against performance benchmarks. The qualitative evaluations compared time series plots of modeled wind speed and wind direction to the observations at specific sites. The qualitative evaluation also compared spatial plots of WRF precipitation estimates against spatial maps of precipitation analysis fields based on observations The evaluation focuses on the meteorological model performance within the 4-km New Mexico domain.

2.4.1 Quantitative Evaluation Using METSTAT

A quantitative model performance evaluation of the NM OAI Study 2014 WRF modeling was conducted using the publicly available METSTAT software (Ramboll Environ, 2015) evaluation tool. Output from the WRF meteorological model was compared against meteorological observations for sites located in New Mexico. This was carried out both graphically and statistically to evaluate model performance for surface winds, temperatures and humidity. The purpose of these evaluations is to establish a first-order acceptance/rejection of the simulation in adequately replicating the weather phenomena in the study area. Thus, this approach screens for obvious model flaws and errors.

2.4.1.1 Quantitative Statistics

The quantitative analysis was conducted using METSTAT. Statistical measures calculated by METSTAT include observation and prediction means, prediction bias, and prediction error that are given as follows.

Mean Observation (M_o) is calculated using values from all sites for a given time period by Eq. **(5-1)**:

$$M_o = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I} O_j^i \qquad (5\text{-}1)$$

where O^i_j is the individual observed quantity at site i and time j, and the summations are over all sites (I) and over time periods (J).

Mean Prediction (M_p) is calculated from simulation results that are interpolated to each observation used to calculate the mean observation for a given time period by Eq. **(5-2)**:

$$M_p = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I} P_j^i \quad (5\text{-}2)$$

where P^i_j is the individual predicted quantity at site *i* and time *j*. Note the predicted mean wind speed and mean resultant direction are derived from the vector-average (for east-west component *u* and north-south component *v*), from which the

Bias (B) is calculated as the mean difference in prediction-observation pairings with valid data within a given analysis region and for a given time period by Eq. **(5-3)**:

$$B = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right) \quad (5\text{-}3)$$

Gross Error (E) is calculated as the mean *absolute* difference in prediction-observation pairings with valid data within a given analysis region and for a given time period by Eq. **(5-4)**:

$$E = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - O_j^i\right| \quad (5\text{-}4)$$

Note that the bias and gross error for winds are calculated from the predicted-observed residuals in speed and direction (not from vector components *u* and *v*). The direction error for a given prediction-observation pairing is limited to range from 0 to ±180°.

Root Mean Square Error (RMSE) is calculated as the square root of the mean squared difference in prediction-observation pairings with valid data within a given analysis region and for a given time period by Eq **(5-5)**:

$$RMSE = \left[\frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right)^2\right]^{\frac{1}{2}} \quad (5\text{-}5)$$

The RMSE, as with the gross error, is a good overall measure of model performance. However, since large errors are weighted heavily (due to squaring), large errors in a small sub-region may produce a large RMSE even though the errors may be small and quite acceptable elsewhere.

2.4.1.2 METSTAT Processing

METSTAT was developed to calculate and graphically present statistics associated with temporally paired meteorological model predictions and observations. The horizontal analysis range can be given for an entire output grid, by a coordinate box, or as a list of specific site identifiers (such as WBAN or AIRS numbers), as labeled on the observational file. This allows for an evaluation at a single site, a subset of specific sites (e.g., within a state) or over an entire regional domain. The program then proceeds to calculate statistics for each hour and for each day of the time window.

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The process involves statistical comparisons of model data from the WRF grid cells to observational measurements located with each grid cell. METSTAT evaluates wind speed and direction, air temperature, and air humidity using both bias and error statistics. METSTAT has been widely applied to WRF runs for many years, across many modeling domains. Using a consistent definition of the statistical quantities to be calculated and a consistent methodology for pairing observations in time, METSTAT allows for more straightforward comparisons between model applications in widely different regions and time periods.

2.4.1.3 Statistical Benchmarks

METSTAT calculates statistical performance metrics for bias, error and correlation for surface winds, temperature, and mixing ratio (i.e., water vapor or humidity). To evaluate the performance of a meteorological model simulation for air quality model applications, a number of performance benchmarks for comparison are typically used. Table 2-3 lists the meteorological model performance benchmarks for simple (Emery et al., 2001) and complex (Kemball-Cook et al., 2005) situations. The simple benchmarks were developed by analyzing well-performing meteorological model evaluation results for simple, mostly flat terrain conditions and simple meteorological conditions (e.g., stationary high pressure) that were mostly conducted to support air quality modeling studies (e.g., ozone SIP modeling). The complex benchmarks were developed during the Western Regional Air Partnership (WRAP) regional haze modeling and are performance benchmarks for more complex conditions, such as the complex terrain of the Rocky Mountains and Alaska (Kemball-Cook et al., 2005). McNally (2009) analyzed multiple annual runs that included complex terrain conditions and suggested an alternative set of benchmarks for temperature under more complex conditions. The purpose of the benchmarks is to understand how good or poor the results are relative to other model applications run for the U.S.

The NM OAI Study 2014 WRF application compared the WRF meteorological variables to the benchmarks as an indication of WRF model performance. These benchmarks include bias and error in temperature, wind direction and mixing ratio as well as the wind speed bias and Root Mean Squared Error (RMSE) between the models and databases.

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Table 2-3. Meteorological model performance benchmarks for simple and complex conditions.

Parameter	Emery et al. (2001)	Kemball-Cook et al. (2005)	McNally (2009)	Resulting Criteria
Conditions	Simple	Complex	Complex	Complex
Temperature Bias	≤ ±0.5 K	≤ ±2.0 K	≤ ±1.0 K	≤ ±1.0 K
Temperature Error	≤ 2.0 K	≤ 3.5 K	≤ 3.0 K	≤ 3.0 K
Temperature IOA	≥ 0.8	(not addressed)	(not addressed)	≥ 0.8
Humidity Bias	≤ ±1.0 g/kg	≤ ±0.8 g/kg	≤ ±1.0 g/kg	≤ ±1.0 g/kg
Humidity Error	≤ 2.0 g/kg	≤ 2.0 g/kg	≤ 2.0 g/kg	≤ 2.0 g/kg
Humidity IOA	≥ 0.6	(not addressed)	(not addressed)	≥ 0.6
Wind Speed Bias	≤ ±0.5 m/s	≤ ±1.5 m/s	(not addressed)	≤ ±1.5 m/s
Wind Speed RMSE	≤ 2.0 m/s	≤ 2.5 m/s	(not addressed)	≤ 2.5 m/s
Wind Speed IOA	≥ 0.6	(not addressed)	(not addressed)	≥ 0.6
Wind Dir. Bias	≤ ±10 degrees	(not addressed)	(not addressed)	≤ ±10 degrees
Wind Dir. Error	≤ 30 degrees	≤ 55 degrees	(not addressed)	≤ 55 degrees

The output from the 2014 WRF 4-km domain was compared against meteorological data obtained from the National Climate Data Center's (NCDC) global-scale, quality-controlled DS3505 integrated surface hourly observational (ISHO) data (NOAA-NCDC, 2015) as verification data. Global hourly and synoptic observations are compiled from numerous sources into a single common ASCII format and common data model. The DS3505 database contains records of most official surface meteorological stations from airports, military bases, reservoirs/dams, agricultural sites, and other sources dating from 1901 to the present.

A standard set of statistical metrics from the METSTAT package was used. These metrics were calculated on hourly, daily and monthly time frames for wind speed, wind direction, temperature, and humidity at the surface, using all available observational weather data. The WRF surface meteorological model performance metrics were compared against the simple and complex model performance goals using "soccer plots." Soccer plots use two WRF performance metrics as X-axis and Y-axis values (e.g., temperature bias as X, and temperature error as Y) along with the performance benchmarks. The closer the symbols are to the zero origin, the better the model performance. It is also easy to see when the two WRF performance metrics fall within the benchmark lines.

2.4.1.4 Surface Wind Speed Performance

Figure 2-3 displays the WRF/NAM and WRF/ERA5 wind speed soccer plot that compares monthly measures of wind speed bias and error across surface monitoring sites in New Mexico with the simple and complex benchmarks. The monthly wind speed performance of the two WRF simulations are remarkably similar with both having near zero bias that achieves the simple benchmark (≤±0.5 m/s). The error (RMSE) for the two WRF simulations falls between the simple and complex benchmarks (i.e., between 2.0 and 2.5 m/s) for all four months (May through August).

2.4.1.5 Surface Wind Direction Performance

The monthly wind direction bias and error statistics for the two WRF simulations are also nearly identical with bias values of ~5 degrees that achieves the ≤±5 degree simple benchmark and error statistics that falls between the 30 degree simple and 50 degree complex benchmarks (Figure 2-4).

2.4.1.6 Surface Temperature Performance

There are differences in the two WRF simulations temperature performance and more differences in the monthly values than seen for winds (Figure 2-5). The WRF/ERA5 simulations has a near zero temperature bias in May and June with the bias and error achieving the simple benchmark for both months. The WRF/NAM has a warm bias for May and June that straddle the simple benchmark upper bound (+0.5 K). The two WRF simulations have similar Jul and August performance that have a warm bias of ~1.0 K that fails to achieve the simple benchmark. For both WRF simulations, the temperature bias is right at but mostly within the 2.0 K simple benchmark.

2.4.1.7 Surface Humidity Performance

The WRF/ERA5 clearly has better surface humidity performance than WRF/NAM (Figure 2-6). For July and August, the WRF/NAM has a wet bias in July and August of ~1.5 g/kg so fails to achieve the simple (≤±0.8 g/kg) and complex (≤±1.0 g/kg) bias benchmarks. The WRF/ERA5 also has a wet bias for July and August that is not as large as WRF/NAM as it is right at the simple benchmark (~ 1.0 g/kg) but achieving the complex benchmark. The WRF/ERA5 also has better humidity error performance in July and August, although both simulations achieve the error performance benchmarks.

The two WRF simulations have better humidity performance in May and June that achieves the simple benchmark, albeit with a moist bias. May is the best performing month with nearly identical humidity model performance with a bias of ~0.6 g/kg and error of ~0.9 g/kg. In June, the WRF/ERA5 humidity performance is slightly better than WRF/NAM.

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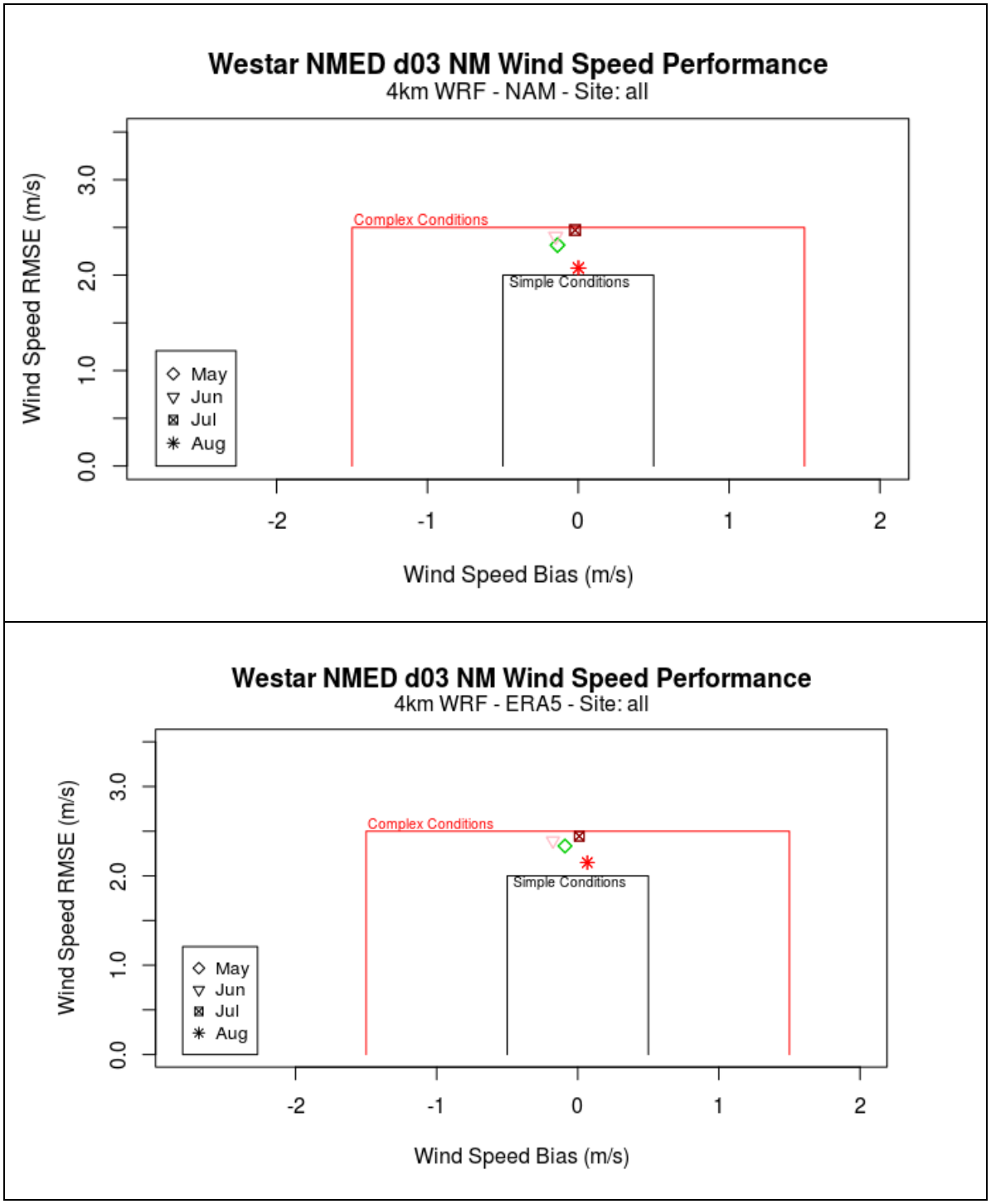


Figure 2-3. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface wind speed (m/s) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

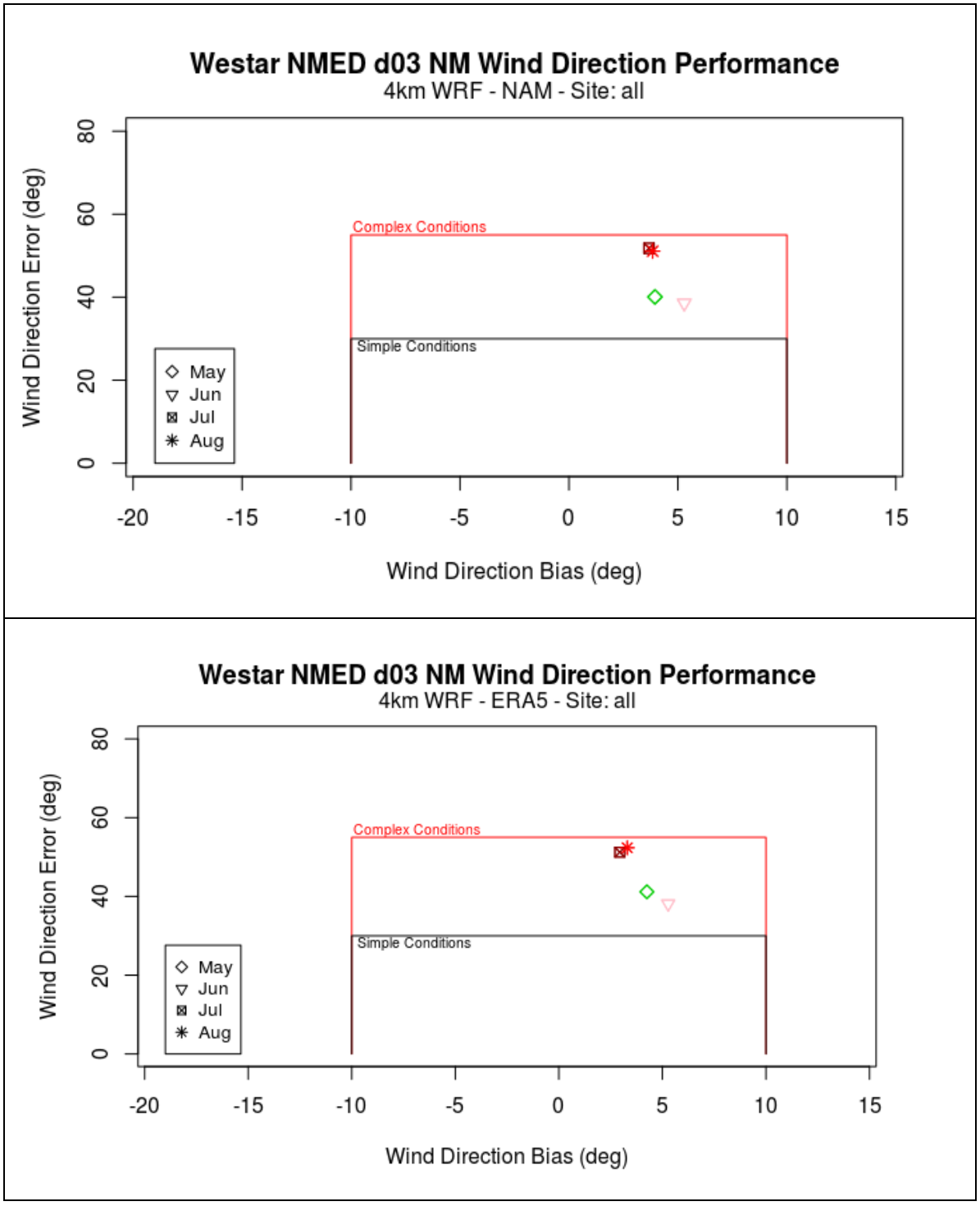


Figure 2-4. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface wind direction (degrees) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

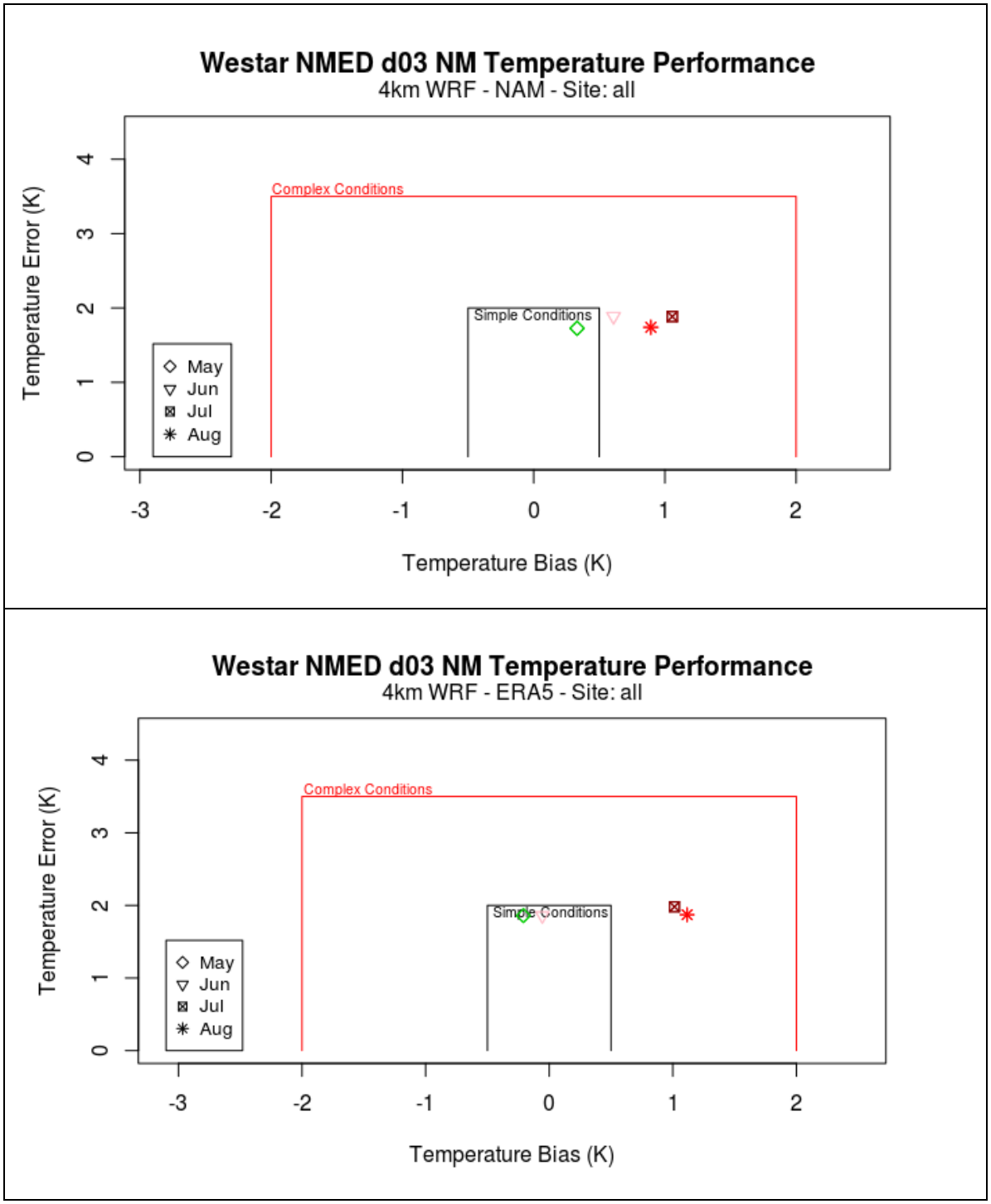


Figure 2-5. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface temperature (K) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

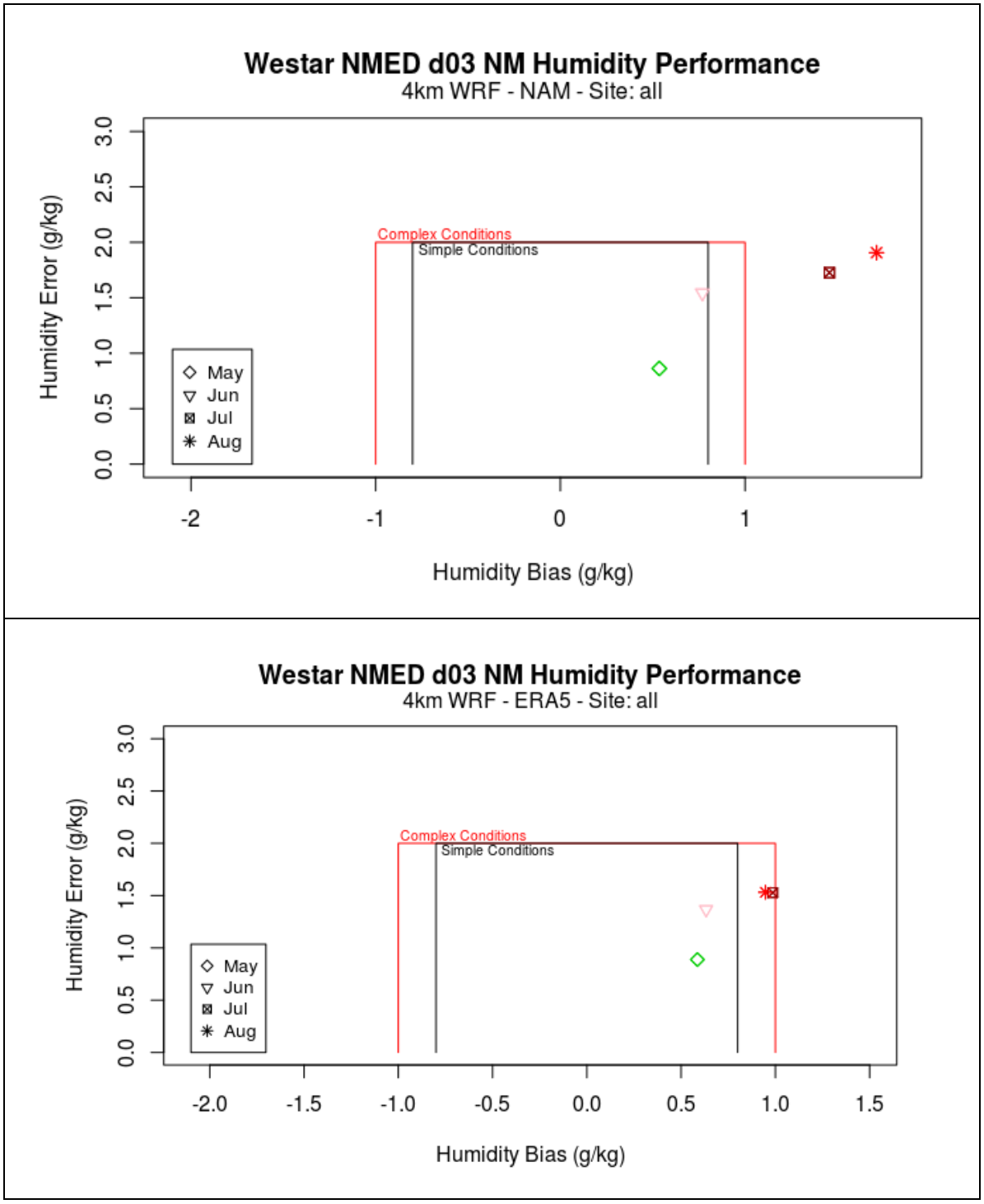


Figure 2-6. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface humidity (g/kg) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

2.4.1.8 Example Site-Specific Humidity Performance

METSTAT was used to evaluate the two WRF simulations for surface meteorological performance for each site in New Mexico. Figures 2-7 and 2-8 show example humidity model performance time series and soccer plots at the Las Cruces International Airport that is 8 miles west of the City of Las Cruces in Dona Ana County. In May, the two WRF simulations have nearly identical daily humidity performance at Las Cruces with a slight overestimation bias that is approximately 0.5 g/kg (Figure 2-7). In June, the humidity performance of the two WRF simulations at Las Cruces start to deviate from each other so by mid-June the WRF/NAM starts to have a large humidity overestimation bias that is as high as 4 g/kg; both simulations have large swings in variations in humidity bias. During the second half of June through July and August the WRF/NAM humidity bias tends to range from 0 to 3 g/kg, while the WRF/ERA5 bias ranges from -1 to +1.5 g/kg. These variations are likely due to the occurrence of monsoonal convective activity that can be very spotty and are also very difficult phenomena for a meteorological model to accurately reproduce.

The soccer plot of monthly humidity model performance at Las Cruces (Figure 2-8) shows that the WRF/ERA5 is clearly performing better with all months achieving the simple benchmark with a slight moist bias of from 0.2 to 0.6 g/kg. The WRF/NAM May humidity performance also achieves the simple benchmark and is nearly identical to WRF/ERA5, but for June, July and August the WRF/NAM monthly humidity performance at Las Cruces has a moist bias of from 1.5 to 2.1 g/kg that fails to achieve the benchmarks (≤±1.0 g/kg).

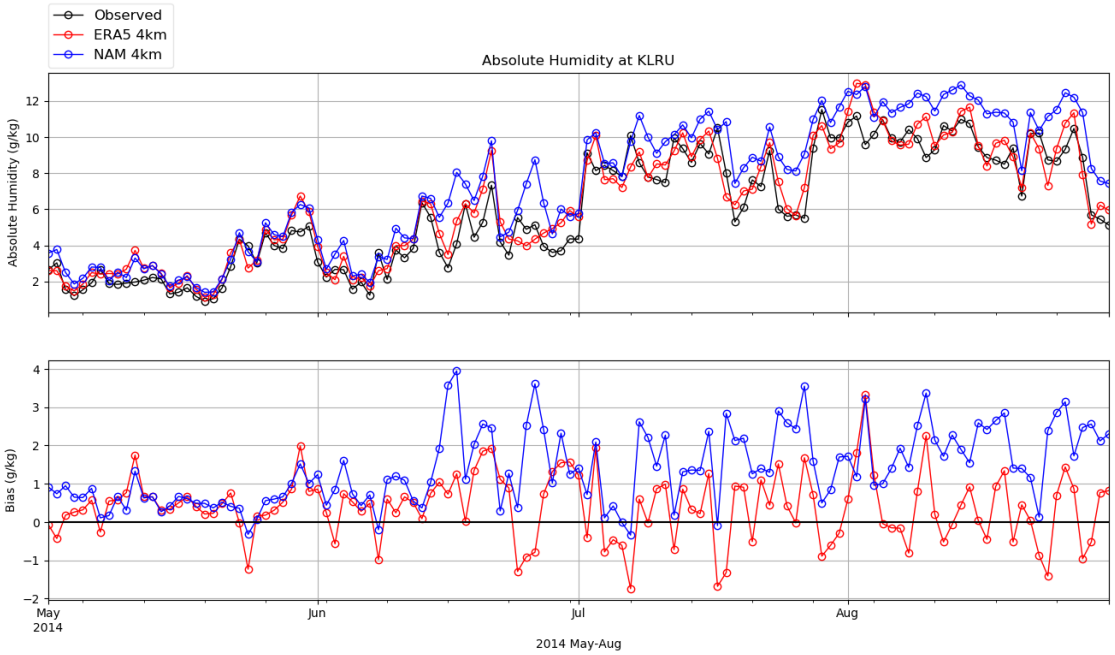


Figure 2-7. Time series plot of predicted and observed (black) daily humidity (g/kg) at Las Cruces International Airport for the WRF/ERA5 (red) and WRF/NAM (blue) simulations.

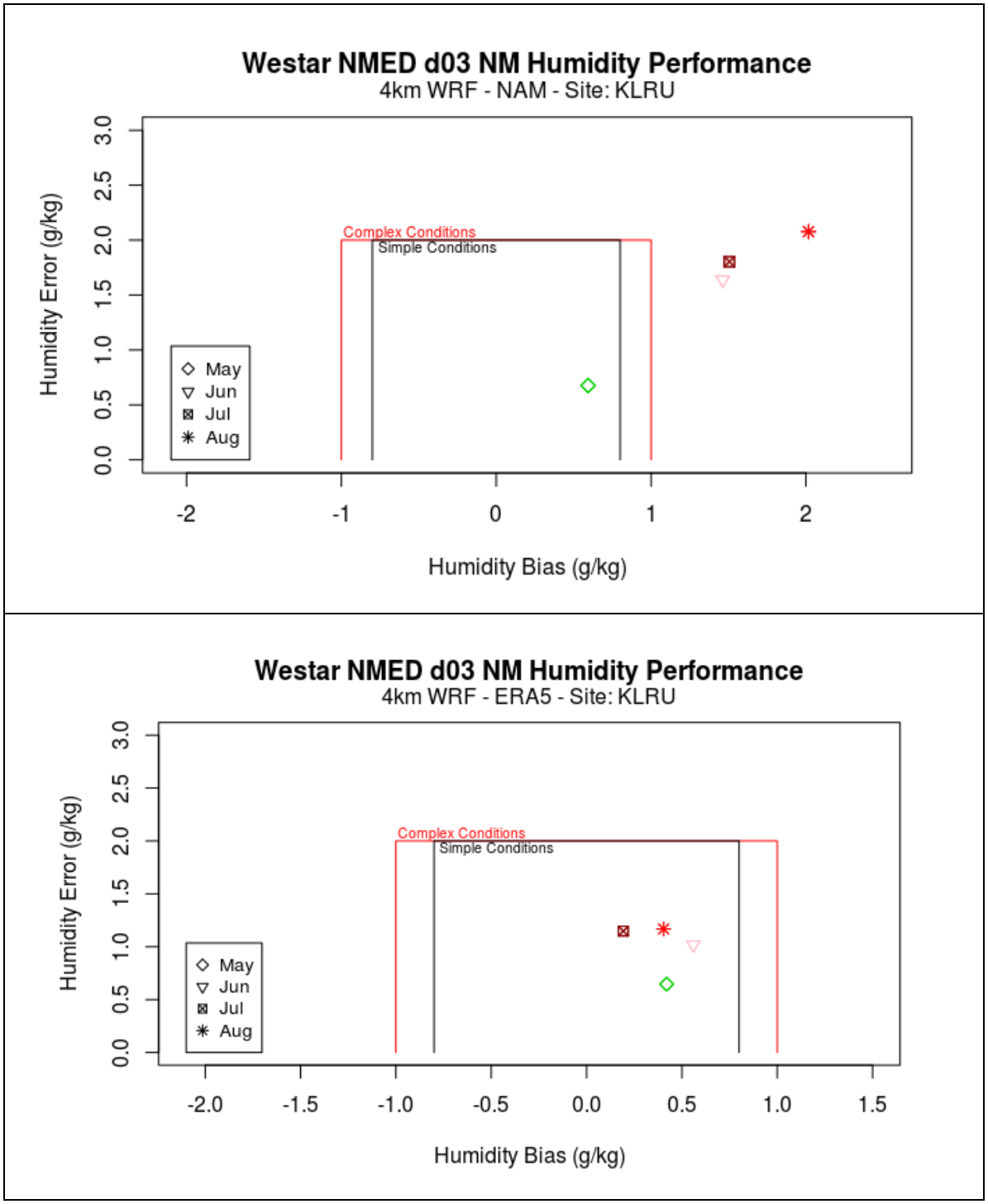


Figure 2-8. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface humidity (g/kg) model performance at Las Cruces International Airport against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

2.4.2 Qualitative Evaluations Using PRISM Data

Oregon State University (OSU) publishes precipitation analysis fields based on observations that can be used to qualitatively evaluate the WRF precipitation fields. The Parameter-elevation Relationships on Independent Slopes Model (PRISM[28]) is used to generate the precipitation analysis fields (Daly et al., 2008). The PRISM interpolation method of observed precipitation reflect, as closely as possible, the current state of knowledge of spatial climate patterns in the United States. PRISM calculates a climate – elevation regression for each digital elevation model (DEM) grid cell, and stations entering the regression are assigned weights based primarily on the physiographic similarity of the station to the grid cell. Factors considered are location, elevation, coastal proximity, topographic facet orientation, vertical atmospheric layer, topographic position, and orographic effectives of the terrain.

Figure 2-9 compares the PRISM May monthly total precipitation across the 4-km New Mexico domain with the WRF/NAM and WRF/ERA5 model estimates. The PRISM and WRF estimate May precipitation amounts over New Mexico are similar with all three estimating little precipitation in the west and small amounts in the central eastern portion of New Mexico. However, neither WRF simulation reproduces the PRISM precipitation in the southeast corner of the 4-km domain in West Texas near Midland. And the WRF/NAM greatly overstates the PRISM precipitation over the Texas panhandle, with WRF/ERA5 just having a slight overstatement in this region.

The June monthly precipitation comparisons are provided in Figure 2-10. Both models have reasonable June monthly precipitation over New Mexico that is very light. And PRISM and the two WRF simulations agree with the much higher precipitation over the Texas panhandle, with WRF/ERA5 performing better than WRF/NAM that has an overestimation bias.

There is much more observed and estimated precipitation over New Mexico in July 2014 (Figure 2-11). WRF/NAM overestimates the July monthly precipitation over northeast New Mexico in July, with WRF/ERA5 having an overestimation bias in most northerly Texas. But both WRF simulations have a dry bias for monthly precipitation over the remainder of New Mexico.

WRF/ERA5 does a better job at reproducing the locations and magnitudes of the August monthly PRISM precipitation than WRF/NAM (Figure 2-12). WRF/NAM overstates the August precipitation in central-south New Mexico.

[28] http://prism.oregonstate.edu/

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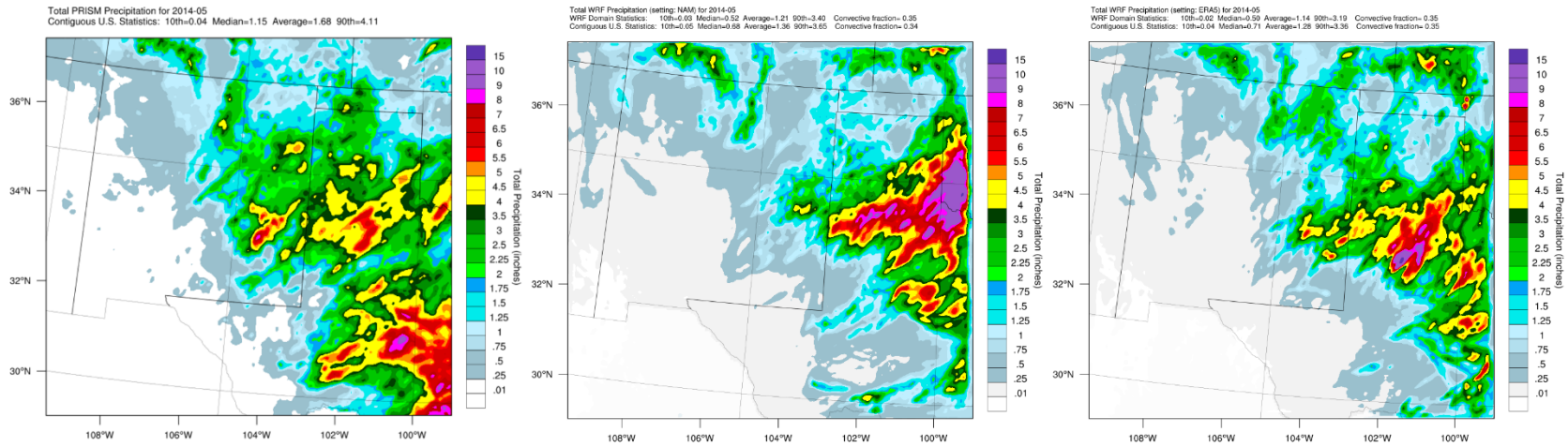


Figure 2-9. May monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

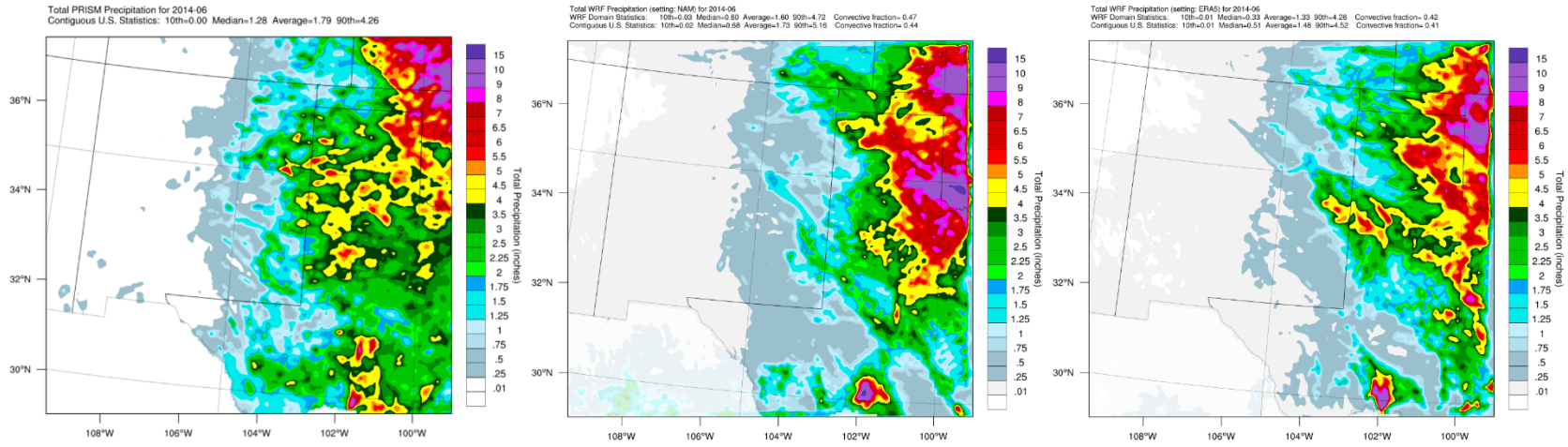


Figure 2-10. June monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

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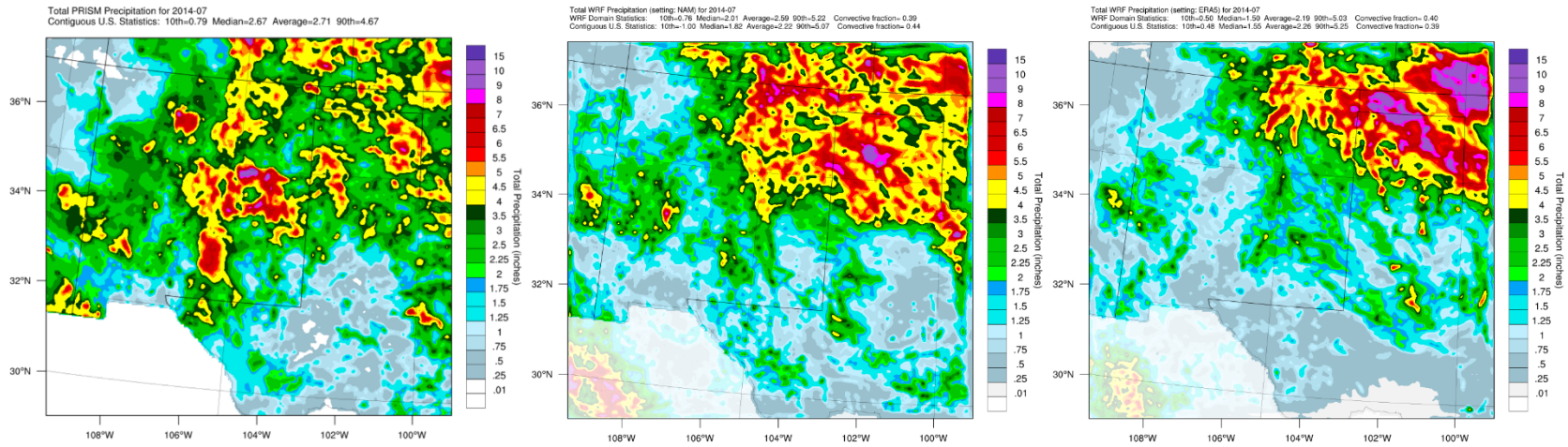


Figure 2-11. July monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

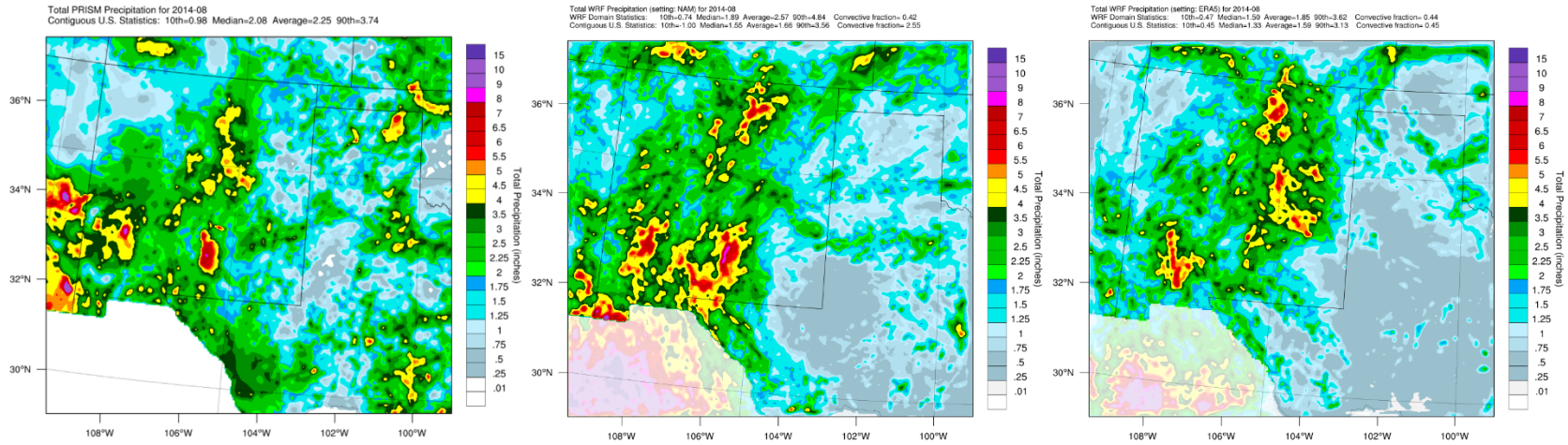


Figure 2-12. June monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

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2.4.3 Conclusions of 2014 WRF Model Performance

The model performance of both WRF simulations is reasonable and very similar for most meteorological variables (e.g., winds and temperature). This is in contrast to the WRAP-WAQS and EPA WRF 2014 simulations that had very different performance characteristics over New Mexico.[29] The biggest difference in the performance of the two WRF simulations was for humidity and precipitation. The WRF/NAM simulation had a moist bias for June-August that is likely partly associated with overactive convective precipitation that was greater in WRF/NAM than WRF/ERA5. It is unclear whether the WRF/NAM overstated precipitation is due to overactive convective events when they occur, or having events occur when they are not observed.

From the meteorological model performance evaluation, it is not possible to determine which set of WRF meteorological inputs will produce better ozone model performance when used as meteorological inputs for CAMx. There are variations in spatial and temporal model performance that are difficult to estimate what effects they will have on ozone concentrations. Furthermore, there may be meteorological inputs (e.g., level of mixing) that are more important for ozone modeling than the parameters we have data to evaluate the meteorological model for (i.e., winds, temperature, humidity and precipitation). Although it appears that WRF/NAM overstates the monthly precipitation, if that does not occur on high ozone days it may not matter to the ozone model performance.

CAMx was run for a portion of the summer of 2014 episode with meteorological inputs based on both the WRF/NAM and WRF/ERA5 simulations and the ozone estimates compared to determine which meteorological inputs performed best so were selected for use in the final CAMX 2014 36/12/4-km base case simulation. The meteorological diagnostic sensitivity tests using the CAMx photochemical model are described in Chapter 5.

[29] https://www.wrapair2.org/pdf/NM_OAI_Study_Webinar1_2020-05-28.pdf

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3. BOUNDARY CONDITION INPUTS

The Boundary Conditions (BCs) for the CAMx most outer 36-km 36US modeling domain lateral boundaries were based on output from a 2014 simulation of the GEOS-Chem global chemistry conducted by WRAP for their 2014v2 modeling platform.

3.1 WRAP 2014 GEOS-Chem Modeling

The WRAP-WAQS 20914v1 36/12-km CAMx and CMAQ base case simulations used BCs based on EPA's 2014 GEOS-Chem simulation that was used in EPA's 2014 modeling platform used in the 2014 National Air Toxics Assessment (NATA[30]). The CAMx and CMAQ 2014v1 base case simulation and sensitivity modeling found that the BCs based on EPA's 2014 GEOS-Chem caused year-long ozone overestimation bias throughout the western U.S.[31] Thus, WRAP conducted their own 2014 GEOS-Chem simulation using newer version of the model with updated emissions that resulted in much better CAMx ozone model performance without the systematic ozone over-prediction bias.[32] Table 3-1 presents the WRAP 2014 GEOS-Chem model configuration.

Table 3-1. 2014 GEOS-Chem simulation model configuration used by WRAP whose output is used to define the 2014 day-specific diurnally varying BC inputs for the NM OAI Study photochemical modeling.

Science Options	WRAP 2014 GEOS-Chem Base Case
Version	Version 12.2.0 (release date: 2019-02-19)
Vertical Grid Mesh	72 Layers
Chemistry mechanism	GEOS-Chem standard chemistry with complex SOA option[33].
Horizontal Grids	2x2.5 degree (Nx, Ny = 144, 91)
Initial Conditions	6-month spin-up; starting from provided initial conditions for standard chemistry
Meteorology	2014 GEOS-FP meteorology
Photolysis mechanism	Default (FAST-J)
Advection Scheme	Default (TPCORE)
Cloud convection scheme	On / Relaxed Arakawa-Schubert
Planetary Boundary Layer mixing	On / non-local scheme implemented by Lin and McElroy
Dry deposition scheme	Default (Wesely)
Chemistry Solver	Default (FLEXCHEM)
Parallelization	Open Multi-Processing (OMP)

[30] https://www.epa.gov/national-air-toxics-assessment

[31] http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx

[32] https://www.wrapair2.org/pdf/WRAP_Shake-Out_Phase-III_Update_RTOWG_2019-09-10v3a.pptx

[33] We recommend turning off semivolatile primary organic aerosol (POA) chemistry and isoprene SOA reactions via the volatility-based scheme (VBS) [Pye et al., 2010] to avoid risk of double-counting in the complex SOA chemistry scheme. For more information, see http://maraisresearchgroup.co.uk/Publications/GC-v11-02-SOA-options.pdf

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3.2 2014 GEOS-Chem Model Evaluation

The results of the WRAP 2014 GEOS-Chem simulation and CAMx sensitivity modeling using the new BCs can be found on the WAQS-WRAP2014v2 model evaluation webpage[34]. Relevant for the NM OAI Study is the fact that this updated 2014 GEOS-Chem BCs do lead to better CAMx model performance for ozone concentrations and corrects a persistent year-long ozone overestimation bias observed with the previous 2014 GEOS-Chem simulation conducted by EPA and used in the EPA 2014 modeling platform. The NM OAI Study evaluated the use of the WRAP 2014 GEOS-Chem BCs for CAMx modeling at several sites in New Mexico and found good ozone performance that achieved ozone model performance goals.[35] Thus, the WAQS-WRAP 2014v2 BC inputs based on the WRAP 2014 GEOS-Chem simulation were used as is for the NM OAI Study.

[34] http://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

[35] https://www.wrapair2.org/pdf/NM_OAI_Study_Webinar1_2020-05-28.pdf

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4. 2014 EMISSION INPUTS

4.1 Available Emissions Inventory Datasets

The emissions inventories for the CAMx 2014 36/2/4-km base case modeling were based on the WRAP-WAQS 2014v2 emissions inventory. Within the 36-km 36US North American and 12-km 12WUS2 western U.S. domains, the WRAP-WAQS CAMx 2014v2 base case emission inputs were used without any changes.

For the 4-km New Mexico domain, the WRAP-WAQS 2014v2 emissions have been reviewed and updated as needed by the NMED. For on-road mobile sources, the 4-km domain emissions were based on MOVES2014 model, 2014 activity data and day-specific hourly gridded 2014 WRF 4-km meteorology run through SMOKE-MOVES.

4.2 Development of CAMx Emission Inputs

CAMx emission inputs were generated mainly by the SMOKE and MEGAN emissions models. CAMx requires two emission input files for each day: (1) low level gridded emissions that are emitted directly into the first layer of the model from sources whose emissions are released at the surface with little or no plume rise; and (2) elevated point sources (stacks) with plume rise calculated from stack parameters and meteorological conditions. CAMx was operated using version 6 revision 4 of the Carbon Bond chemical mechanism (CB6r4) (Yarwood et al., 2010).

The 2014 base case (May to August) 4-km New Mexico domain CAMx emission inputs were based on the WRAP-WAQS 2014v2 emissions that rely on the 2014NEIv2 with updates provide by the western states. The New Mexico emissions from the 2014v2 database were reviewed and updated by the NMED. The 2014v2 emissions for New Mexico and portions of surrounding states within the 4-km New Mexico domain were processed by the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system (UNC, 2015). SMOKE version 4.7 was used, which is the current version of SMOKE that was released in October 2019.[36]

4.2.1 Day-Specific On-Road Mobile Source Emissions

The 2014 on-road mobile source emission inputs for the 4-km New Mexico domain were generated using the SMOKE-MOVES emissions model. SMOKE-MOVES used a 2014 mobile source emission factor (EF) lookup table generated by the Motor Vehicle Emission Simulator (MOVES2014[37]) model (EPA, 2014a,b,c). The SMOKE-MOVES default county-level 2014 vehicle activity data for New Mexico was reviewed by NMED and updated as needed. SMOKE-MOVES uses the 2014 MOVES EF lookup table, hourly gridded 4-km meteorological data from the 2014 WRF simulation conducted in this study and 2014 county-level activity data (e.g., vehicle miles travelled [VMT], speed, etc.) to generate 2014 day-specific hourly gridded on-road mobile source emission inputs for CAMx and the 4-km New Mexico domain.

[36] https://www.cmascenter.org/smoke/

[37] http://www.epa.gov/oms/models/moves/#user

4.2.2 Point Source Emissions

2014 point source emissions were based on the WRAP-WAQS 2014v2 emissions inventory. The 2014v2 New Mexico point source emissions were reviewed and updated by NMED. Point sources were processed in two streams: (1) major point sources with Continuous Emissions Monitoring (CEM) devices, which are primarily fossil-fueled Electrical Generating Units (EGU) with capacity of 25 MW or greater; and (2) point sources without CEMs. For point sources with CEM data, day-specific hourly NO_X and SO_2 emissions were used for the 2014 base case emissions scenario. The VOC, CO and PM emissions for point sources with CEM data were based on the annual emissions data in the 2014v2 inventory temporally allocated to each hour of the year using the CEM hourly heat input. The hourly CEM data available in the Acid Rain database on the EPA Clean Air Market Division (CAMD) website fills hours with missing CEM data with maximum potential to emit (PTE) emission rates and flags the data. This is because the purpose of the Acid Rain database is to assure that the source is not emitting higher emissions than its cap. Using PTE emissions rates for hours with missing CEM data is inappropriate for PGM modeling since the goal is to obtain an accurate estimate of emissions. Thus, a data filling program is used that uses the missing data flags to identify hours when the data filled PTE emissions occur, and they are replaced with typical emission rates.

For all point sources, the locations of the point sources were converted to the LCC coordinate system used in the modeling. Non-CEM point sources were processed by SMOKE to generate the temporally varying (i.e., seasonal, day-of-week and hour-of-day) speciated emissions needed by CAMx. The 2014 point source emissions without CEM data were processed using SMOKE using the default temporal (e.g., monthly, day-of-week and hourly) and speciation profiles.

4.2.3 Area and Non-Road Source Emissions

The 2014v2 area and non-road sources were spatially allocated to the 4-km New Mexico grid using an appropriate surrogate distribution (e.g., population for home heating, etc.). The area sources were temporally allocated by month and by hour of day using the SMOKE source-specific temporal allocation factors, while chemical speciation used the SMOKE source-specific CB6r4 speciation allocation profiles.

4.2.4 Episodic Biogenic Emissions

Biogenic emissions were generated using Version 3.1 of the MEGAN biogenic emissions model. MEGAN uses high resolution GIS data on plant types and biomass loadings and the 2014 WRF surface temperature fields, and solar radiation to develop hourly emissions for biogenic species on the 36/12/4-km grids. MEGAN generates gridded, speciated, temporally allocated emission files. The MEGAN biogenic emissions were used for the 36-km 36US, and 4-km New Mexico modeling domains. Note that the BEIS biogenic emissions were used in the 12-km WRAP-WAQS 2014v2 modeling platform. WRAP/WAQS conducted sensitivity tests using MEGAN v3.0 and BEIS biogenic emissions and found they produced comparable ozone estimates (because the isoprene emissions were similar) but CAMx with BEIS had better Organic Aerosol (OA)

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performance[38] than CAMx with MEGAN v3.0 biogenic emissions so WAQS selected BEIS. Since then, MEGAN has been updated to version 3.1 and the CAMx OA performance is now similar using MEGAN v3.1 and BEIS.

Table 4-1 summarizes MEGAN v3.1 biogenic VOC (BVOC) and soil NOx emissions by month for the 4-km New Mexico domain. Biogenic emissions are controlled by ambient environmental variables, most notably temperature and light. Increases in temperature normally lead to increased BVOC emissions because of higher biological activity as evident in the Table 4-1.

Table 4-1. 2014 base case biogenic emissions summary by month (in short tons per day) for the 4-km New Mexico domain.

Month	NOx (in tons/day)	BVOC (in tons/day)
May	1,131	4,139
Jun	1,415	8,902
Jul	1,666	10,248
Aug	1,323	11,438

4.2.5 *Wildfires, Prescribed Burns, Agricultural Burns*

2014 emissions from open-land burning including wildfires, prescribed burns and agricultural burning were based on the WRAP-WAQS 2014v2 emissions inventory. The WRAP Fire and Smoke Work Group (FSWG[39]) processed the 2014NEIv2 Bluesky/SMARTFIRE fire emissions for the U.S. and classified them as either wildfires (WF), prescribed burns (Rx) or agricultural burning (Ag) and made other updates for the 2014v2 inventory. The 2014NEIv2 fire emissions for Mexico and Canada was used without any changes.

4.2.6 *Other Natural Emissions*

Lightning NO_x (LNOx), and windblown dust (WBD) emissions were generated for the 4-km domain using special CAMx processors and WRF 2014 meteorological data. Oceanic emissions such as sea salt spray aerosol (SSA) and dimethyl sulphide (DMS) were not generated for the 4-km New Mexico domain since this domain does not include any ocean within it. However, the LNOX, WBD and oceanic emissions for the 36-km and 12km were based on the WRAP-WAQS 2014v2 emissions and were included in the modeling.

4.2.7 *QA/QC of Emissions Processing and Emissions Merging*

The emissions for the 4-km New Mexico domain were processed by major source category in several different processing "streams", including area sources, on-road mobile sources, non-road mobile sources, biogenic sources, non-CEM point sources, CEM point sources using day-specific hourly emissions, and emissions from fires. Separate Quality Assurance (QA) and Quality Control (QC) were performed for each stream of emissions processing and in each step following the procedures developed by

[38] http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx

[39] https://www.wrapair2.org/FSWG.aspx

WRAP (Adelman, 2004). SMOKE includes advanced quality assurance features that include error logs when emissions are dropped or added. In addition, the following visual displays were generated:

- Spatial plots of the hourly emissions for each major species (e.g., NO_X, VOC, and CO).
- Summary tables of emissions for major species for each grid and by major source category.
- QA information examined against the original point and area source data and summarized in an overall QA/QC assessment.

Scripts to perform the emissions merging of the appropriate biogenic, on-road, non-road, area and low-level point sources (i.e., point sources with little or no plume rise so they are released into the first layer of the PGM) emission files were written to generate the CAMx-ready two-dimensional day and domain-specific hourly speciated gridded emission inputs. The point source and fire, emissions were then processed into the day-specific hourly speciated emissions in the CAMx-ready point source format.

For the 36/12-km domains the model-ready emissions from the WRAP/WAQS 2014v2 modeling platform were used in this study.

The resultant CAMx model-ready emissions were subjected to a final QA using spatial maps to: (1) assure that the emissions were merged properly and CAMx inputs contain the same total emissions; and (2) provide additional QA/QC information.

4.2.8 Use of the Plume-in-Grid (PiG) Subgrid-Scale Plume Treatment

CAMx includes a Plume-in-Grid (PiG) sub-model that treats the early plume chemistry and dynamics of emissions from point sources and then releases the emissions into the grid model farther downwind at such time that the plume is adequately resolved by the grid. Large NO_X emissions point sources within the 4-km New Mexico domain were selected for treatment by the subgrid-scale PiG module when their emissions rate were 5 tons per day or larger.

4.2.9 QA/QC of Model-Ready Emissions

In addition to the CAMx-ready emission input files generated for each hour of all days modeled in the May-August 2014 modeling period, a number of quality assurance (QA) files were prepared and used to check for gross errors in the emissions inputs. Importing the model-ready emissions into PAVE or VERDI and examine both the spatial and temporal distribution of the emission to investigate the quality and accuracy of the emissions inputs.

- Visualizing the model-ready emissions with the scale of the plots set to a very low value, we can determine whether there are areas omitted from the raw inventory or if emissions sources are erroneously located in water cells;
- Spot-checking the holiday emissions files to confirm that they are temporally allocated like Sundays;

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- Producing pie charts emission summaries that highlight the contribution of each emissions source component (e.g. non-road mobile);
- Normalizing the emissions by population for each state illustrates where the inventories may be deficient and provide a reality check of the inventories.

State inventory summaries prepared prior to the emissions processing were used to compare against SMOKE output report totals generated after each major step of the emissions generation process. To check the chemical speciation of the emissions to CB6 species, we compared reports generated with SMOKE to target these specific areas of the processing. For speciation, the inventory state import totals were compared against the same state totals with the speciation matrix applied.

4.2.10 Summary of Emissions for 4-km New Mexico Domain

This section presents 2014 base case anthropogenic emissions summary for the 4-km New Mexico domain. The emissions were processed by major source category in several different "streams" of emissions modeling. Each stream of emissions modeling generates a pre-merged CAMx-ready emissions model input with all pre-merged emissions inputs merged together to generate the final CAMx-ready two-dimensional gridded low-level (layer 1) and point source emission inputs. Table 4-2 lists an example of separate streams of emissions modeling by source category that are used.

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Table 4-2. New Mexico 4-km domain emissions processing categories.

Country/Region	Sector	Description
US Anthro	afdust_adj	Area fugitive dust
	ag	Agricultural ammonia sources
	nonpt	Other nonpoint sources
	np_oilgas_wrap	Non-point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)
	np_oilgas	Non-point Oil and Gas
	nonroad	Non-road mobile
	rail	Locomotive
	onroad	On-road mobile
	ptegu	EGU point sources
	ptnonipm	Non-EGU point sources
	pt_oilgas_wrap	Point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)
	pt_oilgas_wrap	Point Oil and Gas
	rwc	Residential Wood Combustion
Mexico Anthro	onroad_mex	Mexico onroad mobile
	othar	Mexico area
	othpt	Mexico point sources
Natural	MEGAN	Biogenic
	LtNOx	Lightning Nox
	AG fire	Ag Fire
	RX fire	Prescribed Fire
	WF fire	Wild Fire
	Ptfire_othna	Mexico fire
	WBD	Windblown Dust

Table 4-3 summarizes criteria air pollutant emissions in episode average short tons per day by source category for the 4-km New Mexico domain. These data represent the model-ready emissions input to the CAMx air quality model for the 2014 base case. Generally, emissions are summarized from the SMOKE reports generated by the SMKMRG program. There are a couple of exceptions to this general approach, fugitive dust and EGU sources. The fugitive dust emissions were adjusted after SMOKE processing to account for fugitive dust correction factors that are derived from the Biogenic Emission Landuse Database version 4 (BELD4). The correction factors are necessary to account for dust removal due to local vegetation scavenging so are not

transported downwind. Model-ready emissions for EGU and Mexico point sources were obtained from WRAP/WAQS 2014 platform so were summarized for the 4-km domain outside of SMOKE.

Table 4-3. 2014 base case anthropogenic emissions summary (episode average short tons per day) by source category for the 4-km New Mexico domain.

Country/ Category	Source Category	CO	NH_3	NOx	$PM_{2.5}$	PM_{10}	SO_2	VOC
US Anthro	Area fugitive dust	0.0	0.0	0.0	253.3	1,788.2	0.0	0.0
	Agricultural ammonia sources	0.0	764.7	0.0	0.0	0.0	0.0	43.4
	Non-point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)	237.7	0.0	157.8	4.4	4.4	11.3	567.3
	Remaining Non-point Oil and Gas	286.8	0.0	311.7	6.9	6.9	30.0	1,642.5
	Residential Wood Combustion	7.0	0.1	0.1	0.5	0.5	0.0	1.2
	Other nonpoint sources	141.3	1.5	28.5	9.3	13.4	4.5	213.2
	On-road mobile	1,476.2	6.0	444.5	13.2	20.1	1.7	150.6
	Locomotive	22.9	0.1	122.7	2.9	3.1	0.1	6.2
	Non-road mobile	570.3	0.2	133.4	9.0	9.4	0.3	73.2
	EGU point sources	89.2	3.4	210.6	12.9	17.8	160.0	5.0
	Point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)	89.9	0.0	114.7	1.4	1.4	23.8	56.1
	Remaining Point Oil and Gas	113.8	0.1	205.2	3.2	3.3	27.1	48.4
	Non-EGU point sources	74.4	4.9	47.5	11.4	32.5	49.3	24.4
Mexico Anthro	Mexico area	19.9	33.2	42.2	5.8	15.7	1.7	103.3
	Mexico onroad mobile	356.3	0.6	98.4	1.5	2.6	1.4	34.4
	Mexico point sources	28.4	0.7	20.2	4.8	5.7	16.4	8.3

Figure 4-1 presents pie charts showing the two main ozone precursor (VOCs and NOx) emissions from anthropogenic sources by source category for New Mexico and portion of surrounding states within the 4-km domain. Point and nonpoint oil and gas sectors account for majority of NOx emissions followed by on-road mobile and EGU sources. In New Mexico, oil and gas sources are the largest anthropogenic VOC emitters and accounts for nearly 80% of 4-km domain VOC emissions.

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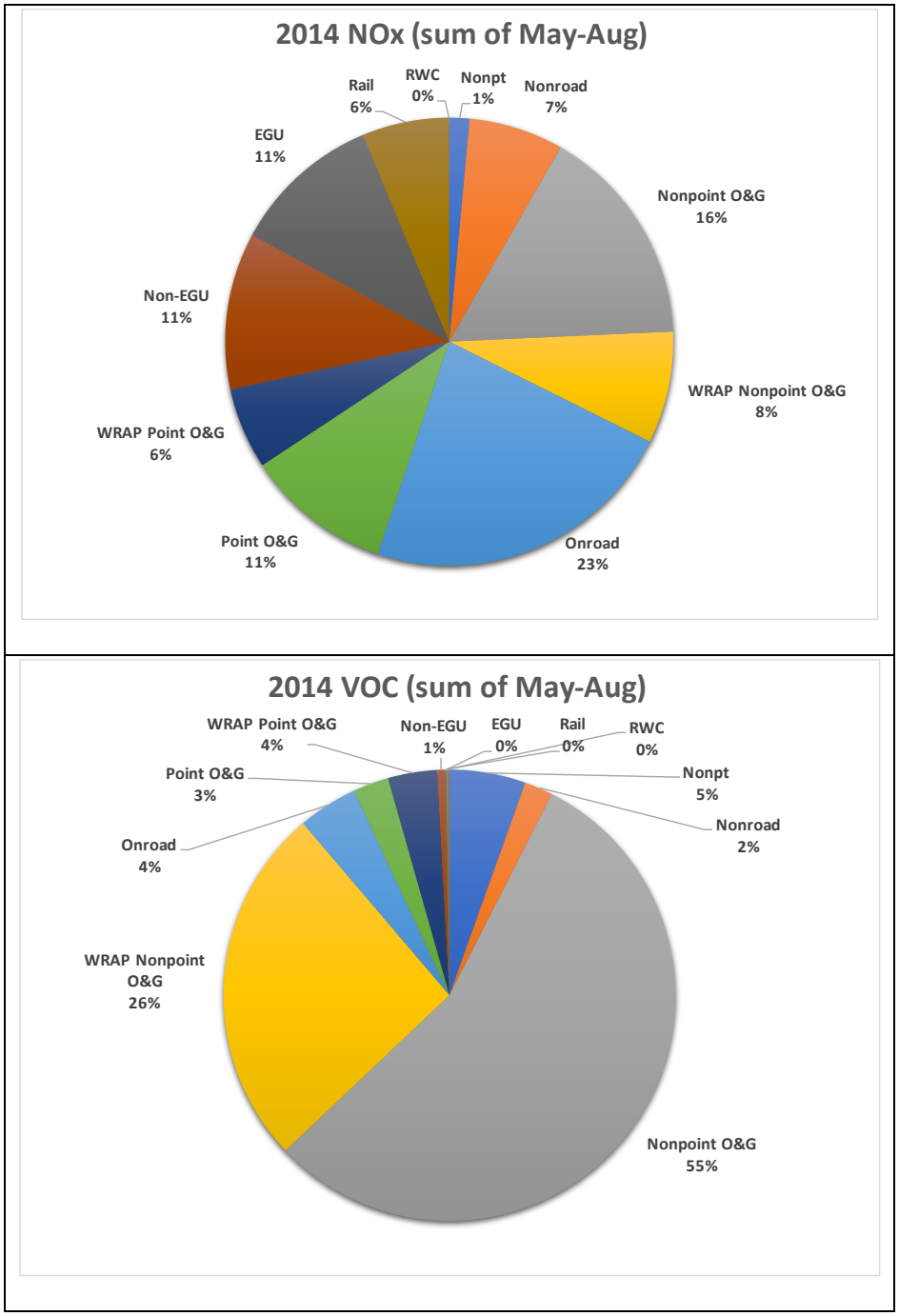


Figure 4-1. New Mexico 2014 base case anthropogenic NOx and VOC emissions by source category.

Figure 4-2 displays spatial maps of NOx and VOC anthropogenic emissions from the oil and gas sector across the 4-km New Mexico domain. Top panel shows emission maps for non-point O&G sources while bottom panel shows point O&G sources. The San Juan and Permian basins are clearly visible on the emissions map and confirm correct spatial allocation of oil and gas emissions. Figure 4-3 shows emission maps for on-road mobile (top panel), rail (middle panel) and non-point sources including non-road equipment (bottom panel).

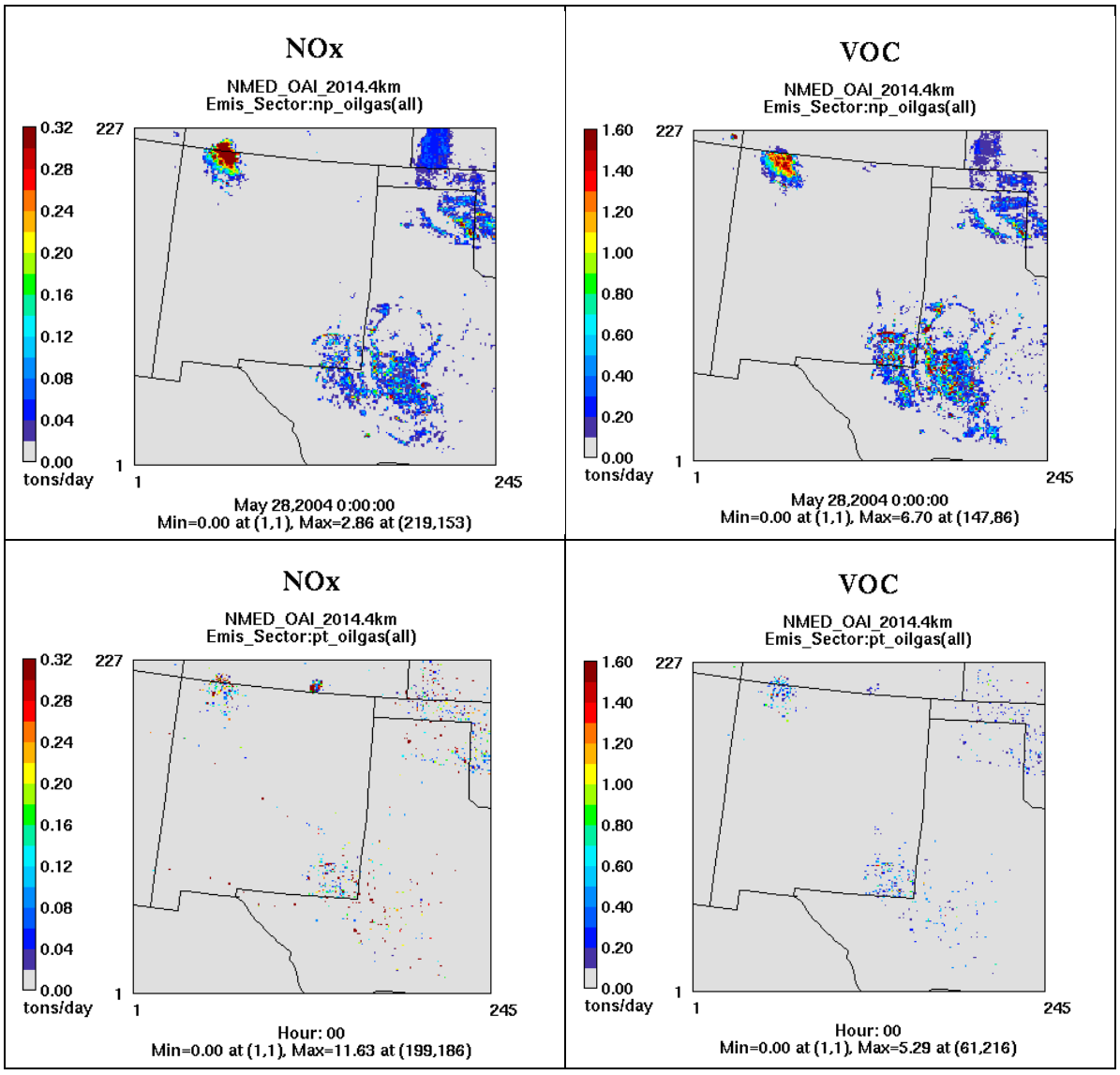


Figure 4-2. Spatial distribution of the non-point (top) and point (bottom) source oil and gas NOx (left) and VOC (right) emissions (episode avg tons per day) for New Mexico 4-km domain.

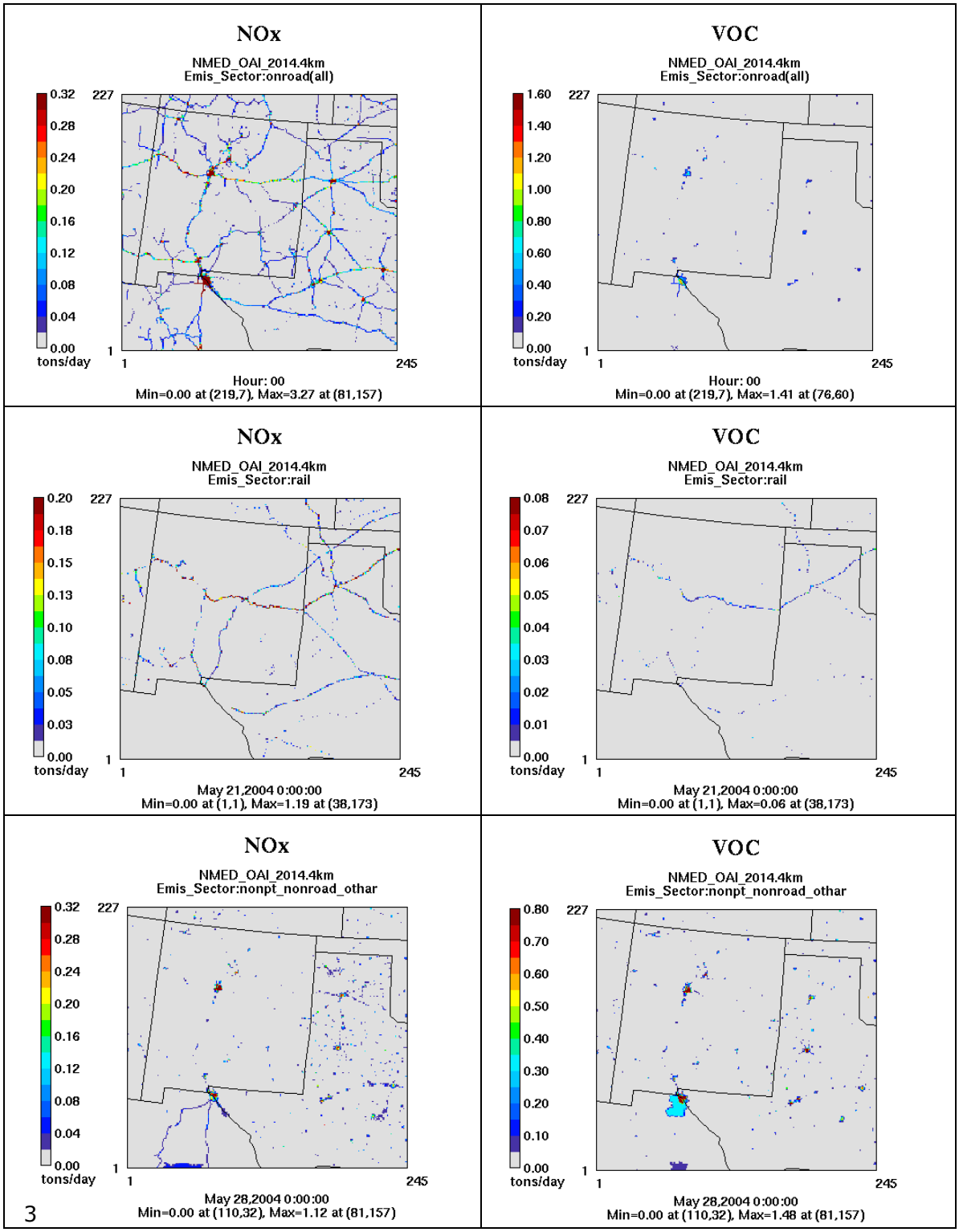


Figure 4-3. Spatial distribution of on-road (top), rail (middle) and non-point/non-road equipment (bottom) NOx (left) and VOC (right) emissions (episode avg tons per day) for New Mexico 4-km domain.

5. DIAGNOSTIC SENSITIVITY TESTS

Several CAMx diagnostic sensitivity tests were conducted to evaluate alternative meteorological inputs based on the 2014 36/12/4-km WRF meteorological model simulations discussed in Chapter 2. To develop the CAMx meteorological inputs, the WRF model output data must first be processed by the WRFCAMx processor.

5.1 WRFCAMx Processing of 2014 WRF Output

The WRFCAMx processor maps WRF meteorological fields to the format required by CAMx. It also calculates turbulent vertical exchange coefficients (Kv) that define the rate and depth of vertical mixing in CAMx. Steps in the WRFCAMx processing are as follows:

- Reading in WRF meteorological model output data;
- Extracting meteorological data for CAMx domain(s);
- Collapsing meteorological data if coarser vertical resolution data is requested in CAMx than used in WRF;
- Computing vertical diffusivities (Kv); and
- Output the meteorological fields in the formats used by CAMx.

Several options are available in WRFCAMx to derive vertical turbulent exchange coefficient (also known as: Kv, Kz or vertical diffusivity) fields from WRF output. When TKE (turbulent kinetic energy) is not available from the WRF output (as is the case with the YSU PBL selected WRF physics options), Kv fields are diagnosed from wind, temperature, and Planetary Boundary Layer (PBL) parameters in WRFCAMx. For this application, the WRFCAMx processing was performed to generate two sets of Kv profiles using two different Kv options in WRFCAMx, the CMAQ-like and YSU Kv profile options.

5.1.1 Treatment of Minimum Kv

The CAMx Kv_patch pre-processor program sets the minimum Kv value to 0.1 to 1.0 m^2/s in the lowest 100 m of the atmosphere depending on the amount urban land use category in a grid cell. This is done to account for the urban heat island effect that enhances vertical mixing through-out the day and night.

5.1.2 Layer Collapsing Strategy

WRF was run with 36 vertical levels (35 vertical layers) as shown in Table 2-1. For the NM OAI Study, a layer collapsing strategy was employed that reduced the 35 WRF vertical layers to 25 layers in CAMx, which reduces the CAMx run time by about a third. Table 5-1 displays the WRF to CAMx layer collapsing strategy. This is the same layer collapsing study employed by WRAP-WAQS.

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Table 5-1. WRF to CAMx vertical layer collapsing strategy used in the NM OAI Study.

CAMx Layers	WRF Layers	WRF hybrid eta	WRF Pressure (mb)	Height (m)
	0	1.0000	1000.0	0
	1	0.9985	998.6	12
1	2	0.9970	997.2	24
	3	0.9950	995.3	40
2	4	0.9930	993.4	56
	5	0.9910	991.5	72
3	6	0.9880	988.6	97
	7	0.9850	985.8	121
4	8	0.9800	981.0	162
5	9	0.9700	971.5	243
6	10	0.9600	962.0	326
7	11	0.9500	952.5	409
	12	0.9400	943.0	492
8	13	0.9300	933.5	577
9	14	0.9100	914.5	747
10	15	0.8900	895.5	921
11	16	0.8700	876.5	1098
12	17	0.8400	848.0	1369
13	18	0.8000	810.0	1742
14	19	0.7600	772.0	2130
15	20	0.7200	734.0	2533
16	21	0.6800	696.0	2954
17	22	0.6400	658.0	3393
18	23	0.6000	620.0	3854
19	24	0.5500	572.5	4463
	25	0.5000	525.0	5115
20	26	0.4500	477.5	5816
	27	0.4000	430.0	6576
21	28	0.3500	382.5	7408
	29	0.3000	335.0	8328
22	30	0.2500	287.5	9360
	31	0.2000	240.0	10541
23	32	0.1500	192.5	11930
	33	0.1000	145.0	13630
24	34	0.0600	107.0	15355
	35	0.0270	75.7	17205
25	36	0.0000	50.0	19260

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5.2 CAMx Meteorological Diagnostic Sensitivity Tests

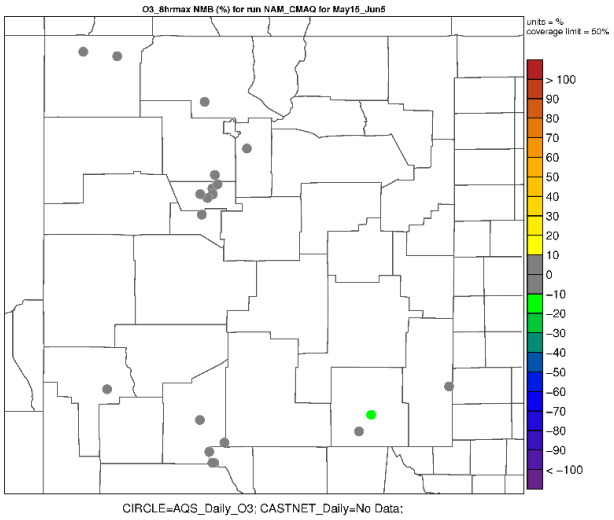
Four separate CAMx 2014 36/12/4-km diagnostic sensitivity tests were conducted for the first portion of the summer 2014 modeling episode that spanned May 15 to June 4, 2014. The purpose of the four meteorological inputs CAMx sensitivity tests was to identify the optimal meteorological inputs for the final CAMx 2014 base case simulation. The four sets of CAMx simulations were based on the WRF/NAM and WRF/ERA5 2014 36/12/4-km simulations described in Chapter 2 processed by WRFCAMx to generate two sets of vertical mixing coefficient (Kv) as described above:

1. WRF/NAM with CMAQ Kv
2. WRF/NAM with YSU Kv
3. WRF/ERA5 with CMAQ Kv
4. WRF/ERA5 with YSU Kv

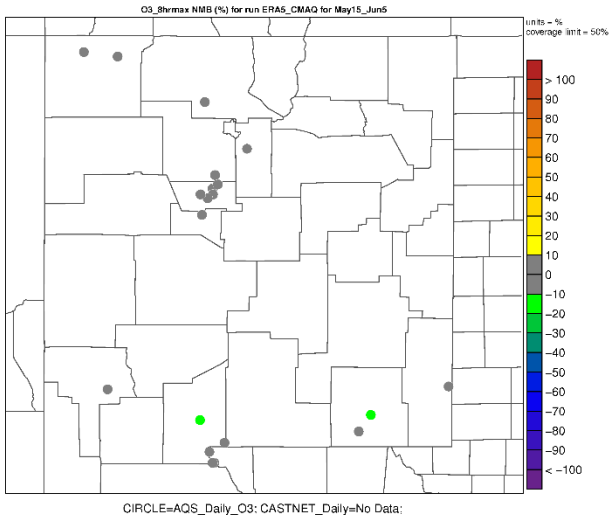
Ozone model predictions from each sensitivity test were compared with observed ozone concentrations in New Mexico. Figures 5-1 and 5-2 summarize the normalized mean bias (NMB) and error (NME) for each site in New Mexico during the modeling period. The statistics presented in these figures were calculated using a 60 ppb cutoff value relative to observed MDA8 ozone concentrations to understand the performance of each sensitivity test when ozone concentrations are most relevant to the NAAQS. Figure 5-1 shows that the NMB is generally within ±10% (colored grey) at almost all sites (note that the NMB performance goal is ±5% and criteria is ±15%). All of the sensitivity simulations have an under-prediction bias for observed ozone greater than 60 ppb at sites in the southern portion of the domain such that for one or two sites have a bias even lower than -10% (i.e., colored bright green). The WRF/NAM with CMAQ Kv sensitivity test has slightly better performance than the others with less underestimation bias (e.g., all sites but one are within ±10% compared to two sites for the other tests). Figure 5-2 shows that the NME is also generally within the performance goal (less than 15%) in all cases, with the southern portions of NM showing the largest errors but still within the performance criteria (less than 25%). The figure shows that CAMx using the WRF/NAM inputs tends to have slightly lower error and better ozone performance than when the WRF/ERA5 meteorological inputs are used.

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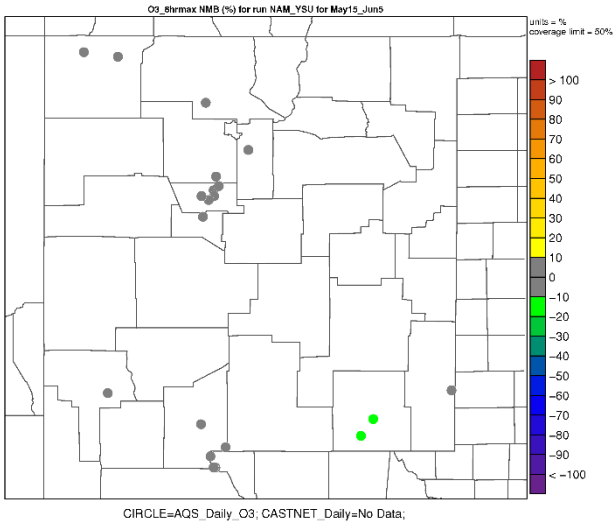
NAM CMAQ



ERA5 CMAQ



NAM YSU



ERA5 YSU

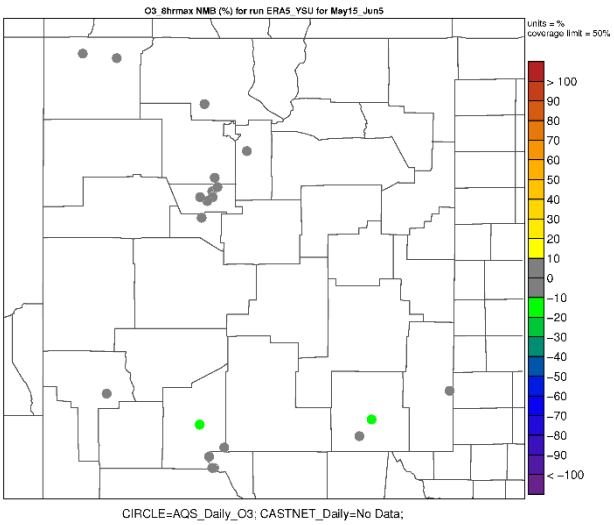
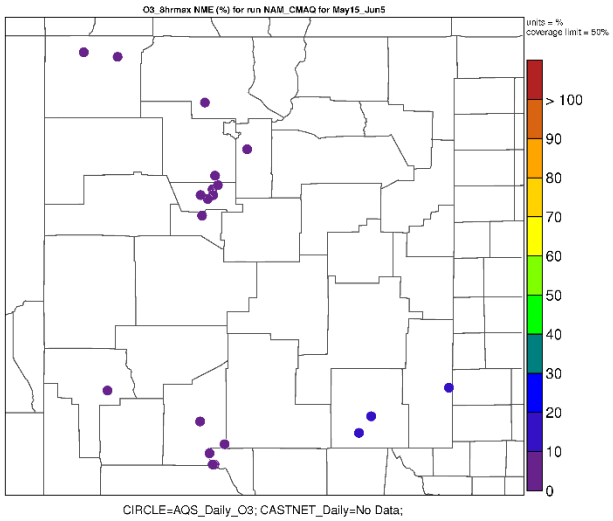
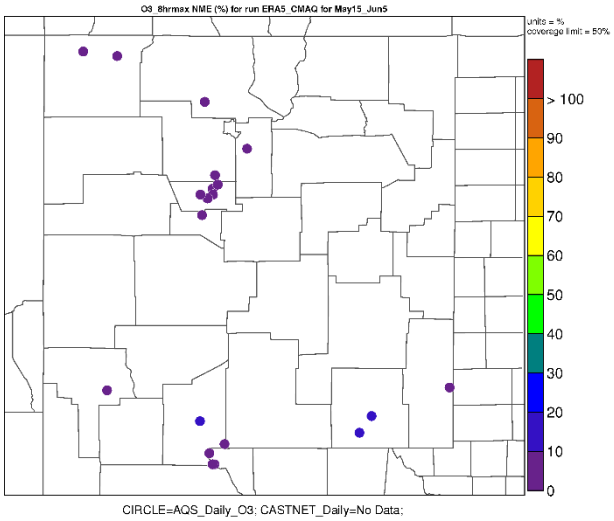


Figure 5-1. Comparison of sensitivity tests NMB with 60 ppb cutoff spatial plots over NM.

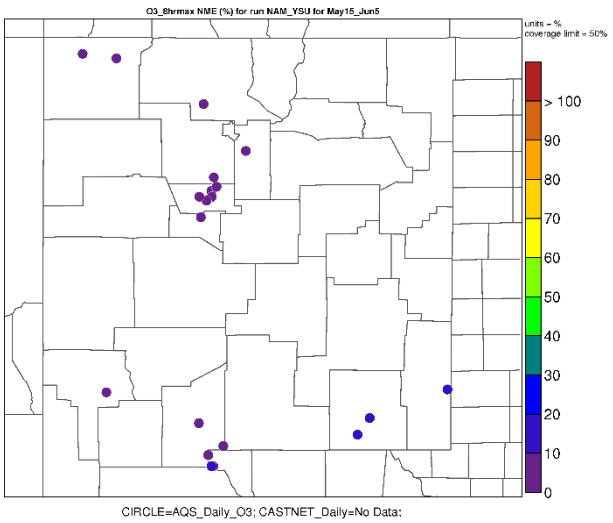
NAM CMAQ



ERA5 CMAQ



NAM YSU



ERA5 YSU

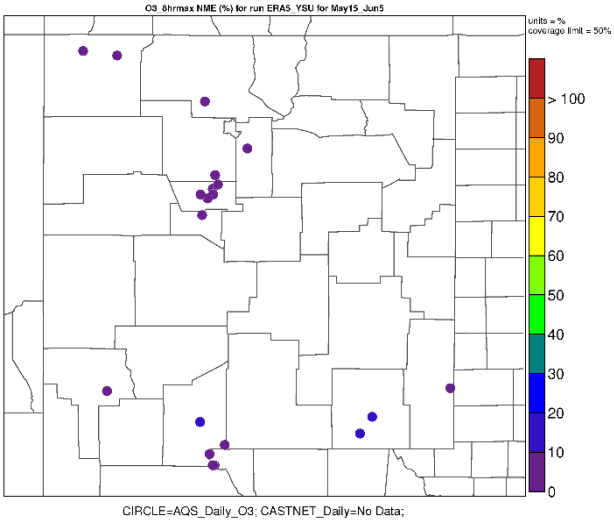


Figure 5-2. Comparison of sensitivity tests NME with 60 ppb cutoff spatial plots over NM.

Figure 5-3 presents soccer plots of bias and error for observed ozone above 60 ppb and all four CAMx sensitivity tests. This figure plots site-specific bias versus error with performance lines in the shape of a soccer goal, when the site-specific bias and error symbol falls within the soccer goal area (i.e., the red box) it is easy to see when the ozone performance goals are achieved. The figure shows that all sites have NMB and NME that fall within the performance criteria for bias (≤±15%) and error (≤25%), with most sites having an underestimation bias of the high (> 60 ppb) observed ozone concentrations. The CAMx simulations with the WRF/NAM meteorological inputs has slightly better performance than when the WRF/ERA5 inputs are used as more sites fall within the performance soccer goal area. Comparison between the NAM cases indicate that the test with CMAQ Kv has slightly smaller errors relative to the test with YSU Kv.

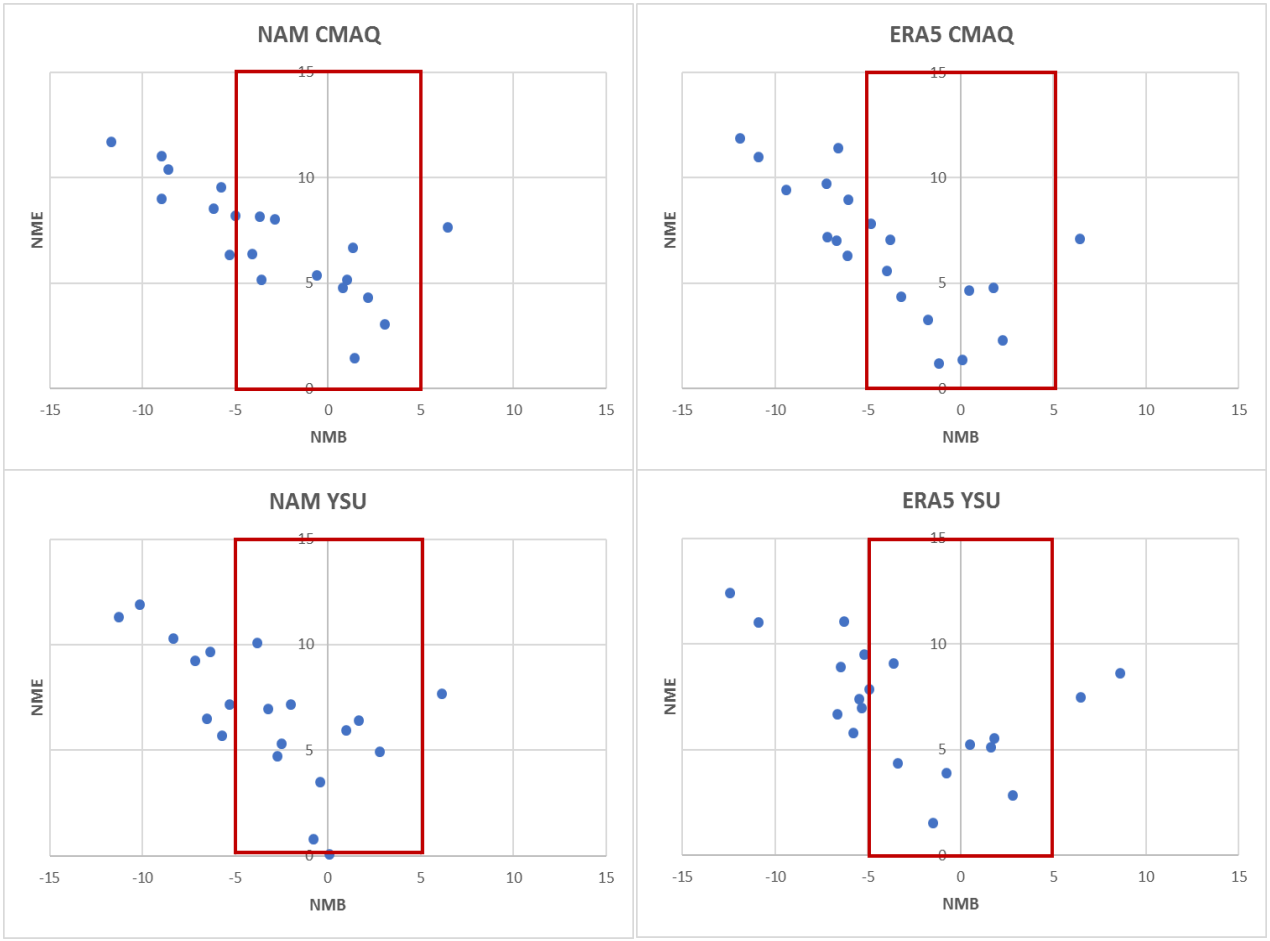


Figure 5-3. Comparison of sensitivity tests soccer plots with 60 ppb cutoff. Red rectangle indicates the performance goal soccer area.

Figures 5-4 to 5-7 present time series of predicted and observed MDA8 ozone concentrations for selected sites in Dona Ana, Eddy and Sandoval counties. At the Solano Road site in Dona Ana County the time series shows that the observed peak ozone concentration on May 29 is matched very well by the CAMx WRF/NAM sensitivity tests, while the CAMx WRF/ERA5 sensitivity test under-predicts by approximately 10 ppb (Figure 5-4). At the Desert View site, which is also in Dona Ana County, all four CAMx sensitivity tests underestimate the high observed ozone on May 28-29, but the CAMx WRF/NAM tests perform slightly better than the CAMx WRF/ERA5 test (Figure 5-5). At the Carlsbad site in Eddy County all test cases under-predict the high ozone concentration from May 27 to May 31 (Figure 5-6). For the site in Sandoval county (Figure 5-7) all four CAMx sensitivity tests track the daily variations of the observed MDA8 ozone including getting the timing and values of the observed ozone peak on May29, but the CAMx WRF/NAM with CMAQ Kv test exhibits the lowest biases.

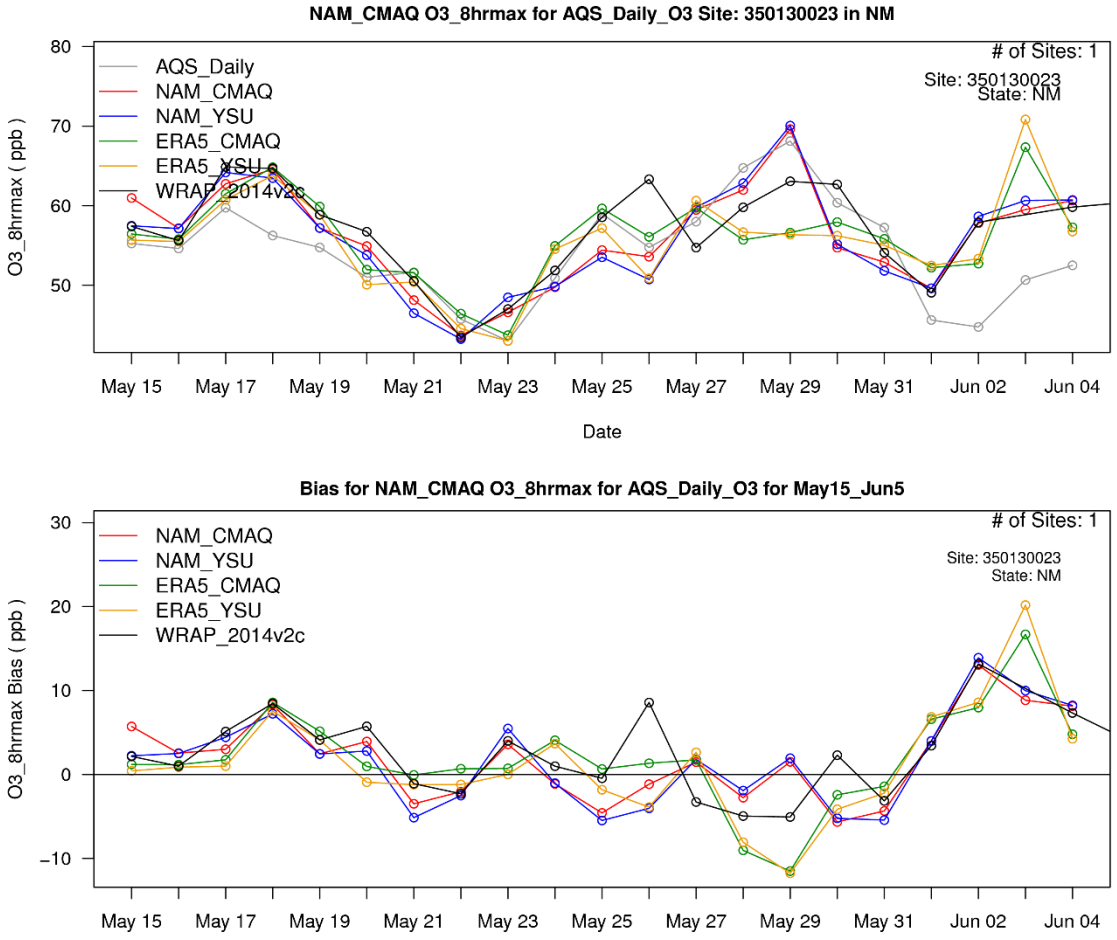


Figure 5-4. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Solano Road site, Dona Ana County

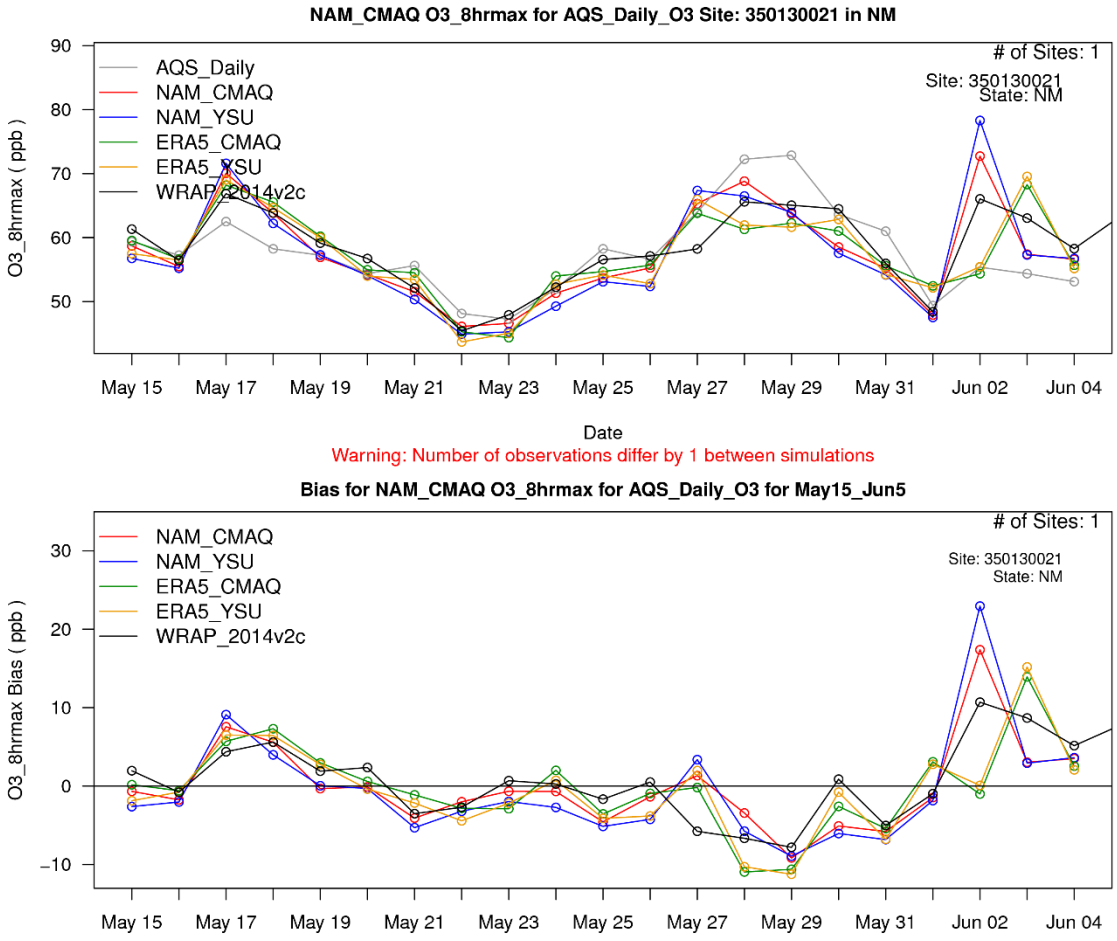


Figure 5-5. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Desert View site, Dona Ana County

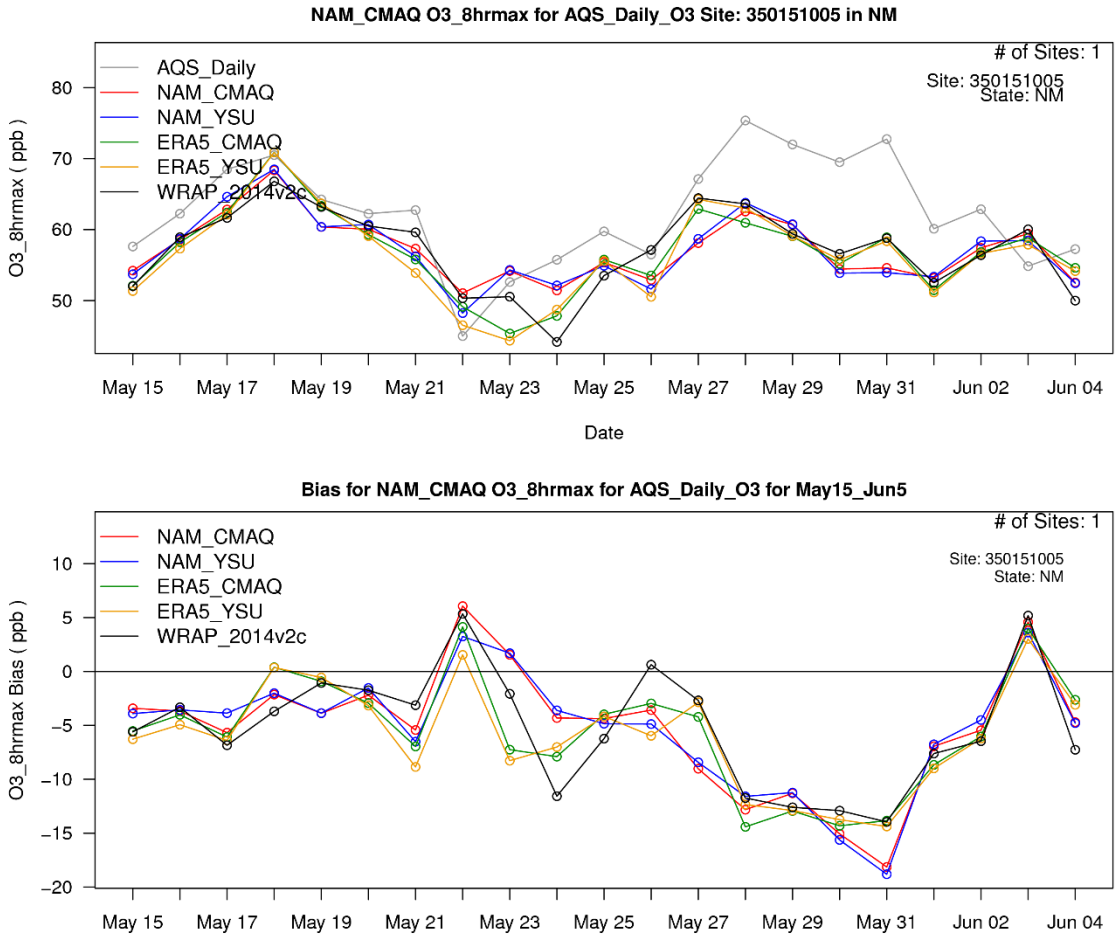


Figure 5-6. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Carlsbad site, Eddy County

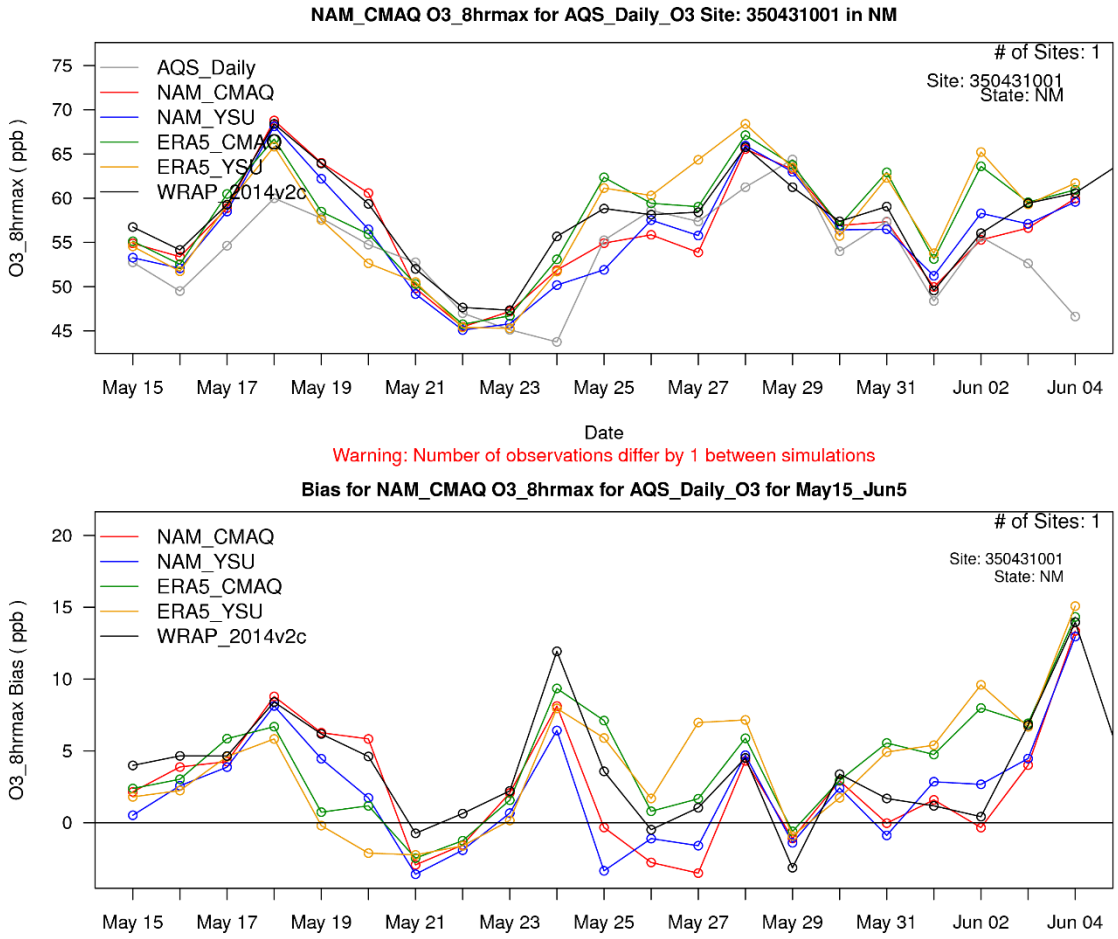


Figure 5-7. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Albuquerque site, Sandoval County

5.3 Summary CAMx Diagnostic Sensitivity Tests

All four of the CAMx meteorological sensitivity cases have biases and errors well within the performance criteria and in most cases even within the more stringent performance goals. For the modeled episode, the differences in performance among all the cases considered are relatively minor. On some sites and days, CAMx using the WRF/NAM meteorology tends to capture peak ozone concentrations better than when the WRF/ERA5 meteorology is used. Note that the sensitivity tests were performed on a period in late spring (May to June) when ozone concentrations exceed the NAAQS, however they may not reflect the observed precipitation biased observed in the WRF MPE for the period of June to August. Also, the WRF performance showed that precipitation biases could occur over northeast NM where there are no ozone monitors so CAMx model performance is unknown in that region. Based on the results presented here, the final CAMx 2014 base case model configuration will use the WRF/NAM with CMAQ Kv treatment meteorological inputs.

6. FINAL MODEL BASE CASE CONFIGURATION

This section summarizes the final CAMx base case model configuration for the summer of 2014 modeling of New Mexico that includes the meteorological, emissions, and air quality inputs as well as CAMx option and configuration. The modeling procedures used in the NM OAI Study modeling are consistent with EPA's latest ozone modeling guidance documents (EPA, 2018d) and past modeling studies of the western U.S. and followed the procedures laid out in the NM OAI Study modeling protocol (WESTAR and Ramboll, 2020a).

6.1 Meteorological Inputs

Procedures for WRF meteorological modeling for the NM OAI Study 2014 36/12/4-km applications are described in Chapter 2. Chapter 5 describes the CAMx diagnostic sensitivity tests using four different meteorological inputs that were based on two 2014 WRF simulations (WRF/NAM and WRF/ERA5) that were processed to generate CAMx inputs using two different two vertical mixing (Kv) options in the WRFCAMx processor (CMAQ-like and YSU). Although the ozone model performance for the four CAMx meteorological sensitivity tests were similar, the CAMx simulation using the WRF/NAM with CMAQ-like vertical mixing coefficients inputs was selected based on the best ozone model performance.

6.2 Emission Inputs

The 36-km and 12-km emissions used in the NM OAI Study CAMx 2014 base case simulation were based on the WRAP-WAQS 2014v2 emissions. Chapter 4 describes the updates to the WRAP-WAQS 2014v2 emissions for New Mexico and the development of the emission inputs for the New Mexico 4-km domain.

6.3 Photochemical Model Inputs

6.3.1 PGM Science Configuration and Input Configuration

This section describes the final CAMx 2014 base case configuration and science options used in the NM OAI Study ozone modeling. Table 6-1 summarizes the CAMx configuration and option used, with more details provided below.

6.3.1.1 PGM Model Versions

The latest version 7.0 (v7.0) of CAMx was used in the NM OAI Study. This is the same version used in the WRAP-WAQS 2014v2 modeling and as well as EPA in their national Regional Haze modeling (EPA, 2019). The model was configured to predict both ozone and PM species.

6.3.1.2 PGM Grid Nesting Strategy

CAMx was operated using the 36/12/4-km nested grid structure shown in Figure 1-10 using two-way grid nesting for all simulations.

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6.3.1.3 Initial and Boundary Conditions

Boundary Conditions (BCs) for the CAMx most outer 36-km 36US modeling domain lateral boundaries were based on output from a 2014 simulation of the GEOS-Chem global chemistry conducted by WRAP for their 2014v2 modeling platform. A zero-gradient top BC was specified where the concentrations above the top of CAMx are assumed to be the same as in the top layer of CAMx.

CAMx was started on May 1, 2016 using the 36/12/4-km domains that allowed the model over two-weeks to initialize the model and wash out the initial concentrations before the first high ozone day on May 17, 2014.

6.3.1.4 Other PGM Model Options

The CAMx model options and setup are defined in Table 6-1. The PPM advection solver (Colella and Woodward, 1984) was used for horizontal transport along with the spatially varying (Smagorinsky) horizontal diffusion approach. K-theory was used for vertical diffusion using the CMAQ-like Kv profiles from the WRFCAMx processing of the WRF/NAM output. The CB6r4 gas-phase chemical mechanism was selected because it includes the very latest chemical kinetic rates with halogen chemistry that affects ozone levels over the ocean. The latest aerosol mechanism was used in CAMx along with the standard wet and dry deposition schemes. The Plume-in-Grid module was used to treat the near-source chemistry and dispersion of major NO_X emissions sources in the New Mexico 4-km domain for sources with greater than 5 tons per day NOx emissions.

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Table 6-1. Final CAMx model configuration for the NM OAI Study.

Science Options	CAMx	Comment
Model Codes	CAMx v7.0	Latest version of CAMx made publicly available May 2020 (www.camx.com)
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes buffer cells
4-km grid	245 x 227 cells	New Mexico 4-km domain. Includes buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 thickness ~20 m. Model top at 50 mb (~19 km). Layer collapsing from 35 vertical layers in WRF
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 17, 2014
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain lateral boundaries
Emissions		
Baseline Emissions Processing	SMOKE, SMOKE-MOVES2014, MEGAN	WRAP/WAQS 2014v2 emissions and EPA 2023fh for future year
Sub-grid-scale Plumes	Plume-in-Grid for major NO_X sources in New Mexico	Point sources with NOx emission s greater than 5 tons per day
Chemistry		
Gas Phase Chemistry	CB6r4	Latest chemical reactions and kinetic rates with halogen chemistry (Yarwood et al., 2010)
Meteorological Processor	WRFCAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh grid size dependence
Vertical Diffusion	CMAQ-like Kv	Evaluated YSU Kv scheme
Diffusivity Lower Limit	Kv-min = 0.1 to 1.0 m^2/s in lowest 100 m	Depends on urban land use fraction
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	rain/snow/graupel
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative(EBI)	EBI fast and accurate solver
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update	Emery et al., (2009a,b; 2011)
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	Colella and Woodward (1984)
Integration Time Step	Wind speed dependent	~0.5-1 min (4-km), 1-5 min (12-km), 5-15 min (36-km)

7. 2014 BASE CASE MODELING AND MODEL PERFORMANCE EVALUATION

This Chapter describes the CAMx 2014 base case simulations and model performance evaluation (MPE). The primary purposes of the MPE is to establish the reliability of the CAMx 2014 base case modeling for predicting maximum daily average 8-hour (MDA8) ozone and related concentrations in New Mexico to have confidence that the modeled ozone responses to changes in emissions are accurate enough for air quality planning in New Mexico. The CAMx 2014 base case model estimates are compared against the observed ambient ozone and other concentrations to establish that the model is able to reproduce the current year observed concentrations, so it is likely a reliable tool for estimating future year ozone levels. The model performance evaluation includes many types of graphical and statistical comparisons of the predicted and observed ozone concentrations, including spatial plots, scatter plots and time series analysis.

7.1 2014 Base Case Modeling

A CAMx 2014 May-August 36/12/4-km base case simulation was performed following the procedures outlined in the previous Chapters.

7.2 EPA Model Performance Evaluation Recommendations

7.2.1 Overview of EPA Model Performance Evaluation Recommendations

EPA's ozone modeling guidance (EPA, 2018d) describes a MPE framework that has four components:

- Operation Evaluation: The Operation Evaluation compares the modeled concentration estimates against concurrent observations using statistical and graphical analysis aimed at determining how well the model simulates the base year observed concentrations (i.e., does the model get the right answer).
- Diagnostic Evaluation: The Diagnostic Evaluation evaluates various components of the modeling system. It focuses on process-oriented evaluation and whether the model simulates the important processes for the air quality problem being studied (i.e., does the model get the right answer for the right reason).
- Dynamic Evaluation: The ability of the model's air quality predictions to correctly respond to changes in emissions and meteorology is part of the Dynamic Evaluation. This can include running the model for historical years to see whether the model's predictions match the changes in observations; comparison of model performance on weekdays versus weekend days can also help elucidate whether the model response to changes in emissions correctly.
- Probabilistic Evaluation: The Probabilistic Evaluation assess the level of confidence in the model predictions and estimates model uncertainty through techniques such as ensemble model simulations.

EPA's guidance recommends that "At a minimum, a model used for air quality planning should include a complete operational MPE using all available ambient monitoring data for the base case model simulations period" (EPA, 2018d, pg. 68). And goes on to say,

"Where practical, the MPE should also include some level of diagnostic evaluation." EPA notes that there is no single definite test for evaluating model performance, but instead there are a series of statistical and graphical MPE elements to examine model performance in as many ways as possible while building a "weight of evidence" (WOE) that the model is performing sufficiently well for the air quality problem being studied.

For the NM OAI Study we conducted an operational MPE for MDA8 ozone focusing on ozone model performance within the state of New Mexico. We also conducted some elements of a diagnostic evaluation as described in Chapter 5.

7.3 Overview of Evaluation of CAMx 2014 Base Case Procedures

This section provides an overview of the approach, procedures and tools used the procedures for evaluating the performance of the CAMx model focusing on ozone in New Mexico.

7.3.1 Photochemical Model Evaluation Methodology

The CAMx model performance evaluations will follow the procedures recommended in the EPA's latest photochemical modeling guidance (EPA, 2018d), some elements of EPA MPE Checklist (EPA, 2015a,b), and procedures discussed by Boylan and Russell (2006), Simon, Baker and Phillips (2012) and Emery and co-workers (2016).

7.3.2 Model Performance Goals and Benchmarks

EPA first proposed the use of ozone model performance goals in their 1991 ozone modeling guidance (EPA, 1991) with goals for bias (≤±15%) and error (≤35%). Since then, EPA has de-emphasized the use model performance goals as some users were focusing on achieving the model performance goals not on whether the model was accurately simulating atmospheric processes that led to the high ozone concentrations. However, model performance goals are still useful for helping interpret model performance and putting the model performance into context. Since the EPA 1991 ozone guidance performance goals, Boylan and Russell (2006) extended the performance goals to PM species and visibility. Simon, Baker and Phillips (2012) summarized the model performance statistics from 69 PGM applications from 2006 to 2012 and found lots of variability but were able to isolate model performance statistical levels for the best performing models.

Emery et al., (2016) built off the work of Simon, Baker and Phillips (2012) adding additional PGM model applications and coming up with a set of PGM model performance goals and criteria based on the variability in the past PGM model performance. "Goals" indicate statistical values that about a third of the top performance past PGM applications have met and should be viewed as the best a model can be expected to achieve. "Criteria" indicates statistics values that about two thirds of past PGM applications have met and should be viewed as what a majority of the models have achieved. In this Chapter we compare the CAMx 2014 base case simulations model performance statistics for normalized mean bias (NMB), normalized mean error (NME) and correlation coefficient (r) against the model performance goals and criteria summarized by Emery et al., (2016) that are given in Table 7-1.

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Table 7-1. Recommended benchmarks for photochemical model statistics (Source: Emery et al., 2016).

Species	NMB		NME		r	
	Goal	Criteria	Goal	Criteria	Goal	Criteria
1-hr & MDA8 Ozone	<±5%	<±15%	<15%	<25%	>0.75	>0.50
24-hr $PM_{2.5}$, SO_4, NH_4	<±10%	<±30%	<35%	<50%	>0.70	>0.40
24-hr NO_3	<±15%	<±65%	<65%	<115%	NA	NA
24-hr OC	<±15%	<±50%	<45%	<65%	NA	NA
24-hr EC	<±20%	<±40%	<55%	<75%	NA	NA

7.3.3 Available Aerometric Data for the Evaluations

There are two main ozone monitoring networks operating in New Mexico in 2014:

EPA AQS Surface Air Quality Data: Data files containing hourly-averaged concentration measurements at a wide variety of state and EPA monitoring networks are available in the Air Quality System (AQS[40]) database throughout the U.S. Typical surface measurements at the ground level routine AIRS monitoring stations include ozone, NO_2, NO_X and CO.

CASTNet Monitoring Network: The Clean Air Status and Trends Network (CASTNet[41]) operates approximately 80 monitoring sites in mainly rural areas across the U.S. CASTNet sites typically collect hourly ozone and weekly speciated $PM_{2.5}$, including HNO3. There is one CASTNet site located in the northwest corner of New Mexico (Chaco Culture NHP), although there are three more CASTNet sites in the 4-km New Mexico modeling domain: Mesa Verde in Colorado, Petrified Forest in Arizona and Palo Duro in Texas.

7.3.4 Atmospheric Model Evaluation Tool (AMET)

The Atmospheric Model Evaluation Tool (AMET[42]) (Appel et al., 2011) is a suite of software designed to facilitate the analysis and evaluation of predictions from meteorological and air quality models. AMET matches the model output for grid cells with observations from monitoring site locations from one or more networks of monitors. AMET also does species mappings to map the modeled species to the corresponding observations. These pairings of values (model and observation) are then used to statistically and graphically analyze the model's performance using a variety of techniques, many of which were used in the CAMx 2014 base case MPE. The latest version of AMET is version 1.4, but AMET website doesn't have any information on its release date or documentation so we assume the documentation for AMET v1.3[43] is pertinent for AMET v1.4.

[40] https://www.epa.gov/aqs

[41] https://www.epa.gov/castnet

[42] https://www.cmascenter.org/amet/

[43] https://www.cmascenter.org/help/documentation.cfm

7.4 Ozone Evaluation Across the 4-km New Mexico Domain

Figure 7-1 shows the scatter plots of predicted and observed MDA8 ozone concentrations across AQS and CASTNet sites. The AQS sites (Figure 7-1, left) represent mainly the urban locations and whereas CASTNET (Figure 7-1, right) represent monitoring sites that are more rural. Most of the observation-model pair dots in the scatter plots appear to lie along the 1:1 line with very few outliers. The center of the AQS MDA8 ozone scatter plot lies slightly above the 1:1 line of perfect agreement indicating a slight overestimation bias. These scatter plots also displays the Normalized Mean Bias (NMB) and Error (NME) metrics. The average NMB for all MDA8 ozone concentrations and across all AQS sites shows an average overestimation bias of 6.2%, which is slightly higher than the bias performance goal (≤±5%) but within the bias performance criteria (≤±15%). The NME for MDA8 ozone across all AQS sites in the 4-km domain is 10.9%, which is well within the error performance goal (≤15%).

The average MDA8 ozone NMB at all CASTNet sites is 0.1% which is very low and quite good ozone performance well within the bias performance goal. The MDA8 ozone NME across the CASTNet sites is also very good at 7.9%.

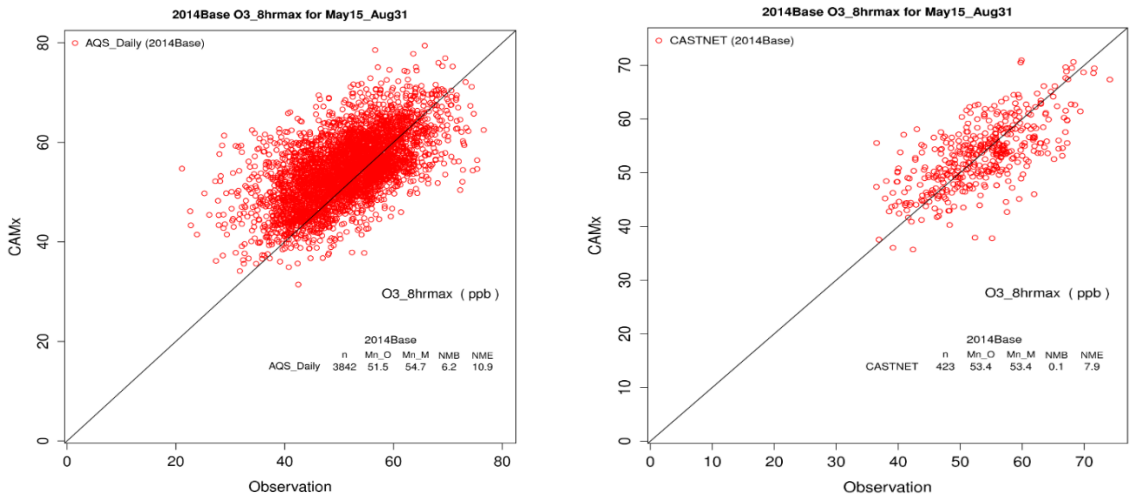


Figure 7-1. Scatter plot of predicted and observed MDA8 ozone across the AQS and CASTNET monitoring sites within the 4-km New Mexico domain during the modeling period (May 15-Aug 31, 2014) for the CAMx 2014 base case simulations.

Figure 7-2 displays the spatial distribution of the AQS and CASTNet site-specific NMB for the modeling period and for all MDA8 ozone (left) and MDA8 ozone when the observed ozone is above a 60 ppb cut-off (here after referred as MDA8_above60). Throughout the domain, the model NMB for all MDA8 ozone achieved the ozone bias performance goal (≤±5%) at majority of the sites (i.e., symbols colored grey). At few sites, the model showed an overprediction (yellow color) in predicting all MDA8 ozone concentrations. With one exception for a site colored orange in El Paso, the sites with the overestimation bias are colored bright yellow that indicates bias in the +5% to +15% range so achieve the ozone bias performance criteria.

For MDA8_above60 (Figure 7-2, right panel) for most sites in the 4-km domain the NMB symbols are colored grey indicting that they achieve the ozone bias performance goal. Several sites are colored bright green that indicates an underestimation bias that are unable to achieve bias performance goal (≤±5%) but is within the ozone bias performance criteria (≤±15%) so the bias is between -5% and -15%.

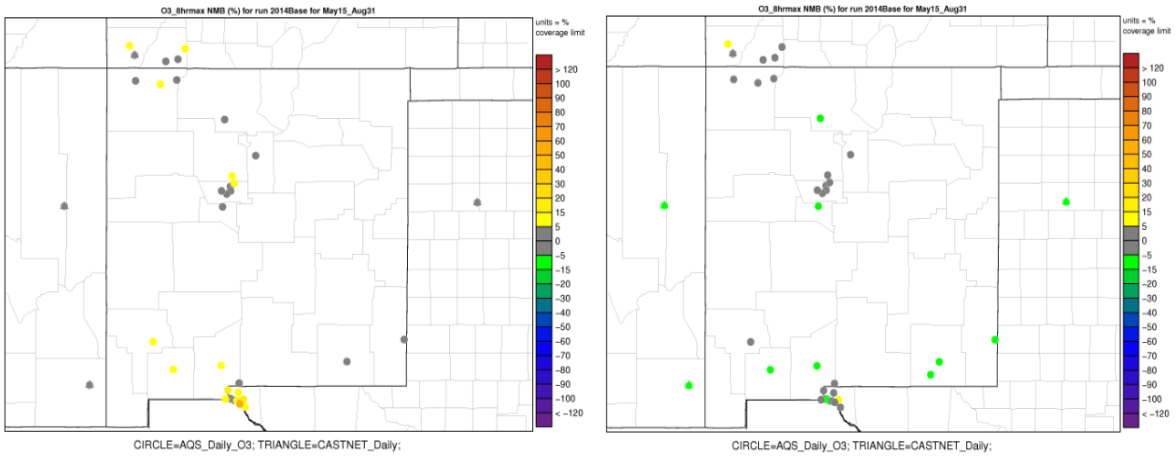


Figure 7-2. Spatial distribution of CAMx 2014 base case simulation period (May15-Aug 31) site-specific Normalized Mean Bias within the 4-km domain for MDA8 O3 (left) and MDA8 O3 above 60ppb cut-off (right).

7.5 Ozone Evaluation Across New Mexico

In this section we evaluated the modeled MDA8 ozone and MDA8_above60 ozone in the state of New Mexico at all AQS monitoring sites using scatter, soccer and spatial overlay plots. Figure 7-3 presents scatter plots of MDA8 and MDA8_above60 ozone modeled and observation paired concentrations, it indicate that the modeled values are close to the observations as majority of them lie along and in the vicinity of 1:1 line. The domain wide all AQS sites MPE statistics of MDA8 and MDA8_above60 ozone NMB (5.0%, -4.3%) and NME (9.8%, 8.0%) metrics are within the ozone performance goals (i.e., NMB<±5% and NME<15%).

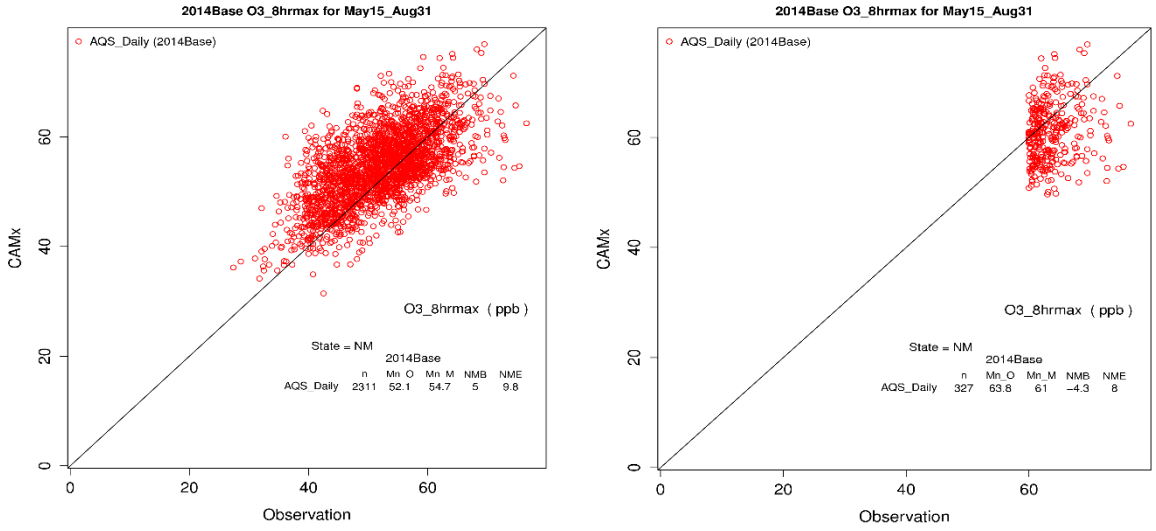


Figure 7-3. Scatter plots of predicted and observed MDA8 ozone (left) and MDA8 ozone when observed value is above 60 ppb cut-off (right) across the AQS monitoring sites in New Mexico during modeling period (May15-Aug 31) for the CAMx 2014 base case simulations.

Figure 7-4 displays the monthly soccer plot for sites in New Mexico and for MDA8 (left) and MDA8_above60 (right) ozone concentrations with the inner rectangle being the performance goal (NMB<±5% and NME<15%) and the outer rectangle being the performance criteria (NMB<±15% and NME<25%). Considering all MDA8 ozone data with no cut-off (i.e., Figure 7-4 left panel), the model is overestimating in the months of July and August achieving the performance criteria but not the performance goals. The months of May and June achieve the performance goals.

Considering the ozone data with 60 ppb cut-off (i.e., Figure 7-4 right panel), the model achieves the ozone performance goals in June, July and August months with an underestimation bias. In May, the underestimation bias for MDA8_above60 is lower than -5% so fails to achieve the bias performance goal, but does achieve the performance criteria. Overall, the soccer plots indicate that the model captures the observed MDA8 and MDA8-above60ppb ozone concentrations well during each month of the summer of 2014

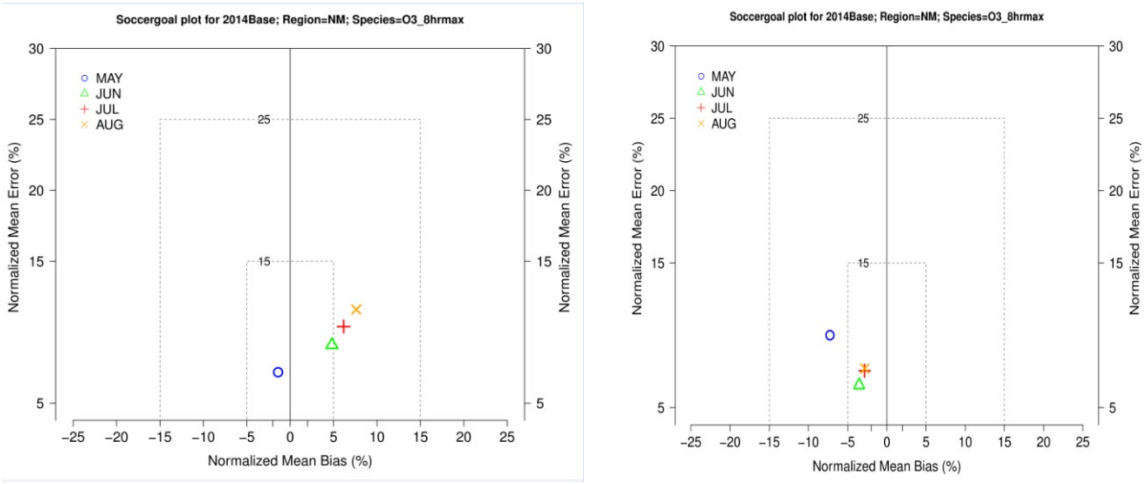


Figure 7-4. Soccer plots of MDA8 ozone (left) and MDA8 ozone when observed value is above a 60 ppb cut-off (right) with monthly average NMB and NME values across sites in New Mexico. The dashed lines represents the performance goals and criteria.

As shown in site-specific spatial NMB plot for New Mexico sites in Figure 7-5, the overestimation of MDA8 ozone (considering all values) that fails to achieve the bias performance goal occurs mainly at southern sites along with three other northerly sites (Bloomfield, North Valley and Foothills). The underestimation of MDA8_above60 that fails to achieve the bias performance goal occurs primarily at southern sites along with two more northerly sites (Coyote Ranger and Los Lunas).

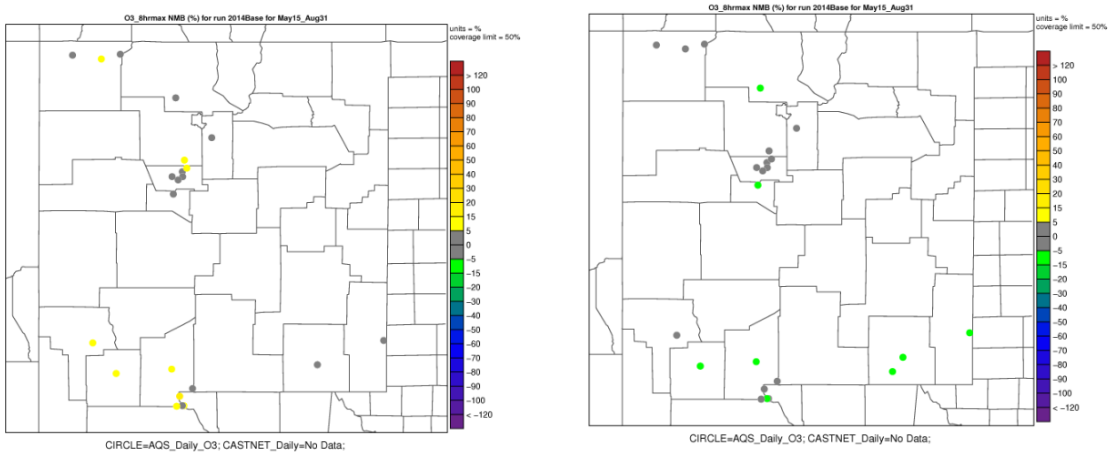


Figure 7-5. Spatial distribution of site-specific Normalized Mean Bias for sites in New Mexico and the CAMx 2014 May-August base case simulation for all MDA8 ozone data (left) and MDA8 ozone with observed value above a 60 ppb cut-off (right).

7.6 Ozone Evaluation in New Mexico Subregions

As shown in the New Mexico ozone performance above, and discussed in the conceptual model in Chapter 1, there are three distinct large regions of ozone formation conditions in New Mexico, each with their own subregional variations: northern New Mexico that shares ozone attributes of other sites in other states in the Four Corners region, Bernalillo County that has many of the attributes of the northern New Mexico sites only also including the presence of a major city; and sites in southern New Mexico. The ozone MPE is conducted separately for each of these major subregions in New Mexico. Table 7-2 shows the AQS sites available in the New Mexico with ozone data during 2014 that are categorized into northern New Mexico (blue), Bernalillo County (yellow) and south New Mexico (orange) subregions. The NMB and NME values shown in Table 7-3 are averaged across all sites in these regions and color coded based on the performance benchmarks for both MDA8 ozone and MDA8above60: green if achieve the performance goal; yellow if falling between the performance goal and criteria; and red if fails to achieve the performance criteria. Both northern and Bernalillo County regions achieve the ozone bias and error performance goal for both MDA8 ozone concentrations without and with an observed MDA8 ozone 60 ppb cut-off threshold. The southern region has NMB that fall between the ozone bias performance goal and criteria due to either a too high overestimation bias (all MDA8 data) or too low underestimation bias (MDA8_above60ppb). Although the bias just barely falls outside of the performance goal.

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Table 7-2. AQS monitoring sites categorized into subregions of southern New Mexico (orange), Bernalillo County (yellow) and southern New Mexico (blue).

Site ID	Site Name	County	Latitude	Longitude
350130022	Santa Teresa	Dona Ana	31.79	-106.68
350130017	Sunland Park Yard	Dona Ana	31.80	-106.56
350130021	Desert View	Dona Ana	31.80	-106.58
350130008	La Union	Dona Ana	31.93	-106.63
350130020	Chaparral	Dona Ana	32.04	-106.41
350290003	Deming Airport	Luna	32.26	-107.72
350130023	Solano	Dona Ana	32.32	-106.77
350151005	Carlsbad	Eddy	32.38	-104.26
350171003	Chino Copper Smelter	Grant	32.69	-108.13
350250008	Hobbs Jefferson	Lea	32.73	-103.12
350610008	Los Lunas	Valencia	34.81	-106.74
350010029	South Valley	Bernalillo	35.02	-106.66
350010024	South East Heights	Bernalillo	35.06	-106.58
350010032	Westside	Bernalillo	35.06	-106.76
350010023	Del Norte	Bernalillo	35.13	-106.59
350011012	Foot Hills	Bernalillo	35.19	-106.51
350431001	Bernalillo	Sandoval	35.30	-106.55
350490021	Santa Fe Airport	Santa Fe	35.62	-106.08
350390026	Coyote Ranger District	Rio Arriba	36.19	-106.70
350450009	Bloomfield	San Juan	36.74	-107.98
350451005	Sub Station	San Juan	36.80	-108.47
350450018	Navajo Lake	San Juan	36.81	-107.65

Table 7-3. Region specific NMB and NME values for MDA8 Ozone and MDA8 Ozone when Observed Value is above 60 ppb.

	MDA8 O3		MDA8 _above60	
Region	NMB (%)	NME (%)	NMB (%)	NME (%)
North NM	4.3	9.1	0	6.4
Bernalillo	4.3	9.4	-2.8	7.1
South NM	5.8	10.5	-6.1	8.5

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7.7 Ozone Evaluation at Individual New Mexico Monitoring Sites

Table 7-4 contain individual AQS site MDA8 ozone model performance statistics for the CAMx 2014 base case simulation from May 15 to Aug 31, 2014. Among the 22 sites in the state, 13 sites (59%) achieve the bias performance goal (green color, NMB ≤±5%) and 8 sites (36%) exceeded the bias performance goal but achieve the bias performance criteria (orange color, NMB ≤±15%) leaving only one site (La Union in Dona Ana County) whose NMB fails to achieve the bias performance goal. With the exception of the Carlsbad monitor whose MDA8 ozone has a slight underestimation bias (NMB of -1.1%), all sites have a positive NMB when compared to all ozone observations indicating an overestimation bias, with just La Union having an NMB so large (17.4%) that it fails to achieve the ozone bias performance criteria. Also shown in Table 7-4 is the Fractional Bias (FB) whose results are similar to the NMB with just the La Union having a FB (16.4%) that fails to achieve the bias performance criteria.

In terms of NME, all sites achieve the error performance criteria and all sites except for two sites (La Union and Foot Hills) achieve the error performance goal (NME ≤15%). The results for the Fractional Error (FE) are similar to NME. Overall based on the average NMB and NME values at each site the model appeared to perform well during the modeling period.

Although not color-coded, the correlation (r) performance criteria (> 0.50) for MDA8 ozone is achieved at all monitoring sites. However, the correlation performance goal (>0.75) is only achieved at one site.

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Table 7-4. CAMx 2014 base case model performance statistics for MDA8 Ozone concentrations by monitoring site for summer (May15-Aug) modeling period.

Site ID	Site Name	N	Avg Obs	Avg Mod	MB	ME	NMB	NME	FB	FE	r
350010023	Del Norte	107	54.0	54.9	0.9	4.4	1.7	8.2	1.8	8.3	0.657
350010024	SE Heights	107	53.8	55.4	1.6	4.5	3.1	8.3	3.1	8.3	0.662
350010029	S Valley	108	53.8	55.4	1.6	4.2	3.1	7.7	3.1	7.7	0.69
350010032	Westside	109	54.2	54.8	0.6	4.3	1.1	7.9	1.1	7.9	0.632
350011012	Foot Hills	107	50.4	57.2	6.9	7.6	13.6	15.1	13.0	14.3	0.571
350130008	La Union	108	47.4	55.6	8.2	8.8	17.4	18.6	16.4	17.4	0.72
350130017	Sunland Park	109	50.3	54.8	4.5	6.1	9.0	12.1	9.1	11.8	0.702
350130020	Chaparral	100	52.3	54.8	2.5	4.9	4.8	9.4	5.0	9.2	0.73
350130021	Desert View	108	54.0	55.7	1.7	4.8	3.2	8.9	3.5	8.7	0.717
350130022	Santa Teresa	83	50.5	54.6	4.2	5.3	8.2	10.5	8.1	10.2	0.769
350130023	Solano	108	51.0	54.0	3.1	4.8	6.1	9.4	6.0	9.1	0.727
350151005	Carlsbad	97	53.7	53.1	-0.6	4.9	-1.1	9.0	-0.2	9.0	0.702
350171003	Chino Smelter	105	47.2	51.5	4.3	5.6	9.1	12.0	9.0	11.7	0.693
350250008	Hobbs Jefferson	105	52.9	54.1	1.1	5.1	2.1	9.6	3.0	9.7	0.586
350290003	Deming Airport	108	49.2	52.2	3.0	4.4	6.2	9.0	6.2	8.9	0.745
350390026	Coyote Ranger	105	52.4	54.2	1.7	5.1	3.3	9.8	3.5	9.8	0.55
350431001	Bernalillo	93	52.6	56.9	4.3	5.5	8.1	10.5	7.9	10.2	0.63
350450009	Bloomfield	109	51.6	55.4	3.7	5.3	7.2	10.3	6.9	10.0	0.62
350450018	Navajo Lake	80	54.1	55.3	1.2	3.8	2.2	7.0	2.0	6.9	0.681
350451005	Sub Station	104	54.1	54.8	0.7	4.2	1.4	7.9	1.0	7.9	0.705
350490021	Santa Fe Airport	107	52.8	54.8	2.0	4.6	3.8	8.7	3.8	8.6	0.591
350610008	Los Lunas	107	53.8	54.3	0.4	4.0	0.8	7.5	0.9	7.5	0.633

Similar to Table 7-4, Table 7-5 contain the individual AQS site performance statistics for MDA8 ozone with predicted and observed pairs when the observed value is above a 60 ppb cut-off threshold. Out of the 22 sites, 16 sites (73%) achieve the bias performance goal and the remainder 6 sites (27%) fall between the bias performance goal and criteria. Overall, all the sites showed a consistent slight under-prediction indicating that the model was unable to predict all of the observed ozone peak concentrations. The NME for all sites achieved the ozone error performance goal. The results for FB and FE are consistent with NMB and NME. Almost all of the correlation coefficients fail to achieve the performance criteria for MDA8_above60ppb, although the

sample size for the site-specific MDA8_above60ppb statistics is very small for some sites so the statistics are less meaningful.

Table 7-5. 2014 Base Case model performance statistics of MDA8 Ozone with an observed ozone 60 ppb cut-off by monitoring site for summer (May 15-Aug) modeling period.

Site ID	Site names	N	Avg Obs	Avg Mod	MB	ME	NMB	NME	FB	FE	r
350010023	Del Norte	26	62.2	59.8	-2.4	4.8	-3.9	7.7	-4.2	7.9	-0.167
350010024	SE Heights	20	62.8	61.3	-1.5	4.4	-2.4	7.0	-2.7	7.1	0.31
350010029	South Valley	18	63.0	61.3	-1.8	4.1	-2.8	6.6	-3.1	6.7	0.333
350010032	Westside	21	62.5	60.4	-2.1	4.5	-3.4	7.2	-3.8	7.4	0.045
350011012	Foot Hills	6	62.0	63.2	1.2	4.0	2.0	6.5	1.8	6.4	-0.23
350130008	La Union	7	65.2	64.2	-1.0	4.4	-1.6	6.8	-1.7	6.9	0.128
350130017	Sunland Park	15	64.9	62.6	-2.3	4.9	-3.6	7.6	-3.8	7.8	-0.041
350130020	Chaparral	18	65.4	62.3	-3.0	5.1	-4.7	7.8	-5.1	8	0.565
350130021	Desert View	25	66.2	62.8	-3.4	5.7	-5.1	8.7	-5.4	8.9	0.221
350130022	Santa Teresa	9	64.9	65.0	0.1	4.1	0.1	6.3	0	6.1	0.39
350130023	Solano	11	63.9	59.8	-4.1	4.1	-6.5	6.5	-6.7	6.7	0.807
350151005	Carlsbad	22	65.8	57.7	-8.1	8.1	-12.3	12.3	-13.0	13	0.283
350171003	Chino Smelter	9	63.3	62.7	-0.6	2.2	-1.0	3.4	-1.0	3.4	0.595
350250008	Hobbs Jefferson	20	64.2	57.8	-6.3	7.1	-9.9	11.0	-10.4	11.5	-0.251
350290003	Deming Airport	4	62.2	59.1	-3.1	5.2	-5.0	8.3	-5.4	8.6	0.118
350390026	Coyote Ranger	13	64.3	60.8	-3.5	3.9	-5.4	6.1	-5.7	6.4	0.432
350431001	Bernalillo	11	61.4	63.8	2.4	4.3	3.8	7.0	3.5	6.8	0.117
350450009	Bloomfield	10	62.7	64.3	1.6	3.1	2.5	5.0	2.3	5	0.624
350450018	Navajo Lake	10	62.9	62.5	-0.4	3.8	-0.6	6.1	-0.9	6.1	0.177
350451005	Sub Station	11	62.6	64.6	2.1	4.8	3.3	7.6	2.8	7.4	0.457
350490021	Santa Fe Airport	12	62.9	61.8	-1.1	4.2	-1.7	6.7	-2.1	7	0.373
350610008	Los Lunas	17	62.9	58.8	-4.1	4.7	-6.5	7.5	-6.9	7.9	0.167

Time series of predicted and observed MDA8 ozone concentrations at five representative sites (Bloomfield, Coyote Ranger, South Valley, Desert View and Carlsbad) are shown in Figure 7-6 to Figure 7-10. Time series sites for all sites are contained in Appendix A. Each time series plot consists of two panels: an upper panel that shows the predicted (blue) and observed (red) daily MDA8 ozone concentrations

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from May 15 to August 31, 2014; and a bottom panel that shows the difference (i.e., daily bias) in the daily predicted and observed MDA8 ozone concentrations. At the Bloomfield monitor in San Juan County in northern New Mexico, the predicted and observed MDA8 ozone concentrations match each other remarkably well in May and June and into the first part of July. However, by mid-July the model estimates a series of three mini ozone episodes at the end of July, beginning of August and mid-August that are not reflected in the observations.

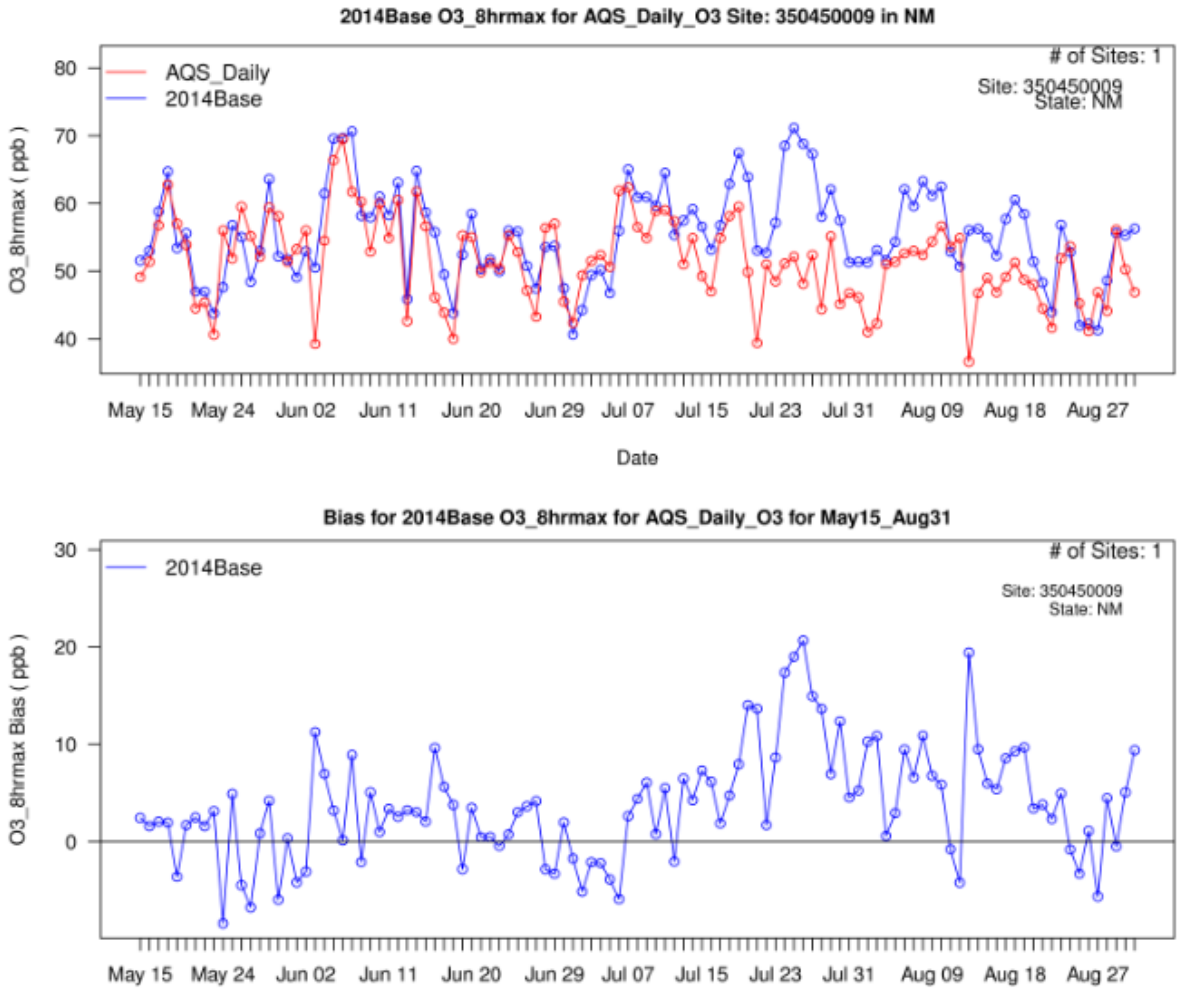


Figure 7-6. Time series of predicted and observed MDA8 ozone concentrations (ppb; top)and daily bias (ppb; bottom) at Bloomfield monitoring site (Site ID: 350450009).

The MDA8 ozone times series Coyote Ranger District site in Rio Arriba County shown in Figure 7-7 shares many of the same characteristics seen at Bloomfield. Extremely good daily MDA8 ozone performance is seen in May and June and the beginning of July. A third of the way into July, however, the model starts to exhibit an ozone overestimation bias with ozone peaks that are 10-20 ppb greater than observed, although better daily ozone performance is seen at Coyote Ranger District the end of August.

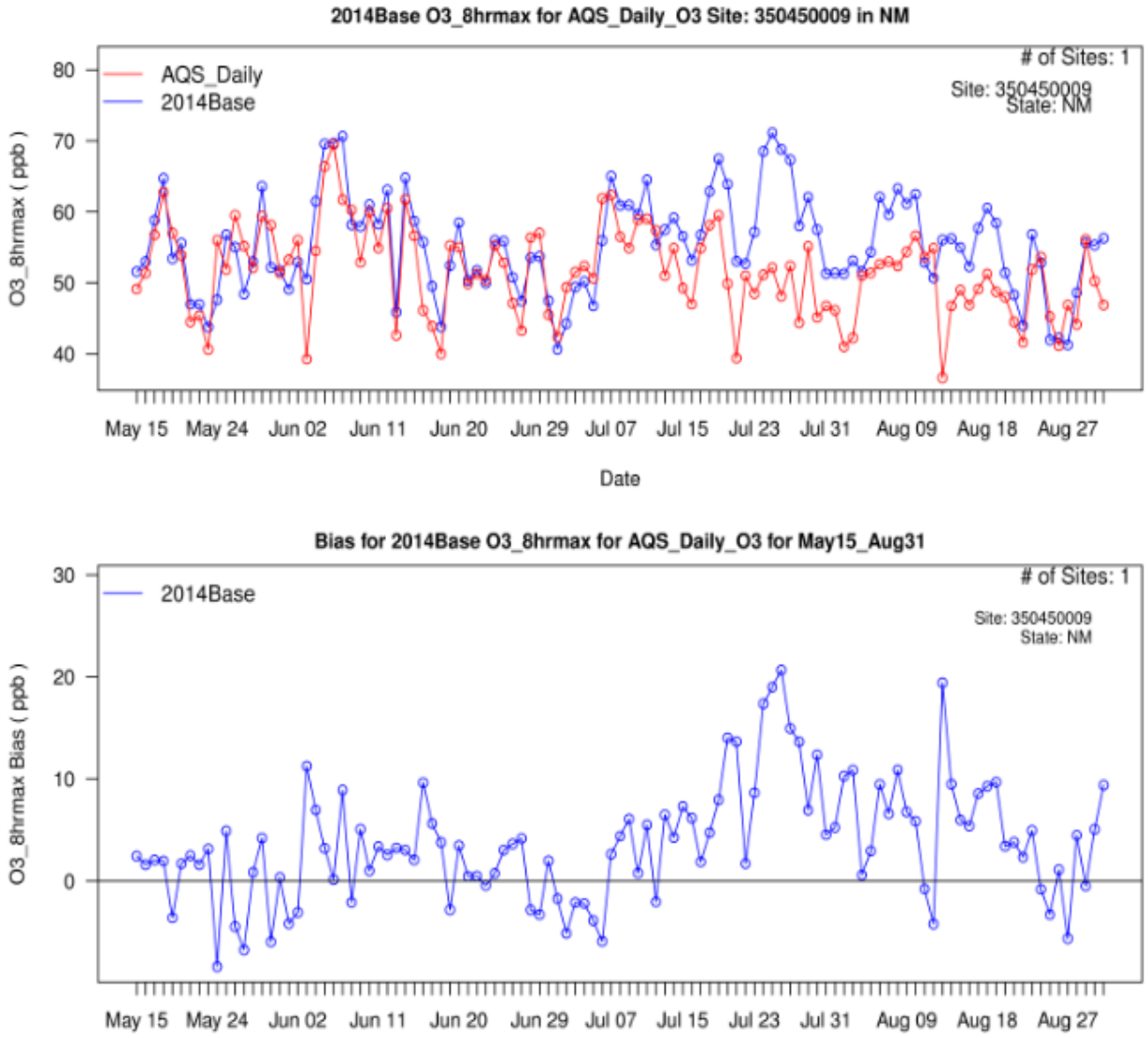


Figure 7-7. Time series of predicted and observed MDA8 ozone concentrations (ppb; top) and daily bias (ppb; bottom) at Coyote Ranger monitoring site (Site ID: 350390026).

The ozone time series at the South Valley site in Bernalillo County is fairly good throughout the May to August episode (Figure 7-8). The daily bias is almost always within ±10% and usually lower than that. The July-August systematic ozone estimation seen at the two northern New Mexico sites is not present, although there is a hint of that phenomena in mid-August.

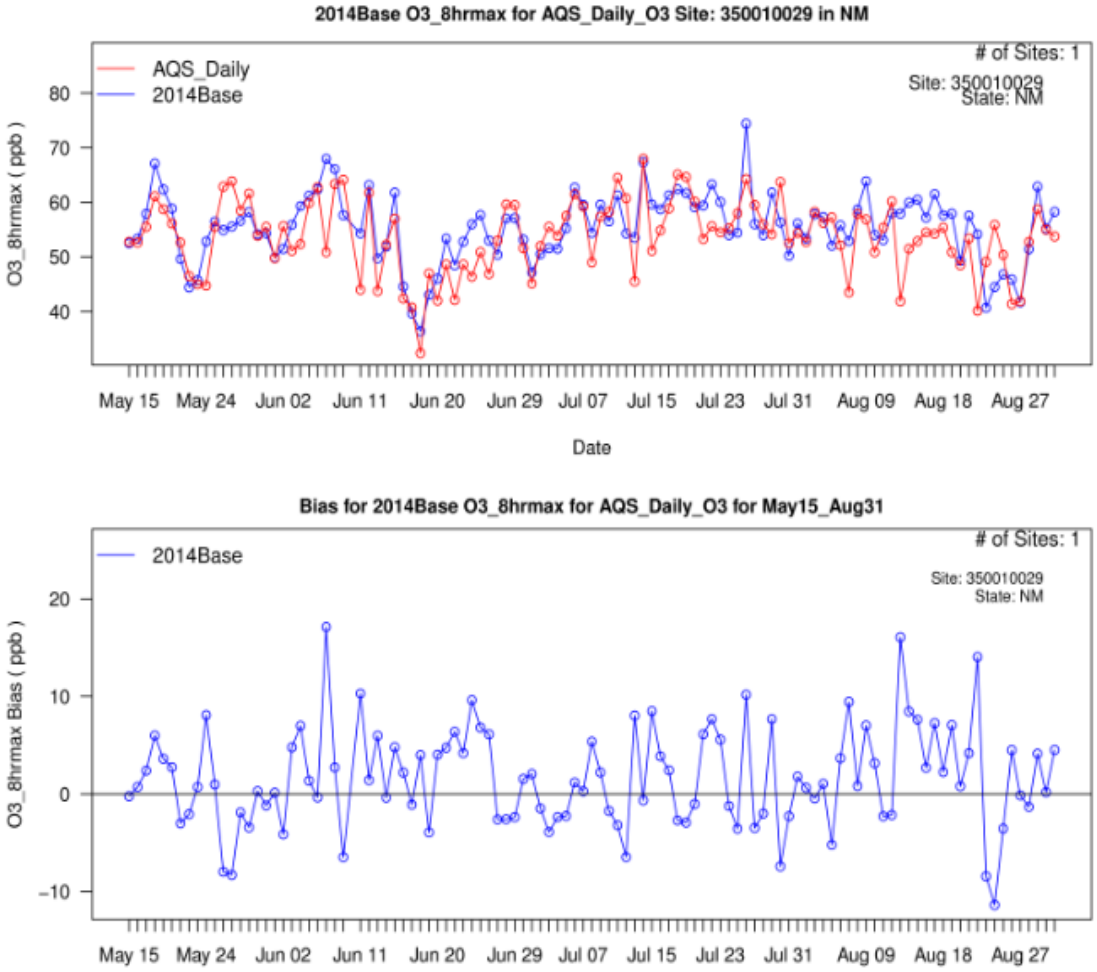


Figure 7-8. Time series of predicted and observed MDA8 ozone concentrations (ppb; top) and daily bias (ppb; bottom) at South Valley monitoring site (Site ID: 350010029).

The observed high MDA8 ozone concentrations at the Desert View monitoring site in Dona Ana County occur as ozone spikes that are a day or two in duration (Figure 7-9). In general, the model follows the observed daily variation on the observed MDA8 ozone concentrations well except for not capturing the observed ozone spikes during May, June and the first part of July. However, for the second half of July and in August the model does a good job in reproducing the observed ozone spikes at Desert View.

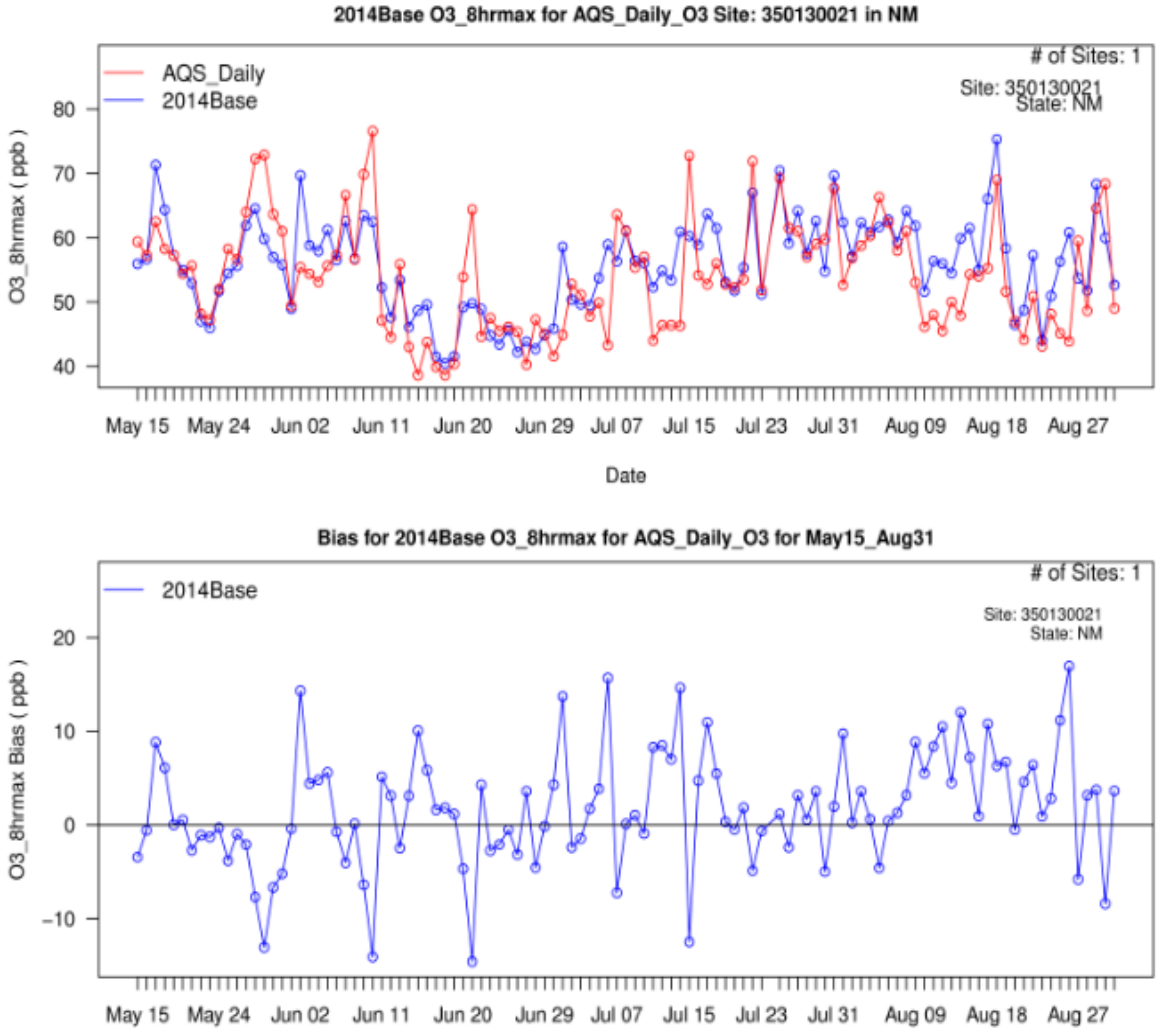


Figure 7-9. Time series of predicted and observed MDA8 ozone concentrations (ppb; top) and daily bias (ppb; bottom) at Desert View monitoring site (Site ID: 350130021).

The observed MDA8 ozone episode during May 29 to June 1 at the Carlsbad site in Eddy County in southeast New Mexico is completely missed by the model (Figure 7-10). Better performance is seen the remainder of the modeling period, although the model misses high ozone periods the end of July and early August. There is also a lot of missing observed data in August, which is unfortunate given the potential presence of high observed ozone during this period based on the data at Desert View.

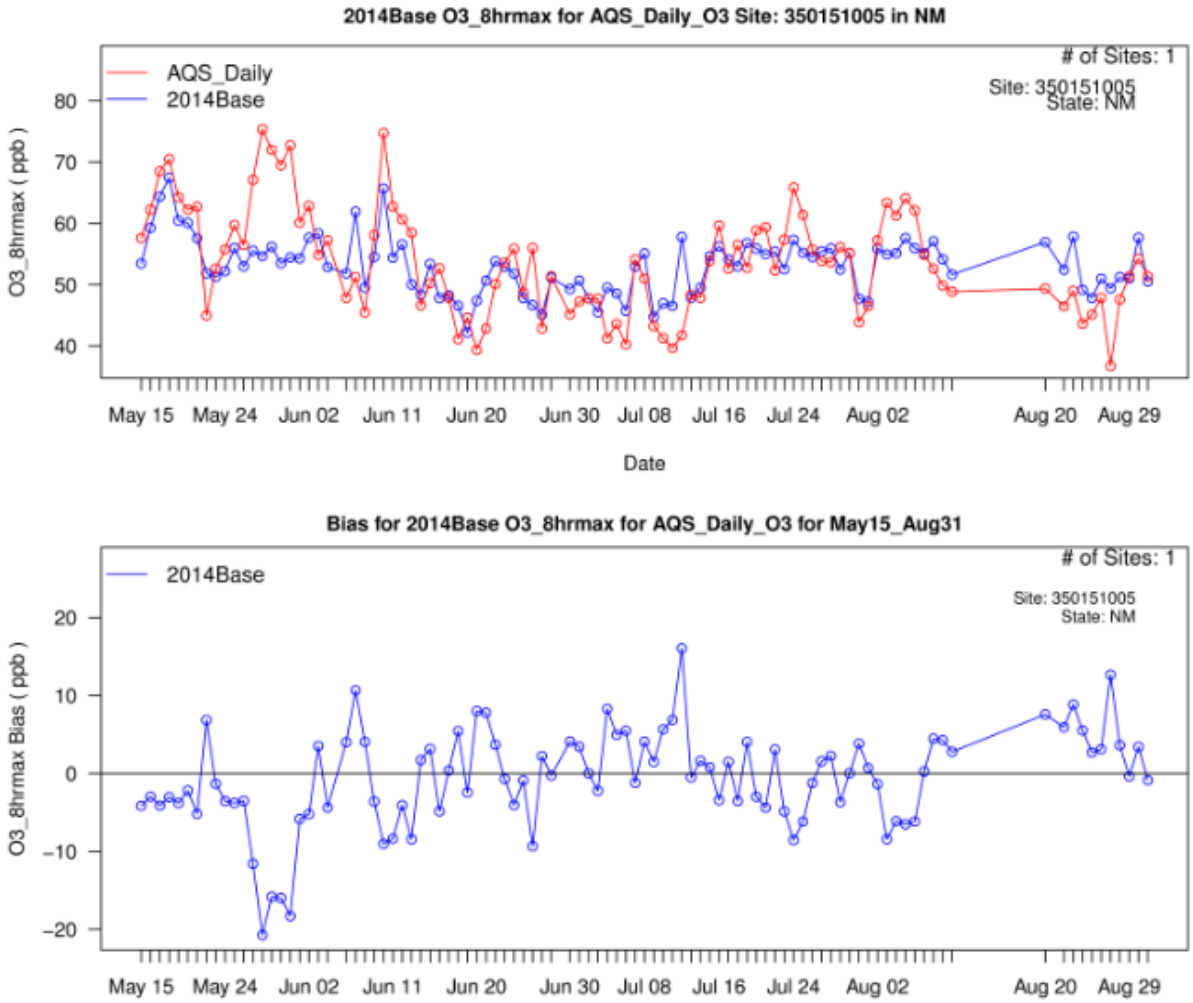


Figure 7-10. Time series of predicted and observed MDA8 ozone concentrations (ppb; top) and daily bias (ppb; bottom) at Carlsbad monitoring site (Site ID: 350151005).

7.8 Ozone Performance Related to Future Year Ozone Projections

EPA's ozone modeling guidance (EPA, 2018d) recommends making future year ozone design value projections using the relative changes in the future year to base year modeled MDA8 ozone concentrations for the 10 highest base year modeled MDA8 ozone concentrations. Thus, the model performance of the CAMx 2014 base case simulation for the 10 highest modeled ozone concentrations is of particular importance. In this

section we examine this issue for three sites: Bloomfield in San Juan County; Desert View in Dona Ana County; and Carlsbad in Eddy County.

7.8.1 Bloomfield Top 10 Ozone Performance

Table 7-2 displays the CAMx 2014 base case 36 highest modeled MDA8 ozone days at Bloomfield with concurrent observed MDA8 ozone, and the bias presented as concentration and percent. The observed top 20 highest MDA8 ozone concentrations are colored yellow, with the darker yellow indicating an observed top 10 MDA8 ozone concentration day. The 10 highest modeled MDA8 ozone concentrations at Bloomfield are also top 20 observed MDA8 ozone days for 6 of the 10 days; the top 10 observed MDA8 ozone concentration days occurring on 5 of the top 10 modeled ozone days. So, there is a good overlap of the top 10 modeled and top 20 observed highest MDA8 ozone days at Bloomfield.

The red shading on the bias percent in Table 7-2 indicates days in the top 10 modeled ozone days whose daily bias exceeds ±10%. An alternative future year ozone design value projection approach to the EPA-recommended modeled top 10 MDA8 ozone days is to use the top 10 modeled ozone days that meet a model performance requirement, such as within ±10% of the observed value. With a 10% MPE criteria projection approach, the additional days used to replace those whose bias exceeds ±10% (i.e., shaded red) are colored blue in Table 7-2. Under the 10% MPE criteria projection approach, the 10 modeled days used in the projection all overlap with the top 20 observed ozone days and 7 of the days are a top 10 observed MDA8 ozone day.

This analysis indicates that the model performance on the modeled top 10 days used for making ozone projections at Bloomfield is quite reasonable and has good overlap with the observed highest ozone days.

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Table 7-6. Predicted and observed MDA8 ozone concentrations (ppb) at Bloomfield for CAMx 2014 base case for modeled ranked 36 highest MDA8 ozone concentrations.

Bloomfield	Obs	Prd	Bias	%
7/25/2014	52.1	71.1	19.0	36.4%
6/7/2014	61.7	70.6	8.9	14.4%
6/6/2014	69.5	69.7	0.2	0.2%
6/5/2014	66.4	69.6	3.2	4.8%
7/26/2014	48.1	68.8	20.7	42.9%
7/24/2014	51.1	68.5	17.4	34.0%
7/19/2014	59.5	67.5	8.0	13.4%
7/27/2014	52.4	67.3	14.9	28.5%
7/7/2014	62.4	65.0	2.6	4.2%
6/14/2014	61.8	64.8	3.0	4.9%
5/18/2014	62.8	64.7	2.0	3.1%
7/11/2014	59.0	64.5	5.5	9.3%
7/20/2014	49.9	63.9	14.0	28.1%
5/29/2014	59.4	63.6	4.2	7.1%
8/8/2014	52.4	63.3	10.9	20.8%
6/12/2014	60.5	63.1	2.6	4.3%
7/18/2014	58.1	62.9	4.7	8.2%
8/10/2014	56.6	62.5	5.9	10.4%
8/6/2014	52.6	62.1	9.5	18.0%
7/29/2014	55.1	62.1	6.9	12.6%
6/4/2014	54.5	61.5	7.0	12.8%
8/9/2014	54.4	61.2	6.8	12.5%
6/10/2014	60.0	61.0	1.0	1.7%
7/9/2014	54.9	60.9	6.1	11.1%
7/8/2014	56.5	60.9	4.4	7.8%
8/18/2014	51.3	60.5	9.3	18.1%

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7.8.2 Desert View Top 10 Ozone Performance

The evaluation of the CAMx 2014 base case for the top 10 modeled MDA8 ozone concentrations at Desert View is shown in Table 7-3. 7 of the top 10 modeled MDA8 ozone concentrations are also top 20 observed ozone days, with 5 of those days also being in the top 10 observed ozone days. Thus, there is good overlap between the highest modeled and observed ozone days at Desert View. 5 of the top 10 modeled ozone days have daily bias that does not meet a within ±10% performance criteria. Imposing a within ±10% performance criteria for selecting the top 10 modeled ozone days results in all 10 days overlapping with observed days in the top 20 of the observed distribution with 7 of those days being top 10 observed ozone days.

Table 7-7. Predicted and observed MDA8 ozone concentrations (ppb) at Desert View for CAMx 2014 base case for modeled ranked 36 highest MDA8 ozone concentrations.

Desert View	Obs	Prd	Bias	%
8/18/2014	69.0	75.3	6.3	9.1%
5/17/2014	62.5	71.3	8.8	14.1%
7/25/2014	69.3	70.4	1.2	1.7%
6/2/2014	55.4	69.7	14.3	25.8%
7/31/2014	67.7	69.7	2.0	2.9%
8/29/2014	64.6	68.3	3.7	5.8%
7/22/2014	71.9	67.0	-4.9	-6.8%
8/17/2014	55.3	66.0	10.8	19.5%
5/28/2014	72.3	64.5	-7.7	-10.7%
5/18/2014	58.3	64.3	6.1	10.4%
8/8/2014	61.0	64.2	3.2	5.2%
7/27/2014	61.0	64.1	3.1	5.2%
7/17/2014	52.8	63.7	10.9	20.7%
6/9/2014	69.9	63.5	-6.4	-9.2%
8/6/2014	62.4	62.8	0.4	0.7%
7/29/2014	59.0	62.6	3.6	6.1%
6/7/2014	66.6	62.6	-4.0	-6.1%
6/10/2014	76.6	62.5	-14.1	-18.4%
8/1/2014	52.6	62.4	9.7	18.5%
8/3/2014	58.8	62.3	3.6	6.1%
5/27/2014	64.0	61.9	-2.1	-3.3%
8/9/2014	53.0	61.8	8.8	16.7%
8/5/2014	66.3	61.7	-4.6	-6.9%
8/15/2014	54.3	61.5	7.2	13.2%
7/18/2014	56.0	61.5	5.5	9.8%
6/5/2014	55.6	61.2	5.6	10.0%

7.8.3 Carlsbad Top 10 Ozone Performance

6 of the top 10 modeled ozone days at Carlsbad occur during observed top 20 ozone days, 4 of those days within the top 10 of the observed ozone distribution (Table 7-4). Five of the modeled top 10 ozone days have bias that does not achieve the within ±10% criteria. When imposing the within ±10% performance criteria for the top 10 modeled ozone days, 7 of those days overlap with observed top 20 days.

Table 7-8. Predicted and observed MDA8 ozone concentrations (ppb) at Carlsbad for CAMx 2014 base case for modeled ranked 36 highest MDA8 ozone concentrations.

Carlsbad	Obs	Prd	Bias	%
5/18/2014	70.5	67.5	-3.0	-4.3%
6/10/2014	74.8	65.7	-9.0	-12.1%
5/17/2014	68.5	64.4	-4.1	-6.0%
6/7/2014	51.3	61.9	10.7	20.8%
5/19/2014	64.3	60.5	-3.8	-5.9%
5/20/2014	62.3	60.1	-2.2	-3.5%
5/16/2014	62.3	59.3	-3.0	-4.8%
6/3/2014	54.9	58.4	3.5	6.5%
8/23/2014	49.0	57.9	8.9	18.1%
7/12/2014	41.8	57.8	16.1	38.5%
6/2/2014	62.9	57.7	-5.2	-8.3%
8/30/2014	54.3	57.7	3.4	6.3%
8/5/2014	64.1	57.6	-6.5	-10.1%
5/21/2014	62.8	57.6	-5.2	-8.2%
7/24/2014	65.9	57.3	-8.5	-13.0%
8/8/2014	52.6	57.1	4.5	8.5%
8/20/2014	49.4	57.0	7.6	15.4%
7/19/2014	52.8	56.8	4.1	7.7%
6/12/2014	60.7	56.6	-4.1	-6.7%
7/16/2014	59.7	56.3	-3.4	-5.7%
5/29/2014	72.0	56.2	-15.8	-22.0%
5/25/2014	59.8	56.0	-3.8	-6.3%
8/6/2014	62.1	56.0	-6.2	-9.9%
7/28/2014	53.7	55.9	2.3	4.2%
8/2/2014	57.3	55.9	-1.3	-2.4%
7/20/2014	58.9	55.9	-3.0	-5.1%

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8. SUMMARY AND CONCLUSIONS

The evaluation of the NM OAI Study CAMx 2014 base case simulation focused on Maximum Daily 8-hour Average (MDA8) ozone model performance across all sites in the 4-km New Mexico domain, across all sites within New Mexico, within three subregions in New Mexico (northern, Bernalillo County, and southern) and at individual sites in New Mexico. When examining MDA8 ozone performance across groups of sites, the CAMx 2014 base case always achieves the ozone performance criteria and usually achieves the ozone performance goals. When examining MDA8 ozone performance across all observations, the model tended to have an ozone overestimation tendency but still always achieved the bias performance criteria (≤±15%) and usually achieved the bias performance goal (≤±5%). When comparing the model's ability to reproduce the highest observed ozone concentrations greater than 60 ppb, the model still always achieved the bias performance criteria and usually achieved the bias performance goal, albeit with an underestimation tendency. The MDA8 ozone error essentially always achieves the performance goal whether examining all ozone observations or just those observations greater than 60 ppb. More specifically:

- Across the 4-km New Mexico domain for all ozone observations, the Normalized Mean Bias (NMB) for the AQS network was 6.2% that achieves the bias performance criteria but not the bias performance goal. However, across the more rural CASTNet network the NMB (0.1%) is near zero achieving the performance goal.
- With New Mexico, the NMB achieves the performance goal whether using all ozone data (5.0%) or just ozone data when the observed ozone is greater than 60 ppb (-4.3%).
- Similar performance attributes are seen in the New Mexico subregional evaluation whether using all data or the 60 ppb ozone cut-off with the NMB in the northern New Mexico (4.3% and 0.0%) and Bernalillo County (4.3% and -2.8%) subregions achieving the bias performance goal. However, the NMB in the southern New Mexico region (5.8% and -6.1%) just barely falls outside of the performance goal region, but achieves the performance criteria.
- At individual monitoring sites using all ozone data the NMB achieves the bias performance criteria at all sites but one (La Union) with a majority of the sites (13 of 22 or 59%) also achieving the bias performance goal.
- The time series of predicted and observed MDA8 ozone concentrations shows that the model has very good agreement and tracks the day-to-day variations of the observed ozone in the northern New Mexico and Bernalillo County sites for the first half of the May-August 2014 modeling period. The second half of the modeling period the model generally has an ozone overestimation tendency at the northern New Mexico sites.
- Time series at the southern New Mexico show that the model has difficulty in reproducing the observed daily ozone spikes in the first half of the modeling period, but does a better job in reproducing the daily observed high ozone concentrations in the second half of the episode.

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An evaluation of the model performance for the top 10 modeled ozone days that are used for making future year ozone projections revels that they are also high observed ozone days over half of the time.

In conclusion, the NM OAI Study CAMx 2014 base case ozone model performance within New Mexico is as good or better than most recent PGM applications (e.g., WRAP-WAQS, EPA 2016v1 and Denver ozone SIP) and appears to be a reliable PGM modeling platform for evaluating emission reduction strategies for reducing ozone concentrations in New Mexico.

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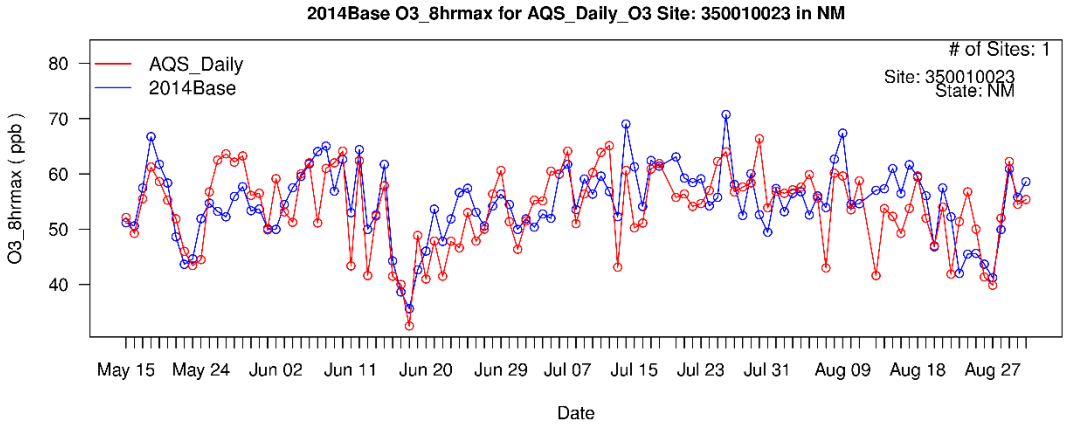
Zhang, L., S. Gong, J. Padro, L. Barrie. 2001. A size-segregated particle dry deposition scheme for an atmospheric aerosol module. *Atmos. Environ.*, **35**, 549-560.

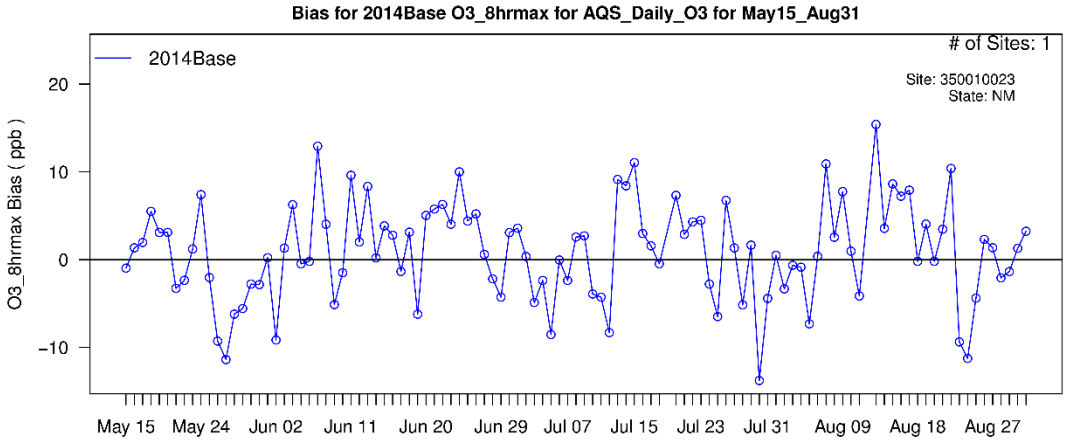
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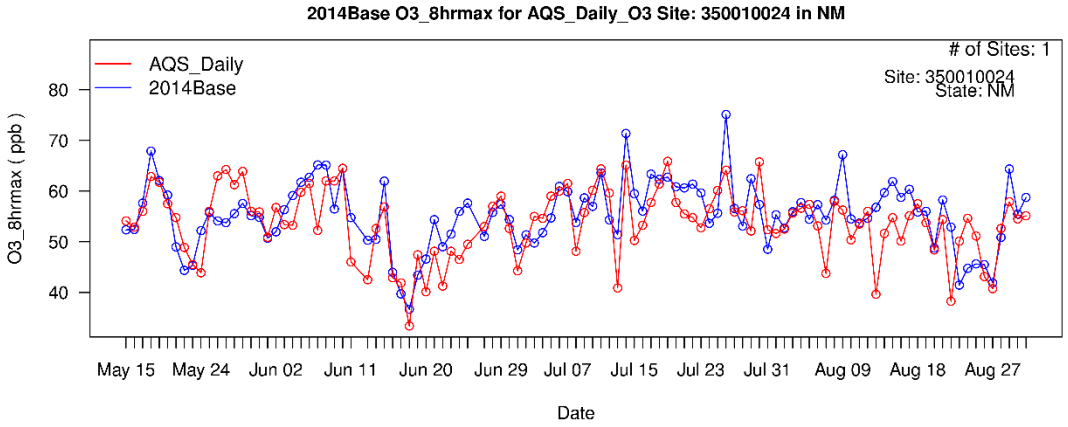
Appendix A

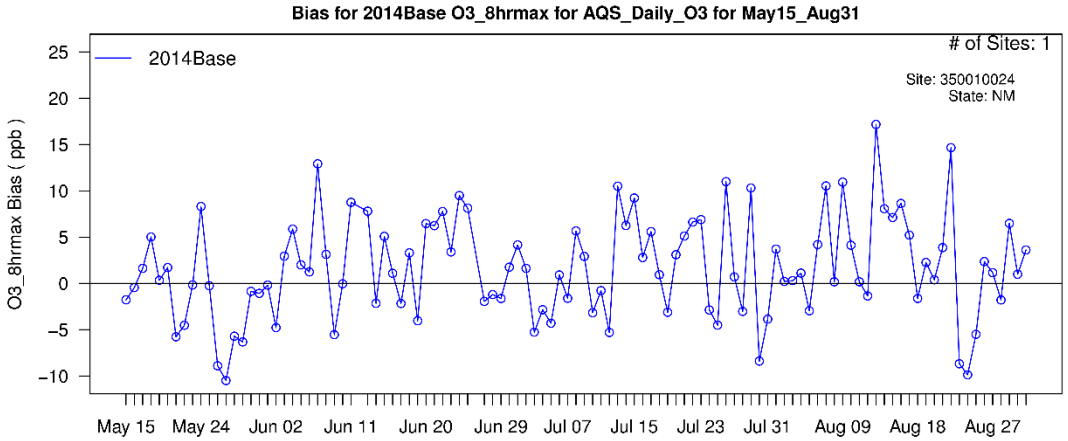
Time Series of Predicted and Observed MDA8 Ozone Concentrations at Sites in New Mexico

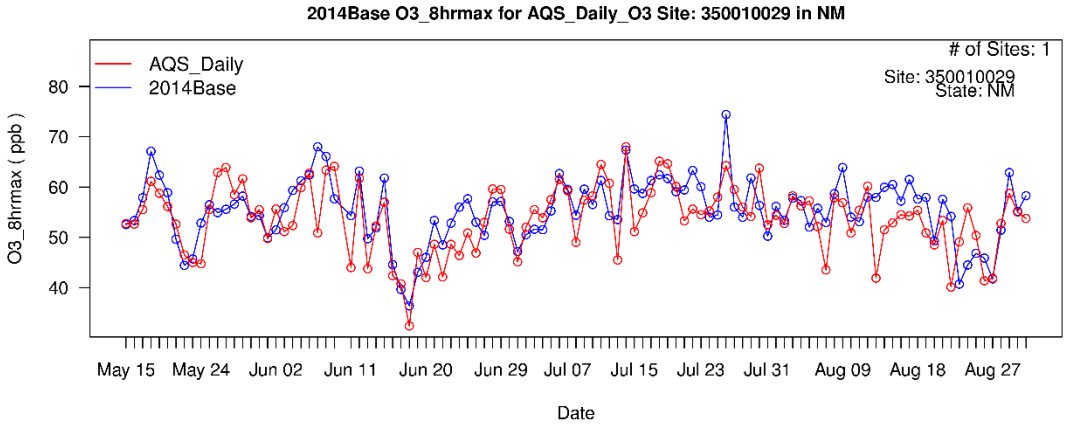
NMED Exhibit 16

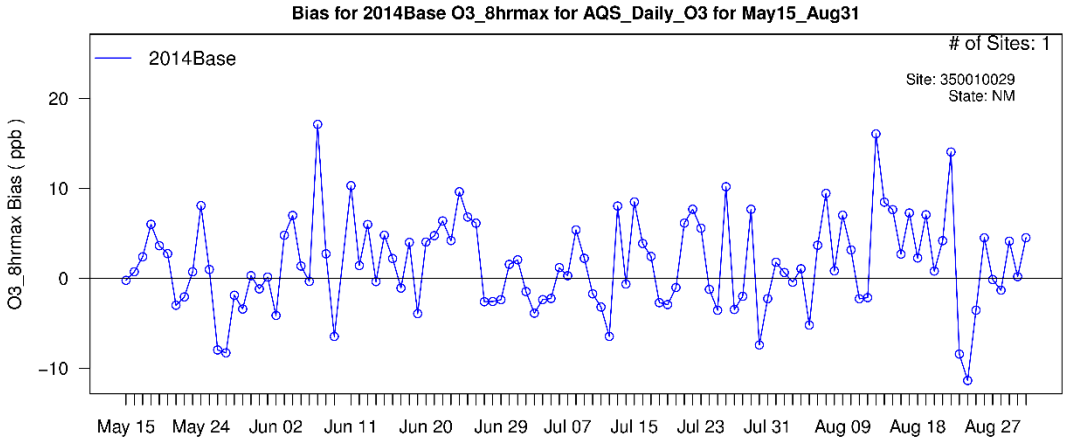

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AQS_Daily
2014Base
# of Sites: 1
Site: 350010023
State: NM
O3_8hrmax (ppb)
80
70
60
50
40
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Jun 02
Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27
Date

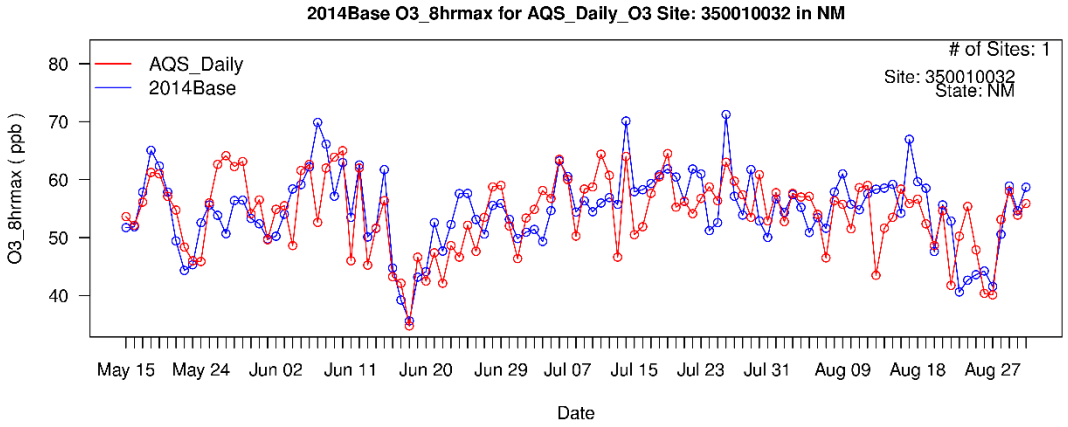

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
2014Base
# of Sites: 1
Site: 350010023
State: NM
O3_8hrmax Bias (ppb)
20
10
0
−10
May 15
May 24
Jun 02
Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27

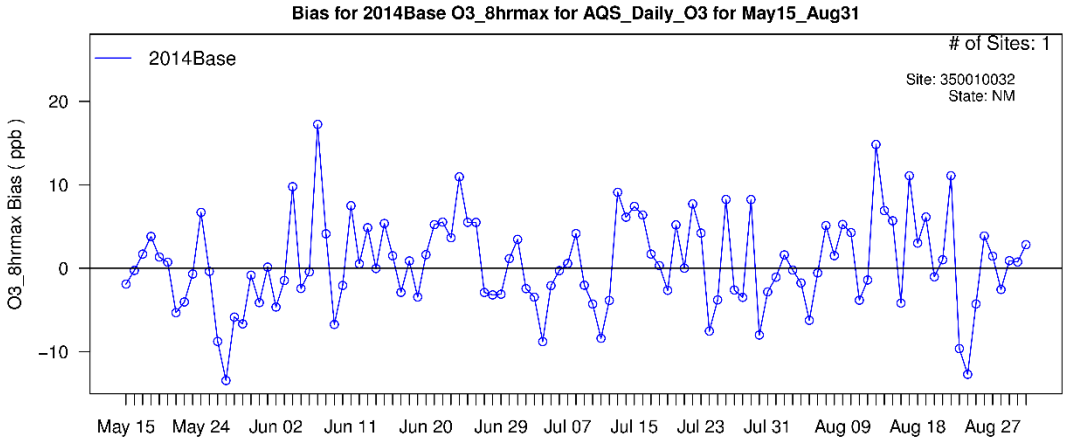

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AQS_Daily
2014Base
# of Sites: 1
Site: 350010024
State: NM
O3_8hrmax (ppb)
80
70
60
50
40
May 15
May 24
Jun 02
Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27
Date

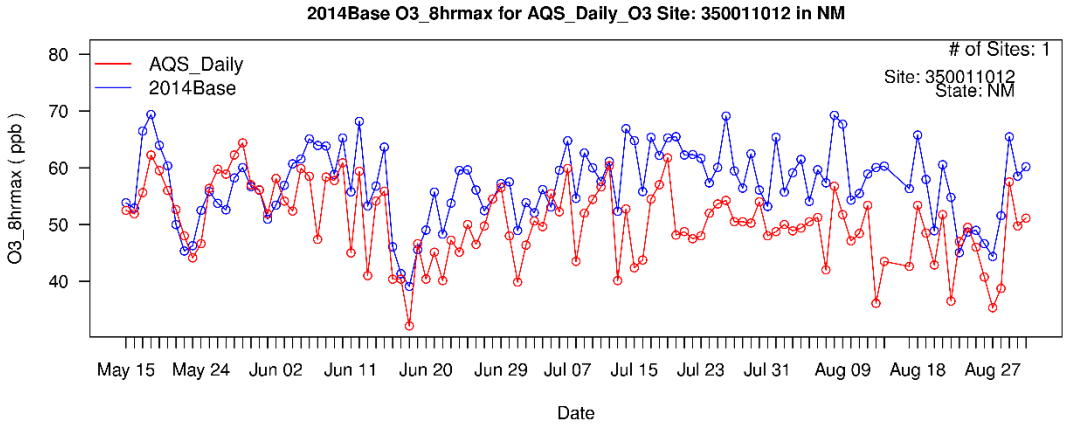

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
2014Base
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Site: 350010024
State: NM
O3_8hrmax Bias (ppb)
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20
15
10
5
0
−5
−10
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May 24
Jun 02
Jun 11
Jun 20
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Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27

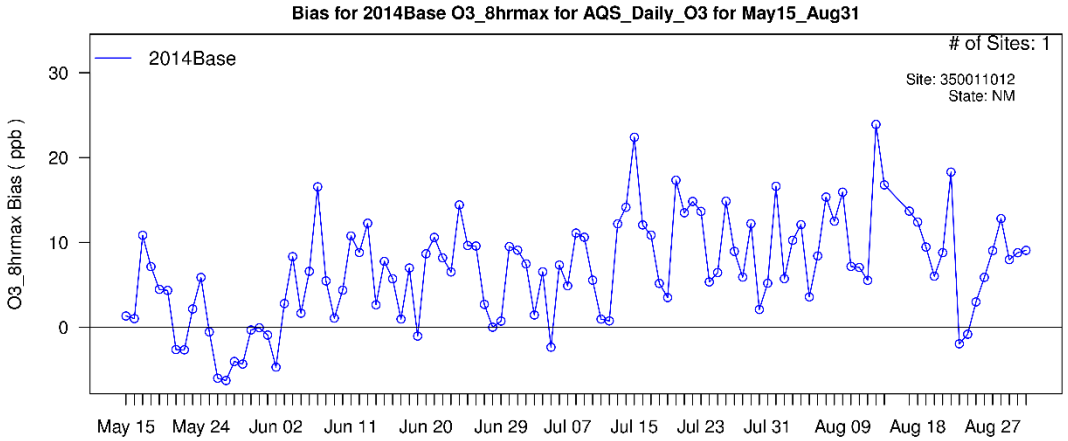

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AQS_Daily
2014Base
# of Sites: 1
Site: 350010029
State: NM
O3_8hrmax (ppb)
80
70
60
50
40
May 15
May 24
Jun 02
Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27
Date

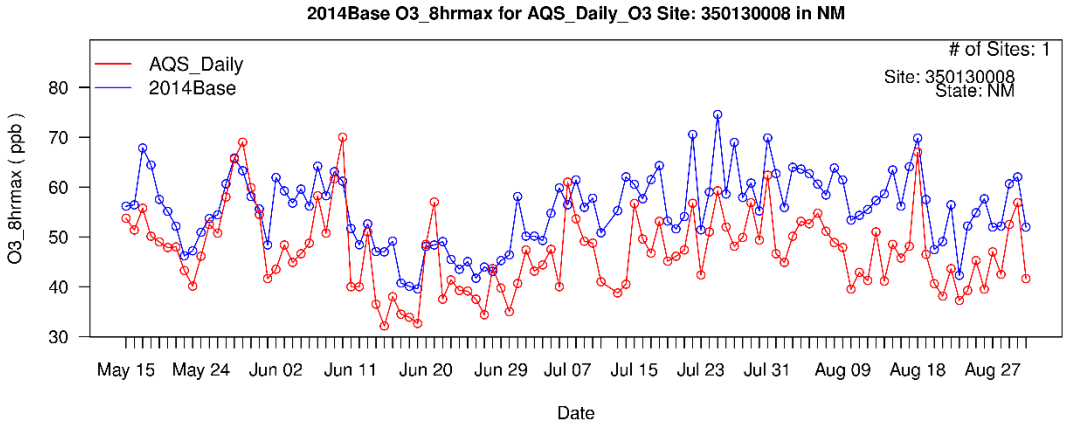

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
2014Base
# of Sites: 1
Site: 350010029
State: NM
O3_8hrmax Bias (ppb)
20
10
0
−10
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May 24
Jun 02
Jun 11
Jun 20
Jun 29
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Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27

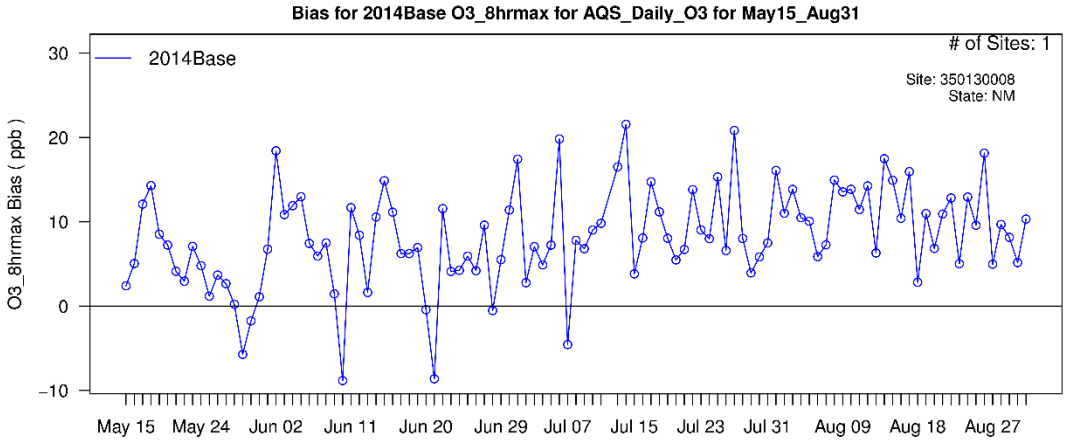

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AQS_Daily
2014Base
# of Sites: 1
Site: 350010032
State: NM
O3_8hrmax (ppb)
80
70
60
50
40
May 15
May 24
Jun 02
Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27
Date

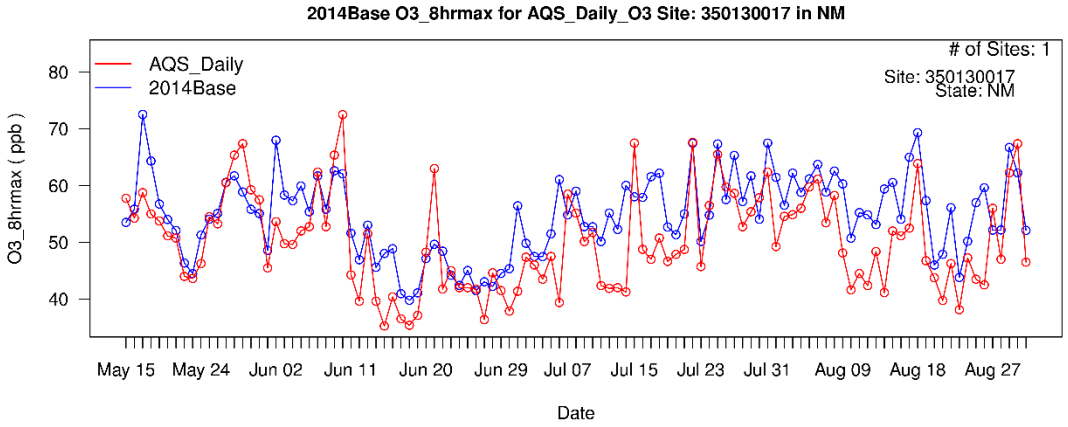

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
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# of Sites: 1
Site: 350010032
State: NM
O3_8hrmax Bias (ppb)
20
10
0
−10
May 15
May 24
Jun 02
Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27

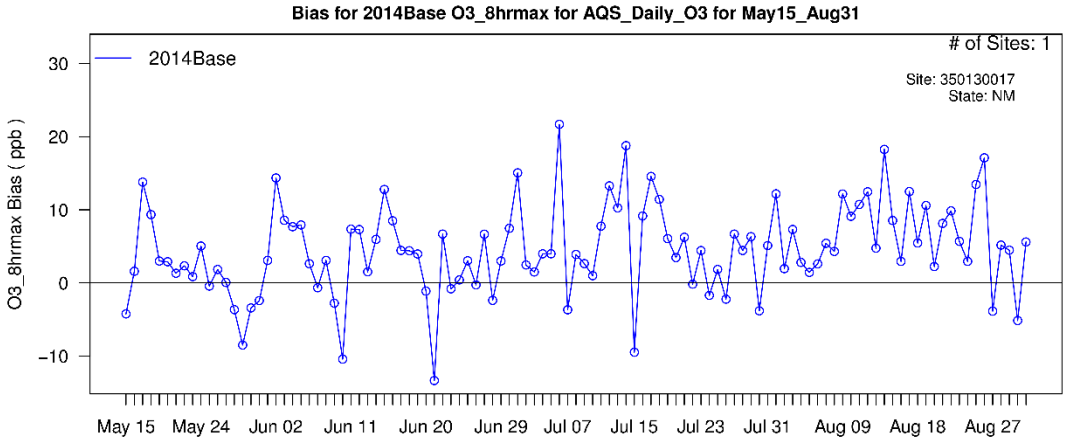

2014Base O3_8hrmax for AQS_Daily_O3 Site: 350011012 in NM
AQS_Daily
2014Base
# of Sites: 1
Site: 350011012
State: NM
O3_8hrmax (ppb)
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70
60
50
40
May 15
May 24
Jun 02
Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
Jul 31
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Aug 18
Aug 27
Date

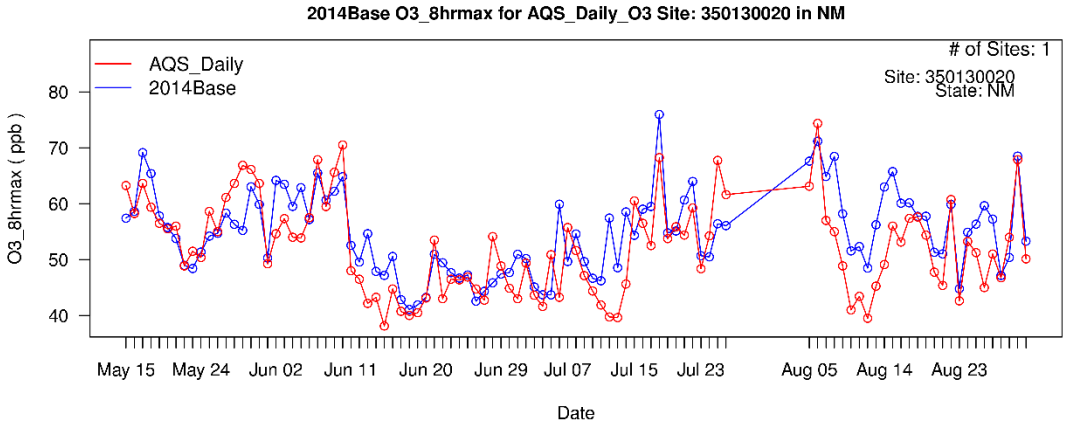

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# of Sites: 1
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State: NM
O3_8hrmax Bias (ppb)
30
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10
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May 24
Jun 02
Jun 11
Jun 20
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Jul 15
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Jul 31
Aug 09
Aug 18
Aug 27

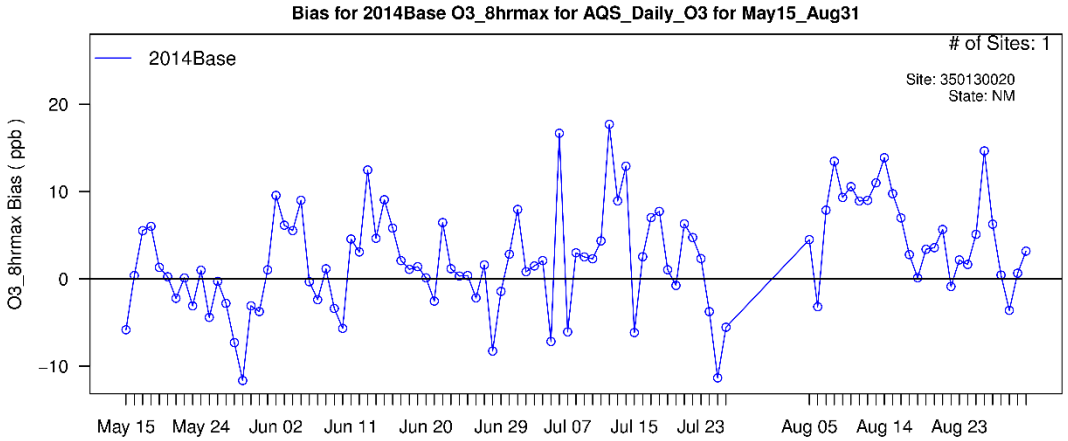

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AQS_Daily
2014Base
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Site: 350130008
State: NM
O3_8hrmax (ppb)
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70
60
50
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Jul 31
Aug 09
Aug 18
Aug 27
Date

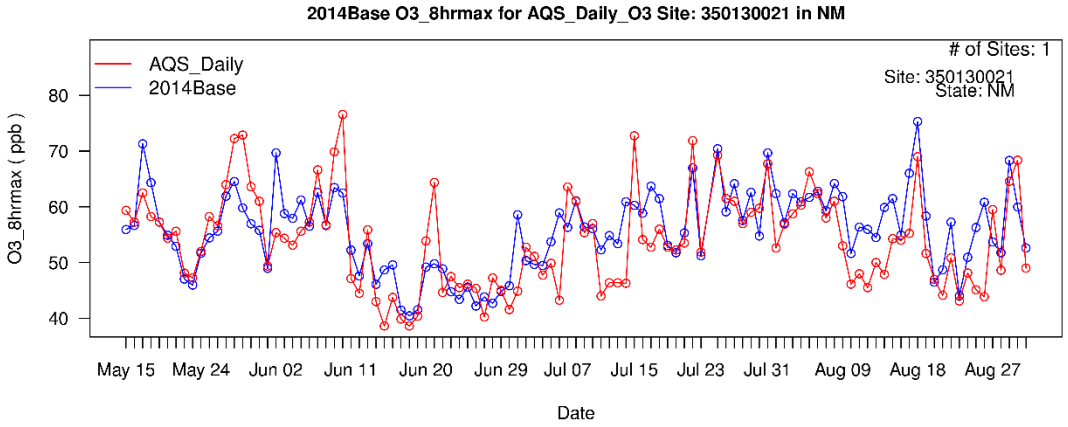

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
2014Base
# of Sites: 1
Site: 350130008
State: NM
O3_8hrmax Bias (ppb)
30
20
10
0
−10
May 15
May 24
Jun 02
Jun 11
Jun 20
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Jul 15
Jul 23
Jul 31
Aug 09
Aug 18
Aug 27

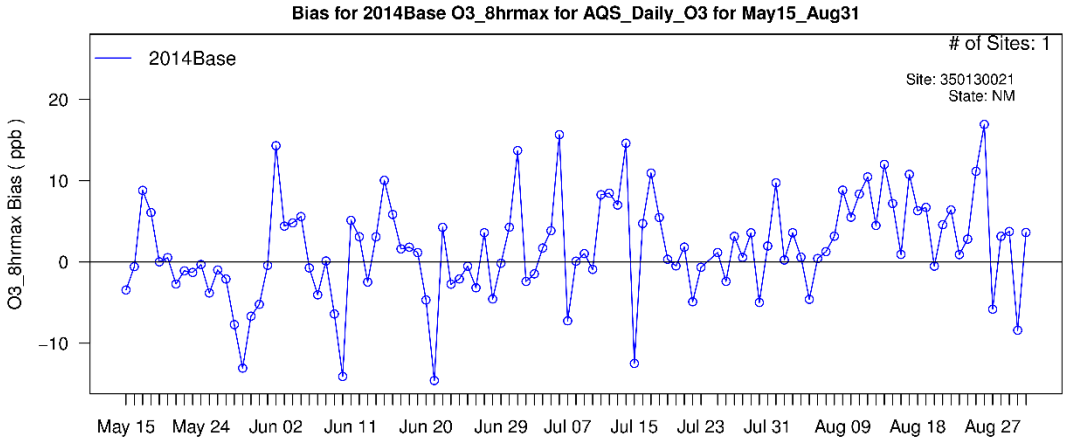

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AQS_Daily
2014Base
# of Sites: 1
Site: 350130017
State: NM
O3_8hrmax (ppb)
80
70
60
50
40
May 15
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Jun 02
Jun 11
Jun 20
Jun 29
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Jul 15
Jul 23
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Aug 18
Aug 27
Date

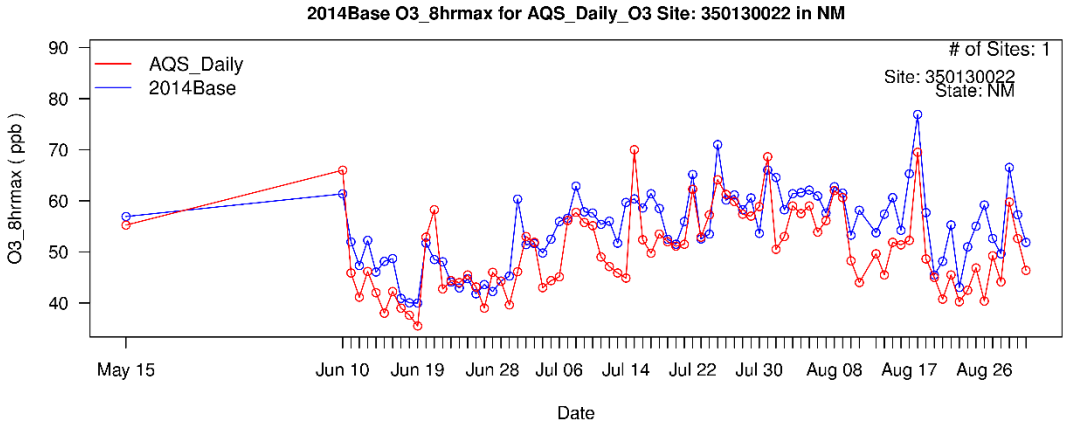

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State: NM
O3_8hrmax Bias (ppb)
30
20
10
0
−10
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May 24
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Jun 11
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Jul 15
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Aug 18
Aug 27

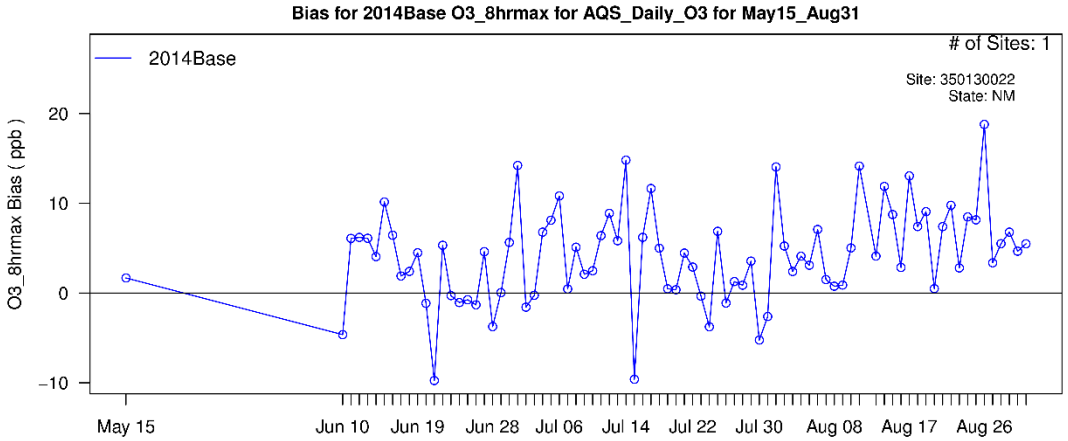

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2014Base
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80
70
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40
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May 24
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Aug 14
Aug 23
Date

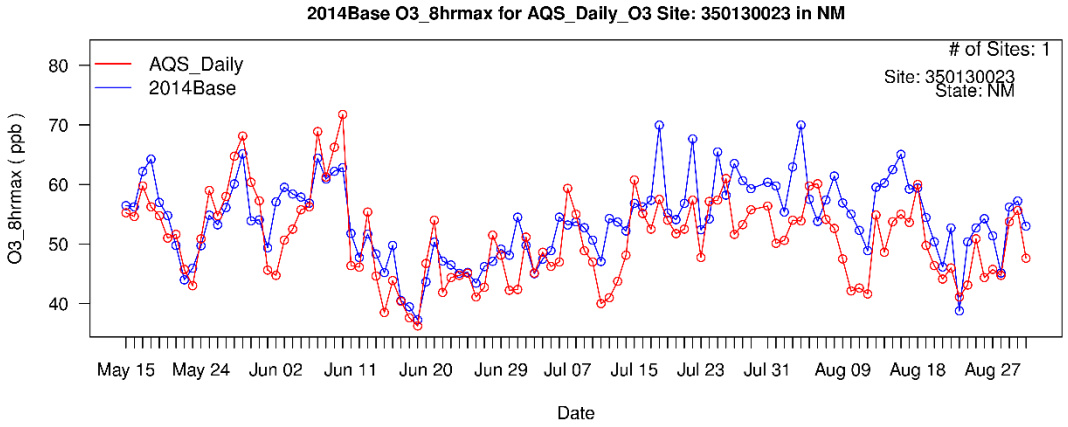

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O3_8hrmax Bias (ppb)
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Aug 23

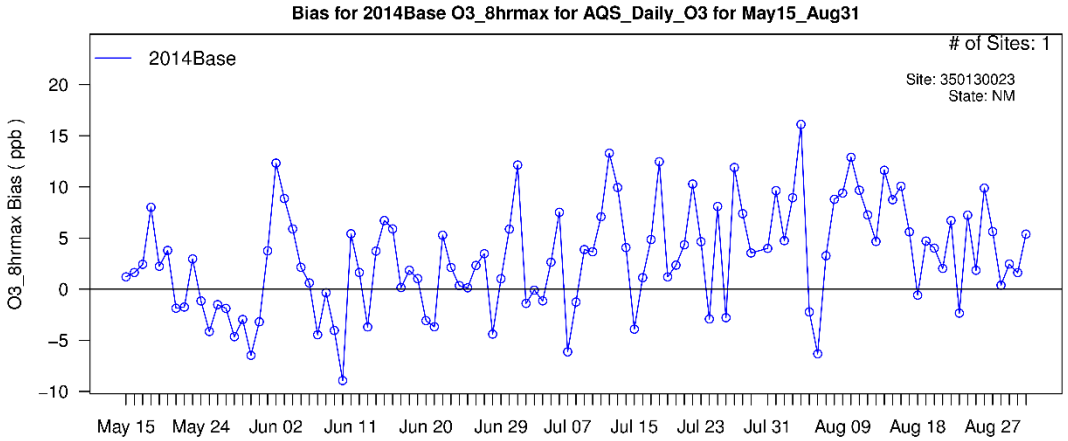

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2014Base
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Site: 350130021
State: NM
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70
60
50
40
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May 24
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Jun 11
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Jul 07
Jul 15
Jul 23
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Aug 18
Aug 27
Date

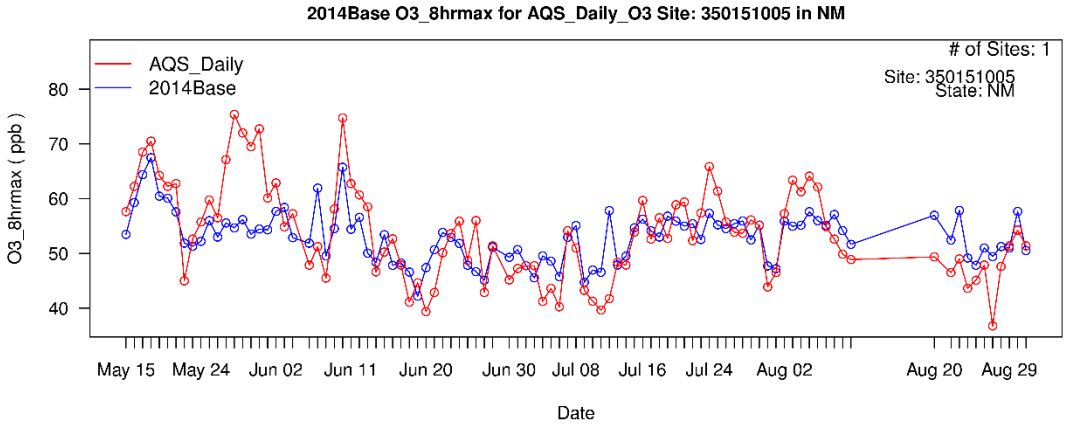

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
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Site: 350130021
State: NM
O3_8hrmax Bias (ppb)
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Aug 18
Aug 27

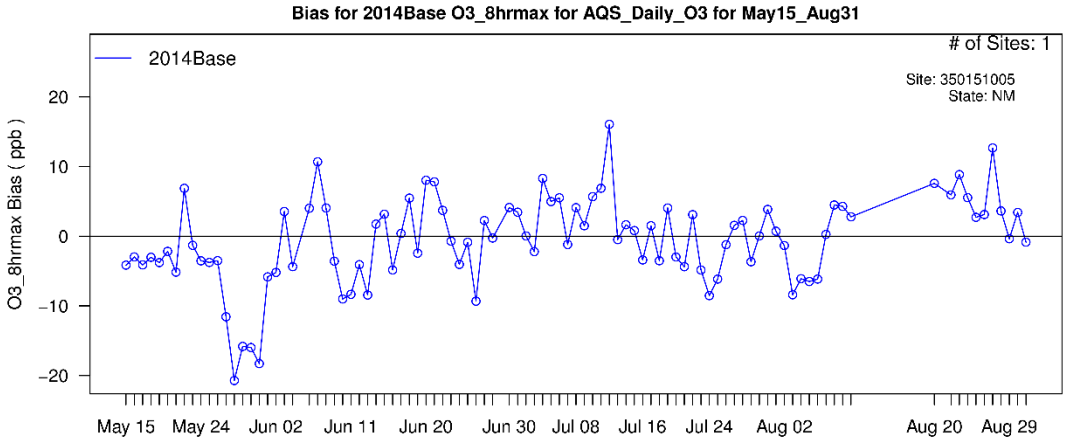

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2014Base
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Site: 350130022
State: NM
O3_8hrmax (ppb)
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Date

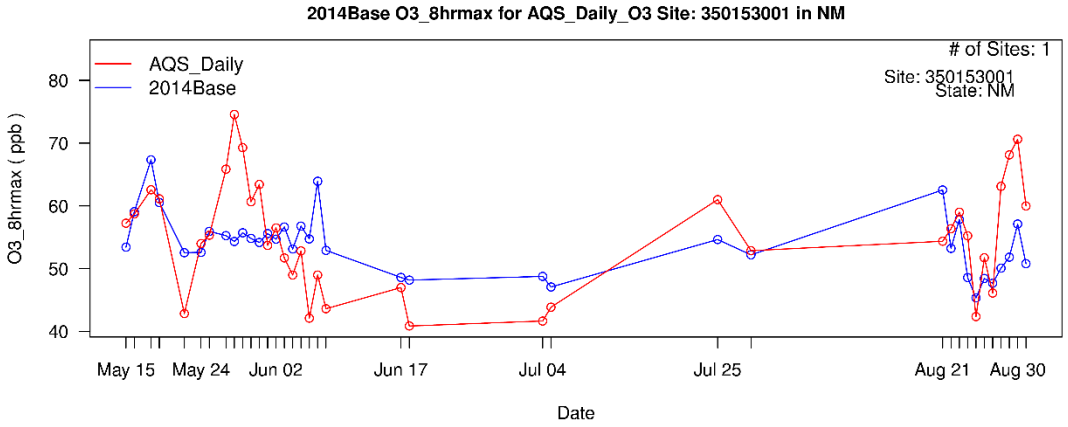

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
2014Base
# of Sites: 1
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State: NM
O3_8hrmax Bias (ppb)
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−10
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Jun 19
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Aug 08
Aug 17
Aug 26

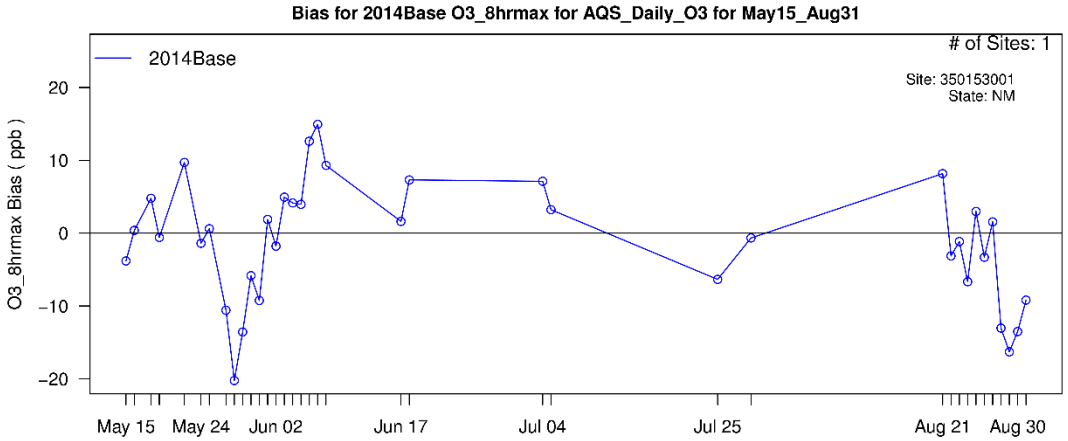

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AQS_Daily
2014Base
# of Sites: 1
Site: 350130023
State: NM
O3_8hrmax (ppb)
80
70
60
50
40
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May 24
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Jun 11
Jun 20
Jun 29
Jul 07
Jul 15
Jul 23
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Aug 18
Aug 27
Date

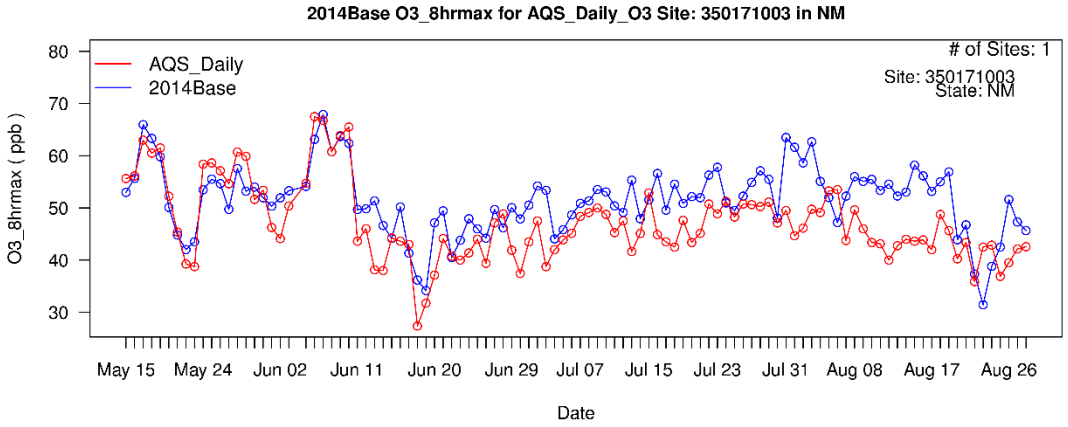

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
2014Base
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Site: 350130023
State: NM
O3_8hrmax Bias (ppb)
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15
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5
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Aug 27

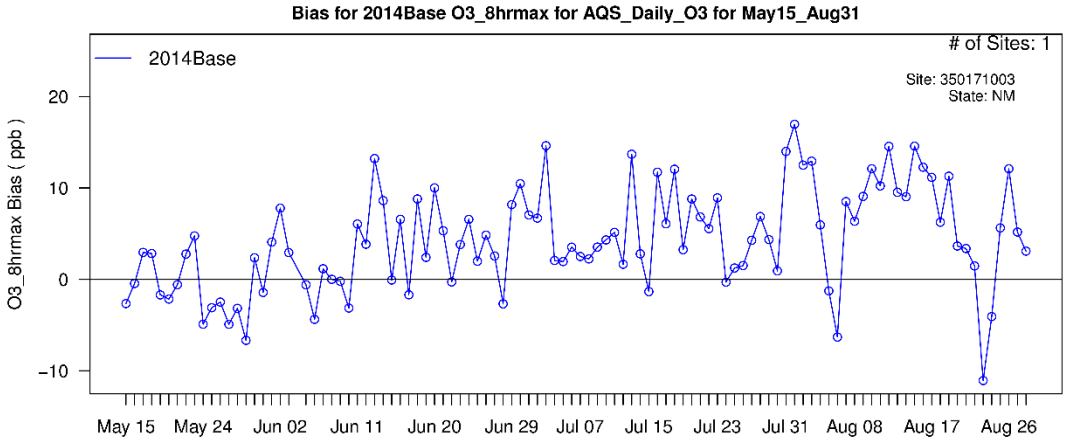

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AQS_Daily
2014Base
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State: NM
O3_8hrmax (ppb)
80
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50
40
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Jul 16
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Aug 20
Aug 29
Date

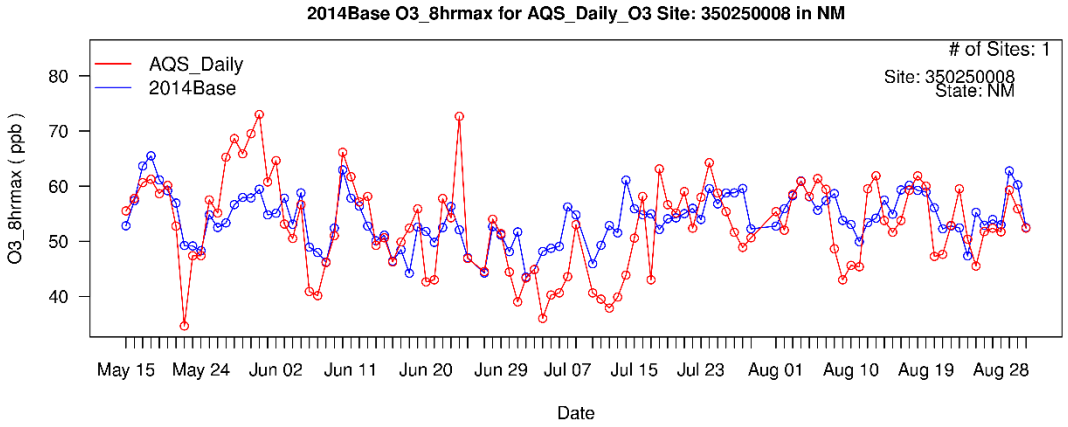

Bias for 2014Base O3_8hrmax for AQS_Daily_O3 for May15_Aug31
2014Base
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Site: 350151005
State: NM
O3_8hrmax Bias (ppb)
20
10
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Aug 02
Aug 20
Aug 29

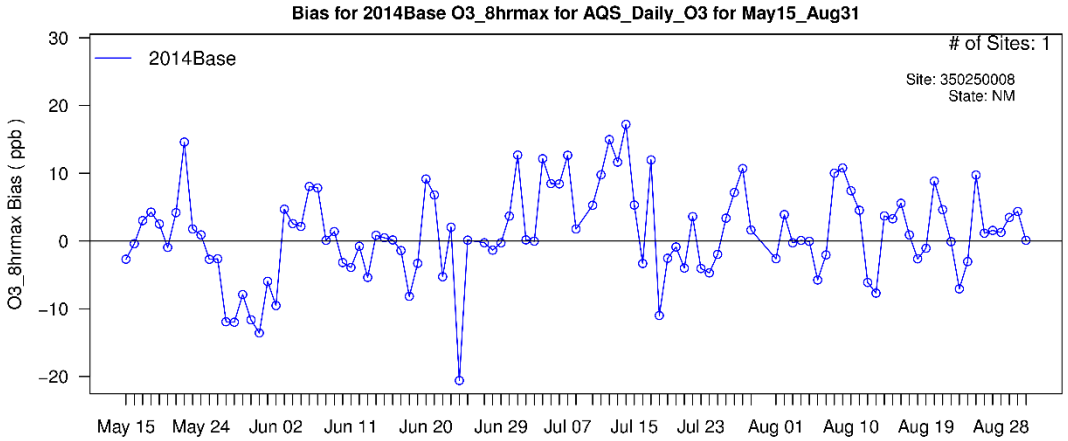

2014Base O3_8hrmax for AQS_Daily_O3 Site: 350153001 in NM
AQS_Daily
2014Base
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Site: 350153001
State: NM
O3_8hrmax (ppb)
80
70
60
50
40
May 15
May 24
Jun 02
Jun 17
Jul 04
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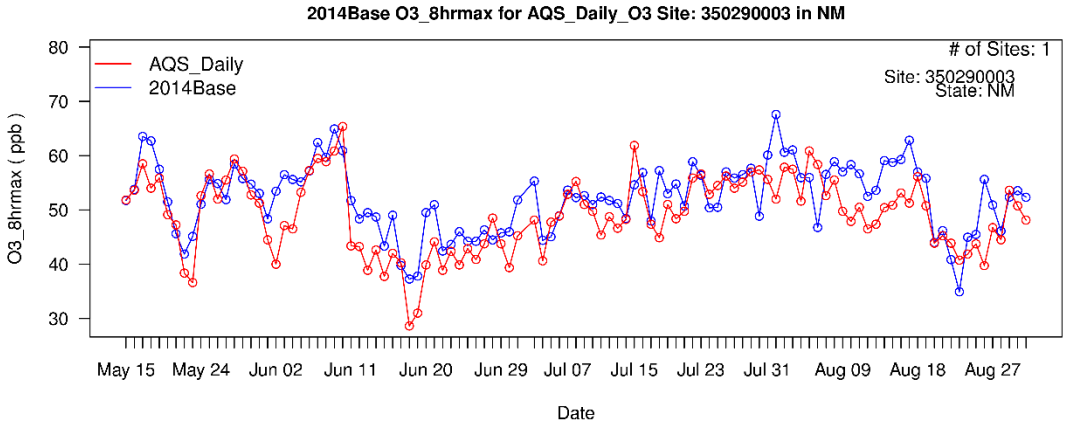

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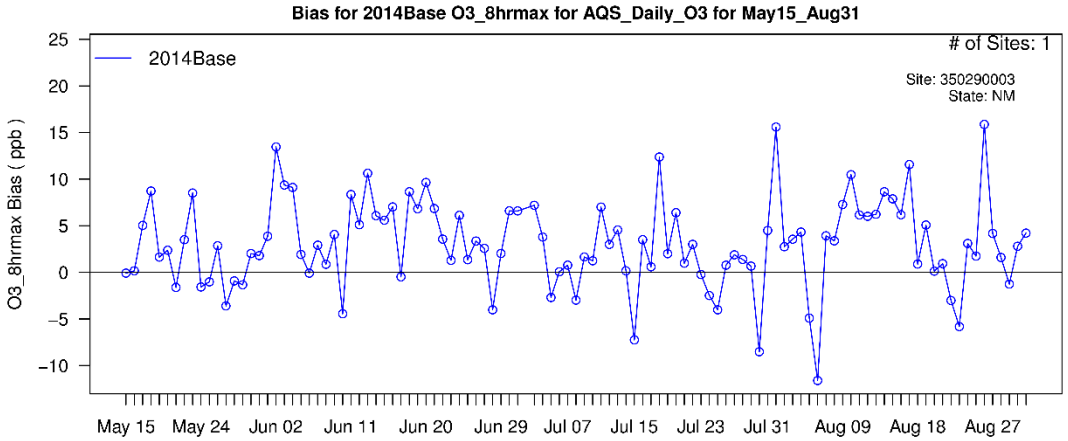

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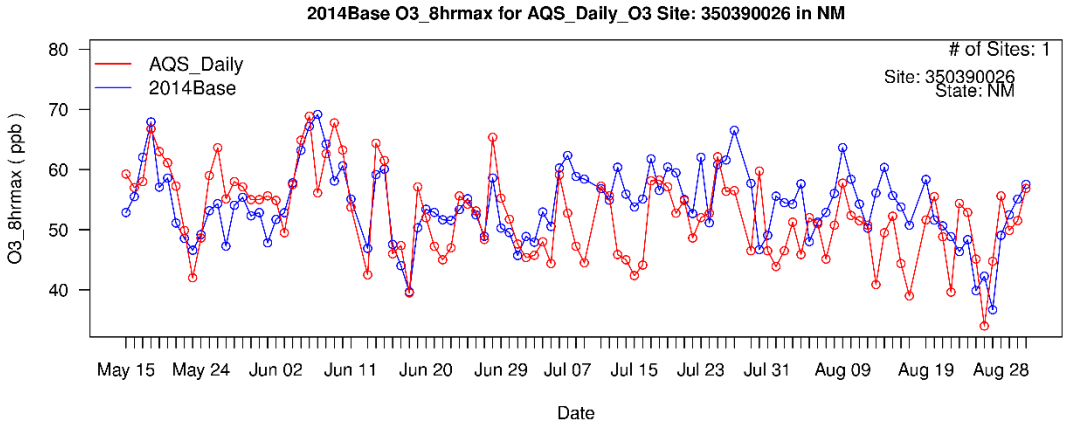

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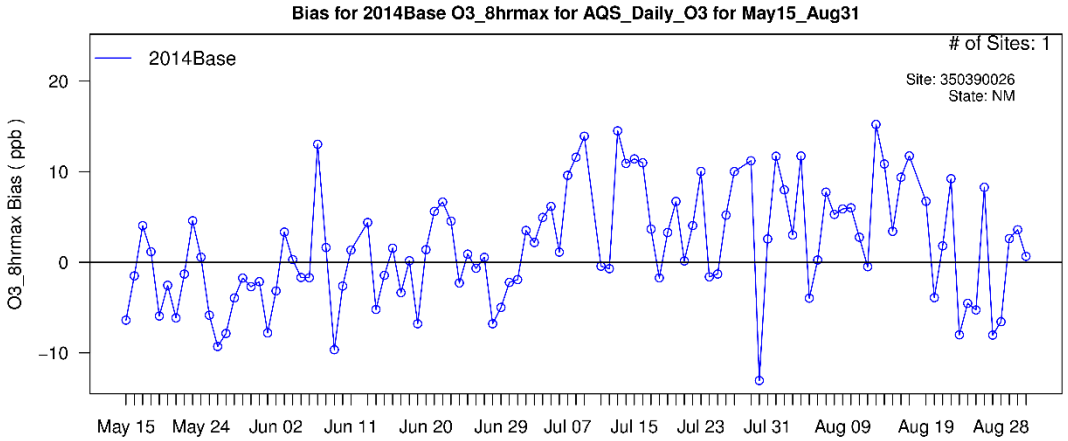

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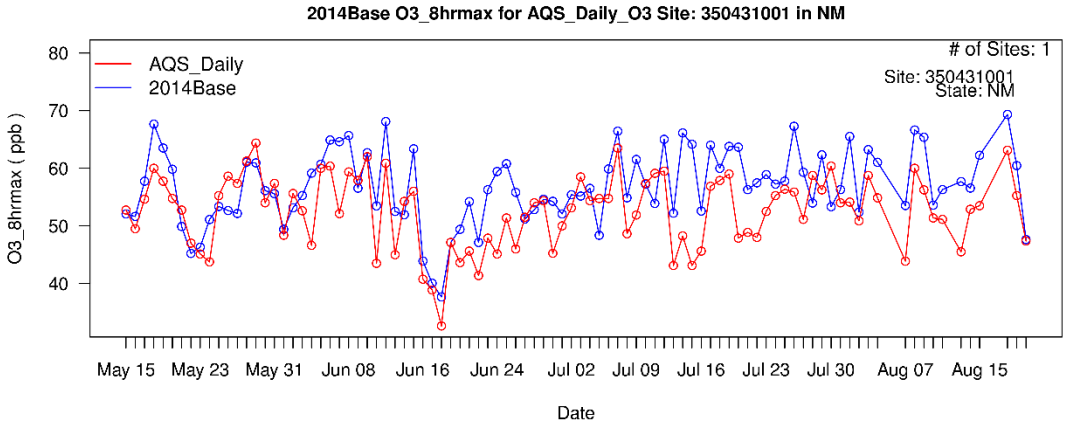

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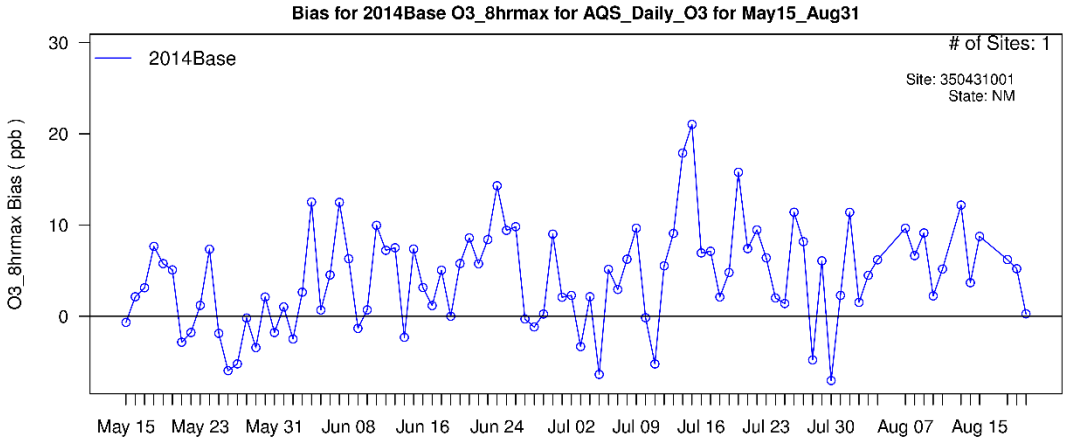

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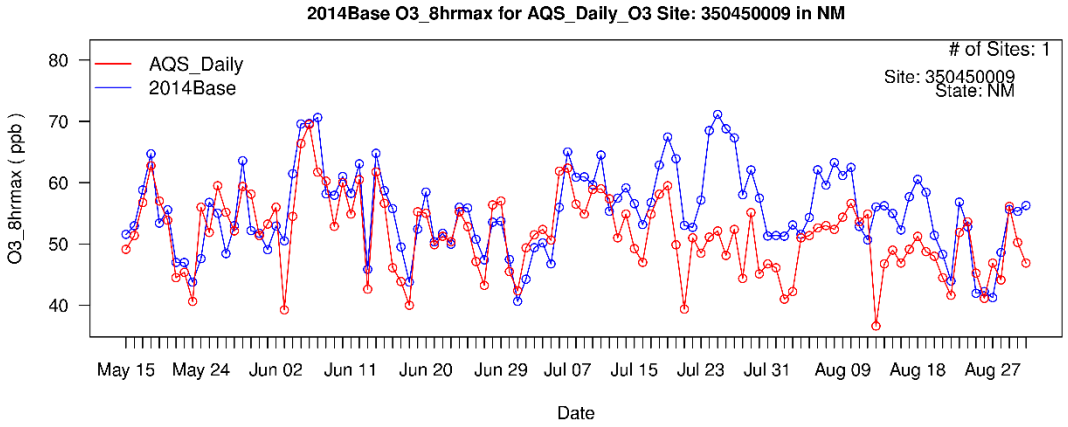

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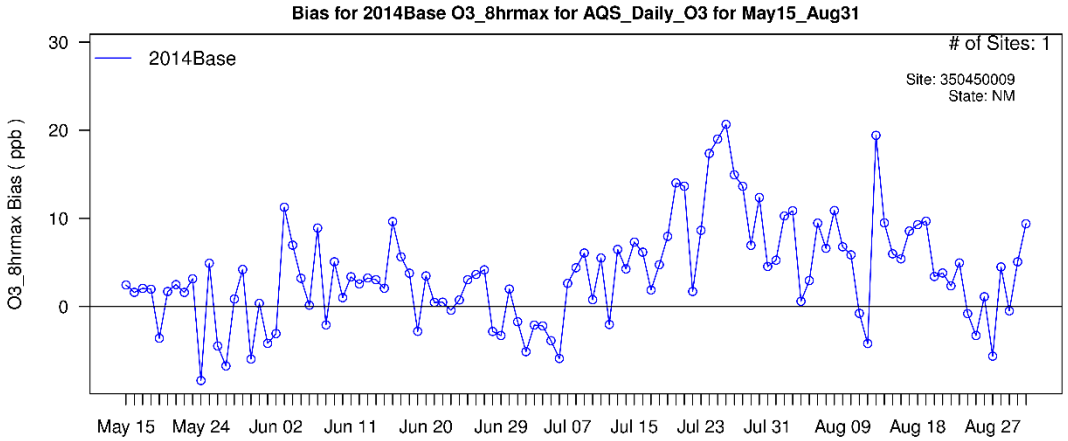

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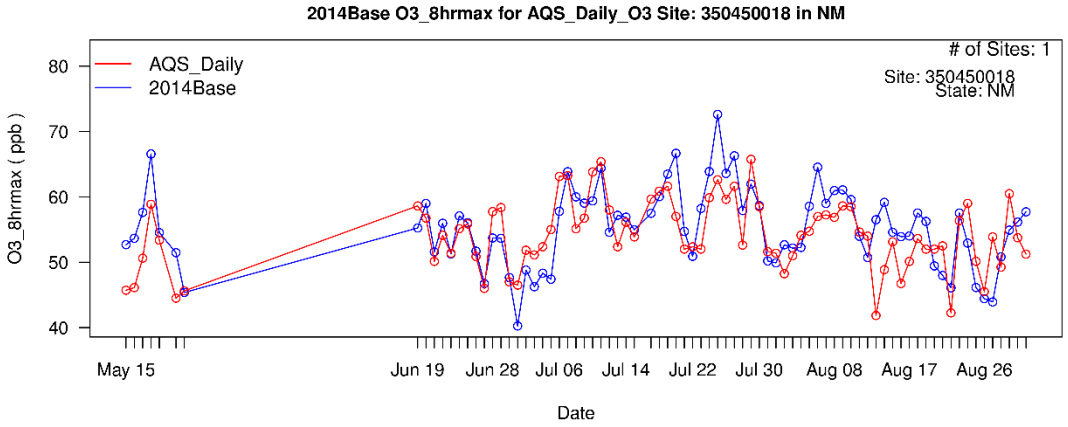

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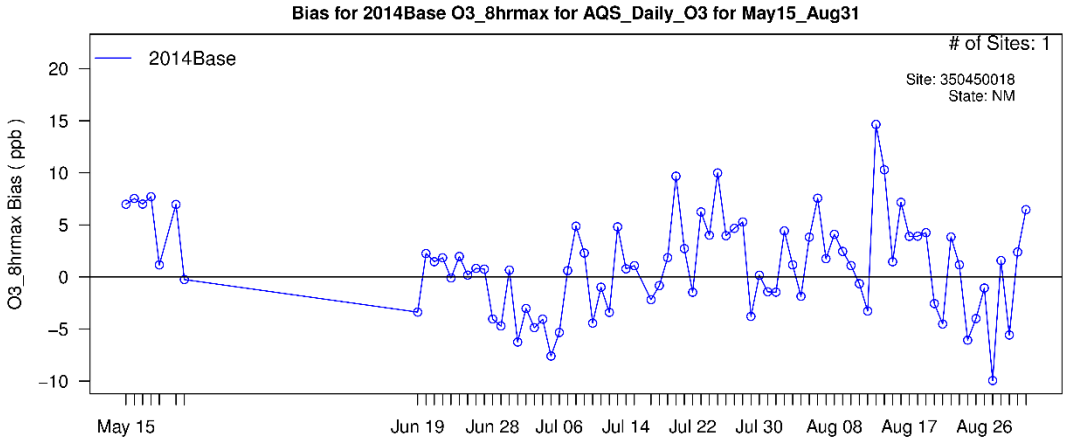

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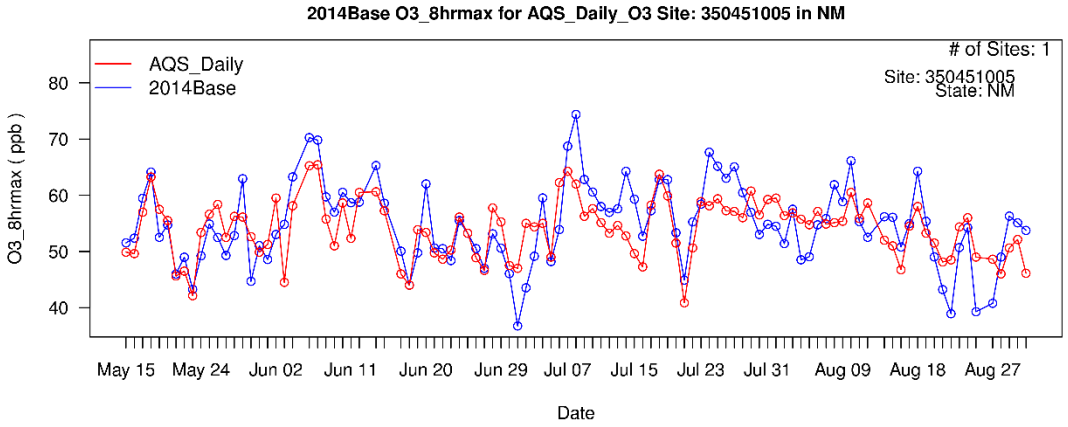

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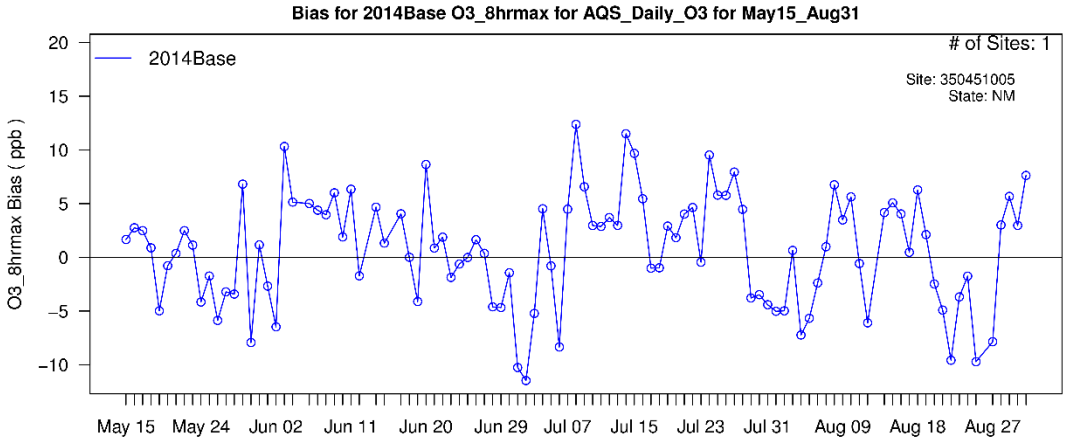

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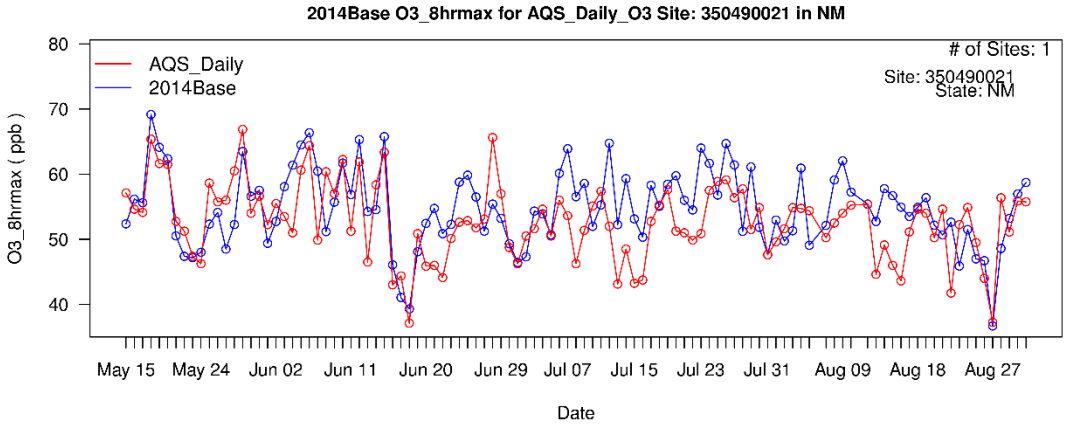

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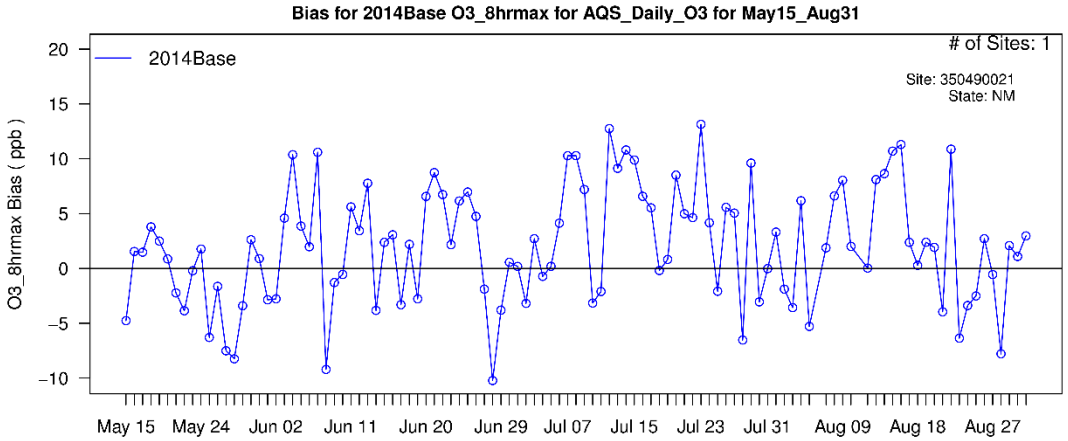

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AQS_Daily
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Site: 350450018
State: NM
O3_8hrmax (ppb)
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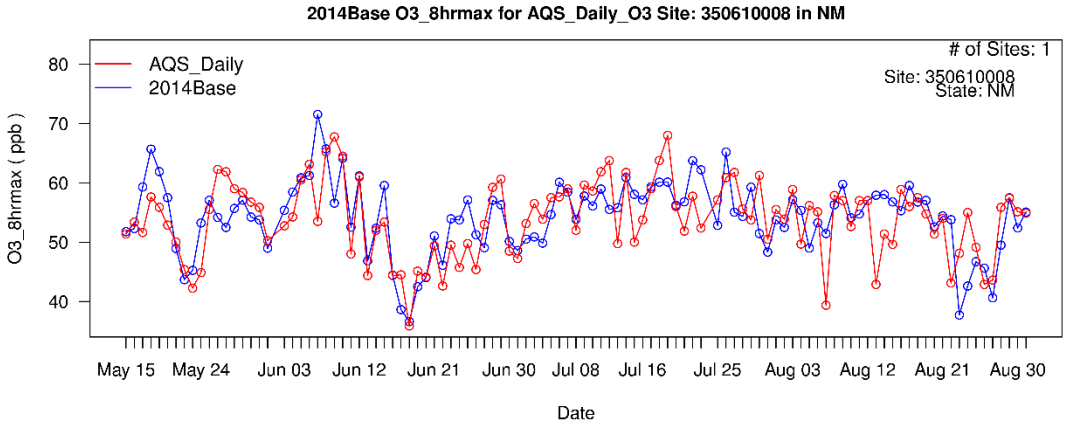

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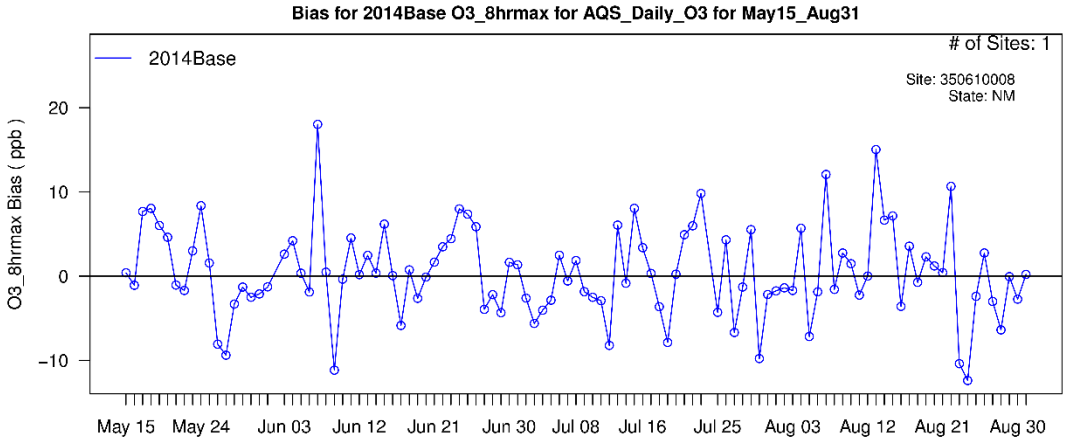

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2014Base
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AQS_Daily
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# of Sites: 1
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State: NM
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AQS_Daily
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O3_8hrmax (ppb)
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0
−10
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May 24
Jun 03
Jun 12
Jun 21
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Jul 08
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Aug 03
Aug 12
Aug 21
Aug 30

May 2021

NEW MEXICO OZONE ATTAINMENT INITIATIVE PHOTOCHEMICAL MODELING STUDY – DRAFT FINAL AIR QUALITY TECHNICAL SUPPORT DOCUMENT



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Western States Air Resources Council

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NEW MEXICO OZONE ATTAINMENT INITIATIVE PHOTOCHEMICAL MODELING STUDY – DRAFT FINAL AIR QUALITY TECHNICAL SUPPORT DOCUMENT

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ACRONYMS AND ABBREVIATIONS

3SAQS	Three-State Air Quality Study
AIRS	Aerometric Information Retrieval System
AMET	Atmospheric Model Evaluation Tool
APCA	Anthropogenic Precursor Culpability Assessment
AQ	Air Quality
AQS	Air Quality System
AQTSD	Air Quality Technical Support Document
BC	Boundary Condition
BLM	Bureau of Land Management
CAMx	Comprehensive Air-quality Model with extensions
CARB	California Air Resources Board
CASTNet	Clean Air Status and Trends Network
CB6r2	Carbon Bond mechanism version 6, revision 2
CMAQ	Community Multiscale Air Quality modeling system
CONUS	Continental United States
CPC	Center for Prediction of Climate
CSAPR	Cross State Air Pollution Rule
CSN	Chemical Speciation Network
DV	Ozone Design Value
DVC	Current Year Ozone Design Value
DVF	Future Year Ozone Design Value
EC	Elemental Carbon Fine Particulate Matter
ECMWF	European Center for Medium Range Weather Forecasting
EGU	Electrical Generating Units
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
ERA5	ECMWF global hourly meteorological forecasts at 30-km
ERG	Eastern Research Group
FB	Fractional Bias
FE	Fractional Error
FRM	Federal Reference Method
GCM	Global Chemistry Model
GEOS-Chem	Goddard Earth Observing System (GEOS) global chemistry model
GIRAS	Geographic Information Retrieval and Analysis System
IMPROVE	Interagency Monitoring of PROtected Visual Environments
IWDW	Intermountain West Data Warehouse
LCC	Lambert Conformal Conic projection
LSM	Land Surface Model
MADIS	Meteorological Assimilation Data Ingest System
MATS	Modeled Attainment Test Software
MCIP	Meteorology-Chemistry Interface Processor
MEGAN	Model of Emissions of Gases and Aerosols in Nature
MNGE	Mean Normalized Gross Error
MNB	Mean Normalized Bias
MNE	Mean Normalized Error
MOVES	Motor Vehicle Emissions Simulator
MOZART	Model for OZone And Related chemical Tracers

MPE	Model Performance Evaluation
MSKF	Multi-Scale Kain-Fritsch Cumulus Parameterization
NAAQS	National Ambient Air Quality Standard
NAM	North American Mesoscale Forecast System
NCAR	National Center for Atmospheric Research
NCEP	National Center for Environmental Prediction
NCDC	National Climatic Data Center
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NH_4	Ammonium Fine Particulate Matter
NMB	Normalized Mean Bias
NME	Normalized Mean Error
NMED	New Mexico Environmental Department
NO_2	Nitrogen Dioxide
NO_3	Nitrate Fine Particulate Matter
NOAA	National Oceanic and Atmospheric Administration
OA	Organic Aerosol Fine Particulate Matter
OAI	Ozone Attainment Initiative
OC	Organic Carbon Fine Particulate Matter
OSAT	Ozone Source Apportionment Technology
O&G	Oil and Gas
PAVE	Package for Analysis and Visualization
PBL	Planetary Boundary Layer
PGM	Photochemical Grid Model
PM	Particulate Matter
PPB	Parts Per Billion
PPM	Parts Per Million
PPM	Piecewise Parabolic Method
QA	Quality Assurance
QC	Quality Control
RMP	Resource Management Plan
RRF	Relative Response Factor
SCC	Source Classification Code
SIP	State Implementation Plan
SMAT	Software for Modeled Attainment Test
SMOKE	Sparse Matrix Kernel Emissions modeling system
SNMOS	Southern New Mexico Ozone Study
SOA	Secondary Organic Aerosol
SO_2	Sulfur Dioxide
SO_4	Sulfate Fine Particulate Matter
TCEQ	Texas Commission on Environmental Quality
UNC-IE	University of North Carolina Institute for the Environment
USFS	United States Forest Service
VERDI	Visualization Environment for Rich Data Interpretation
VMT	Vehicle Miles Traveled
WBD	Wind Blown Dust model
WAQS	Western Air Quality Study
WESTAR	Western States Air Resources Council
WestJumpAQMS	West-Wide Jump-Start Air Quality Modeling Study

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WESTUS	Western United States
WRAP	Western Regional Air Partnership
WGA	Western Governors' Association
WRF	Weather Research Forecast model

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1. INTRODUCTION

This is a draft final Air Quality Technical Support Document (AQTSD) for the New Mexico (NM) Ozone Attainment Initiative (OAI) Photochemical Modeling Study ("NM OAI Study"). The NM OAI Study has developed a 2014 base year photochemical grid model (PGM) modeling platform and conducted 2028 future year modeling for a Base Case and an Oil and Gas (O&G) Control Strategy scenario that implemented proposed controls on 2028 New Mexico O&G sources. The New Mexico Environmental Department (NMED) has contracted with a team consisting of Western States Air Resources Council (WESTAR) and Ramboll US Corporation (Ramboll) to conduct the NM OAI Study.

The NM OAI Study leverages the 2014 PGM modeling platform developed by the Western Regional Air Partnership (WRAP) in the Western Air Quality Study (WAQS) and enhances it by adding a 4-km grid resolution modeling domain covering New Mexico and adjacent regions. The NM OAI Study AQTSD documents the 2014 base case, 2028 future year base case and 2028 NM O&G control strategy modeling and includes a summary of the development of the 2014 PGM modeling platform with more details found on the NM OAI Study Website[1] and reports:

- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Modeling Protocol (Ramboll and WESTAR, 2020a).[2]
- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Draft Work Plan (Ramboll and WESTAR, 2020b).[3]
- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – 2014 Modeling Platform Development and Model Evaluation (Ramboll and WESTAR2020c).[4]
- New Mexico Ozone Attainment Initiative Photochemical Modeling Study – Revised 2014v2 Base Case and Model Performance Evaluation (Ramboll and WESTAR, 2021).[5]

Although the WESTAR/Ramboll team conducted the 2014 base year and 2028 base and O&G Control Strategy future year modeling, the implementation of the proposed NMED O&G ozone precursor control strategy in the 2028 O&G emissions was conducted by Eastern Research Group (ERG) under separate contract with NMED so is not documented in this report.

1.1 NM OAI Photochemical Modeling Study Genesis

The NMED Air Quality Bureau has authority over air quality management activities throughout the state of New Mexico, with the exception Bernalillo County and Tribal Lands. The City of Albuquerque/Air Quality Division has authority in Bernalillo County and, except for where Tribal Implementation Plans have been approved, EPA oversees air quality issues in Tribal Lands. The New Mexico Air Quality Control Act (NMAQCA) requires the NMED to develop a plan to address elevated ozone levels when air quality

[1] https://www.wrapair2.org/NMOAI.aspx
[2] https://www.wrapair2.org/pdf/NM_OAI_Modeling_Protocol_v5.pdf.
[3] https://www.wrapair2.org/pdf/NM_OAI_Work_Plan_v2.pdf
[4] https://www.wrapair2.org/pdf/NM_OAI_2014_BaseCase_MPE_v3.pdf
[5] https://www.wrapair2.org/NMOAI.aspx

is within 95% of the ozone NAAQS (74-3-5.3, NMSA 1978[6]). The ozone NAAQS was revised in 2015 with a threshold of 0.070 ppm (70 ppb) with the relevant metric being the ozone Design Value (DV) that is expressed as the three-year average of the fourth highest Maximum Daily Average 8-hour (MDA8) ozone concentrations. Table 1-1 lists the observed ozone DVs at New Mexico monitoring sites from 2010 to 2019. The DVs are color-coded when they exceed the 75 ppb 2008 ozone NAAQS (red), 70 ppb 2015 ozone NAAQS (yellow) and within 95% of the 70 ppb ozone NAAQS (green, i.e., ≥ 67 ppb). In more recent years, the ozone DVs have exceeded the 70 ppb 2015 ozone NAAQS at several sites in southern New Mexico (e.g., in Doña Ana and Eddy Counties). In particular, the 2017-2019 ozone DVs are particularly high and even exceeded the 75 ppb 2008 ozone NAAQS at three sites in southern New Mexico (colored red in Table 1-1).

[6] https://law.justia.com/codes/new-mexico/2017/chapter-74/article-2/section-74-2-5.3/

Table 1-1. Ozone design values (ppm) at sites in New Mexico from 2010 to 2019. Red above the 75 ppb 2008 NAAQS, yellow above 2015 70 ppb NAAQS and green within 95% of the 2015 NAAQS.

AQS Site ID	Local Site Name	County Name	2008-2010	2009-2011	2010-2012	2011-2013	2012-2014	2013-2015	2014-2016	2015-2017	2016-2018	2017-2019
350010023	Del Norte HS	Bernalillo	0.064	0.066	0.068	0.070	0.068	0.066	0.065	0.067	0.070	0.070
350010024	SE Heights	Bernalillo	0.066	0.068	0.070	0.070	0.068					
350010027	Westside	Bernalillo	0.067	0.068	0.071	0.071						
350010029	South Valley	Bernalillo	0.066	0.067	0.069	0.070	0.067	0.066	0.065	0.065	0.066	0.067
350010032	Westside	Bernalillo			0.070	0.070	0.067					
350011012	Foothills	Bernalillo	0.068	0.070	0.074	0.072	0.067	0.064	0.064	0.067	0.069	0.071
350011013	North Valley	Bernalillo	0.067	0.068	0.069	0.069						
350130008	La Union	Doña Ana	0.064	0.062	0.065	0.067	0.067	0.066	0.066	0.068	0.068	0.070
350130017	Sunland Park	Doña Ana	0.064	0.065	0.068	0.067	0.067					
350130020	Chaparral	Doña Ana	0.066	0.067	0.067	0.069	0.068	0.067	0.066	0.068	0.071	0.073
350130021	Desert View	Doña Ana	0.070	0.069	0.072	0.072	0.072	0.072	0.072	0.072	0.074	0.077
350130022	Santa Teresa	Doña Ana	0.067	0.066	0.070	0.075	0.074	0.072	0.068	0.072	0.074	0.076
350130023	Solano	Doña Ana	0.063	0.063	0.065	0.065	0.065	0.065	0.065	0.066	0.067	0.070
350151005	Carlsbad City	Eddy	0.067	0.068	0.071	0.071	0.071	0.069	0.067	0.068	0.074	0.079
350153001	Carlsbad Caverns	Eddy									0.071	
350171003	Chino Copper	Grant	0.063	0.065	0.067	0.063	0.062					
350250008	Hobbs Jefferson	Lea	0.059	0.061	0.061	0.066	0.065	0.067	0.066	0.067	0.070	0.071
350290003	Deming Airport	Luna	0.057	0.058	0.064	0.067	0.066					
350390026	Coyote Ranger District	Rio Arriba							0.064	0.065	0.067	0.067
350431001	Bernalillo	Sandoval	0.060	0.061	0.061	0.063	0.063	0.065	0.064	0.065	0.068	0.068
350439004	Pueblo of Jemez	Sandoval		0.062								
350450009	Bloomfield	San Juan	0.060	0.061	0.067	0.068	0.067	0.064	0.062	0.064	0.069	0.068
350450018	Navajo Lake	San Juan			0.071	0.071	0.068	0.067	0.066	0.068	0.070	0.069
350451005	Substation	San Juan	0.063	0.063	0.067	0.068	0.066	0.063	0.062	0.064	0.069	0.069
350490021	Santa Fe Airport	Santa Fe	0.063	0.062	0.065	0.066	0.066	0.064	0.063	0.063	0.066	0.066
350610008	Los Lunas	Valencia			0.067	0.070	0.069	0.066	0.064	0.065	0.067	0.068

To address the high observed ozone concentrations in New Mexico, the NMED has embarked on an Ozone Attainment Initiative (OAI[7]) to protect the ozone attainment status of the state and ensure health and welfare of the residents of the state for future generations. The OAI was initiated in Spring 2018. As part of the OAI, NMED released a Request for Proposal (RFP#20 667 4040 0001) for the NM OAI Study and the NM OAI Study PGM modeling was awarded to a contracting team of WESTAR and Ramboll.

[7] https://www.env.nm.gov/air-quality/o3-initiative/

1.2 Overview of NM OAI Study Modeling Approach

The procedures used for the NM OAI Study photochemical modeling were described in a detailed Modeling Protocol dated May 19, 2020 (Ramboll and WESTAR, 2020a). A description of the tasks and schedule for completing the NM OAI Study is contained in a Work Plan (Ramboll and WESTAR, 2020b) with presentations, results and reports posted to the NM OAI Study webpage[8] as they are produced. One objective of the study was to evaluate a proposed regulation to control ozone precursor emissions from oil and gas (O&G) development sources in New Mexico. The original future year emissions scenario in the NM OAI Study was 2023, when the proposed O&G rule would not be fully implemented. Thus, the future year to be modeled was changed to 2028 in a December 2020 Contract Amendment from NMED to the WESTAR/Ramboll team.

The NM OAI Study is conducting PGM modeling by enhancing the WRAP-WAQS 2014v2 36/12-km PGM modeling platform[9] with the addition of a new 4-km grid resolution domain covering New Mexico and surrounding areas, especially the O&G production regions in the Permian and San Juan Basins. The NM OAI Study PGM modeling is performing 2014 base year modeling and model performance evaluation. 2028 future year modeling was also conducted. The NM OAI Study PGM modeling is being conducted in accordance with EPA's guidance for ozone State Implementation Plan (SIP) ozone attainment demonstration modeling (EPA, 2018).

1.2.1 WRAP-WAQS 2014 PGM Platform Development

The WRAP-WAQS developed an annual 2014 PGM modeling platform to address air quality issues in the western states. An initial WRAP-WAQS 2014v1 PGM modeling platform was developed in 2019 for the CAMx and CMAQ PGMs that is documented in a webpage[10] on the Intermountain West Data Warehouse (IWDW). Additional diagnostic sensitivity tests were conducted to address several model performance issues culminating in the WRAP-WAQS 2014v2 36/12-km CAMx modeling database that was used as the starting point for the NM OAI Study CAMx summer of 2014 36/12/4-km modeling database. The development of the WRAP-WAQS 2014v2 PGM database and model performance evaluation is available in a webpage[11] on the IWDW.

The WRAP-WAQS 2014v2 CAMx platform used a 36/12-km grid resolution domain structure with meteorological inputs based on the WAQS 2014 36/12-km WRF meteorological model simulation (Bowden, Talgo and Adelman, 2016[12]). The 2014 emissions were based on the 2014 National Emissions Inventory (2014NEI[13]) with updates from western states[14]. Boundary Condition (BC) inputs were based on a WRAP 2014 GEOS-Chem model simulation.

Because the NM OAI Study requires a 4-km modeling domain for New Mexico, new summer of 2014 36/12/4-km WRF meteorological modeling was conducted, as

[8] https://www.wrapair2.org/NMOAI.aspx
[9] http://views.cira.colostate.edu/wiki#WAQS-2014-Modeling-Platform
[10] http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx
[11] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx
[12] http://views.cira.colostate.edu/wiki/Attachments/Modeling/WAQS_2014_WRF_MPE_January2016.pdf
[13] https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data
[14] https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf

described in Chapter 2, that was used to develop 36/12/4-km meteorological inputs for CAMx. The NM OAI Study defined their 36/12-km domains to match WRAP-WAQS 2014v2 36/12-km domains so the WRAP-WAQS 2014v2 36/12-km emission and some other inputs (e.g., BCs) can be used directly in the NM OAI Study PGM modeling. Figure 1-1 shows the 36/12/4-km modeling domains used for the NM OAI Study PGM modeling with the 4-km grid resolution New Mexico domain shown in Figure 1-2.

1.2.2 Episode Selection

The May-August 2014 modeling period was selected as it has a high quality emissions inventory with western state updates and has a PGM platform already developed from the WRAP-WAQS regional haze modeling that can be leveraged for the NM OAI Study. Details on the episode selection are contained in Chapter 3 of the NM OAI Study Modeling Protocol (Ramboll and WESTAR, 2020a).

1.2.3 Model Selection

Details on the rationale for model selection are provided in Chapter 2 of the NM OAI Study Modeling Protocol (Ramboll and WESTAR, 2020a). The Weather Research Forecast (WRF) prognostic meteorological model was selected. Emissions modeling was conducted using the Sparse Matric Operator Kernel Emissions (SMOKE) model for most source categories. The Model of Emissions of Gases and Aerosols from Nature (MEGAN v3.1) was used initially for biogenic emissions in the 4-km domain for the original CAMx 2014 Base Case, but was ultimately replaced by biogenic emission based on the BEIS v3.7 model in the final CAMx 2014v2 base case. There are special processors for fires, windblown dust (WBD), lightning NO_x (LNO_x) and oceanic sea salt (NaCl) and Dimethyl Sulfide (DMS) emissions that were used. The 2014 version of the Motor Vehicle Emissions Simulator (MOVES2014b) on-road mobile source emissions model was used with SMOKE-MOVES and WRF meteorological data to generate on-road mobile source emissions for the 4-km New Mexico modeling domain.

The Comprehensive Air-quality Model with extensions (CAMx) photochemical grid model (PGM) was used because it supports two-way grid nesting, was used in the WRAP-WAQS regional haze modeling, contains a well-vetted ozone source apportionment tool and has a rich and successful history of successful application to the region.

1.2.4 Domain Selection

The NM OAI Study modeling is using the same 36-km 36US and 12-km 12WUS2 domains as used in the WRAP-WAQS 2014 modeling platform. A new 4-km New Mexico domain was added to the 36/12-km domain structure. Figure 1-1 displays the 36/12/4-km domain structure with Figure 1-1 showing the 4-km New Mexico domain. New WRF 2014 36/12/4-km meteorological modeling was conducted to generate finer scale 4-km meteorological conditions for the New Mexico domain and consistent meteorology among the 36/12/4-km domains. The domains use a Lambert Conformal Conic (LCC) projection using the parameters given in Table 1-2 with the definitions of the extent of the 36/12/4-km domains given in Table 1-3. CAMx was run using the 36/12/4-km domain structure shown in Figure 1-1 using two-way interactive grid nesting.

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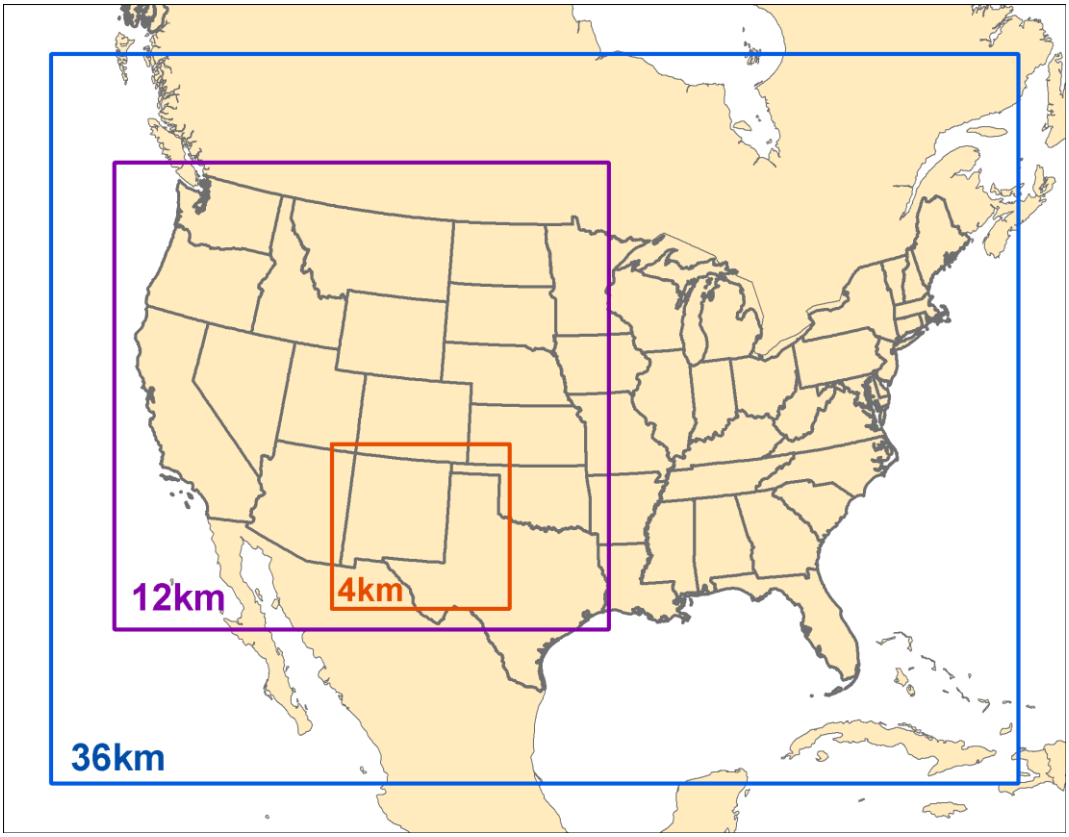


Figure 1-1. NM OAI Study 2014 36/12/4-km PGM and emissions modeling domains.

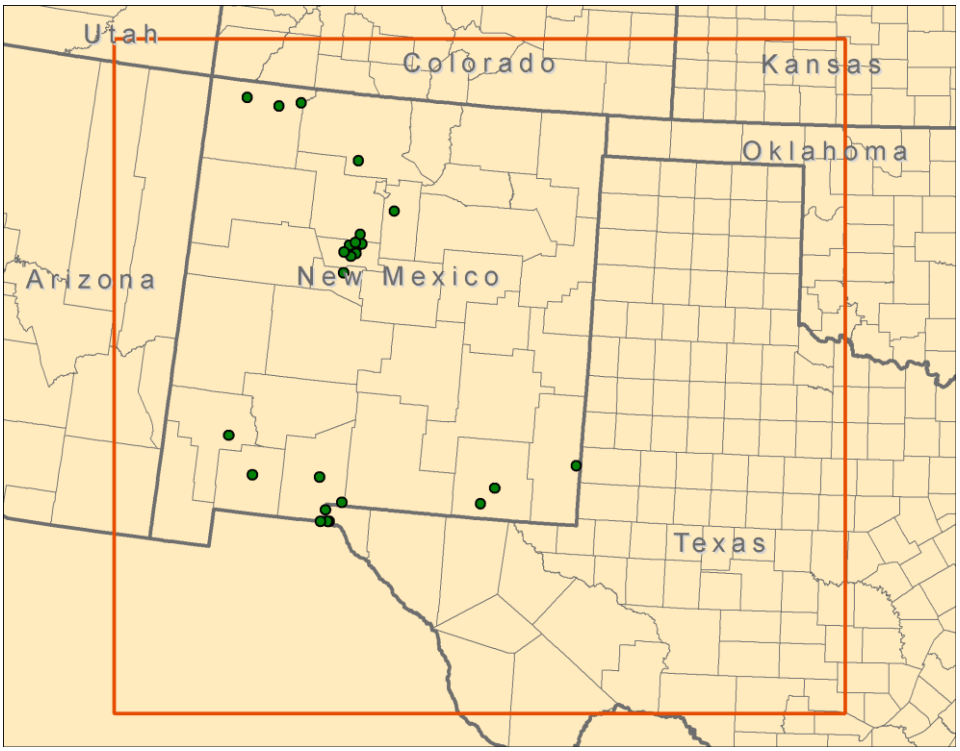


Figure 1-2. 4-km New Mexico modeling domain for PGM and emissions modeling, with locations of New Mexico ozone monitors that were operating during some portion of 2014.

Table 1-2. Lambert Conformal Conic (LCC) projection parameters for the NM OAI Study 36/12/4 modeling domains.

Parameter	Value
Projection	Lambert-Conformal
1st True Latitude	33 degrees N
2nd True Latitude	45 degrees N
Central Longitude	-97 degrees W
Central Latitude	40 degrees N

Table 1-3. Grid definitions for CAMx NM OAI Study 2014 36/12/4-km modeling domains.

Grid	Origin (SW) (km)	Extent (NE) (km)	NX	NY
36-km	(-2736, -2088)	(2592, 1944)	148	112
12-km*	(-2388, -1236)	(336, 1344)	227	215
4-km*	(-1192, -1120)	(-212, -212)	245	227

*Definition includes outer row/column of buffer cells required by CAMx for nested domains

1.2.5 Base and Future Year Emissions Data

The 2014 base year emissions data were based on the WRAP-WAQS 2014v2 emissions that were in turn based on the 2014NEIv2 with updates from western states. New emissions were generated for natural emission sources (e.g., biogenic and LNO_x). 2028 emissions were based on the WRAP 2028 On-the-Books (2028OTBa2) emissions scenario with updated 2028 O&G emissions for New Mexico and using actual 2014 fires instead of Representative Baseline fires as used in the WRAP 2028OTBa2 scenario. The development of the 2014 and 2028 emission scenarios are discussed in Chapter 4.

1.2.6 Initial and Boundary Conditions Development

The first two-weeks of May were run on the 36/12/4-km domains to spin-up the model before the first high ozone day in New Mexico (68 ppb on May 17). This washed out the influence of the initial concentrations (IC) before elevated ozone concentrations occur in New Mexico.

Boundary conditions (BC) for the outer 36-km 36US domain were based on a 2014 simulation of the GEOS-Chem global chemistry model conducted by WRAP processed by the GC2CAMx converter. The result is day-specific diurnally varying BCs for the lateral boundaries around the 36-km 36US modeling domain. The top BC was based on a zero-gradient assumption where concentrations above the top of the model (above 50 mb, or ~19-km above sea level) are assumed to be the same as in the top vertical layer of CAMx.

Due to uncertainties in projecting future year international emissions, the CAMx BCs based on the 2014 GEOS-Chem global model simulation were held constant for the 2028 modeling. This is likely a conservative estimate of 2028 BCs.

Chapter 3 provides a summary of the development of the 2014 CAMx BC inputs with more details in Ramboll and WESTAR (2020c) and on the WRAP-WAQS 2014v2 modeling website.

1.2.7 Diagnostic Sensitivity Analyses

The NM OAI Study conducted four diagnostic sensitivity tests for the CAMx 2014 36/12/4-km base case that compared the CAMx ozone performance for four alternative meteorological inputs. The NM OAI Study conducted two WRF 2014 36/12/4-km WRF simulations that used different analysis fields as input. The two 2014 36/12/4-km WRF outputs were processed with WRFCAMx using two different options for vertical turbulent exchange (i.e., vertical mixing) coefficients (Kv). This resulted in four different CAMx meteorological inputs that were evaluated using CAMx diagnostic sensitivity tests that are summarized in Chapter 5 with details provided in Ramboll and WESTAR (2020c).

1.2.8 Model Performance Evaluation

The NM OAI Study CAMx 2014 36/12/4-km base case simulation Model Performance Evaluation (MPE) followed EPA's MPE recommendations in their ozone modeling guidance (EPA, 2018) and other sources (e.g., Simon, Baker and Phillips, 2012; Emery et al., 2016). The CAMx 2014 36/12/4-km base case simulation MPE focused on ozone model performance within the 4-km New Mexico domain, and especially within New Mexico. Two CAMx 2014 base case simulations were performed and subjected to an MPE. An original CAMx 2014 base case simulation used CAMx v7.0 and biogenic

emissions in the 4-km NM domain based on the MEGAN v3.1 model whose evaluation is documented in NM OAI Study 2014 platform development and 2014 base case modeling report (Ramboll and WESTAR, 2020c). A revised 2014v2 base case was conducted using CAMx v7.1 and biogenic emissions based on the BEIS v3.7, whose results are documented in an Addendum to the 2014 base case modeling report (Ramboll and WESTAR, 2021).

1.2.9 2028 Future Year Base and Control Strategy Modeling

2028 future year ozone modeling was conducted using the WRAP 2028OTBa2 emissions scenario with updated 2028 O&G emissions in New Mexico and using 2014 actual fires instead of the Representative Baseline fires used in the 2028OTBa2 scenario. These fire inventories were prepared for the WRAP Fire and Smoke Work Group and are documented in a report (Air Sciences, 2020) and presentation.[15] A CAMx 2028 future year 36/12/4-km base case simulation was conducted using CAMx v7.1 and used to project 2028 future year ozone design values (DVs). The procedures to calculate projected ozone DVs followed EPA's latest guidance (EPA, 2018). These procedures use the modeling results in a relative fashion to scale the current year observed 2012-2016 8-hour ozone design values (i.e., $DVC_{2012\text{-}2016}$) to project 2028 future year ozone Design Values (DVFs). The scaling factors are called Relative Response Factors (RRFs) and are the ratio of the future-year to current-year modeling results for the 10 highest base year modeled MDA8 ozone days near the monitoring site. EPA has developed the Speciated Modeled Attainment Test (SMAT[16]) tool that includes the recommended procedures in the latest EPA guidance for projecting ozone DVFs.

The NM OAI Study also conducted future year modeling for a 2028 O&G Control Strategy that implemented controls on ozone precursors from O&G sources within the San Juan and Permian Basins. The WESTAR/Ramboll team provided the 2028 NM O&G emissions to ERG who, under separate contract to NMED, implemented the proposed NM O&G ozone precursor control strategy in the 2028 NM O&G emissions and provided them to WESTAR/Ramboll for ozone modeling. This report does not document the implementation of the NM O&G ozone precursor control strategy as that was not performed by WESTAR/Ramboll.

1.2.10 Future Year Source Apportionment Modeling

The NM OAI Study also is conducting future year ozone source apportionment modeling for the 2028 O&G Control Strategy scenario using the CAMx ozone source apportionment tool. The CAMx 2028 Source Sector APCA ozone source apportionment modeling examined the ozone contributions of several major anthropogenic emission source sectors in New Mexico and other states as well as contributions of International anthropogenic emissions on ozone concentrations in New Mexico and is discussed in Chapter 9. CAMx 2028 VOC/NO_x Sensitivity OSAT ozone source apportionment modeling was also conducted to examine the level of VOC sensitive versus NO_x sensitive ozone formation in New Mexico and is discussed in Chapter 10.

[15] https://www.wrapair2.org/pdf/FireEIandFutureScenariosResults_to_regional_planners_20200520.pptx
[16] https://www.epa.gov/scram/photochemical-modeling-tools

2. 2014 WRF METEOROLOGICAL MODELING

The NM OAI Study conducted WRF meteorological modeling for the summer of 2014 to generate CAMx meteorological inputs for the 36/12/4-km horizontal domain structure shown in Figure 1-1.

2.1 WRF Meteorological Model

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs (Skamarock, 2004; 2006; Skamarock et al., 2005; 2008; 2019). The Advanced Research WRF (ARW) version of WRF was used in the NM OAI Study.

This chapter summarizes the application and evaluation of the WRF meteorological model to generate 2014 36/12/4-km meteorological inputs for CAMx photochemical grid modeling with more details provided in Chapter 2 of Ramboll and WESTAR (2020c).

2.2 WRF Horizontal Modeling Domain

The WRF 2014 36/12/4-km modeling domains were defined slightly larger than the PGM 36/12/4-km domains (Figure 1-1) so that any modeling artifacts that occur near the WRF boundaries as the boundary conditions (BCs) come into dynamic balance with the WRF numerical algorithms are not present in the PGM meteorological inputs.

2.3 WRF Model Configuration

WRF version 4.2 was used for this modeling analysis. The NM OAI Study 36/12-km WRF/PGM grid configuration (e.g., horizontal domains and vertical layer structure) was designed to be identical to the WRAP-WAQS 2014 WRF/PGM grid configuration in order to facilitate the use of data between the two studies. A 4-km domain was added covering New Mexico and adjacent regions.

The WAQS 2011/2014 WRF modeling used 36 vertical levels (35 vertical layers) from the surface to a 50 mb (hPa) height (approximately 19-km above sea level). The EPA 2014, 2015 and 2016 WRF modeling also used 35 vertical layers up to a 50 mb height.

Table 2-1 displays the 36-vertical layer structure used in the WRAP-WAQS 2011/2014 WRF modeling that was also adopted for the NM OAI Study WRF 2014 36/12/4-km modeling.

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Table 2-1. WRF 36 level vertical layer structure for the NM OAI study. This is the same WRF layer structure as used in WAQS 2011/2014/2016 and EPA 2016 WRF modeling.

WRF Layer	Sigma	Pressure (mb)	Height (m)	Thickness (m)
36	0.0000	50.00	19260	2055
35	0.0270	75.65	17205	1850
34	0.0600	107.00	15355	1725
33	0.1000	145.00	13630	1701
32	0.1500	192.50	11930	1389
31	0.2000	240.00	10541	1181
30	0.2500	287.50	9360	1032
29	0.3000	335.00	8328	920
28	0.3500	382.50	7408	832
27	0.4000	430.00	6576	760
26	0.4500	477.50	5816	701
25	0.5000	525.00	5115	652
24	0.5500	572.50	4463	609
23	0.6000	620.00	3854	461
22	0.6400	658.00	3393	440
21	0.6800	696.00	2954	421
20	0.7200	734.00	2533	403
19	0.7600	772.00	2130	388
18	0.8000	810.00	1742	373
17	0.8400	848.00	1369	271
16	0.8700	876.50	1098	177
15	0.8900	895.50	921	174
14	0.9100	914.50	747	171
13	0.9300	933.50	577	84
12	0.9400	943.00	492	84
11	0.9500	952.50	409	83
10	0.9600	962.00	326	82
9	0.9700	971.50	243	82
8	0.9800	981.00	162	41
7	0.9850	985.75	121	24
6	0.9880	988.60	97	24
5	0.9910	991.45	72	16
4	0.9930	993.35	56	16
3	0.9950	995.25	40	16
2	0.9970	997.15	24	12
1	0.9985	998.58	12	12
0	1.0000	1000.00	0	

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2.3.1 Vertical Coordinate

Since its inception, WRF has used the eta (sometimes called sigma or "terrain-following") vertical coordinate system. One weakness of the eta coordinate is that variations in terrain (especially steep topography) can increase numerical errors in the model. To reduce these errors, Park et al., (2018) developed a hybrid sigma–pressure coordinate that is now included as the default vertical coordinate system for the WRF model (Skamarock et al., 2019).

For the NM OAI Study 2014 36/12/4-km WRF modeling, we used the new hybrid vertical coordinate system and a new version of the WRFCAMx processor that has been updated to use WRF's hybrid vertical coordinate. The hybrid vertical coordinate system and use of 4-km New Mexico domain are the two biggest differences between the NM OAI Study and WRAP-WAQS 2014 WRF modeling. The WRAP-WAQS 2014 WRF/CAMx modeling did not use the hybrid vertical coordinate system in WRF because at the time it was not supported in the WRFCAMx processor.

2.3.2 Topographic Inputs

Topographic information for WRF was based on a combination of the standard WRF terrain databases and high-resolution terrain. The 36-km 36US domain used the 10-minute global data, the 12-km 12WUS2 domain used the 2-minute data, and the 4-km New Mexico domain used the 30 second data.

2.3.3 Vegetation Type and Land Use Inputs

Vegetation type and land use information used the United States Geological Survey (USGS) land use databases from the most recently released WRF databases provided with the WRF distribution. Standard WRF surface characteristics corresponding to each land use category was employed.

2.3.4 Atmospheric Data Inputs

WRF relies on other model or re-analysis output meteorological fields to provide initial and boundary conditions (IC/BC) and fields for the four-dimensional data assimilation (FDDA). FDDA refers to the nudging of the WRF meteorological fields to observed analysis fields so that the WRF meteorological fields better represent what was observed and prevent the model from drifting away from the observed meteorology. The NM OAI Study conducted two WRF simulations that used two different analysis fields that were evaluated for their performance against meteorological variables as well as their effect on CAMx ozone model performance. Both the 12-km resolution North American Model (NAM) and the ~30-km resolution European Center for Medium-Range Weather Forecasting (ECMWF) Re-Analysis (ERA5[17]) dataset analysis fields were used for IC/BC and FDDA in the two WRF 2014 36/12/4-km sensitivity simulations.

Analysis nudging (i.e., FDDA) was used for winds, temperature, and humidity on the 36-km and 12-km domains. Both surface and aloft nudging was used but nudging for temperature and mixing ratio was not performed within the boundary layer. Observation nudging was not used, even on the 4-km domain.

[17] https://www.ecmwf.int/en/forecasts/datasets/archive-datasets/reanalysis-datasets/era5

The effects of the two 2014 WRF simulations on CAMx ozone performance was evaluated in diagnostic sensitivity simulations and the best performing configuration selected as the final CAMx meteorological inputs, as described in Chapter 5.

2.3.5 New Lightning Data Assimilation

More recently, the assimilation of lightning data in WRF simulations has shown to improve the locations and amounts of convective precipitation. The use of lighting detection networks, such as the National Lightning Detection Network (NLDN), have been used in WRF simulations and used to force deep convection (thunderstorms) when lightning is observed and only allow shallow convection when lightning is not present. The use of the new lightning assimilation approach has been demonstrated to improve both WRF convective precipitation as well as PGM concentration and deposition performance (Heath et al., 2016). The new lightning data assimilation algorithms was not used in the NM OAI Study 2014 WRF modeling for the following reasons: (1) it would have to be tested and evaluated and there is insufficient time in the schedule to conduct such diagnostic testing; (2) the NLDN data used to date with the WRF lightning assimilation is a commercial product that is expensive and not within the budget; (3) the implementation of the lightning detection data assimilation in WRF has a flaw that it doesn't distinguish between no lightning detects and missing data and suppresses convection in areas with missing data (e.g., over the Gulf of Mexico); and (4) most importantly, the lightning detection data assimilation algorithm has not been implemented in the latest versions of WRF so its use would limit the use of other model new options, such as the hybrid vertical coordinate system.

2.3.6 PBL and LSM Physics Options

As used in the WRAP-WAQS 2014 WRF modeling, the YSU Planetary Boundary Layer (PBL) and Noah Land Surface Model (LSM) physics options were used in the NM OAI Study 2014 36/12/4-km WRF modeling. Previous WRF sensitivity modeling for the intermountain west region found the YSU/Noah PBL/LSM schemes produces the most realistic meteorological fields. Note that EPA's 2014/2015/2016 WRF modeling uses the ACM2 PBL and Pleim-Xiu (PX) LSM schemes (EPA, 2019).

2.3.7 Remaining WRF Physics Options

Table 2-2 lists the remaining WRF physics options for the NM OAI Study 2014 36/12/4-km WRF application. These are standard WRF physics options and consistent with the WRF options used in the WRAP-WAQS 2014 and EPA 2014/2015/2016 WRF modeling. Our comparison of 2014 WRAP-WAQS and 2014 EPA WRF modeling for summertime precipitation performance in New Mexico found that the WRAP-WAQS WRF meteorological model performance was better than EPA WRF for most variables. Therefore, we used the same microphysics and cumulus schemes for the NM OAI Study as used in 2014 WRAP-WAQS (Thompson and Multi-Scale Kain-Fritsch, respectively) and most of the same other physics options (see Table 2-2).

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Table 2-2. NM OAI Study 2014 WRF model configuration and comparison with the WRF configuration used in the WRAP-WAQS 2014 and EPA 2014/2015/2016 WRF modeling.

WRF Option	NM OAI Study	2014 WRAP-WAQS	2014 EPA
Horizontal Domains	36/12/4-km	36/12/4-km	12-km
Vertical Coordinate	Hybrid Sigma	Sigma	Sigma
Microphysics	Thompson	Thompson	Morrison 2
LW Radiation	RRTMG	RRTMG	RRTMG
SW Radiation	RRTMG	RRTMG	RRTMG
Sfc Layer Physics	MM5 similarity	MM5 similarity	MM5 similarity
LSM	Noah	Noah	Pleim-Xiu
PBL scheme	Yonsei University (YSU)	YSU	ACM2
Cumulus	36/12/4-km Multi-scale Kain Fritsch	36/12-km Multi-scale_Kain Fritsch; 4-km None	Kain-Fritsch
BC, IC Analysis Nudging Source	36/12-km NAM & ERA5	36/12-km NAM	12-km NAM
Analysis Nudging Grids	36/12-km	36/12-km	12-km
Obs Nudging	None	4-km	None
Sea Sfc Temp	FNMOC	FNMOC	FNMOC

2.3.8 Application Methodology

The WRF model was executed in 5.5-day blocks initialized at 12Z every five days. Model results were output every 60 minutes, split at twelve (12) hour intervals. Twelve (12) hours of spin-up is included in each 5-day block before the data is used in the subsequent evaluation and PGM meteorological inputs.

2.4 WRF Model Evaluation

Quantitative and qualitative evaluations of the NM OAI Study 2014 WRF 36/12/4-km simulation meteorological performance was conducted for both the WRF/NAM and WRF/ERA5 applications. The quantitative evaluations compare integrated surface hourly meteorological observations with WRF predictions matched by time and location and included the calculation of model performance statistical metrics that were compared against performance benchmarks. The qualitative evaluations compared time series plots of modeled wind speed and wind direction to the observations at specific sites. The qualitative evaluation also compared spatial plots of WRF precipitation estimates against spatial maps of precipitation analysis fields based on observations

2.4.1 Quantitative Evaluation Using METSTAT

METSTAT was used to evaluate the WRF/NAM and WRF/ERA model performance against observed surface meteorological observations of wind speed and direction, temperature and mixing ratio (humidity). Figure 2-1 displays the WRF/NAM and WRF/ERA5 wind speed soccer plot that compares monthly measures of wind speed bias and error across surface monitoring sites in New Mexico with the simple and complex performance benchmarks. The monthly wind speed performance of the two WRF simulations are remarkably similar with both having near zero bias that achieves the simple benchmark (≤±0.5 m/s). The error (RMSE) for the two WRF simulations falls between the simple

and complex benchmarks (i.e., between 2.0 and 2.5 m/s) for all four months (May through August).

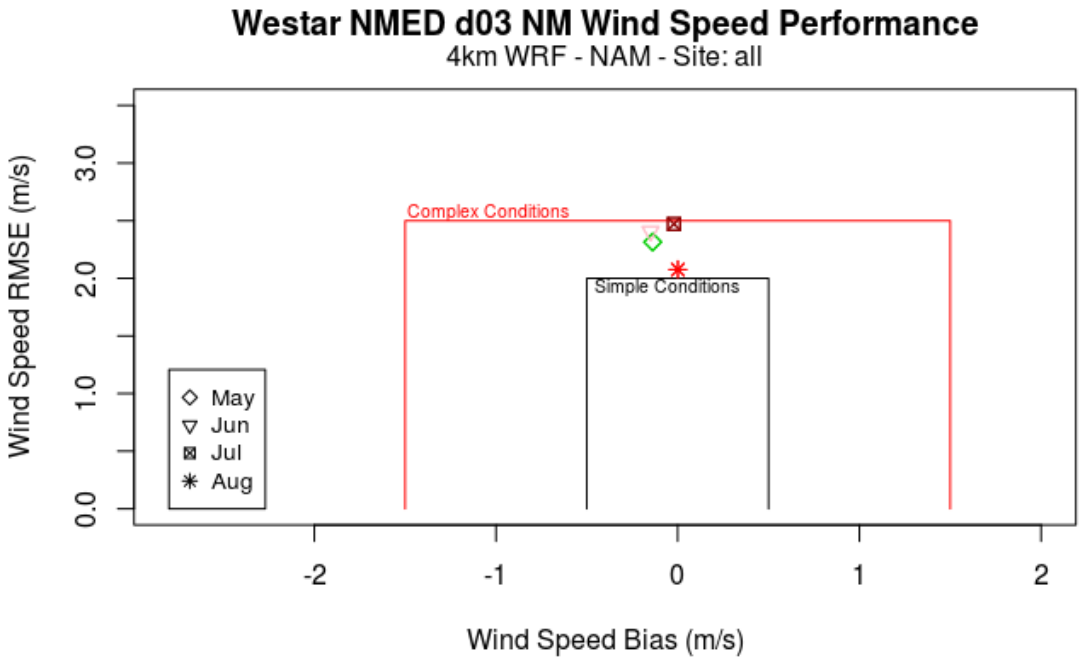
The monthly wind direction bias and error statistics for the two WRF simulations are also nearly identical with bias values of ~5 degrees that achieves the ≤±5 degree simple benchmark and error statistics that falls between the 30 degree simple and 50 degree complex benchmarks (Figure 2-2).

There are differences in the two WRF simulations temperature performance and more differences in the monthly values than seen for winds (Figure 2-3). The WRF/ERA5 simulations has a near zero temperature bias in May and June with the bias and error achieving the simple benchmark for both months. The WRF/NAM has a warm bias for May and June that straddle the simple benchmark upper bound (+0.5 K). The two WRF simulations have similar July and August performance that have a warm bias of ~1.0 K that fails to achieve the simple benchmark. For both WRF simulations, the temperature bias is right at, but mostly within, the 2.0 K simple benchmark.

The WRF/ERA5 clearly has better surface humidity performance than WRF/NAM (Figure 2-4). For July and August, the WRF/NAM has a wet bias in July and August of ~1.5 g/kg so fails to achieve the simple (≤±0.8 g/kg) and complex (≤±1.0 g/kg) bias benchmarks. The WRF/ERA5 also has a wet bias for July and August that is not as large as WRF/NAM as it is right at the simple benchmark (~ 1.0 g/kg) but achieving the complex benchmark. The WRF/ERA5 also has better humidity error performance in July and August, although both simulations achieve the error performance benchmarks.

The two WRF simulations have better humidity performance in May and June that achieves the simple benchmark, albeit with a moist bias. May is the best performing month with nearly identical humidity model performance with a bias of ~0.6 g/kg and error of ~0.9 g/kg. In June, the WRF/ERA5 humidity performance is slightly better than WRF/NAM.

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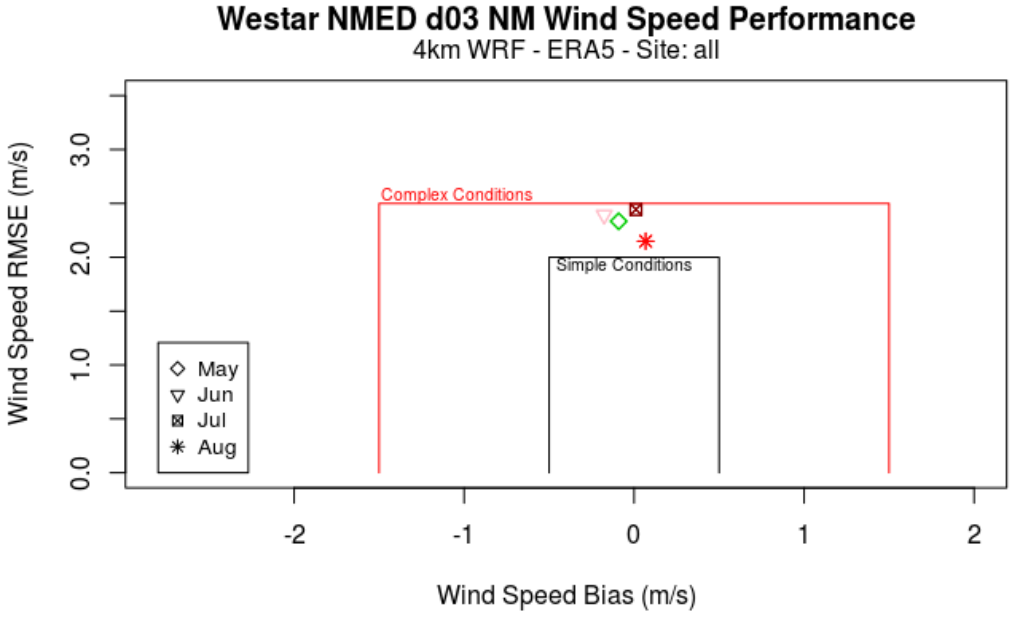


Figure 2-1. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface wind speed (m/s) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

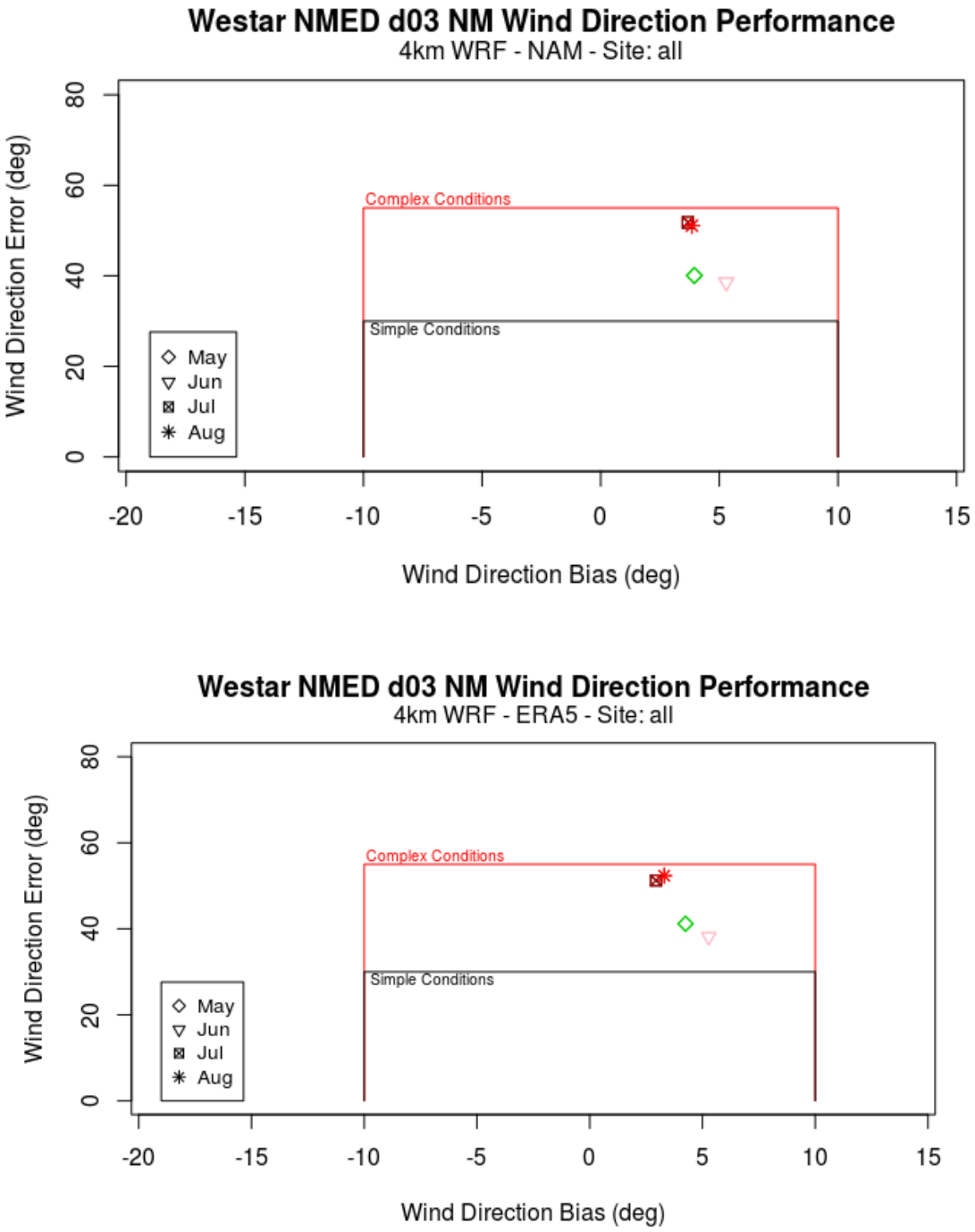


Figure 2-2. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface wind direction (degrees) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

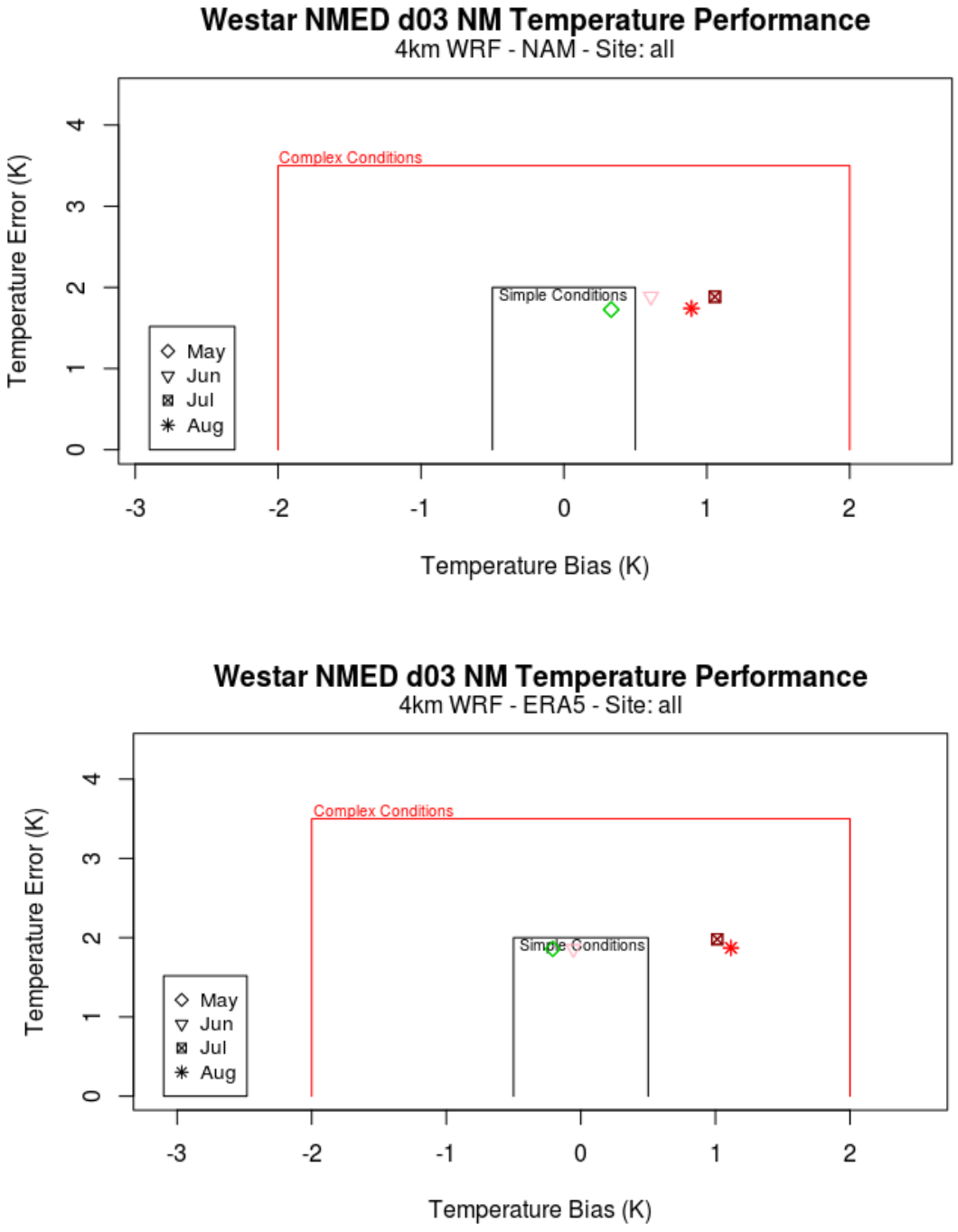


Figure 2-3. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface temperature (K) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

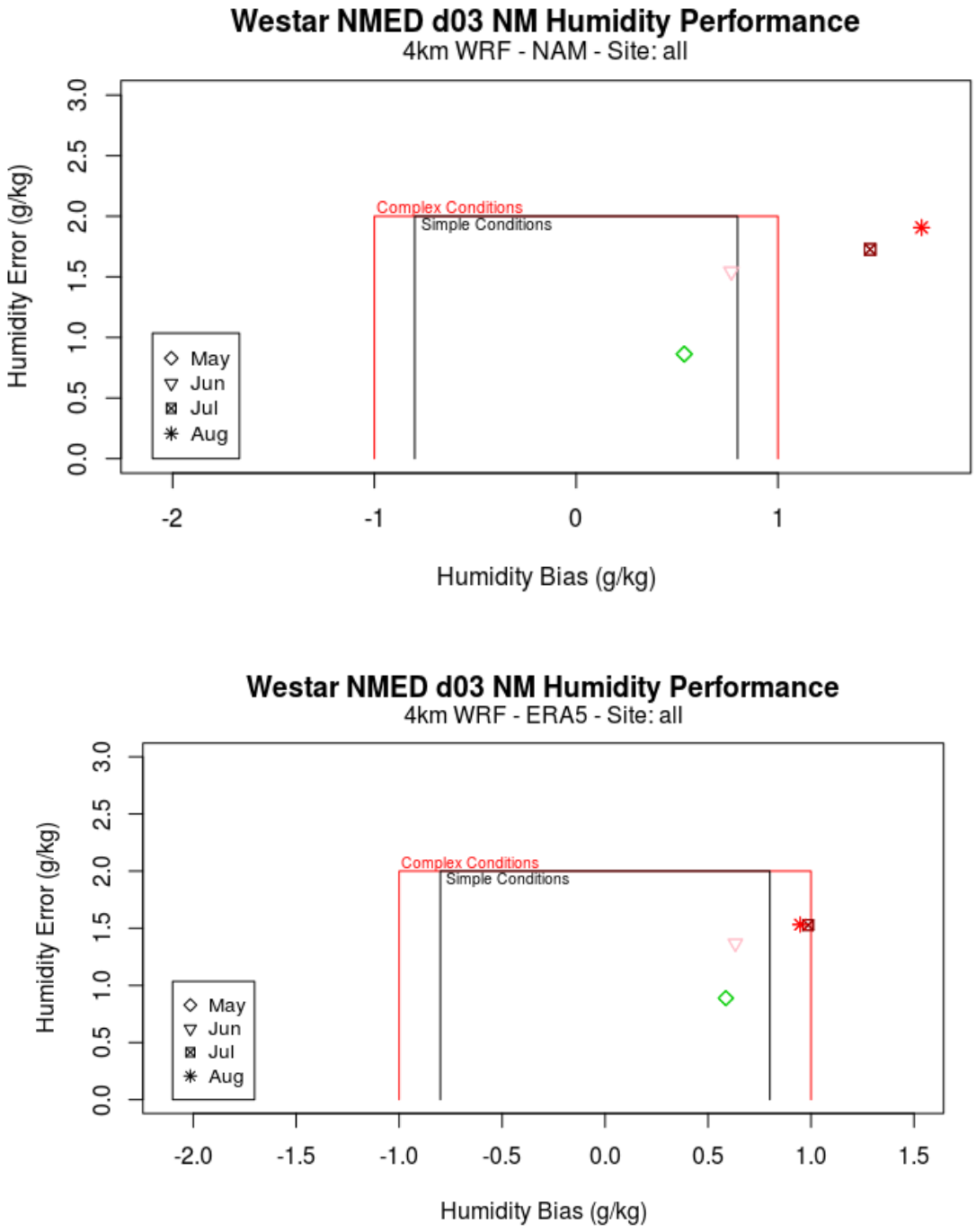


Figure 2-4. Soccer plot comparing WRF/NAM (top) and WRF/ERA5 (bottom) surface humidity (g/kg) model performance against the Simple and Complex Benchmarks for monthly RMSE (y-axis) and Mean Bias (x-axis).

2.4.2 Qualitative Evaluations for Precipitation Using PRISM Data

Oregon State University (OSU) publishes precipitation analysis fields based on observations that can be used to qualitatively evaluate the WRF precipitation fields. The Parameter-elevation Relationships on Independent Slopes Model (PRISM[18]) is used to generate the precipitation analysis fields (Daly et al., 2008). The PRISM interpolation method of observed precipitation reflects, as closely as possible, the current state of knowledge of spatial climate patterns in the United States. PRISM calculates a climate – elevation regression for each digital elevation model (DEM) grid cell, and stations entering the regression are assigned weights based primarily on the physiographic similarity of the station to the grid cell.

Figures 2-5 and 2-6 compares the PRISM monthly total precipitation across the 4-km New Mexico domain with the WRF/NAM and WRF/ERA5 model estimates for, respectively, July and August. Results for other months can be found in Ramboll and WESTAR (2020c). WRF/NAM overestimates the July monthly precipitation over northeast New Mexico, with WRF/ERA5 having an overestimation bias in most northerly Texas. But both WRF simulations have a dry bias for monthly precipitation over the remainder of New Mexico.

WRF/ERA5 does a better job at reproducing the locations and magnitudes of the August monthly PRISM precipitation than WRF/NAM (Figure 2-6). WRF/NAM overstates the August precipitation in central-south New Mexico.

[18] http://prism.oregonstate.edu/

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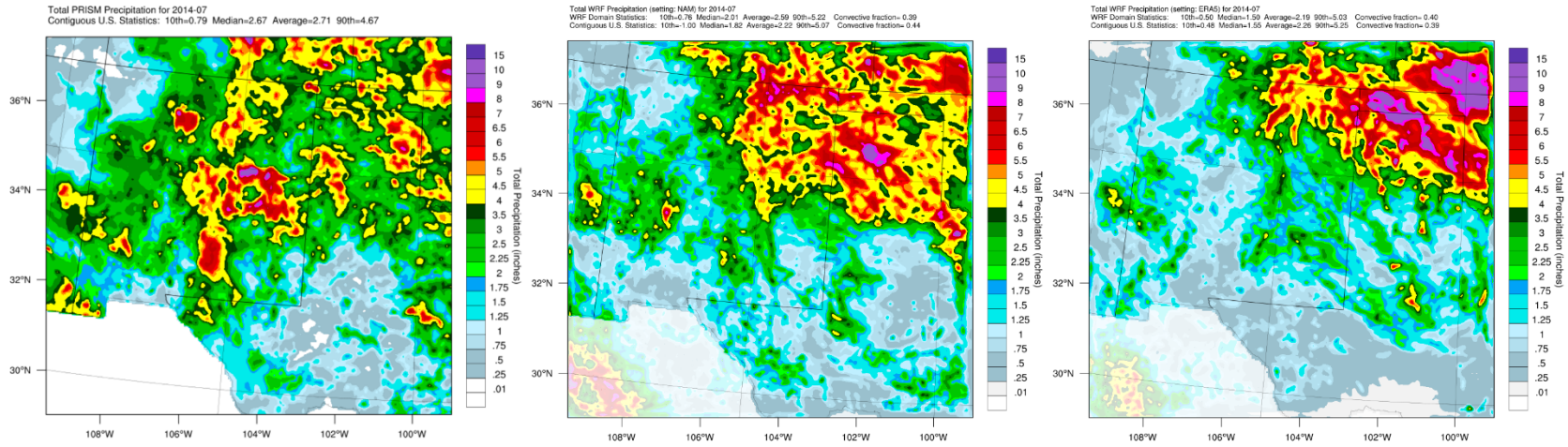


Figure 2-5. July monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

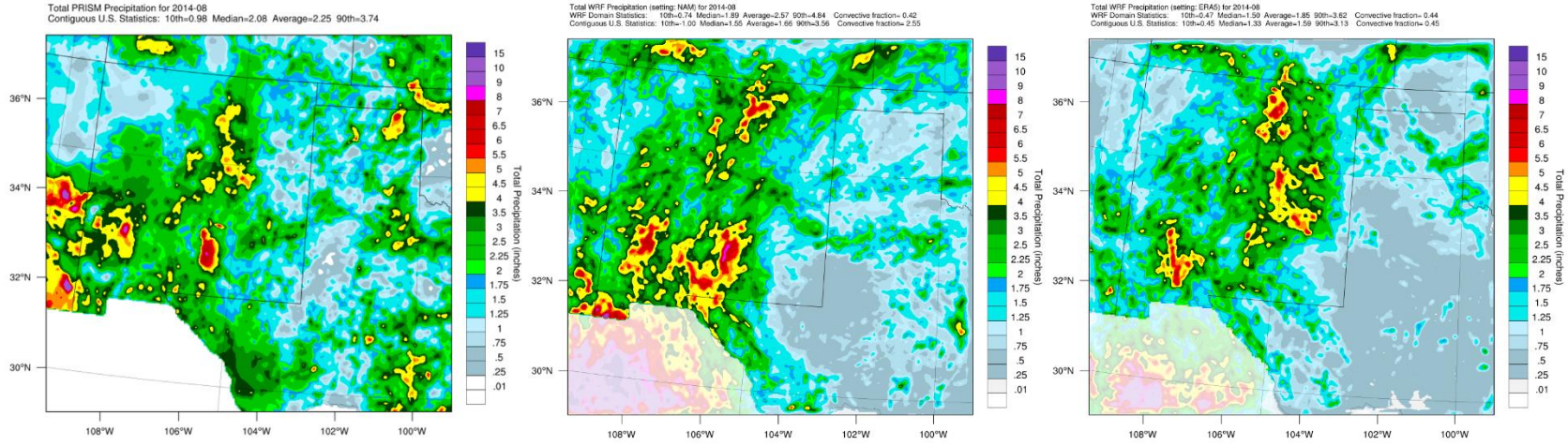


Figure 2-6. August monthly precipitation amounts from PRISM based on observations (left) and predicted by WRF/NAM (middle) and WRF/ERA5 (right).

2.4.3 Conclusions of 2014 WRF Model Performance

The model performance of the WRF/NAM and WRF/ERA5 simulations are reasonable and very similar for most meteorological variables (e.g., winds and temperature). This is in contrast to the WRAP-WAQS and EPA WRF 2014 simulations that had very different performance characteristics over New Mexico.[19] The biggest difference in the performance of the two WRF simulations was for humidity and precipitation. The WRF/NAM simulation had a moist bias for June-August that is likely partly associated with overactive convective precipitation that was greater in WRF/NAM than WRF/ERA5. It is unclear whether the WRF/NAM overstated precipitation is due to overactive convective events when they occur, or having events occur when they are not observed.

From the meteorological model performance evaluation, it is not possible to determine which set of WRF meteorological inputs will produce better ozone model performance when used as meteorological inputs for CAMx. There are variations in spatial and temporal model performance that are difficult to estimate what effects they will have on ozone concentrations. Furthermore, there may be meteorological inputs (e.g., level of mixing) that are more important for ozone modeling than the parameters we have observed data to evaluate the meteorological model for (i.e., winds, temperature, humidity and precipitation). Although it appears that WRF/NAM overstates the monthly precipitation if that does not occur on high ozone days it may not matter to the ozone model performance.

CAMx was run for a portion of the summer of 2014 episode with meteorological inputs based on both the WRF/NAM and WRF/ERA5 simulations and the ozone estimates compared to determine which meteorological inputs performed best so were selected for use in the final CAMX 2014 36/12/4-km base case simulation. The meteorological diagnostic sensitivity tests using the CAMx photochemical model are described in Chapter 5.

[19] https://www.wrapair2.org/pdf/NM_OAI_Study_Webinar1_2020-05-28.pdf

3. BOUNDARY CONDITION INPUTS

The Boundary Conditions (BCs) for the CAMx most outer 36-km 36US modeling domain lateral boundaries were based on output from a 2014 simulation of the GEOS-Chem global chemistry conducted by WRAP for their 2014v2 modeling platform.

3.1 WRAP 2014 GEOS-Chem Modeling

The WRAP-WAQS 2014v1 36/12-km CAMx and CMAQ base case simulations used BCs based on EPA's 2014 GEOS-Chem simulation that was used in EPA's 2014 modeling platform used in the 2014 National Air Toxics Assessment (NATA[20]). The CAMx and CMAQ 2014v1 base case simulation and sensitivity modeling found that the BCs based on EPA's 2014 GEOS-Chem caused year-long ozone overestimation bias throughout the western U.S.[21] Thus, WRAP conducted their own 2014 GEOS-Chem simulation using a newer version of the model and with updated emissions that resulted in much better CAMx ozone model performance without the systematic ozone over-prediction bias.[22] Table 3-1 presents the WRAP 2014 GEOS-Chem model configuration.

Table 3-1. 2014 GEOS-Chem simulation model configuration used by WRAP whose output is used to define the 2014 day-specific diurnally varying BC inputs for the NM OAI Study photochemical modeling.

Science Options	WRAP 2014 GEOS-Chem Base Case
Version	Version 12.2.0 (release date: 2019-02-19)
Vertical Grid Mesh	72 Layers
Chemistry mechanism	GEOS-Chem standard chemistry with complex SOA option[23].
Horizontal Grids	2x2.5 degree (Nx, Ny = 144, 91)
Initial Conditions	6-month spin-up; starting from provided initial conditions for standard chemistry
Meteorology	2014 GEOS-FP meteorology
Photolysis mechanism	Default (FAST-J)
Advection Scheme	Default (TPCORE)
Cloud convection scheme	On / Relaxed Arakawa-Schubert
Planetary Boundary Layer mixing	On / non-local scheme implemented by Lin and McElroy
Dry deposition scheme	Default (Wesely)
Chemistry Solver	Default (FLEXCHEM)
Parallelization	Open Multi-Processing (OMP)

[20] https://www.epa.gov/national-air-toxics-assessment
[21] http://views.cira.colostate.edu/iwdw/docs/waqs_2014v1_shakeout_study.aspx
[22] https://www.wrapair2.org/pdf/WRAP_Shake-Out_Phase-III_Update_RTOWG_2019-09-10v3a.pptx
[23] We recommend turning off semivolatile primary organic aerosol (POA) chemistry and isoprene SOA reactions via the volatility-based scheme (VBS) [Pye et al., 2010] to avoid risk of double-counting in the complex SOA chemistry scheme. For more information, see http://maraisresearchgroup.co.uk/Publications/GC-v11-02-SOA-options.pdf

3.2 2014 GEOS-Chem Model Evaluation

The results of the WRAP 2014 GEOS-Chem simulation and CAMx sensitivity modeling using the new BCs can be found on the WAQS-WRAP2014v2 model evaluation webpage[24]. Relevant for the NM OAI Study is the fact that this updated 2014 GEOS-Chem BCs do lead to better CAMx model performance for ozone concentrations and corrects a persistent year-long ozone overestimation bias that occurred using the previous 2014 GEOS-Chem simulation conducted by EPA and used in the EPA 2014 modeling platform. The NM OAI Study evaluated the use of the WRAP 2014 GEOS-Chem BCs for CAMx modeling at several sites in New Mexico and found good ozone performance that achieved ozone model performance goals.[25] Thus, the WAQS-WRAP 2014v2 BC inputs based on the WRAP 2014 GEOS-Chem simulation were used "as is" for the NM OAI Study.

[24] http://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx
[25] https://www.wrapair2.org/pdf/NM_OAI_Study_Webinar1_2020-05-28.pdf

4. 2014 AND 2028 EMISSION INPUTS

4.1 Summary of Emissions Used in 2014 and 2028 Modeling

The emissions inventories for the CAMx 2014 36/2/4-km base case modeling were based on the WRAP-WAQS 2014v2 emissions inventory. Within the 36-km 36US North American and 12-km 12WUS2 western U.S. domains, the WRAP-WAQS CAMx 2014v2 base case emission inputs were used without any changes.

For the 4-km New Mexico domain, the WRAP-WAQS 2014v2 emissions have been reviewed and updated as needed by the NMED. For on-road mobile sources, the 4-km domain emissions were based on MOVES2014 model, 2014 activity data and day-specific hourly gridded 2014 WRF 4-km meteorology run through SMOKE-MOVES.

For the NM OAI Study future year 2028 Base Case and 2028 New Mexico O&G Control Strategy, the emissions were based on the WRAP 2028OTBa2 emissions inventory with updated New Mexico O&G emissions and use of 2014 actual fires instead of the Representative Baseline fires. The 2028OTBa2 CAMx-ready emission inputs for the 36/12-km domains were used "as is", substituting the 2014v2 actual 20014 fires for the Representative Baseline fires. For the 4-km NM domain, the 2028OTBa2 emissions were processed using SMOKE, with the new 2028 New Mexico (NM) oil and gas (O&G) emissions substituted for the NM O&G emissions used in the 2028OTBa2 emissions scenario.

The NM OAI Study 2028 O&G Control Strategy scenario used the exact same emissions as the NM OAI Study 2028 Base Case, only the controlled 2028 O&G emissions were used in New Mexico. The 2028 NM O&G Control Strategy oil and gas emissions were provided by ERG under separate contract to NMED.

4.2 Development of CAMx 2014 Base Case Emission Inputs

The CAMx 2014 base case emission inputs for the 36/12-km domains were based on the WRAP 2014v2 CAMx model-ready emission inputs and were used "as is." For the 4-km NM domain, the New Mexico emissions from the 2014v2 database were reviewed and updated by the NMED. The 2014v2 emissions for New Mexico and portions of surrounding states within the 4-km New Mexico domain were then processed by the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system (UNC, 2015). SMOKE version 4.7 was used, which was released in October 2019.[26]

4.2.1 Day-Specific On-Road Mobile Source Emissions

The 2014 on-road mobile source emission inputs for the 4-km New Mexico domain were generated using the SMOKE-MOVES emissions model. SMOKE-MOVES used a 2014 mobile source emission factor (EF) lookup table generated by the Motor Vehicle Emission Simulator (MOVES2014[27]) model (EPA, 2014a,b,c). The SMOKE-MOVES default county-level 2014 vehicle activity data for New Mexico was reviewed by NMED and updated as needed. SMOKE-MOVES uses the 2014 MOVES EF lookup table, hourly gridded 4-km meteorological data from the 2014 WRF simulation conducted in this study (see Chapter 2) and 2014 county-level activity data (e.g., vehicle miles travelled

[26] https://www.cmascenter.org/smoke/
[27] https://www.epa.gov/moves/moves-onroad-technical-reports#moves2014

[VMT], speed, etc.) to generate 2014 day-specific hourly gridded on-road mobile source emission inputs for CAMx and the 4-km New Mexico domain.

4.2.2 Point Source Emissions

2014 point source emissions were based on the WRAP-WAQS 2014v2 emissions inventory. The 2014v2 New Mexico point source emissions were reviewed and updated by NMED. Point sources were processed in two streams: (1) major point sources with Continuous Emissions Monitoring (CEM) devices, which are primarily fossil-fueled Electrical Generating Units (EGU) with capacity of 25 MW or greater; and (2) point sources without CEMs. For point sources with CEM data, day-specific hourly NO_X and SO_2 emissions were used for the 2014 base case emissions scenario. The VOC, CO, and PM emissions for point sources with CEM data were based on the annual emissions data in the 2014v2 inventory temporally allocated to each hour of the year using the CEM hourly heat input.

4.2.3 Area and Non-Road Source Emissions

The 2014 area and non-road sources were spatially allocated to the 4-km New Mexico grid using an appropriate surrogate distribution (e.g., population for home heating, etc.). The area sources were temporally allocated by month and by hour of day using the SMOKE source-specific temporal allocation factors, while chemical speciation used the SMOKE source-specific CB6r4 speciation allocation profiles.

4.2.4 Episodic Biogenic Emissions

Two different CAMx 2014 base case simulations were conducted using two different biogenic emission inputs within the 4-km NM domain. The first CAMx 2014 base case 4-km domain biogenic emissions were generated using Version 3.1 of the MEGAN biogenic emissions model. MEGAN v3.1 is a new version of MEGAN and comes with a Leaf Area Index (LAI) database that defines the vegetative biomass and type that when combined with temperature and light dependent emission factors produces biogenic VOC emissions using the day-specific hourly gridded WRF meteorology. However, the new LAI data in MEGAN v3.1 were missing for urban areas producing "holes" in the biogenic VOC emission inputs. Thus, revised CAMx 2014v2 base case 4-km NM biogenic emission inputs used the BEIS v3.7 biogenic emissions model. BEIS3.7 is the most recent version of BEIS released by EPA in October 2020. BEIS3.7 uses updated biomass and emissions factors, and the Biogenic Emissions Landcover Database version 5 (BELD5). Table 4-1 compares the biogenic NO_x and VOC emissions by month (in tons/month) for the 4-km NM domain and the two biogenic models. The BEIS NO_x emissions are substantially lower than MEGAN, and VOC emissions are mostly lower except early summer month showing slightly higher emissions with BEIS. Figure 4-1 displays the spatial distributions of emissions in the 4-km NM domain expressed as episode average tons per day. The BEIS NO_x and VOC emissions are mostly lower than MEGAN throughout the domain. The missing biogenic VOC emissions in urban areas (e.g., El Paso/Juarez) using MEGAN v3.1 is also evident in the spatial maps.

Table 4-1. 2014 biogenic emissions (tons/month) in the 4-km NM domain estimated by MEGAN3.1 and BEIS3.7.

Tons/month		MEGAN	BEIS	% Diff (BEIS-MEGAN)
NO_x	May	35,050	10,602	-69.8%
	Jun	42,445	13,134	-69.1%
	Jul	51,639	12,838	-75.1%
	Aug	41,002	11,923	-70.9%
VOC	May	128,323	159,809	24.5%
	Jun	267,055	256,379	-4.0%
	Jul	317,697	251,562	-20.8%
	Aug	354,570	216,032	-39.1%

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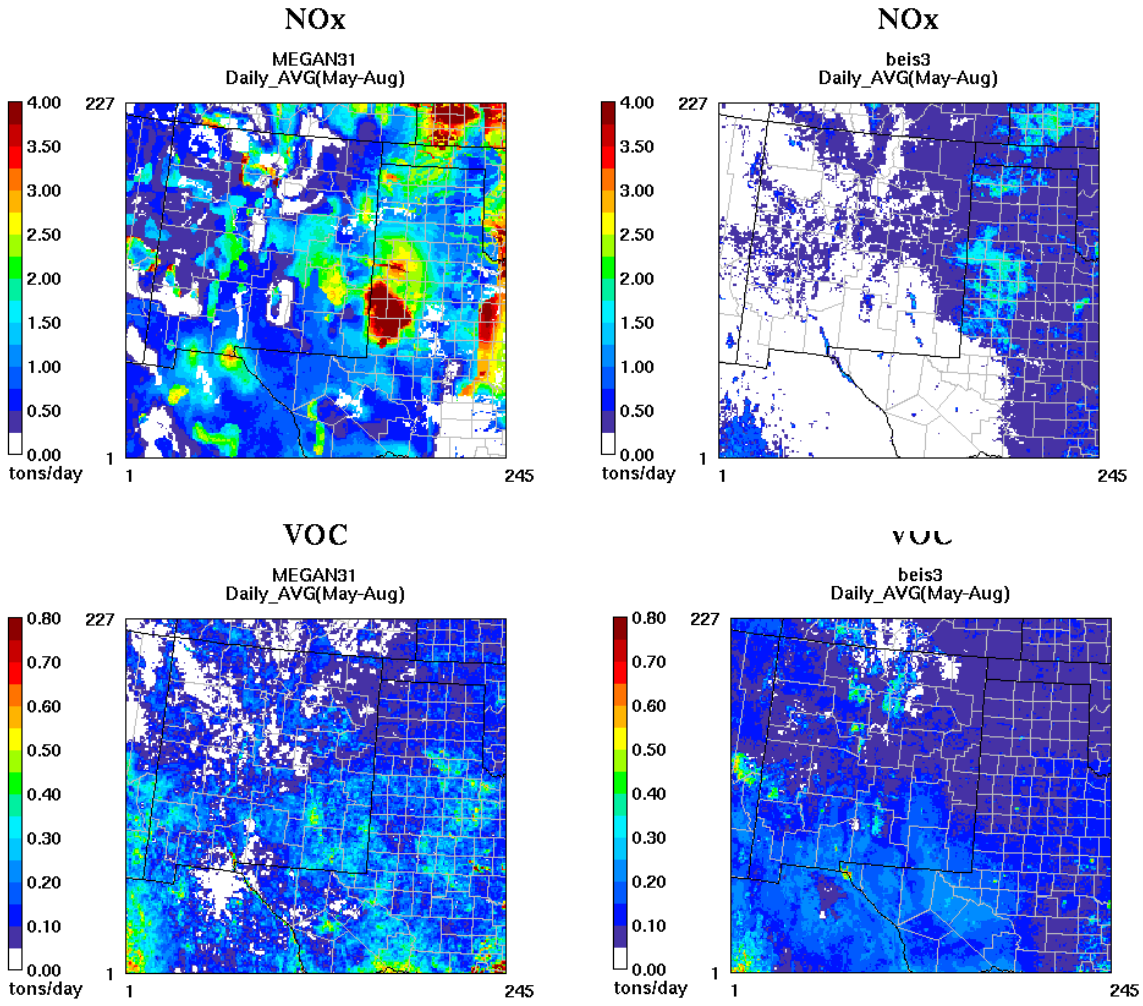


Figure 4-1. Spatial distribution of NO_x (top panel) and VOC (bottom panel) biogenic emissions (episode average tons per day) in the 4-km NM domain estimated by MEGAN3.1 (left) and BEIS3.7 (right).

4.2.5 Wildfires, Prescribed Burns, Agricultural Burns

2014 emissions from open-land burning including wildfires, wildland prescribed burns and agricultural burning were based on the WRAP-WAQS 2014v2 emissions inventory. The WRAP Fire and Smoke Work Group (FSWG[28]) processed the 2014NEIv2 Bluesky/SMARTFIRE fire emissions for the U.S. and classified them as either wildfires (WF), wildland prescribed burns (Rx) or agricultural burning (Ag) and made other updates for the 2014v2 inventory. The 2014NEIv2 fire emissions for Mexico and Canada were used without any changes. Table 4-2 displays NO_x and VOC emissions by month and fire type within the 4-km NM domain. Figure 4-2 displays spatial maps of NO_x emissions from 2014 summer fires for the 4-km NM domain. Emissions are expressed as episode average tons per day per grid cell. We see some hotspots on the wildfires plot in New Mexico and Arizona near the western boundary of the 4-km domain.

[28] https://www.wrapair2.org/FSWG.aspx

Table 4-2. 2014 fire emissions summary (tons/month) by fire type for the 4-km NM domain

Tons/month	Pollutant	Ag fires	Prescribed fires	Wildfires	Mexico fires
NO_x	May	36	90	597	49
	Jun	11	81	1,056	32
	Jul	18	13	332	8
	Aug	18	69	39	2
VOC	May	60	617	6,663	92
	Jun	18	736	17,641	187
	Jul	29	82	4,985	40
	Aug	28	1,376	371	13

NMED Exhibit 17

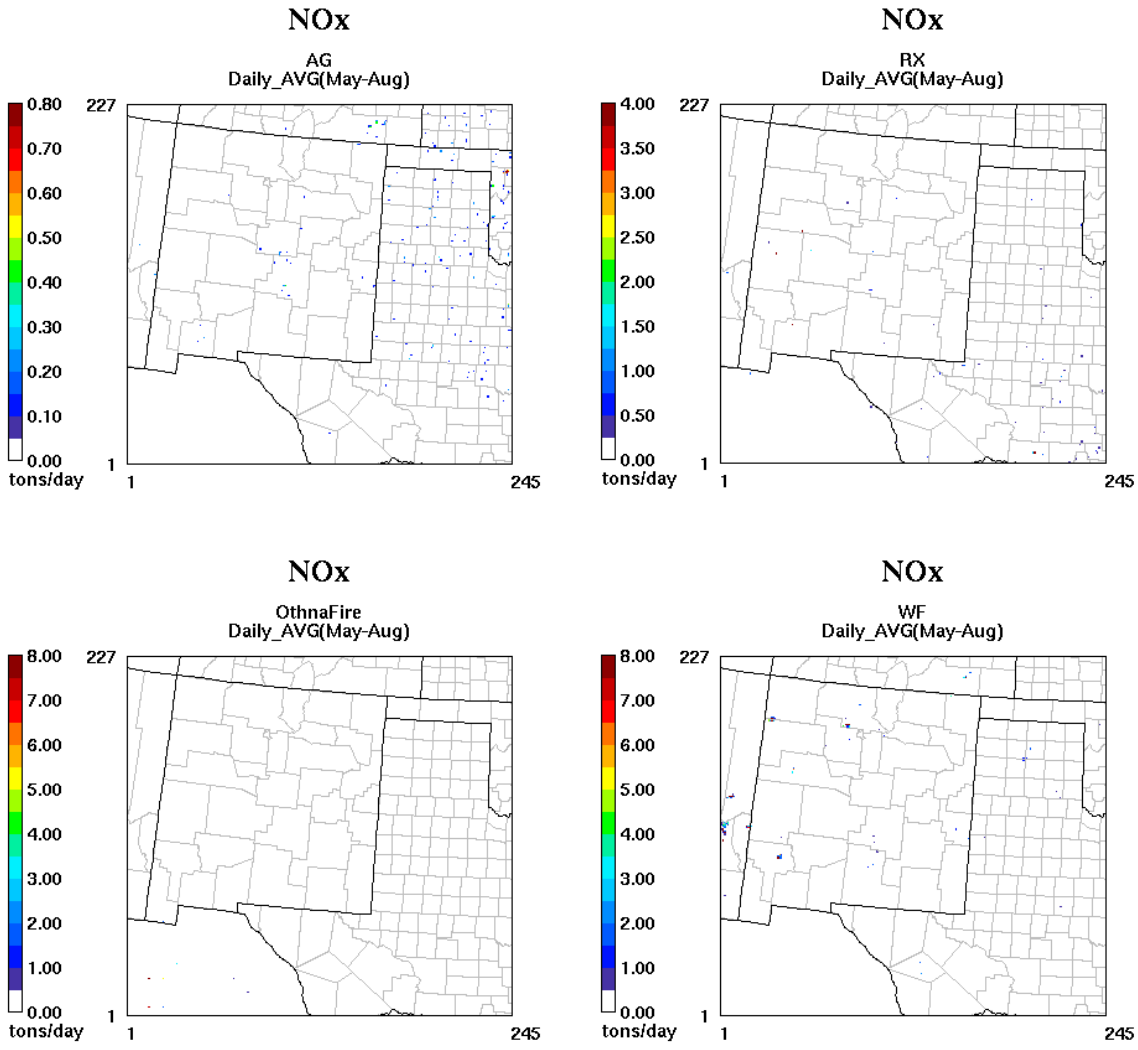


Figure 4-2. Spatial distribution of agricultural fires, prescribed fires, wildfires and Mexico fires (clockwise starting from top left) NO_x emissions (episode avg tons per day) for New Mexico 4-km domain.

4.2.6 Other Natural Emissions

Lightning NO_x (LNO_X), and windblown dust (WBD) emissions were generated for the 4-km domain using special CAMx processors and WRF 2014 meteorological data. Oceanic emissions such as sea salt spray aerosol (SSA) and dimethyl sulphide (DMS) were not generated for the 4-km New Mexico domain since this domain does not include any ocean within it. However, the LNO_X, WBD and oceanic emissions for the 36-km and 12km were based on the WRAP-WAQS 2014v2 emissions and were included in the modeling.

4.2.7 2014 Emission Results

Table 4-3 summarizes the 2014 criteria air pollutant emissions in episode average short tons per day by source category for the 4-km New Mexico domain. These data represent the model-ready emissions input to the CAMx air quality model for the 2014

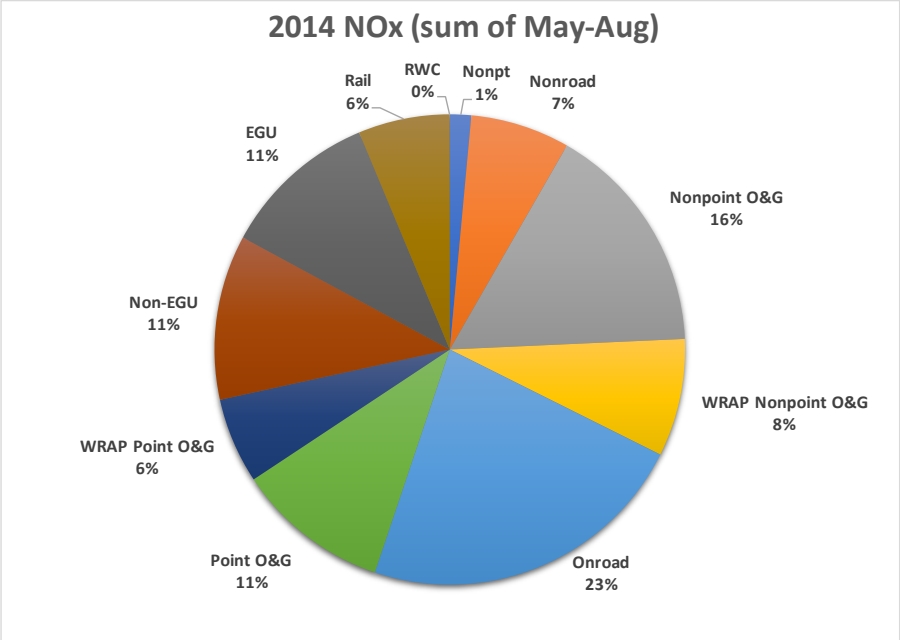
base case. Mostly, emissions are summarized from the SMOKE reports generated by the SMKMRG program. There are a couple of exceptions to this general approach, fugitive dust and EGU sources. The fugitive dust emissions were adjusted after SMOKE processing to account for fugitive dust correction factors that are derived from the Biogenic Emission Landuse Database version 4 (BELD4). The correction factors are necessary to account for dust removal due to local vegetation scavenging so are not transported downwind. Model-ready emissions for EGU and Mexico point sources were obtained from WRAP/WAQS 2014 platform so were summarized for the 4-km domain outside of SMOKE.

Table 4-3. 2014 base case anthropogenic emissions summary (episode average short tons per day) by source category for the 4-km New Mexico domain.

Country/ Category	Source Category	CO	NH_3	NO_x	$PM_{2.5}$	PM_{10}	SO_2	VOC
US Anthro	Area fugitive dust	0.0	0.0	0.0	253.3	1,788.2	0.0	0.0
	Agricultural ammonia sources	0.0	764.7	0.0	0.0	0.0	0.0	43.4
	Non-point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)	237.7	0.0	157.8	4.4	4.4	11.3	567.3
	Remaining Non-point Oil and Gas	286.8	0.0	311.7	6.9	6.9	30.0	1,642.5
	Residential Wood Combustion	7.0	0.1	0.1	0.5	0.5	0.0	1.2
	Other nonpoint sources	141.3	1.5	28.5	9.3	13.4	4.5	213.2
	On-road mobile	1,476.2	6.0	444.5	13.2	20.1	1.7	150.6
	Locomotive	22.9	0.1	122.7	2.9	3.1	0.1	6.2
	Non-road mobile	570.3	0.2	133.4	9.0	9.4	0.3	73.2
	EGU point sources	89.2	3.4	210.6	12.9	17.8	160.0	5.0
	Point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)	89.9	0.0	114.7	1.4	1.4	23.8	56.1
	Remaining Point Oil and Gas	113.8	0.1	205.2	3.2	3.3	27.1	48.4
	Non-EGU point sources	74.4	4.9	47.5	11.4	32.5	49.3	24.4
Mexico Anthro	Mexico area	19.9	33.2	42.2	5.8	15.7	1.7	103.3
	Mexico on-road mobile	356.3	0.6	98.4	1.5	2.6	1.4	34.4
	Mexico point sources	28.4	0.7	20.2	4.8	5.7	16.4	8.3

Figure 4-3 presents pie charts showing VOCs and NO_x emissions from anthropogenic sources by source category for New Mexico and portion of surrounding states within the 4-km domain. Point and non-point oil and gas sectors account for majority of NO_x emissions followed by on-road mobile and EGU sources. In New Mexico, oil and gas sources are the largest anthropogenic VOC emitters and accounts for nearly 80% of 4-km domain VOC emissions.

NMED Exhibit 17



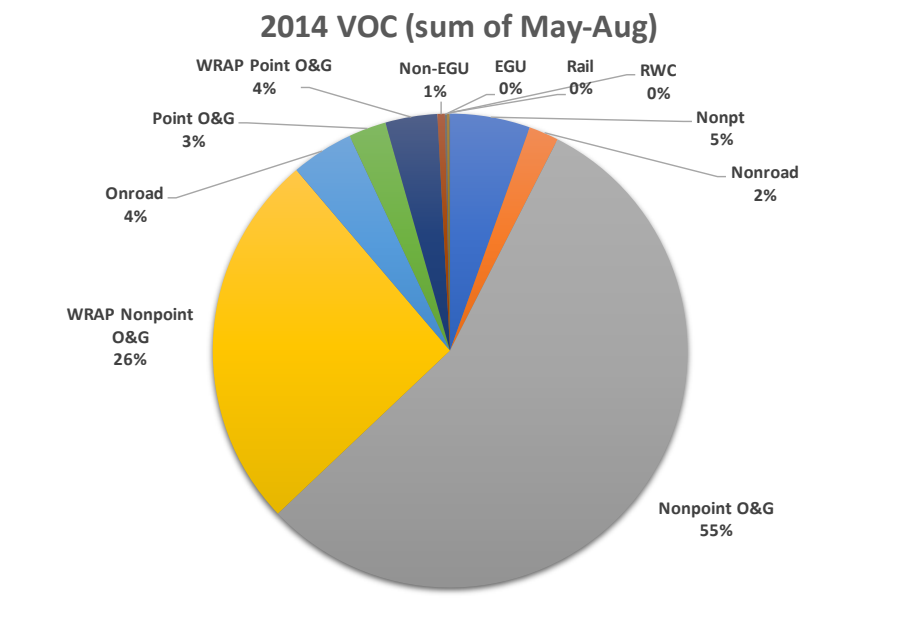


Figure 4-3. New Mexico 2014 base case anthropogenic NO_x and VOC emissions by source category.

Figure 4-4 displays spatial maps of NO_x and VOC anthropogenic emissions from the oil and gas sector across the 4-km New Mexico domain. Top panel shows emission maps for non-point O&G sources while bottom panel shows point O&G sources. The San Juan and Permian basins are clearly visible on the emissions map and confirm correct spatial allocation of oil and gas emissions. Figure 4-5 shows emission maps for on-road mobile (top panel), rail (middle panel) and non-point sources including non-road equipment (bottom panel).

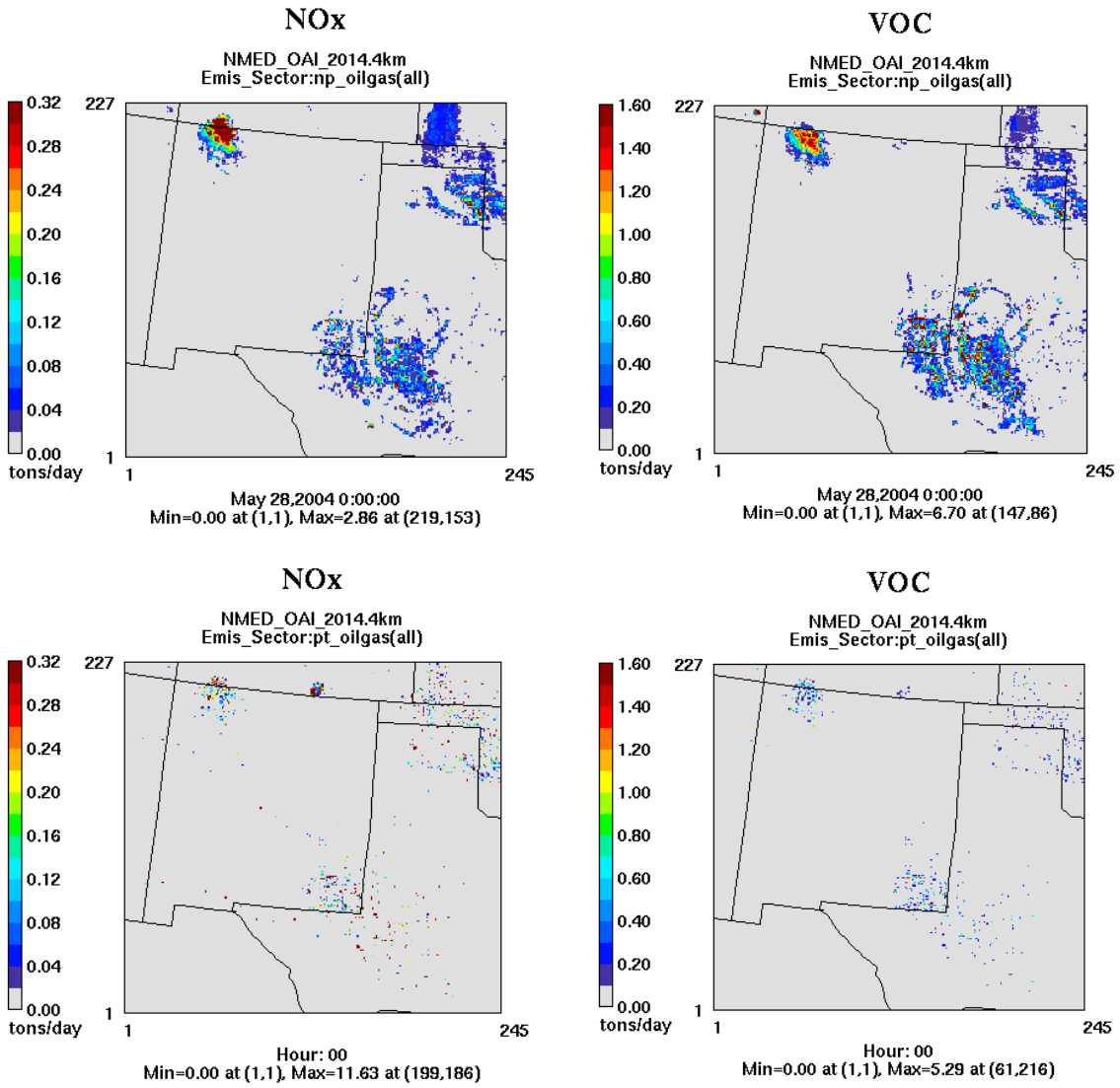
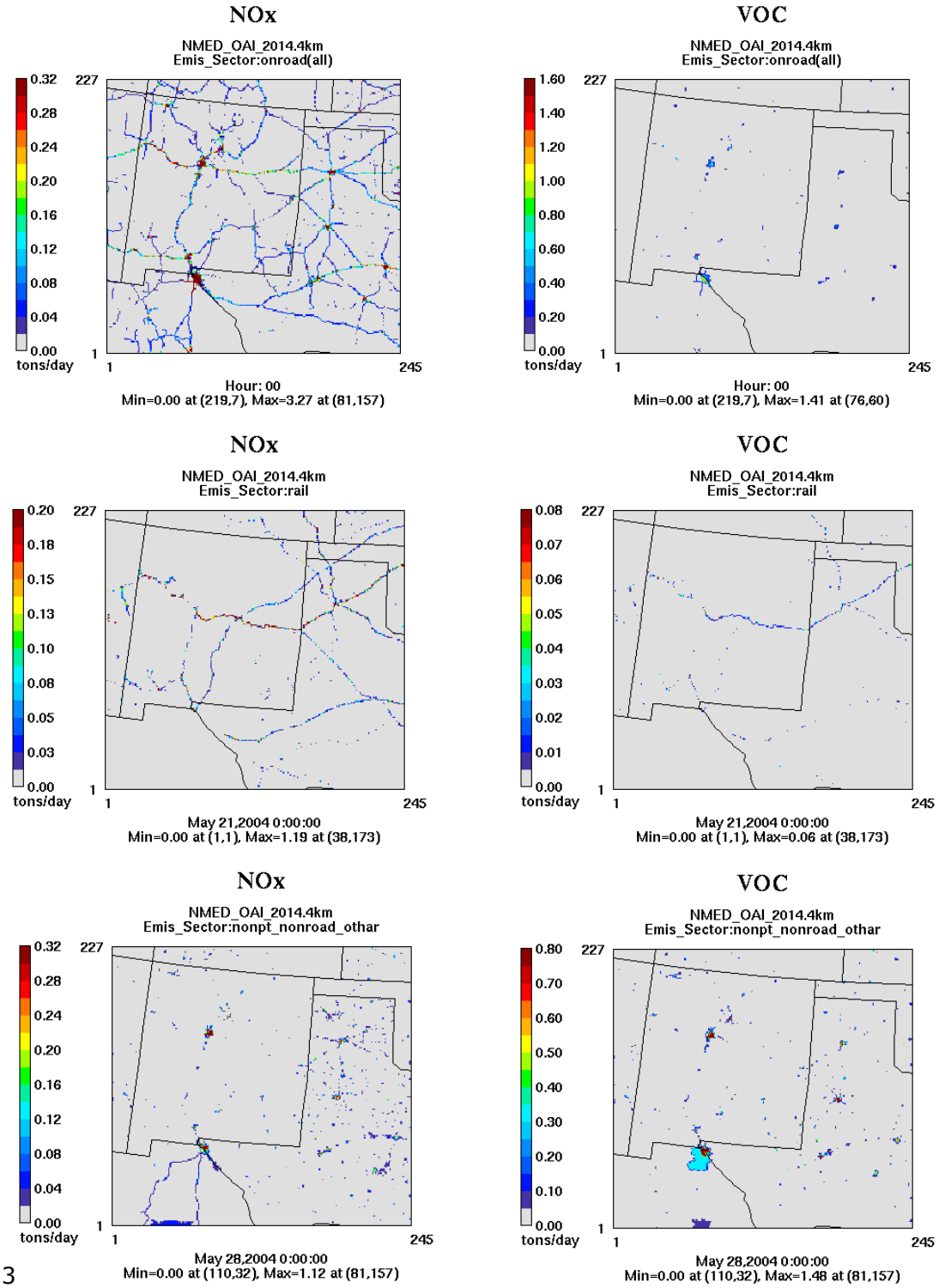


Figure 4-4. Spatial distribution of the non-point (top) and point (bottom) source oil and gas NO_x (left) and VOC (right) emissions (episode avg tons per day) for New Mexico 4-km domain.



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Figure 4-5. Spatial distribution of on-road (top), rail (middle) and non-point/non-road equipment (bottom) NO_x (left) and VOC (right) emissions (episode avg tons per day) for New Mexico 4-km domain.

4.3 Development of CAMx 2028 Emission Scenarios

The NM OAI Study 2028 base case and 2028 O&G Control Strategy emissions were based on the WRAP 2028OTBa2 emissions inventory with updates to NM O&G emissions and using 2014 actual fires. Details on the 2028OTBa2 emission assumptions are contained in the WRAP Representative Baseline (RepBase2) and 2028 On-the-Books (2028OTBa2) CAMx Simulation Run Specification Sheet.[29] The original WRAP 2028OTBa emissions scenario used EPA's 2028 emission projections from their 2016v1 modeling platform[30] for several source sectors (e.g., non-EGU Point Sources). However, some of EPA's 2028 emission projections were inconsistent with the WRAP 2014v2 emission updates for the western states and there were double counted sources in EPA's 2016v1 platform 2028 emission projections. Thus, WRAP elected to use more source sector emissions from the EPA 2016v1 and WRAP 2014v2 emissions inventories that were vetted by many states resulting in the following source sectors used in the 2028OTBa2 emissions inventory with deviations from the WRAP 2028OTBa2 from the NM OAI Study 2028 base case discussed below (see details in Run Specification Sheet cited in footnote):

- The California Air Resources Board provided 2028 emissions for California and all source sectors.
- 2028 emissions for Electrical Generating Units (EGU) for fossil-fueled EGUs in WRAP states were reviewed in detail by the individual states starting from the results of the WRAP EGU Analysis Project.[31] 2028 emissions for Non-fossil-fueled EGU in the WRAP region and all EGUs outside of the WRAP region were based on EPA's 2016v1 modeling platform 2028 projections.
- 2028 O&G emissions for New Mexico were based on new estimates developed in the NM OAI Study as described later in this chapter. 2028 O&G emissions for other non-New Mexico WRAP region O&G basins are based on the WRAP projections out to 2023 (Ramboll, 2020a). The EPA 2016v1 platform 2016 O&G emissions were used for non-WRAP states. The 2028OTBa2 O&G emissions were reviewed in detail by WRAP region states to eliminate duplications and update sources as needed.
- Non-EGU Point Source emissions for the WRAP states were reviewed in detail by the individual states starting from the WRAP 2014v2 emissions, while the EPA 2016v1 platform emissions for 2016 were used for non-WRAP states.
- The SMOKE-MOVES model with 2014 meteorology, 2028 vehicle activity and 2028 MOVES2014 Emissions Factor Look-Up tables were used to generate 2028 on-road mobile source emissions by either WRAP[32] for the 12-km domain or the NM OAI Study for the 4-km domain.
- 2028 Non-road emissions were based on 2028 estimates by WRAP in the Mobile Source Emissions Inventory Projection Project for the WRAP region and EPA's 2028 estimates for the non-WRAP states.

[29] https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/EmissionsSpecifications_WRAP_RepBase2_and_2028OTBa2_RegionalHazeModelingScenarios_Sept30_2020.pdf

[30] https://www.epa.gov/air-emissions-modeling/2016v1-platform

[31] https://www.wrapair2.org/EGU.aspx

[32] WRAP Mobile Source Emissions Inventory Projections Project

- WRAP region 2014v2 and EPA 2016v1 emissions were used for the Non-Point source sector in the 2028OTBa2 emissions scenario.
- The NM OAI Study 2028 fires were based on the WRAP region 2014v2 actual fire estimates.
- Natural emissions (biogenic, lighting NO_x, windblown dust and oceanic) were the same as used in the WRAP 2014v2, RepBase2 and 2028OTBa2 emission scenarios

4.3.1 2028 Base Case New Mexico Oil and Gas Emissions

A circa 2028 forecast oil and gas (O&G) emission inventory was developed for New Mexico for use in the NM OAI Study 2028 Base Case emission scenario. The basis of the forecast O&G emission inventory is circa 2028 O&G activity estimates provided by BLM[33] and emissions and emission per unit of O&G activity from the future year WRAP Oil and Gas Working Group (OGWG) emission inventory (Ramboll, 2020a). The WRAP OGWG developed 2023 future year O&G emissions for 7 of the WRAP states.

The 2028 New Mexico O&G emission inventory includes wellsite, gathering, and processing subsectors, which are items 1, 5, and 6 in Figure 4-6. Item 1 are On-Shore Petroleum and Natural Gas Production is referred to as "wellsite" sources; emissions from wellsite sources are classified as nonpoint sources. Item 2 are Gathering and Boosting sources. Item 6 consists of Gas Processing Plants are collectively referred to as "midstream" sources; emissions from midstream sources are classified as point sources. The classification of well-site emissions as nonpoint and midstream emissions as point sources is consistent with other O&G emission inventory classifications used in prior studies, such as the BLM Colorado Air Resource Management Modeling Study (CARMMS)[34].

[33] Email communication from BLM Staff (Forrest Cook) to Ramboll (John Grant). September 15, 2020.
[34] https://www.blm.gov/programs/natural-resources/soil-air-water/air/colorado

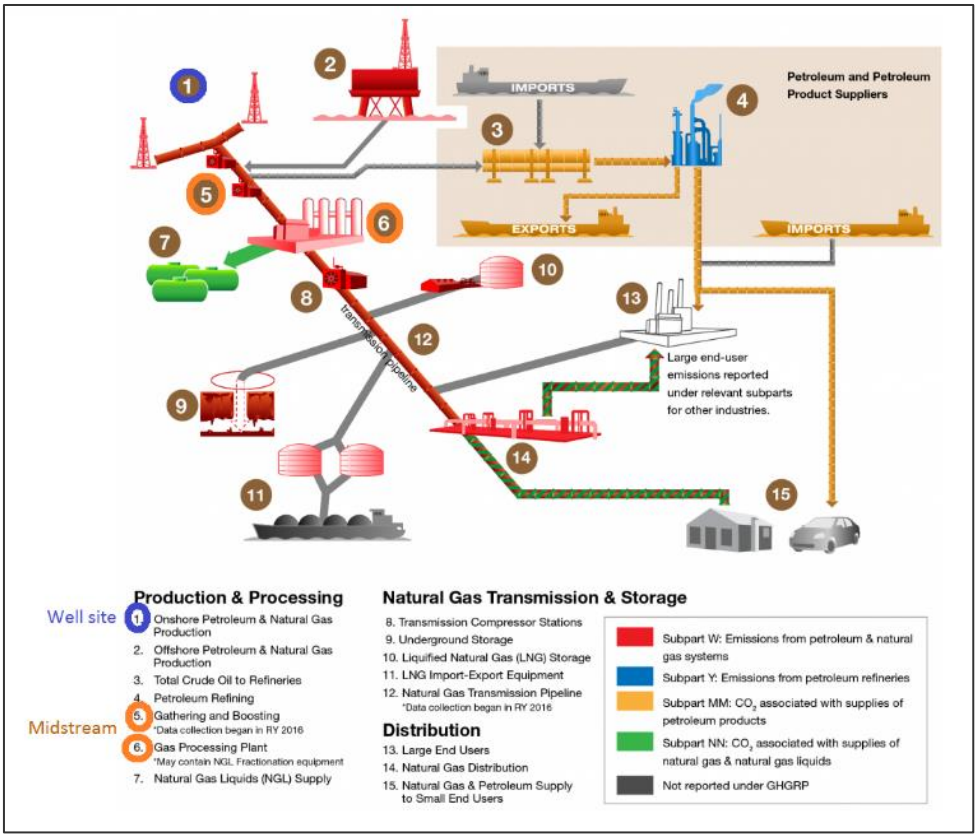


Figure 4-6. Example Petroleum and Natural Gas Industry schematic[35].

The BLM O&G forecast factors were used to project New Mexico O&G emissions to 2028. Table 4-4 compares the New Mexico O&G VOC and NO_x activity for the WRAP 2014 and 2023 scenarios with the NM OAI Study 2028 base case activity based on BLM forecasts. With the exception of spud count, the 2028 NM O&G activity is greater than 2014.

A comparison of the WRAP OGWG 2014 and 2023 New Mexico O&G emissions with the 2028 values from the NM OAI Study are given in Table 4-5. Across New Mexico, 2028 O&G NO_x and VOC emissions are, respectively, 29% and 15% higher than in 2014. In the Permian Basin, New Mexico 2028 O&G NO_x emissions are 64% higher than 2014, with VOC emissions 19% higher. The 2028 and 2014 New Mexico O&G emissions in the San Juan Basin are more comparable, with 2028 NO_x and VOC emissions, respectively, 1% and 10% higher than 2014.

[35] Source: https://www.epa.gov/ghgreporting/ghgrp-and-oil-and-gas-industry, accessed in April 2020.

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Table 4-4. Comparison of WRAP OGWG 2014 and 2023 New Mexico O&G emissions used in the 2014v2 and 2028OTBa2 scenarios with the NM OAI study 2028 base case New Mexico O&G emissions based on BLM forecast.

Activity Metric	WRAP OGWG		BLM Forecast
	2014	2023	Circa- 2028
Permian Basin (NM)			
Oil Production (million bbl)	119	276	166
Gas Production (BCF)	508	1,190	790
Well Count	28,615	27,335	40,478
Spud Count	1,178	651	794
San Juan Basin (NM)			
Oil Production (million bbl)	6	7	7
Gas Production (BCF)	713	440	1,138
Well Count	21,687	19,604	23,073
Spud Count	146	64	94
Las Vegas-Raton Basin (NM)			
Oil Production (million bbl)	0	0	0
Gas Production (BCF)	24	24	20
Well Count	835	835	835
Spud Count	0	0	0
Sierra Grande Uplift (NM)			
Oil Production (million bbl)	0	0	0
Gas Production (BCF)	0.02	0.02	0.27
Well Count	1	1	8
Spud Count	34	34	0.4

Table 4-5. Comparison of WRAP OGWG 2014 and 2023 NO_x and VOC New Mexico O&G emissions with the NM OAI Study 2028 base case.

Pollutant	WRAP OGWG		NMED OAI EI
	2014	2023	2028
New Mexico State Total			
NOx	81,188	93,719	104,955
VOC	185,269	226,032	213,073
Permian , NM			
NOx	35,251	52,074	57,922
VOC	97,977	149,609	116,896
San Juan , NM			
NOx	44,730	39,789	45,200
VOC	86,567	75,670	95,500
Estancia Basin , NM			
NOx	113	645	645
VOC	5	26	26
Orogrande Basin , NM			
NOx	541	548	548
VOC	28	30	29
Raton , NM			
NOx	8	8	6
VOC	646	646	600
Pedregosa Basin , NM			
NOx	262	373	373
VOC	6	9	9
Basin-And-Range Province , NM			
NOx	261	261	261
VOC	10	11	11
Sierra Grande Uplift , NM			
NOx	23	23	0
VOC	31	31	2

4.4 Summary of 2014 and 2028 Base Case Emissions

Tables 4-6 through 4-8 summarizes the total emissions in New Mexico for the 2014 and 2028 base case emission scenarios and their differences. Graphical comparisons of the changes in NO_x and VOC emissions between 2014 and 2028 base cases are shown in, respectively, Figures 4-7 and 4-8. And the distribution of NO_x and VOC emissions across source sectors are shown in Figures 4-9 and 4-10, respectively. Total NO_x emissions in New Mexico are estimated to be reduced by -28% between 2014 and 2028 with the largest reductions coming from on-road mobile (-72%), EGU point (-69%) and non-road mobile (-51%) source sectors (Table 4-6 and Figure 4-7). These NO_x emission reductions were offset somewhat by increases in O&G point (+40%) and non-point (+36%) source sectors. Although there are large reductions in on-road (-61%) and non-road (-49%) mobile source VOC emissions between 2014 and 2028 base cases, the total reduction in New Mexico VOC emissions between 2014 and 2028 is only -6% because non-point O&G dominates (~75%; Figure 4-10) anthropogenic VOC emissions in New Mexico and they are only reduced by -5%.

Table 4-6. Summary of total emissions (tons/year) in New Mexico for the 2014 base case emissions scenario.

Category	CO	NH_3	NO_X	$PM_{2.5}$	PMC	SO_2	VOC
Fugitive Dust	0	0	0	31,152	188,801	0	0
Agricultural	0	28,774	0	0	0	0	2,825
Non-Point	23,039	262	5,934	1,561	794	937	28,621
Non-Road	77,821	13	7,334	548	40	18	9,397
O&G Non-Point	76,949	0	45,476	1,362	0	4,129	321,608
On-Road	246,144	939	75,861	2,194	1,042	252	26,275
O&G Point	23,458	0	31,125	436	0	8,623	40,744
EGU Point	11,309	422	43,071	1,507	650	11,911	429
Non-EGU Point	5,479	54	3,829	592	1,577	308	2,043
Rail	3,527	11	20,114	490	52	12	1,033
RWC	1,375	10	23	93	0	4	214
Total	469,102	30,485	232,766	39,935	192,956	26,194	433,188

Table 4-7. Summary of total emissions (tons/year) in New Mexico for the 2028 base case emissions scenario.

Category	CO	NH_3	NO_X	$PM_{2.5}$	PMC	SO_2	VOC
Fugitive Dust	0	0	0	31,152	188,801	0	0
Agricultural	0	28,774	0	0	0	0	2,825
Non-Point	23,039	262	5,934	1,561	794	937	28,621
Non-Road	69,460	15	3,618	244	24	11	4,767
O&G Non-Point	106,267	0	61,987	1,989	0	21,789	304,635
On-Road	111,251	821	21,610	688	1,178	143	10,311
O&G Point	37,205	0	43,480	706	55	11,912	53,212
EGU Point	7,173	301	13,389	1,292	755	3,385	256
Non-EGU Point	5,479	54	4,126	592	1,577	639	2,043
Rail	3,845	12	14,493	300	11	14	603
RWC	1,375	10	23	93	0	4	214
Total	365,093	30,248	168,661	38,617	193,195	38,834	407,488

Table 4-8. Percent differences in total New Mexico emissions between the 2014 and 2028 emission scenarios.

Category	CO	NH_3	NO_X	$PM_{2.5}$	PMC	SO_2	VOC
Fugitive Dust				0%	0%		
Agricultural		0%					0%
Non-Point	0%	0%	0%	0%	0%	0%	0%
Non-Road	-11%	17%	-51%	-56%	-41%	-37%	-49%
O&G Non-Point	38%		36%	46%	-98%	428%	-5%
On-Road	-55%	-13%	-72%	-69%	13%	-43%	-61%
O&G Point	59%		40%	62%		38%	31%
EGU Point	-37%	-29%	-69%	-14%	16%	-72%	-40%
Non-EGU Point	0%	0%	8%	0%	0%	107%	0%
Rail	9%	9%	-28%	-39%	-78%	9%	-42%
RWC	0%	0%	0%	0%	0%	0%	0%
Total	-22%	-1%	-28%	-3%	0%	48%	-6%

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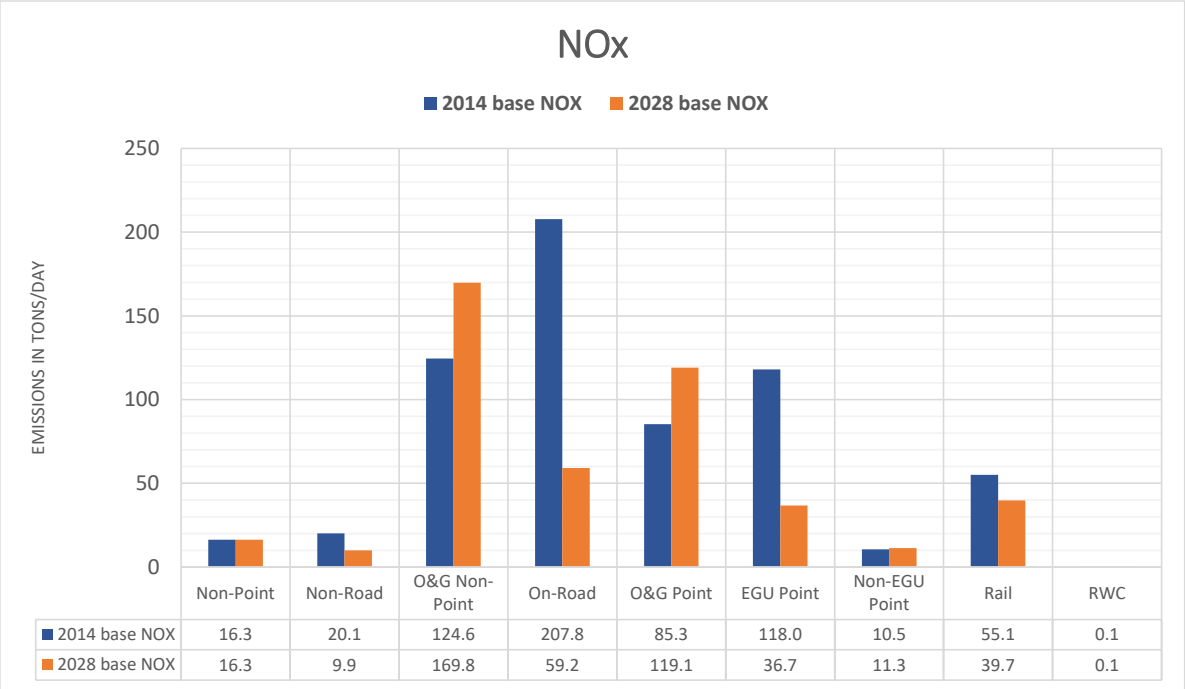


Figure 4-7. Comparison of 2014 and 2028 New Mexico NO_X emissions by source sector.

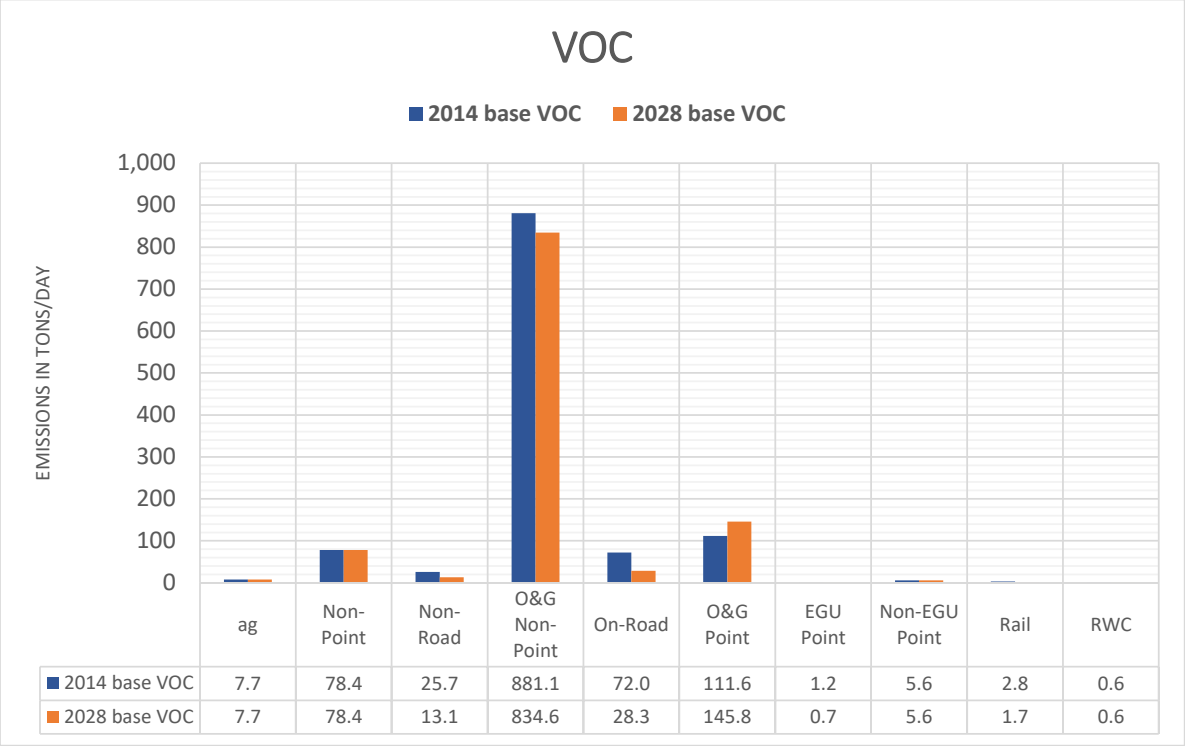


Figure 4-8. Comparison of 2014 and 2028 New Mexico NO_X emissions by source sector.

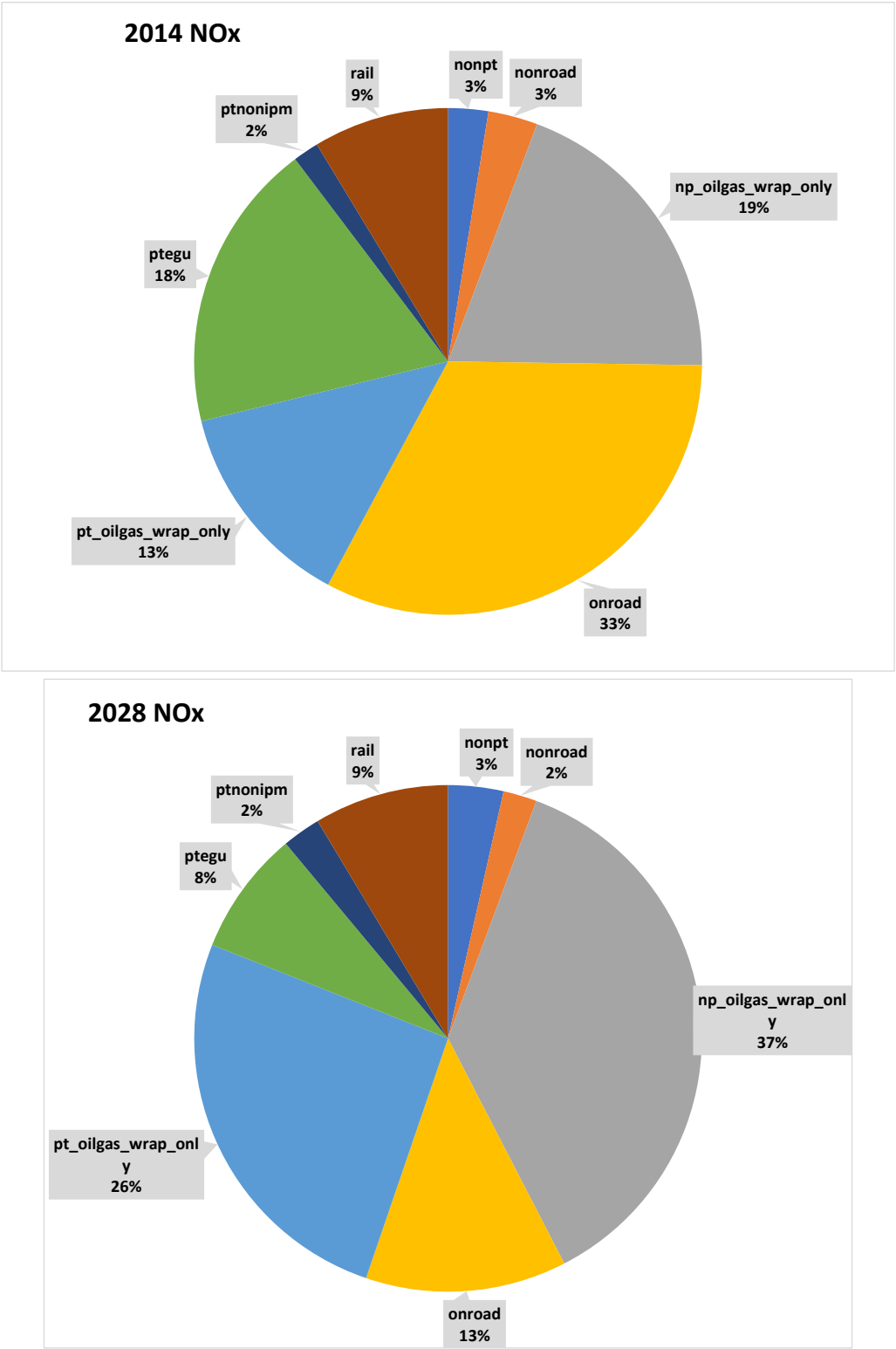


Figure 4-9. Distribution of New Mexico NO_x emissions across source sectors for the 2014 (top) and 2028 (bottom) base cases.

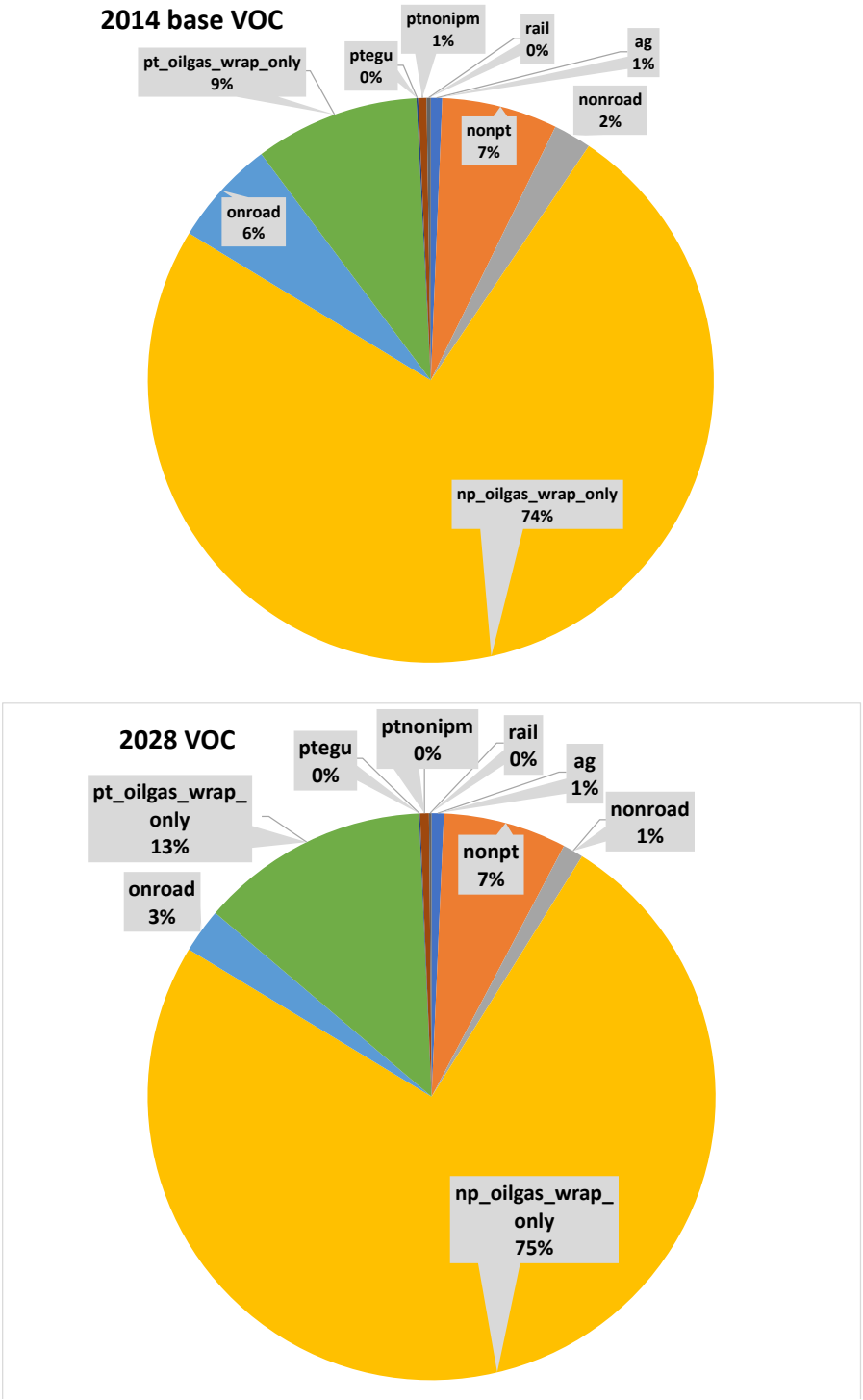


Figure 4-10. Distribution of New Mexico VOC emissions across source sectors for the 2014 (top) and 2028 (bottom) base cases.

4.5 2028 New Mexico Oil and Gas Control Strategy

The WESTAR/Ramboll Team provided the New Mexico 2028 O&G base case emissions to the NMED. The Eastern Research Group (ERG) under separate contract with NMED implemented the emission controls in the 2028 NM O&G emissions based on their interpretation of the proposed New Mexico "Ozone Precursor Rule for Oil and Natural Gas Sector."[36] The 2028 O&G Control Strategy reduced O&G emissions in 7 counties in New Mexico.

The 2028 NM O&G controlled emissions were processed by SMOKE and substituted for the 2028 NM O&G Base Case emissions to create the 2028 O&G Control Strategy emissions scenario. The only difference between the NM OAI Study 2028 Base Case and 2028 O&G Control Strategy were the controls on O&G emissions in New Mexico as implemented by ERG.

Table 4-9 displays the New Mexico state-wide O&G emissions for the 2028 Base Case and 2028 O&G Control Strategy. State-wide O&G NO_x emissions are reduced approximately -45% with similar reductions from both the Point and Non-Point source sectors. State-wide O&G VOC emission reductions are reduced approximately -50% with more reductions coming from the Non-Point (-53%) than Point (-35%) source sectors.

Table 4-9. New Mexico NO_x and VOC O&G emissions (tons per year) for the 2028 Base Case and 2028 NM O&G control strategy.

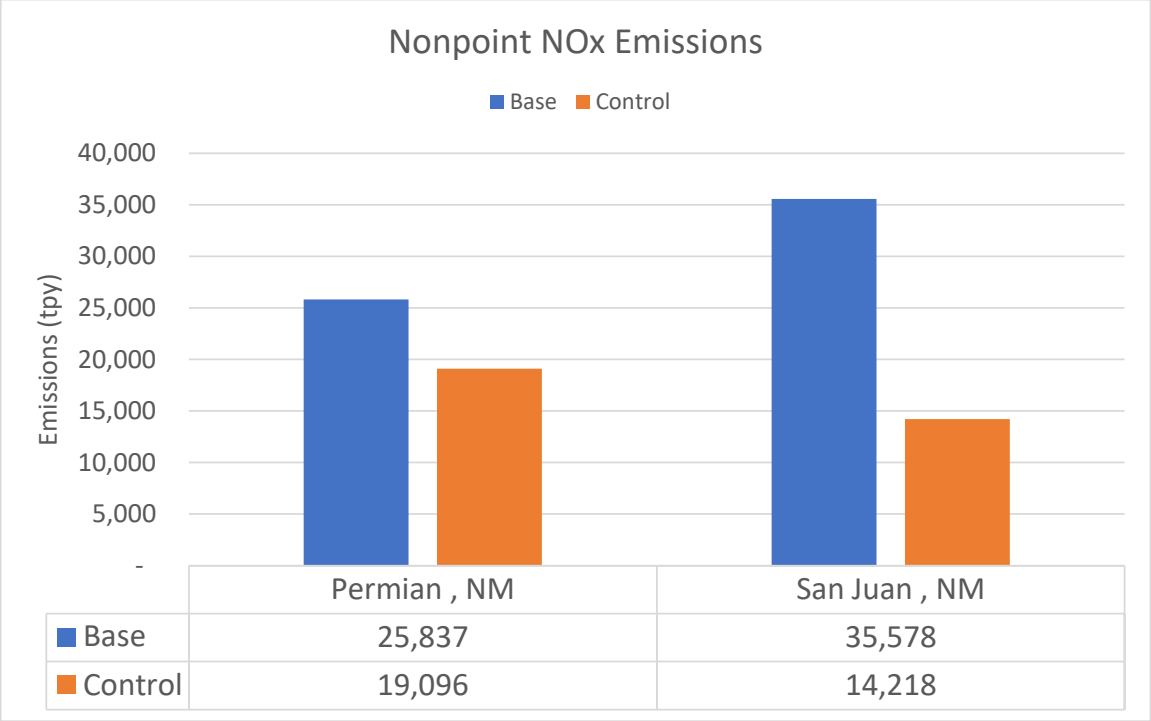
Source Sector	NO_x Emissions (TPY)			VOC Emissions (TPY)		
	Base	Control	Diff	Base	Control	Diff
Non-Point	61,245	33,144	-46%	181,252	85,564	-53%
Point	41,066	22,872	-44%	30,340	19,608	-35%
Total	102,311	56,016	-45%	211,592	105,172	-50%

Figures 4-11 and 4-12 display the changes in, respectively, NO_x and VOC emissions in the Permian and San Juan Basins between the 2028 base and 2028 control cases. In the Permian Basin, O&G NO_x emissions are estimated to be reduced by approximately 21,000 TPY (64%). In the San Juan Basin, O&G NO_x emissions are estimated to be reduced by approximately 25,000 TPY (44%). 2028 VOC O&G emissions in the Permian and San Juan Basins are estimated to be reduced by approximately 53,000 TPY each (-46% and -55% reduction, respectively).

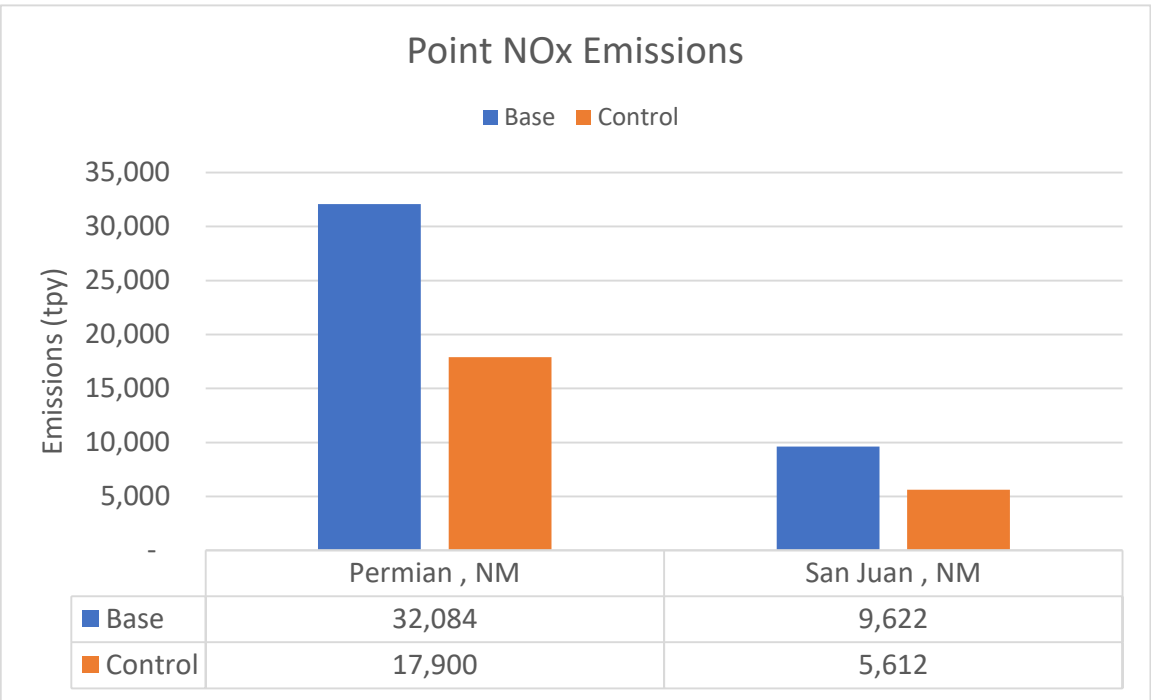
Figure 4-13 shows the spatial distribution of the differences Non-Point and Point O&G NO_x and VOC emissions between the 2028 Base Case and 2028 O&G Control Strategy scenario. The O&G emission reductions are restricted to the New Mexico portions of the San Juan and Permian Basins.

[36] https://www.env.nm.gov/new-mexico-methane-strategy/wp-content/uploads/sites/15/2020/07/Draft-Ozone-Precursor-Rule-for-Oil-and-Natural-Gas-Sector-Version-Date-7.20.20.pdf

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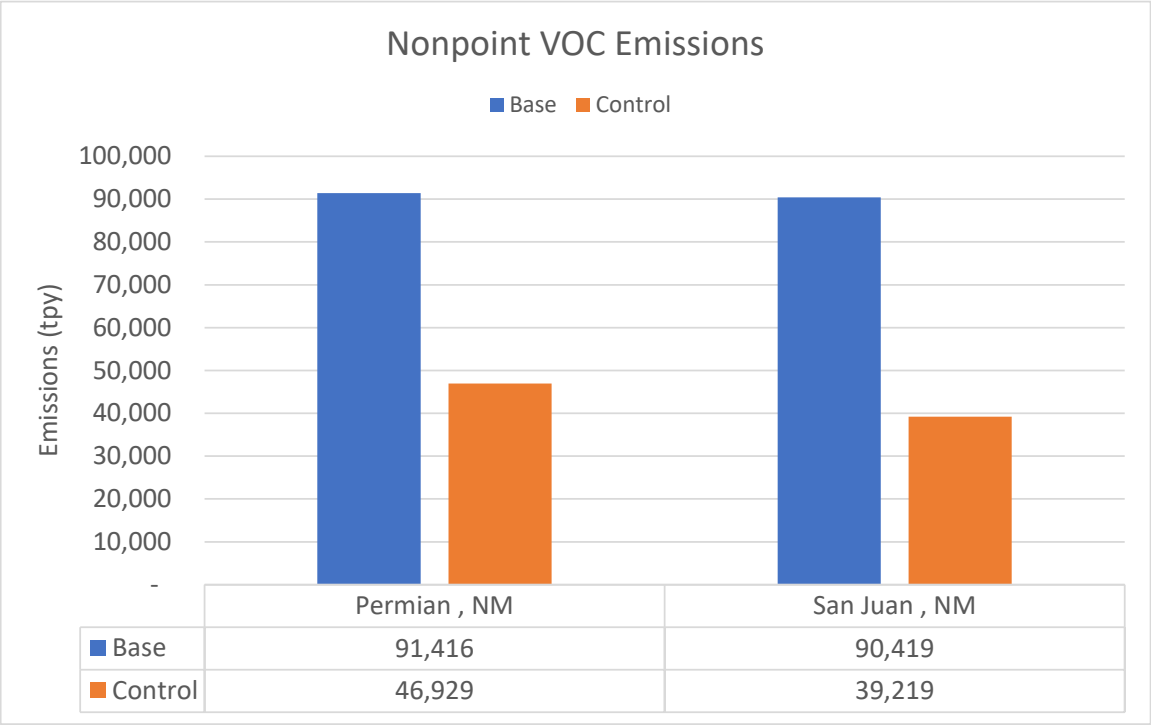
	Permian , NM	San Juan , NM
Base	25,837	35,578
Control	19,096	14,218



	Permian , NM	San Juan , NM
Base	32,084	9,622
Control	17,900	5,612

Figure 4-11. Comparison of 2028 Base Case and 2028 NM O&G control strategy NO_x emissions for the Non-Point (top) and Point (bottom) source sectors and the Permian (left) and San Juan (right) basins.

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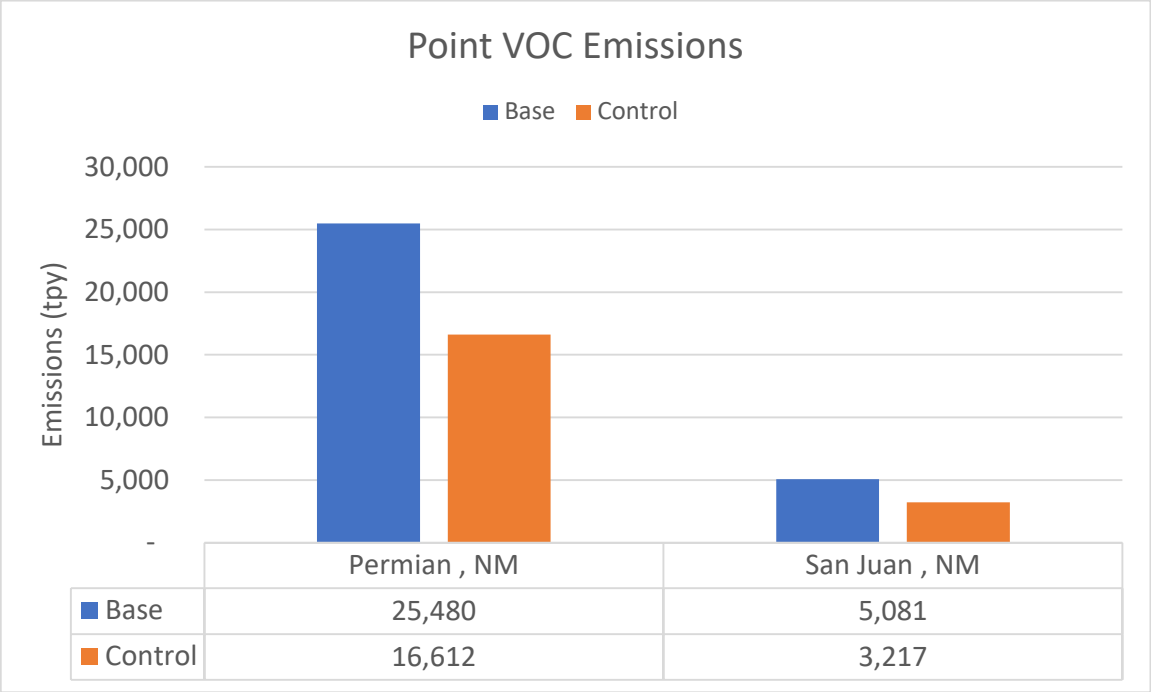


Figure 4-12. Comparison of 2028 Base Case and 2028 NM O&G control strategy VOC emissions for the Non-Point (top) and Point (bottom) source sectors and the Permian (left) and San Juan (right) basins.

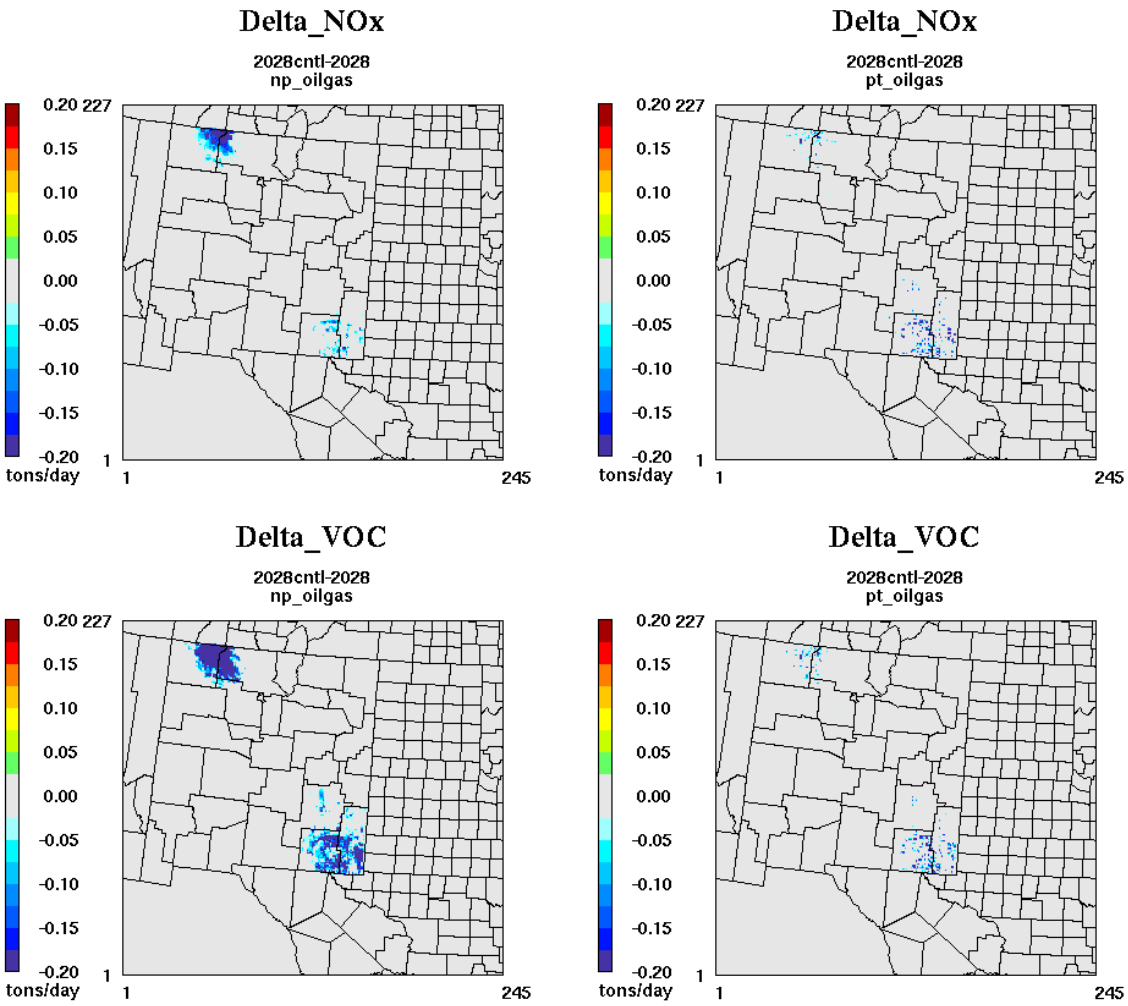


Figure 4-13. Differences in 2028 O&G Control Strategy and 2028 Base Case oil and gas NO_x (top) and VOC (bottom) emissions for the Non-Point (left) and Point (right) source sectors.

5. DIAGNOSTIC SENSITIVITY TESTS

Several CAMx diagnostic sensitivity tests were conducted to evaluate the effects that alternative meteorological inputs have on ozone concentrations.

5.1 WRFCAMx Processing of 2014 WRF Output

The WRFCAMx processor maps WRF meteorological fields to the format required by CAMx. It also calculates turbulent vertical exchange coefficients that define the rate and depth of vertical mixing in CAMx. Several options are available in WRFCAMx to derive vertical turbulent exchange coefficient (also known as Kv or vertical diffusivity) fields from WRF output. The Kv fields are diagnosed from wind, temperature, and Planetary Boundary Layer (PBL) parameters in WRFCAMx. For this application, the WRFCAMx processing was performed to generate two sets of Kv profiles using two different Kv options in WRFCAMx, the CMAQ-like and YSU Kv profile options.

The CAMx Kv_patch pre-processor program was used to set the minimum Kv value to 0.1 to 1.0 m^2/s in the lowest 100 m of the atmosphere depending on the amount urban land use category in a grid cell. This is done to account for the urban heat island effect that enhances vertical mixing through-out the day and night.

WRF was run with 36 vertical levels (35 vertical layers) as shown in Table 2-1. For the NM OAI Study, a layer collapsing strategy was employed that reduced the 35 WRF vertical layers to 25 layers in CAMx, which reduces the CAMx run time by about a third. Table 5-1 displays the WRF to CAMx layer collapsing strategy. This is the same layer collapsing study employed by WRAP-WAQS 2014 modeling platform.

5.2 CAMx Meteorological Diagnostic Sensitivity Tests

Four separate CAMx 2014 36/12/4-km diagnostic sensitivity tests were conducted for the first portion of the summer 2014 modeling episode that spanned May 15 to June 4, 2014. The purpose of the four meteorological inputs CAMx sensitivity tests was to identify the optimal meteorological inputs for the final CAMx 2014 base case simulation. The four sets of CAMx simulations were based on the WRF/NAM and WRF/ERA5 2014 36/12/4-km simulations described in Chapter 2 processed by WRFCAMx to generate two sets of vertical mixing coefficient (Kv) as described above:

1. WRF/NAM with CMAQ Kv
2. WRF/NAM with YSU Kv
3. WRF/ERA5 with CMAQ Kv
4. WRF/ERA5 with YSU Kv

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Table 5-1. WRF to CAMx vertical layer collapsing strategy used in the NM OAI Study.

CAMx Layers	WRF Layers	WRF hybrid eta	WRF Pressure (mb)	Height (m)
	0	1.0000	1000.0	0
	1	0.9985	998.6	12
1	2	0.9970	997.2	24
	3	0.9950	995.3	40
2	4	0.9930	993.4	56
	5	0.9910	991.5	72
3	6	0.9880	988.6	97
	7	0.9850	985.8	121
4	8	0.9800	981.0	162
5	9	0.9700	971.5	243
6	10	0.9600	962.0	326
7	11	0.9500	952.5	409
	12	0.9400	943.0	492
8	13	0.9300	933.5	577
9	14	0.9100	914.5	747
10	15	0.8900	895.5	921
11	16	0.8700	876.5	1098
12	17	0.8400	848.0	1369
13	18	0.8000	810.0	1742
14	19	0.7600	772.0	2130
15	20	0.7200	734.0	2533
16	21	0.6800	696.0	2954
17	22	0.6400	658.0	3393
18	23	0.6000	620.0	3854
19	24	0.5500	572.5	4463
	25	0.5000	525.0	5115
20	26	0.4500	477.5	5816
	27	0.4000	430.0	6576
21	28	0.3500	382.5	7408
	29	0.3000	335.0	8328
22	30	0.2500	287.5	9360
	31	0.2000	240.0	10541
23	32	0.1500	192.5	11930
	33	0.1000	145.0	13630
24	34	0.0600	107.0	15355
	35	0.0270	75.7	17205
25	36	0.0000	50.0	19260

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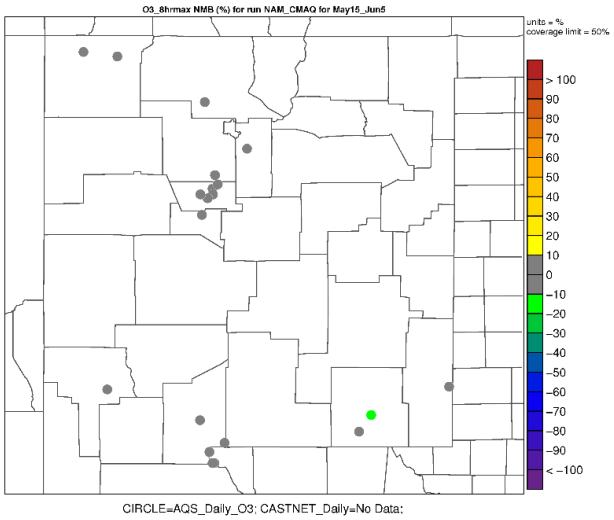
NMED Exhibit 17

Figures 5-1 and 5-2 summarize the CAMx MDA8 ozone normalized mean bias (NMB) and error (NME) statistical performance metrics for each site in New Mexico and the four WRF meteorological inputs sensitivity tests. The statistics presented in these figures were calculated using a 60 ppb cutoff value relative to observed MDA8 ozone concentrations to understand the performance of each sensitivity test when ozone concentrations are most relevant to the NAAQS. Figure 5-1 shows that the NMB is generally within ±10% (colored grey) at almost all sites (note that the NMB performance goal is within ±5% and performance criteria is within ±15%). All of the sensitivity simulations have an under-prediction bias for observed ozone greater than 60 ppb at sites in the southern portion of the domain such that for one or two sites have a bias even lower than -10% (i.e., colored bright green). The WRF/NAM with CMAQ Kv sensitivity test has slightly better performance than the others with less underestimation bias (e.g., all sites but one are within ±10% compared to two sites for the other tests). Figure 5-2 shows that the NME is also generally within the performance goal (less than 15%) in all cases, with the southern portions of NM showing the largest errors but still within the performance criteria (less than 25%). The figure shows that CAMx using the WRF/NAM inputs tends to have slightly lower error and better ozone performance than when the WRF/ERA5 meteorological inputs are used.

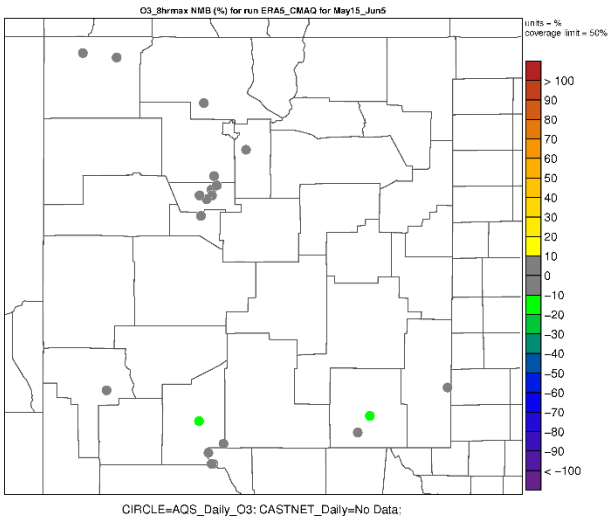
Figure 5-3 presents soccer plots of bias and error for observed ozone above 60 ppb and all four CAMx sensitivity tests. This figure plots site-specific bias versus error with performance lines in the shape of a soccer goal, when the site-specific bias and error symbol falls within the soccer goal area (i.e., the red box) it is easy to see when the ozone performance goals are achieved. The figure shows that all sites have NMB and NME that fall within the performance criteria for bias (≤±15%) and error (≤25%), with most sites having an underestimation bias of the high (> 60 ppb) observed ozone concentrations. The CAMx simulations with the WRF/NAM meteorological inputs has slightly better performance than when the WRF/ERA5 inputs are used as more sites fall within the performance goal area. Comparison between the NAM cases indicate that the CAMx sensitivity test with CMAQ Kv has slightly smaller errors relative to the test with YSU Kv.

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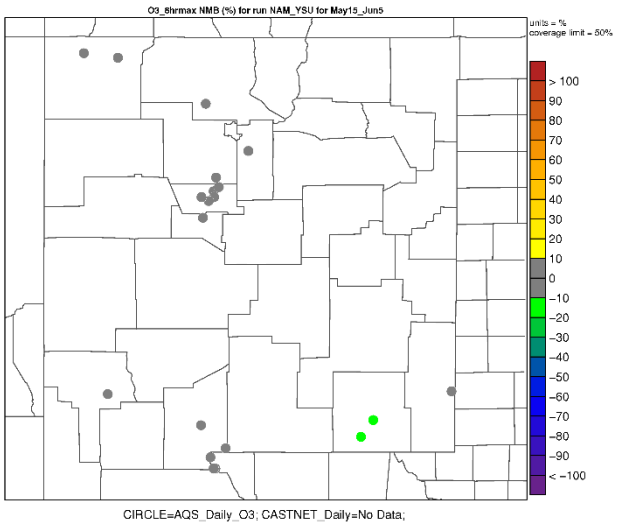
NAM CMAQ



ERA5 CMAQ



NAM YSU



ERA5 YSU

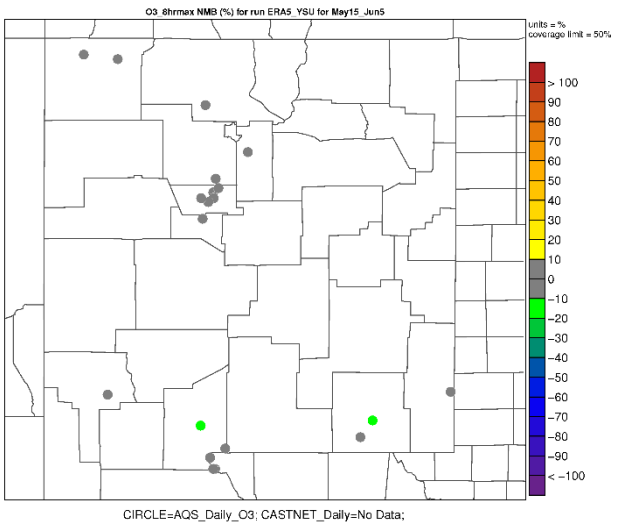
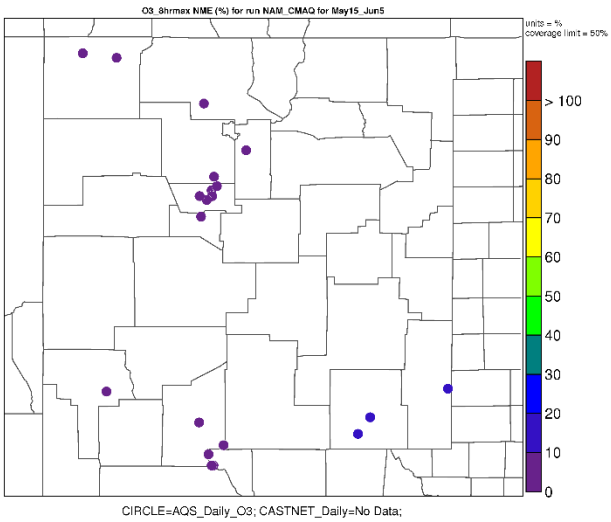


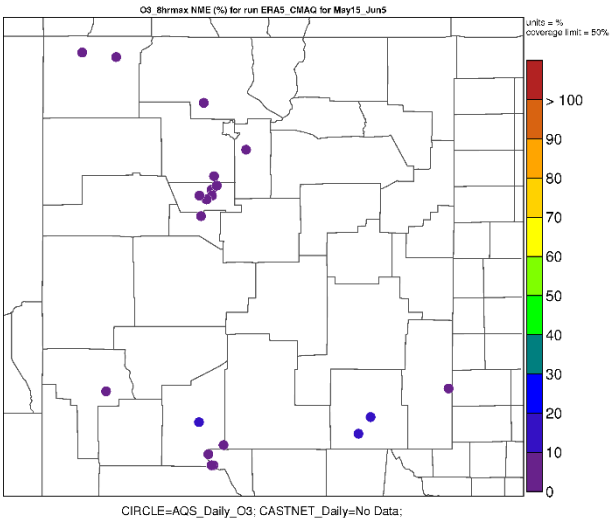
Figure 5-1. Comparison of sensitivity tests NMB with 60 ppb cutoff spatial plots over NM.

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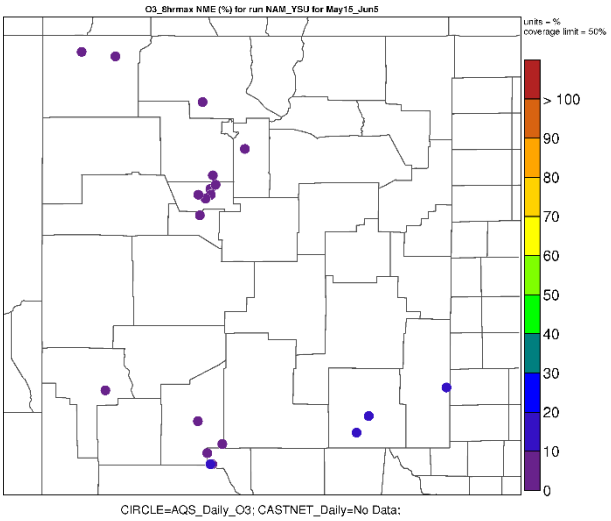
NAM CMAQ



ERA5 CMAQ



NAM YSU



ERA5 YSU

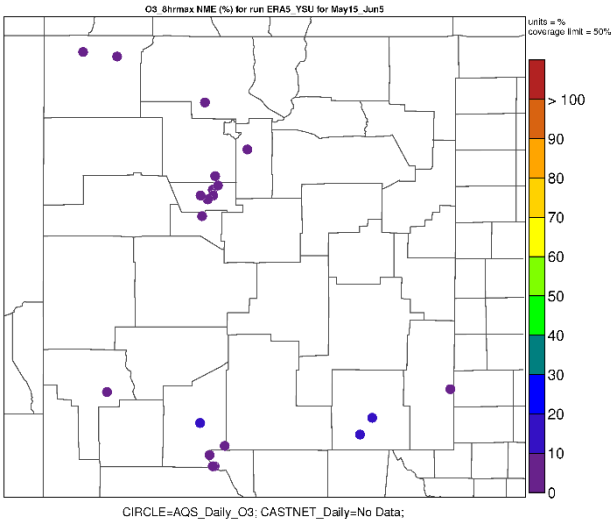


Figure 5-2. Comparison of sensitivity tests NME with 60 ppb cutoff spatial plots over NM.

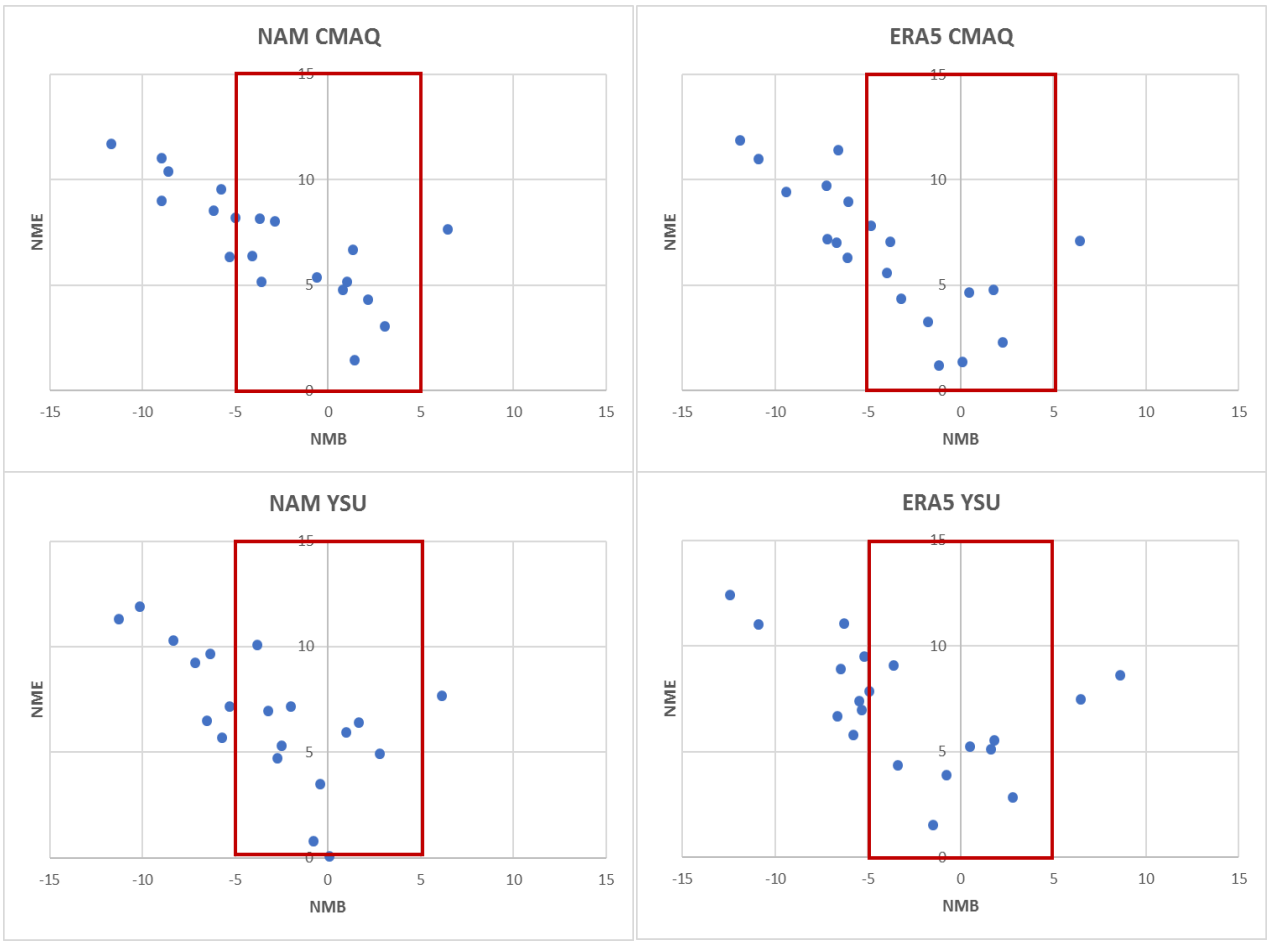


Figure 5-3. Comparison of sensitivity tests soccer plots with 60 ppb cutoff. Red rectangle indicates the performance goal soccer area.

Figures 5-4 to 5-7 present time series of predicted and observed MDA8 ozone concentrations for selected sites in Doña Ana, Eddy and Sandoval counties. At the Solano Road site in Doña Ana County the time series shows that the observed peak ozone concentration on May 29 is matched very well by the CAMx WRF/NAM sensitivity tests, while the CAMx WRF/ERA5 sensitivity test under-predicts by approximately 10 ppb (Figure 5-4). At the Desert View site, which is also in Doña Ana County, all four CAMx sensitivity tests underestimate the high observed ozone on May 28-29, but the CAMx WRF/NAM tests perform slightly better than the CAMx WRF/ERA5 test (Figure 5-5). At the Carlsbad site in Eddy County all test cases under-predict the high ozone concentration from May 27 to May 31 (Figure 5-6). For the site in Sandoval county (Figure 5-7) all four CAMx sensitivity tests track the daily variations of the observed MDA8 ozone including getting the timing and values of the observed ozone peak on May29, but the CAMx WRF/NAM with CMAQ Kv test exhibits the lowest biases.

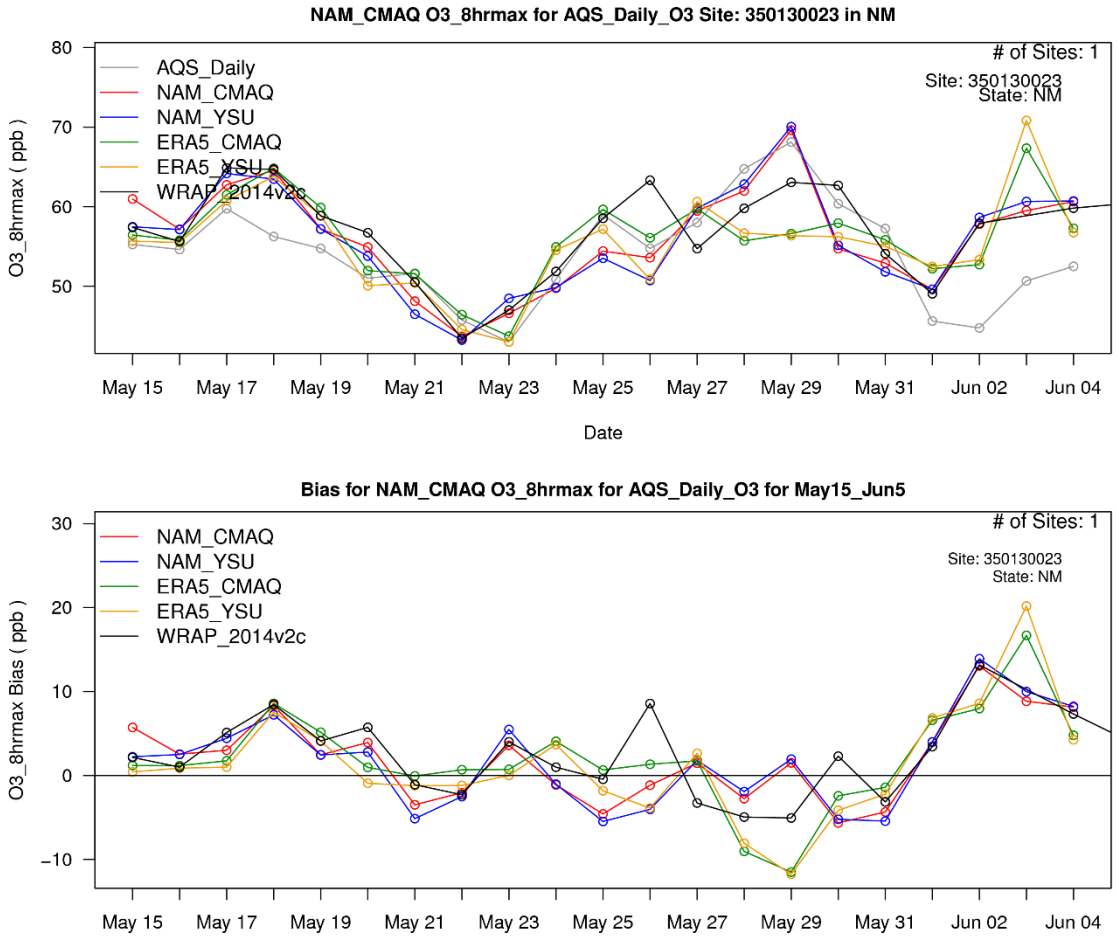


Figure 5-4. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Solano Road site in Doña Ana County

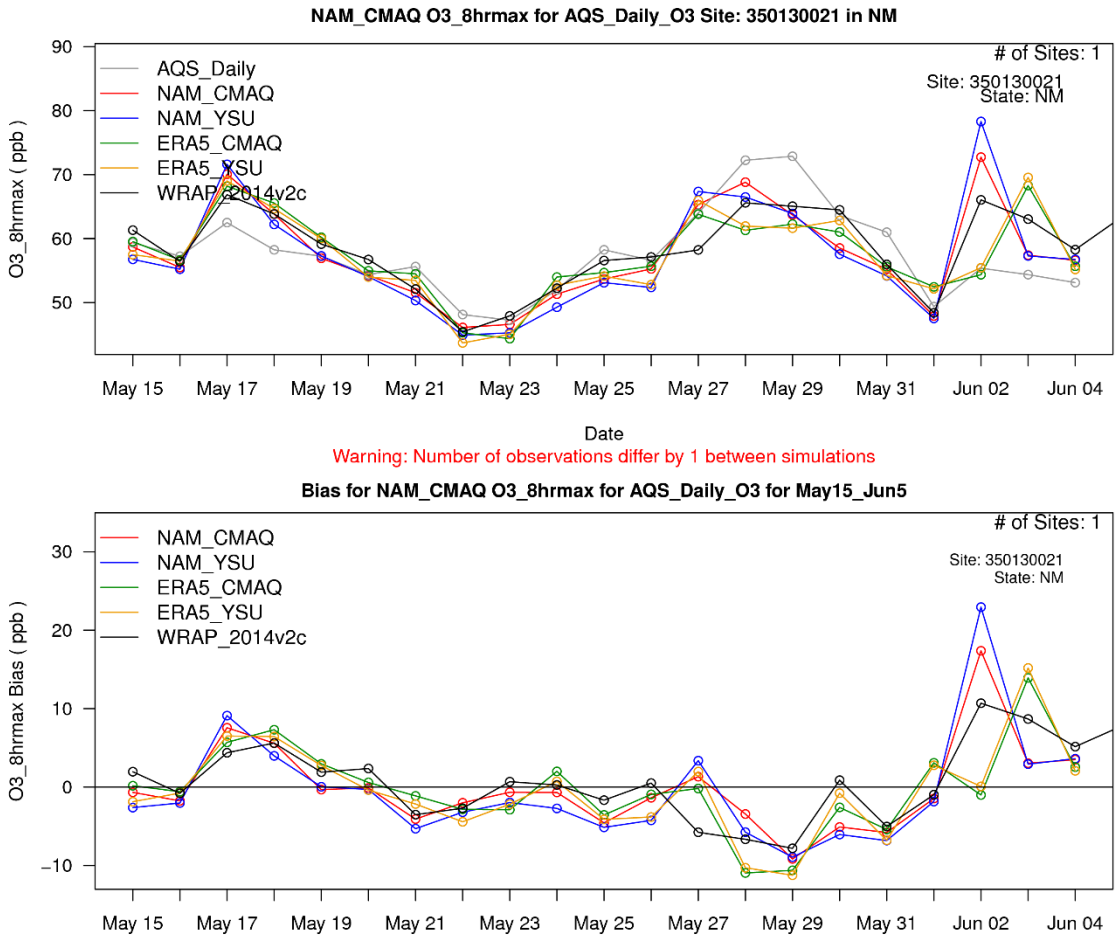


Figure 5-5. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Desert View site in Doña Ana County

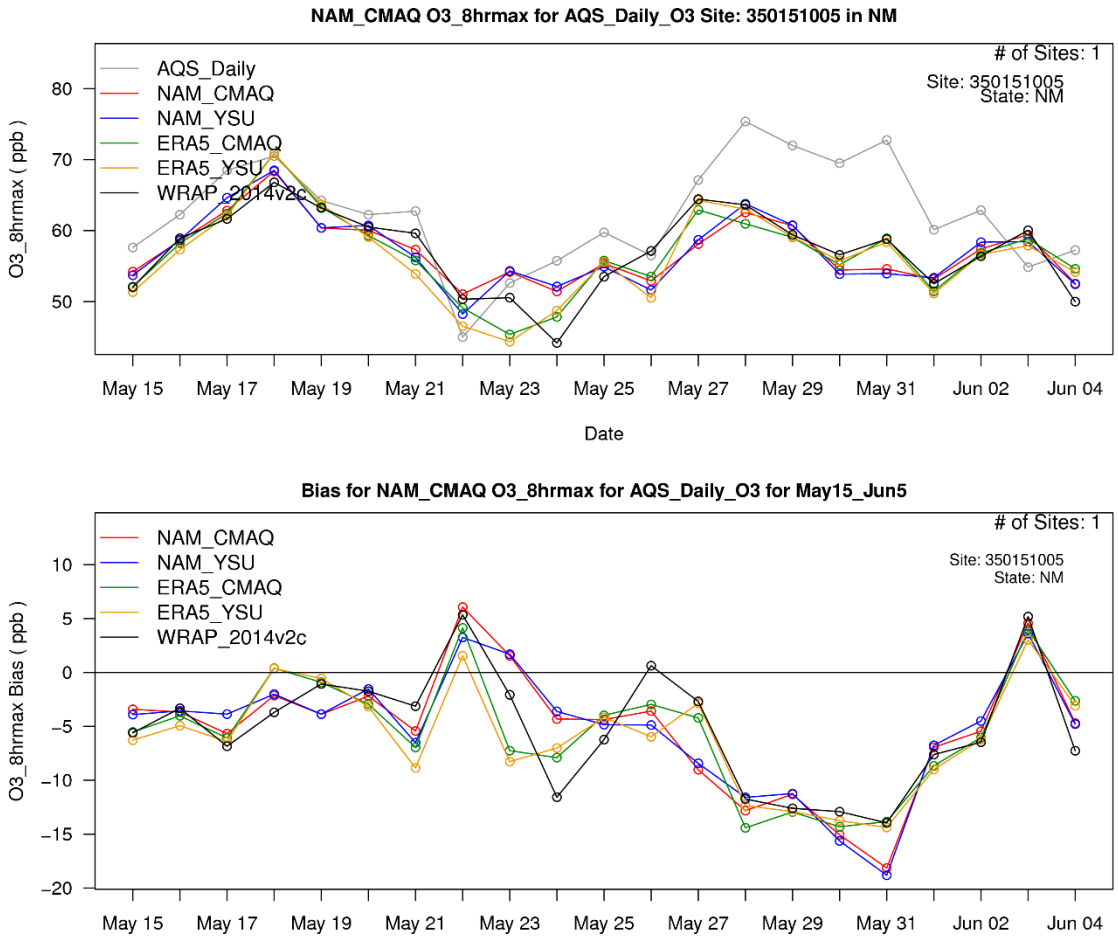


Figure 5-6. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Carlsbad site in Eddy County

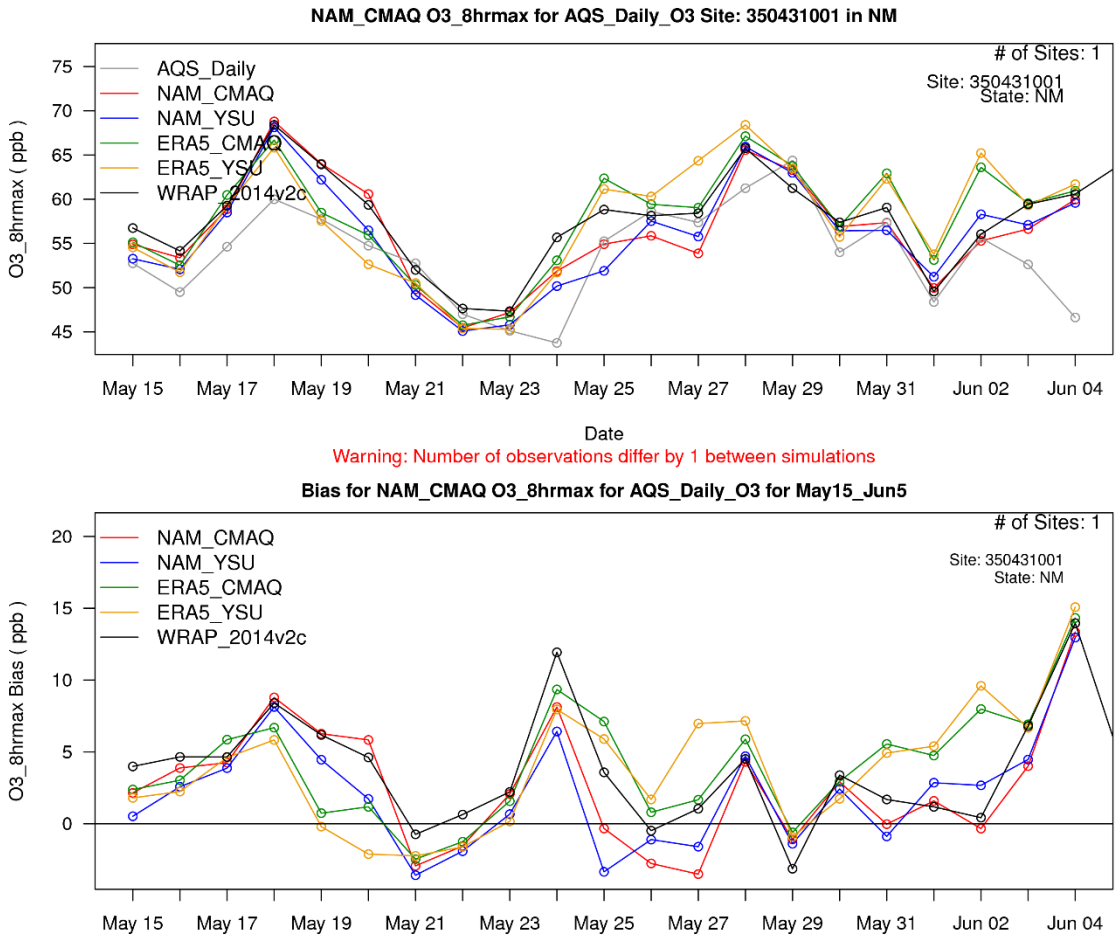


Figure 5-7. Timeseries comparison of sensitivity tests with observations (top) and bias (bottom) at Albuquerque site in Sandoval County

5.3 Summary of CAMx Diagnostic Sensitivity Tests

All four of the CAMx meteorological sensitivity cases have biases and errors well within the performance criteria and in most cases even within the more stringent performance goals. For the modeled episode, the differences in performance among all the cases considered are relatively minor. On some sites and days, CAMx using the WRF/NAM meteorology tends to capture peak ozone concentrations better than when the WRF/ERA5 meteorology is used. Based on the results presented here, the final CAMx 2014 base case model configuration used the WRF/NAM with CMAQ Kv treatment meteorological inputs.

6. 2014 BASE CASE MODELING AND MODEL PERFORMANCE EVALUATION

The NM OAI Study conducted two CAMx 2014 36/12/4-km base case simulations. The original 2014 base case simulation used CAMx v7.0 and biogenic emissions in the 4-km based on the MEGAN v3.1 model and is documented in Ramboll and WESTAR (2020c). There were errors in the CAMx v7.0 source apportionment algorithms that did not significantly affect the CAMx v7.0 2014 base case ozone estimates but would affect planned future year ozone source apportionment modeling. So, a second CAMx 2014v2 base case simulation was performed using CAMx v7.1 that had corrections to the ozone source apportionment algorithms. The revised CAMx v7.1 2014v2 base case simulation also updated the biogenic emissions in the 4-km domain using the BEIS v3.7 biogenic emissions model. The MEGAN v3.1 biogenic model used in the first CAMx v7.0 2014 base case was missing leaf area index (LAI) data for urban areas so produced zero biogenic VOC emissions for the urban land use type. The development of New Mexico-specific urban LAI inputs was beyond the resource and time constraints of the study, so BEIS biogenic emissions were used for the revised 2014v2 CAMX base case simulation. Details on the CAMx 2014v2 final base case simulation and model performance are provided in Ramboll and WESTAR (2021) with a summary provided below.

6.1 Final CAMx 2014v2 Base Case Configuration

The final CAMx meteorological inputs were based on the WRF/NAM simulations using the CMAQ-like Kv profiles as described in Chapters 2 and 5.

The 2014 emissions used in the 36-km and 12-km domains were the same as the WRAP-WAQS 2014v2 emissions. For the 4-km New Mexico domain, the WRAP 2014v2 emissions were processed by the SMOKE emissions model to generate the gridded hourly speciated emissions for CAMx. Chapter 4 describes the updates to the WRAP-WAQS 2014v2 emissions for New Mexico and the development of the emission inputs for the New Mexico 4-km domain.

Table 6-1 summarizes the CAMx configuration and options used for the CAMx 20114v2 base case simulation. Version 7.1 (v7.1) of CAMx released in January 2021 was used in the final 2014v2 base case simulation. CAMx was operated using the 36/12/4-km nested grid structure shown in Figure 1-1 using two-way grid nesting for all simulations. Boundary Conditions (BCs) for the CAMx most outer 36-km 36US modeling domain lateral boundaries were based on output from a 2014 simulation of the GEOS-Chem global chemistry conducted by WRAP for their 2014v2 modeling platform. CAMx was started on May 1, 2016 using the 36/12/4-km domains that allowed the model over two-weeks to initialize the model and wash out the initial concentrations before the first high ozone day on May 17, 2014.

Other CAMx model options and setup are defined in Table 6-1. The PPM advection solver (Colella and Woodward, 1984) was used for horizontal transport along with the spatially varying (Smagorinsky) horizontal diffusion approach. K-theory was used for vertical diffusion using the CMAQ-like Kv profiles from the WRFCAMx processing of the WRF/NAM output. The CB6r4 gas-phase chemical mechanism was selected because it includes the very latest chemical kinetic rates with halogen chemistry that affects ozone levels over the ocean. The latest aerosol mechanism was used in CAMx along with the

standard wet and dry deposition schemes. The Plume-in-Grid module was used to treat the near-source chemistry and dispersion of major NO_X emissions sources in the New Mexico 4-km domain for sources with greater than 5 tons per day NO_x emissions.

Table 6-1. Final CAMx model configuration for the 2014v2 base case simulation in NM OAI Study.

Science Options	CAMx	Comment
Model Codes	CAMx v7.1	Latest version of CAMx at time of study released in January 2020 (www.camx.com)
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes buffer cells
4-km grid	245 x 227 cells	New Mexico 4-km domain. Includes buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 thickness ~20 m. Model top at 50 mb (~19 km). Layer collapsing from 35 vertical layers in WRF
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 17, 2014
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain lateral boundaries
Emissions		
Baseline Emissions Processing	SMOKE, SMOKE-MOVES2014, BEIS v3.7	WRAP/WAQS 2014v2 emissions
Sub-grid-scale Plumes	Plume-in-Grid for major NO_X sources in New Mexico	Point sources with NO_x emission s greater than 5 tons per day
Chemistry		
Gas Phase Chemistry	CB6r4	Latest chemical reactions and kinetic rates with halogen chemistry (Yarwood et al., 2010)
Meteorological Processor	WRFCAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh grid size dependence
Vertical Diffusion	CMAQ-like Kv	Evaluated YSU Kv scheme
Diffusivity Lower Limit	Kv-min = 0.1 to 1.0 m^2/s in lowest 100 m	Depends on urban land use fraction
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	rain/snow/graupel
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative(EBI)	EBI fast and accurate solver
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update	Emery et al., (2009a,b; 2011)
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	Colella and Woodward (1984)
Integration Time Step	Wind speed dependent	~0.5-1 min (4-km), 1-5 min (12-km), 5-15 min (36-km)

6.2 Ozone Model Performance Goals and Criteria

Emery and co-workers (2016) analyzed almost 100 PGM model applications and developed a set of PGM model performance goals and criteria based on the variability in the past PGM model performance. "Goals" indicate statistical values that approximately a third of the top performance past PGM applications have met and should be viewed as the best a model can be expected to achieve. "Criteria" indicates statistics values that about two thirds of past PGM applications have met and should be viewed as what a majority of the models have achieved. The CAMx revised 2014v2 and original 2014 base case simulations ozone model performance statistics for normalized mean bias (NMB) and normalized mean error (NME) are compared against the ozone model performance goals and criteria developed by Emery et al., (2016) that are given in Table 6-2.

Table 6-2. Recommended ozone benchmarks for photochemical model statistics (Source: Emery et al., 2016).

Species	NMB		NME		r	
	Goal	Criteria	Goal	Criteria	Goal	Criteria
1-hr & MDA8 Ozone	<±5%	<±15%	<15%	<25%	>0.75	>0.50

6.3 Spatial Ozone Model Performance

Figures 6-1 and 6-2 display the spatial distribution of bias (NMB) performance at monitoring sites in the 4-km NM domain for the revised 2014v2 and original 2014 CAMx base case simulation with and without using a 60 ppb observed ozone cutoff concentrations (i.e., only include predicted and observed MDA8 ozone pairs in the statistics when the observed MDA8 ozone is greater than 60 ppb). When the symbols are grey, they achieve the within ±5% ozone bias Performance Goal and when the symbols are the brightest green or yellow colors they are within the ozone bias Performance Criteria (i.e., between ±5% and ±15%).

With the exception of one monitoring site in El Paso, the NMB at all of the ozone sites in the 4-km domain achieve the ozone Performance Criteria using no cutoff in both CAMx base case simulations, although some sites have an overestimation bias greater than 5% Performance Goal (Figure 6-1). The CAMx 2014v2 and 2014 base case ozone bias performance looks nearly identical with the only noticeable differences being two sites (one in Doña Ana County and one in Luna County) that achieve the ozone bias Performance Goal in the revised 2014v2 CAMx base case (i.e., are colored grey in Figure 6-1, top) but have bias between the 5% and 15% in the original CAMx base case (Figure 6-1, bottom) so fall between the Performance Goal and Criteria (i.e., are colored bright yellow).

Whereas the CAMx base cases tend to have a small ozone overestimation bias when no observed ozone 60 ppb cutoff is used, when using a 60 ppb observed ozone cutoff both base cases tend to have a small underestimation bias (Figure 6-2). With one exception, when using the cutoff all sites achieve the ozone Performance Criteria and many sites achieve the ozone bias Performance Goal. The bias performance of the two base case simulations are nearly identical. The one exception is the Carlsbad site in Eddy County that is between the Performance Goal and Criteria (i.e., between -5% and -15%) in the

original 2014 base case (Figure 3-2, bottom), but has a NMB between -15% and -20% in the revised 2014v2 base case so fails to achieve the ozone bias Performance Criteria (Figure 3-2, top).

We also compared the spatial model performance of the two base cases for error (NME) and correlation (r), but the spatial maps were identical so did not provide any relevant information on the relative performance of the two base case simulations.

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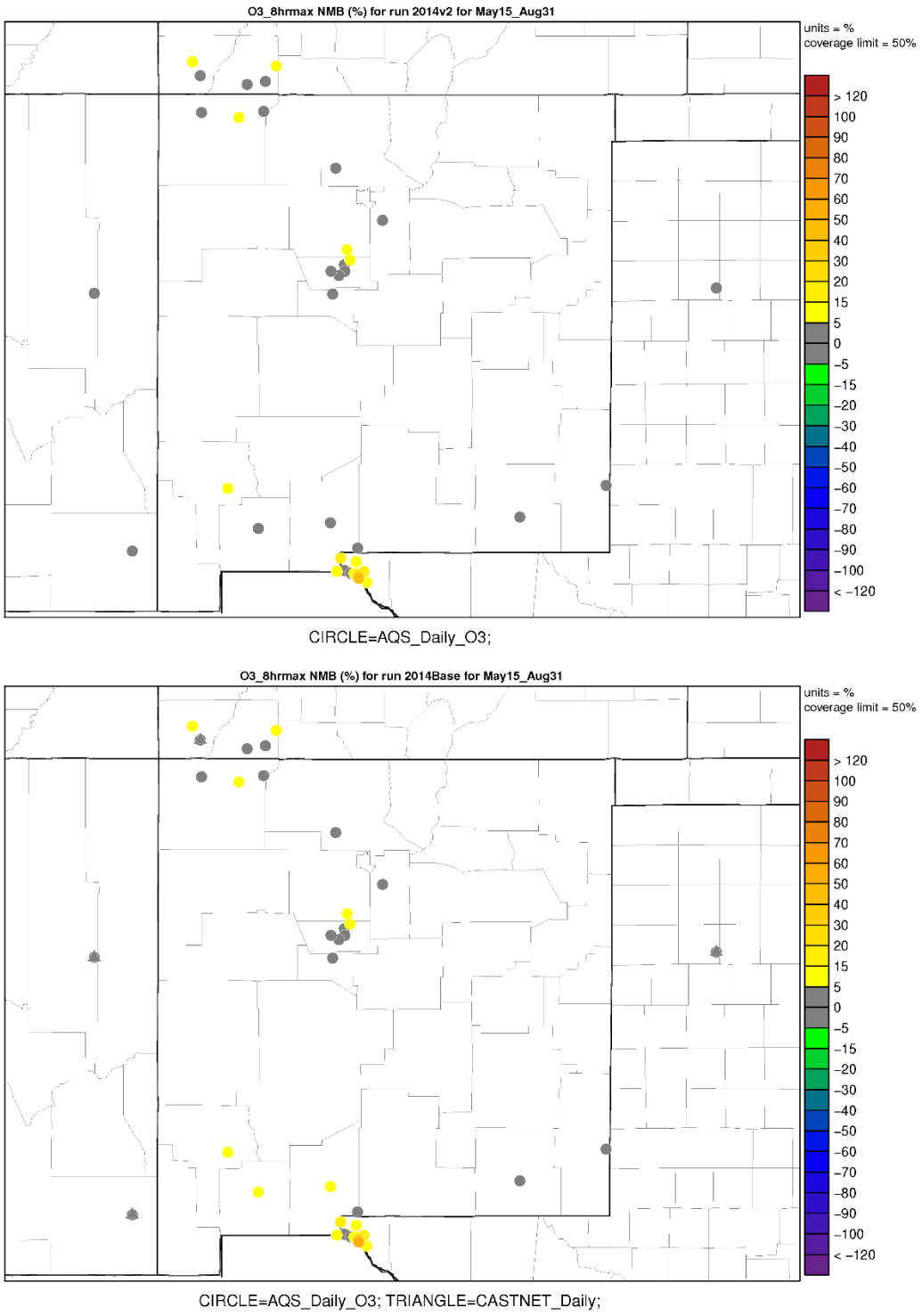


Figure 6-1. Normalized Mean Bias (NMB) for MDA8 ozone concentrations for the revised 2014v2 (top) and original 2014 (bottom) CAMx base case simulations with no ozone cutoff.

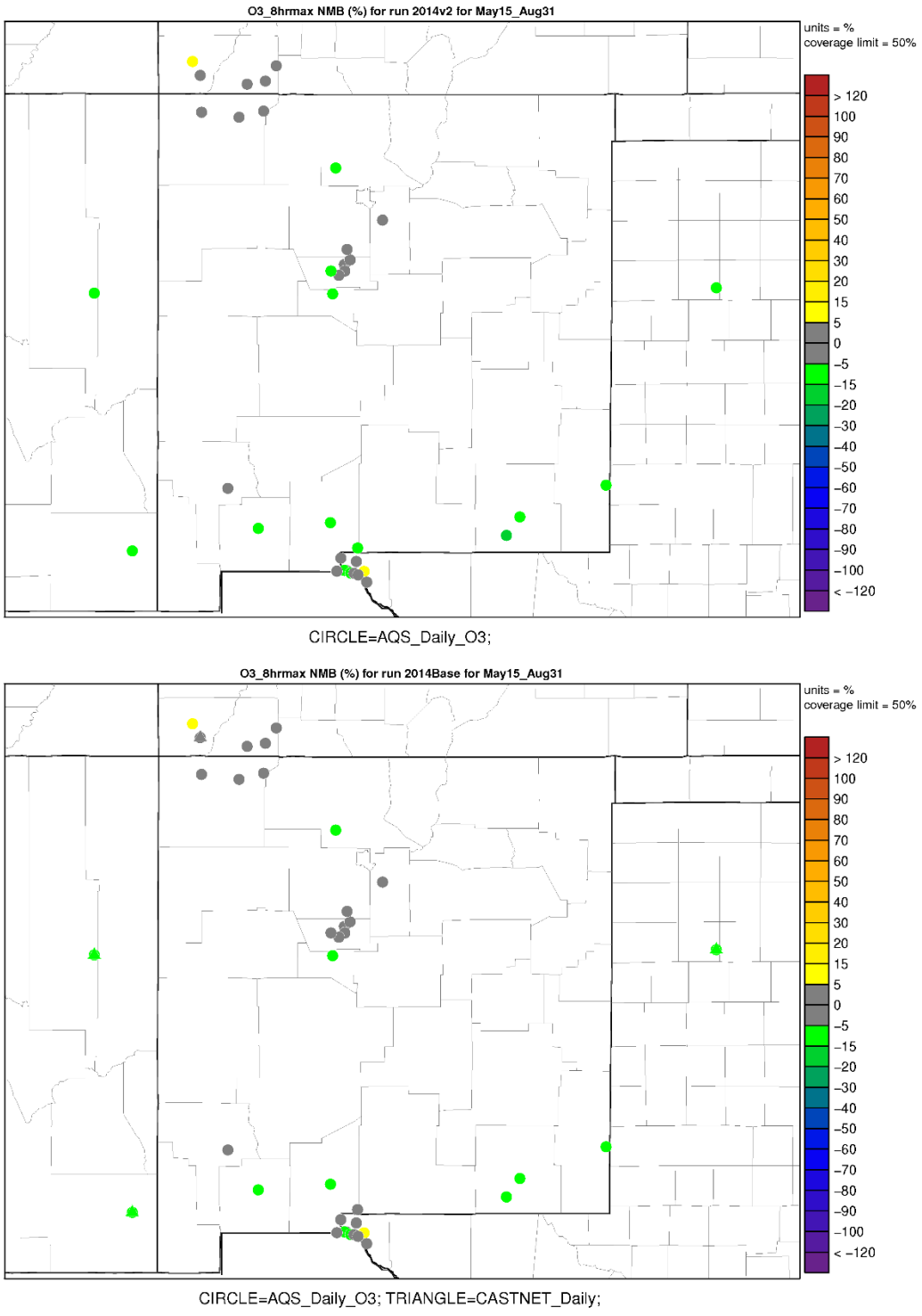


Figure 6-2. Normalized Mean Bias (NMB) for MDA8 ozone concentrations for the revised 2014v2 (top) and original 2014 (bottom) CAMx base case simulations with an observed 60 ppb ozone cutoff.

6.4 Scatter Plots of MDA8 Ozone

Figure 6-3 display scatter plots and summary statistics of MDA8 ozone across AQS or CASTNet sites in the 4-km domain for the revised 2014v2 and original 2014 CAMx base case simulations. The 2014v2 and 2014 MDA8 scatter plots look identical with the MDA8 performance at the AQS sites exhibiting a slight MDA8 ozone overestimation bias as indicated by the center density of the scatterplot being slightly above the 1:1 line of perfect agreement. This is in contrast to the CASTNet MDA8 scatterplots that are centered on the 1:1 line of perfect agreement so the two base case simulations are less biased.

The AQS performance statistics across the 4-km domain for the May-August 2014 modeling period show that the 2014v2 and 2014 MDA8 ozone performance is not exactly identical with the revised 2014v2 base case having a NMB of 4.4% that achieves the ozone bias Performance Goal, whereas the original 2014 base case has a NMB of 6.2% that falls between the ozone bias Performance Goal and Criteria. The 2014v2 NME (10.6%) is also slightly better than the original 2014 base case (10.9%).

Both CAMx base case simulations exhibit extremely good MDA8 ozone model performance across the CASTNet sites in the 4-km domain with near zero bias (-1.4% and +0.1%) and errors (8.1% and 7.9%) that are almost half the ozone error Performance Goal (<15%).

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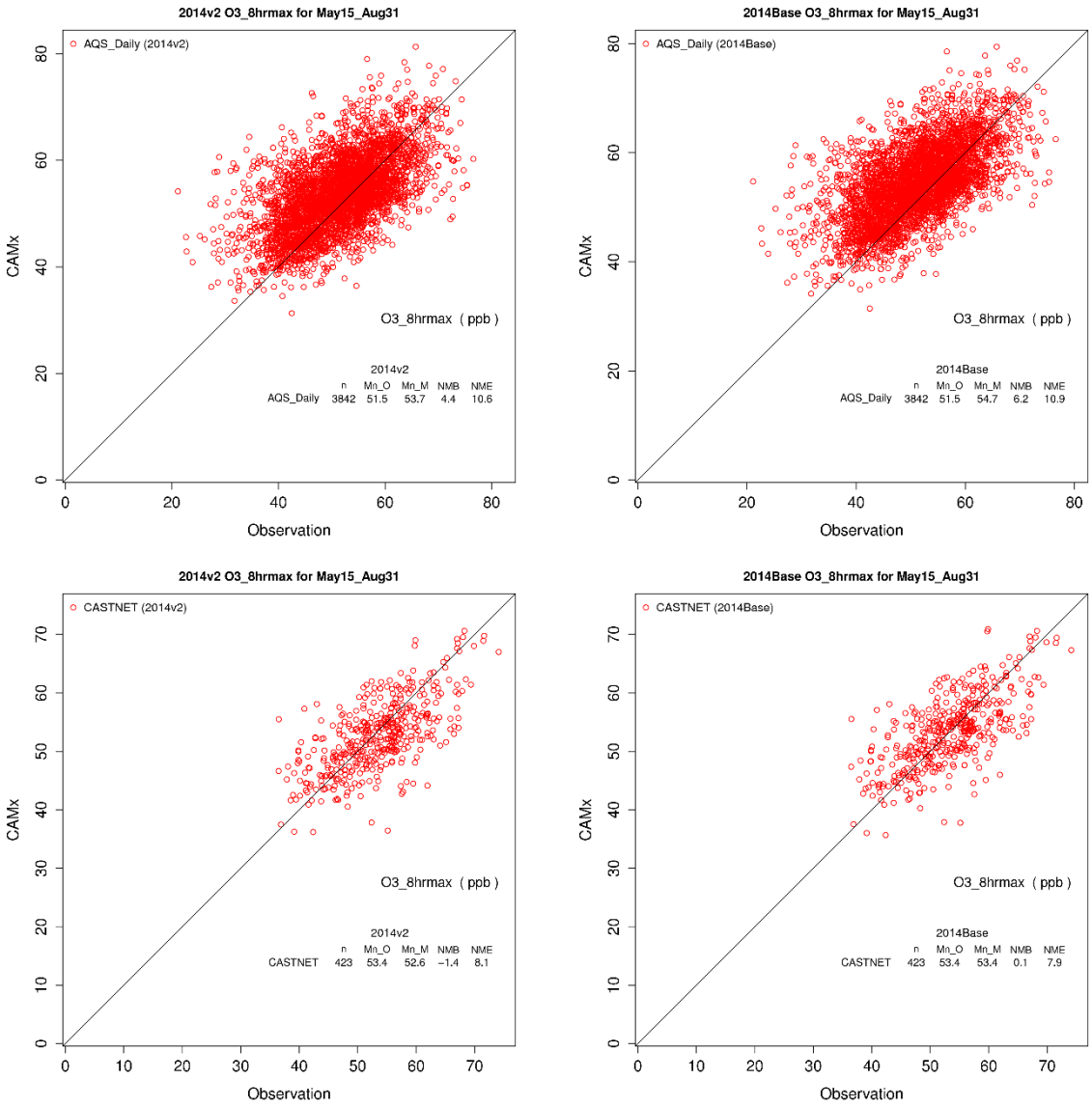


Figure 6-3. Scatter plots of predicted and observed MDA8 ozone concentrations for AQS (top) and CASTNet (bottom) monitoring sites within the 4-km New Mexico domain and the revised 2014v2 (left) and original 2014 (right) CAMx base case simulations.

6.5 MDA8 Ozone Time Series

Example predicted and observed MDA8 ozone time series at selected sites are presented below, with time series at all sites contained in the Appendix in Ramboll and WESTAR (2021). Figure 6-4 displays MDA8 ozone time series at the Desert View monitoring site in Doña Ana County in southern New Mexico. The CAMx MDA8 ozone predictions for the revised 2014v2 (blue) and original 2014 (green) base case simulations are almost on top of each other. In general, when they are a little different the revised 2014v2 MDA8 ozone is slightly lower, although that is not always the case as seen in the MDA8 ozone peaks in early June, mid-July, and end of August.

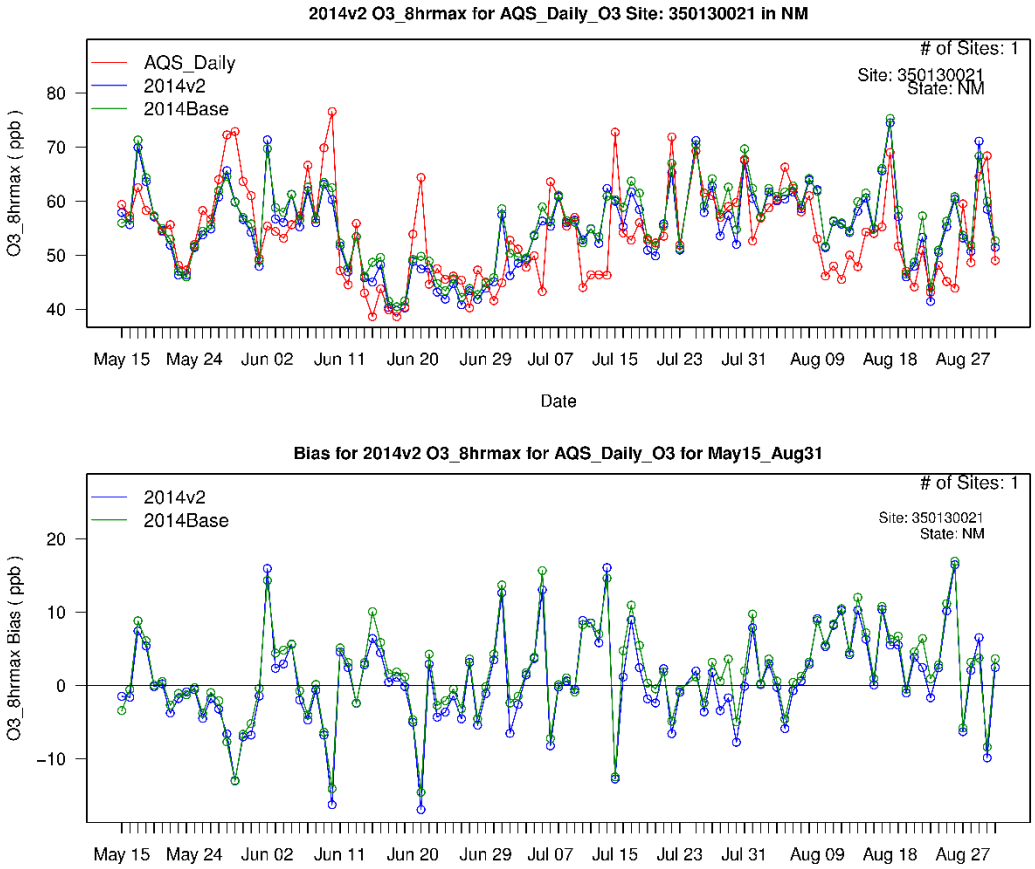


Figure 6-4. Time series of predicted and observed (red) MDA8 ozone at Desert View in Doña Ana County for the CAMx revised 2014v2 (blue) and original 2014 (green) CAMx base case simulations.

The MDA8 ozone time series comparison for the South East Heights monitoring site in Bernalillo County is shown in Figure 6-5. With the exception of a period in early July where the revised 2014v2 base case has a larger underestimation bias compared to the original 2014 base case, the two CAMx base case simulations are predicting nearly identical MDA8 ozone concentrations at this site.

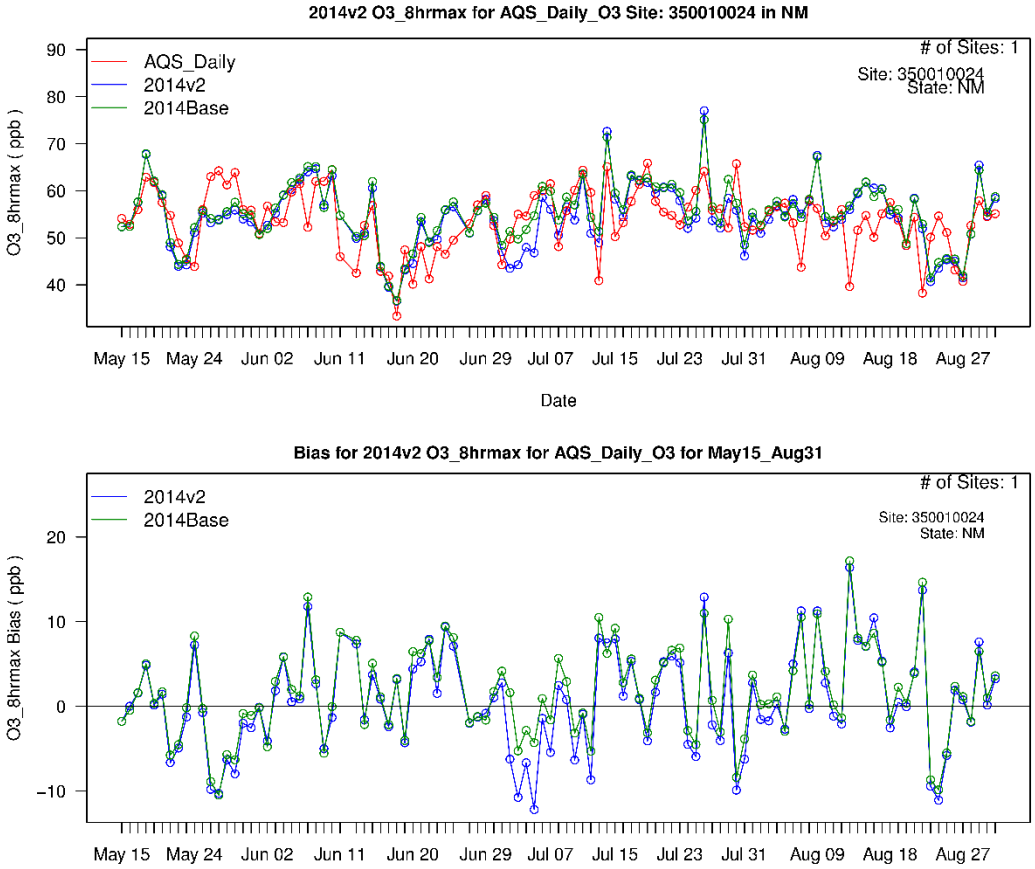


Figure 6-5. Time series of predicted and observed (red) MDA8 ozone at South East Heights in Bernalillo County for the CAMx revised 2014v2 (blue) and original 2014 (green) CAMx base case simulations.

The ozone time series at the Substation monitoring site in San Juan County is shown in Figure 6-6. Both CAMx base cases track the observed MDA8 ozone concentrations very well at the Substation monitoring site. Most of the time, the predicted MDA8 ozone are on top or nearly on top of each other and when different the revised 2014v2 MDA8 ozone is a little lower than the original CAMx 2014 base case.

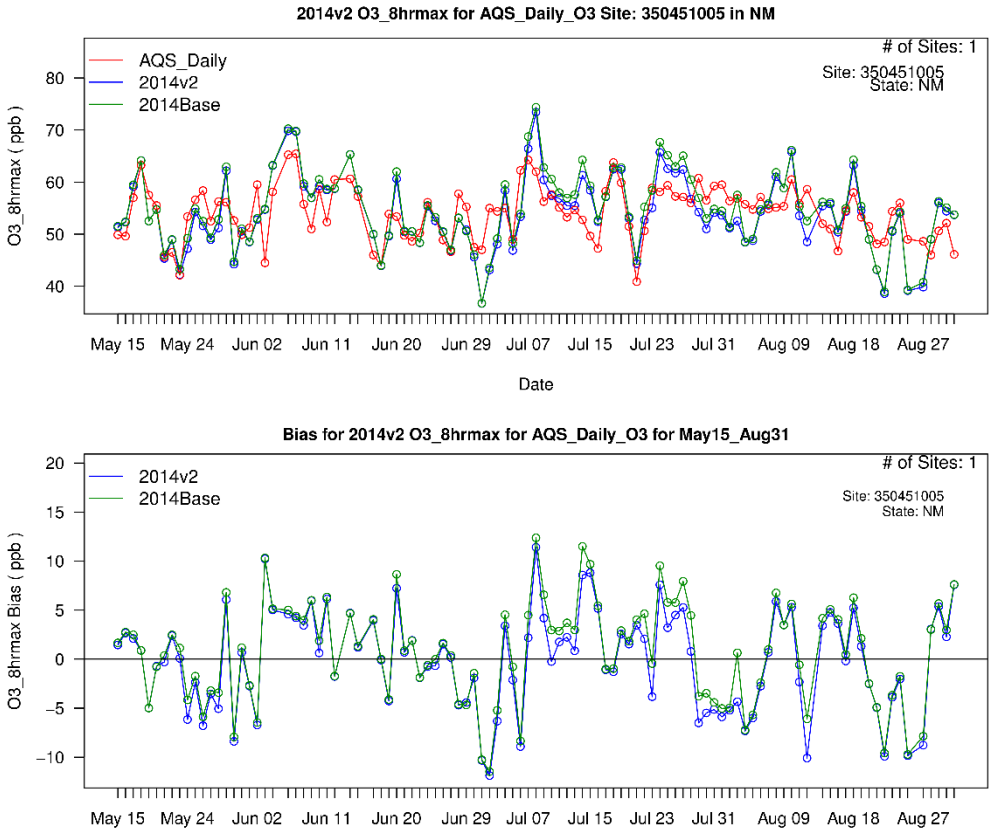


Figure 6-6. Time series of predicted and observed (red) MDA8 ozone at Sub Station in San Juan County for the CAMx revised 2014v2 (blue) and original 2014 (green) CAMx base case simulations.

6.6 Summary Ozone Model Performance Statistics in New Mexico

Ozone model performance statistics were calculated for three geographic regions in New Mexico. The central region was defined as all monitoring sites within Bernalillo County with the southern and northern regions defined as sites, respectively, south and north of Bernalillo County.

Tables 6-3 and 6-4 display the bias and error MDA8 ozone performance statistics with and without the observed MDA8 ozone 60 ppb cutoff for the three New Mexico subregions and the, respectively, original 2014 and revised 2014v2 CAMx base case simulations. The bias and error MDA8 ozone performance statistics are colored green when they achieve the Performance Goal, yellow when they lie between the Performance Goal and Criteria and red when they fail to achieve the Performance Criteria. The CAMx 2014 and 2014v2 base case performance statistics within the three New Mexico subregions are very good and very similar with the bias for the revised 2014v2 base case being 1-2 percentage points lower than the original 2014 CAMx base case simulation. Using no cutoff, when CAMx has a slight ozone overestimation tendency, the revised 2014v2 exhibits better performance statistics than the original 2014 base case. For example, the bias in the southern New Mexico region in original 2014 base case (5.8%) fails to achieve the ozone bias Performance Goal due to too high ozone overestimation, but achieves the ozone bias Performance Goal in the revised 2014v2 base case (3.5%). On the other hand, when an observed ozone 60 ppb cutoff is used the model tends to underestimate ozone a little so the revised 2014v2 base case ozone model performance is degraded a little compared to the original 2014 base case. For example, for the southern New Mexico subregion the original CAMx 2014 base case has a -6.1% NMB that is -7.8% for the revised CAMx 2014v2 base case, both of these NMB ozone performance statistics fall between the ozone bias Performance Goal and Criteria.

Table 6-3. Bias and error MDA8 ozone performance statistics for the original CAMx 2014 base case and the three subregions of New Mexico calculated with and without using an observed MDA8 ozone 60 ppb cutoff.

	Nocutoff		Withcutoff	
Region	NMB(%)	NME(%)	NMB(%)	NME(%)
North NM	4.3	9.1	0	6.4
Bernalillo	4.3	9.4	-2.8	7.1
South NM	5.8	10.5	-6.1	8.5

Table 6-4. Bias and error MDA8 ozone performance statistics for the revised CAMx 2014v2 base case and the three subregions of New Mexico calculated with and without using an observed MDA8 ozone 60 ppb cutoff.

	Nocutoff		Withcutoff	
Region	NMB(%)	NME(%)	NMB(%)	NME(%)
North NM	2.6	8.6	-1.0	6.6
Bernalillo	2.6	9.6	-4.3	8.5
South NM	3.5	10.2	-7.8	9.9

Tables 6-5 and 6-6 contain the bias performance statistics with and without a cutoff for each monitoring site in New Mexico and the, respectively, original CAMx 2014 and revised CAMx 2014v2 base case simulations. When not using the observed ozone cutoff, the original 2014 base case has 59% of the sites achieving the ozone bias Performance Goal with 36% of the sites falling between the Performance Goal and Criteria and one site failing to achieve the ozone bias Performance Criteria due to a 17.4% overestimation bias. The revised 2014v2 base case bias with no cutoff has 68% of the sites achieving the Performance Goal, 27% falling between the Performance Goal and Criteria and one site right at (15.0%) the Performance Criteria.

When an observed ozone cutoff is used, the number of sites achieving the ozone bias Performance Goal is flipped between the two base cases with 68% of the sites achieving the Performance Goal for the original 2014 base case and 59% of the sites achieving the Performance Goal for the revised 2014v2 base case with the remainder of the sites falling between the ozone bias Performance Goal and Criteria.

NMED Exhibit 17

Table 6-5. Bias MDA8 ozone performance statistics with and without an observed ozone cutoff for each site in New Mexico and the original CAMx 2014 base case simulation.

2014Base (with MEGAN)			
SiteID	**SiteNames**	**NMB No Cutoff**	**NMB 60 ppb Cutoff**
350010023	Del Norte	1.7	-3.9
350010024	South East Heights	3.1	-2.4
350010029	South Valley	3.1	-2.8
350010032	Westside	1.1	-3.4
350011012	Foot Hills	13.6	2.0
350130008	La Union	17.4	-1.6
350130017	Sunland Park Yard	9.0	-3.6
350130020	Chaparral	4.8	-4.7
350130021	Desert View	3.2	-5.1
350130022	Santa Teresa	8.2	0.1
350130023	Solano	6.1	-6.5
350151005	Carlsbad	-1.1	-12.3
350171003	Chino Copper	9.1	-1.0
350250008	Hobbs Jefferson	2.1	-9.9
350290003	Deming Airport	6.2	-5.0
350390026	Coyote Ranger	3.3	-5.4
350431001	Bernalillo	8.1	3.8
350450009	Bloomfield	7.2	2.5
350450018	Navajo Lake	2.2	-0.6
350451005	Sub Station	1.4	3.3
350490021	Santa Fe Airport	3.8	-1.7
350610008	Los Lunas	0.8	-6.5

Table 6-6. Bias MDA8 ozone performance statistics with and without an observed ozone cutoff for each site in New Mexico and the revised CAMx 2014v2 base case simulation.

2014v2 (with BEIS)			
SiteID	**SiteNames**	**NMB No Cutoff**	**NMB 60 ppb Cutoff**
350010023	Del Norte	0.5	-4.9
350010024	South East Heights	1.3	-3.6
350010029	South Valley	0.9	-4.4
350010032	Westside	-1.0	-5.4
350011012	Foot Hills	11.9	0.8
350130008	La Union	15.0	-3.0
350130017	Sunland Park Yard	7.4	-4.1
350130020	Chaparral	2.8	-5.8
350130021	Desert View	1.4	-6.3
350130022	Santa Teresa	5.8	-1.8
350130023	Solano	3.9	-8.2
350151005	Carlsbad	-4.3	-14.5
350171003	Chino Copper	7.0	-1.8
350250008	Hobbs Jefferson	-1.2	-12.6
350290003	Deming Airport	3.8	-8.6
350390026	Coyote Ranger	1.2	-5.6
350431001	Bernalillo	6.4	3.3
350450009	Bloomfield	6.0	1.7
350450018	Navajo Lake	0.5	-3.6
350451005	Sub Station	-0.1	2.2
350490021	Santa Fe Airport	1.5	-2.5
350610008	Los Lunas	-1.7	-9.0

6.7 Conclusions of 2014 Base Case Modeling and Model Performance Evaluation

The evaluation of the NM OAI Study CAMx original 2014 and revised 2014v2 base case simulations focused on MDA8 ozone model performance across all sites within New Mexico, within three subregions in New Mexico (northern, Bernalillo County, and southern) and at individual sites in New Mexico. When examining MDA8 ozone performance across groups of sites, both CAMx 2014 base cases always achieves the ozone Performance Criteria and usually achieves the ozone Performance Goals. Except for one site (La Union in Doña Ana County) both CAMx base cases also achieve the ozone Performance Criteria at all monitoring sites and achieve the ozone Performance Goals as a majority of the sites in New Mexico. When examining MDA8 ozone performance across all observations, the model tended to have an ozone overestimation tendency but still always achieved the bias performance criteria (≤±15%) and usually achieved the bias performance goal (≤±5%). When comparing the model's ability to reproduce the highest observed ozone concentrations greater than 60 ppb, the model still always achieved the bias performance criteria and usually achieved the bias performance goal, albeit with an underestimation tendency. The

MDA8 ozone error essentially always achieves the performance goal whether examining all ozone observations or just those observations greater than 60 ppb.

In conclusion, the NM OAI Study original CAMx 2014 and revised CAMx 2014v2 base case simulations ozone model performance within New Mexico is as good or better than most recent PGM applications (e.g., WRAP-WAQS, EPA 2016v1 and Denver ozone SIP) and appears to be a reliable PGM modeling platform for evaluating emission reduction strategies for reducing ozone concentrations in New Mexico.

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7. 2028 BASE CASE MODELING AND OZONE DESIGN VALUE PROJECTIONS

A CAMx v7.1 2028 36/12/4-km Base Case model simulation was conducted using the WRF/NAM meteorological, 2014 Boundary Conditions (BCs) and 2028 base case emission inputs described in, respectively, Chapters 2, 3 and 4. The CAMx 2028 base case simulation used the same model configuration as used in the CAMx v7.1 2014v2 revised base case simulations presented in Chapter 6 only with the 2028 Base Case anthropogenic emissions.

The CAMx 2014v2 and 2028 Base Case simulations were used to make 2028 future-year ozone design value (DVF) projections.

7.1 EPA Recommended Ozone Design Value Projection Procedure

EPA recommends using photochemical grid model (PGM) modeling results in a relative fashion to scale the observed current year ozone design value (DVC) to estimate the future year ozone design value (DVF). The model derived scaling factors are called Relative Response Factors (RRF) and are the ratio of future (2028) to base (2014v2) year ozone modeling results averaged over the 10 highest base year base case modeled Maximum Daily 8-hour Average (MDA8) ozone concentrations near the monitor:

$$RRF = \sum Model_{2028} / \sum Model_{2014}$$

$$DVF = DVC \times RRF$$

EPA guidance recommends that the DVC is calculated as the average of three-years of ozone design values (DV) centered on the base modeling year, which is 2014 in this case:

$$DVC_{2012\text{-}2016} = (DV_{2012\text{-}2014} + DV_{2013\text{-}2015} + DV_{2014\text{-}2016}) / 3$$

By near the monitor, EPA guidance recommends that the highest modeled base year MDA8 ozone is selected within a 3x3 array of grid cells centered on the monitor. For the future year, the future year MDA8 ozone is selected from the same grid cell in the 3x3 array centered on the monitor as used in the base year.

EPA guidance recommends using the 10 highest modeled base year MDA8 ozone concentrations days with MDA8 ozone greater than 60 ppb in the RRFs. If there are less than 10 modeled days with base year MDA8 ozone greater than 60 ppb, EPA guidance states that RRFs can still be calculated as long as there are at least 5 days with ozone greater than 60 ppb.

EPA has codified their recommended ozone DVF projection approach in the Software for the Modeled Attainment Test (SMAT[37]). The SMAT tool was used to make 2028 ozone DVF projections in the NM OAI Study. The default SMAT specification were used except

[37] https://www.epa.gov/scram/photochemical-modeling-tools

that the minimum number of days needed to calculated an RRF was lowered from 5 to 4 in order to obtain 2028 ozone DV projections at all sites in New Mexico.

7.1.1 Ozone DV Unmonitored Area Analysis (UAA)

SMAT includes an unmonitored area analysis (UAA) that examines projected future year ozone DVFs away from the monitoring sites. The first step in the UAA is the spatial interpolation of the monitor-based ozone DVCs ($DVC_{2012\text{-}2016}$) across the domain being analyzed, which is the 4-km New Mexico domain in this case. The SMAT spatial interpolation of the monitoring site ozone DVC can be performed with and without using the modeled ozone concentration gradients. As shown below, the SMAT UAA analysis was run for the NM OAI Study 2028 base case ozone DVC projections with and without using the modeled concentration gradients. We recommend using the interpolation without the modeled concentration gradients because of the influence of fires on UAA interpolated ozone DVCs that are uncertain, unverifiable, and not regulatory relevant.

The SMAT UAA procedure for projecting the spatially interpolated ozone DVCs is the same as used at the monitor described above, only instead of using the modeling results in the in a 3x3 array of grid cells with the highest 2014 modeled MDA8 ozone to define near the monitor, the value at the grid cell is used (i.e., 1x1 array).

7.2 2028 Base Case Ozone DVF Projections at Monitoring Sites

Table 7-1 displays the current year $DVC_{2012\text{-}2016}$ and projected 2028 ozone DVFs at monitoring sites in New Mexico for the 2028 Base Case simulation and their differences. There are two sites in Doña Ana County with current year $DVC_{2012\text{-}2016}$ above the 70 ppb 2015 ozone NAAQS, Desert View (72.0 ppb) and Santa Teresa (71.3 ppb). However, it should be noted that measured ozone concentrations in Southern New Mexico have been higher in more recent years, as shown in Table 1-1. This issue is examined in a DVC sensitivity analysis presented in Chapter 9.

The 2028 Base Case ozone DVFs at monitoring sites in northern New Mexico are projected to be -2.2 ppb to -5.6 ppb lower than the observed $DVC_{2012\text{-}2016}$. For the northern New Mexico sites, Navajo Lake has the highest ozone $DVC_{2012\text{-}2016}$ (67.0 ppb) and 2028 Base Case projected DVF (64.8) and is the site with the lowest reduction between the DVC and DVF (-2.2 ppb).

The current observed $DVC_{2012\text{-}2016}$ in Bernalillo County range from 65.0 to 68.0 ppb and are projected to be reduced by -4.4 ppb to -5.9 ppb by 2028 with all 2028 Base Case projected ozone DVFs in Bernalillo County below 63 ppb.

The current ozone $DVC_{2012\text{-}2016}$ at the southern New Mexico sites range from 62.0 to 72.0 ppb and are reduced by -2.0 ppb to -6.3 ppb in the 2028 Base Case. The sites in Doña Ana County have the largest ozone DV reductions between 2014 and 2028 (-4.7 to -6.3 ppb). While those monitoring sites in southeast New Mexico have the lowest ozone DVF reduction between 2014 and 2028 Base Cases, -2.3 ppb at Carlsbad and -2.0 ppb at Hobbs in, respectively, Eddy and Lea Counties. The lower reductions in 2028 Base Case ozone DVFs at the two southeastern New Mexico sites are due to increased oil and gas emissions in the Permian Basin between 2014 and 2028 that offset the effects due to emission reductions from other source sectors, such as mobile sources (see Chapter 4).

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Table 7-1. Current year $DVC_{2012-2016}$ and projected 2028 Base Case ozone DVFs at New Mexico monitoring sites within the 4-km NM domain.

AQS_ID	2012-2016 DVC (ppb)	2028 Base DVF Base (ppb)	Difference 2028 DVF minus $DVC_{2012-16}$ (ppb)	Site Name	State	County
Northern New Mexico						
350390026	64.0	60.8	-3.2	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	-5.6	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	-3.3	Bloomfield	NM	San Juan
350450018	67.0	64.8	-2.2	Navajo Lake	NM	San Juan
350451005	63.7	60.8	-2.9	Substation	NM	San Juan
350490021	64.3	60.6	-3.7	Santa Fe Airport	NM	Santa Fe
Bernalillo County						
350010023	66.3	60.9	-5.4	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	-5.7	South East Heights	NM	Bernalillo
350010029	66.0	61.0	-5.0	South Valley	NM	Bernalillo
350010032	67.0	62.6	-4.4	Westside	NM	Bernalillo
350011012	65.0	59.1	-5.9	Foothills	NM	Bernalillo
Southern New Mexico						
350130008	66.3	60.0	-6.3	La Union	NM	Doña Ana
350130017	67.0	61.9	-5.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	-4.7	Chaparral	NM	Doña Ana
350130021	72.0	67.0	-5.0	Desert View	NM	Doña Ana
350130022	71.3	66.1	-5.2	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	-4.7	Solano	NM	Doña Ana
350151005	69.0	66.7	-2.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	-3.0	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	-2.0	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	-3.3	Deming Airport	NM	Luna
350610008	66.3	62.2	-4.1	Los Lunas (Los Lentes)	NM	Valencia

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The current year $DVC_{2012\text{-}2016}$ and projected 2028 Base Case ozone DVFs at monitoring sites within the 4-km NM domain but outside of New Mexico are shown in Table 7-2. The El Paso UTEP site is the only site in Table 7-2 that has a $DVC_{2012\text{-}2016}$ that exceeds (71.0 ppb) the 2015 ozone NAAQS. Design values at monitoring sites in El Paso are projected to go down between -3.2 ppb to -5.2 ppb with projected 2028 Base Case ozone DVFs ranging from 62.5 ppb to 66.2 ppb.

The sites in Arizona and Colorado have current year $DVC_{2012\text{-}2016}$ that are 68 ppb or lower and are reduced from -1.6 ppb to -5.2 ppb with the smallest reductions occurring in La Plata County, Colorado and the largest reductions occurring in El Paso.

Table 7-2. Current year $DVC_{2012\text{-}2016}$ and projected 2028 Base Case ozone DVFs at monitoring sites within the 4-km NM domain but outside of New Mexico.

AQS_ID	2012-2016 DVC (ppb)	2028 Base DVF Base (ppb)	Difference 2028 DVF minus $DVC_{2012\text{-}16}$ (ppb)	Site Name	State	County
Arizona, Colorado and Texas						
40038001	68.0	64.0	-4.0	Chiricahua NM	AZ	Cochise
40170119	66.7	61.9	-4.8	Petrified Forest	AZ	Navajo
80677001	67.7	66.1	-1.6	UTE 1	CO	La Plata
80677003	66.7	64.4	-2.3	UTE 3	CO	La Plata
80830006	63.0	59.7	-3.3	Cortez - Health Dept	CO	Montezuma
80830101	66.0	62.4	-3.6	Mesa Verde NP	CO	Montezuma
481410029	61.0	58.0	-3.0	Ivanhoe	TX	El Paso
481410037	71.0	66.2	-4.8	El Paso UTEP	TX	El Paso
481410044	67.7	62.5	-5.2	El Paso Chamizal	TX	El Paso
481410055	62.7	59.2	-3.5	Ascarate Park SE	TX	El Paso
481410057	66.5	63.3	-3.2	Socorro Hueco	TX	El Paso
481410058	68.0	63.4	-4.6	Skyline Park	TX	El Paso
483819991	66.7	62.4	-4.3	Palo Duro	TX	Randall

7.3 2028 Base Case Ozone DVF Unmonitored Area Analysis

SMAT was run using output the 2014v2 and 2028 Base Case CAMx simulations to obtain the spatial distribution of interpolated current year ozone $DVC_{2012\text{-}2016}$ and projected 2028 ozone DVF throughout the 4-km NM domain using the Unmonitored Area Analysis (UAA) feature. SMAT UAA was run with and without using modeled concentration gradients in the spatial interpolation of the observed ozone $DVC_{2012\text{-}2016}$ at the monitoring sites to each grid cell in the 4-km NM domain.

Figure 7-1 displays the spatial distribution of the SMAT UAA ozone $DVC_{2012\text{-}2016}$ and DVF across the 4-km NM domain calculated using CAMx modeled ozone concentrations gradients in the spatial interpolation of the $DVC_{2012\text{-}2016}$. Although the highest $DVC_{2012\text{-}2016}$ at a monitoring site is 72.0 ppb at Desert View, using modeled concentration

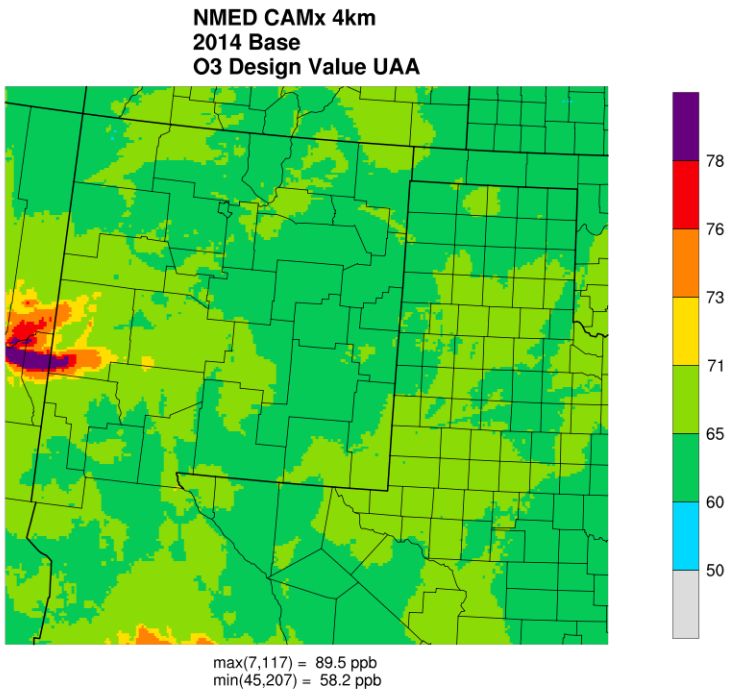
gradients produces an interpolated $DVC_{2012\text{-}2016}$ as high as 89.5 ppb that occurs in Arizona on the border with New Mexico that is reduced to 84.0 ppb for the maximum 2028 Base Case UAA DVF. These high MDA8 ozone concentrations in eastern Arizona and southwestern New Mexico are due to elevated ozone concentrations from wildfire emissions that are used in the SMAT UAA $DVC_{2012\text{-}2016}$ spatial interpolation when the option to use modeled concentration gradients is selected. Because they occur away from any monitoring sites, whether actual elevated ozone occurred in these wildfire ozone plumes is not known. Away from these wildfire ozone plumes, the SMAT UAA $DVC_{2012\text{-}2016}$ range from 60 to 71 ppb that are reduced to the 50 to 65 ppb range in for the SMAT UAA 2028 ozone DVF with small patches in the 65-71 ppb range scattered across New Mexico.

The SMAT UAA ozone $DVC_{2012\text{-}2016}$ and 2028 Base Case projections obtained without using the modeled concentrations gradients are shown in Figure 7-2. When doing the SMAT UAA spatial interpolation of the $DVC_{2012\text{-}2016}$ without including the concentrations gradients the ozone $DVC_{2012\text{-}2016}$ across the 4-km NM modeling domain are constrained by the $DVC_{2012\text{-}2016}$ values at the monitoring sites (i.e., Tables 7-1 and 7-2), which range from 61.4 to 71.0 ppb (10 ppb range; Figure 7-2). This is in contrast when the modeled concentrations gradients are used in the SMAT UAA interpolation and the $DVC_{2012\text{-}2016}$ range from 58.2 to 89.5 ppb across the domain (31 ppb range; Figure 7-1).

Figure 7-3 displays a spatial map of the differences in ozone $DVC_{2012\text{-}2016}$ and 2028 base case DVF (DVF – DVC) from the SMAT UAA with the top panel shown the differences with and the bottom panel showing the differences without using the modeled spatial gradients in the interpolation. Using the modeled concentration gradients in the interpolation has a significant effect on the DVC/DVFs, but has little effect on the differences in the SMAT UAA DVF and DVC. In fact, the only perceptible change in the ozone DVF and DVC differences is near the location of the modeled wildfire ozone plume in eastern Arizona.

The largest differences in current year ozone DVC and the 2028 Base Case DVF occurs in the eastern part of the domain with reductions of -4 to-11 ppb that are coming in from east Texas where there are larger emission reductions due to larger population centers. Over most of New Mexico, there are small reductions in the -1 to -4 ppb range with reductions in the -4 to -6 ppb range near Albuquerque. However, within the Permian and San Juan Basins there are small areas of ozone DVF increases with the largest increase of +3 ppb.

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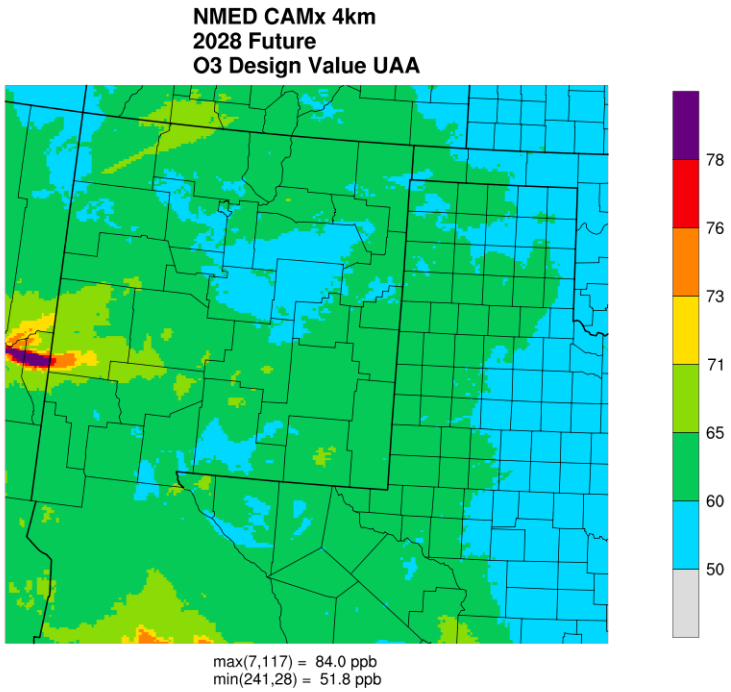


Figure 7-1. SMAT UAA current year ozone $DVC_{2012\text{-}2016}$ and projected 2028 future year ozone DVF for the 2028 Base Case using spatial interpolation with concentration gradients.

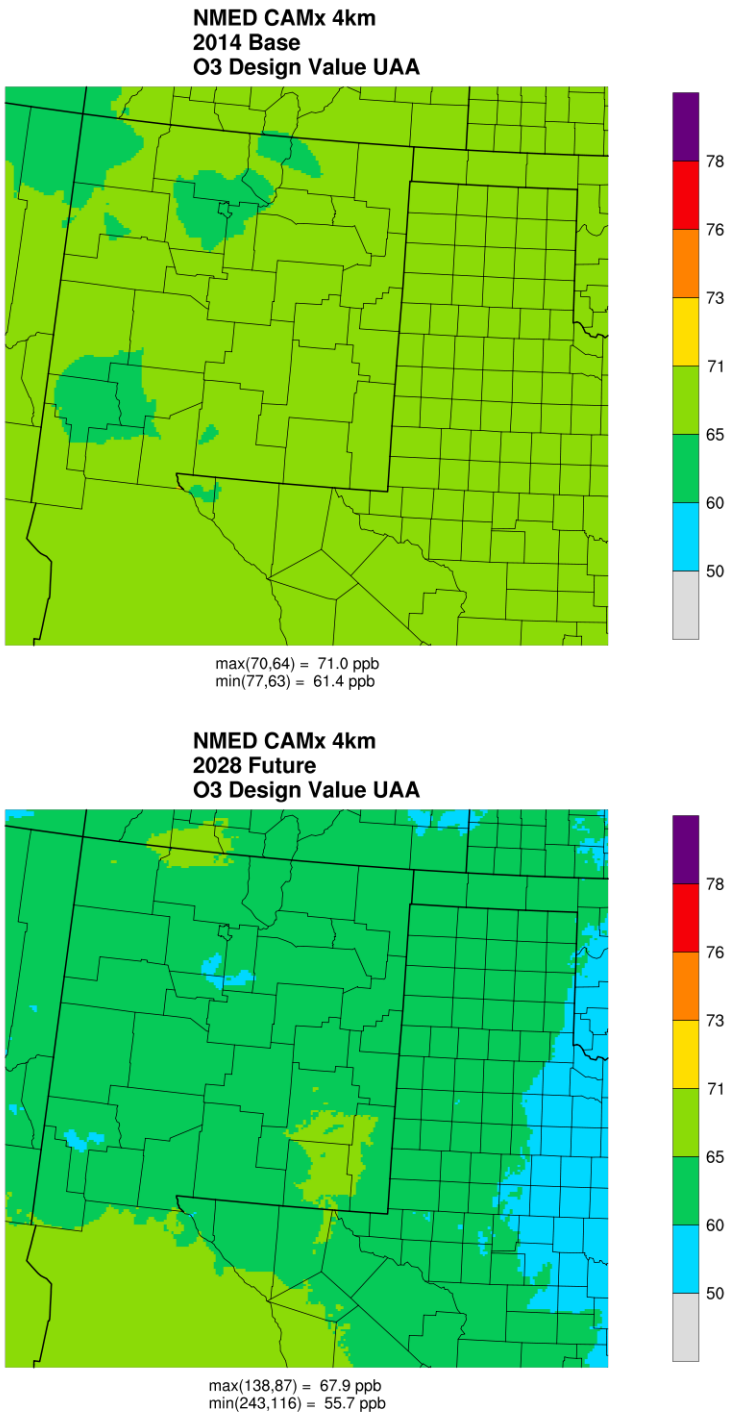


Figure 7-2. SMAT UAA current year ozone $DVC_{2012\text{-}2016}$ (top) and projected 2028 future year ozone DVF for the 2028 Base Case using spatial interpolation without concentration gradients.

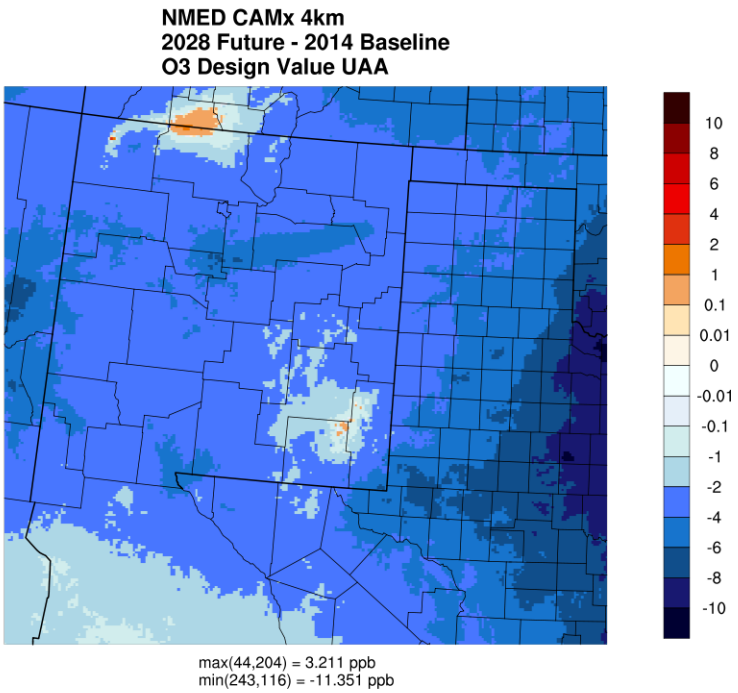


Figure 7-3. Differences between SMAT UAA current year ozone $DVC_{2012\text{-}2016}$ and projected 2028 future year ozone DVF for the 2028 Base Case using spatial interpolation with (top) and without (bottom) concentration gradients.

7.4 2014v2 and 2028 MDA8 Ozone Concentrations

In this section we present spatial maps of daily MDA8 ozone and the differences in MDA8 ozone for the 2014v2 and 2028 Base Case CAMx simulations for six example days. MDA8 ozone concentration and difference plots were generated for all ~100 days of the modeling episode, most of which were fairly low ozone concentration days so are of less interest.

7.4.1 Daily 2014v2 and 2028 Base Case MDA8 Ozone Concentrations

Figures 7-4 through 7-9 display example spatial maps of MDA8 ozone concentrations for the CAMx 2014v2 and 2028 Base Case simulations and their differences for six example days.

The most prominent features in the estimated MDA8 ozone concentrations on May 17, 2014 are locations of very high (> 80 ppb) ozone concentrations in eastern Arizona and southwest New Mexico (Figure 7-4). These high ozone concentrations have a signature of ozone from wildfires with the largest being an ozone plume being transported into western New Mexico from a wildfire in eastern Arizona. Although there are no ozone monitors located in the center of these model-estimated highly elevated ozone plumes, the Chino Copper Smelter site in Grant County is within the edge of the plume where the model estimates MDA8 ozone concentrations in the 65-71 ppb range that match the observed concentrations at this site extremely well for the May-June 2014 portion of the episode (see Appendix A in Ramboll and WESTAR, 2020c; 2021). Over most of New Mexico, the 2028 Base Case has lower MDA8 ozone concentrations with reductions as high as -11 ppb in southwest Torrance County. However, the 2028 Base Case has MDA8 ozone increases in the San Juan and Permian Basins with a maximum MDA8 ozone increase of +5 ppb in Eddy County.

On June 5, 2014, the 2014v2 Base Case has CAMx-estimated MDA8 ozone concentrations in the 65-71 ppb range in northwest New Mexico and in Doña Ana County with even a small location of MDA8 ozone exceeding the 2015 ozone NAAQS in the northeast corner of San Juan County and a modeled peak MDA8 ozone concentration of 72.9 ppb occurring in El Paso just over the border from Doña Ana County (Figure 7-5). Although the emission changes from 2014v2 to 2028 reduce the intrusion of elevated ozone entering Doña Ana County from El Paso, the elevated ozone in northwest New Mexico is increased. The area of estimated MDA8 ozone in San Juan County that is above the 2015 ozone NAAQS is larger in the 2028 Base Case than the 2014v2 Base Case and stretches into Rio Arriba County with a peak ozone value of 74 ppb in Colorado at the border with New Mexico. As shown in the MDA8 ozone difference plot in Figure 7-5, increases in MDA8 ozone concentrations in the 2028 Base Case are due to increased O&G emissions within the Permian and San Juan Basins.

Although the 2014v2 and 2028 Base Case estimated MDA8 ozone on July 12, 2014 is well below the NAAQS (mostly < 60 ppb with small pockets in the 60-65 ppb range), the 2028 Base Case has increases MDA8 ozone in the San Juan and Permian Basins with a maximum increase of +11.4 ppb (Figure 7-6). The maximum decrease in MDA8 ozone is -7.6 ppb near Albuquerque.

On July 24, 2014, the CAMx 2014v2 Base Case estimates elevated MDA8 ozone concentrations in northwest New Mexico with values even exceeding the 2015 ozone

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NAAQS in San Juan County and a peak value of 74.7 ppb in Colorado at the border with New Mexico (Figure 7-7). The 2028 Base Case has lower ozone than the 2014v2 Base Case across New Mexico with only small areas of ozone increases. The area of MDA8 ozone in San Juan County that was above the 2015 ozone NAAQS in the 2014v2 Base Case is reduced to below the NAAQS in the 2028 Base Case, although the peak MDA8 ozone in Colorado at the border of New Mexico still exceeds the NAAQS (71.3 ppb).

The CAMx 2014v2 Base Case estimates a high peak MDA8 ozone concentration of 78.4 ppb in Albuquerque with several additional areas of high ozone above the NAAQS occurring in other northern New Mexico Counties on July 26, 2014 (Figure 7-8). Although the 2028 Base Case has reduced almost all of the areas with 2014v2 MDA8 ozone above the NAAQS, there is still an estimate ozone peak above the NAAQS (72.3 ppb) just west of Albuquerque in northeast Cibola County. Ozone increases are seen in the Permian and San Juan Basins on July 26 with the highest increase of +5.7 ppb occurring in the San Juan Basin.

An ozone peak of 74.1 ppb occurs on August 14 on the border of Doña Ana County and El Paso with ozone in excess of the NAAQS stretching into Doña County (Figure 7-9). The emission reductions in the 2028 Base Case appear reduce the estimated ozone in Doña County to below the NAAQS, although the peak ozone (71.2 ppb) just over the border in El Paso still exceeds the NAAQS. Ozone increases in the Permian and San Juan Basins are mostly less than +1 ppb and fairly isolated on this day.

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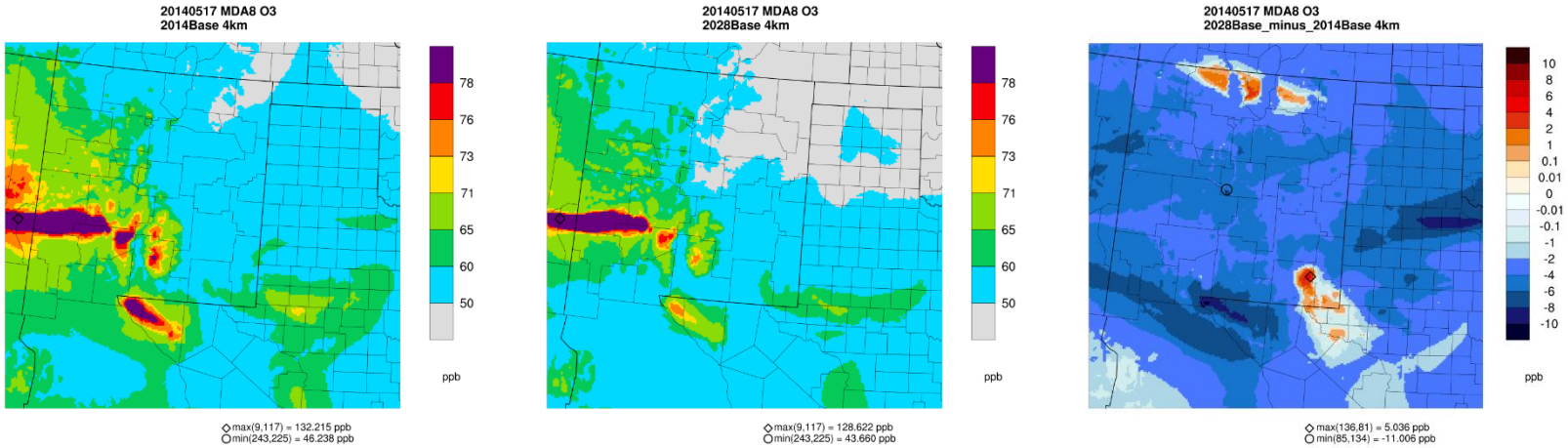


Figure 7-4. CAMx estimated MDA8 ozone concentrations (ppb) on May 17, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

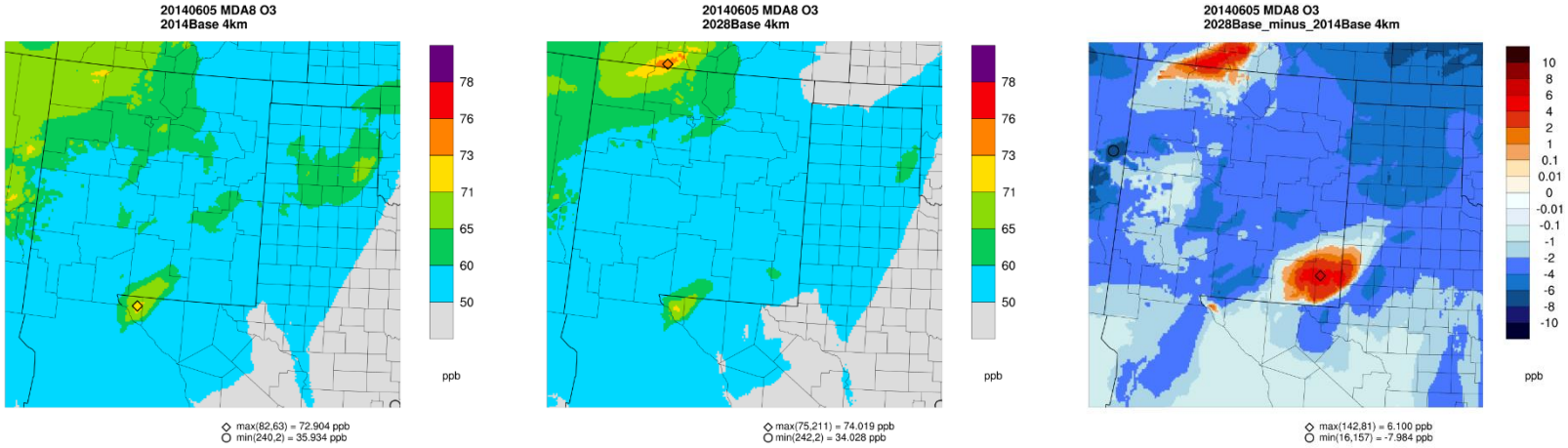


Figure 7-5. CAMx estimated MDA8 ozone concentrations (ppb) on June 5, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

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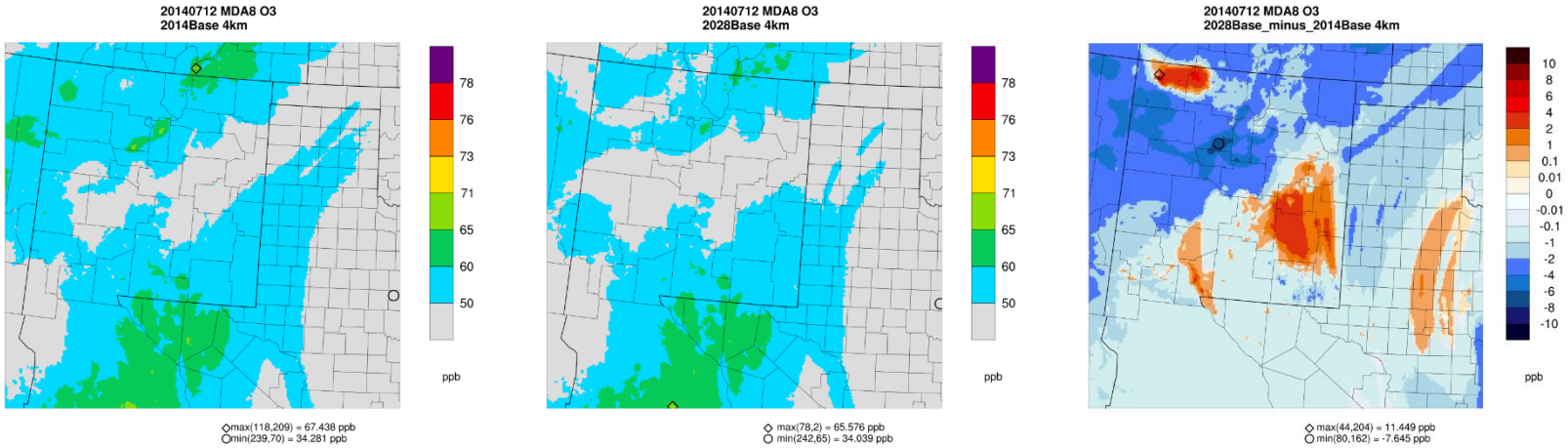


Figure 7-6. CAMx estimated MDA8 ozone concentrations (ppb) on July 12, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

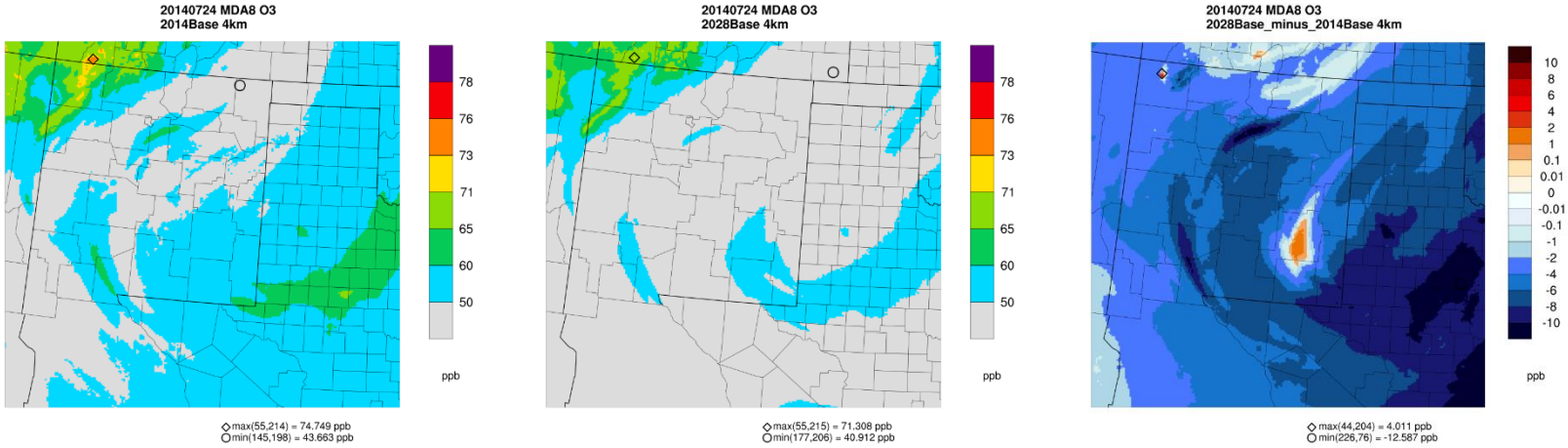


Figure 7-7. CAMx estimated MDA8 ozone concentrations (ppb) on July 24, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

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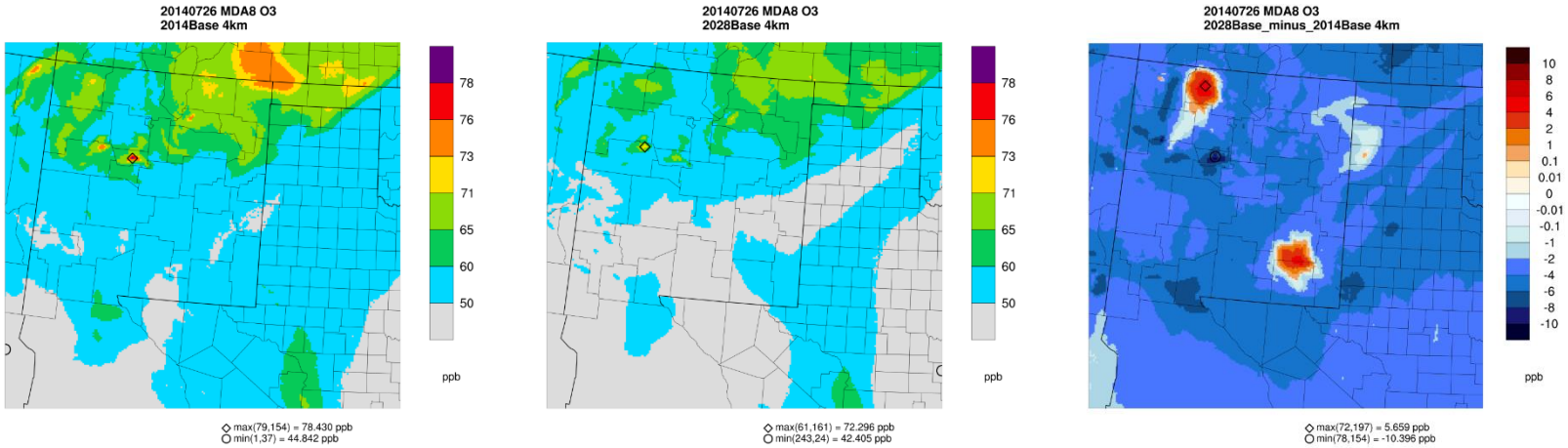


Figure 7-8. CAMx estimated MDA8 ozone concentrations (ppb) on July 26, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

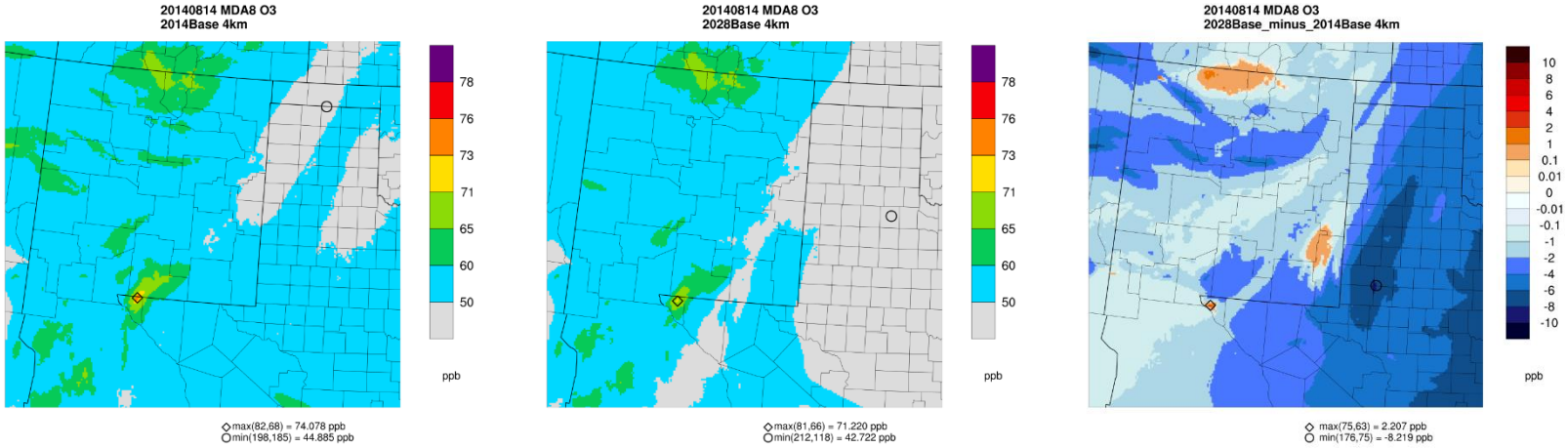


Figure 7-9. CAMx estimated MDA8 ozone concentrations (ppb) on August 14, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

7.4.2 Comparison of Episode Maximum MDA8 and SMAT UAA Ozone DVF Differences

Figure 7-10 compare the differences in episode maximum MDA8 ozone concentrations and SMAT UAA ozone DVs between the 2014v2 and 2028 Base Case simulations (the SMAT UAA ozone DV differences are without using concentration gradients and was shown previously in the bottom panel of Figure 7-3). Not surprisingly, since the SMAT UAA DVs represents an average across several modeling days, the episode maximum MDA8 ozone differences have higher changes than the SMAT UAA ozone differences with a maximum increase of +5 ppb vs. +3 ppb and maximum decrease of -12 ppb vs. -11 ppb for the, respectively, episode maximum MDA8 ozone and UAA DVs. The largest decreases occur in Albuquerque and in southern Doña Ana County on the border with El Paso. The largest increases in ozone occur in the San Juan and Permian Basin.

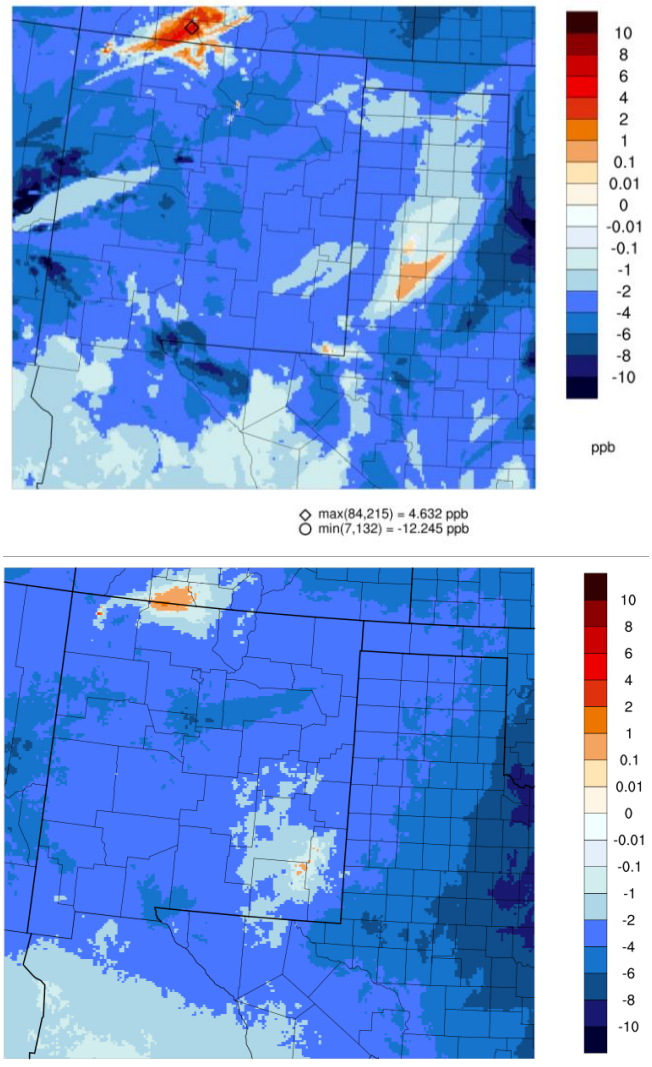


Figure 7-10. Differences in episode maximum MDA8 ozone concentrations (top) and SMAT UAA ozone DVs (bottom) between the 2014v2 and 2028 CAMx Base Case simulations.

8. 2028 OIL AND GAS CONTROL STRATEGY MODELING AND OZONE DESIGN VALUE PROJECTIONS

The implementation of the proposed New Mexico oil and gas (O&G) ozone precursor control strategy reduces VOC and NO_x emissions in the New Mexico portions of the San Juan and Permian Basins, as discussed in Section 4.5. Most of the O&G emission reduction in the San Juan Basin occur in northeastern San Juan and northwestern Rio Arriba Counties. While most of the emission reductions in the Permian Basin occur in Eddy and Lea Counties.

8.1 2028 Ozone Design Value Comparisons

The same procedures as used to project 2028 ozone DVFs for the CAMx 2028 Base Case (DVF_{Base}) were used to project the 2028 ozone DVFs for the 2028 O&G Control Strategy scenario (DVF_{Cntl}). These procedures start with an observed current year design value that is an average of 3 design values over 5-years ($DVC_{2012\text{-}2016}$) that is scaled by Relative Response Factors (RRFs) based on the ratio of the 2028 O&G Control Strategy over the 2014v2 Base Case CAMx ozone results to obtained a projected 2028 ozone DVF_{Cntl} for the 2028 O&G Control Strategy.

8.1.1 Ozone Design Values at the Monitoring Sites

Table 8-1 list the current year ozone $DVC_{2012\text{-}2016}$ and the projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control Strategy and the differences in the two 2028 ozone DVFs (DVF_{Cntl} – DVF_{Base}).

At monitoring sites in northern New Mexico, the 2028 ozone DVF_{Base} values are estimated to be reduced by -0.2 to -1.5 ppb due to the 2028 O&G Control Strategy with the largest reductions occurring at the Navajo Lake (-1.5 ppb) and Substation (-1.2 ppb) monitoring sites in San Juan County. After implementation of the 2028 O&G Control Strategy, the projected 2028 ozone DVF_{Cntl} in northern New Mexico range from 58.1 to 63.3 ppb.

Although not as close to the 2028 O&G emission reductions, the 2028 projected ozone DVF_{Cntl} in Bernalillo County see benefits of the 2028 O&G Control Strategy with ozone DVF reductions of -0.2 to -0.5 ppb. After implementation of the 2028 O&G Control Strategy, the projected 2028 ozone DVF_{Cntl} range from 58.8 to 62.1 ppb in Bernalillo County.

The 2028 ozone DVF reductions due to the 2028 O&G Control Strategy at the southern New Mexico monitoring sites range from -0.2 to -0.7 ppb with the largest reductions occurring at the Hobbs (-0.7 ppb) and Carlsbad (-0.3 ppb) monitoring sites in, respectively, Eddy and Lea Counties that lie within the Permian Basin. The other monitoring sites in southern New Mexico are farther away from the Permian Basin so have much more modest reductions in ozone DVFs (-0.1 to -0.2 ppb) due to the controls on oil and gas sources. After implementation of the 2028 O&G Control Strategies, the projected 2028 ozone DVF_{Cntl} at southern New Mexico sites range from 58.9 ppb to 66.8 ppb.

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Table 8-1. Observed ozone $DVC_{2012-2016}$ and projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control strategy and differences in the 2028 ozone DVFs ($DVF_{Cntl} - DVF_{Base}$).

AQS_ID	2012-16	Projected 2028 DVF			Site Name	State	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base			
Northern New Mexico							
350390026	64.0	60.8	60.0	-0.8	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	58.1	-0.3	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	60.2	-0.8	Bloomfield	NM	San Juan
350450018	67.0	64.8	63.3	-1.5	Navajo Lake	NM	San Juan
350451005	63.7	60.8	59.6	-1.2	Substation	NM	San Juan
350490021	64.3	60.6	60.4	-0.2	Santa Fe Airport	NM	Santa Fe
Bernalillo County							
350010023	66.3	60.9	60.7	-0.2	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	62.0	-0.3	South East Heights	NM	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	NM	Bernalillo
350010032	67.0	62.6	62.1	-0.5	Westside	NM	Bernalillo
350011012	65.0	59.1	58.8	-0.3	Foothills	NM	Bernalillo
Southern New Mexico							
350130008	66.3	60.0	59.8	-0.2	La Union	NM	Doña Ana
350130017	67.0	61.9	61.8	-0.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	62.2	-0.1	Chaparral	NM	Doña Ana
350130021	72.0	67.0	66.8	-0.2	Desert View	NM	Doña Ana
350130022	71.3	66.1	66.0	-0.1	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	60.2	-0.1	Solano	NM	Doña Ana
350151005	69.0	66.7	66.4	-0.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	58.9	-0.1	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	63.3	-0.7	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	62.5	-0.2	Deming Airport	NM	Luna
350610008	66.3	62.2	62.0	-0.2	Los Lunas (Los Lentes)	NM	Valencia

Table 8-2 list the observed ozone $DVC_{2012\text{-}2016}$ and projected 2028 ozone DVFs for monitoring sites outside of New Mexico but within the 4-km NM modeling domain. There are small reductions in projected ozone DVFs in Arizona (0.0 and -0.1 ppb) and El Paso, Texas (0.0 to -0.2 ppb) due to the New Mexico 2028 O&G Control Strategy. However, there are more substantial reductions in projected 2028 ozone DVFs at sites in La Plata (-0.7 and -0.9 ppb) and Montezuma (-0.5 ppb) counties in southwestern Colorado that are adjacent to the New Mexico portion of the San Juan Basin where some of the 2028 O&G Control Strategy emission reductions occur.

Table 8-2. Observed ozone $DVC_{2012\text{-}2016}$ and projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control strategy and differences in the 2028 ozone DVFs ($DVF_{Cntl} - DVF_{Base}$).

AQS_ID	2012-16	Projected 2028 DVF			Site Name	State	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base			
Arizona, Colorado and Texas							
40038001	68.0	64.0	63.9	-0.1	Chiricahua NM	AZ	Cochise
40170119	66.7	61.9	61.9	0.0	Petrified Forest	AZ	Navajo
80677001	67.7	66.1	65.2	-0.9	UTE 1	CO	La Plata
80677003	66.7	64.4	63.7	-0.7	UTE 3	CO	La Plata
80830006	63.0	59.7	59.2	-0.5	Cortez - Health Dept	CO	Montezuma
80830101	66.0	62.4	61.9	-0.5	Mesa Verde NP	CO	Montezuma
481410029	61.0	58.0	57.9	-0.1	Ivanhoe	TX	El Paso
481410037	71.0	66.2	66.1	-0.1	El Paso UTEP	TX	El Paso
481410044	67.7	62.5	62.4	-0.1	El Paso Chamizal	TX	El Paso
481410055	62.7	59.2	59.1	-0.1	Ascarate Park SE	TX	El Paso
481410057	66.5	63.3	63.2	-0.1	Socorro Hueco	TX	El Paso
481410058	68.0	63.4	63.4	0.0	Skyline Park	TX	El Paso
483819991	66.7	62.4	62.2	-0.2	Palo Duro	TX	Randall

8.1.2 2028 O&G Control Strategy Ozone DVF Unmonitored Area Analysis

The SMAT Unmonitored Area Analysis (UAA) was applied to estimate the spatial distribution of projected 2028 ozone DVF_{Cntl} throughout the 4-km NM modeling domain. Figure 8-1 displays the spatial distribution of the SMAT UAA ozone DVFs for the 2028 Base Case and 2028 O&G Control Strategy where the SMAT UAA was applied without using concentration gradients in the spatial interpolation of the $DVC_{2012\text{-}2016}$. Within New Mexico, the projected 2028 DVF_{Base} tends to be mostly in the 60-71 ppb range, with a few small locations with the values dropping below 60 ppb. The highest ozone concentrations (65-71 ppb) in New Mexico for the 2028 ozone DVF_{Base} occur in the San Juan and Permian Basin as indicated by the lighter green shading (Figure 8-1, top panel). When the O&G Control Strategy is applied, the ozone DVF_{Cntl} in the San Juan Basin is lower (i.e., in the 60-65 ppb with the light green shading completely gone) and the area of ozone DVF_{Base} in the 65-71 ppb range is greatly reduced for the ozone DVF_{Cntl} case.

Figure 8-2 shows a spatial map of the differences in SMAT UAA projected 2028 ozone DVFs between the 2028 Base Case and 2028 O&G Control Strategy (DVF_{Cntl} – DVF_{Base}) where the top and bottom panels represent ozone DVF differences without and with using the modeled concentration gradients in the SMAT UAA spatial interpolation. As shown in Chapter 7, use of concentration gradients has a large effect on the projected 2028 ozone DVFs, but it has no material effect on the differences in the ozone DVFs for the two 2028 emission scenarios as the plots appear almost identical.

Within the Permian Basin, the 2028 O&G Control Strategy reduces the ozone DVF by -0.5 to -1.5 ppb with most of the largest reductions (-1.0 to -1.5 ppb) occurring in Lea County. The 2028 O&G Control Strategy has a larger effect on the 2028 ozone DVF in the San Jun Basin with reductions of -1.0 to -3.0 ppb with the largest reductions (-2.0 to -3.0 ppb) straddling the New Mexico/Colorado state line at Rio Arriba/Archuleta Counties.

There are also isolated grid cells of SMAT UAA ozone DVF increases in the Permian and San Juan Basins due to the 2028 O&G Control Strategy. These ozone DVF increases appear to be several isolated 4-km grid cells and are likely due to highly localized ozone increases at the locations of O&G point source NO_x emission reductions due to the O&G Control Strategy. Most (e.g., 90-95%) fresh emissions of oxides of nitrogen (NO_x) are in the form of nitric oxide (NO) that is converted fairly quickly to nitrogen dioxide (NO_2). The NO-O_3 titration reaction ($NO + O_3 \rightarrow NO_2 + O_2$) occurs very quickly and can locally deplete ozone concentrations due to the fresh NO emissions while forming NO_2 that can form ozone further downwind during photochemistry. This can result in localized ozone increases when NO_x emissions are reduced in high NO_x emission areas, such as large urban areas or within NO_x point source plumes. The so called "NO_x Disbenefits" effects (i.e., local ozone increases due to NO_x emission reductions) has been verified in numerous measurement and modeling studies and has been one reason that in the past Los Angeles was more likely to have higher ozone on weekend days than weekdays because of the lower morning NO_x emissions on weekend days (the "weekend effect"). Over the years as NO_x emissions have been controlled, the effects of "NO_x Disbenefits" has been lessening but can still occur in major urban areas and in NO_x point source plumes.

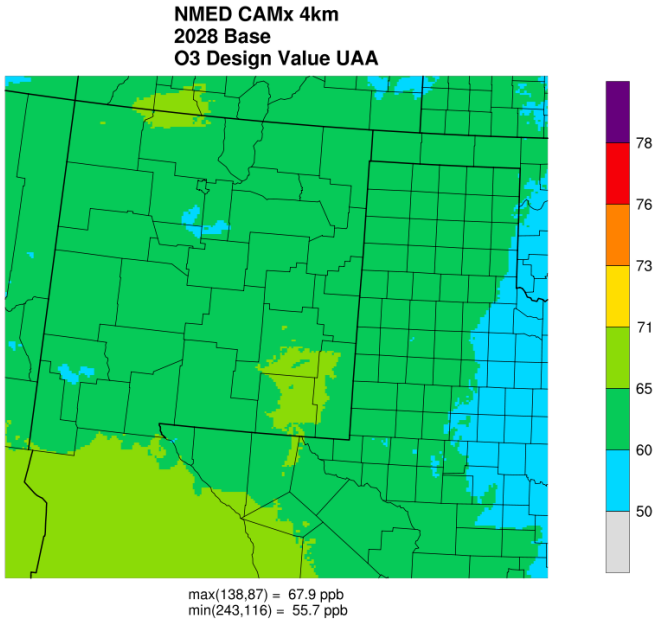


Figure 8-1. SMAT UAA spatial distribution of projected 2028 ozone DVF_{Base} (top) and DVF_{Cntl} (bottom).

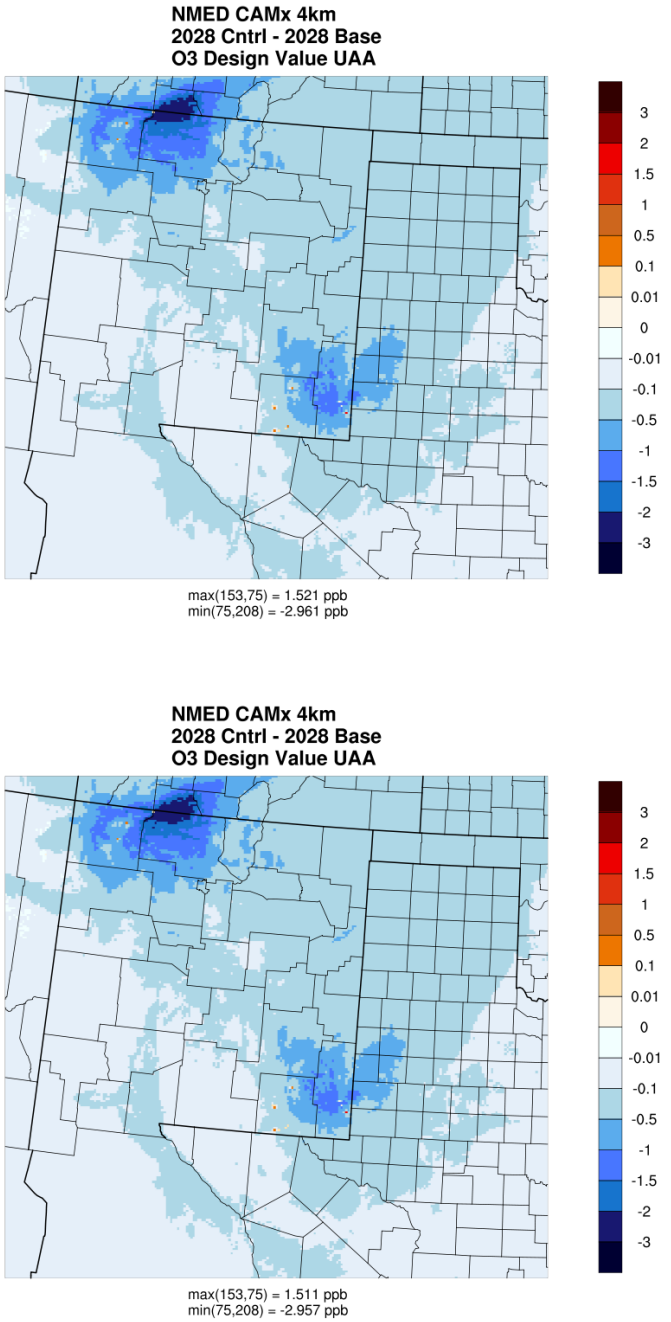


Figure 8-2. Differences in SMAT UAA projected 2028 ozone DVFs (ppb) for the 2028 Base Case and 2028 O&G Control Strategy (DVF_{Cntl} – DVF_{Base}) running SMAT without (top) and with (bottom) using modeled concentration gradients in the $DVC_{2012\text{-}2016}$ spatial interpolation.

8.2 2028 Base Case and 2028 O&G Control Strategy MDA8 Ozone Concentrations

In this section we present spatial maps of modeled MDA8 ozone and the differences in MDA8 ozone for the 2028 Base Case and O&G Control Strategy emission scenarios for several example days.

8.2.1 Daily 2014v2 and 2028 Base Case MDA8 Ozone Concentrations

Figures 8-3 through 8-8 display example spatial maps of MDA8 ozone concentrations and their differences for the two CAMx 2028 emission scenarios for the same six days that were used to compare the 2014v2 and 2028 Base Case results that were presented in Figures 7- through 7-9. However, in the MDA8 difference plots for the two 2028 emission scenarios, a finer scale is used to better illustrate the 2028 MDA8 ozone differences due to the implementation of the O&G Control Strategy in 2028.

As discussed in Chapter 7, CAMx estimates very high MDA8 ozone concentrations on May 17, 2014 that are due to emissions from wildfires (Figure 8-3). The 2028 O&G Control Strategy scenario reduces the MDA8 ozone within the San Juan and Permian Basins by from -1 to -3 ppb on May 17th, with ozone reductions of -0.1 to -0.5 ppb spanning the area between the two Basins. There are areas of MDA8 ozone increases around the western edges of the O&G control area in the San Juan Basin with ozone increases as high as +1.4 ppb.

On June 5, 2014, the 2028 Base Case has CAMx-estimated MDA8 ozone concentrations in excess of the 70 ppb 2015 ozone NAAQS in northeast San Juan and northwest Rio Arriba Counties with a peak MDA8 ozone of 74 ppb on the border with and just inside of Colorado (Figure 8-4). The 2028 O&G Control Strategy is very effectively reducing these high MDA8 ozone exceedances in the San Juan Basin with ozone reductions of up to -4.6 ppb that reduce the MDA8 ozone to below the 2015 ozone NAAQS in San Juan and Rio Arriba Counties. MDA8 ozone is also reduced in the Permian Basin, although not nearly as great as in the San Juan Basin on this day. There are very small areas of ozone increases due to the 2028 O&G Control Strategy within New Mexico that are less than 0.1 ppb, although they are as high as 0.4 ppb near the Four Corners location.

The 2028 Base Case MDA8 ozone on July 12, 2014 in New Mexico is mostly below 60 ppb (blue) with some isolated areas slightly above that (green; Figure 8-5). The 2028 O&G Control Strategy results in MDA8 ozone reductions of more than -0.5 ppb over large areas expanding out of the two O&G Basins with reductions as high as -4.6 ppb in the San Juan Basin and as high as -1.0 to -1.5 ppb reduction in the Permian Basin. In the Permian Basin in the southeast corner of New Mexico, there are ozone increases due to the 2028 O&G Control Strategy that appear to be mostly in the +0.1 to +0.5 ppb range, with a peak increase of +1.6 ppb.

Elevated MDA8 ozone concentrations approaching, but below, the 2015 ozone NAAQS are estimated to occur in San Juan County on July 24, 2014 with a peak value of 71.3 ppb that is above the NAAQS occurring right across the border in Colorado (Figure 8-6). Although the 2028 O&G Control Strategy reduces the MDA8 ozone on this day across wide areas of New Mexico, with ozone reductions as high as -2.8 ppb in the Permian Basin, there are estimated increases in MDA8 ozone in San Juan County. These MDA8 ozone increases in San Juan County due to the 2028 O&G Control Strategy and are as high as +6.4 ppb. These increased in MDA8 ozone concentrations in San Juan County

due to the 2028 O&G Control Strategy are sufficient to increase the MDA8 ozone concentration in one grid cell to 71.0 ppb, which exceeds the 2015 ozone NAAQS.

On July 26th there are patches of elevated MDA8 ozone in the 2028 Base Case in the 65-71 ppb range in northern New Mexico with a peak MDA8 ozone concentration of 72.3 ppb in the northeast corner of Cibola County that exceeds the ozone NAAQS (Figure 8-7). The 2028 O&G Control Strategy reduces the MDA8 ozone Peak in Cibola County by -0.4 ppb to 71.9 ppb, which still exceeds the NAAQS. The 2028 O&G Control Strategy results in reductions in MDA8 ozone concentrations in excess of -3.0 ppb in the San Juan and Permian Basins with a maximum reduction 0f -5.4 ppb. The ozone reductions in the San Juan Basin are sufficient to reduce MDA8 ozone concentrations that were in the 65-71 ppb range in the 2028 Base Case to below 65 ppb.

On August 14, 2014, there are small areas of MDA8 ozone concentrations in the 65-71 ppb range in New Mexico on the northern border with Colorado and in southern border in Doña Ana County with the domain-wide peak ozone of 71.2 ppb just over the border from Doña Ana County in El Paso (Figure 8-8). The 2028 O&G Control Strategy has little effects on the MDA8 ozone peak in El Paso that remains at 71.2 ppb. The 2028 O&G Control Strategy reduces MDA8 ozone in the San Juan and Permian Basins by as much as -1.8 ppb; the ozone reductions in San Juan County reduce the size of the elevated ozone in the 65-71 ppb range. There are also areas of ozone increases to the west and northeast of the San Juan Basin due to the 2028 O&G Control Strategy that are as much as +1.6 ppb.

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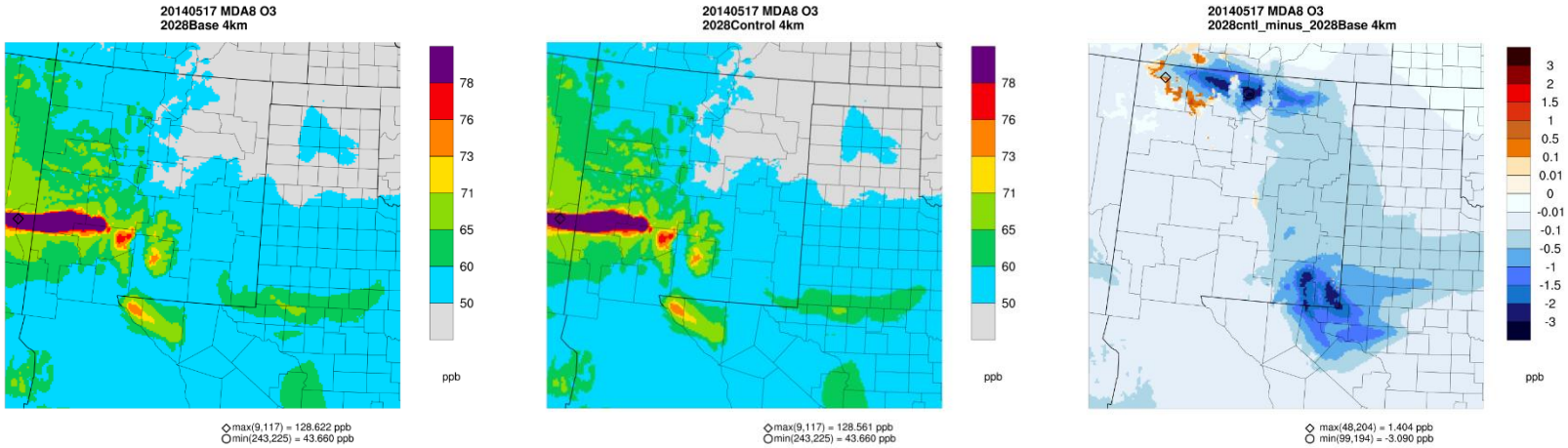


Figure 8-3. CAMx estimated MDA8 ozone concentrations (ppb) on May 17, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy Case (middle) and their difference (right).

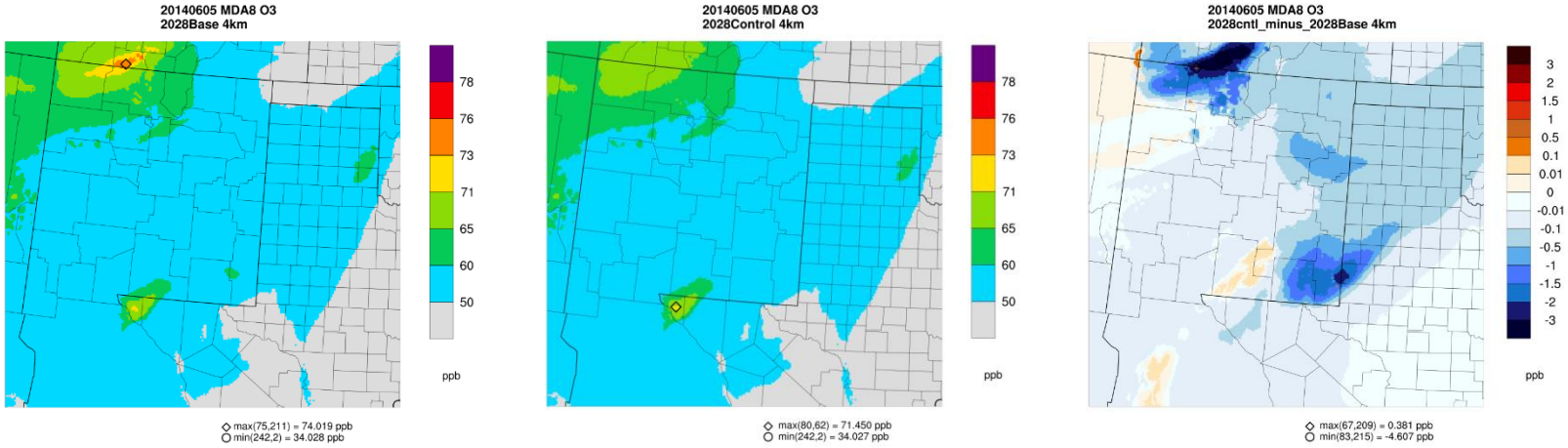


Figure 8-4. CAMx estimated MDA8 ozone concentrations (ppb) on June 5, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy (middle) and their difference (right).

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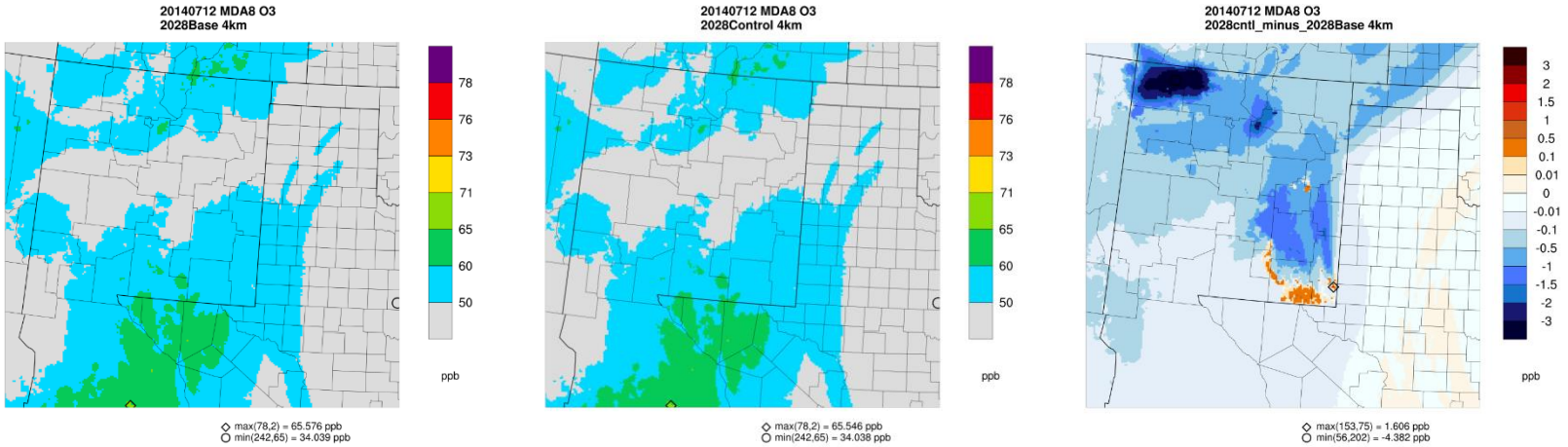


Figure 8-5. CAMx estimated MDA8 ozone concentrations (ppb) on July 12, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy (middle) and their difference (right).

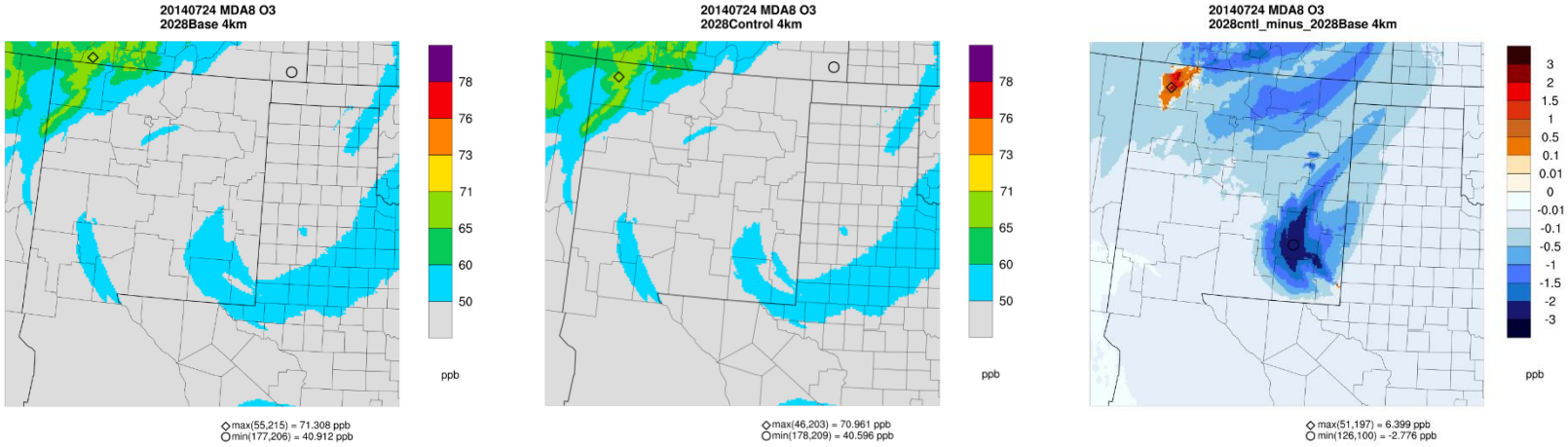


Figure 8-6. CAMx estimated MDA8 ozone concentrations (ppb) on July 24, 2014 for the 2028 Base Case (left), 2028 O&G Control Strategy (middle) and their difference (right).

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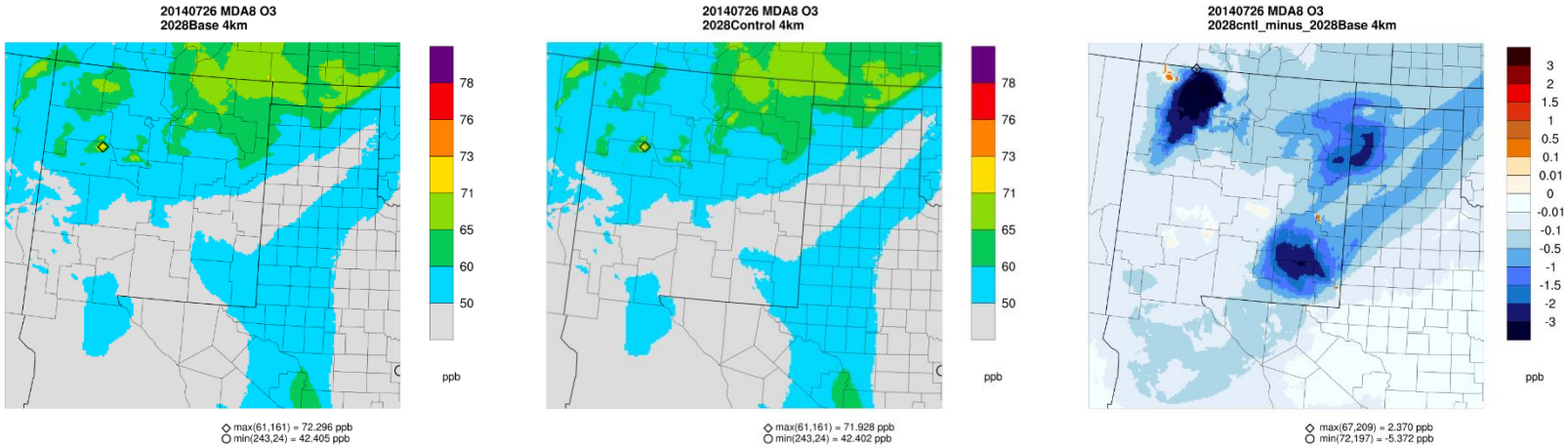


Figure 8-7. CAMx estimated MDA8 ozone concentrations (ppb) on July 26, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

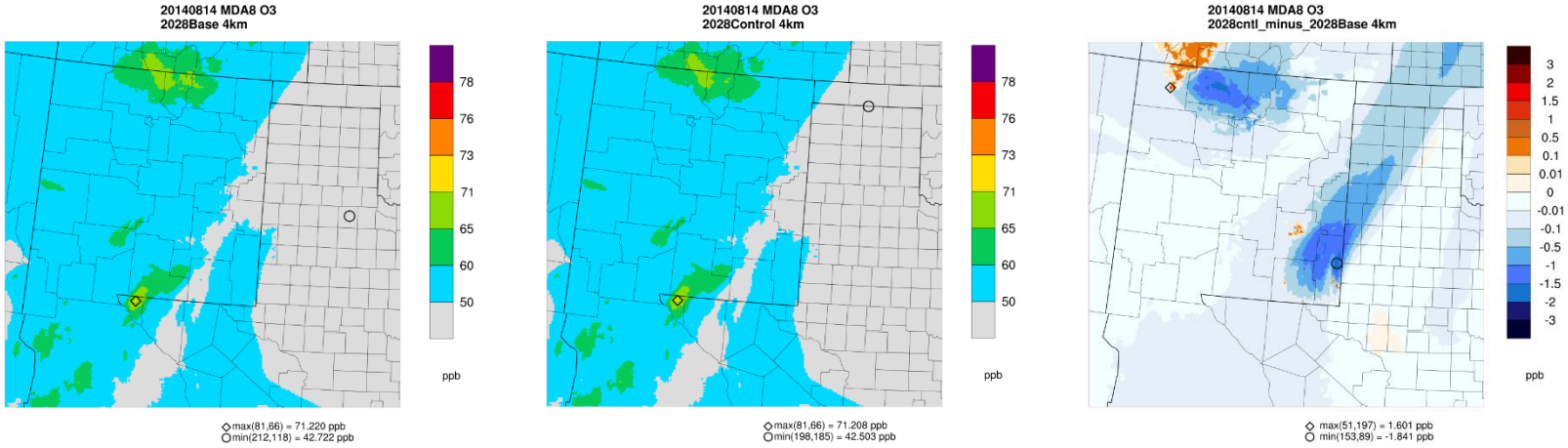


Figure 8-8. CAMx estimated MDA8 ozone concentrations (ppb) on August 14, 2014 for the 2014v2 Base Case (left), 2028 Base Case (middle) and their difference (right).

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8.3 Conclusions of the 2028 Base and 2028 O&G Control Strategy Modeling

The O&G Control Strategy results in wide areas of reductions in 2028 Base Case MDA8 ozone concentrations and SMAT UAA projected 2028 ozone DVFs across large portions of New Mexico, with the largest ozone reductions occurring in the San Juan and Permian Basins. There are also areas of increases in MDA8 ozone and SMAT UAA projected 2028 ozone DVFs due to the O&G Control Strategy that usually occur in isolated locations within and near the San Juan and Permian Basin. The ozone increases in the SMAT UAA projected DFVs across New Mexico due to the O&G Control Strategy occur in a few isolated grid cells in the San Juan and Permian Basins; the projected 2028 ozone DVFs at all the monitoring sites saw only ozone reductions with no ozone increases due to the O&G Control Strategy. The size of the areas and magnitudes of the ozone reductions due to the 2028 O&G Control Strategy scenario were much greater than the ozone increases.

Using the current year ozone design value from 2012-2016 ($DVC_{2012\text{-}2016}$), the projected 2028 ozone DVFs for both the 2028 Base Case and 2028 O&G Control Strategy are below the 70 ppb 2015 ozone NAAQS with the highest values for the 2028 Base and O&G Control Cases occurring at the Desert View (67.0 and 66.8 ppb) monitoring site in Doña Ana County and the Carlsbad (66.7 and 66.4 ppb) monitoring site in Eddy County. However, as noted in Chapter 1 (Table 1-1), more recent observed DVs at Desert View and Carlsbad are much higher than the observed current year $DVC_{2012\text{-}2016}$ used in the 2028 ozone DVF projections presented in Chapters 7 and 8. The sensitivity of the choice of current year DVC on the projected 2028 ozone DVFs is analyzed in Chapter 9.

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9. SENSITIVITY OF PROJECTED 2028 OZONE DESIGN VALUES TO CURRENT YEAR OZONE DESIGN VALUES

Following EPA photochemical grid modeling guidance ozone projection procedures, the projected 2028 future year ozone design values (DVFs) were below the 70 ppb 2015 ozone NAAQS at all monitoring sites in New Mexico. EPA's guidance uses as a starting point for the future year ozone projections an average of three current year design values centered on the base modeling year (i.e., $DVC_{2012\text{-}2016}$). However, at many sites in New Mexico, the current year $DVC_{2012\text{-}2016}$ is lower than the most recent 2017-2019 ozone design values ($DV_{2017\text{-}2019}$). For example, at the Desert View site in Doña Ana County the most recent $DV_{2017\text{-}2019}$ is 77 ppb that is 5 ppb higher than the $DVC_{2012\text{-}2016}$ (72.0 ppb). And the most recent $DV_{2017\text{-}2019}$ at the Carlsbad site in Eddy County (79 ppb) is 7.7 ppb higher than the $DVC_{2012\text{-}2016}$ (71.3 ppb) used in the 2028 ozone DVF projections presented in Chapters 7 and 8.

In this Chapter we examine the sensitivity of the 2028 ozone DVF projections to the observed current year ozone design value (DVC) used as the starting point for the 2028 ozone DVF projections. Instead of using the $DVC_{2012\text{-}2016}$ as the starting point for the 2028 ozone DVF projections, we use the average of three ozone design values from 2015-2019 5-year period (i.e., $DVC_{2015\text{-}2019}$) and also conduct 2028 ozone DVF projections using the latest ozone $DV_{2017\text{-}2019}$ as the DVC. Note that we are still using the CAMx 2014v2 Base Case modeling results for the denominator of the RRFs used to make the 2028 ozone DVF projections that will not account for the changes in emissions between 2014 and the more current years that affect the magnitude of the ozone $DVC_{2015\text{-}2019}$ and $DV_{2017\text{-}2019}$. This includes emission reductions from mobile sources as well as emission increases from O&G sources. Thus, the 2028 ozone DVF projection sensitivity analysis to base year ozone DVC has uncertainties and will likely overstate 2028 ozone DVFs in and near the Permian Basin where the more current year O&G emissions are higher than they were in 2014 and understate the DVFs in areas not affected by O&G emissions from the Permian Basin.

9.1 2028 Ozone Design Value Sensitivity Analysis using $DVC_{2015\text{-}2019}$

Table 9-1 presents the current year ozone design value from 2015-2019 ($DVC_{2015\text{-}2019}$) and the projected 2028 ozone DVFs using the $DVC_{2015\text{-}2019}$ as the ozone projection DVC starting point. The $DVC_{2015\text{-}2019}$ are higher than the EPA-recommended (EPA, 2018) $DVC_{2012\text{-}2016}$ used as the ozone DVF projection starting point in Chapters 7 and 8. For example, there are four monitoring sites with $DVC_{2015\text{-}2019}$ above the NAAQS with Desert View (74.3 ppb), Santa Teresa (74.0 ppb), and Carlsbad (73.7 ppb) having $DVC_{2015\text{-}2019}$ of, respectively, 2.3, 2.7 and 4.7 ppb higher than the corresponding $DVC_{2012\text{-}2016}$. Note that the $DVC_{2015\text{-}2019}$ at Carlsbad Caverns NP (71.0 ppb) also exceeds the NAAQS, however it was not in operation for the $DVC_{2012\text{-}2016}$ period and the $DVC_{2015\text{-}2019}$ is based on just 3-years of data (2016-2018), so is actually based on just one design value, $DV_{2016\text{-}2018}$.

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The 2028 projected ozone DVFs for the 2028 Base Case using the current year $DVC_{2015\text{-}2019}$ has one monitoring site that exceeds the 2015 ozone NAAQS, 71.2 ppb at Carlsbad. The next highest 2028 ozone DVFs for the 2028 Base Case are 69.3 ppb at Carlsbad Caverns NP and 69.1 ppb at Desert View.

The emissions controls in the 2028 O&G Control Strategy are sufficient to reduce the 2028 Base Case ozone DVF at Carlsbad (71.2 ppb) to below the ozone NAAQS (70.9 ppb) when $DVC_{2015\text{-}2019}$ current year design value is used in the 2028 ozone DVF projections.

Table 9-1. Projected 2028 ozone DVFs for the 2015-2019 current year design value $DVC_{2015\text{-}2019}$ sensitivity analysis.

AQS_ID	2015-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	69.0	63.4	63.1	-0.3	Del Norte HS	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	Bernalillo
350011012	69.0	62.7	62.4	-0.3	Foothills	Bernalillo
350130008	68.7	62.1	62.0	-0.1	La Union	Doña Ana
350130020	70.7	65.7	65.7	0.0	Chaparral	Doña Ana
350130021	74.3	69.1	68.9	-0.2	Desert View	Doña Ana
350130022	74.0	68.6	68.5	-0.1	Santa Teresa	Doña Ana
350130023	67.7	62.9	62.7	-0.2	Solano	Doña Ana
350151005	73.7	71.2	70.9	-0.3	Carlsbad	Eddy
350153001	71.0	69.3	69.3	0.0	Carlsbad Caverns NP	Eddy
350250008	69.3	67.2	66.5	-0.7	Hobbs Jefferson	Lea
350390026	66.3	63.0	62.2	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	67.0	61.2	60.9	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	67.0	63.6	62.8	-0.8	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	67.3	64.2	62.9	-1.3	Substation	San Juan
350490021	65.0	61.2	61.0	-0.2	Santa Fe Airport	Santa Fe
350610008	66.7	62.6	62.3	-0.3	Los Lunas (Los Lentes)	Valencia

9.2 2028 Ozone Design Value Sensitivity Analysis using $DVC_{2017\text{-}2019}$

Table 9-2 shows the results of the 2028 ozone DVF projection current year ozone design value sensitivity analysis using the latest 2017-2019 ozone design value as the starting point for the 2028 ozone projections. There are three monitors in New Mexico with $DV_{2015\text{-}2019}$ above the NAAQS: Desert View (77.0 ppb), Santa Teresa (76.0 ppb) and Carlsbad (79 ppb). These $DV_{2017\text{-}2019}$ values are, respectively, 5.0, 4.7 and 10.0 ppb higher than the $DVC_{2012\text{-}2016}$ used as the

ozone projection starting point in the 2028 ozone DVF projections presented in Chapters 7 and 8.

For the 2028 Base Case, there are two sites with projected 2028 ozone DVFs in the $DV_{2017\text{-}2019}$ current year design value sensitivity test that have DVF values above the 2015 ozone NAAQS: 71.6 ppb at Desert View and 76.4 ppb at Carlsbad. The 76.0 ppb $DV_{2017\text{-}2019}$ at Santa Teresa is reduced to 70.5 ppb under the 2028 Base Case so attains the ozone NAAQS.

The projected 2028 ozone DVF using the $DV_{2017\text{-}2019}$ as the current year DVC under the O&G Control Strategy are 71.4 ppb at Desert View and 76.0 at Carlsbad so still exceed the 2015 ozone NAAQS. In fact, the Carlsbad 76.0 ppb ozone DVF even exceeds the 2008 ozone NAAQS.

Table 9-2. Projected 2028 ozone DVFs for the 2017-2019 current year design value $DV_{2017\text{-}2019}$ sensitivity analysis.

AQS_ID	2017-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	70.0	64.3	64.0	-0.3	Del Norte HS	Bernalillo
350010029	67.0	61.9	61.4	-0.5	South Valley	Bernalillo
350011012	71.0	64.5	64.2	-0.3	Foothills	Bernalillo
350130008	70.0	63.3	63.2	-0.1	La Union	Doña Ana
350130020	73.0	67.8	67.8	0.0	Chaparral	Doña Ana
350130021	77.0	71.6	71.4	-0.2	Desert View	Doña Ana
350130022	76.0	70.5	70.3	-0.2	Santa Teresa	Doña Ana
350130023	70.0	65.0	64.8	-0.2	Solano	Doña Ana
350151005	79.0	76.4	76.0	-0.4	Carlsbad	Eddy
350250008	71.0	68.9	68.1	-0.8	Hobbs Jefferson	Lea
350390026	67.0	63.6	62.8	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	68.0	62.1	61.8	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	68.0	64.6	63.7	-0.9	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	69.0	65.8	64.5	-1.3	Substation	San Juan
350490021	66.0	62.2	62.0	-0.2	Santa Fe Airport	Santa Fe
350610008	68.0	63.8	63.5	-0.3	Los Lunas (Los Lentes)	Valencia

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10. 2028 SOURCE SECTOR APCA OZONE SOURCE APPORTIONMENT MODELING

Ozone source apportionment modeling was conducted to determine the contributions of Source Sectors within New Mexico to 2028 ozone concentrations and projected future year ozone design values (DVF) under the 2028 New Mexico oil and gas (O&G) control strategy emissions scenario. The Anthropogenic Precursor Culpability Assessment (APCA) version of the CAMx ozone source apportionment tool was used and the modeling also obtained contributions from Colorado, Texas and the remainder of U.S. states as well as international anthropogenic emissions.

10.1 Versions of Ozone Source Apportionment

CAMx includes two ozone source apportionment tools: the Ozone Source Apportionment Technology (OSAT) and the Anthropogenic Precursor Culpability Assessment (APCA). Both use tagged tracer species that track ozone formation from VOC (V_i) and NO_x (NIT_i + RGN_i) emissions from each user-specified Source Group (i). A Source Group can consist of a Source Region and/or Source Category. A typical OSAT/APCA application will use a Source Region map that divides the modeling domain into geographic regions and separate emission files of different Source Categories are provided as input to CAMx; ozone source apportionment is obtained for Source Groups that are defined as the intersection of the Source Regions with the Source Categories (e.g., on-road mobile sources from New Mexico). The ozone source apportionment tool runs in parallel to the CAMx host model and extracts information on ozone formation and assigns it to the user-defined Source Groups.

There are 10 reactive tracers used to track ozone formation for each user-defined Source Group as follows:

V_i	VOC emissions
NIT_i	Nitric oxide (NO) and nitrous acid (HONO) emissions
RGN_i	Nitrogen dioxide (NO_2), nitrate radical (NO_3) and dinitrogen pentoxide (N_2O_5)
TPN_i	Peroxyl acetyl nitrate (PAN), analogues of PAN and peroxy nitric acid (PNA)
NTR_i	Organic nitrates (RNO_3)
$HN3_i$	Gaseous nitric acid (HNO_3)
$O3N_i$	Ozone formed under NOx sensitive conditions
$O3V_i$	Ozone formed under VOC sensitive conditions
OON_i	Odd-oxygen in NO_2 formed from O3Ni
OOV_i	Odd-oxygen in NO_2 formed from O3Vi

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For each time step and grid cell, when ozone is formed in the host model OSAT determines whether the ozone formation was more VOC sensitive or NO_x sensitive and apportions the ozone formed to Source Groups based on the relative contribution of the limiting precursor to the total precursor (e.g., under VOC sensitive conditions $V_i / \sum V_i$). APCA differs from OSAT in that it will only allocate ozone formed to natural (e.g., biogenic) emissions Source Groups when the ozone formed is due to natural VOC interacting with natural NO_x. So when ozone is formed due to biogenic VOC emissions interacting with anthropogenic NO_x emissions under VOC sensitive ozone formation conditions, a case OSAT would assign to the natural Source Group $O3V_i$ tracer, APCA redirects the ozone formed to the anthropogenic Source Group $O3N_i$ tracer. APCA was designed to provide more control strategy relevant information than OSAT and is used in identifying ozone contributions in emissions culpability assessments (e.g., CSAPR[38]). However, OSAT has to be used to obtain information on whether ozone formation is more VOC or NO_x sensitive. Details on the CAMx OSAT and APCA source apportionment tools are provided in Chapter 7 of the CAMx user's guide.[39] Since we are running CAMx v7.1, it uses the third version of OSAT3 and corresponding version of APCA.

As the main focus of the 2028 Source Sector ozone source apportionment modeling is to identify the contributions of anthropogenic emission source sectors and regions to elevated MDA8 ozone concentrations in New Mexico, the APCA version of ozone source apportionment tool was used.

10.2 2028 Source Sector APCA Ozone Source Apportionment Specifications

Details on the design and specifications of the 2028 Source Sector APCA ozone source apportionment simulate are provide below.

10.2.1 2028 O&G Control Strategy Emissions Scenario

The 2028 Source Sector APCA ozone source apportionment was conducted using the 2028 New Mexico O&G Control Strategy emissions scenario.

10.2.2 Definition of Source Groups

The 2028 Source Sector APCA ozone source apportionment simulation used a Source Region map to define geographic regions of emission areas to be tracked. Separate source contributions were also obtained for 9 emission Source Categories as well as contributions due to Boundary Conditions (BCs) around the lateral edges of the 36-km grid resolution domain.

10.2.2.1 Boundary Conditions

The CAMx v7 source apportionment tool has a new capability to provide separate contributions due to stratified BCs. Typically, these stratifications will be different source sectors from outside of the CAMx modeling domain. WRAP conducted 2014 GEOS-Chem modeling for a base case (BASE), a 2014 GEOS-Chem no

[38] https://www.epa.gov/csapr
[39] http://www.camx.com/files/camxusersguide_v7-10.pdf

international anthropogenic emissions case (i.e., Zero-out Rest of World or ZROW) and a no global anthropogenic emissions case (i.e., just natural emissions). Output from the three 2014 GEOS-Chem runs were processed to generate lateral BCs for the CAMx 36-km 36US1 North America modeling domain that contained: (1) the contributions of international anthropogenic emissions (BC_{Intl}); (2) the contributions of U.S. anthropogenic emissions (BC_{US}); and (3) the contributions of natural sources ($BC_{Natural}$). Details on the WRAP 2014 GEOS-Chem base, ZROW and Natural modeling are contained in a Run Specification Sheet[40] and the WRAP/WAQS 2014v2 model performance evaluation webpage.[41]

This results in the 2028 Source Sector APCA ozone source apportionment simulation tracking ozone contributions from three Source Groups for the lateral boundaries ($BC_{Natural}$, BC_{Intl} and BC_{US}). Contributions due to the top BC concentration as well as Initial Concentrations (IC) were also separately tracked resulting in 5 Source Groups used to track the contributions of BC and IC.

10.2.2.2 Source Regions

Five source regions were used in the 2028 Source Sector APCA ozone source apportionment simulation as shown in Figure 10-1:

1. New Mexico;
2. Texas;
3. Colorado;
4. Remainder U.S. states plus coastal water out to 200 nautical miles (nmi) from the U.S. coast; and
5. International, which included Mexico, Canada and waters off their coasts plus waters more than 200 nmi off the U.S. coast.

[40] https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/Run_Spec_WRAP_2014_Task1-7_NAT-ZROW_v4.pdf
[41] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

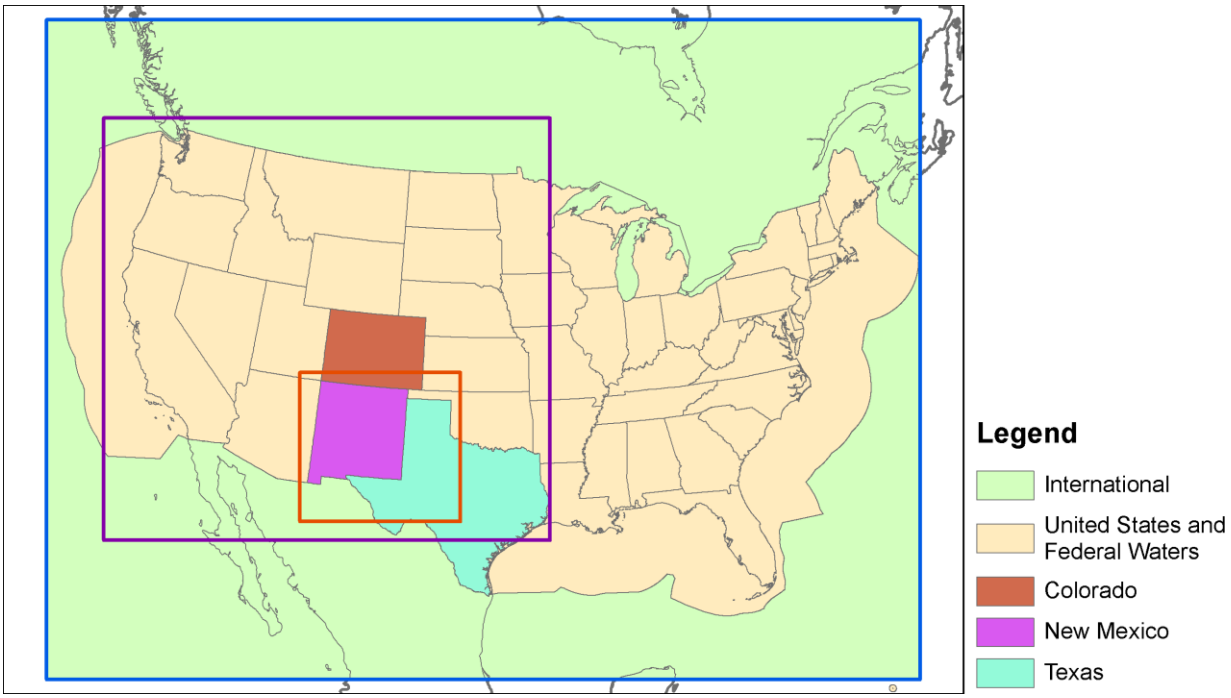


Figure 10-1. Source regions used in the 2028 Source Sector APCA ozone source apportionment simulation.

10.2.2.3 Source Categories

The emissions inventory was divided up into 9 Source Categories in the 2028 Source Sector APCA ozone source apportionment modeling as follows:

1. Natural (biogenic, lightning NO_x, windblown dust and oceanic [sea salt and dimethyl sulfide]);
2. Fires (U.S. wildfires, wildland prescribed burns and agricultural burning and other [Mexico/Canada] fires);
3. Oil and gas point sources (surrogate for midstream O&G);
4. Oil and gas non-point sources (surrogate for upstream O&G);
5. EGU point;
6. Non-EGU point;
7. On-road mobile;
8. Non-road mobile; and
9. Remainder anthropogenic.

Since the APCA version of the CAMx ozone source apportionment tool is being utilized, Natural emissions has to be the first Source Category so APCA knows which Source Category is uncontrollable.

10.2.2.4 Source Groups

With 5 Source Regions and 9 Source Categories, plus 5 Source Groups for IC/BC, there is a total of 50 Source Groups that separate ozone source contributions are obtained (50 = 5 x 9 + 5).

10.3 2028 Source Sector APCA Ozone Source Apportionment Modeling Results

The 2028 Source Sector APCA ozone source apportionment modeling results were analyzed to obtain the contributions of the different Source Sectors within New Mexico to projected future year 2028 ozone design values (DVFs) as well as contributions to Maximum Daily Average 8-hour (MDA8) ozone concentrations. The 2028 ozone DVF and modeled MDA8 ozone concentrations were analyzed at the monitoring sites as well as across the 4-km New Mexico domain. Figure 10-2 shows the locations of the monitoring sites within the 4-km New Mexico domain.

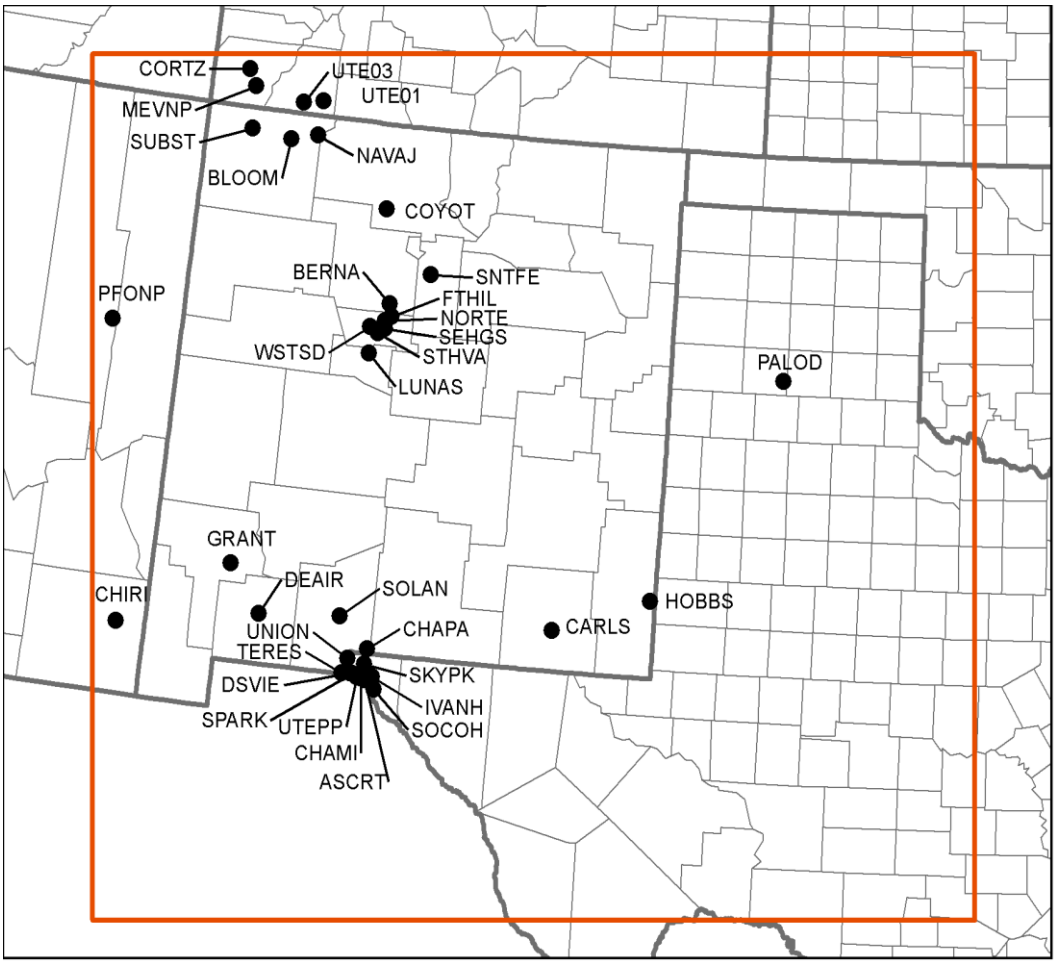


Figure 10-2. Locations of ozone monitoring sites within the 4-km New Mexico modeling domain.

10.3.1 Source Sector Contributions to Projected 2028 Ozone DVFs

In this section, the contributions of Source Sector emissions within New Mexico and the entire United States to future year projected 2028 ozone design values (DVF) at New Mexico monitoring sites and across the 4-km New Mexico domain are analyzed.

10.3.1.1 New Mexico Source Sector 2028 Ozone DVF Contributions

Table 10-1 displays the current year 2012-2016 DVC, the projected 2028 ozone DVF for the 2028 O&G Control Scenario and the reductions in the 2028 ozone DVF due to the removal of anthropogenic emissions in New Mexico for each of the 7 anthropogenic emissions Source Sectors at all monitoring sites in New Mexico. The incremental ozone contributions in the 2028 ozone DVF due to New Mexico emissions from the 7 Source Sectors are shown for several New Mexico monitoring sites in Figures 10-3 through 10-18.

At the three monitoring sites in San Juan County, New Mexico emissions from EGU and O&G Source Sectors contribute the most to the 2028 ozone DVF (Table 10-1). The largest ozone contribution is 3.1 ppb for the New Mexico EGU Source Sector at the SUBST site (Figure 10-5) due to its close proximity to the Four Corners Power Plant (FCPP) that is assumed to have Units 4 and 5 operating in 2028. The EGU ozone contributions fall off with distance from the FCPP as seen at the BLOOM (1.9 ppb; Figure 10-4), NAVAJ (1.7 ppb; Figure 10-3) and COYOT (0.5 ppb; Figure 10-6) monitoring sites. New Mexico O&G Point contributes 0.2 to 0.9 ppb and O&G Non-Point contributes 0.5 to 2.1 ppb to 2028 ozone DVFs at the four northern New Mexico monitoring sites in San Juan and Rio Arriba Counties. All other Source Sectors have contributions of 0.5 ppb or less at the northern New Mexico sites.

Sites in Central New Mexico include those in Bernalillo County (Figures 10-7 through 10-10) as well as two sites in neighboring counties (Figures 10-11 and 10-12). Ozone concentrations in Bernalillo County are highly influenced by emissions from Albuquerque, which is by far the largest city in New Mexico. So, Source Sectors associated with population centers (e.g., on-road, non-road and other anthropogenic) tend to have the highest contributions to the 2028 ozone DVFs at these sites. Although they have different magnitudes of ozone contributions, the rankings of the Source Sector contributions are very similar at the Bernalillo County sites with Other Anthropogenic being highest followed by On-Road and Non-Road mobile with the other four Source Sectors being half or less of the top three Source Sectors. On-Road mobile is the highest followed by Other Anthropogenic and Non-Road at the Santa Fe (Figure 10-11) and Sandoval County (Figure 10-12) sites, with all other Source Sector contributions being much lower.

Sites in the southern New Mexico (Figures 10-13 through 10-18) include those in southern Doña Ana County on the border with Texas that tend to have mostly small contributions from New Mexico Source Sectors with the exception of EGU (0.7 to 0.9 ppb), due to the close proximity of the Rio Grande Power Plant to some of the sites, and On-Road mobile (0.4-0.5 ppb) due to population centers along I-25 (e.g., Sunland Park, Santa Teresa, etc.). The Solano monitor (Figure 10-16) has higher ozone contributions due to On-Road (1.2 ppb) and Non-Road (0.7 ppb) mobile sources because of the higher mobile emissions from the City of Las Cruces, which is the second largest city in New Mexico.

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New Mexico emissions from the O&G Point and Non-Point Sources sectors have the highest ozone contribution at the Carlsbad (0.5 and 0.5 ppb) and Hobbs (0.9 and 1.1 ppb) monitoring sites in southeastern New Mexico (Figures 10-17 and 10-18). These two southeastern New Mexico monitors are essentially within the Permian Basin. The contribution of On-Road to the 2028 ozone DVF at Carlsbad and Hobbs sites is 0.3 ppb, with all other Source Sector contributions being lower.

Table 10-1. Reduction in 2028 ozone DVF due to the elimination of emissions from 7 Source Sectors in New Mexico.

AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	OnRoad	NonRoad	OAnth
Northern New Mexico										
350390026	COYOT	64.0	60.0	-0.2	-0.5	-0.5	0.0	-0.2	-0.1	0.0
350450009	BLOOM	64.3	60.2	-0.7	-1.4	-1.9	0.0	-0.4	-0.1	-0.1
350450018	NAVAJ	67.0	63.3	-0.9	-2.1	-1.7	-0.1	-0.4	-0.2	-0.1
350451005	SUBST	63.7	59.6	-0.6	-1.5	-3.1	-0.1	-0.5	-0.2	-0.2
Central New Mexico										
350010023	NORTE	66.3	60.7	-0.2	-0.3	-0.5	-1.0	-2.7	-2.0	-3.6
350010024	SEHGS	68.0	62.0	-0.2	-0.3	-0.5	-1.1	-2.5	-1.9	-3.2
350010029	STHVA	66.0	60.5	-0.3	-0.5	-0.5	-1.0	-2.2	-1.7	-2.4
350010032	WSTSD	67.0	62.1	-0.2	-0.4	-0.4	-0.4	-1.6	-1.2	-1.8
350011012	FTHIL	65.0	58.8	-0.2	-0.3	-0.5	-0.7	-2.5	-2.0	-3.0
350431001	BERNA	64.0	58.1	-0.1	-0.2	-0.4	-0.4	-2.1	-1.5	-1.9
350490021	SNTFE	64.3	60.4	-0.2	-0.3	-0.2	-0.3	-1.2	-0.7	-0.8
Southern New Mexico										
350130008	UNION	66.3	59.8	-0.2	-0.2	-0.7	0.0	-0.5	-0.3	-0.1
350130017	SPARK	67.0	61.8	-0.2	-0.2	-0.9	0.0	-0.4	-0.2	-0.2
350130020	CHAPA	67.0	62.2	-0.1	-0.1	-0.3	0.0	-0.2	-0.1	-0.1
350130021	DSVIE	72.0	66.8	-0.2	-0.3	-0.9	-0.1	-0.5	-0.3	-0.2
350130022	TERES	71.3	66.0	-0.3	-0.3	-0.7	-0.1	-0.5	-0.3	-0.2
350130023	SOLAN	65.0	60.2	-0.2	-0.2	-0.2	-0.2	-1.2	-0.7	-0.3
350151005	CARLS	69.0	66.4	-0.5	-0.5	-0.2	-0.1	-0.3	-0.2	-0.1
350171003	GRANT	62.0	58.9	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0
350250008	HOBBS	66.0	63.3	-0.9	-1.1	-0.2	0.0	-0.3	-0.2	-0.1
350290003	DEAIR	66.0	62.5	-0.2	-0.1	-0.2	0.0	-0.6	-0.4	0.0

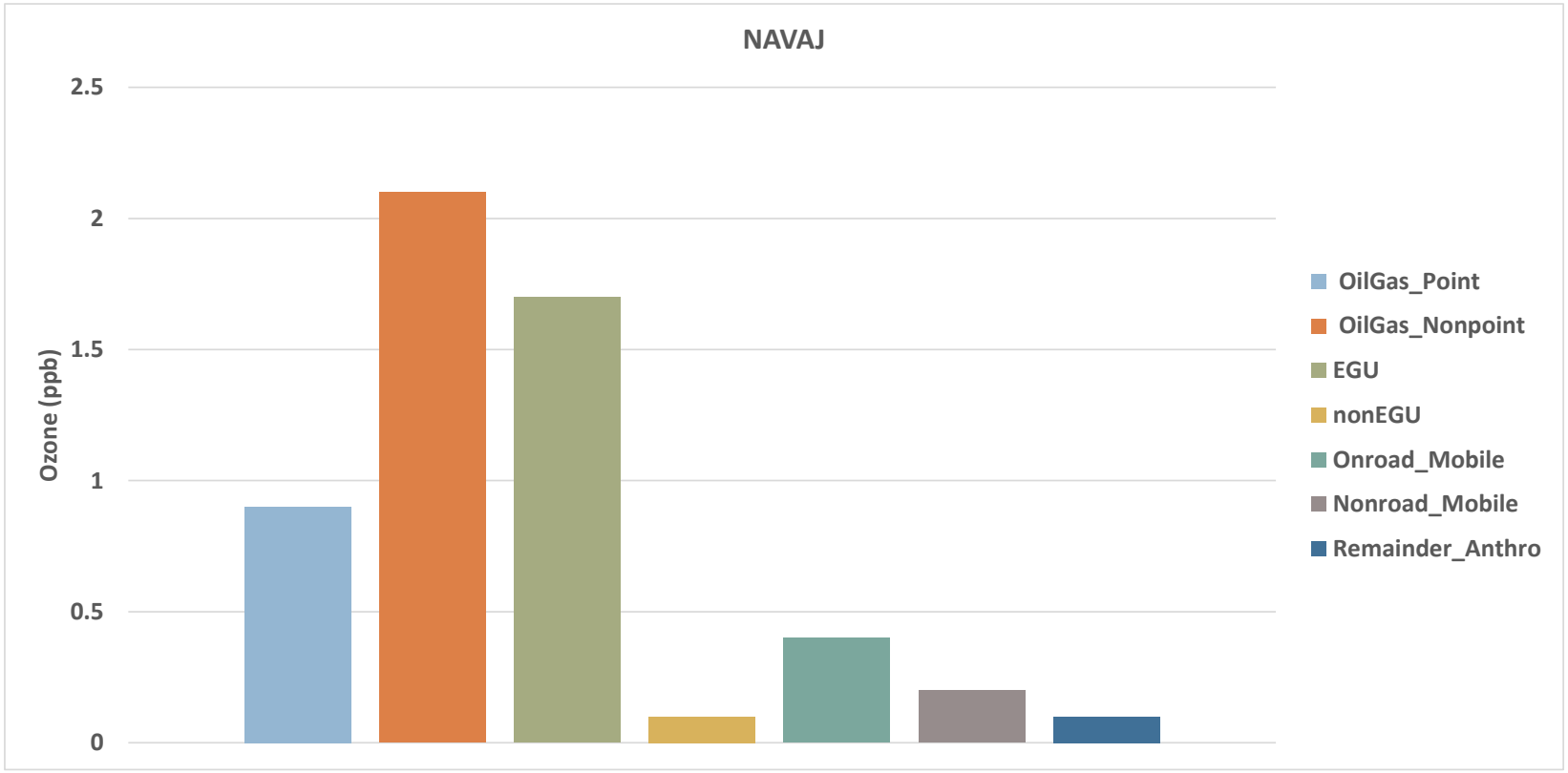


Figure 10-3. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Navajo Lake in San Juan County.

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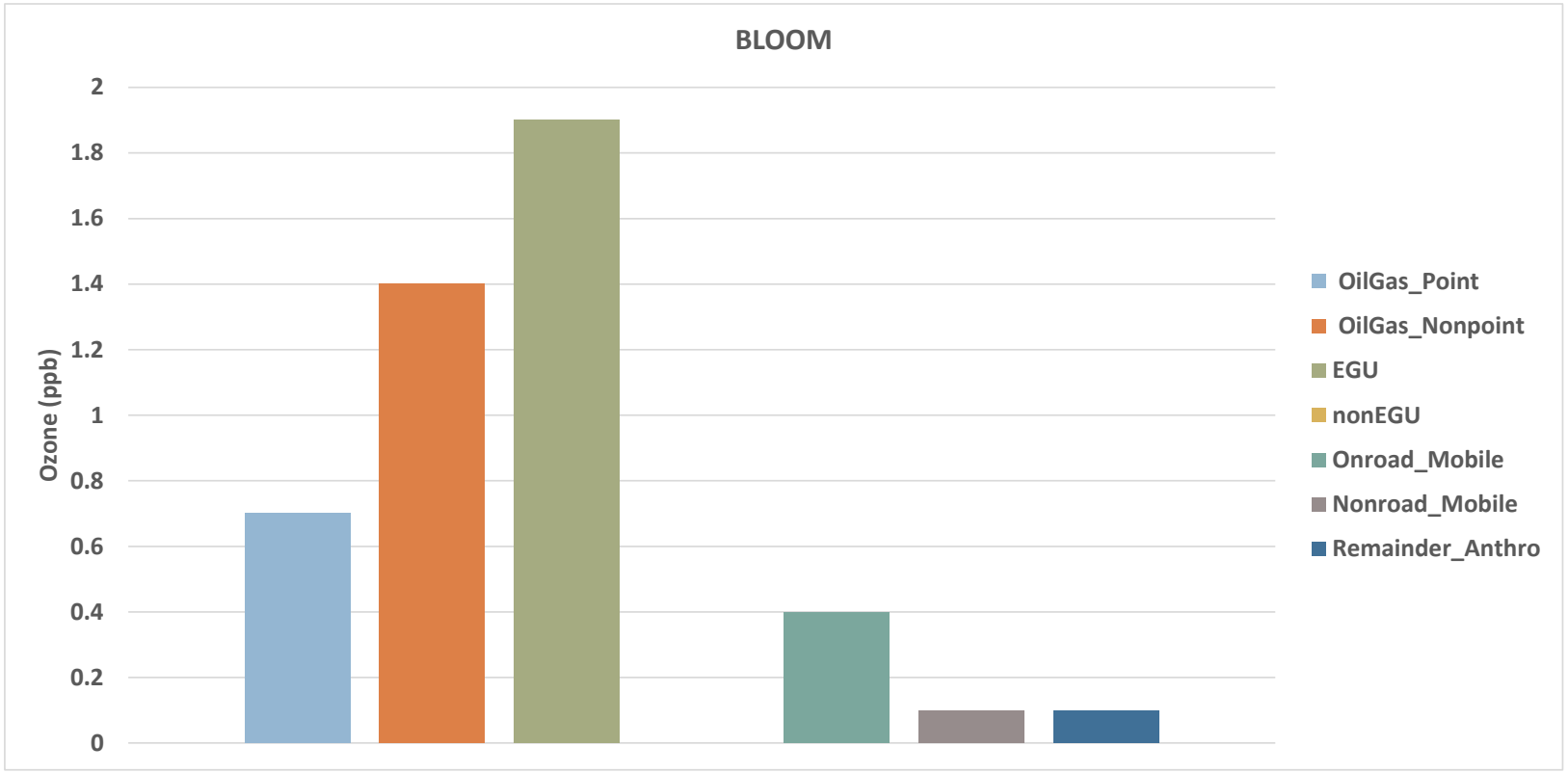


Figure 10-4. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Bloomfield in San Juan County.

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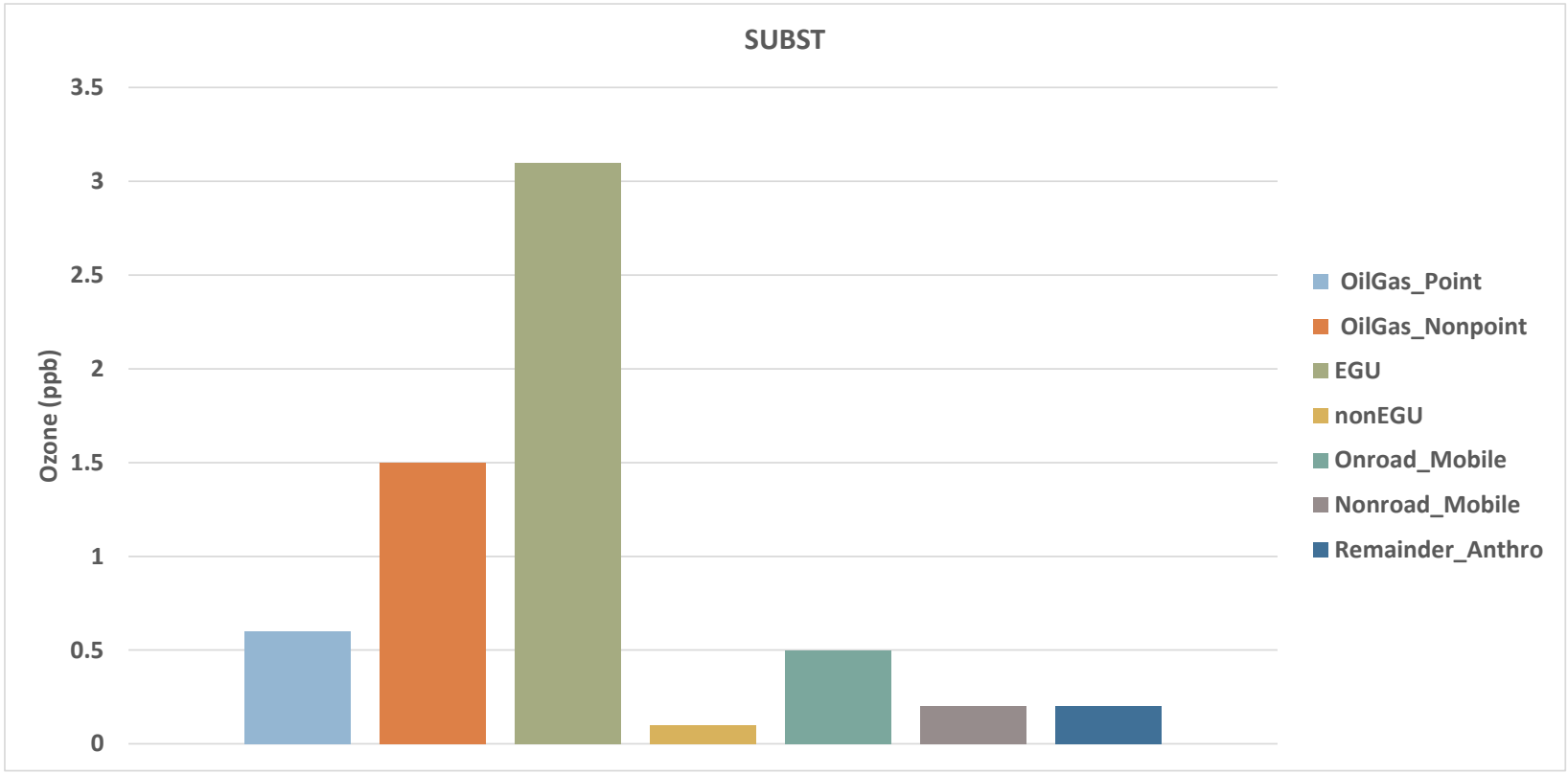


Figure 10-5. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Substation in San Juan County.

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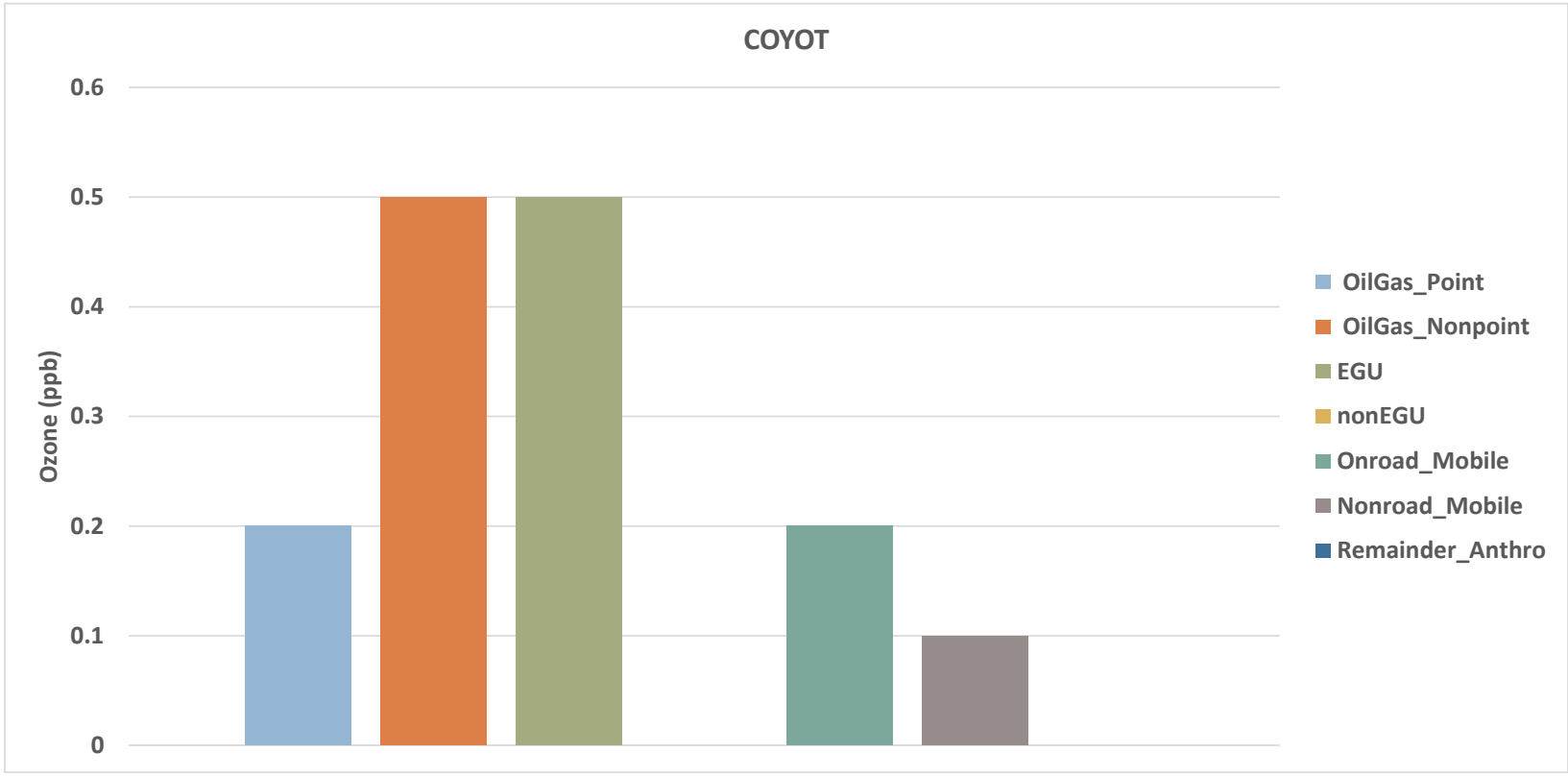


Figure 10-6. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Coyote Ranger District in Rio Arriba County.

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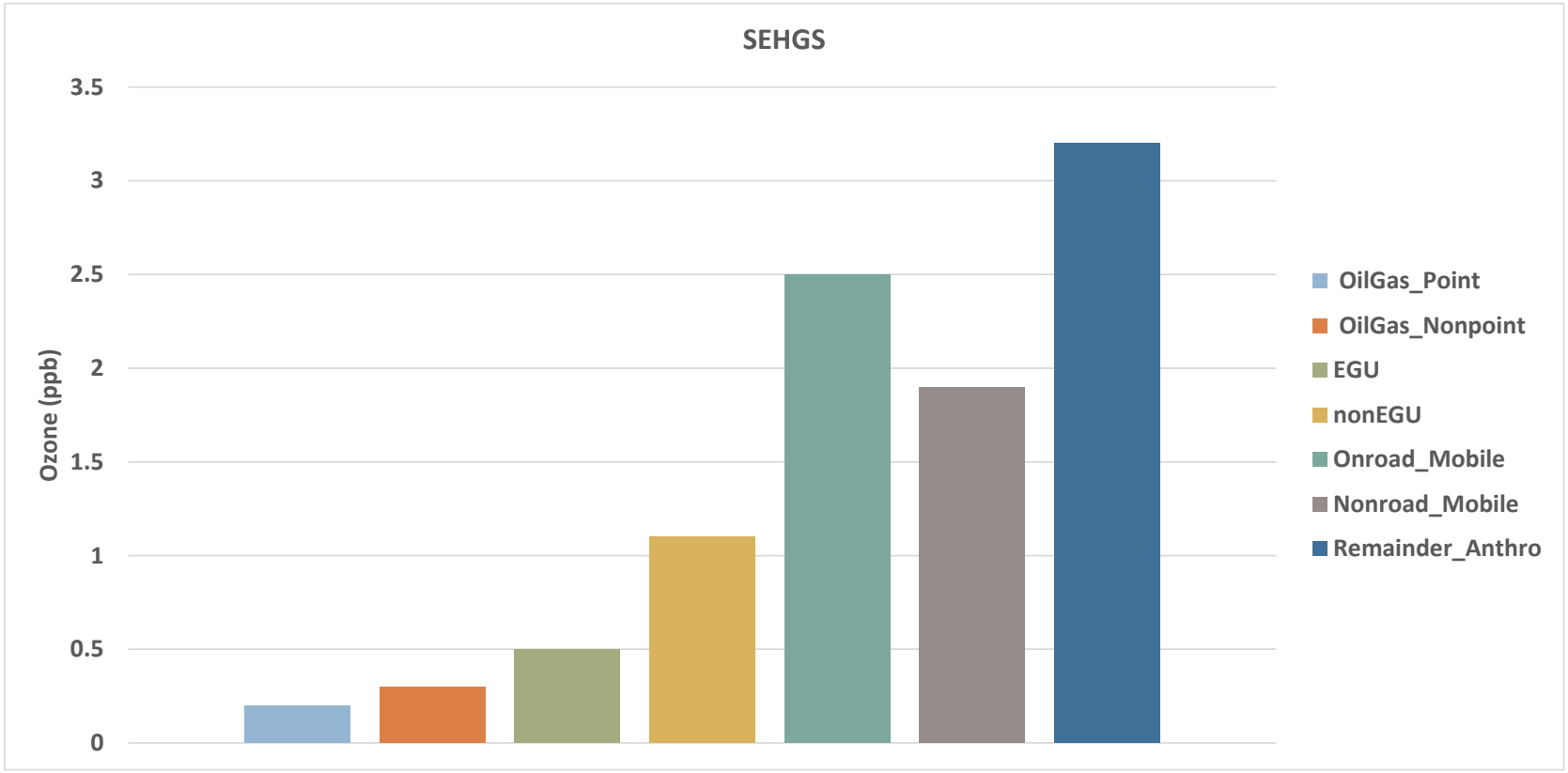


Figure 10-7. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Southeast Heights in Bernalillo County.

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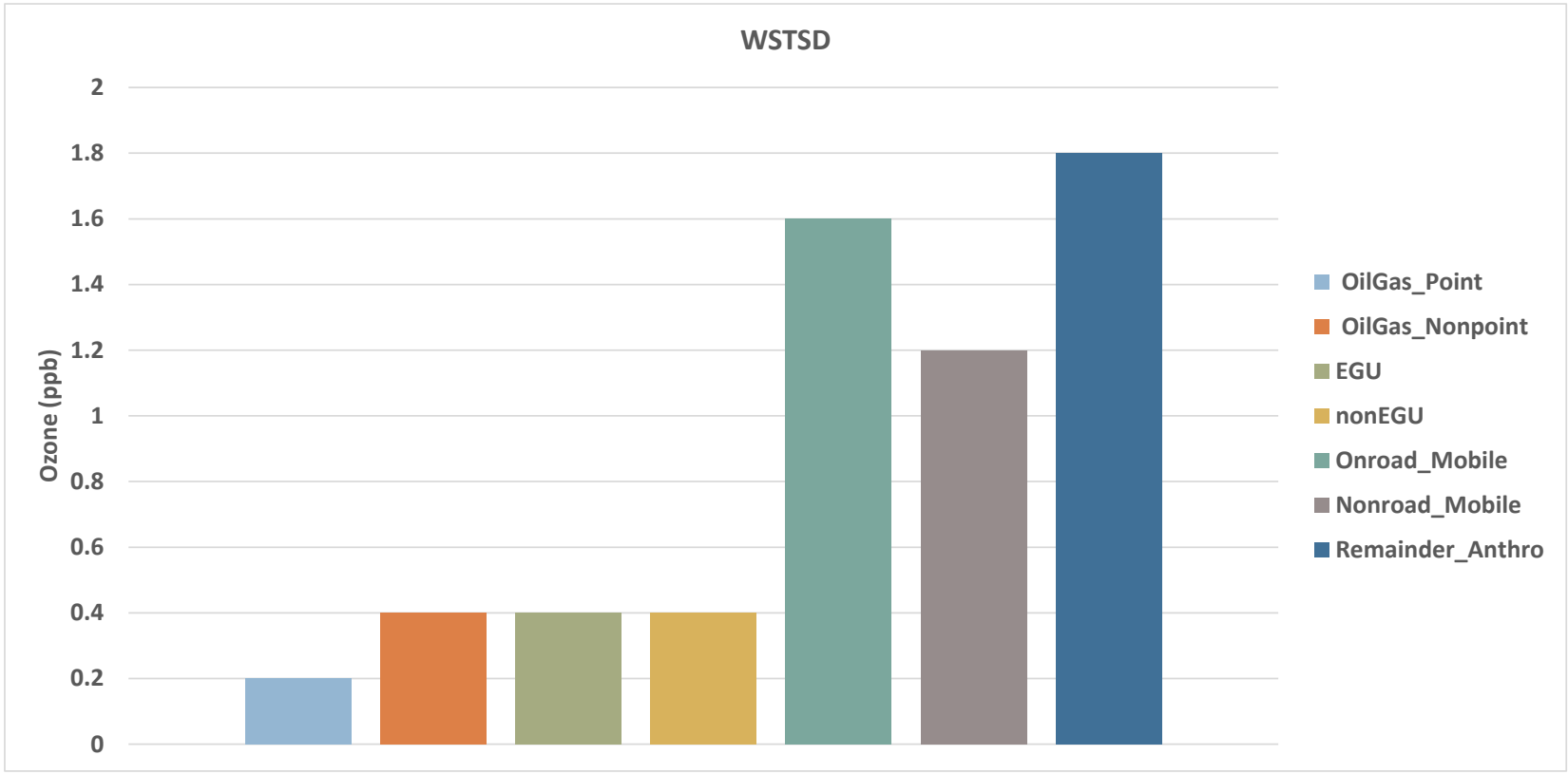


Figure 10-8. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Westside in Bernalillo County.

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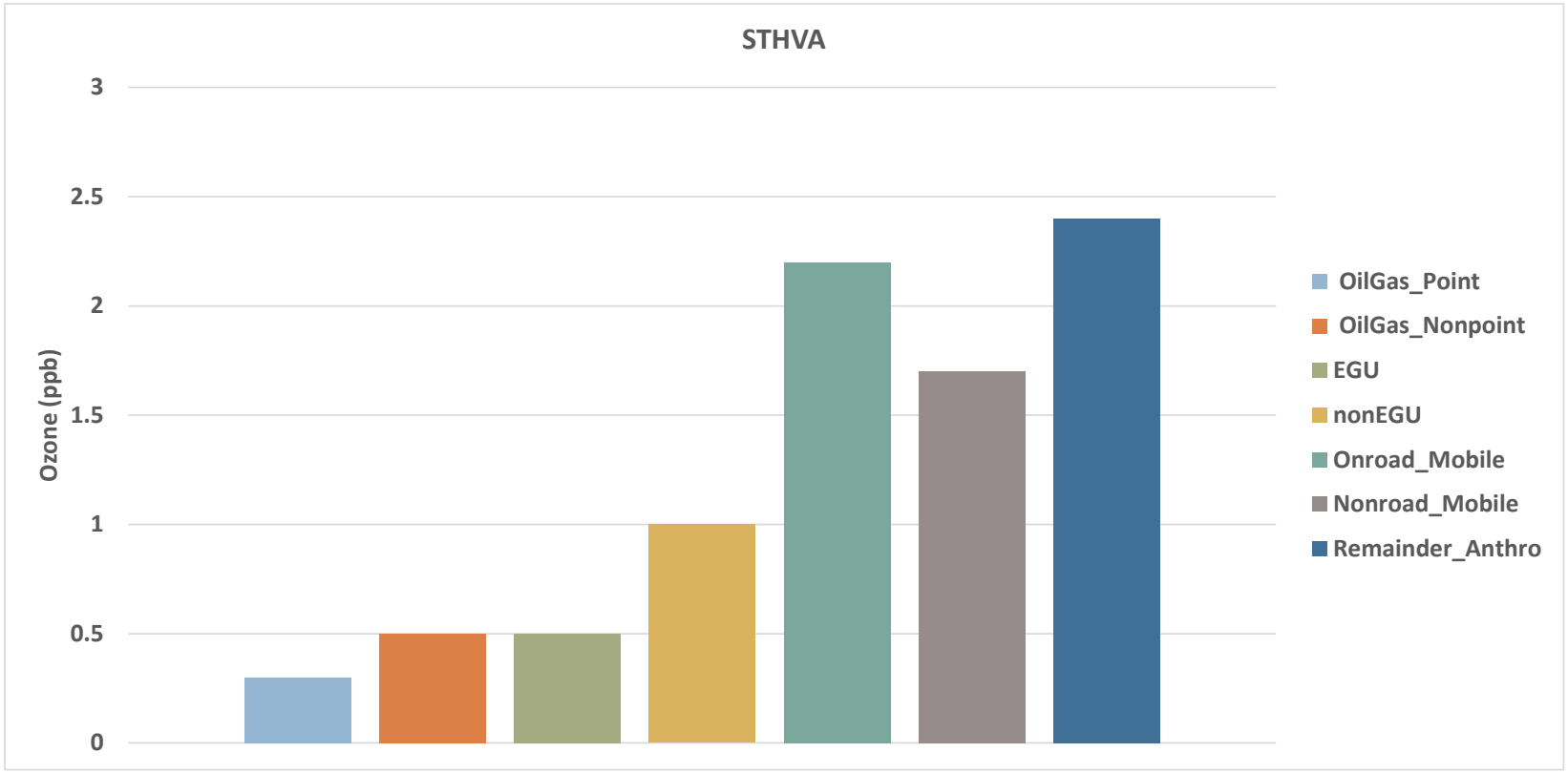


Figure 10-9. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at South Valley in Bernalillo County.

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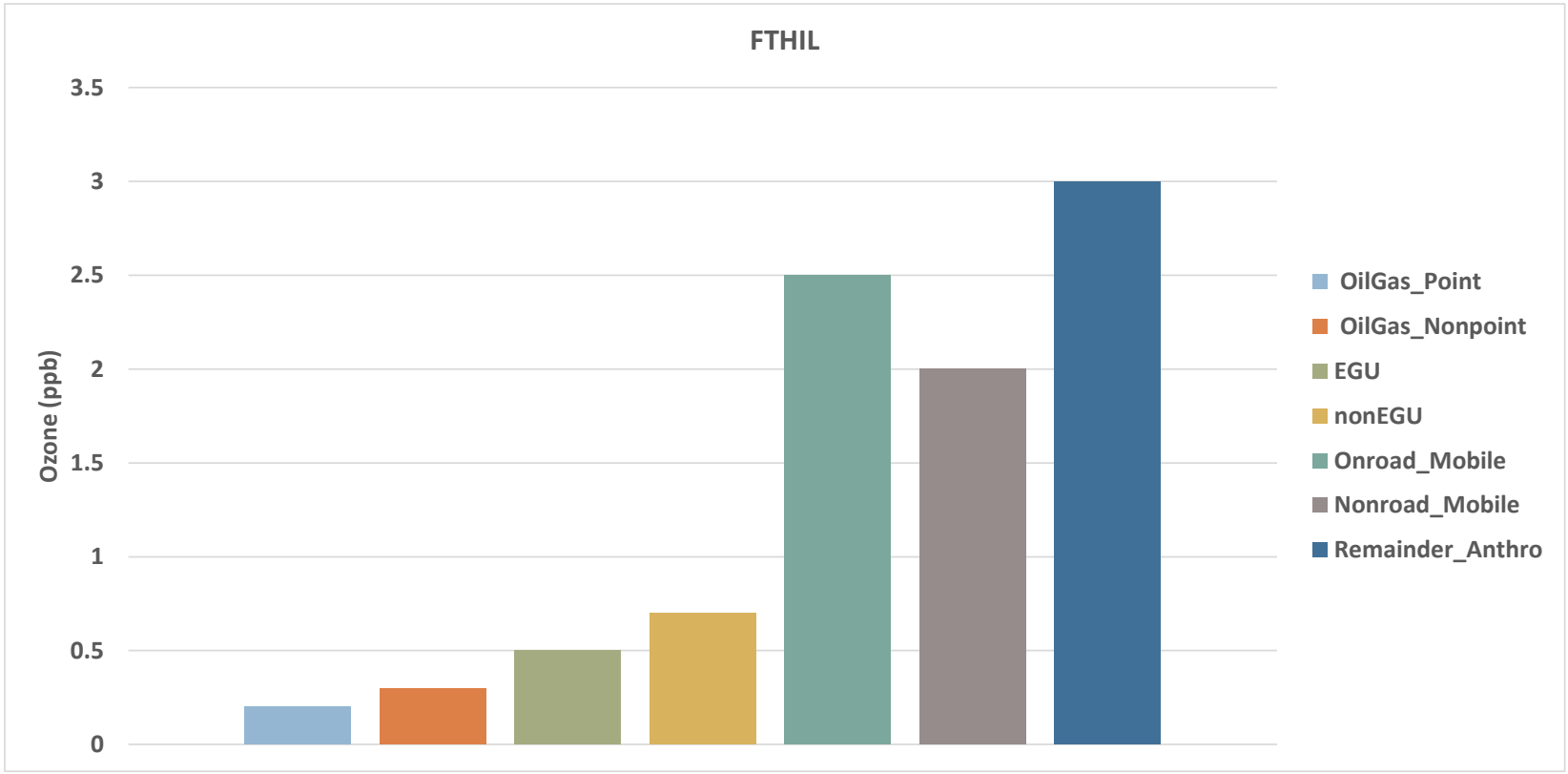


Figure 10-10. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Foothills in Bernalillo County.

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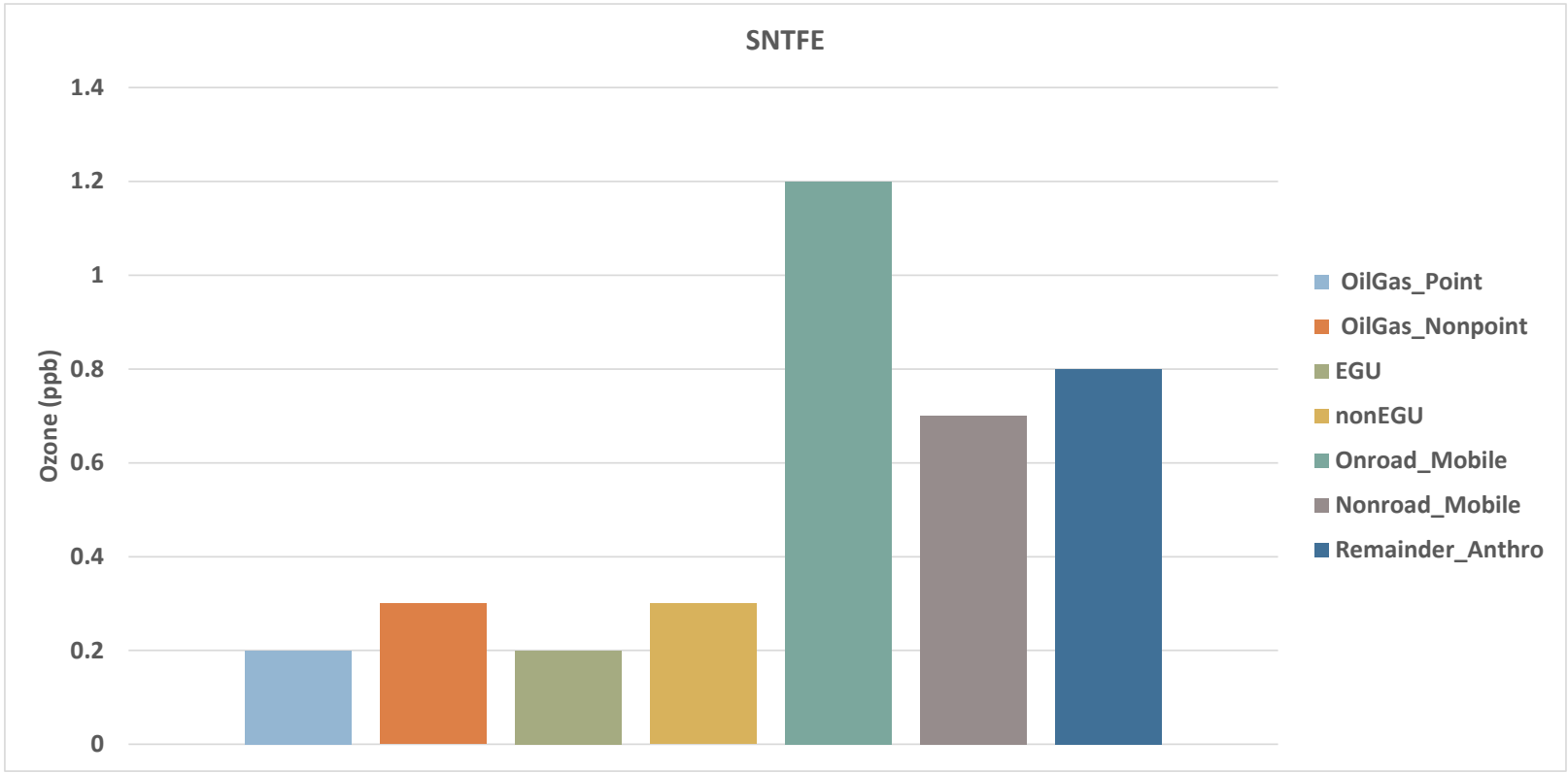


Figure 10-11. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Santa Fe in Santa Fe County.

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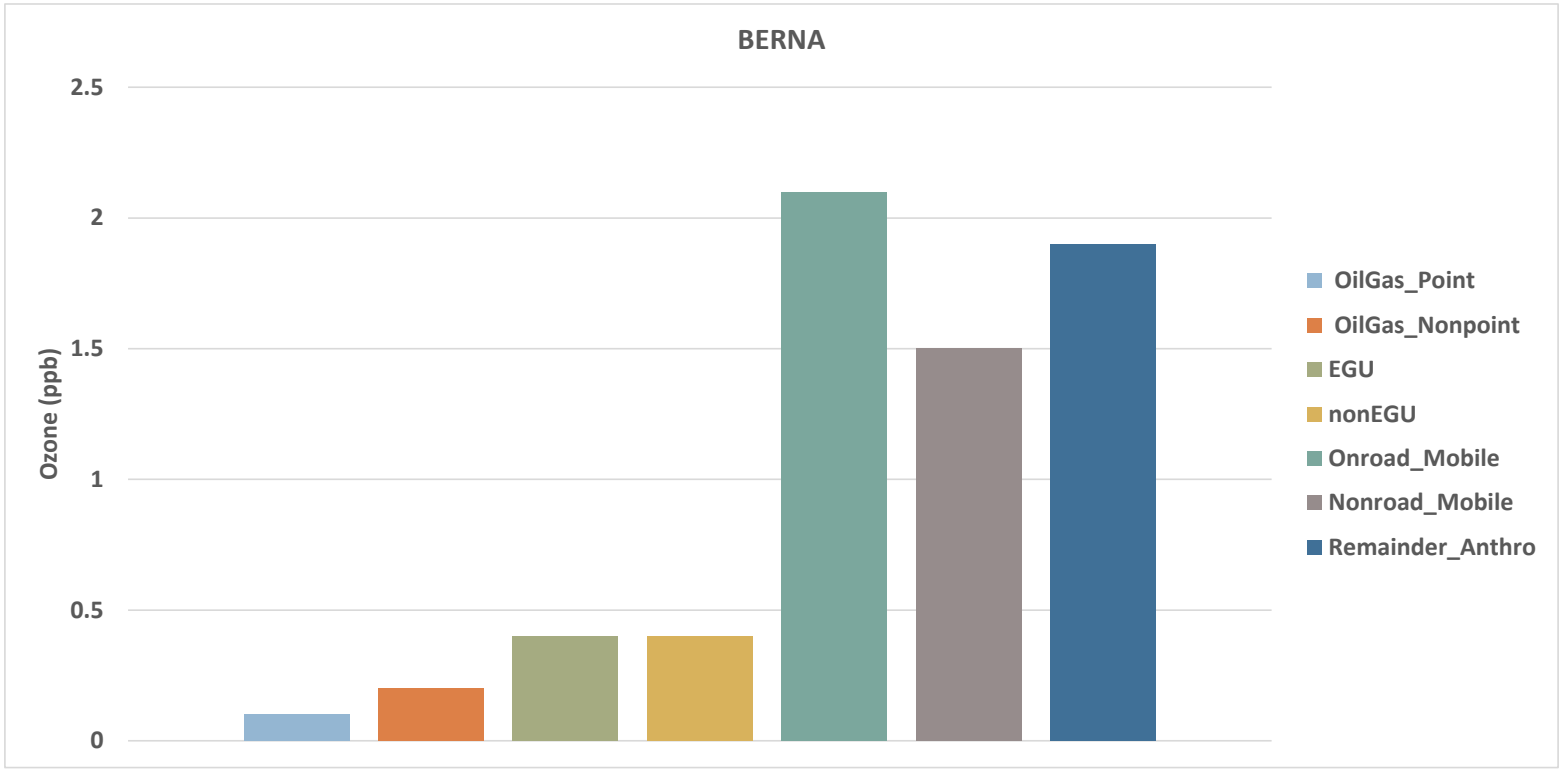


Figure 10-12. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Bernalillo in Sandoval County.

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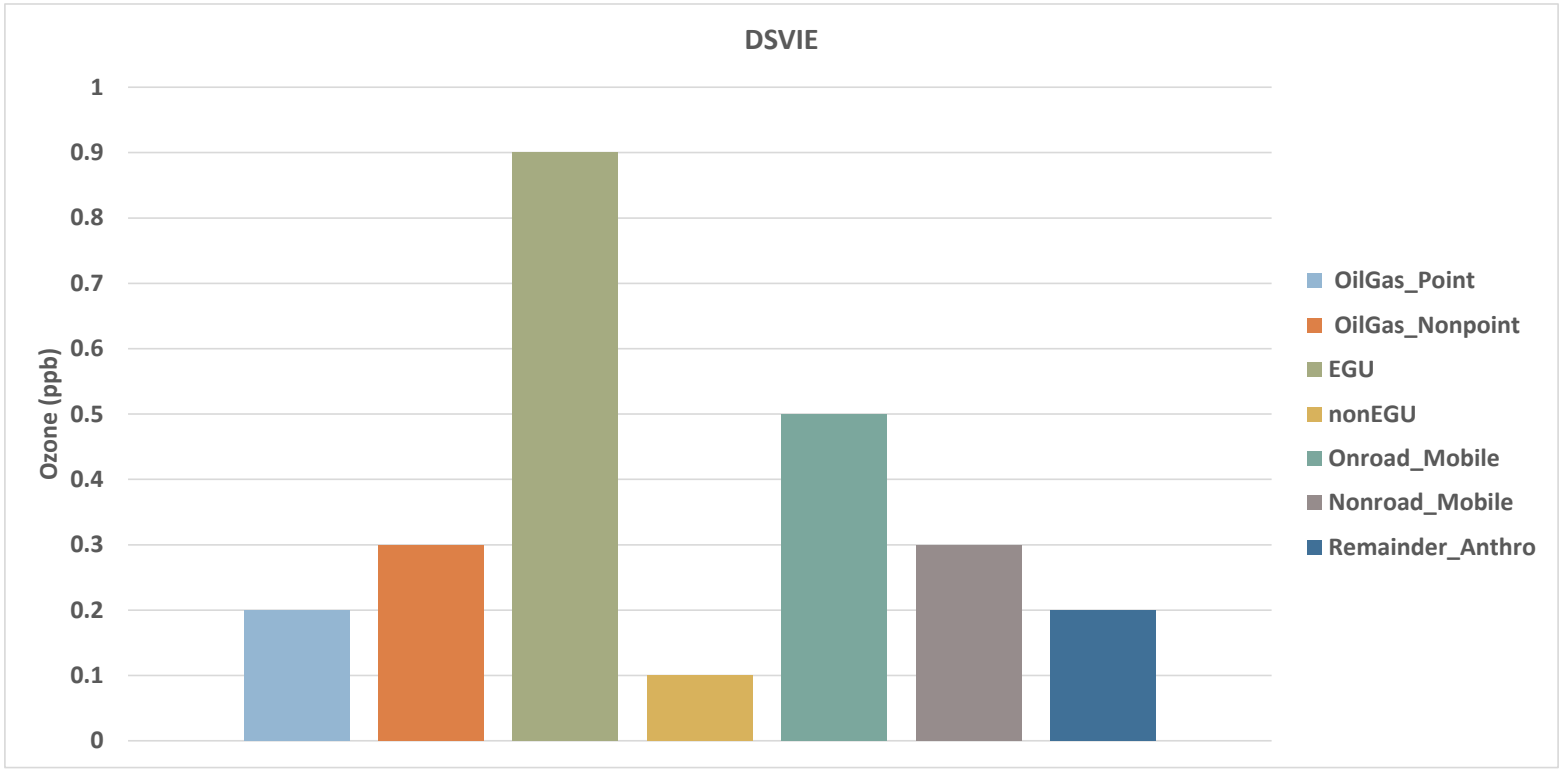


Figure 10-13. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Desert View in Doña Ana County in southern New Mexico.

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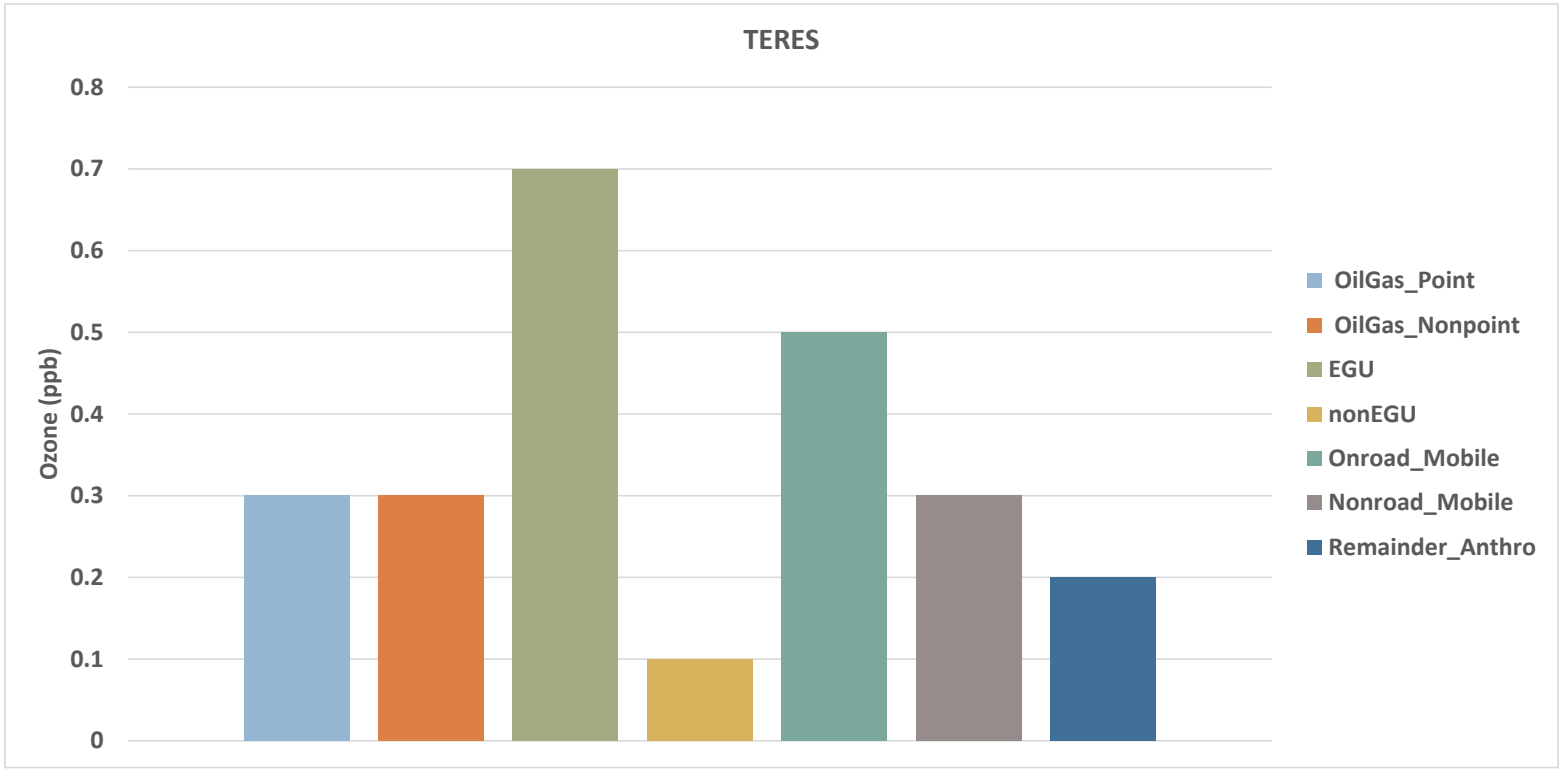


Figure 10-14. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Santa Teresa in Doña Ana County in southern New Mexico.

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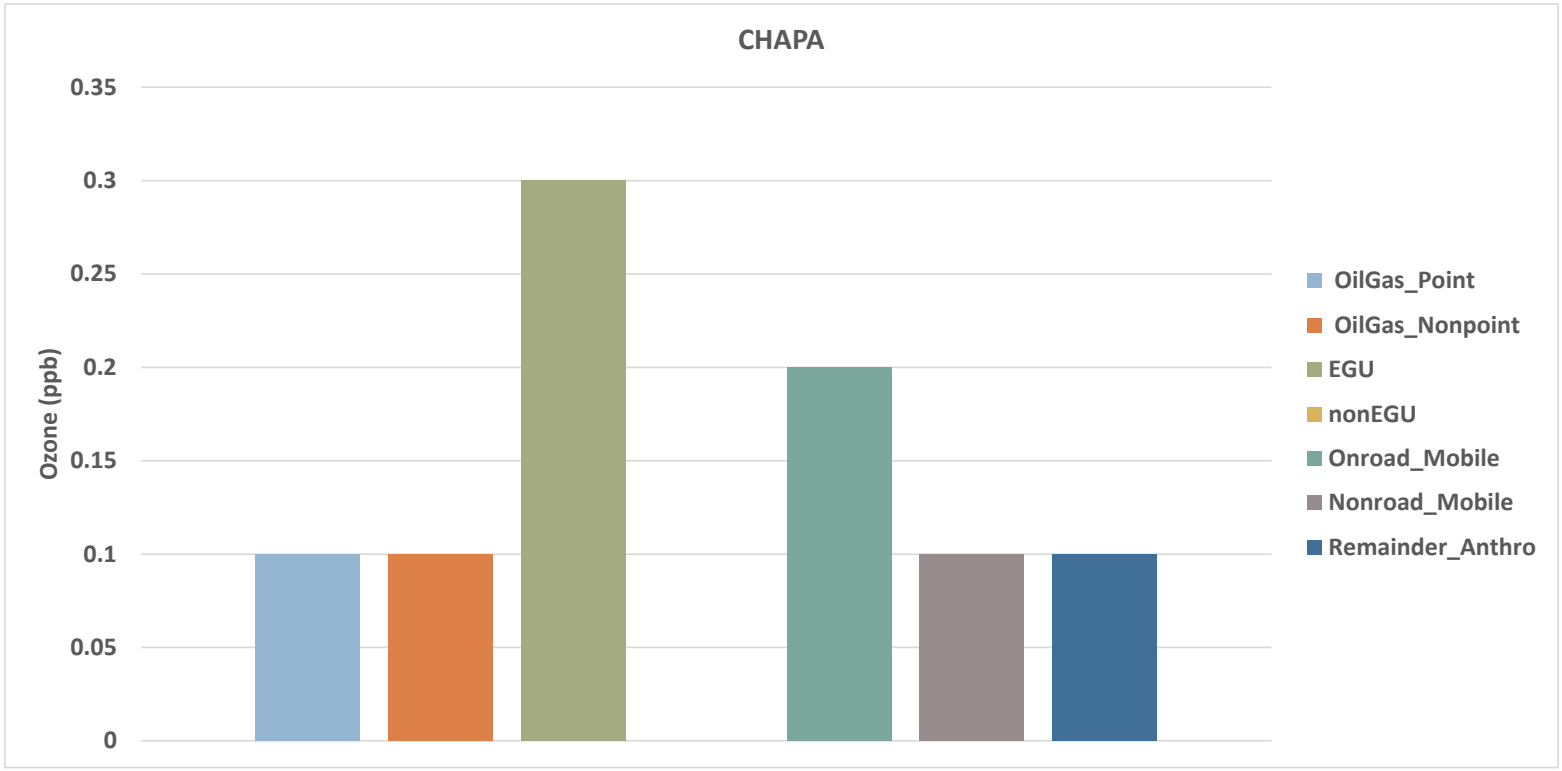


Figure 10-15. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Chaparral in Doña Ana County in southern New Mexico.

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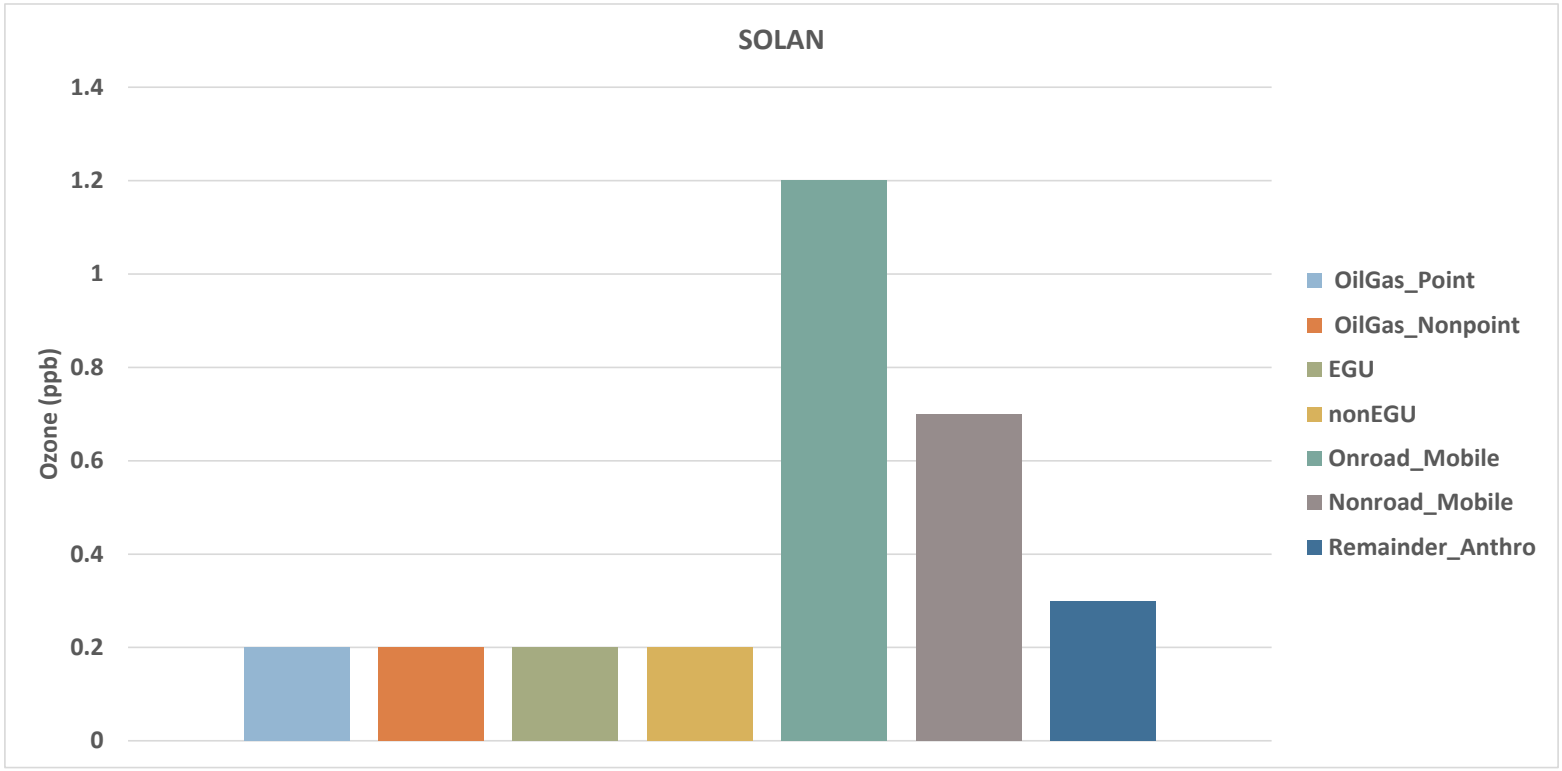


Figure 10-16. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Solano in Doña Ana County in southern New Mexico.

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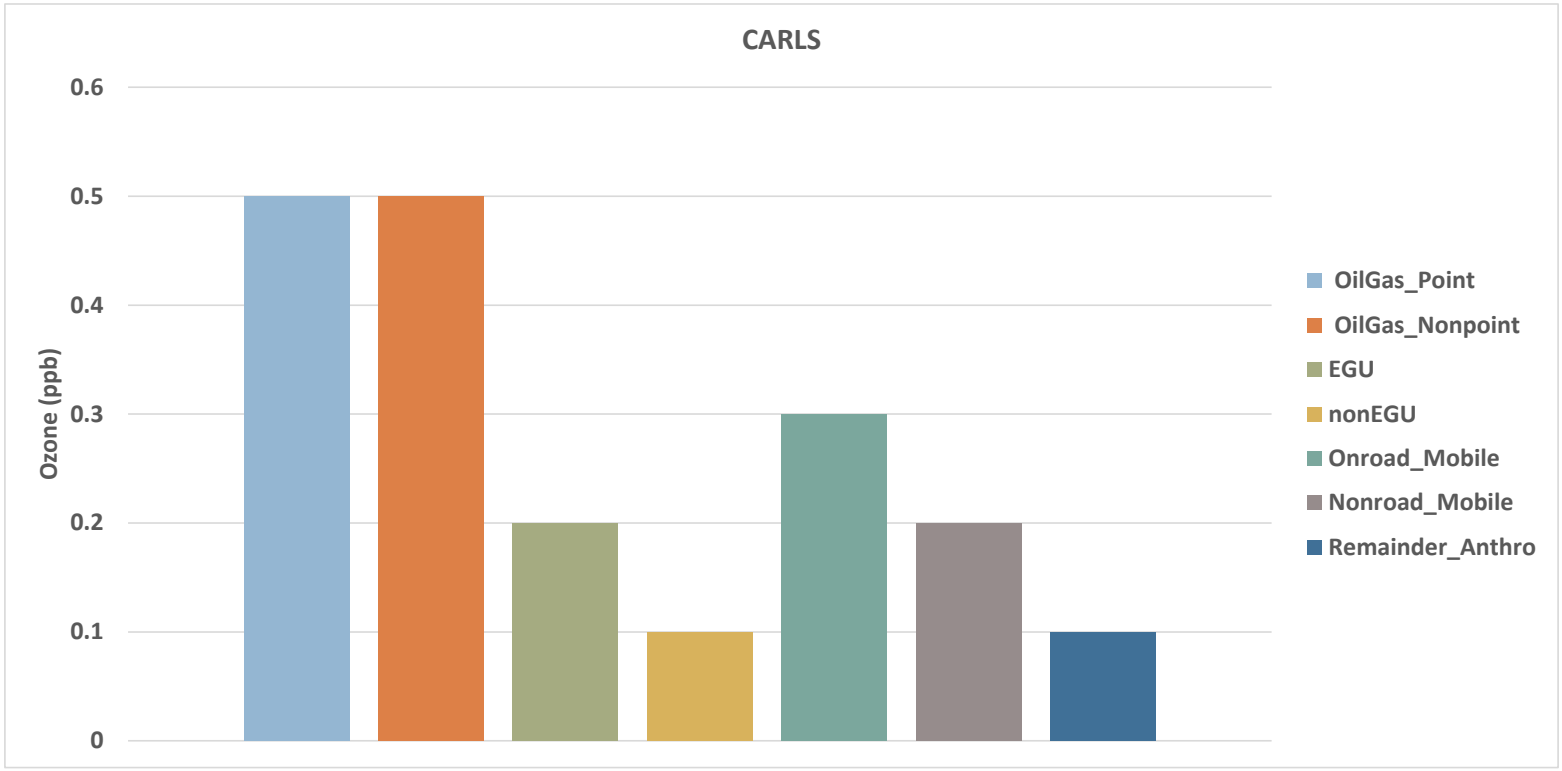


Figure 10-17. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Carlsbad in Eddy County in southeastern New Mexico.

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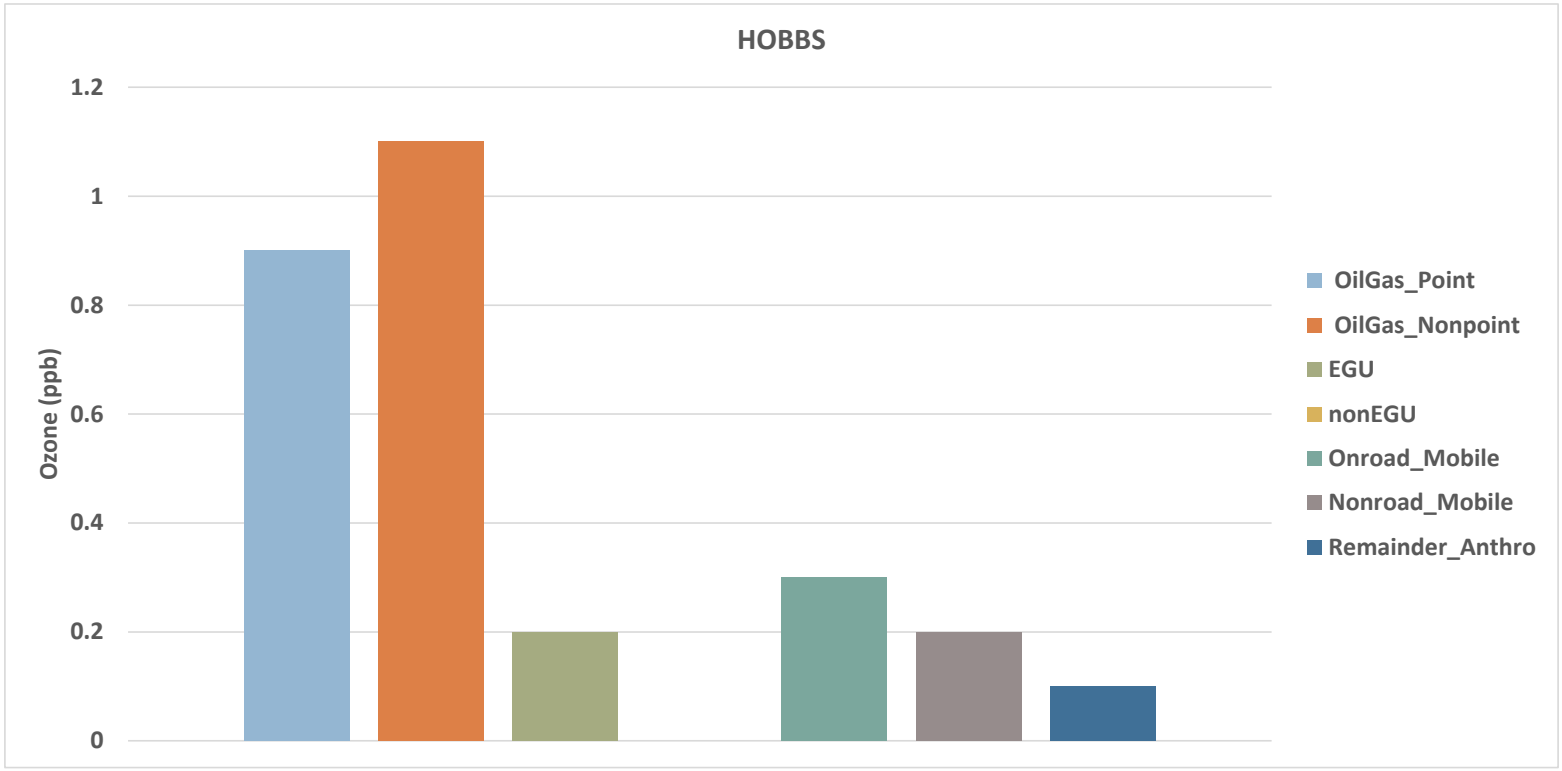


Figure 10-18. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Hobbs in Lea County in southeastern New Mexico.

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The SMAT Unmonitored Area Analysis (UAA) feature was used to estimate the spatial distribution 2028 ozone DVFs across the 4-km New Mexico domain for the 2028 O&G Control Scenario without New Mexico emissions from each of the 7 anthropogenic emission Source Sectors. Figures 10-19 and 10-20 display the reduction in 2028 ozone DVFs across the New Mexico 4-km domain due to the removal of New Mexico emissions for the 7 Source Sectors. Removing New Mexico EGU emissions reduces the 2028 ozone DVF by as much as 3.1 ppb in San Juan County with ozone reductions of 0.1 to 1.0 ppb in the upper half of New Mexico and from Doña Ana to Lea Counties in southern New Mexico (Figure 10-19a). The removal of New Mexico Non-EGU Point emissions results in a reduction of 1.3 ppb in eastern Bernalillo County and reductions of 0.1 to 1.0 in adjacent counties, with little effect over the rest of New Mexico away from Bernalillo County (Figure 10-19b).

New Mexico On-Road mobile contributes as much as 2.6 ppb to the 2028 ozone DVF with reductions of 1-2 ppb stretching from Albuquerque to Santa Fe and in Las Cruces (Figure 10-19c). New Mexico Non-Road mobile contributes as much as 2.1 ppb in Bernalillo County (Figure 10-19d).

New Mexico Non-Point O&G has large (> 2 ppb) contributions to the 2028 ozone DVF in the San Juan and Permian Basins (Figure 10-20a). Whereas, New Mexico Point O&G contributes as much as 1-2 ppb in the Permian Basin but less than 1 ppb in the San Juan Basin (Figure 10-20b). The Other Anthropogenic Source Sector contributions has a similar distribution as the two mobile Source Sectors with the highest ozone contributions centered on Bernalillo County (Figure 10-20c).

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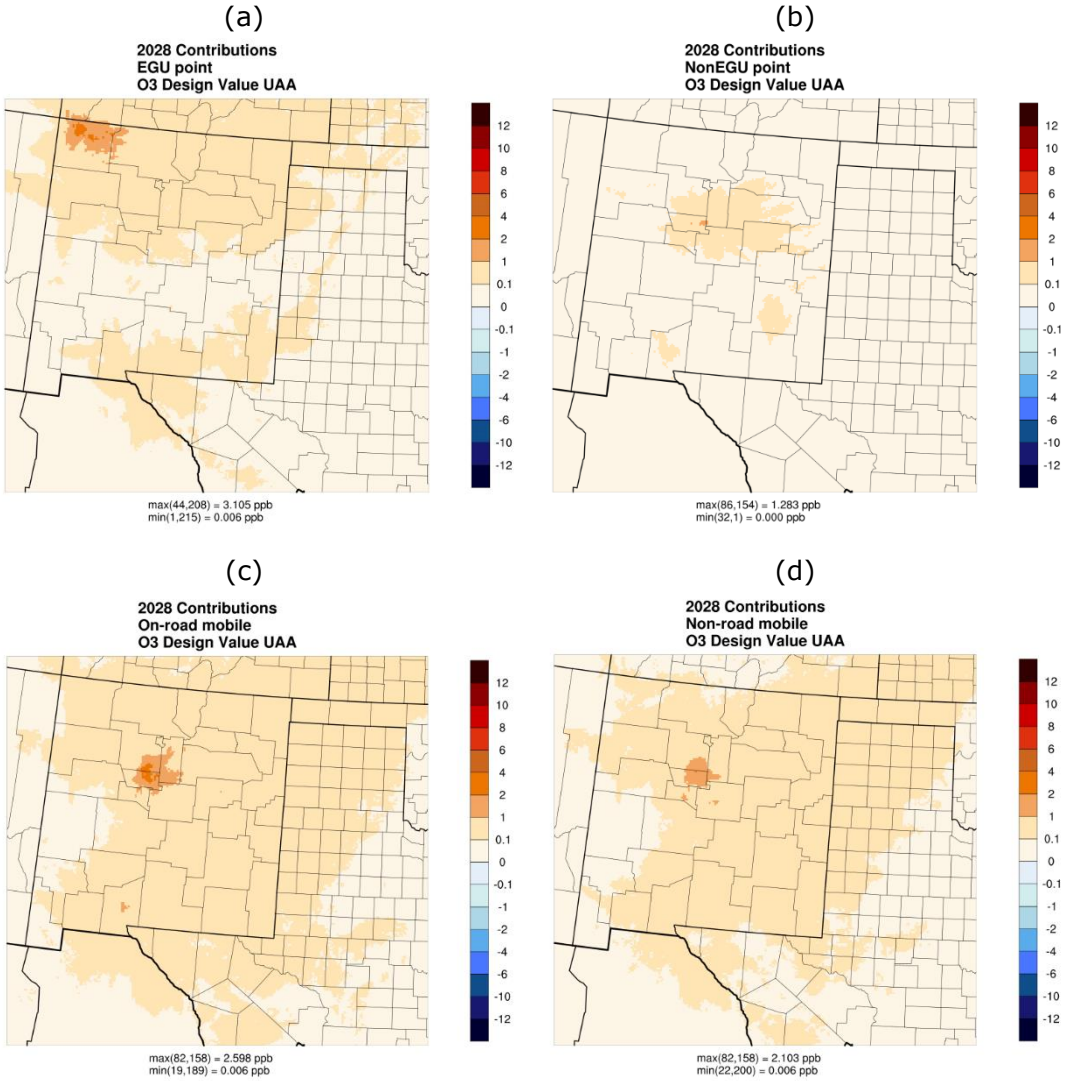


Figure 10-19. Reduction in 2028 ozone DVF due to removal of New Mexico Source Sector emissions for: (a) EGU Point; (b) Non-EGU Point; (c) On-Road Mobile; and (d) Non-Road Mobile.

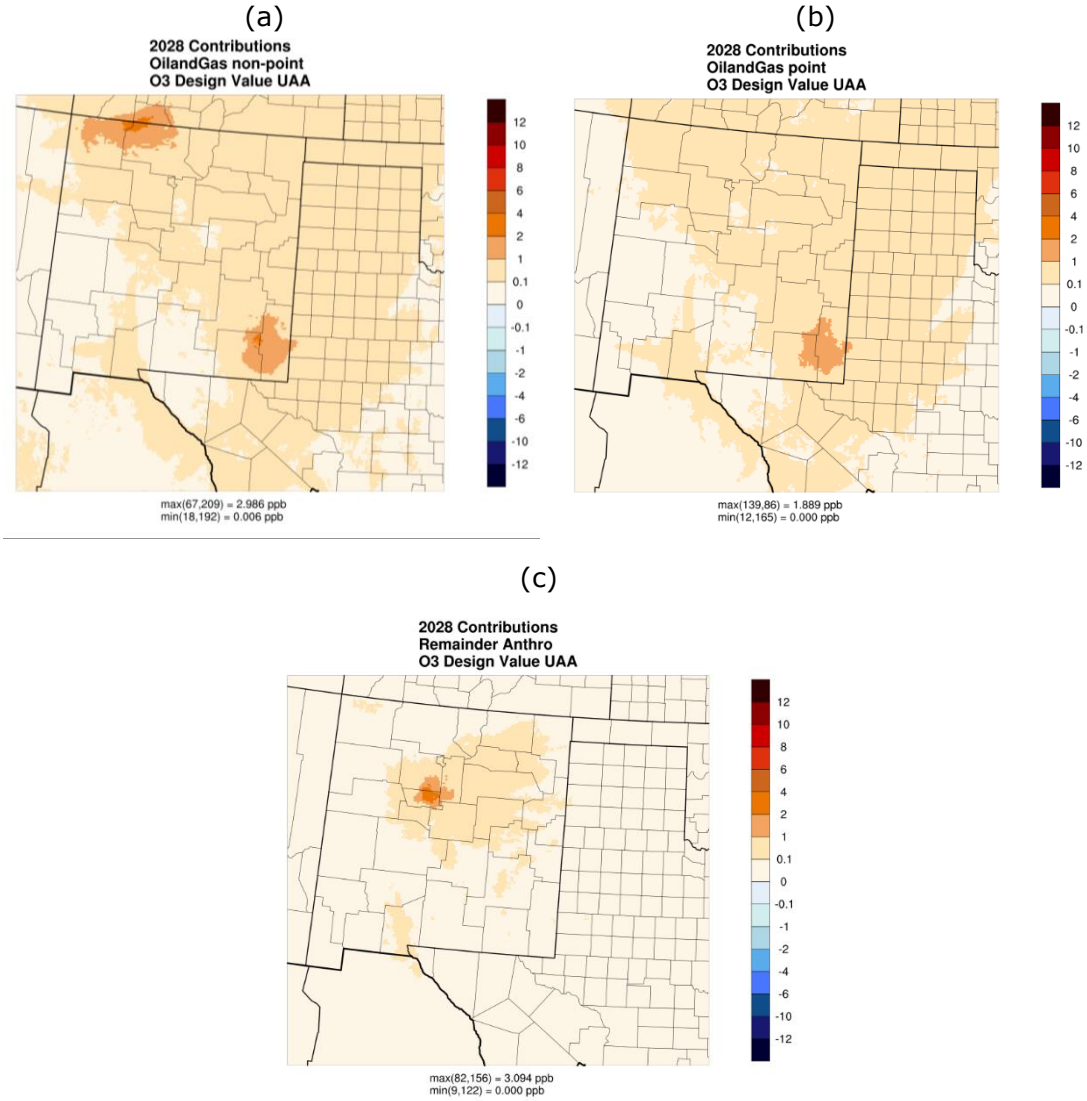


Figure 10-20. Reduction in 2028 ozone DVF due to removal of New Mexico Source Sector emissions for: (a) Non-Point O&G; (b) Point O&G; and (c) Other Anthropogenic.

10.3.1.2 United States Source Sector 2028 Ozone DVF Contributions

Table 10-2 displays the reductions in 2028 ozone DVFs due to the elimination of Source Sector emissions throughout the United States. Table 10-3 shows the percent of the all U.S. Source Sector ozone reduction that was due to just the Source Sector emissions in New Mexico (i.e., the percent the ozone reductions in Table 10-1 are of the ozone reductions in Table 10-2). At the three San Juan County sites, O&G non-point contributes the most (2-3 ppb) with approximately 60-78% coming from O&G non-point sources in New Mexico. Oil and gas point contributes 1.1 to 1.3 ppb at the three San Juan County sites with 55-69% coming from sources in New Mexico. The U.S. EGU Source Sector contributes 2.0 to 3.6 ppb to the 2028 ozone DVF at the three San Juan County sites with a vast majority (~85%) coming from New Mexico. On the other hand, the U.S. On-Road (1.7 ppb) and Non-Road (1.2 ppb) contribution at the three San Juan County sites comes mostly from outside of New Mexico (10-30%).

For sites in Bernalillo County in central New Mexico, 40% to 86% of the U.S. Source Sector contributions come from sources within New Mexico. The largest U.S. Source Sector contributions are for On-Road (3-4 ppb) and Non-Road (2-3 ppb) for which 60-70% of the contribution is due to sources from New Mexico.

At the Doña Ana County monitoring sites, approximately 25% (13-38%) of the U.S. O&G and 22-50% of the U.S. EGU Source Sector is from New Mexico. However, only 9-17% of the U.S. On-Road ozone contribution is from New Mexico sources with the exception of Solano that has 44% of the U.S. on-road mobile ozone contribution due to New Mexico on-road emissions. .

The Carlsbad and Hobbs monitors in southeast New Mexico have approximately half of their U.S. O&G ozone contributions from New Mexico sources, with only ~20% of U.S. mobile contribution coming from New Mexico.

The Grant monitor in southwest New Mexico has almost no ozone contributions from sources in New Mexico.

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Table 10-2. Reduction in 2028 ozone DVF due to the elimination of emissions from 7 Source Sectors in United States.

AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	On-Road	Non-Road	OAnth
Northern New Mexico										
350390026	COYOT	64.0	60.0	-0.5	-0.9	-0.8	-0.7	-1.5	-1.0	-0.7
350450009	BLOOM	64.3	60.2	-1.1	-2.1	-2.3	-0.7	-1.7	-1.1	-0.6
350450018	NAVAJ	67.0	63.3	-1.3	-2.7	-2.0	-0.8	-1.7	-1.2	-0.8
350451005	SUBST	63.7	59.6	-1.1	-2.5	-3.6	-0.8	-1.7	-1.2	-0.7
Central New Mexico										
350010023	NORTE	66.3	60.7	-0.5	-0.7	-1.1	-1.7	-3.9	-3.0	-4.2
350010024	SEHGS	68.0	62.0	-0.5	-0.7	-1.0	-1.7	-3.6	-2.8	-3.7
350010029	STHVA	66.0	60.5	-0.6	-0.9	-1.0	-1.6	-3.3	-2.5	-2.9
350010032	WSTSD	67.0	62.1	-0.4	-0.7	-0.9	-1.0	-2.7	-2.0	-2.4
350011012	FTHIL	65.0	58.8	-0.5	-0.7	-1.1	-1.4	-3.8	-3.0	-3.7
350431001	BERNA	64.0	58.1	-0.4	-0.6	-0.8	-1.1	-3.4	-2.5	-2.6
350490021	SNTFE	64.3	60.4	-0.5	-0.7	-0.7	-0.7	-2.0	-1.4	-1.3
Southern New Mexico										
350130008	UNION	66.3	59.8	-0.8	-0.9	-1.6	-1.5	-3.2	-2.3	-1.5
350130017	SPARK	67.0	61.8	-0.7	-1.0	-1.8	-1.5	-3.0	-2.1	-1.7
350130020	CHAPA	67.0	62.2	-0.6	-0.8	-1.3	-1.4	-2.3	-1.7	-1.3
350130021	DSVIE	72.0	66.8	-0.8	-1.1	-1.8	-1.6	-3.1	-2.2	-1.8
350130022	TERES	71.3	66.0	-0.8	-1.1	-1.6	-1.5	-2.9	-2.1	-1.5
350130023	SOLAN	65.0	60.2	-0.7	-1.0	-0.9	-1.1	-2.7	-1.8	-1.1
350151005	CARLS	69.0	66.4	-0.8	-1.1	-0.5	-0.8	-1.3	-0.9	-0.7
350171003	GRANT	62.0	58.9	-0.2	-0.3	-0.4	-0.7	-1.3	-1.0	-0.7
350250008	HOBBS	66.0	63.3	-1.6	-2.2	-0.7	-0.6	-1.4	-1.0	-0.7
350290003	DEAIR	66.0	62.5	-0.4	-0.5	-0.6	-0.7	-1.7	-1.2	-0.7

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Table 10-3. Percent contribution of New Mexico Source Sectors to All United Source Sectors reduction in 2028 ozone DVF.

AQS_ID	Site_ID	O&GPT	O&GNP	EGU	NonEGU	On-Road	Non-Road	OAnth
Northern New Mexico								
350390026	COYOT	40%	56%	63%	0%	13%	10%	0%
350450009	BLOOM	64%	67%	83%	0%	24%	9%	17%
350450018	NAVAJ	69%	78%	85%	13%	24%	17%	13%
350451005	SUBST	55%	60%	86%	13%	29%	17%	29%
Central New Mexico								
350010023	NORTE	40%	43%	45%	59%	69%	67%	86%
350010024	SEHGS	40%	43%	50%	65%	69%	68%	86%
350010029	STHVA	50%	56%	50%	63%	67%	68%	83%
350010032	WSTSD	50%	57%	44%	40%	59%	60%	75%
350011012	FTHIL	40%	43%	45%	50%	66%	67%	81%
350431001	BERNA	25%	33%	50%	36%	62%	60%	73%
350490021	SNTFE	40%	43%	29%	43%	60%	50%	62%
Southern New Mexico								
350130008	UNION	25%	22%	44%	0%	16%	13%	7%
350130017	SPARK	29%	20%	50%	0%	13%	10%	12%
350130020	CHAPA	17%	13%	23%	0%	9%	6%	8%
350130021	DSVIE	25%	27%	50%	6%	16%	14%	11%
350130022	TERES	38%	27%	44%	7%	17%	14%	13%
350130023	SOLAN	29%	20%	22%	18%	44%	39%	27%
350151005	CARLS	63%	45%	40%	13%	23%	22%	14%
350171003	GRANT	0%	0%	0%	0%	8%	10%	0%
350250008	HOBBS	56%	50%	29%	0%	21%	20%	14%
350290003	DEAIR	50%	20%	33%	0%	35%	33%	0%

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10.3.2 Source Sector Contributions to Modeled MDA8 Ozone Concentrations

The contributions of the Source Sector emissions to the absolute CAMx modeling results 2028 daily MDA8 ozone concentrations are analyzed in this section. We first present spatial maps of the episode maximum MDA8 ozone contributions across the 4-km New Mexico domain for each Source Region. The contributions of all and New Mexico Source Sectors to MDA8 ozone concentrations are then presented at four example New Mexico monitoring sites for the 10 days used to make the 2028 ozone DVF projections (i.e., the 10 SMAT days). Finally, the spatial maps of New Mexico and all United States Source sector contributions to daily MDA8 ozone concentrations are presented for six example days during the May-August 2014 modeling episode.

10.3.2.1 Episode Maximum Source Sector MDA8 Ozone Contributions by Source Region

Figures 10-21 and 10-22 display the episode maximum MDA8 ozone contributions due to Source Sector emissions from New Mexico. The maximum New Mexico EGU MDA8 ozone contribution is 10.9 ppb and occurs at the location of the Four Corners Power Plan in San Juan County (Figure 10-21a). Elevated ozone due to emissions from New Mexico EGUs is also seen in Lea County at the location of the Hobbs, Cunningham and Maddox EGUs and in southern Doña Ana County at the location of the Rio Grande EGU (Figure 10-21a). The highest New Mexico Non-EGU Point source contribution is 3.1 ppb in eastern Bernalillo County with the Non-EGU Point contribution mostly less than 1 ppb away from Bernalillo County (Figure 10-21b). The maximum New Mexico On-Road (4.7 ppb) and Non-Road (4.0 ppb) ozone contributions both occur in Albuquerque, with a secondary ozone maximum occurring in Las Cruces (Figure 10-21c and d). The On-Road ozone spatial patterns follow the major freeways, including east-west I-40 and north-south I-25, with even I-10 evident in Luna County in southwest New Mexico (Figure 10-21c).

The highest New Mexico O&G Non-Point (7.6 ppb) and O&G Point (5.4 ppb) both occur at the same location in the Permian Basin (Figure 10-22a and b). The O&G Non-Point ozone contributions exceed 5 ppb over large portions of the Permian and San Juan Basins (Figure 10-22a). The O&G Point source ozone contributions are lower, exceeding 3 ppb over large portions of the Permian Basin with much lower ozone contributions in the San Juan Basin (Figure 10-22b). The Other Anthropogenic ozone contribution has a bull’s eye centered on Albuquerque with a maximum of 6.2 ppb (Figure 10-22c). Fires are highly episodic with four distinct fire ozone plumes present in New Mexico with episode maximum exceeding 20 ppb (Figure 10-22d).

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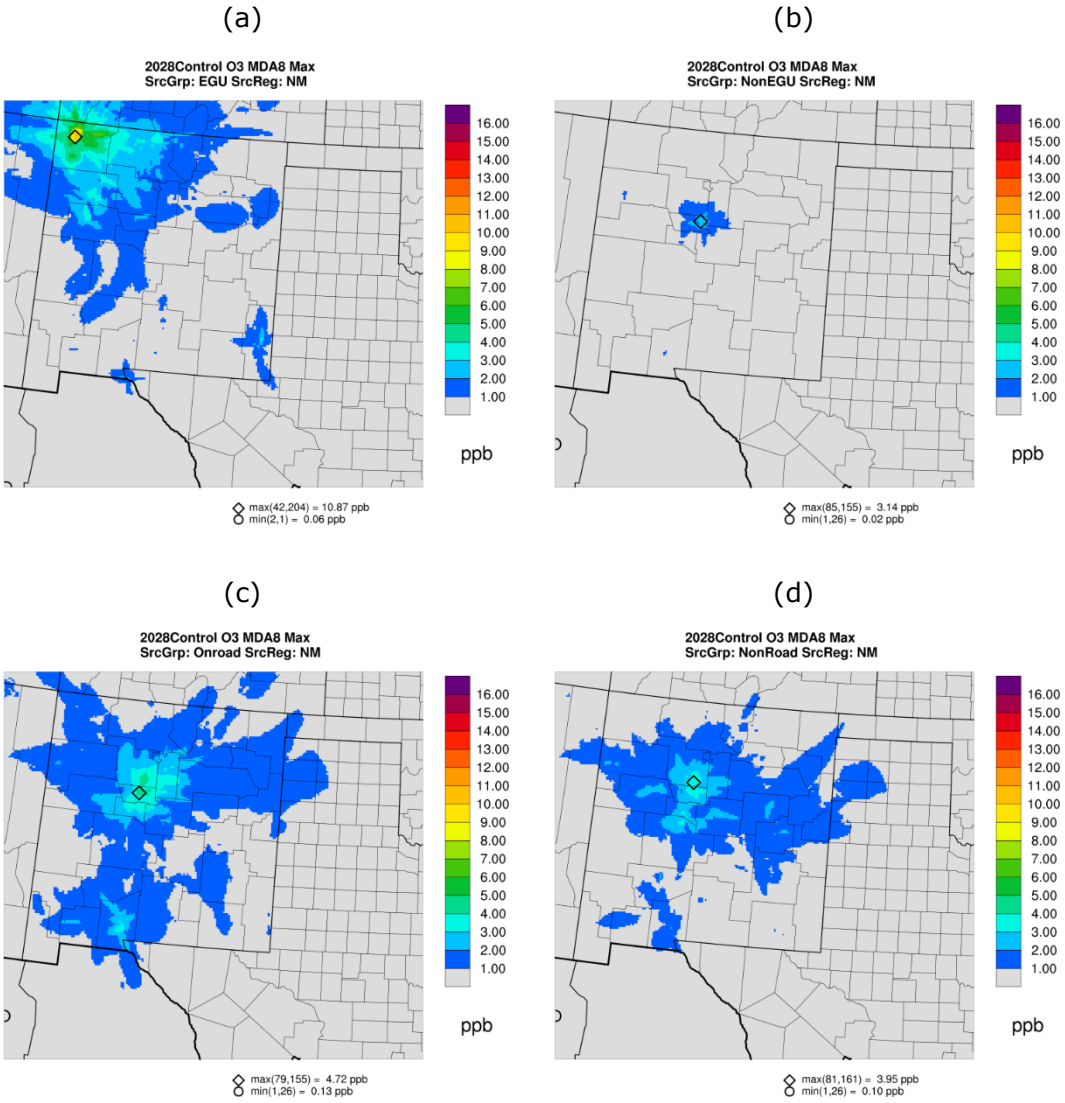


Figure 10-21. Episode maximum daily MDA8 ozone contributions from Source Sectors in New Mexico for: (a) EGU Point; (b) Non-EGU Point; (c) On-Road Mobile; and (d) Non-Road Mobile.

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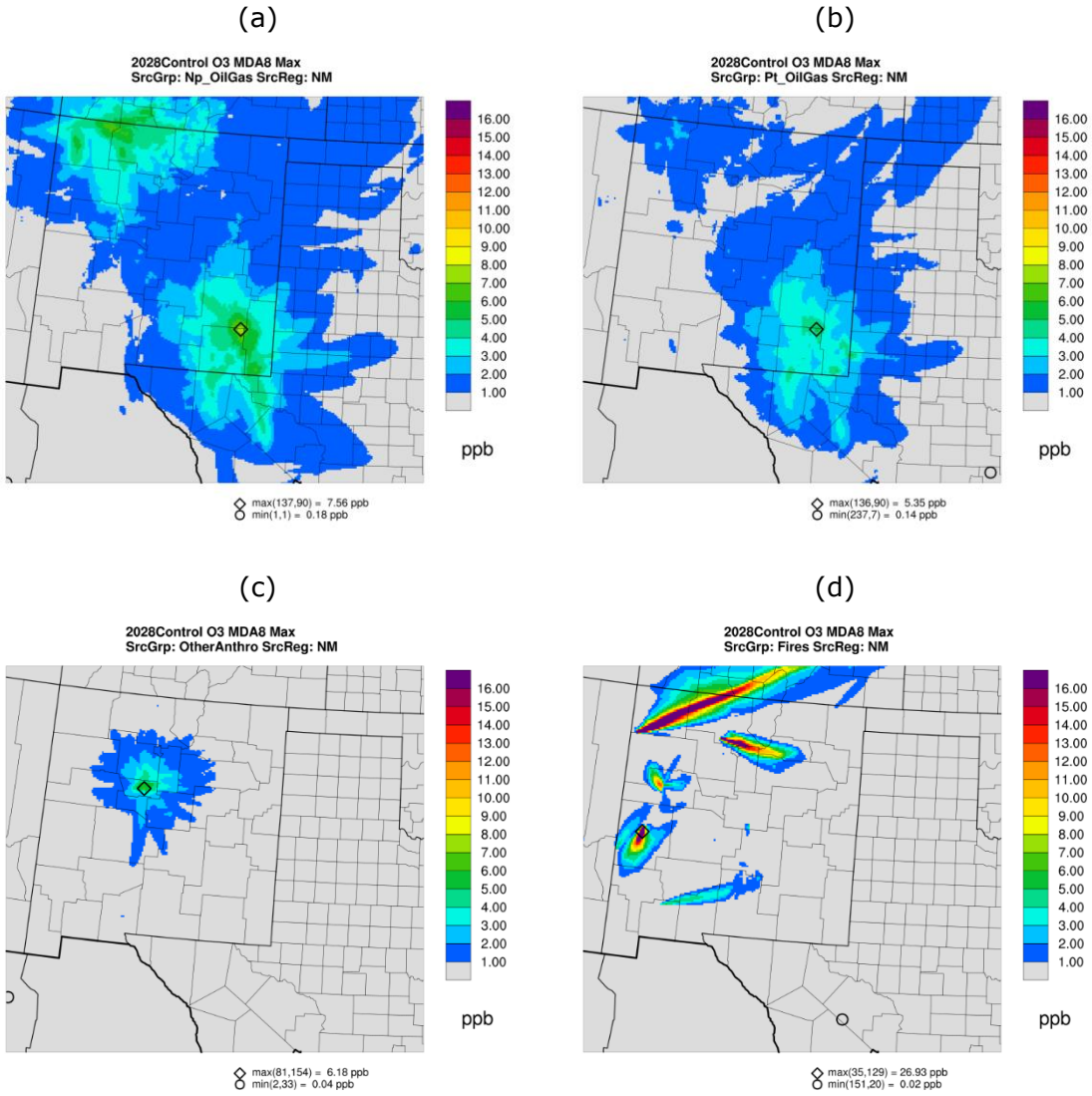


Figure 10-22. Episode maximum daily MDA8 ozone contributions from Source Sectors in New Mexico for: (a) Non-Point O&G; (b) Point O&G; (c) Other Anthropogenic; and (d) Fires.

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Figure 10-23 displays the episode maximum MDA8 ozone contributions due to emissions from Texas for 9 Source Sectors (7 anthropogenic Source Sectors plus fires and natural). The presence of EGUs in the Texas Panhandle is clearly evident (e.g., 1,100 MW Tolk coal EGU) that produce ozone in excess of 2 ppb entering eastern New Mexico (Figure 10-23, top left). Elevated ozone due to Texas Non-EGU Point, On-Road, Non-Road, and Other Anthropogenic is seen in El Paso with elevated ozone concentrations entering Doña Ana County. The Texas anthropogenic Source Sector that contributes the most to ozone in New Mexico is O&G. Texas O&G Non-Point (Figure 10-23, middle right) produces ozone above 4 ppb in Lea County and ozone in excess of 2 ppb as far north as Santa Fe and San Miguel Counties. Within the New Mexico portion of the Permian Basin, the maximum Texas O&G Non-Point ozone contribution exceeds 3 ppb and the maximum Texas O&G Point contribution exceeds 2 ppb.

The Colorado Source Sector with the largest contribution to New Mexico ozone concentrations is O&G Non-Point that has a peak ozone contribution in the 4-km domain of 7 ppb that occurs in Colorado just north of the border of San Juan and Rio Arriba Counties (Figure 10-24, middle right). Colorado O&G Non-Point contributes ozone in excess of 4 ppb in the northern portion of the two northwest New Mexico counties and ozone in excess of 1.5-2.0 ppb stretching south to Bernalillo County. Other Colorado anthropogenic emissions Source Sectors contribute ozone in excess of 0.5 ppb across large portions of New Mexico with O&G Point contributing ozone in excess of 1 ppb in San Juan County.

The highest Source Sector ozone contributions in the 4-km New Mexico domain due to all emissions in the U.S. are shown in Figure 10-25. The peak U.S. EGU ozone contribution is 11.5 ppb at the same locations as the New Mexico EGU peak ozone contribution with most of the U.S. EGU contribution at this location due to the FCPP in New Mexico (10.9 ppb, see Figure 10-21a). In addition to the EGU ozone hotspots in the Texas panhandle discussed above (Figure 10-23), there are also all U.S. EGU ozone hotspots in eastern Arizona at the locations of the Springerville and Coronado Generating Stations (Figure 10-25, top left). The U.S. On-Road, Non-Road and Other Anthropogenic ozone contributions (Figure 10-25) look similar to the New Mexico alone ozone contributions (Figures 10-21 and 10-22) with the addition of an incremental ozone concentrations across the 4-km domain due to the U.S. Source Sector emissions from outside New Mexico.

The peak U.S. O&G Non-Point ozone contribution is 10.5 ppb (Figure 10-25, middle right) and occurs at the same location in Colorado on the border with New Mexico as where the Colorado O&G Non-Point peak ozone (7.0 ppb) occurred (Figure 10-24, middle right). The additional 4.5 ppb ozone comes mainly from New Mexico O&G Non-Point emissions (Figure 10-22a). Ozone due to U.S. O&G Non-Point exceeds 8 ppb in the New Mexico portions of the San Juan and Permian Basins. Ozone due to U.S. O&G Point sources exceeds 4 ppb over a wide area in the Permian Basin, whereas U.S. O&G Point rarely exceeds 4 ppb in the San Juan Basin.

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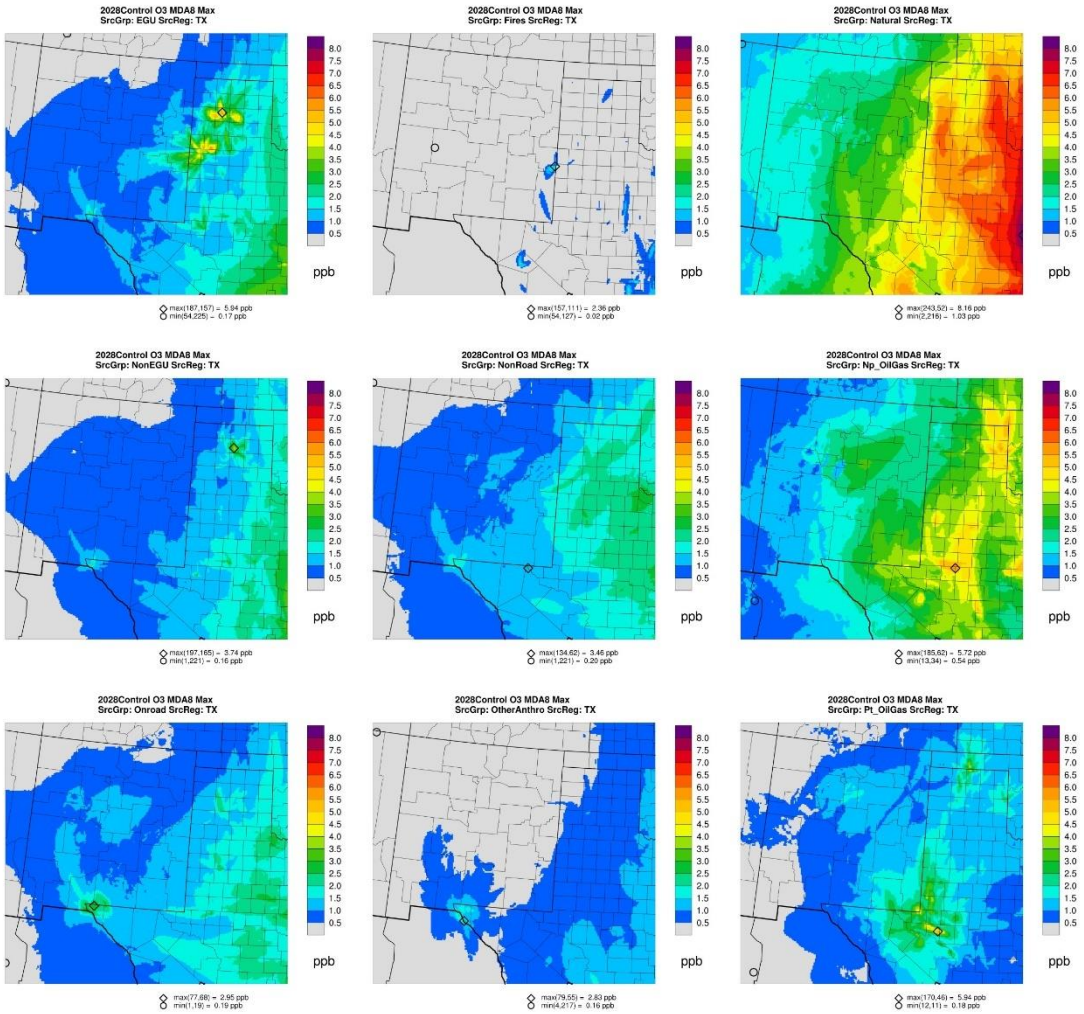


Figure 10-23. Episode maximum MDA8 ozone contributions from Source Sectors in Texas for EGU Point (top left), Fires (top middle), Natural (top right), Non-EGU Point (middle left), Non-Road (middle middle), O&G Non-Point (middle right), On-Road (bottom left), Other Anthropogenic (bottom middle) and O&G Point (bottom right) from the 2028 O&G Control Strategy emissions scenario.

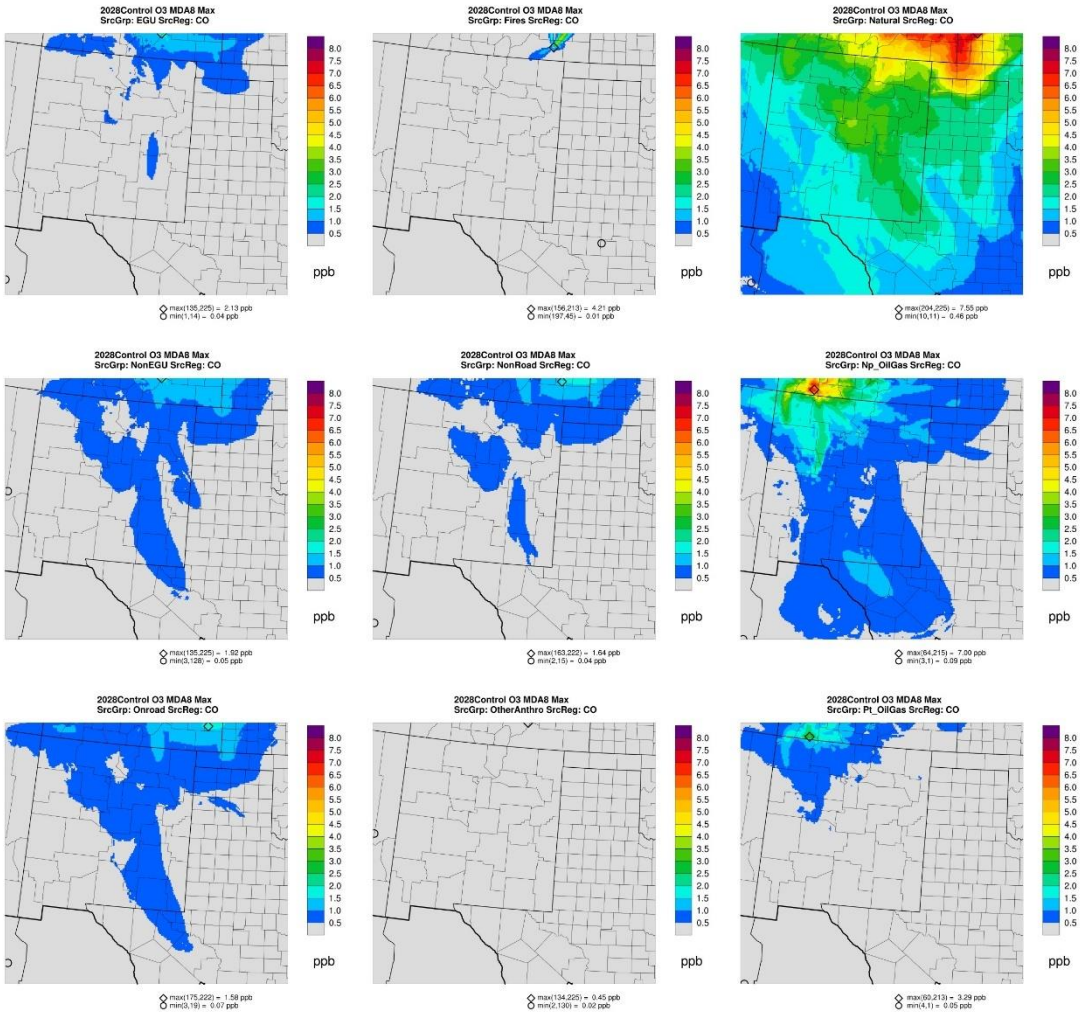


Figure 10-24. Episode maximum MDA8 ozone contributions from Source Sectors in Colorado for EGU Point (top left), Fires (top middle), Natural (top right), Non-EGU Point (middle left), Non-Road (middle middle), O&G Non-Point (middle right), On-Road (bottom left), Other Anthropogenic (bottom middle) and O&G Point (bottom right) from the 2028 O&G Control Strategy emissions scenario.

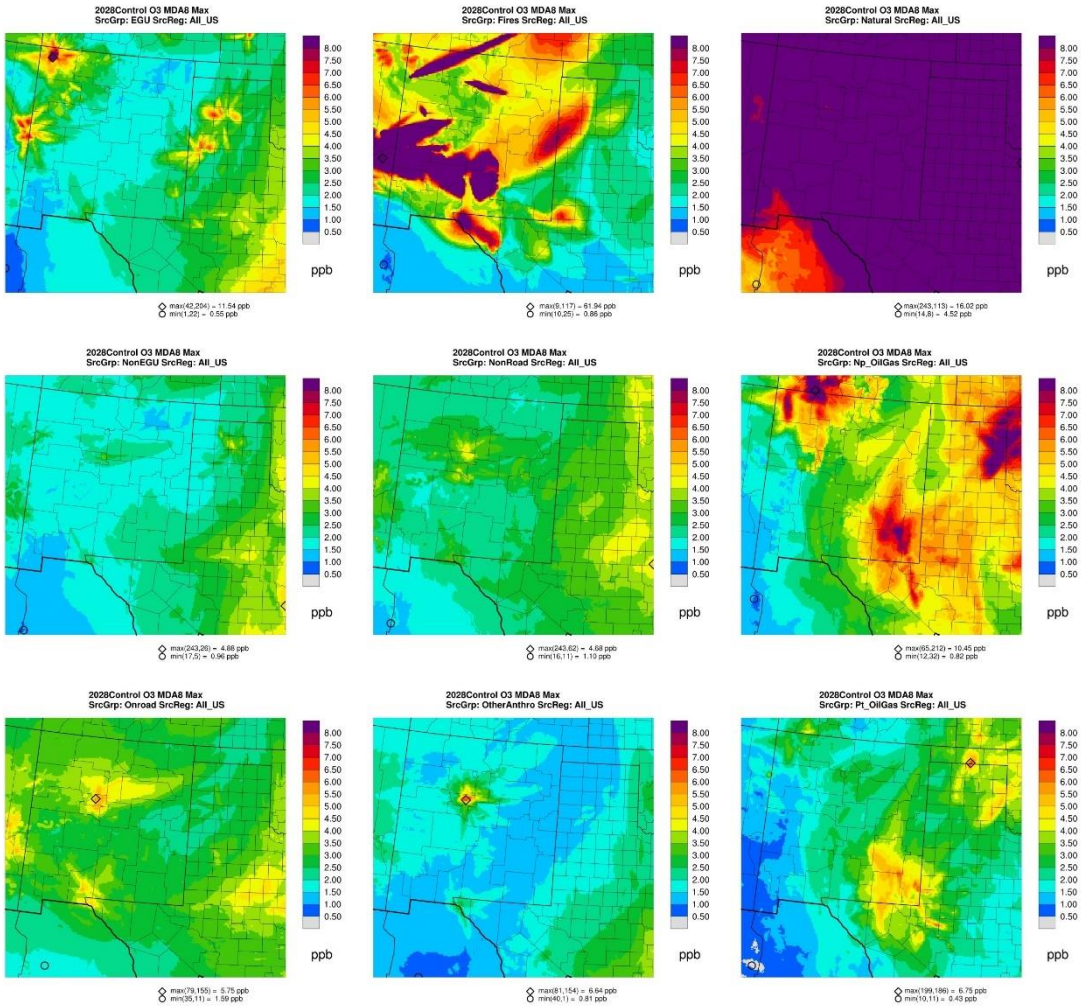


Figure 10-25. Episode maximum MDA8 ozone contributions from Source Sectors in United States for EGU Point (top left), Fires (top middle), Natural (top right), Non-EGU Point (middle left), Non-Road (middle middle), O&G Non-Point (middle right), On-Road (bottom left), Other Anthropogenic (bottom middle) and O&G Point (bottom right) from the 2028 O&G Control Strategy emissions scenario.

The top two panels in Figure 10-26 display the episode maximum MDA8 ozone contributions due to international anthropogenic emissions that are either within the CAMx 36/12/4-km modeling domain (i.e., mainly from in-domain Mexico emissions) or coming through the BCs (BC_{Intl}) from international emissions from outside of the CAMx modeling domains that were generated from 2014 GEOS-Chem simulations. The in-domain international anthropogenic emissions contribute high ozone concentrations in southern New Mexico with values exceeding 16 ppb stretching into Doña Ana, Luna and Otero Counties. The southeastern half of New Mexico has ozone contributions in excess of 8 ppb due to in-domain international emissions. Although the ozone peaks are not as high as the in-domain international anthropogenic emissions, the BC_{Intl} ozone contributions exceed 10 ppb across all of New Mexico and are as high as 13 ppb

(Figure 10-26b). The $BC_{Natural}$ ozone contributions is as high as 49 ppb in San Juan County (Figure 10-26c), while the BC_{US} ozone contributions ranges from 3-4 ppb across New Mexico (Figure 10-26d).

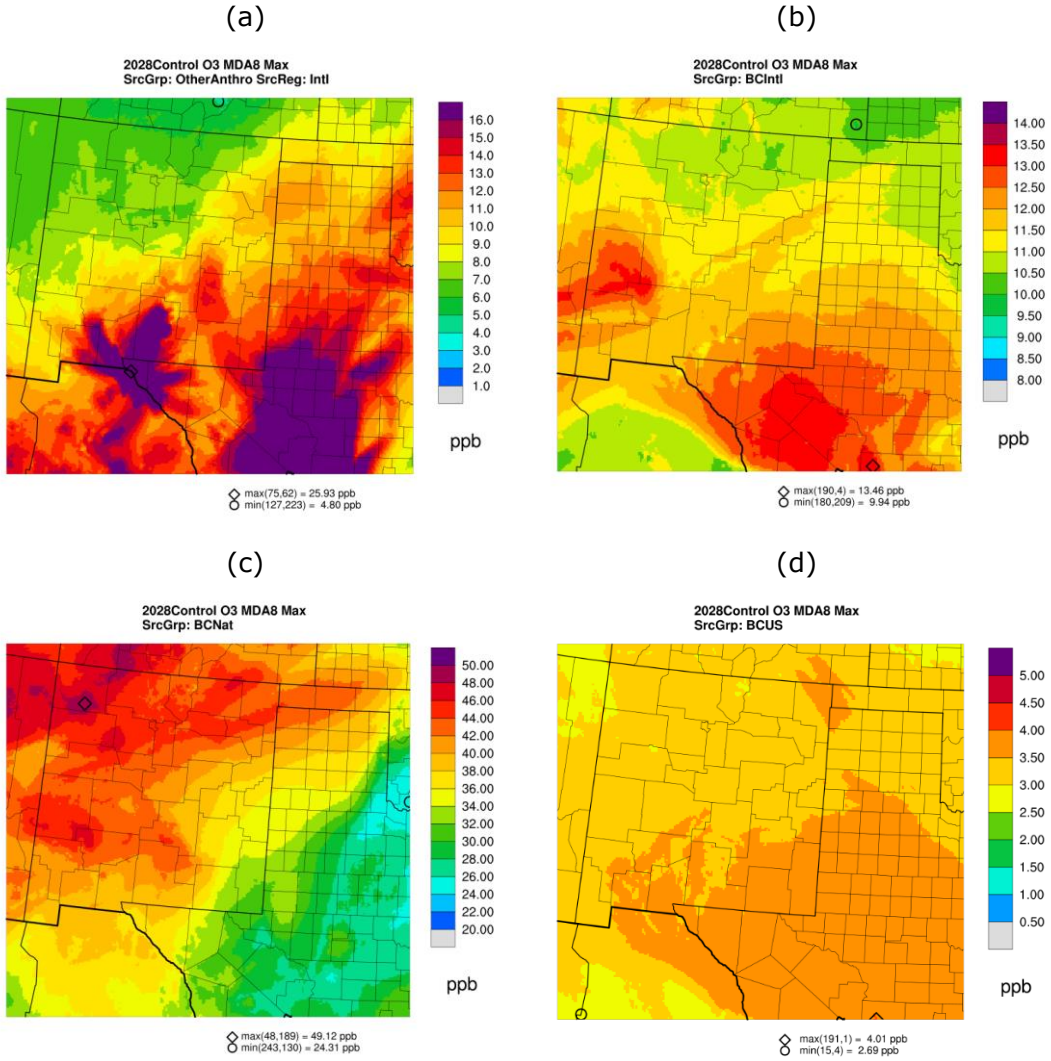


Figure 10-26. Episode maximum MDA8 ozone contributions from: (a) International Anthropogenic Emissions within CAMx 36/12/4-km domains; (b) BCs due to International Anthropogenic Emissions (BC_{Intl}); (c) BCs due to Natural sources ($BC_{Natural}$); and (d) BCs due to U.S. Anthropogenic Emissions (BC_{US}).

10.3.2.2 Source Sector Ozone Contributions to MDA8 Ozone Concentrations on Modeled High Ozone Days

The daily CAMx 2028 Source Sector APCA ozone source apportionment modeling results were extracted at the locations of the New Mexico ozone monitoring sites and loaded into an Excel Dashboard to visualize the source contributions using stacked bar, pie and tree charts. The Dashboard displays modeled 2028 MDA8 ozone concentrations at a user-selected monitoring site in groups of 10 high ozone days, and the average across the 10 days. These 10 days include the 10 days used in the SMAT 2028 ozone DVF projections, as well as the modeled 2028 first and second highest group of 10 days.

Figures 10-27 through 10-34 display results from the Dashboard for 5 monitoring sites representing different locations in New Mexico. Figures 10-27 and 10-28 display the modeled 2028 ozone results at the Navajo Lake monitor in northwest New Mexico for the 10 SMAT days. The top panel in Figure 10-27 shows stacked bar charts of daily MDA8 ozone contributions by Source Region and BCs for the 10 SMAT days at Navajo Lake. The total MDA8 ozone concentrations are 60-70 ppb and the BCs (grey bar) contribute by far the most with contributions ranging from 26 to 60 ppb. The New Mexico contribution ranges from near zero to 10.9 ppb. The bottom panel in Figure 10-27 shows a Tree Chart and breaks down each Source Region's contribution by Source Category averaged across the 10 SMAT days at Navajo Lake. The Natural category dominates the BC contribution followed by the BC International Anthropogenic Emissions category.

Figure 10-28 focuses on contributions due to emissions from New Mexico Source Categories to MDA8 ozone on the 10 SMAT days at Navajo Lake showing day by day results in the top panel and a pie chart of New Mexico contributions averaged across the 10 days in the bottom panel. For the Navajo Lake site, New Mexico O&G Non-Point is always the largest contributor (38% on average) followed by EGU (29% on average) and then O&G Point (16% on average). Next most important is either On-Road or Natural, depending on the day (6-7% on average). The other two San Juan County sites have higher EGU contributions, with EGU being the highest New Mexico Source Category accounting for 50% and 32% of the New Mexico ozone contribution at, respectively, Substation and Bloomfield.

Figures 10-29 and 10-30 show ozone contribution results for the 10 SMAT days at the Foothills monitoring site and represents typical contributions for sites in Bernalillo County. There is a wide-range of variation in the New Mexico ozone contribution to the 10 SMAT days at Foothills, from near zero to 15 ppb. BCs contribute the most, 27 to 47 ppb. The remaining U.S. and in-domain international emissions also contribute a fair amount. The three most important New Mexico Source Categories contributing to modeled MDA8 ozone at Foothills averaged across the 10 SMAT days are Other Anthropogenic (27%), On-Road (35%) and Non-Road (20%) (Figure 10-30).

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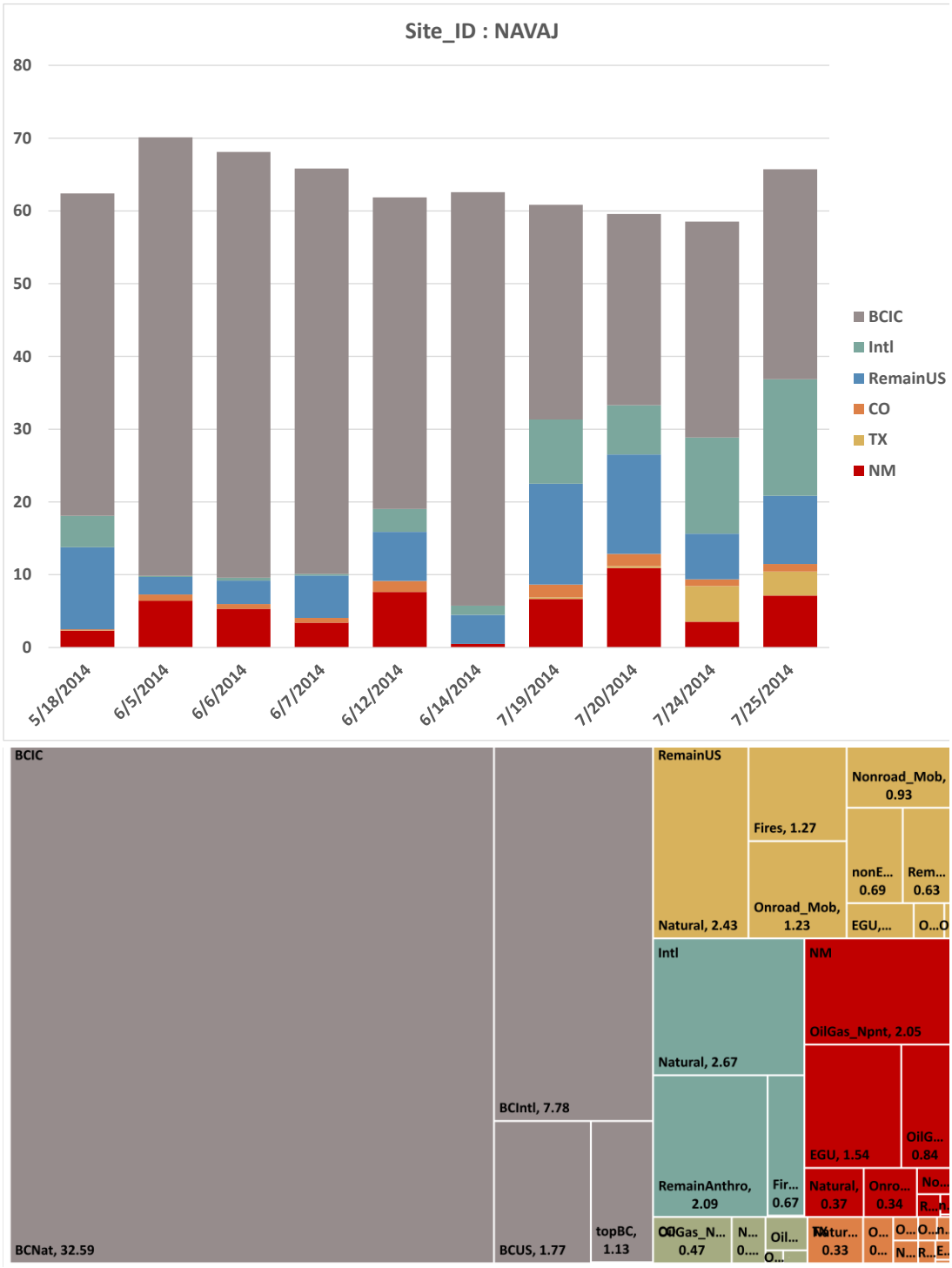


Figure 10-27. Contributions of all Source Groups to total MDA8 ozone concentrations at Navajo Lake for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

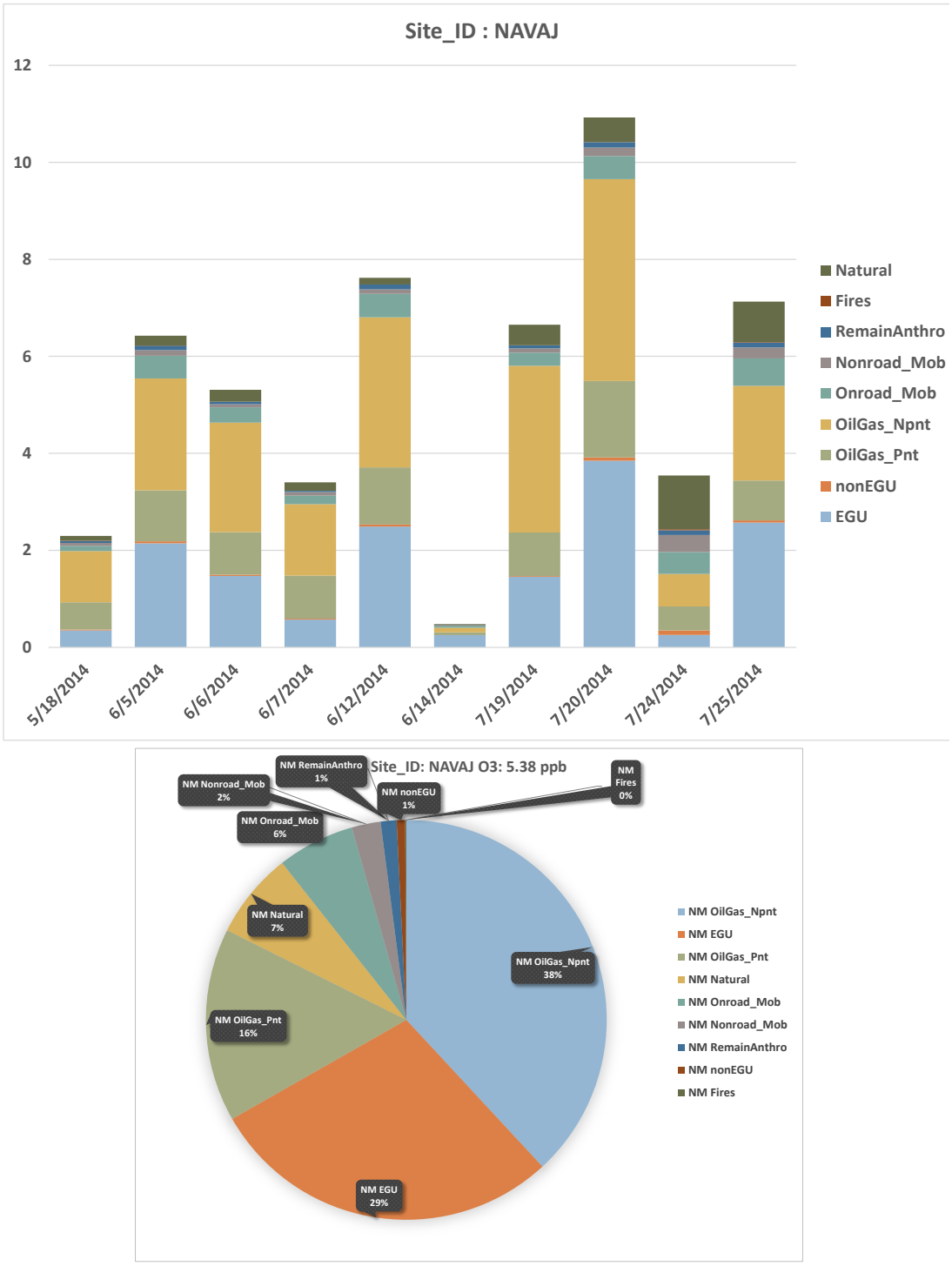


Figure 10-28. Contributions of New Mexico Source Groups to MDA8 ozone concentrations from New Mexico at Navajo Lake for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

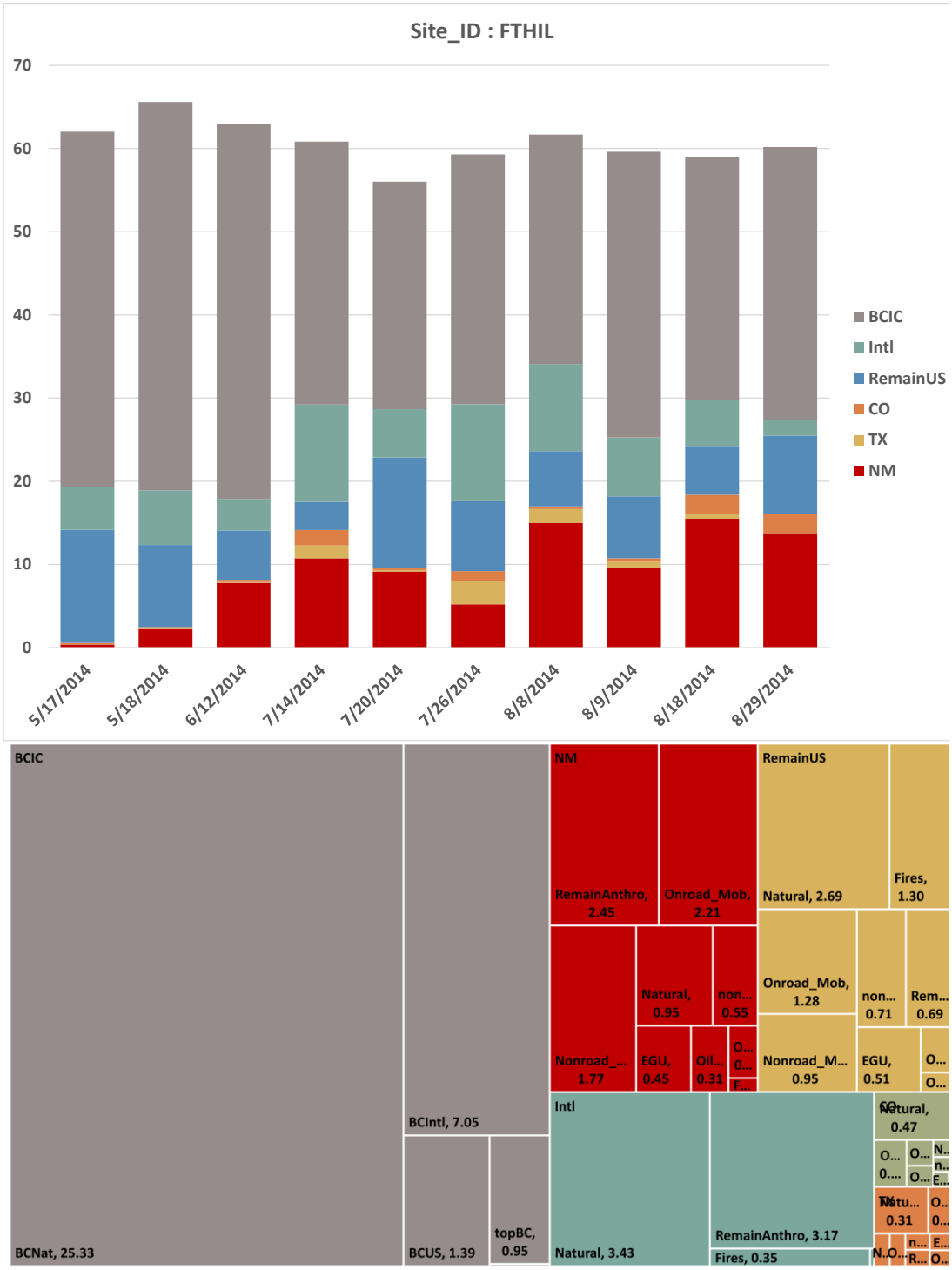


Figure 10-29. Contributions of all Source Groups to total MDA8 ozone concentrations at Foothills for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

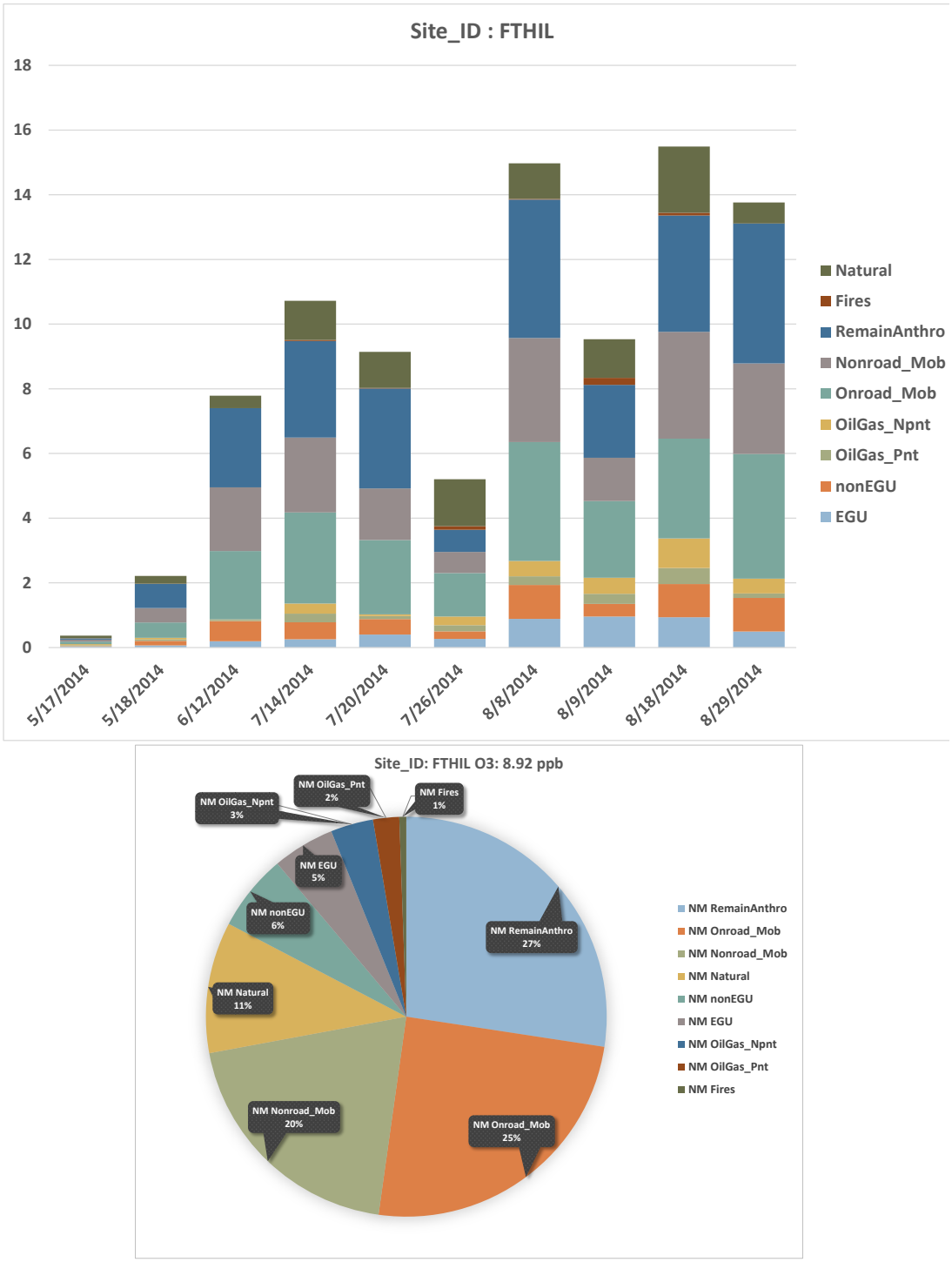


Figure 10-30. Contributions of New Mexico Source Groups to MDA8 ozone concentrations from New Mexico at Foothills for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

Ozone contributions for the 10 SMAT days at the Desert View monitor in Doña Ana County are shown in Figures 10-31 and 10-32. BCs from outside the 36-km North American domain is the largest contributor (45% on average), followed by in-domain international emissions (27%), Remainder US (14%) and Texas (8%). Emissions from New Mexico only contribute 4% of the total ozone averaged across the 10 SMAT days at Desert View. International anthropogenic emissions from BCs (5.8 ppb) and in-domain (i.e., Mexico) sources (13.0 ppb) contribute a combined 18.8 ppb (30%) of the average ozone across the 10 SMAT days at Desert View (Figure 10-31, bottom). As shown in Figure 10-32, the contributions from sources in New Mexico contributes from 1.3 to 4.4 ppb to the total MDA8 ozone on the 10 SMAT days, with an average contribution of 2.8 ppb. The largest New Mexico contributing Source Sector is EGU (29%), followed by Natural (18%), On-Road (15%) with 10% contribution coming from Non-Road and Remaining Anthropogenic (Figure 10-32, bottom).

Figures 10-33 and 10-34 displays the 10 SMAT day ozone contributions at the Carlsbad monitoring site. BC and in-domain international emissions contribute the most to ozone at Carlsbad. There is a lot of variation in the day-to-day contributions from New Mexico (0.2 to 5 ppb) with an average contribution of 2.0 ppb. Similar results are seen for Texas (0.5 to 9 ppb with an average of 2.5 ppb). Non-Point O&G and then Point O&G are the two largest anthropogenic Source Sector contributors from both New Mexico and Texas.

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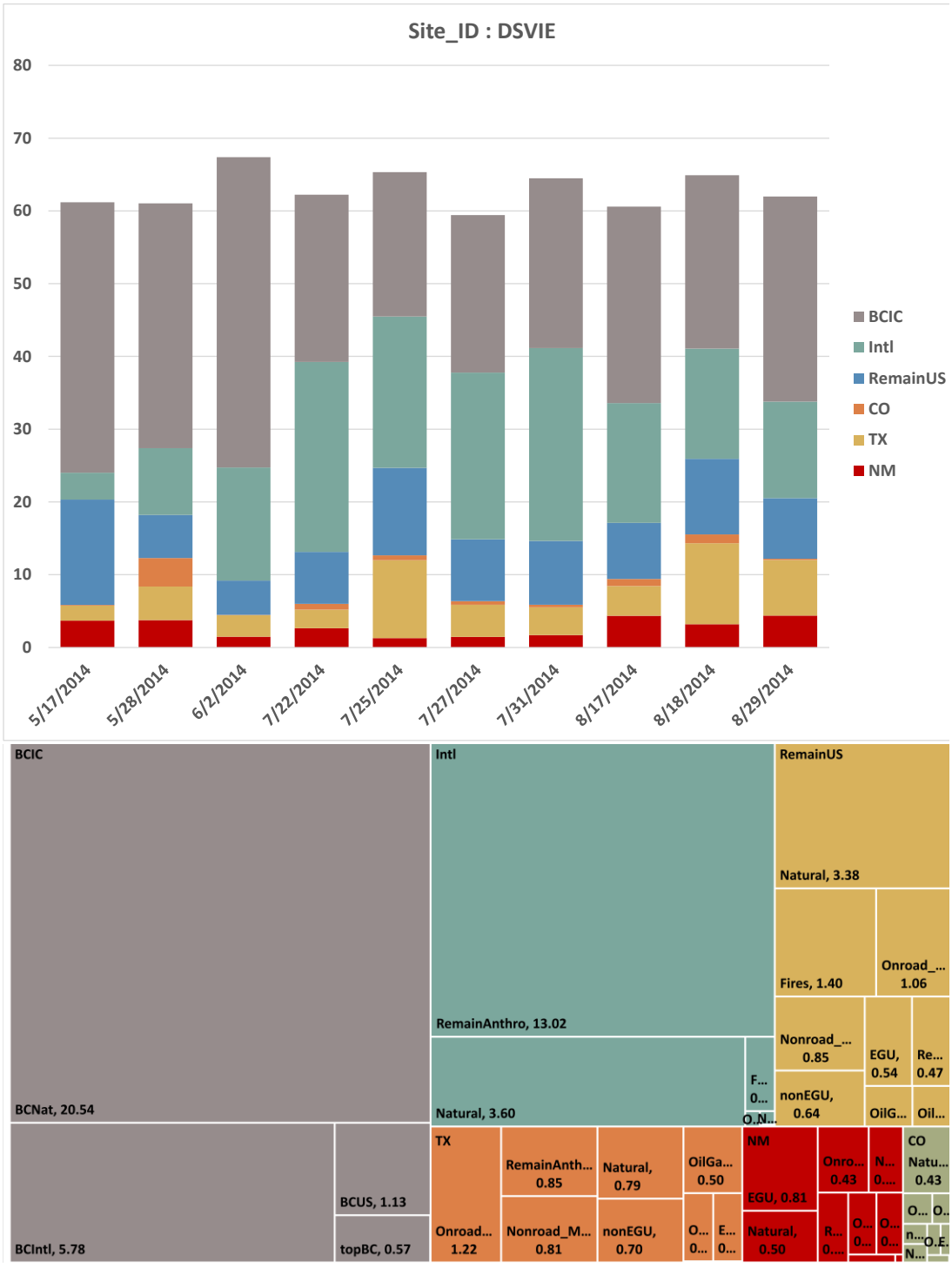


Figure 10-31. Contributions of all Source Groups to total MDA8 ozone concentrations at Desert View for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

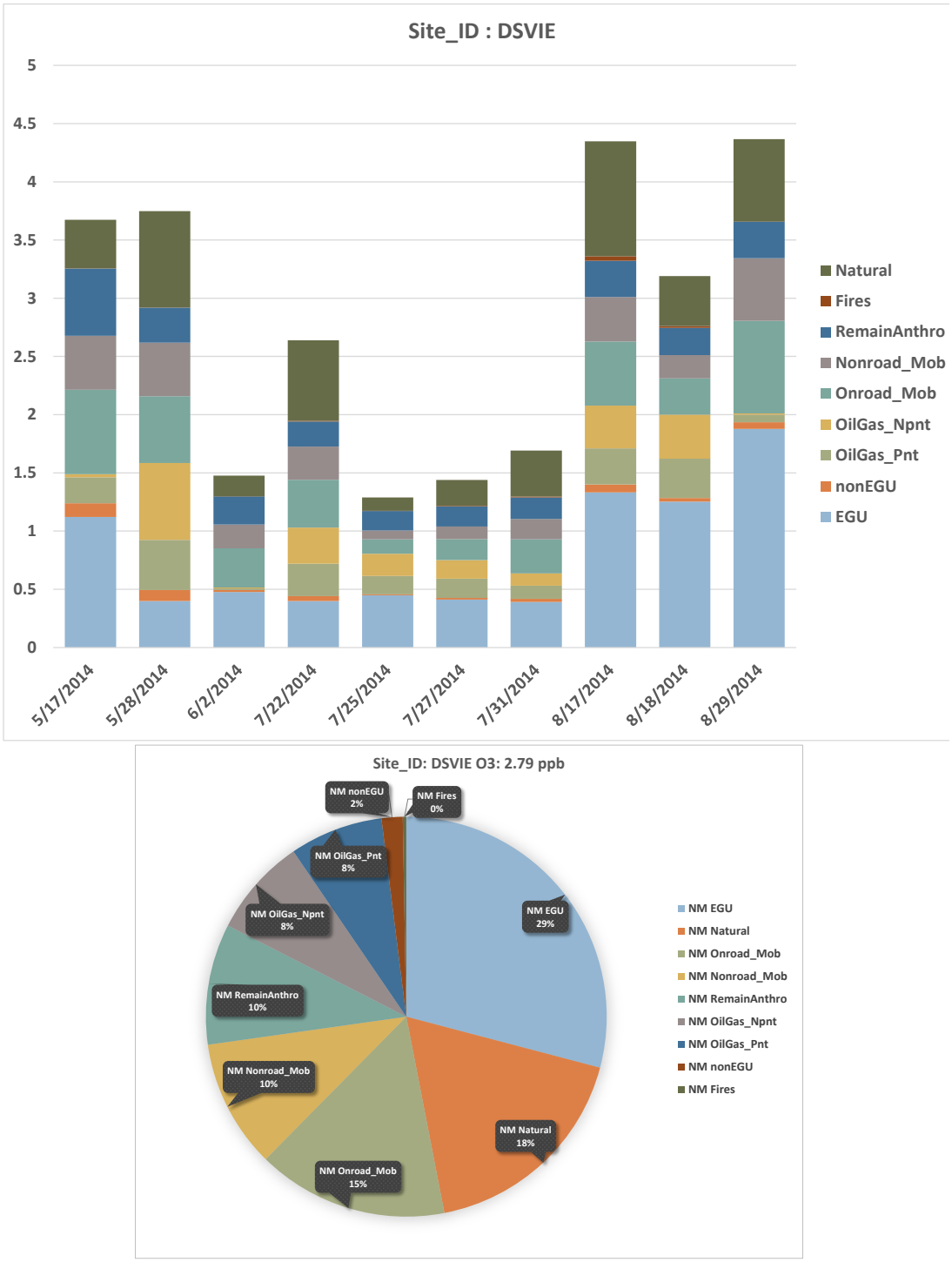


Figure 10-32. Contributions of New Mexico Source Groups to MDA8 ozone concentrations at Desert View for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

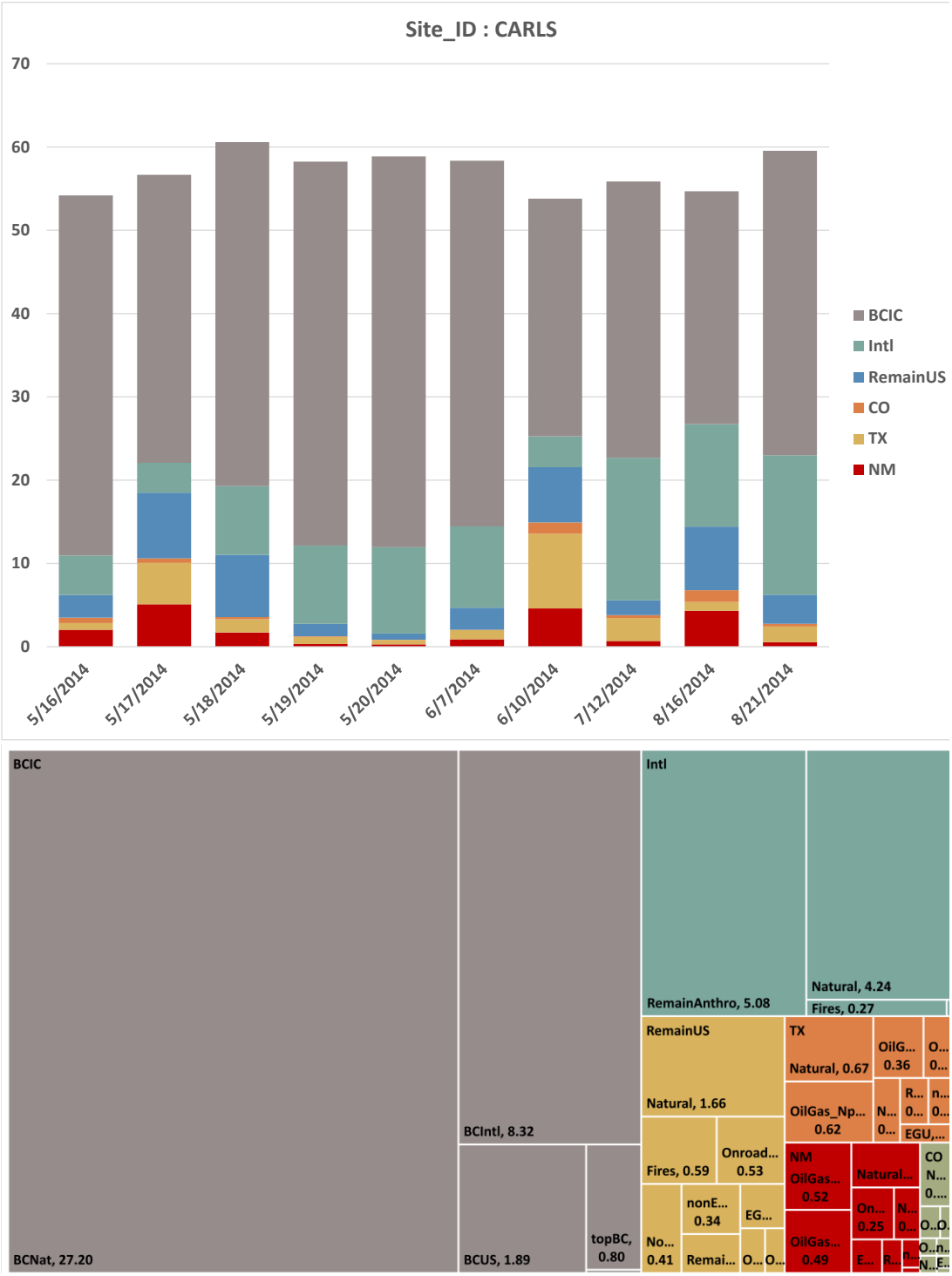


Figure 10-33. Contributions of all Source Groups to total MDA8 ozone concentrations at Carlsbad for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

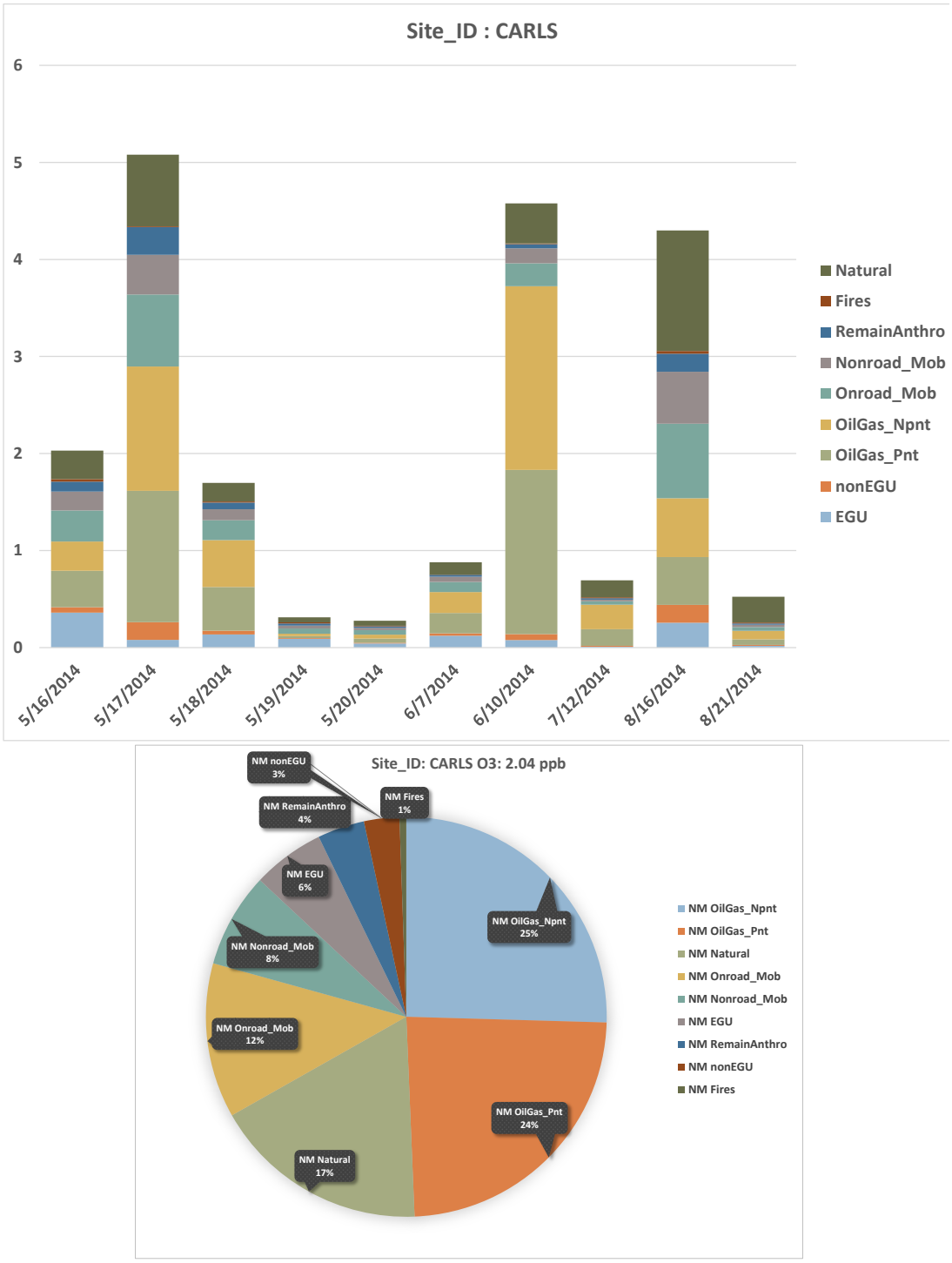


Figure 10-34. Contributions of New Mexico Source Groups to MDA8 ozone concentrations at Carlsbad for the 10 high SMAT ozone days (top) and average across the 10 SMAT days (bottom).

10.3.3 International Anthropogenic Emissions Contributions to Projected 2028 ozone DVFs

The SMAT ozone DVF projection tool was run using the CAMx 2028 O&G Control Strategy output with the contributions of international anthropogenic emissions removed. The ozone concentrations due to the BC_{Intl} and in-domain international emissions (i.e., Mexico, Canada and CMV_{Intl}) were removed from the CAMx 2028 O&G Control Strategy output and SMAT was run to obtain projected 2028 ozone DVFs without any contributions of international anthropogenic emissions. SMAT was run using three different current year ozone design values: $DVC_{2012\text{-}2016}$, $DVC_{2015\text{-}2019}$ and $DVC_{2017\text{-}2019}$ using the same procedures as used in the 2028 ozone DVF projection DVC sensitivity analysis discussed in Chapter 9. Tables 10-4 through 10-6 display the projected 2028 ozone DVFs for the 2028 O&G Control Strategy and 2028 no international anthropogenic emissions scenarios using the three sets of DVCs.

The elimination of the international anthropogenic emissions reduces the projected 2028 ozone DVFs by 13 to 25 ppb with the smallest reductions at the northern and largest reductions at the southern sites in New Mexico. For all DVC scenarios, the projected 2028 ozone DVFs at all monitoring sites in New Mexico are below the 2015 70 ppb ozone NAAQS when ozone contributions due to international anthropogenic emissions are removed. The highest projected 2028 ozone DVF under the no international anthropogenic emissions scenario is 52.8 ppb at the Carlsbad monitoring site when the $DVC_{2017\text{-}2019}$ current year design value is used in the 2028 ozone DVF projection.

Figure 10-35 displays the spatial distribution of the current year ozone DVC and the projected 2028 ozone DVF for the 2028 O&G Control Strategy using the SMAT UAA tool and the three definitions of DVCs. Using the $DVC_{2012\text{-}2016}$ and $DVC_{2015\text{-}2019}$, the SMAT projected 2028 ozone DVFs are all below the 2015 ozone NAAQS under the 2028 O&G Control Strategy emissions scenario. However, when the $DVC_{2017\text{-}2019}$ is used, the SMAT UAA estimates projected 2028 ozone DVFs in excess of the 2015 ozone NAAQS across all of Eddy County in southeast New Mexico.

The spatial distribution of the projected 2028 ozone DVF with no international anthropogenic emissions and its differences with the 2028 O&G Control Strategy 2028 ozone DVF using the three DVC definitions are shown in Figure 10-36. The removal of the international anthropogenic emission contributions reduces the 2028 ozone DVFs in New Mexico by 10-30 ppb. The highest 2028 ozone DVF in the 4-km New Mexico domain are 52.5, 55.2 and 56.4 ppb for the, respectively, $DVC_{2012\text{-}2016}$, $DVC_{2015\text{-}2019}$ and $DVC_{2017\text{-}2019}$ current year design value sensitivity scenarios, which are well below the 2015 70 ppb ozone NAAQS.

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Table 10-4. Projected 2028 ozone DVFs for the 2028 O&G Control Strategy (2028OGCS) and 2028 no international anthropogenic emissions (2028INTL) scenarios using the $DVC_{2012\text{-}2016}$ current year ozone DVC.

AQS_ID	2012-16 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name	County
350010023	66.3	60.7	47.2	-13.5	Del Norte HS	Bernalillo
350010024	68.0	62.0	48.5	-13.5	South East Heights	Bernalillo
350010029	66.0	60.5	47.1	-13.4	South Valley	Bernalillo
350010032	67.0	62.1	48.5	-13.6	Westside	Bernalillo
350011012	65.0	58.8	45.7	-13.1	Foothills	Bernalillo
350130008	66.3	59.8	39.9	-19.9	La Union	Doña Ana
350130017	67.0	61.8	38.4	-23.4	Sunland Park	Doña Ana
350130020	67.0	62.2	39.6	-22.6	Chaparral	Doña Ana
350130021	72.0	66.8	42.6	-24.2	Desert View	Doña Ana
350130022	71.3	66.0	42.2	-23.8	Santa Teresa	Doña Ana
350130023	65.0	60.2	41.5	-18.7	Solano	Doña Ana
350151005	69.0	66.4	46.1	-20.3	Carlsbad	Eddy
350171003	62.0	58.9	43.0	-15.9	Chino Copper Smelt	Grant
350250008	66.0	63.3	44.9	-18.4	Hobbs Jefferson	Lea
350290003	66.0	62.5	43.3	-19.2	Deming Airport	Luna
350390026	64.0	60.0	47.4	-12.6	Coyote Ranger Dist	Rio Arriba
350431001	64.0	58.1	44.4	-13.7	Bernalillo (E Avenida)	Sandoval
350450009	64.3	60.2	46.4	-13.8	Bloomfield	San Juan
350450018	67.0	63.3	50.2	-13.1	Navajo Lake	San Juan
350451005	63.7	59.6	48.5	-11.1	Substation	San Juan
350490021	64.3	60.4	47.9	-12.5	Santa Fe Airport	Santa Fe
350610008	66.3	62.0	47.5	-14.5	Los Lunas (Los Lentes)	Valencia

Table 10-5. Projected 2028 ozone DVFs for the 2028 O&G Control Strategy (2028OGCS) and 2028 no international anthropogenic emissions (2028INTL) scenarios using the $DVC_{2015\text{-}2019}$ current year ozone DVC.

AQS_ID	2015-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name	County
350010023	69.0	63.1	49.2	-13.9	Del Norte HS	Bernalillo
350010029	66.0	60.5	47.1	-13.4	South Valley	Bernalillo
350011012	69.0	62.4	48.5	-13.9	Foothills	Bernalillo
350130008	68.7	62.0	41.3	-20.7	La Union	Doña Ana
350130020	70.7	65.7	41.8	-23.9	Chaparral	Doña Ana
350130021	74.3	68.9	43.9	-25.0	Desert View	Doña Ana
350130022	74.0	68.5	43.8	-24.7	Santa Teresa	Doña Ana
350130023	67.7	62.7	43.3	-19.4	Solano	Doña Ana
350151005	73.7	70.9	49.2	-21.7	Carlsbad	Eddy
350153001	71.0	69.3	44.1	-25.2	Carlsbad NP	Eddy
350250008	69.3	66.5	47.1	-19.4	Hobbs Jefferson	Lea
350390026	66.3	62.2	49.1	-13.1	Coyote Ranger Dist	Rio Arriba
350431001	67.0	60.9	46.5	-14.4	Bernalillo (E Avenida)	Sandoval
350450009	67.0	62.8	48.3	-14.5	Bloomfield	San Juan
350450018	69.0	65.2	51.7	-13.5	Navajo Lake	San Juan
350451005	67.3	62.9	51.2	-11.7	Substation	San Juan
350490021	65.0	61.0	48.4	-12.6	Santa Fe Airport	Santa Fe
350610008	66.7	62.3	47.8	-14.5	Los Lunas (Los Lentes)	Valencia

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Table 10-6. Projected 2028 ozone DVFs for the 2028 O&G Control Strategy (2028OGCS) and 2028 no international anthropogenic emissions (2028INTL) scenarios using the $DVC_{2017\text{-}2019}$ current year ozone DVC.

AQS_ID	2017-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name	County
350010023	70.0	64.0	49.9	-14.1	Del Norte HS	Bernalillo
350010029	67.0	61.4	47.8	-13.6	South Valley	Bernalillo
350011012	71.0	64.2	49.9	-14.3	Foothills	Bernalillo
350130008	70.0	63.2	42.1	-21.1	La Union	Doña Ana
350130020	73.0	67.8	43.1	-24.7	Chaparral	Doña Ana
350130021	77.0	71.4	45.5	-25.9	Desert View	Doña Ana
350130022	76.0	70.3	45.0	-25.3	Santa Teresa	Doña Ana
350130023	70.0	64.8	44.7	-20.1	Solano	Doña Ana
350151005	79.0	76.0	52.8	-23.2	Carlsbad	Eddy
350250008	71.0	68.1	48.3	-19.8	Hobbs Jefferson	Lea
350390026	67.0	62.8	49.6	-13.2	Coyote Ranger Dist	Rio Arriba
350431001	68.0	61.8	47.2	-14.6	Bernalillo (E Avenida)	Sandoval
350450009	68.0	63.7	49.1	-14.6	Bloomfield	San Juan
350450018	69.0	65.2	51.7	-13.5	Navajo Lake	San Juan
350451005	69.0	64.5	52.5	-12.0	Substation	San Juan
350490021	66.0	62.0	49.1	-12.9	Santa Fe Airport	Santa Fe
350610008	68.0	63.5	48.7	-14.8	Los Lunas (Los Lentes)	Valencia

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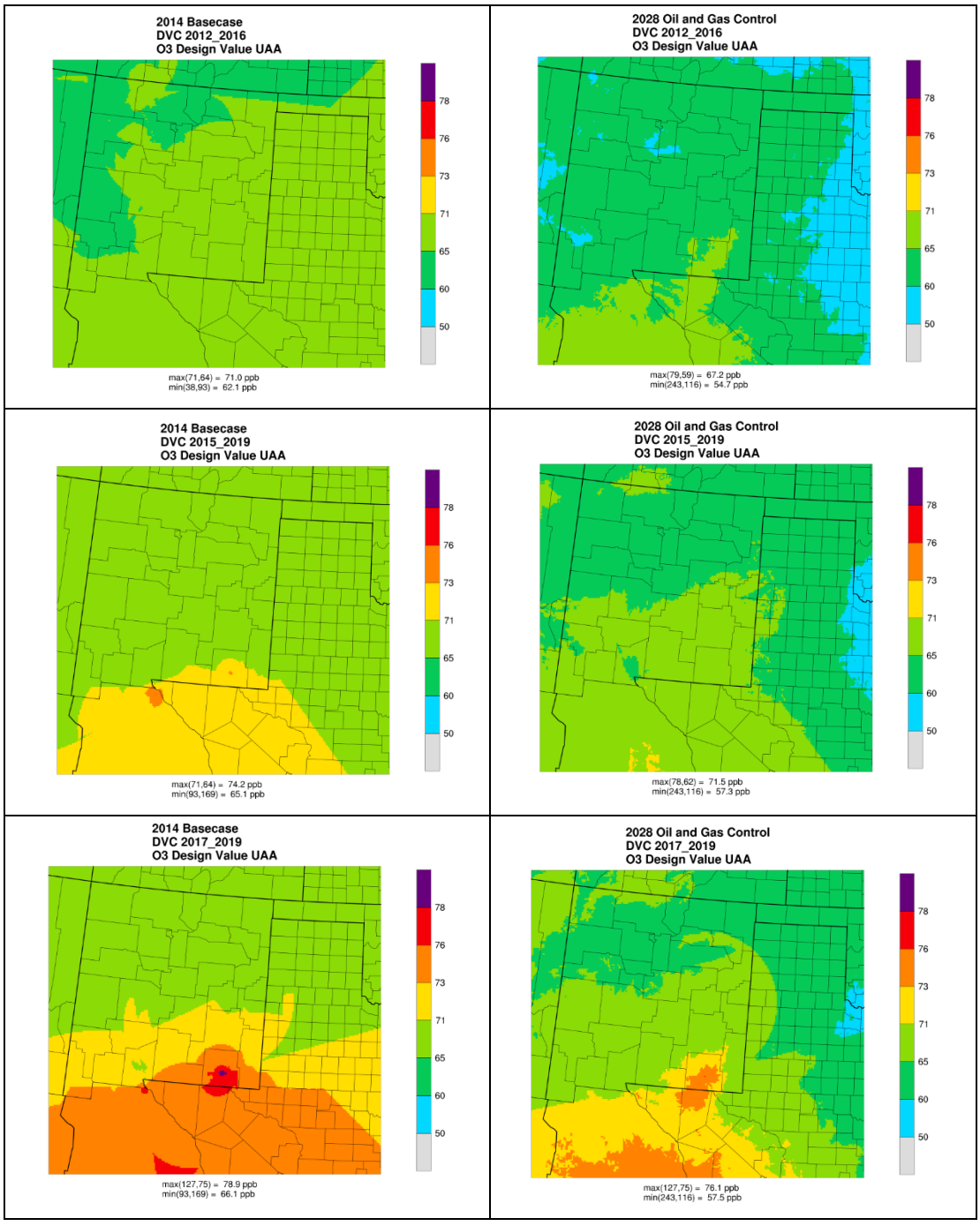


Figure 10-35. SMAT UAA ozone design values (ppb) for the current year ozone DVC (left) and projected 2028 ozone DVF for the 2028 O&G Control Strategy (right) using current year DVCs based on 2012-2016 (top), 2015-2019 (middle) and 2017-2019 (bottom) ozone design values.

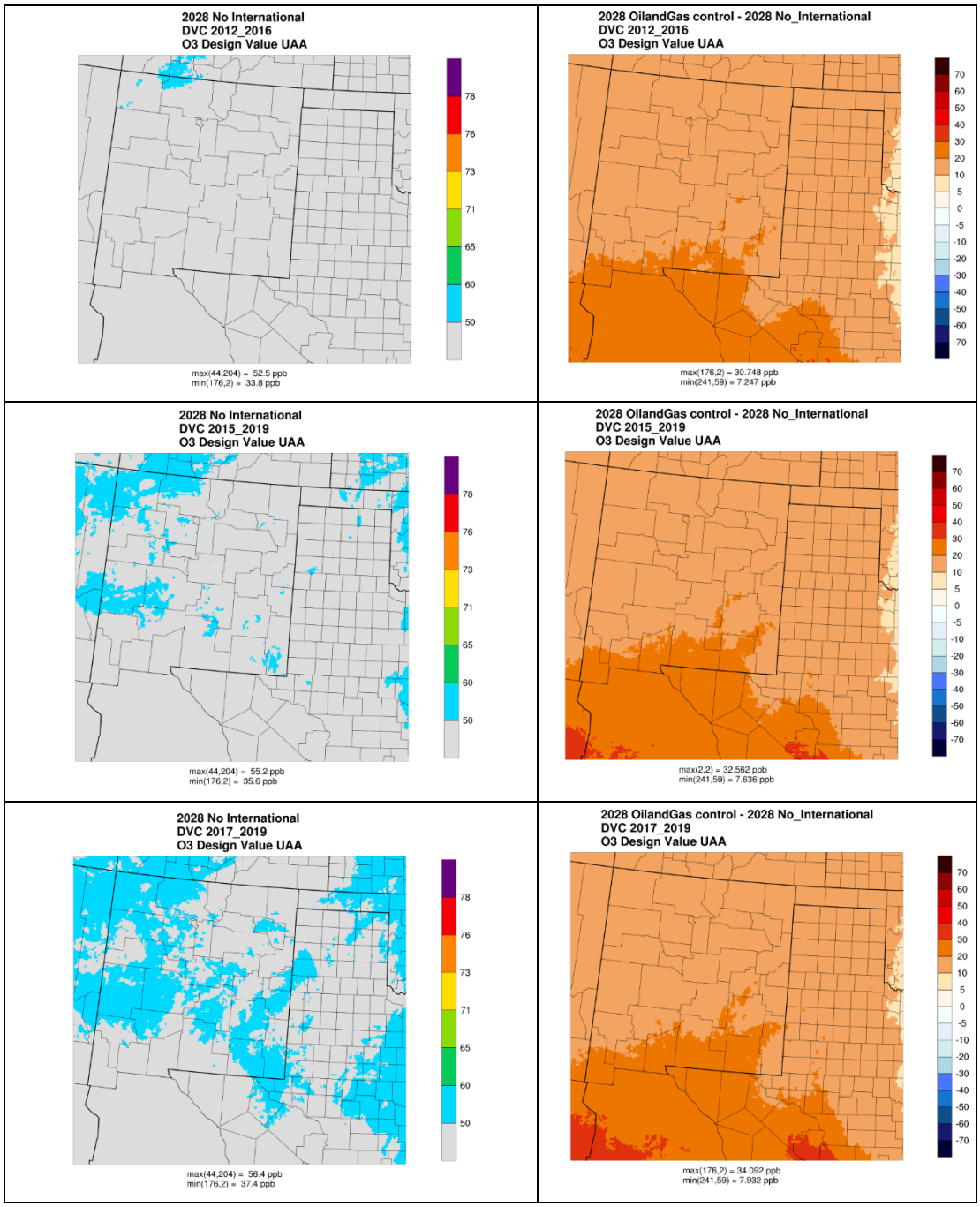


Figure 10-36. SMAT UAA ozone design values (ppb) for the projected 2028 ozone DVF from the 2028 No International Anthropogenic Emissions scenario (left) and differences in 2028 ozone DVFs between the 2028 No International Emissions and 2028 O&G Control Strategy scenarios (right) using current year DVCs based on 2012-2016 (top), 2015-2019 (middle) and 2017-2019 (bottom) ozone design values.

11. 2028 VOC AND NOX SENSITIVITY OSAT OZONE SOURCE APPORTIONMENT MODELING

A second CAMx 2028 ozone source apportionment model simulation was performed to estimate whether ozone formation that leads to elevated ozone concentrations in New Mexico occurs under conditions that are more sensitive to VOC or NO_x emissions. The VOC/NO_x emissions sensitivity ozone source apportionment simulation used the Ozone Source Apportionment Technology (OSAT) version of the CAMx ozone source apportionment tools. As discussed in Section 10.1, when using OSAT, the relative amounts of the O3V and O3N ozone source apportionment tracers provide an indication of whether ozone formation is more sensitive to VOC or NO_x emissions.

11.1 2028 OSAT Ozone Source Apportionment Design

The CAMx 2028 OSAT VOC/ NO_x sensitivity ozone source apportionment simulation used the 36/12/4-km nested domain structure, summer of 2014 meteorology and the 2028 O&G Control Strategy emissions scenario. The same five Source Regions as used in the 2028 Source Sector APCA ozone source apportionment simulation were used (See Figure 10-1):

1. New Mexico;
2. Texas;
3. Colorado;
4. Remainder U.S. states plus coastal water out to 200 nautical miles (nmi) of the U.S. coast; and
5. International, which include Mexico, Canada and waters off their coasts, plus waters more than 200 nmi off the U.S. coast.

Three Source Categories were specified in the 2028 OSAT ozone source apportionment modeling:

1. Anthropogenic emissions;
2. Fires; and
3. Natural emissions.

Fires include U.S. wildfires (WF), wildland prescribed burns (Rx) and agricultural burning (Ag), and other fires from Mexico and Canada. Natural emissions include biogenic, lightning NO_x (LNO_x), windblown dust (WBD) and oceanic (sea salt and DMS) sources.

With 5 Source Regions and 3 Source Categories, plus separate Source Groups for Initial Concentrations (IC) and Boundary Conditions (BC), that results in a total of 17 Source Groups for which separate ozone source contributions will be obtained in the 2028 OSAT ozone source apportionment modeling (17 = 5 x 3 + 2).

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11.2 Spatial Distribution of VOC/NO_x Ozone Formation Sensitivity

The sensitivity of ozone formation to VOC and NO_x emissions is obtained for each of the 15 emission Source Groups that consist of emissions from 3 source categories (i.e., anthropogenic, fires and natural) emitting from 5 Source Regions. The percent contribution of NO_x sensitive ozone formation metric is used to display the ozone formation sensitivity that is defined as follows:

$$\text{Percent } NO_x \text{ Sensitive Ozone (\%NOxSens)} = 100 \times \sum O3N_i \,/\, \sum (O3V_i + O3N_i)$$

Where the sum is performed over the 15 different emissions Source Groups (i) that consist of the three emission Source Categories emitting from the 5 Source Regions. The Percent VOC Sensitive Ozone will be 100 minus the Percent NO_x Sensitive Ozone metric.

Note that the O3V and O3N tracers for the IC and BC Source Groups are not used in the Percent NO_x Sensitive Ozone metric since they were defined from the 2014 simulation of the 2014 GEOS-Chem global chemistry model and the CAMx GEOS2CAMx processor arbitrarily assigns half of the GEOS-Chem total ozone to the O3V and O3N tracers each so do they not have accurate information on whether such IC/BC ozone concentrations are more VOC or NO_x sensitive.

Spatial displays of the Percent NO_x Sensitive Ozone metric were generated for Maximum Daily Average 8-hour (MDA8) ozone concentrations and several combinations of Source Groups for each day of the May-August 2014 modeling episode. When presenting the Percent NO_x Sensitive Ozone metric for a combination of Source Groups, it is also important to know the total MDA8 ozone due to the same combination of Source Groups in order to interpret the significance of the %NOxSens metric; if the MDA8 ozone concentrations due to the combination of Source Groups is very small (e.g., < 0.01 ppb), whether the ozone formed was more sensitive to VOC or NO_x emissions is inconsequential. Spatial maps across the New Mexico 4-km modeling domains were generated for total MDA8 ozone and Percent NO_x Sensitive Ozone for the following combinations of Source Groups:

- All emissions based Source Groups (i.e., anthropogenic, fires and natural emissions emitted from the 5 Source Regions in the CAMx modeling domain).
- All anthropogenic emissions based Source Groups across the CAMx modeling domain.
- The New Mexico anthropogenic emissions Source Group.

The Percent NO_x Sensitive Ozone for the New Mexico anthropogenic emissions Source Group provides information on whether New Mexico VOC or NO_x emissions may be more important to ozone formation.

Figures 11-1 through 11-8 display the total MDA8 ozone and Percent NO_x Sensitive ozone metric for eight example days during the episode that tended to have relatively higher ozone concentrations and included the six example days displayed in previous Chapters.

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11.2.1 Percent NO_x Sensitive Ozone on May 17, 2014

Figure 11-1 displays the 2028 OSAT source apportionment results for the May 17, 2014 day that was dominated by ozone concentrations from a fire in eastern Arizona that caused modeled elevated ozone concentrations in southwestern New Mexico. Figure 11-1a displays the MDA8 ozone concentrations from all Source Groups, including IC/BC, and is the modeled total MDA8 ozone on this day. The modeled peak MDA8 ozone on May 17th is 129 ppb and occurs within the fire ozone plume in eastern Arizona. The Percent NO_x Sensitive Ozone due to all emissions based source groups indicates ozone formation across the 4-km NM domain is more NO_x sensitive than VOC sensitive with the color scale going from green (%NOxSens > 65%) to red/orange (%NOxSens > 85%) (Figure 11-1b). Although, it is interesting to note that at the locations of the higher total MDA8 ozone concentrations, the amount of %NOxSens ozone is less, with the lowest value (%NOxSens = 64%) occurring at the same location as the peak modeled MDA8 ozone concentration in eastern Arizona.

Figure 11-1c and d show the MDA8 ozone and %NOxSens metric for all anthropogenic emissions on May 17th, with the anthropogenic emissions %NOxSens metric being mostly orange and red (%NOxSens > 90%), indicating mostly NO_x sensitive ozone formation. There are areas of high MDA8 ozone due to anthropogenic emissions in west Texas (peak of 23 ppb) where %NOxSens ozone is a little lower (80-90%), as well as a small area on the Colorado side of the San Juan Basin with lower %NOxSens metric. Figure 11-1e and f show the MDA8 ozone and %NOxSens metric for New Mexico anthropogenic emissions on May 17th. The highest contribution of New Mexico anthropogenic emissions to MDA8 ozone is 9 ppb and occurs in the Permian Basin with ozone formation being very NO_x sensitive (%NOxSens > 85%). The lowest New Mexico NO_x sensitive ozone is in the San Juan Basin with a minimum value of 32%, indicating a VOC sensitive ozone formation value of 68% (Figure 11-1f). The New Mexico anthropogenic emissions ozone contribution in the San Juan Basin is less than 3 ppb (Figure 11-1e).

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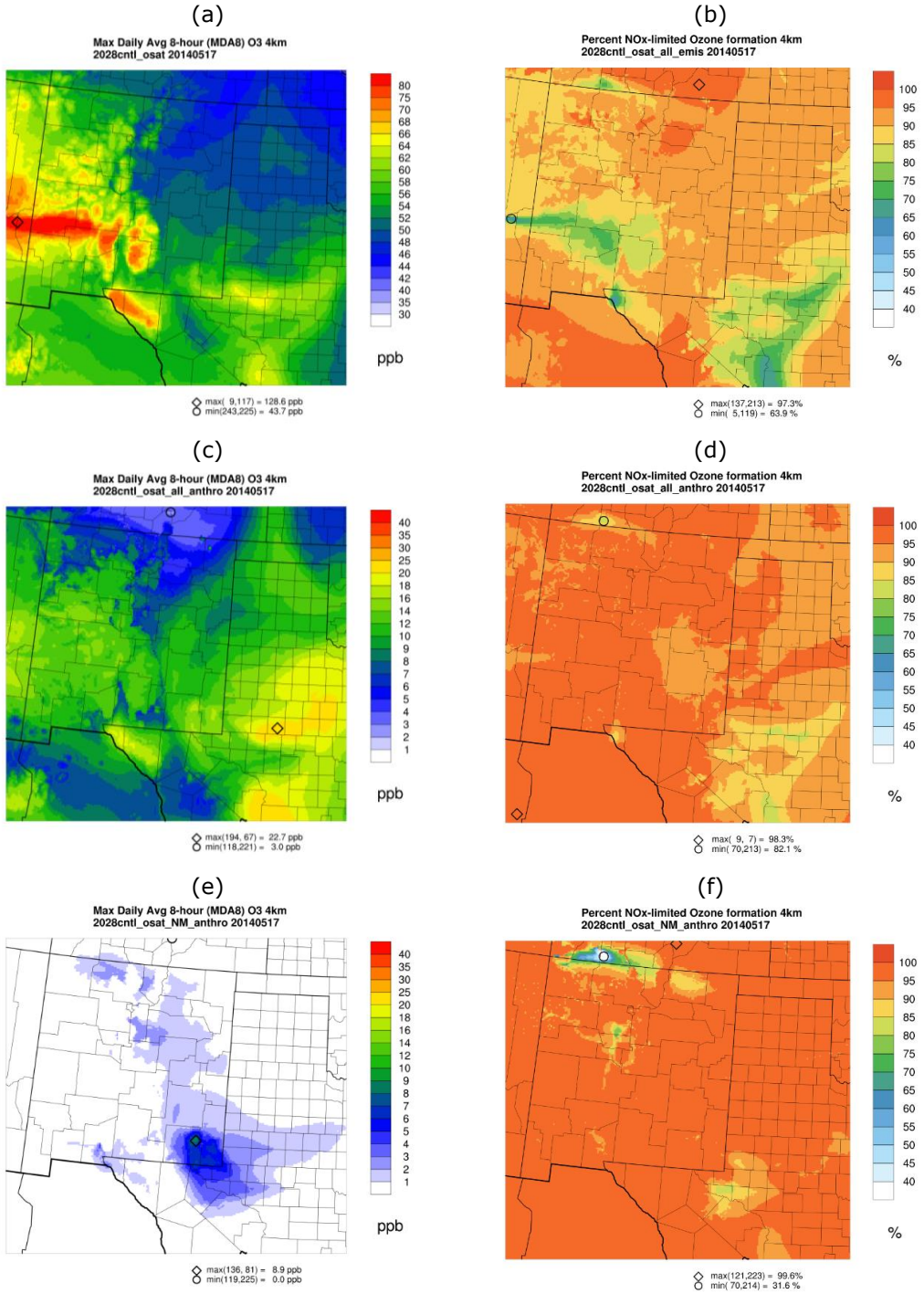


Figure 11-1. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on May 17, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

11.2.2 Percent NO_x Sensitive Ozone on May 26, 2014

On May 26th, the peak modeled MDA8 ozone concentrations is 58 ppb and occurs in San Juan County (Figure 11-2a). Ozone formation from all emissions is mostly NO_x sensitive across New Mexico (Figure 11-2b). Although the lowest %NOxSens due to all emissions on May 26 (68%) occurs at the location of the peak MDA8 ozone in San Juan County. When looking at just anthropogenic emissions, the %NOxSens ozone is mostly greater than 90% across most of New Mexico on May 26th with the exception of San Juan County and stretching south into McKinley County with a %NOxSens minimum of 69% (Figure 11-2d) occurring at the same location as the modeled 58 ppb peak. The maximum MDA8 ozone due to New Mexico anthropogenic emissions on May 26th is 7 ppb and occurs at the same location as the 58 ppb total MDA8 ozone peak in San Juan County. Ozone formation due to New Mexico emissions at the location of this MDA8 ozone peak in San Juan County is split approximately equally between VOC and NO_x sensitive ozone formation (%NOxSens = 45%; Figure 11-2f).

11.2.3 Percent NO_x Sensitive Ozone on May 28, 2014

May 28th has elevated ozone concentrations in southern New Mexico, including southern Doña Ana County and the Permian Basin, as well as within the Albuquerque urban plume (Figure 11-3a). Ozone formation across New Mexico due to anthropogenic emission tends to be mostly NO_x sensitive on May 28th with the lowest NO_x sensitive ozone of 73% occurring at almost the exact same location in southern Doña Ana County as the ozone peak (Figure 11-3b). When just looking at the sensitivity of anthropogenic emissions, the %NOxSens value at the location of the peak in southern Doña Ana County increases from 73% to 81% (Figure 11-3d). Finally, the contributions of New Mexico anthropogenic emissions to the ozone peak in southern Doña Ana County is 2-4 ppb and is very NO_x sensitive (%NOxSens > 90%) (Figure 11-3e and f). The highest MDA8 ozone due to New Mexico anthropogenic emissions on May 28th is 9 ppb in the Albuquerque urban plume where %NOxSens is slightly lower than the surrounding areas (85-90%), with the lowest New Mexico anthropogenic emissions %NOxSens being 75% in a high ozone area in the Permian Basin.

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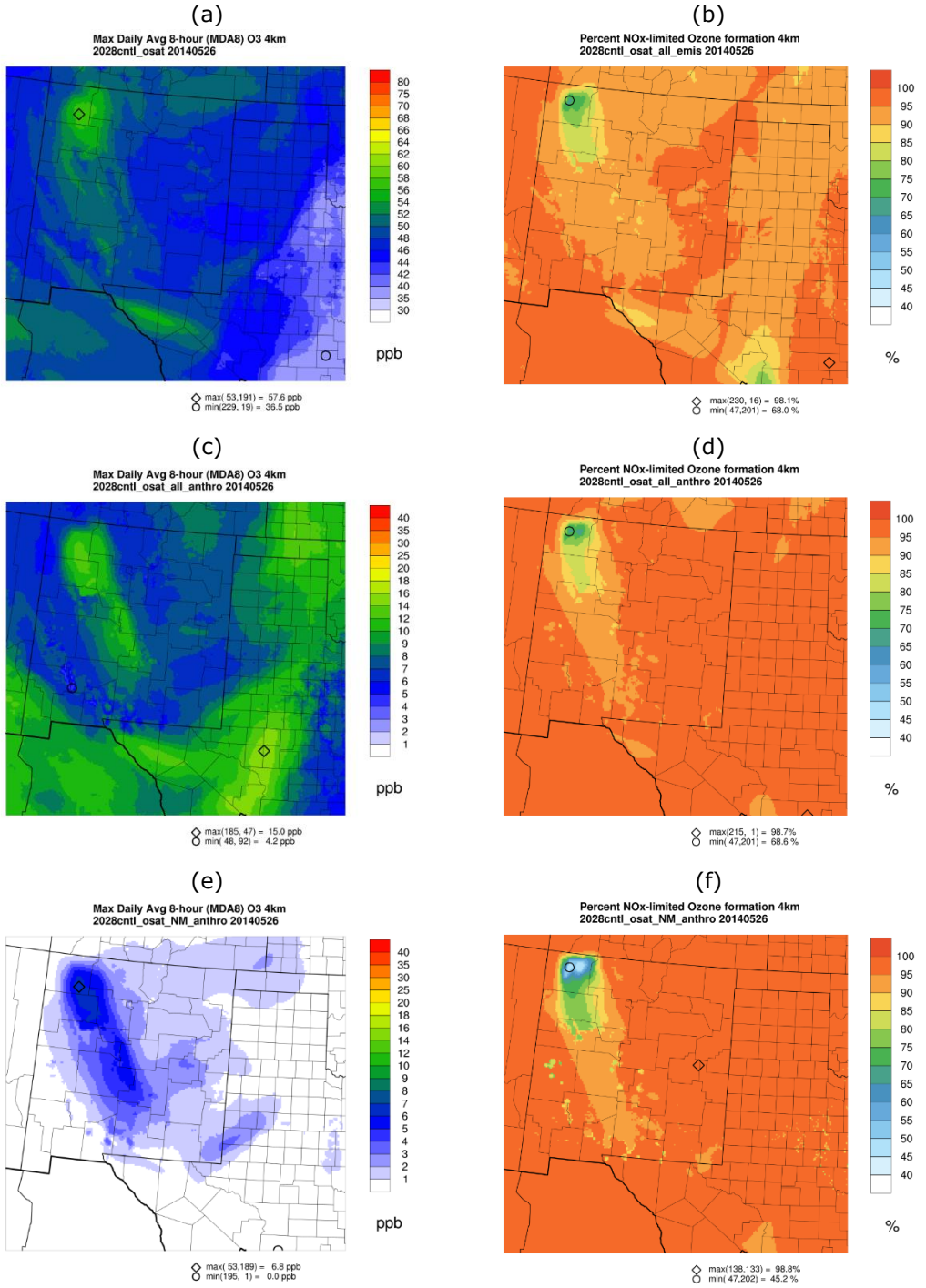


Figure 11-2. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on May 26, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

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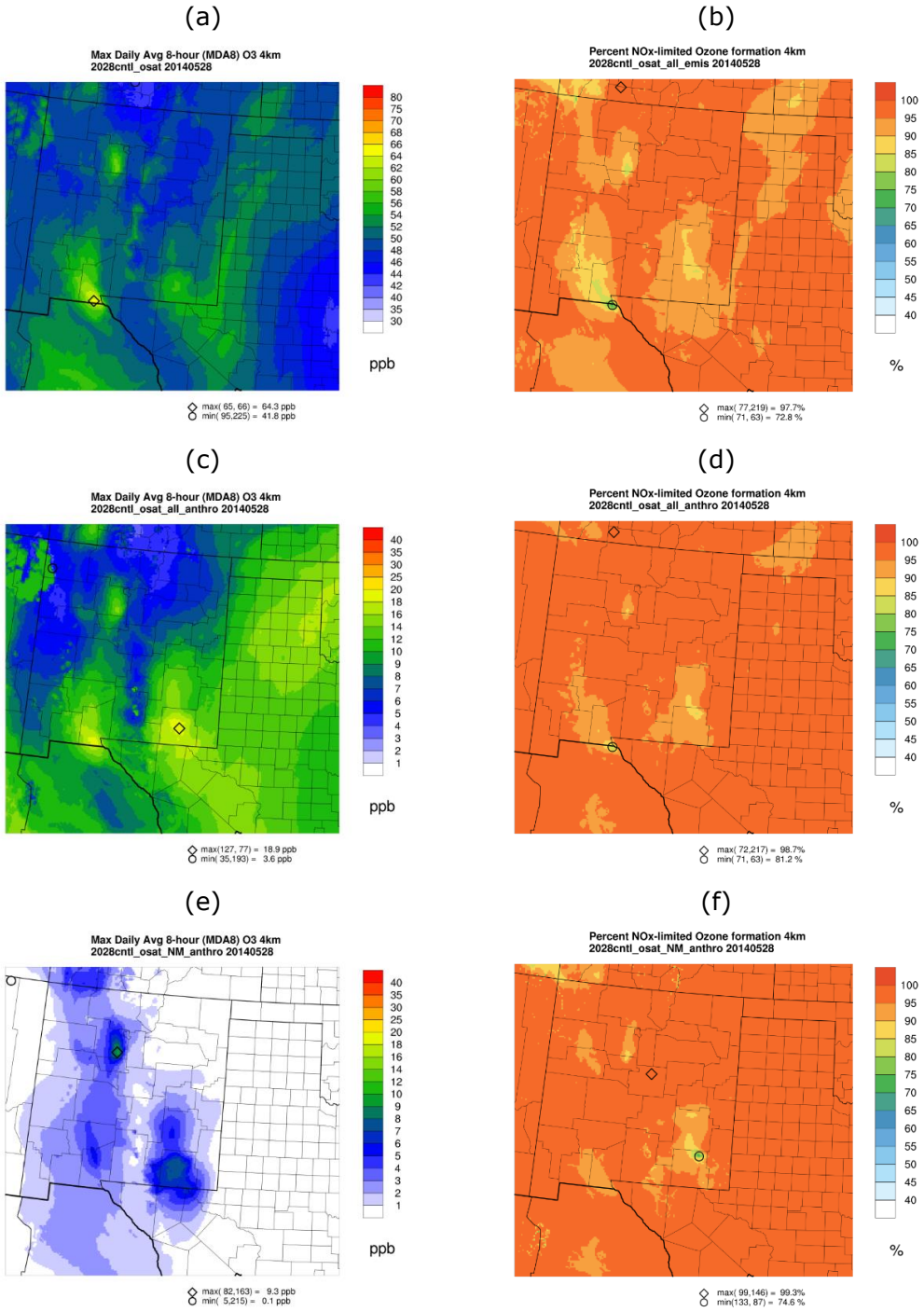


Figure 11-3. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on May 28, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions .

11.2.4 Percent NO_x Sensitive Ozone on June 5, 2014

CAMx estimates 2028 high MDA8 ozone concentrations in excess of the 70 ppb ozone NAAQS on June 5, 2014 in the San Juan Basin and El Paso (Figure 11-4a). In these high ozone locations, ozone formation is split approximately 50%/50% between VOC and NO_x sensitive ozone formation conditions (Figure 11-4b). When looking at just anthropogenic emissions, ozone formation tends to be more NO_x sensitive with %NOxSens ranging from 60-85% in El Paso and 70-85% in San Juan Basin (Figure 11-4d). Ozone from New Mexico anthropogenic emissions is mainly NO_x sensitive in El Paso on June 5th, but in the San Juan Basin there is more VOC sensitive ozone formation with New Mexico anthropogenic emissions ozone contribution ranging from 1 to 4 ppb (Figure 11-4e and f). In particular, there are large areas of blue shaded %NOxSens ozone in San Juan County due to New Mexico anthropogenic emissions that indicates that New Mexico VOC and NO_x anthropogenic emissions are equally important to ozone formation in San Juan County on this day. On the other hand, ozone formation within the Permian Basin appears to be more NO_x sensitive on June 5th.

11.2.5 Percent NO_x Sensitive Ozone on July 12, 2014

The total MDA8 ozone on July 12th has elevated ozone concentrations entering New Mexico from the south that appears to have originated in Mexico (Figure 11-5a). Ozone formation from anthropogenic emissions on this day is estimated to occur primarily under NO_x sensitive conditions (%NOxSens of 86% to 100%; Figure 11-5d). Ozone formation from New Mexico anthropogenic emissions is primarily NO_x sensitive on July 12th with a relative larger amount of VOC sensitive ozone in the south where elevated ozone concentrations occur, but New Mexico's anthropogenic emissions ozone contribution is less than 1 ppb (Figure 11-5e and f).

11.2.6 Percent NO_x Sensitive Ozone on July 24, 2014

On July 24th, the peak MDA8 ozone in the 4-km domain is above the NAAQS (71.1 ppb) and occurs in San Juan County (Figure 11-6a). Although ozone formation is primarily NO_x sensitive across the 4-km NM domain, the largest VOC sensitive ozone due to all emissions (23% or %NOxSens = 77%) occurs at the location of the peak ozone in San Juan County (Figure 11-6b). However, the amount of VOC sensitive ozone at this location due to anthropogenic emissions is 13% (Figure 11-6d), and less than that (~10%) for anthropogenic emission from New Mexico (Figure 11-6f).

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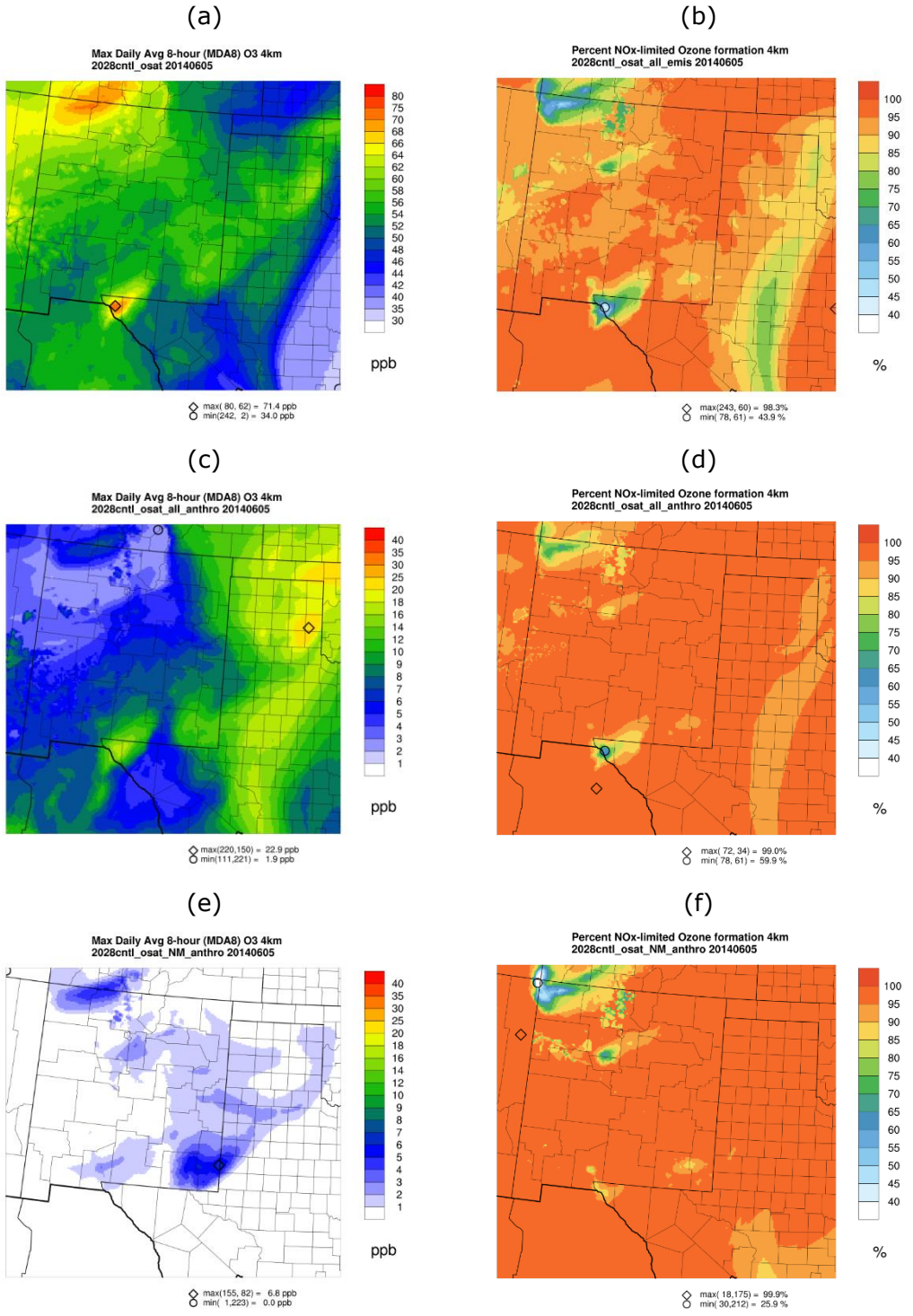


Figure 11-4. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on June 5, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions .

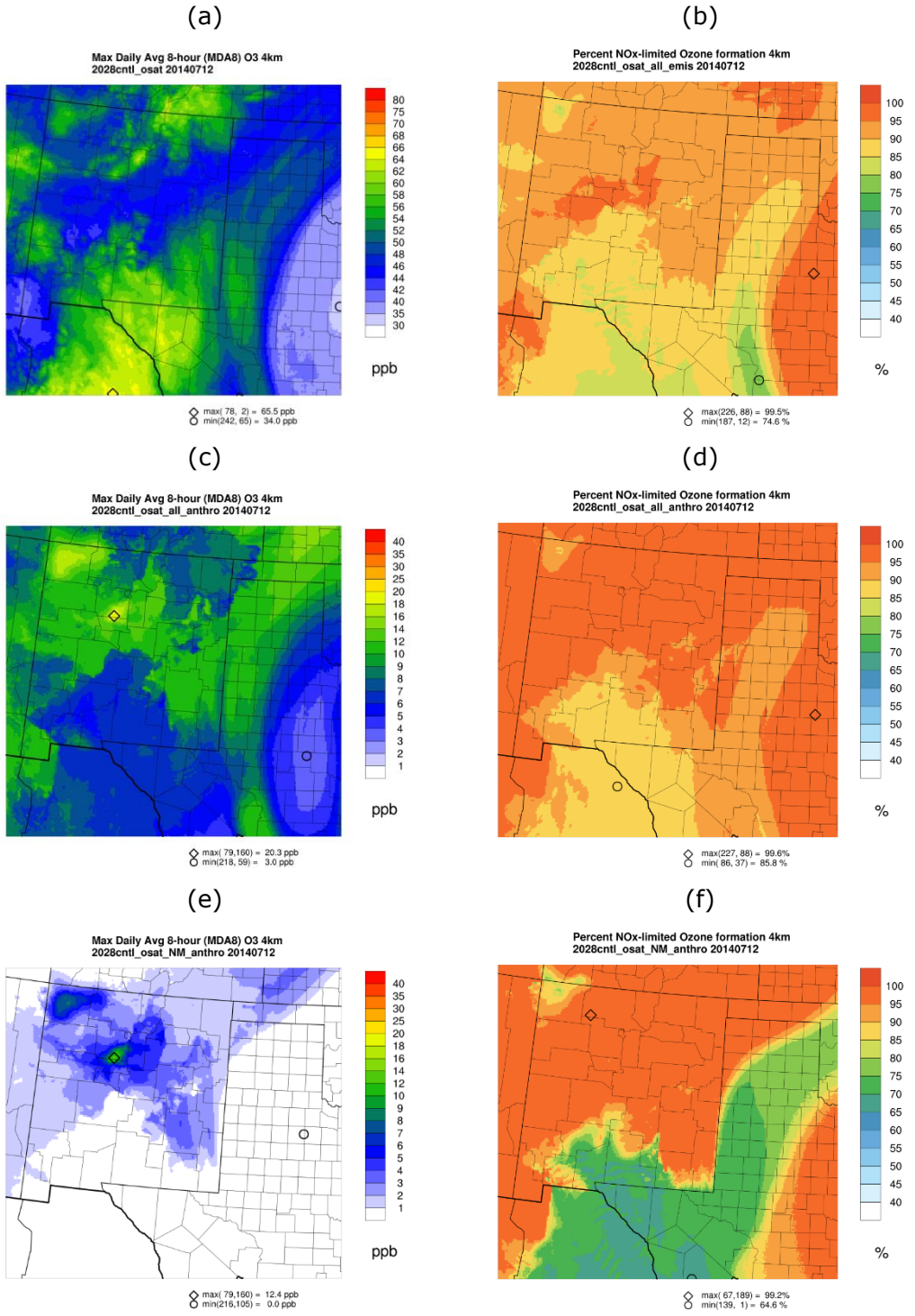


Figure 11-5. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on July 12, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

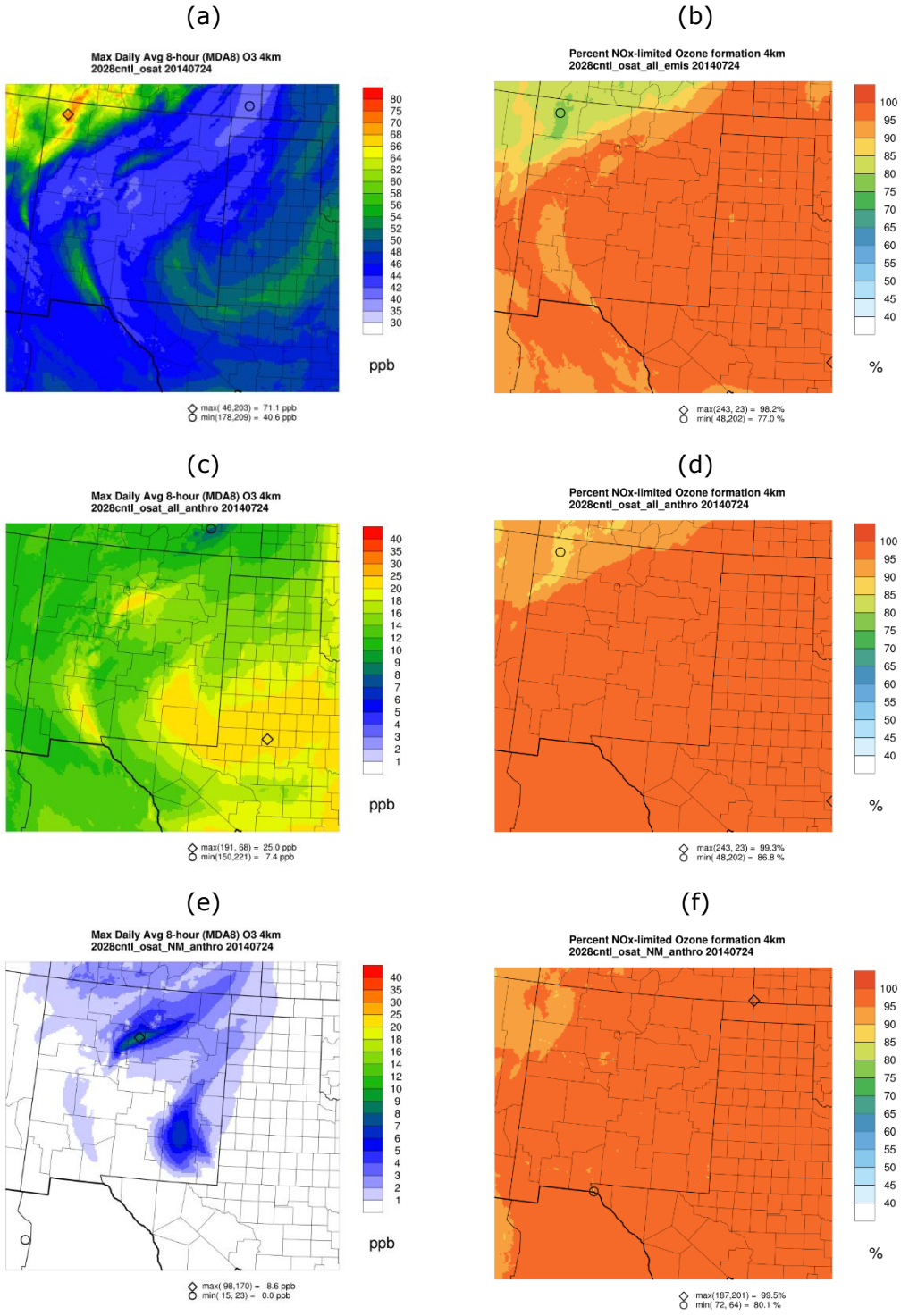


Figure 11-6. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on July 24, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

11.2.7 Percent NO_x Sensitive Ozone on July 26, 2014

Modeled elevated MDA8 ozone concentrations occur in northern New Mexico on July 26th with a maximum value above the NAAQS (72 ppb) in northeast Cibola County, west of Albuquerque (Figure 11-7a). Ozone formation is primarily NO_x sensitive across northern New Mexico on this day (%NOxSens > 85%) with the lowest NO_x sensitivity occurring at the location of the 72 ppb ozone peak in Cibola County (78%; Figure 11-7b). However, the NO_x sensitive ozone formation due to anthropogenic emissions at this location is 88% (Figure 11-7d) with a similar value estimated for anthropogenic emission from New Mexico (Figure 11-7f). New Mexico anthropogenic emissions contribute a significant amount (14 ppb) of the 72 ppb ozone peak in northeast Cibola County (Figure 11-7e). Ozone formation due to New Mexico anthropogenic emissions in the San Juan Basin is more VOC sensitive than the rest of New Mexico on July 26th.

11.2.8 Percent NO_x Sensitive Ozone on August 14, 2014

On August 14th there is modeled elevated MDA8 ozone concentrations in northern Rio Arriba County in the San Juan Basin as well as in southern New Mexico with a peak MDA8 ozone in the 4-km domain of 71.2 ppb in El Paso (Figure 11-8a). Although ozone formation is primarily (85-95%) NO_x sensitive across New Mexico on this day, at the locations of the highest MDA8 ozone concentrations, there is relatively more VOC sensitive ozone formation (Figure 11-8b). At the location of the 71.2 ppb ozone peak in El Paso, the CAMx OSAT simulation estimates that ozone formation due to anthropogenic emissions is ~75% NO_x sensitive and ~25% VOC sensitive. Anthropogenic emissions from New Mexico contribute approximately 1 ppb to the ozone peak in El Paso that is primarily formed under NO_x sensitive conditions (Figure 11-8e and f).

11.2.9 Percent NO_x Sensitive Ozone due to New Mexico Anthropogenic Emissions

Figure 11-9 displays the spatial distribution of the Percent NO_x Sensitive Ozone metric due to New Mexico anthropogenic emissions for 15 example days from the May-August 2014 modeling episode, including the 8 days discussed above. As expected, given its mostly rural nature, the CAMx OSAT simulations estimates that ozone formation due to New Mexico anthropogenic emissions is primarily NO_x sensitive. However, there are several locations where ozone formation is estimated to have relatively higher VOC sensitive ozone formation conditions. The San Juan Basin consistently has higher VOC sensitive ozone formation conditions due to New Mexico anthropogenic emissions. Albuquerque also has higher VOC sensitive ozone formation conditions due to New Mexico anthropogenic emissions, and occasionally, ozone formation in the Permian Basin also has relatively higher VOC sensitive ozone formation. As discussed above, the highest MDA8 ozone conditions also have relatively higher VOC sensitive ozone formation conditions. For example, at the location of the relatively high (58 ppb) MDA8 ozone in San Juan County on May 26th the fraction of VOC sensitive ozone is 32% for all emissions, 31% for all anthropogenic emissions and 55% for New Mexico anthropogenic emissions (Figure 11-2). On May 28th the high ozone (64 ppb) in southern Dona Ana County on the border with Texas has a Percent VOC Sensitive Ozone of 27% for all emissions and 19% for all anthropogenic emissions with New Mexico anthropogenic emissions having Percent VOC

Sensitive Ozone for a secondary peak in the Permian Basin of 25% (Figure 11-3). June 5th is a day where there is high MDA8 ozone in the San Juan and Rio Arriba Counties that is approaching the NAAQS that is split approximately equally between VOC and NO_X sensitive ozone (Figure 11-4). On August 14th the modeled ozone peak exceeds the ozone NAAQS in El Paso and ~30% of the ozone was formed under VOC sensitive conditions (Figure 11-8).

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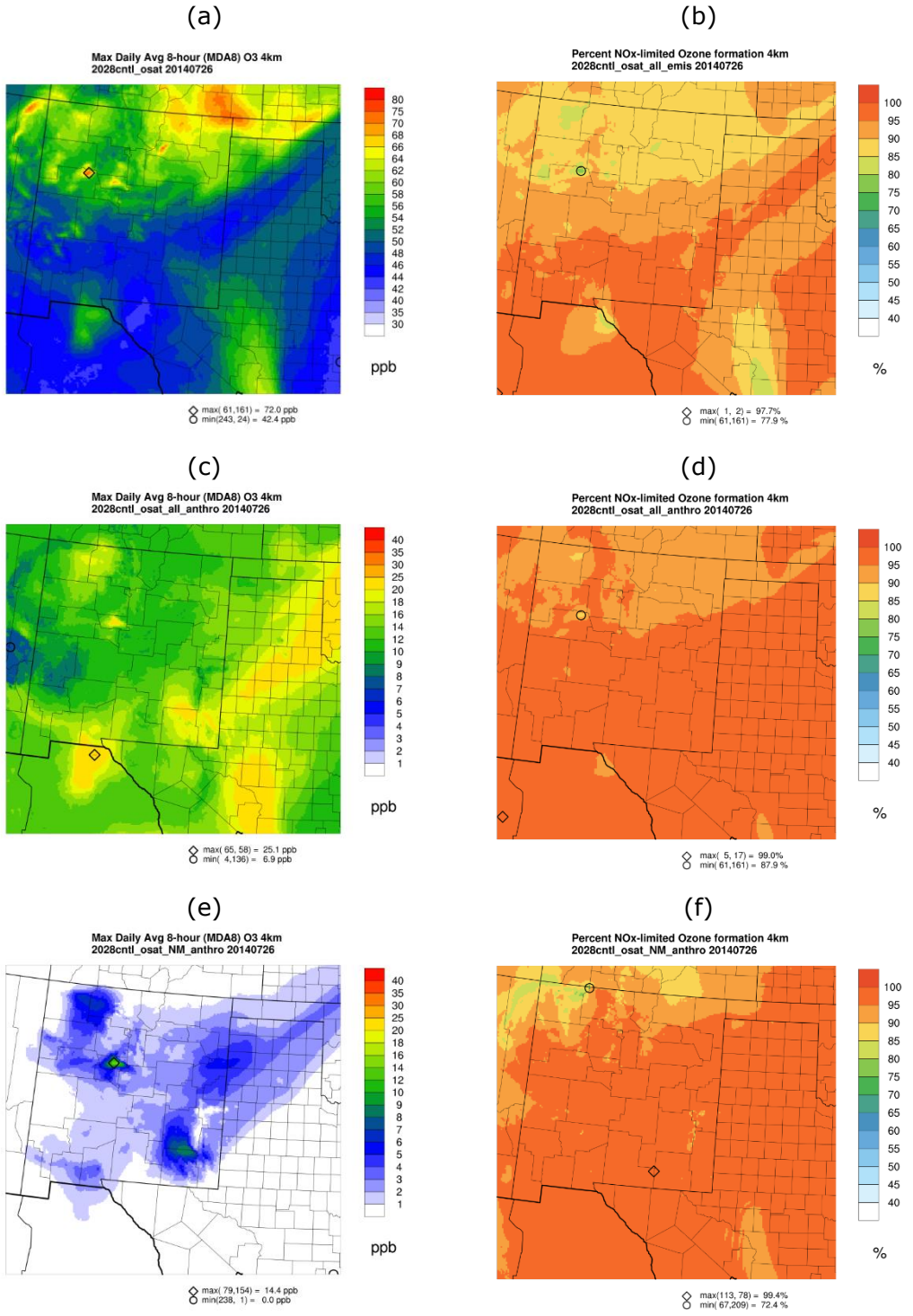


Figure 11-7. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on July 26, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

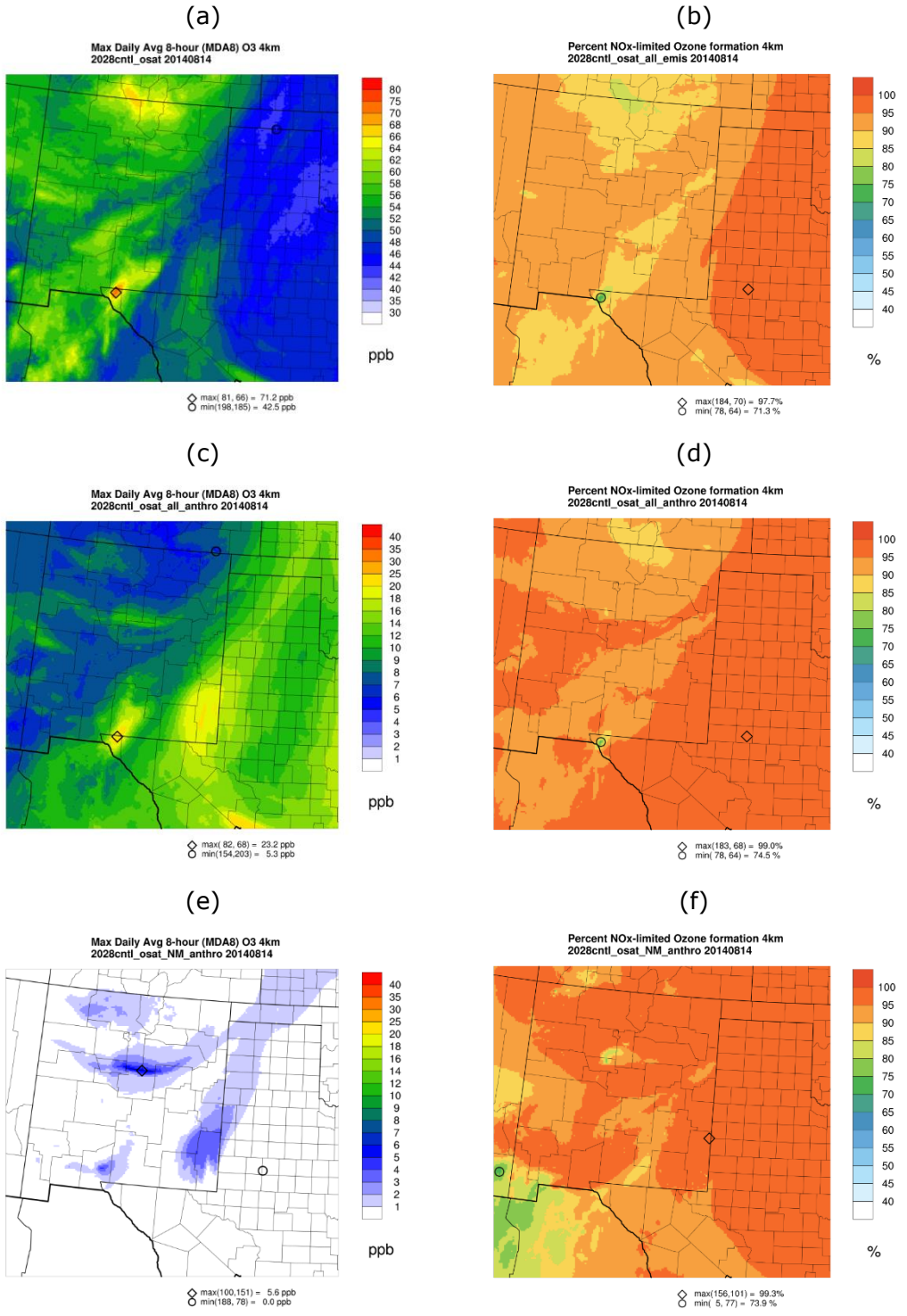


Figure 11-8. 2028 MDA8 ozone (left) and Percent NO_X Sensitive Ozone (right) on August 14, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

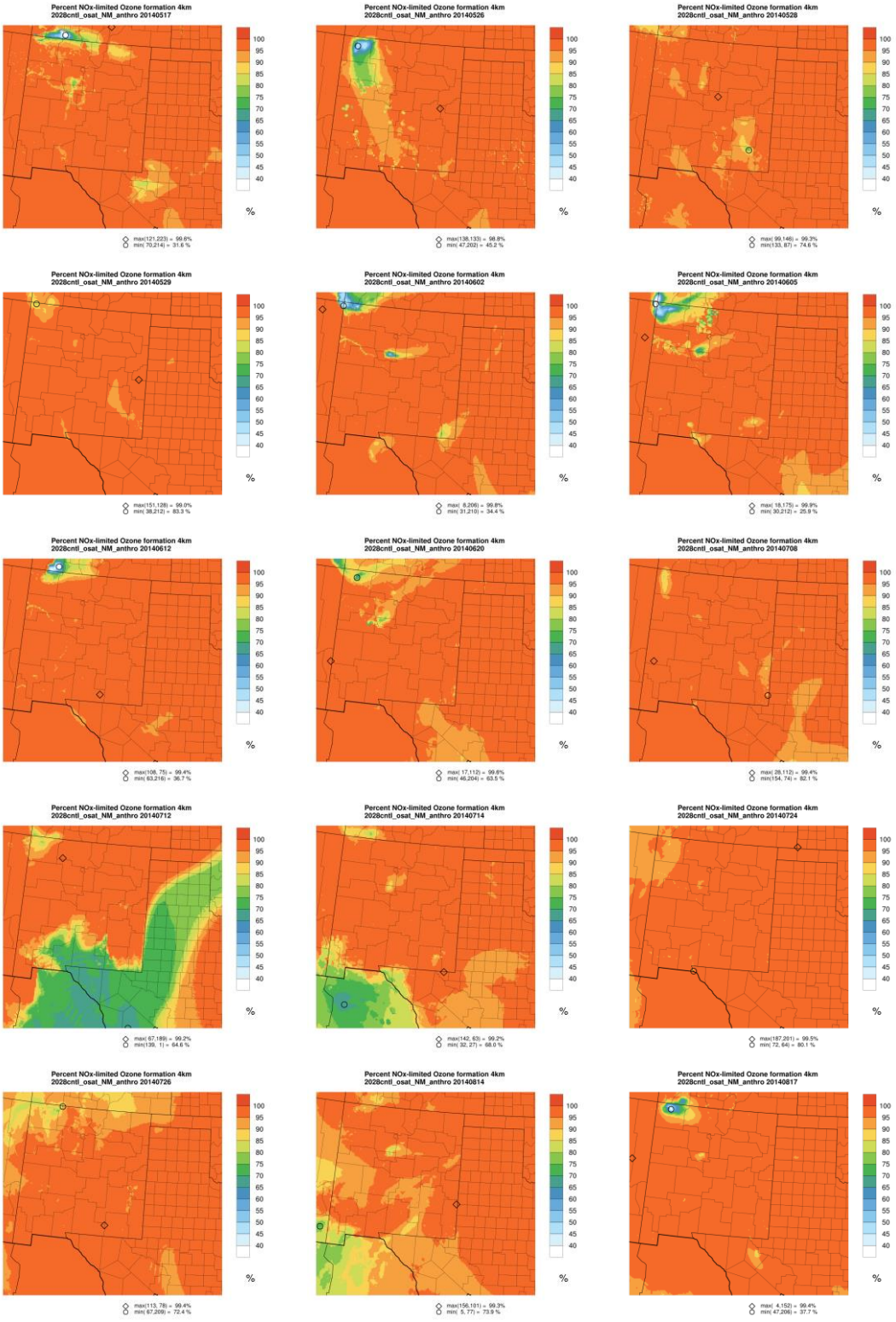


Figure 11-9. Spatial distribution of Percent NO_x Sensitive Ozone due to New Mexico anthropogenic emissions across the 4-km New Mexico domain for 15 days of relatively higher MDA8 ozone concentrations.

11.3 Analysis of VOC/NOx Ozone Formation Sensitivity at Monitoring Sites in New Mexico

The CAMx 2028 OSAT ozone source apportionment results were extracted at the locations of the New Mexico monitoring sites and loaded into an Excel Dashboard where the source apportionment contributions to daily MDA8 ozone concentrations can be visualized. The Dashboard displays the OSAT source apportionment O3V and O3N results for groups of 10 days and the average across the 10 days for different combinations of the 3 Source Categories and 5 Source regions within the CAMx modeling domain, with examples for several monitoring sites discussed below.

11.3.1 VOC/NO_x Sensitivity at Substation in San Juan County

Figure 11-10 displays the CAMx OSAT results at the Substation site in San Juan County using daily stacked bar charts of O3V and O3N for the 10 days used by SMAT to make the 2028 ozone DVF projections, along with a pie chart of the O3V and O3N results averaged across the 10 SMAT days. The Dashboard can also display results for the highest and second highest 10 modeled MDA8 ozone concentration days from the CAMx 2028 O&G Control Strategy simulation. As discussed in Chapter 7, the 10 SMAT days are selected as the 10 days with the highest modeled MDA8 ozone near the monitor in the CAMx 2014v2 Base Case, so there is a lot of overlap in days between the 10 SMAT days and the 10 highest modeled 2028 MDA8 ozone days.

The displays in Figure 11-10 use warmer colors (e.g., red) for the NO_x sensitive ozone O3N and cooler colors (e.g., blue) for the VOC sensitive ozone O3V. Emissions within the CAMx domain contribute from 6 to 36 ppb to the total MDA8 ozone across the 10 SMAT days at Substation, with a vast majority of the ozone formed being NO_x sensitive, whose daily variation ranges from approximately 70% to 90% of the SMAT 10 days daily MDA8 ozone concentrations due to emissions (Figure 11-10, top). Averaged across the 10 SMAT days, the total MDA8 ozone at Substation is 63.7 ppb with 67% of that due to BCs and the rest (21.1 ppb) due to in-domain emissions, of which 81% is NO_x sensitive and 19% is VOC sensitive (Figure 11-10, bottom). Since Figure 11-10 is for all emissions sources, the region-specific stacked bars and pie slices display the contributions of anthropogenic, fire and natural emissions from all of the Source Regions.

The Dashboard can be used to isolate the amount of VOC and NO_x sensitive ozone from the different Source Categories and Regions used in the CAMx OSAT simulation with two example pie charts averaged across the 10 SMAT days at Substation shown in Figure 11-11. The top pie chart in Figure 11-11 shows ozone contributions averaged across the 10 SMAT days for all anthropogenic emissions and all Source Regions. All emissions in the domain contributed 21.1 ppb to the average of the 10 SMAT days at Substation of which 11.4 is due to the anthropogenic emissions (Figure 11-11, top) so the remainder (9.7 ppb) is due to natural and fire emissions. Of the 11.4 ppb all anthropogenic emissions ozone contribution, 91% was formed under NOx sensitive and 9% was formed under VOC sensitive conditions. The bottom pie chart in Figure 11-11 shows the contributions to the average of the 10 SMAT days at Substation due to anthropogenic emissions from New Mexico and shows that New Mexico is

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contributing 42% of the anthropogenic emissions contribution (4.7 of 11.4 ppb) at Substation with most of that (87%) being NO_x sensitive ozone.

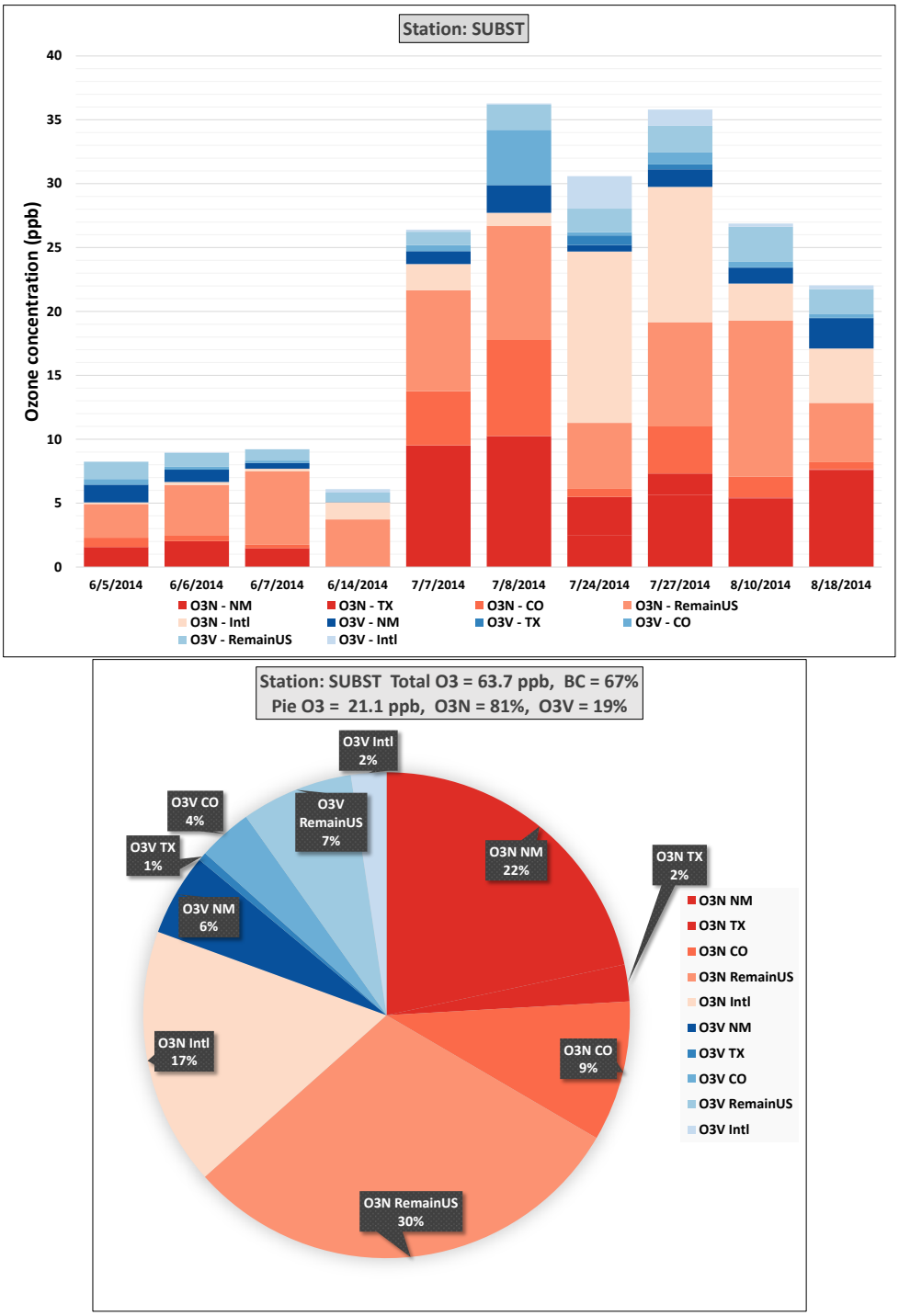


Figure 11-10. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the Substation monitor in San Juan County.

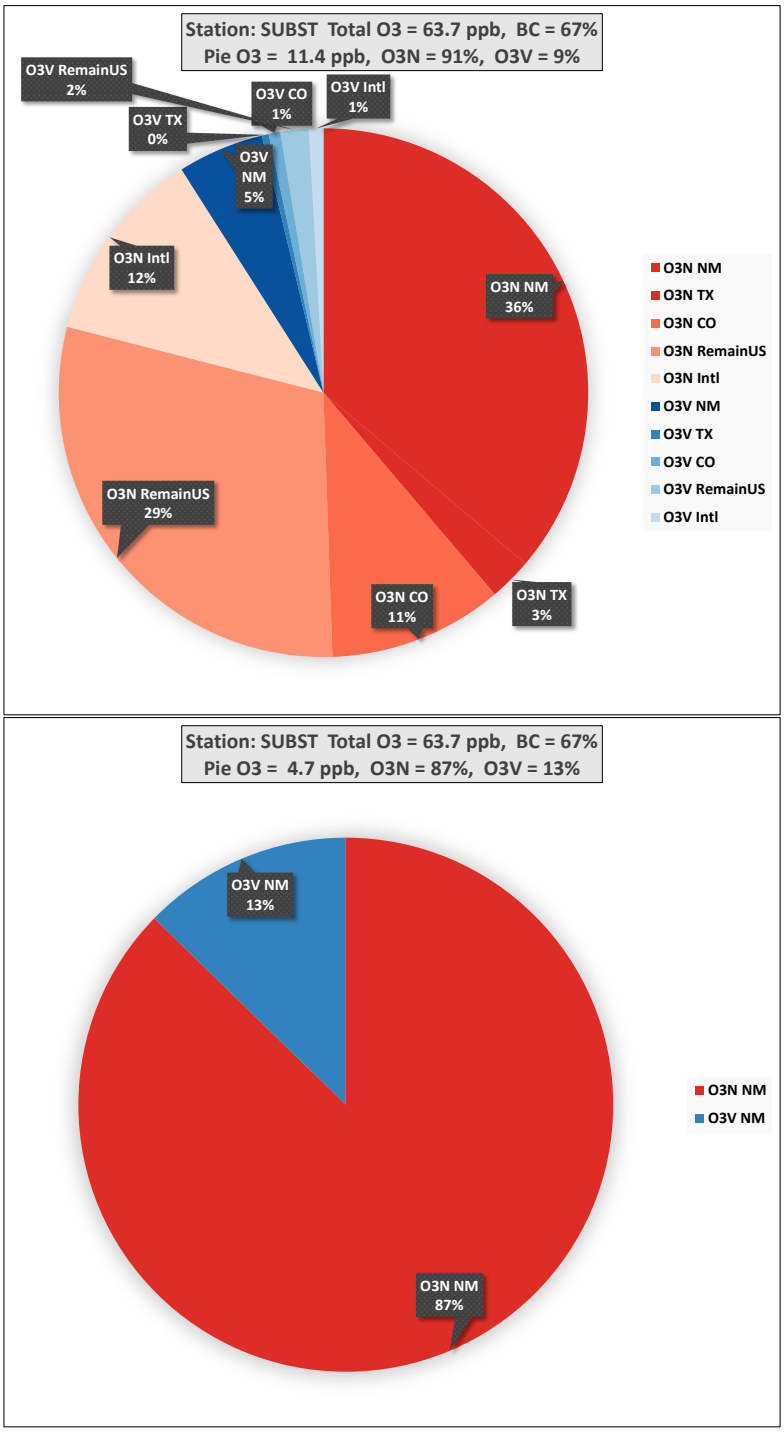


Figure 11-11. O3V and O3N contributions averaged across the 10 SMAT days at Substation for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).

11.3.2 VOC/NO_x Sensitivity at South East Heights in Bernalillo County

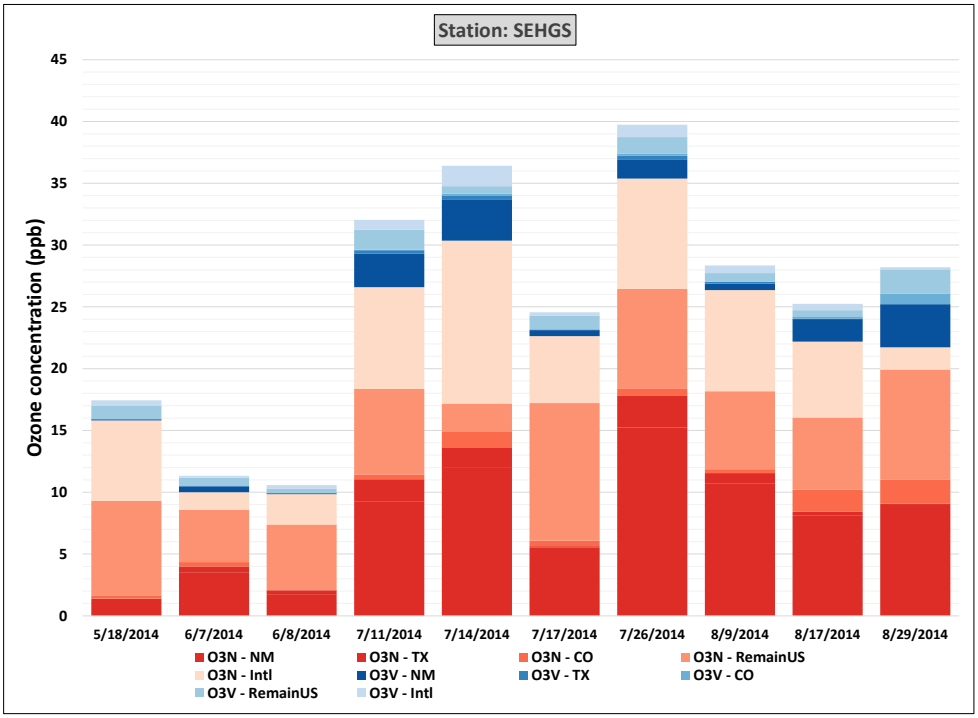
The CAMx OSAT source apportionment results for the 10 SMAT days and all sources at the South East Heights monitoring in Bernalillo County are shown in Figure 11-12. There is a lot of day-to-day variability across the 10 SMAT days with in-domain emissions estimated to contribute from 10 to 40 ppb, with the remainder of the ozone coming from the BCs. On the two lowest in-domain emissions ozone days (June 7 and 8 with 10 and 11 ppb ozone from in-domain emissions), the ozone is almost completely (> 90%) NO_x sensitive, whereas on other days the VOC sensitive ozone can exceed 20% (e.g., August 29). This daily variation in VOC and NO_x sensitivity in Bernalillo County was also seen in the spatial maps (e.g., Figure 11-9). Averaged across the 10 SMAT days at South East Heights, in-domain emission sources contribute 25.4 ppb, of which 87% is NO_x sensitive ozone with the O3N from New Mexico (30%), remainder U.S. (26%) and international (25%) being the highest contributors.

A vast majority (93%) of the 14.5 ppb anthropogenic emissions ozone contribution at South East Heights was formed under NO_x sensitive conditions (Figure 11-12, top) with over half of that coming from New Mexico (7.4 ppb) that was also primarily (92%) NO_x sensitive ozone (Figure 11-13, bottom).

11.3.3 VOC/NO_x Sensitivity at Desert View in Doña Ana County

The CAMx OSAT results for the Desert View monitoring site in Doña Ana County are shown in Figures 11-14 and 11-15. Ozone from Texas and Mexico contributes greatly to ozone levels at Desert View. This includes ozone from El Paso that can have a higher fraction of VOC sensitive ozone (e.g., see Figure 11-4) that is seen on some days in the daily bar charts in Figure 11-14 (e.g., July 24, 2014). Emissions within the CAMx domain contribute 24 to 46 ppb of the daily MDA8 ozone on the 10 SMAT days at Desert View with 14 to 28 ppb of that being anthropogenic in origin. Across all emissions, the average of the 10 SMAT days is 81% NO_x sensitive, with the anthropogenic component of ozone being much more NO_x sensitive (90%) than the natural/fire component (69%). New Mexico anthropogenic emissions contribute 2 ppb (10%; Figure 11-15, bottom) of the 20.9 ppb anthropogenic ozone (Figure 11-15, top) at Desert View with emissions from Mexico contributing approximately half (10.6 ppb) and Texas (3.9 ppb), almost 20%.

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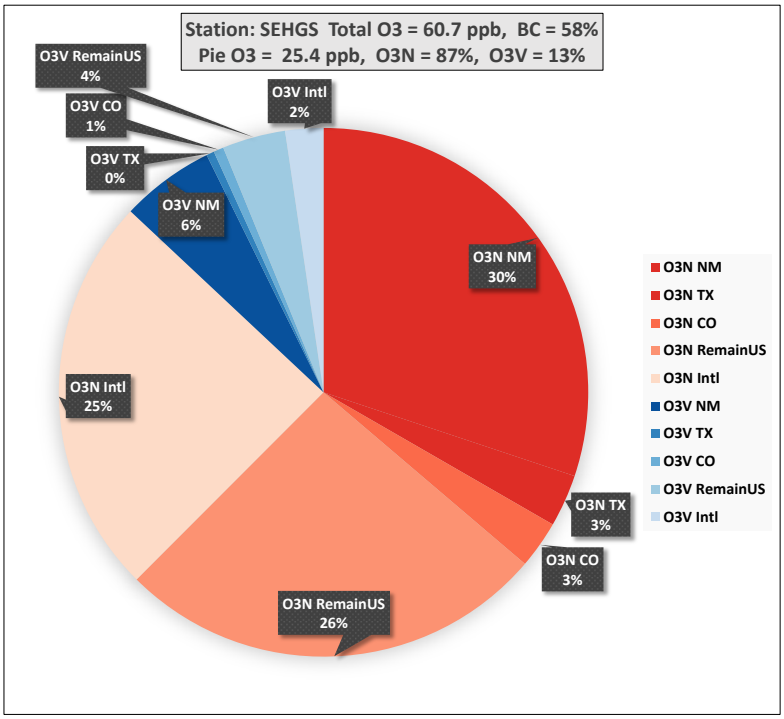


Figure 11-12. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the South East Heights monitor in Bernalillo County.

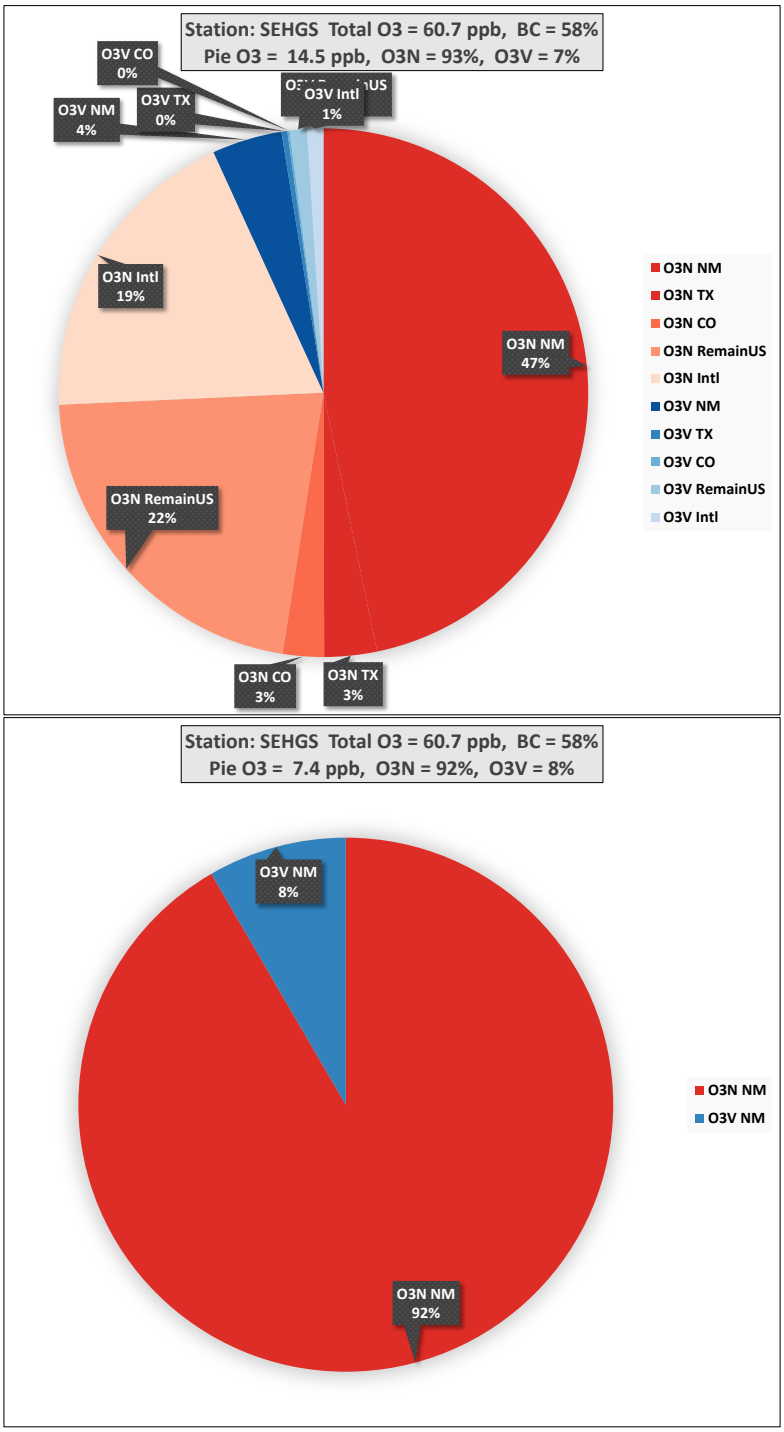
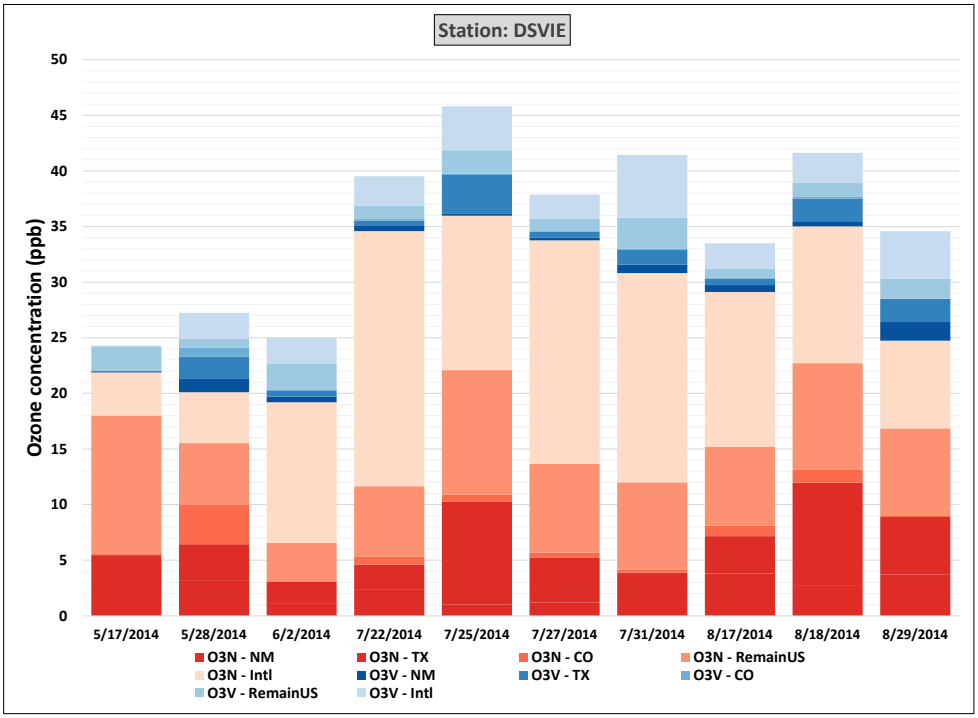


Figure 11-13. O3V and O3N contributions averaged across the 10 SMAT days at South East Heights monitoring site for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).



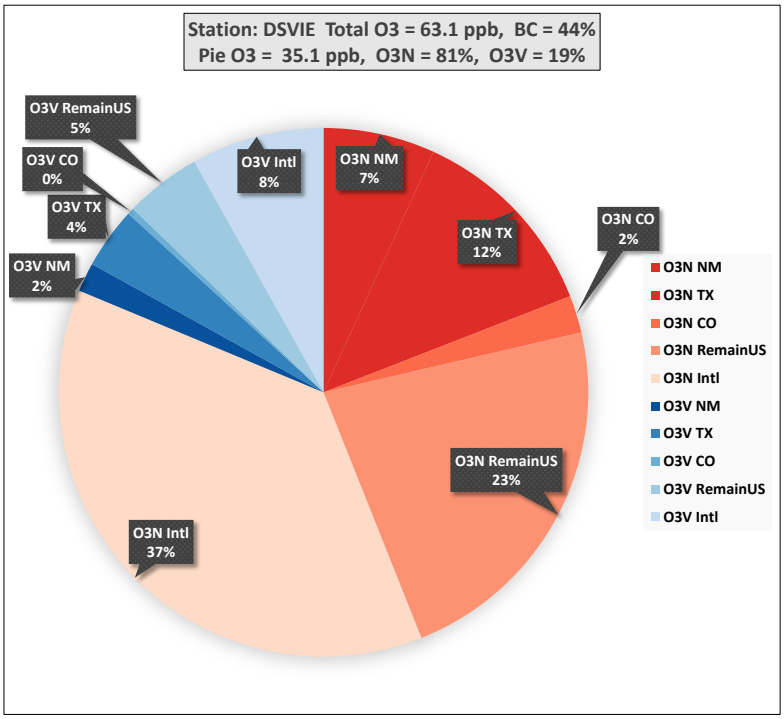


Figure 11-14. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the Desert View monitor in Doña Ana County.

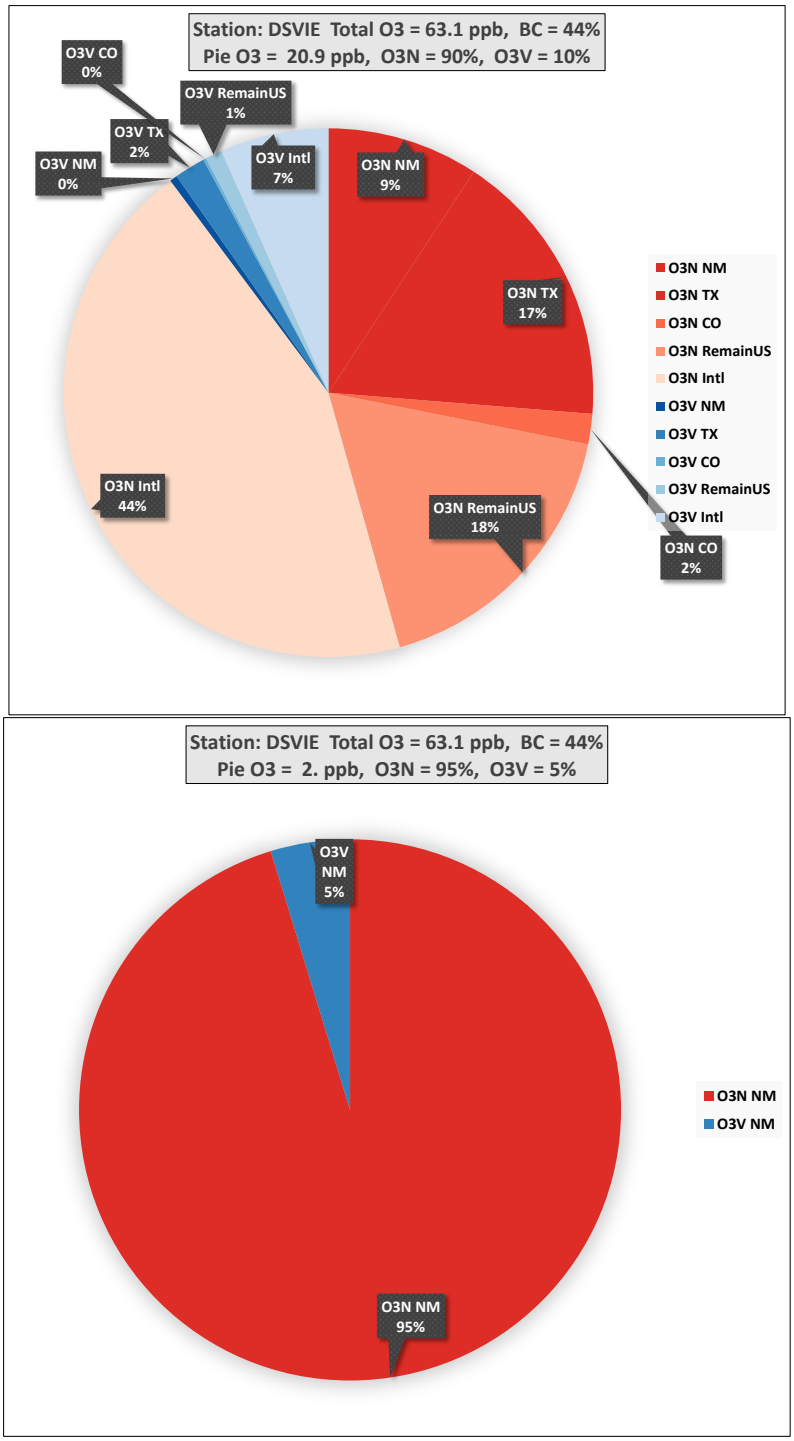


Figure 11-15. O3V and O3N contributions averaged across the 10 SMAT days at Desert View monitoring site for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).

11.3.4 VOC/NO_x Sensitivity at Carlsbad in Eddy County

Figures 11-16 and 11-17 display the CAMx 2028 OSAT results at the Carlsbad monitor in Eddy County. Across the 10 SMAT days, emissions within the CAMx domain account for 11 to 27 ppb of the daily ozone at Carlsbad (Figure 11-16, top). The model estimates more NO_x sensitive ozone at Carlsbad (91% on average) than Desert View (81% on average). The ozone due to emissions averaged across the 10 SMAT days at Carlsbad is 19.1 ppb that is approximately equally split between anthropogenic (10.0 ppb) and natural/fire (9.1 ppb) sources, with the ozone from the anthropogenic emissions (94%) being more NO_x sensitive than the ozone from the natural/fire emissions (87%). Of the 10 ppb from anthropogenic emissions, almost half (4.7 ppb) is from international emissions with anthropogenic emissions from New Mexico and Texas both contributing 16% (1.6 ppb) each (Figure 11-17).

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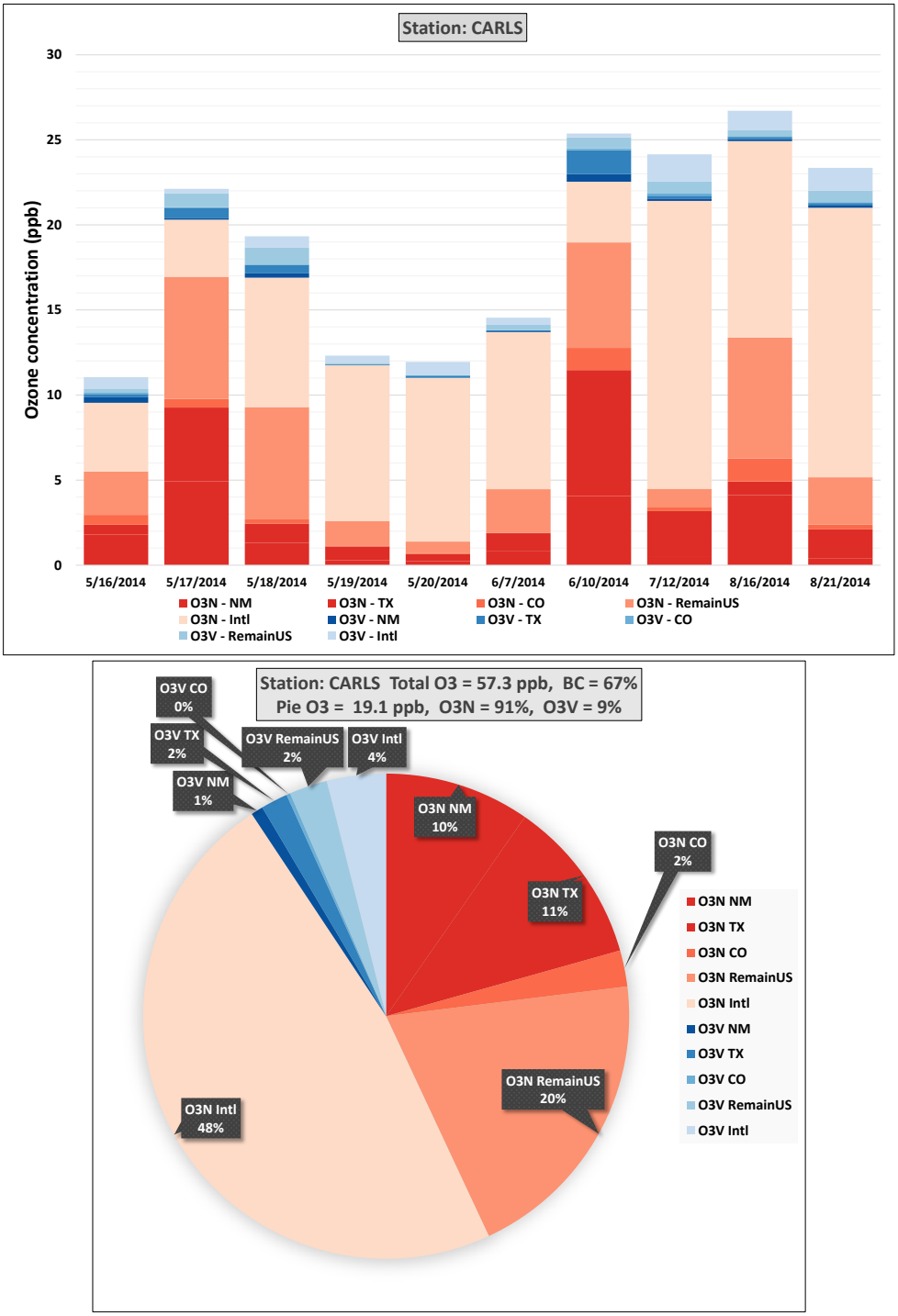


Figure 11-16. Bar Chart of daily O3V (blue) and O3N (red) contributions across the 10 days used by SMAT and pie chart of ozone contributions averaged across the 10 SMAT days for all Source Categories and Source Regions and the Carlsbad monitor in Eddy County.

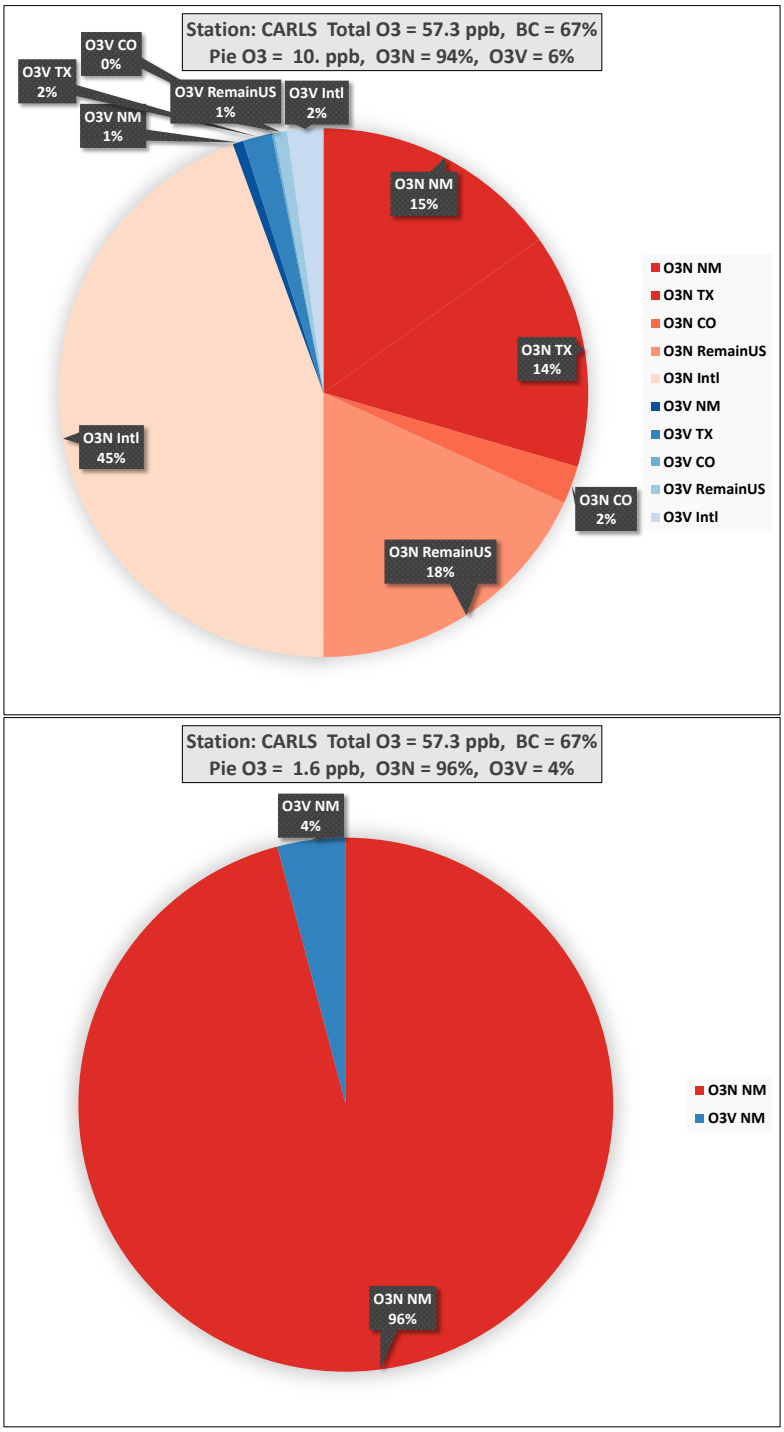


Figure 11-17. O3V and O3N contributions averaged across the 10 SMAT days at Carlsbad monitoring site for all anthropogenic emissions (top) and New Mexico anthropogenic emissions (bottom).

12. SUMMARY AND CONCLUSIONS

12.1 Summary of CAMx 2014 36/12/4-km Photochemical Model Platform Development

A CAMx 2014 36/12/4-km ozone modeling platform was developed with the 4-km domain focused on New Mexico and adjacent states. The CAMx 2014 36/12/4-km modeling platform was based on the Western Regional Air Partnership (WRAP), Western Air Quality Study (WAQS) CAMx 2014 36/12-km modeling platform. WRF meteorological modeling was conducted to generate CAMx meteorological inputs for the 36/12/4-km domains and summer of 2014. A model performance evaluation was conducted that compared CAMx 2014 estimated ozone concentrations with concurrent ozone observations that produced good ozone model performance. A revised CAMx 2014v2 base case was conducted with a newer version of the CAMx model and updated biogenic emissions that also produced very good ozone model performance.

SMOKE emission and CAMx ozone modeling was conducted for a 2014v2 Base Case, a 2028 Base Case and a 2028 O&G Control Strategy that implemented O&G controls on O&G sources in the New Mexico portions of the San Juan and Permian Basins. The proposed New Mexico O&G ozone precursor rule controls were implemented in the 2028 Base Case NM O&G emissions by Eastern Research Group (ERG) under separate contract with NMED.

12.2 Summary of 2028 Ozone Modeling Results and Ozone Design Value Projections

2028 projected future year ozone design values (DVF) were made using the CAMx 2014v2, 2028 Base Case and 2028 O&G Control Strategy modeling results following EPA's latest photochemical modeling guidance (EPA, 2018). EPA's modeling guidance recommends scaling the current year design value (DVC) using a Relative Response Factor (RRF) based on the ratio of the future to current year modeling results (i.e., RRF = CAMx $Ozone_{2028}$/CAMx $Ozone_{2014}$). The guidance recommends using a DVC based on an average of three ozone design values centered on the base modeling year, which in this case is 2014, so design values from 2012-2016 are used (i.e., $DVC_{2012\text{-}2016}$). Following EPA's ozone projection approach guidance, all 2028 projected ozone DVFs were below the 2015 ozone NAAQS at all monitoring sites in New Mexico using the $DVC_{2012\text{-}2016}$ observed ozone starting point for the projections.

A comparison of the CAMx absolute modeled daily MDA8 ozone concentrations for the 2028 Base Case and 2028 O&G Control Strategy found that the strategy resulted in MDA8 ozone reductions over large areas of New Mexico, with the largest ozone reductions occurring in the San Juan and Permian Basins. However, there were also isolated areas of ozone increases due to the 2028 O&G Control Strategy that usually occurred in or near the San Juan and Permian Basins that are likely due to "NO_x Disbenefits" where NO_x emission reductions can cause localized ozone increases. For at least one day (June 5, 2014) that CAMx 2028 Base Case had a large area with MDA8 ozone concentrations that exceeded the 70 ppb ozone NAAQS in San Juan County, the 2028 O&G Control Strategy was sufficient to reduce the MDA8 ozone concentrations to below the NAAQS. On

another day (July 24, 2014), the "NO_x Disbenefits" of the 2028 O&G Control Strategy was sufficient to increase the MDA8 ozone concentrations in one 4-km grid cell in San Juan County that was below the NAAQS in the 2028 Base Case to right at the threshold for exceeding the NAAQS (71.0 ppb) in the 2028 O&G Control Strategy.

12.3 Sensitivity of 2028 Ozone Design Value Projections to Current Year Ozone Design Value

Given the upward trend in ozone design values in southern New Mexico in recent years (see Table 1-1), the sensitivity of the 2028 future year ozone DVF projections to the current year ozone design value (DVC) was investigated by making 2028 ozone DVF projections using current year design values based on observations from 2015-2019 (i.e., $DVC_{2015\text{-}2019}$) and 2017-2019 (i.e., $DV_{2017\text{-}2019}$) instead of the $DVC_{2012\text{-}2016}$ current year design value recommended in EPA's ozone modeling guidance (EPA, 2018).

There were four monitoring sites with $DVC_{2015\text{-}2019}$ exceeding the 70 ppb ozone NAAQS, compared to two using the $DVC_{2012\text{-}2016}$. The Carlsbad site projected 2028 ozone DVF (71.2 ppb) still exceeded the ozone NAAQS for the 2028 Base Case when the $DVC_{2015\text{-}2019}$ current year design value was used in the projection. However, the emission reductions in the 2028 O&G Control Strategy were sufficient to bring the projected 2028 ozone DVF at the Carlsbad site (70.9 ppb) to below the ozone NAAQS in the $DVC_{2015\text{-}2019}$ current year design value sensitivity analysis.

Three monitors exceeded the 70 ppb ozone NAAQS using the most recent ozone design value ($DV_{2017\text{-}2019}$), but one of the sites that had their $DVC_{2015\text{-}2019}$ exceeding the NAAQS was no longer in operation in 2017-2019 (i.e., Carlsbad Caverns NP). Two of the sites were still estimated to have projected 2028 ozone DVFs that exceeded the ozone NAAQS for both the 2028 Base Case and 2028 O&G Control Strategy in the $DV_{2017\text{-}2019}$ current year DVC sensitivity analysis. Under the 2028 O&G Control Strategy, the projected 2028 ozone DVFs at Carlsbad and Desert View were, respectively, 76.0 and 71.4 ppb using the $DV_{2017\text{-}2019}$ as the current year DVC in the ozone projections.

There were significant increases in O&G emissions within the Permian Basin since 2014 that are not accounted for in the CAMx ozone modeling results in the $DVC_{2015\text{-}2019}$ and $DV_{2017\text{-}2019}$ current year design value sensitivity tests. If those additional O&G emissions were included in the CAMx base year base case simulations, the projected 2028 ozone DVFs would be lower in the vicinity of the Permian Basin because of the higher denominator in the RRF projections factors due to higher O&G emissions than occurred in 2014.

EPA recommends using the average of three years of design values for the DVC as it is more stable and has less year-to-year variability than a single design value period (EPA, 2018, pp. 101[42]). So, the 2028 ozone DVFs projection sensitivity test using the $DV_{2017\text{-}2019}$ has an additional caveat as it is less stable and more influenced by year-to-year variability in ozone concentrations.

[42] https://www.epa.gov/sites/production/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf

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12.4 2028 Source Sector APCA Ozone Source Apportionment Modeling

The 2028 O&G Control Strategy Source Sector APCA ozone source apportionment modeling found that approximately half to two-thirds of the ozone on high MDA8 ozone days in New Mexico is due to Boundary Conditions (BCs) that are mainly from international and natural emissions from outside of the CAMx 36-km North America modeling domain. The highest contributing New Mexico Source Sector varied by location. For sites in San Juan County in northwestern New Mexico, EGU and O&G Non-Point sources were the two highest contributing Source Sectors followed by O&G Point sources. For sites in Bernalillo County in the central part of New Mexico, Other Anthropogenic, On-Road and Non-Road were the highest contributing Source Sectors. In Doña Ana County in southern New Mexico, New Mexico EGU and On-Road were the highest contribution Source Sectors. O&G Non-Point and Point sources were the highest contributing New Mexico Source Sectors at the Carlsbad and Hobbs sites in southeastern New Mexico. Texas and Mexico had large contributions to ozone in southern New Mexico, whereas Colorado had large contributions in northwestern New Mexico.

International anthropogenic emissions contributed 13 to 26 ppb to the projected 2028 ozone DVFs at New Mexico sites, with larger international contributions at the southern New Mexico sites. The elimination of the contributions of international anthropogenic emissions reduced the projected 2028 ozone DVFs to below 60 ppb under all scenarios, even when the $DVC_{2017\text{-}2019}$ was used that produced a projected 2028 ozone DVF at Carlsbad that exceeded both the 2008 and 2015 ozone NAAQS.

12.5 2028 VOC/NO_x Sensitivity OSAT Ozone Source Apportionment Modeling

The 2028 VOC/NO_x Sensitivity OSAT ozone source apportionment simulation found that ozone formation across New Mexico was primarily NO_x sensitive. There were some areas that had relatively higher VOC sensitive ozone formation conditions on some days, including the San Juan Basin, Albuquerque, the Texas part of El Paso, and to a lesser extent, the Permian Basin. There are even days (e.g., June 5th) where elevated MDA8 ozone concentrations in San Juan Basin that approached the ozone NAAQS and ozone formation was approximately evenly split between NO_x and VOC sensitive ozone formation conditions. But overall, ozone formation was more NO_x sensitive than VOC sensitive. The highest modeled ozone concentrations tend to have relatively higher VOC sensitive ozone concentrations. Thus, although ozone formation appears to be mainly NO_x sensitive, VOC controls will also have benefits in reducing some of the highest ozone concentrations in New Mexico.

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New Mexico OAI Study Photochemical Modeling – 1st Monthly Webinar May 2020



WESTAR and Ramboll

May 28, 2020

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Bright ideas. Sustainable change.

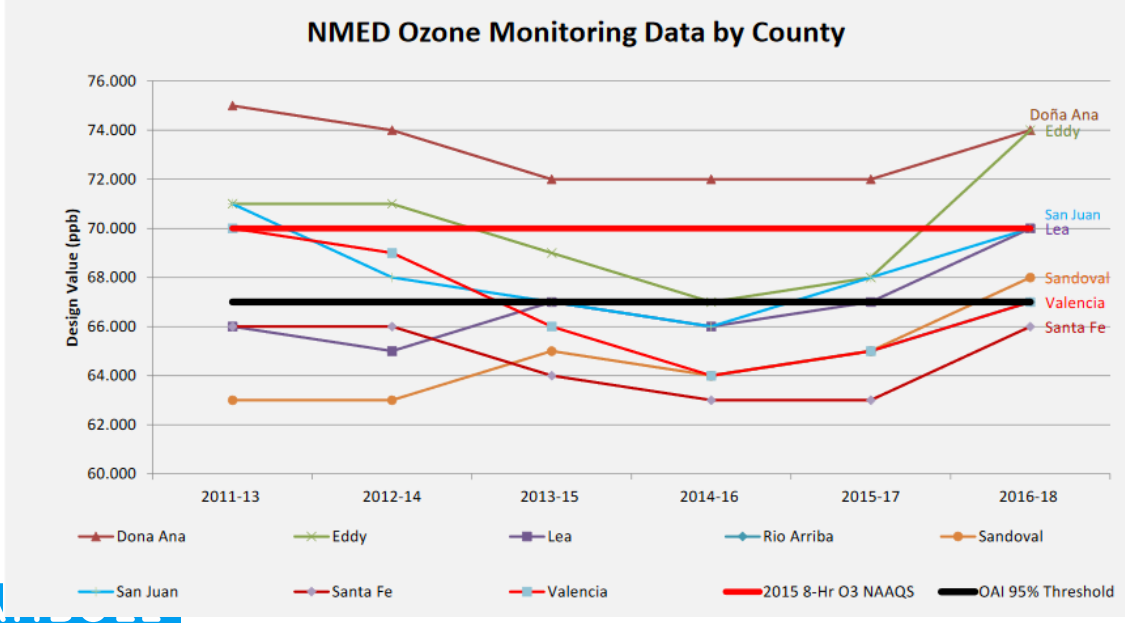
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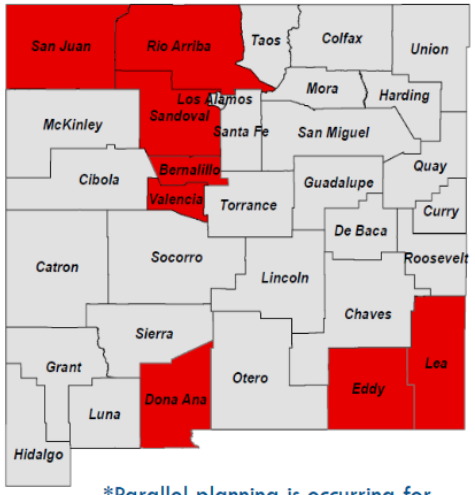
- Introduction
- Work Plan
- Evaluation of Existing 2014 WRF and Proposed NM OAI Study WRF Configuration
- Evaluation of 2014 Boundary Conditions (BCs) from WRAP 2014 GEOS-Chem
- Modeling Protocol Overview
- 2014 and 2023 Emissions for New Mexico
- 2014 and 2023 Mobile Source Assumptions and Activity Data for New Mexico
- Next Steps

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Introduction

- New Mexico Air Quality Control Act (NMAQCA) requires the NMED to develop a plan to address elevated ozone levels when air quality is within 95% of the ozone NAAQS (74-3-5.3, NMSA 1978)
- There are 8 counties in New Mexico with measured ozone concentrations within 95% of the 70 ppb 2015 ozone NAAQS
- NMED contracted with WESTAR/Ramboll to conduct 2014 and 2023 photochemical modeling to assess the contributions of sources to and effects of control measures on ozone concentrations





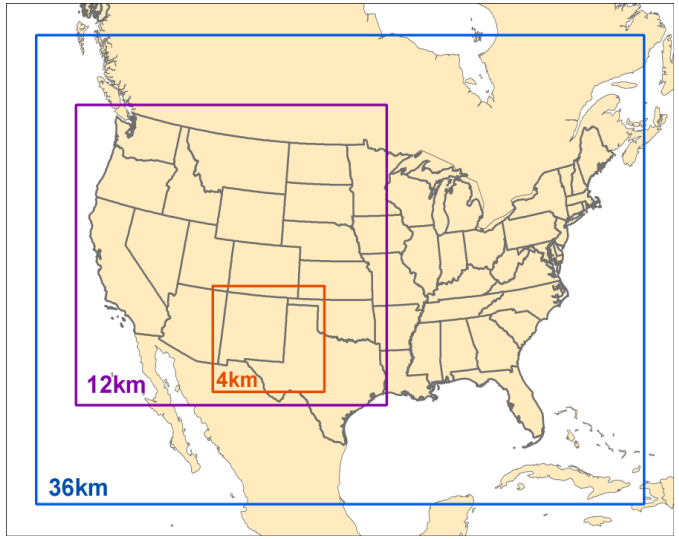
*Parallel planning is occurring for Bernalillo County through the Albuquerque/Bernalillo County Department of Environmental Health

- Counties within 95% of the standard:
  - San Juan (Navajo Lake, 70 ppb)
  - Doña Ana (several monitors, 74 ppb)
  - Eddy (Carlsbad, 74 ppb)
  - Lea (Hobbs, 70 ppb)
  - Rio Arriba (Coyote, 67 ppb)
  - Sandoval (Bernalillo, 68 ppb)
  - Valencia (Los Lunas, 67 ppb)

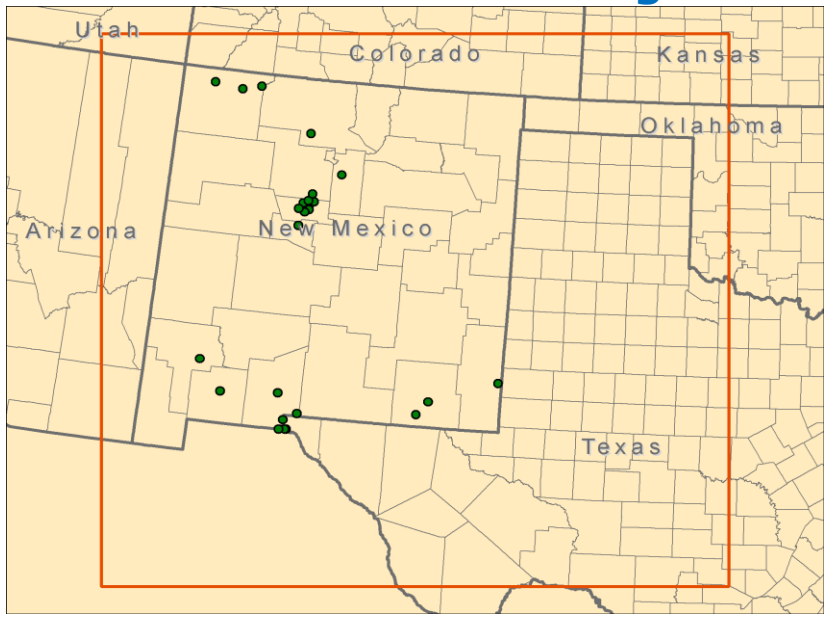
Work Plan (1 of 2)

- Task 1: Development Modeling Protocol/QAPP and Work Plan
  - Modeling Plan provides a roadmap on how the study will be carried, including episode, domain and model selection and current and future year modeling approaches

36/12/4-km Domain Structure



New Mexico 4-km Modeling Domain



- Task 2: WRF Meteorological Modeling
  - Develop CAMx meteorological inputs for May-Aug 2014 and 36/12/4-km domains
- Task 3: Evaluate Boundary Condition Inputs
  - Based on WRAP 2014 GEOS-Chem global chemistry model

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Work Plan (2 of 2)

- Task 4: 2014 and 2023 Emissions Development
  - Sources of 2014 and 2023 Emissions
  - Mobile Source Emissions
  - Natural Emissions
  - SMOKE Emissions Modeling
  - 2023 Emission Control Measures
- Task 5: CAMx 2014 Base Case Modeling
  - Model Performance Evaluation
  - Formal 2016 Base Case Modeling and MPE Report on Tasks 2-5
- Task 6: 2023 Future Year CAMx Modeling
  - 2023 Base Case and Future Year Ozone Design Value Projections
  - 2023 Ozone Source Apportionment Modeling
  - 2023 Control Measure Evaluation
- Task 7: Air Quality Technical Support Document (AQTSD)
  - Prepare formal AQTSD documenting the study
  - Transfer Modeling Databases and Results to Intermountain West Data Warehouse (IWDW)
  - Maintain NM OAI Study Webpage on WRAP website throughout the study

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Current Schedule

Task	Deliverable	Date
1. Formal Modeling Protocol/QAPP and Work Plan		
	Kick-Off Conference Call	Apr 2020
	Draft Modeling Protocol/QAPP and Work Plan	May 2020
	PPT on final approach and project plan	May 2020
	Final Modeling Protocol/QAPP and Work Plan	May2020
	Response-to-Comments (RTC) Document	May 2020
2. Base Year Meteorological Modeling (Met)		
2.1 Evaluate Met Model	*PPT on 2014 WAQS and EPA WRF*	May 2020
2.2 Additional Met Model	*PPT on New WRF 4-km MPE in New Mexico*	Jun 2020
2.3 Process Met Data	PGM summer 2014 36/12/4-km met inputs	Jun 2020
3. Boundary Conditions (BC)		
3.1 Evaluate BC Data	*PPT on WRAP 2014 GEOS-Chem BCs*	Jun 2020
4. Base Year (2014) and Future Year (2023) Emissions		
4.1 2014 and 2023 Emissions for 4-km New Mexico Domain	*PPT on sources of 2014 and 2023 New Mexico EI*	May 2020
	PPT and tile plots/excel spreadsheets for 2014 and 2023 emissions in the 4-km NM domain	Jun 2020
4.2 Mobile Sources		
4.2.1 Evaluate Mobile EI	*PPT on options for 2014/2023 mobile sources*	Jun 2020
	PPT on final 2014/2023 mobile source EI	Jun 2020
4.2.3 Prepare Mobile Source Emission Inputs	*PPT on 2014/2023 SMOKE-MOVES*	Aug 2020
	Model-ready 2014/2023 mobile source inputs	Aug 2020
4.3 Biogenic/Natural Emissions	*PPT on biogenic and natural emission modeling*	Jul 2020
	Model-ready 2014 natural emissions inputs	Jul 2020
4.4 SMOKE Modeling	*PPT on 2014/2023 SMOKE modeling*	Aug 2020
	Model-ready 2014/2023 anthropogenic EI inputs	Aug 2020
4.5 FY Emissions Strategies	*PPT on FY 2023 SMOKE control/strategies*	Aug 2020
	Summary tables/plots for 2023 scenarios	Aug 2020
5. 2014 Base Year (2014) Air Quality Modeling		
	Webinar PPT on final 2014 base case and MPE	Sep 2020
	Draft report on Tasks 2-5, 2014 Base and MPE	Sep 2020
	Final report on Tasks 2-5, 2014 Base and MPE	Oct 2020
	RtC on 2014 base case and MPE report	Oct 2020
6. Future Year (2023) Air Quality Modeling		
6.1 FY PGM Modeling	*PPT on 2023 PGM Modeling*	Oct 2020
	Difference plots of FY-BY Ozone Concentrations	Oct 2020
6.2 Attainment Test	*PPT on 2023 ozone DV projections*	Oct 2020
	PPT on FY Source Apportionment Modeling	Nov 2020

4.1 2014 and 2023 Emissions for 4-km New Mexico Domain	*PPT on sources of 2014 and 2023 New Mexico EI*	May 2020
	PPT and tile plots/excel spreadsheets for 2014 and 2023 emissions in the 4-km NM domain	Jun 2020
4.2 Mobile Sources		
4.2.1 Evaluate Mobile EI	*PPT on options for 2014/2023 mobile sources*	Jun 2020
	PPT on final 2014/2023 mobile source EI	Jun 2020
4.2.3 Prepare Mobile Source Emission Inputs	*PPT on 2014/2023 SMOKE-MOVES*	Aug 2020
	Model-ready 2014/2023 mobile source inputs	Aug 2020
4.3 Biogenic/Natural Emissions	*PPT on biogenic and natural emission modeling*	Jul 2020
	Model-ready 2014 natural emissions inputs	Jul 2020
4.4 SMOKE Modeling	*PPT on 2014/2023 SMOKE modeling*	Aug 2020
	Model-ready 2014/2023 anthropogenic EI inputs	Aug 2020
4.5 FY Emissions Strategies	*PPT on FY 2023 SMOKE control/strategies*	Aug 2020
	Summary tables/plots for 2023 scenarios	Aug 2020
5. 2014 Base Year (2014) Air Quality Modeling		
	Webinar PPT on final 2014 base case and MPE	Sep 2020
	Draft report on Tasks 2-5, 2014 Base and MPE	Sep 2020
	Final report on Tasks 2-5, 2014 Base and MPE	Oct 2020
	RtC on 2014 base case and MPE report	Oct 2020
6. Future Year (2023) Air Quality Modeling		
6.1 FY PGM Modeling	*PPT on 2023 PGM Modeling*	Oct 2020
	Difference plots of FY-BY Ozone Concentrations	Oct 2020
6.2 Attainment Test	*PPT on 2023 ozone DV projections*	Oct 2020
	PPT on FY Source Apportionment Modeling	Nov 2020

Current Webinar Schedule and Content

Webinar No.	Webinar Topics by Task	Date
1.	1. Modeling Protocol and Work Plan 2.1 Evaluate Existing Met 4.1 Recommend 2014 and 2023 Emissions 4.2.1 Recommend 2014 & 2023 Mobile Source Emissions	May 2020
2.	2.2 Additional Met Modeling 3.1 Evaluate BC Data 4.1 Summary of 2014 and 2023 Emissions	Jun 2020
3.	4.2.1 Summary of 2014 and 2023 Mobile Source Emissions 4.3 2014 Natural Emissions Results (e.g., Biogenic, LNOx)	Jul 2020
4.	4.2.3 2014/2023 SMOKE-MOVES for 4-km NM Domain 4.4 2014 & 2023 SMOKE Emissions Modeling Results	Aug 2020
5.	4.5 FY Emissions Strategy Results 5. 2014 CAMx Base Case Modeling and MPE	Sep 2020
6.	6.1 2023 CAMx Modeling Results 6.2 2023 Ozone Design Value Projections	Oct 2020
7.	6.3 2023 Control Strategy Results 6.4 2023 Source Apportionment Modeling Results	Nov 2020

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Subtask 2.1: Evaluate Existing 2014 Meteorology and Define NM OAI Study WRF 2014 36/12/4-km Model Configuration



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NM OAI vs WAQS vs EPA WRF Configurations

WRF Option	Proposed NM OAI	2014 WAQS	2014/2015 EPA
Vertical Coordinate	hybrid	eta	eta
Domains run	36/12/4-km	36/12/4-km	12-km
Microphysics	Thompson	Thompson	Morrison 2
LW Radiation	RRTMG	RRTMG	RRTMG
SW Radiation	RRTMG	RRTMG	RRTMG
LSM	Noah	Noah	Pleim-Xiu
PBL scheme	YSU	YSU	ACM2
Sfc Layer Physics	MM5 similarity	MM5 similarity	MM5 similarity
Cumulus	36/12/4-km Multi-scale Kain Fritsch	36/12-km Multi-scale Kain Fritsch	Kain-Fritsch
BC, IC Analysis Nudging Source	12-km NAM/ERA5	12-km NAM	12-km NAM
Analysis Nudging Grids	36/12-km	36/12-km	12-km
Obs Nudging	None	4-km	None
Sea Sfc Temp	FNMOC	FNMOC	FNMOC

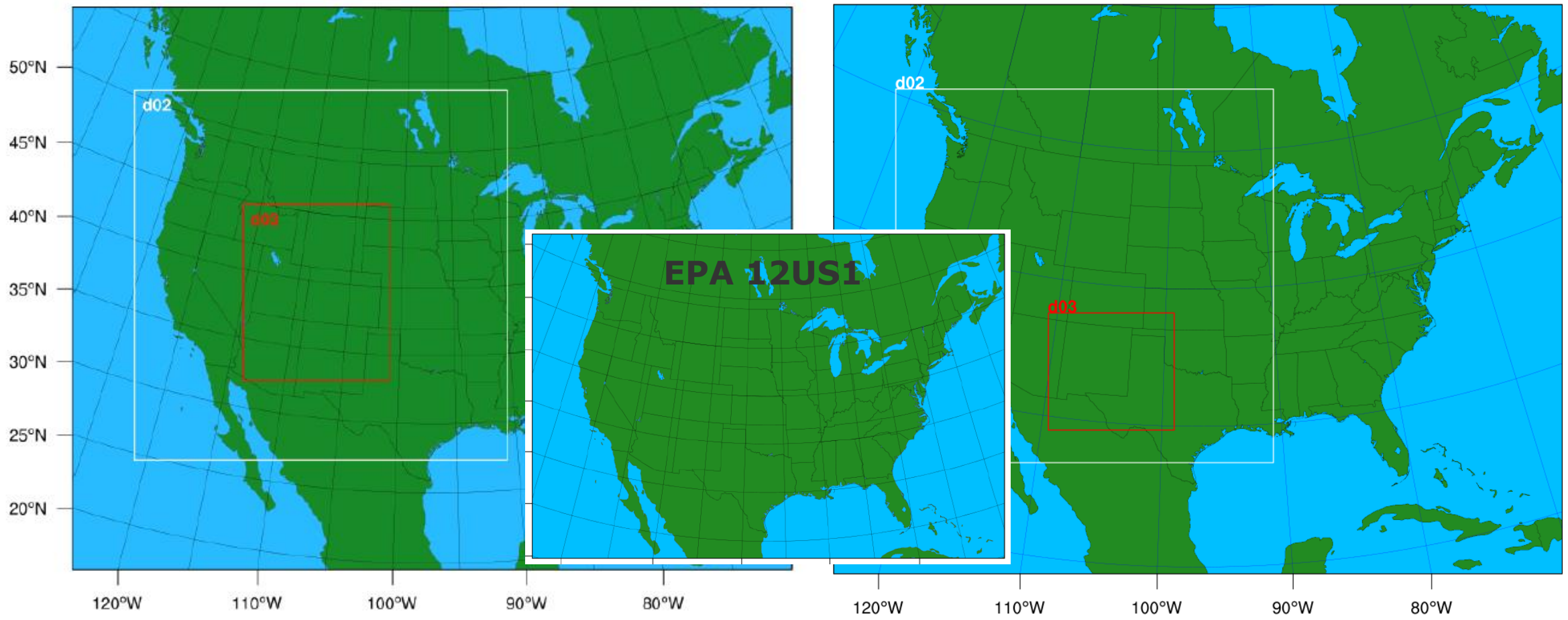
RAMBOLL

NMED Exhibit 18 - 0009

NM OAI vs WAQS vs EPA WRF Domains

WAQS 36/12/4 km

NM OAI 36/12/4 km



NMED Exhibit 18 - 0010

EPA vs WAQS WRF MPE Approach

- Evaluate EPA 12US1 and WAQS 12WUS2 for April-August 2014
  - For both EPA and WAQS, include observation sites within New Mexico only
- Quantitative Evaluation
  - METSTAT – model/obs pairing, bias/error statistics against NCAR ds3505 observations
    - Soccer plots – monthly stats
    - Time series – hourly and daily
    - Plots for all sites in NM, and each individual site within NM
- Qualitative Evaluation
  - PRISM precipitation spatial maps
    - Monthly and daily

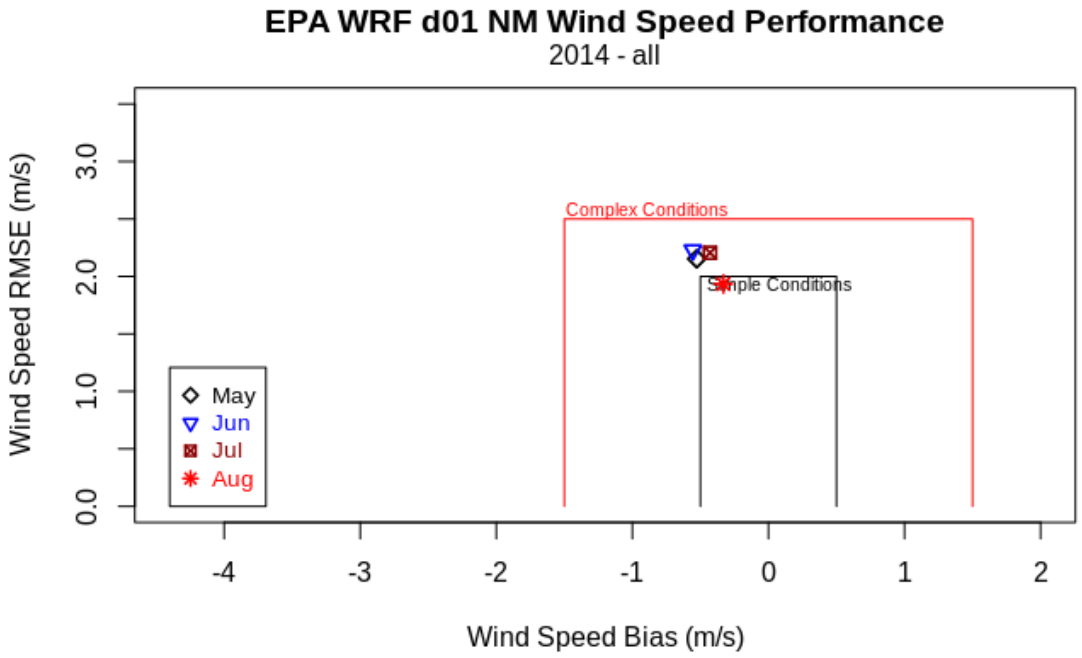
WRF Statistical Benchmarks

Meteorological Variable	Simple Conditions		Complex Conditions	
	Bias	Error	Bias	Error
Temperature	< ±0.5 °C	< 2.0 °C	< ±2.0 °C	< 2.5 °C
Wind Speed	< ±0.5 m/s	< 2.0 m/s (RMSE)	< ±1.5 m/s	< 2.5 m/s (RMSE)
Wind Direction	< ±10 degrees	< 30 degrees	< ±10 degrees	< 50 degrees
Humidity	< ±0.8 g/kg	< 2.0 g/kg	< ±1.0 g/kg	< 2.0 g/kg

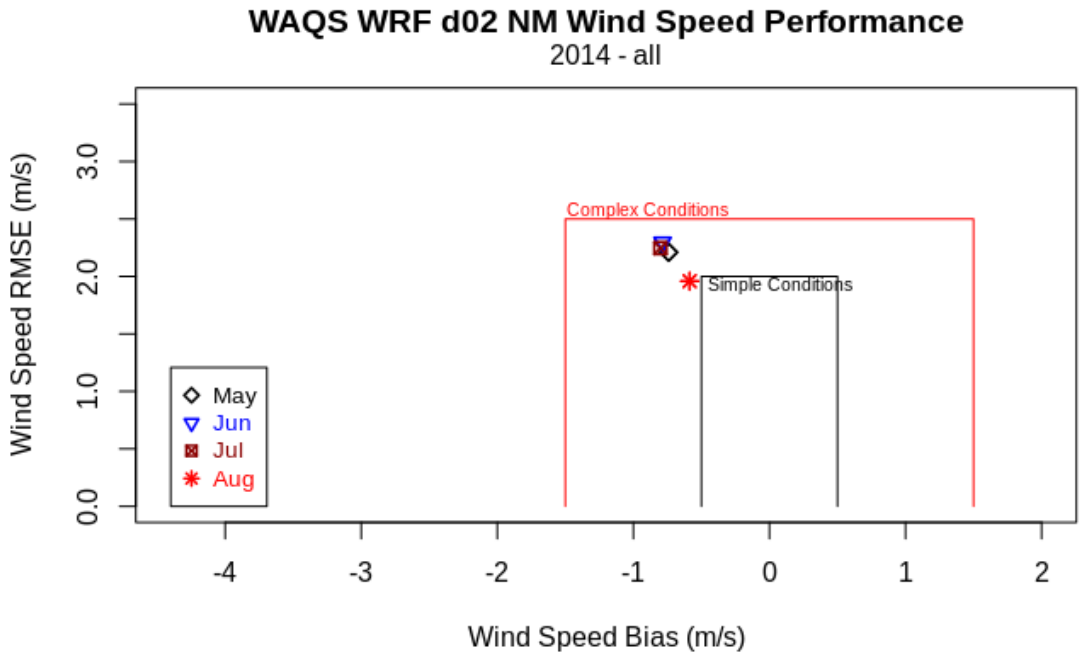
NMED Exhibit 18 - 0012

Soccer Plots – Wind Speed for all NM sites

EPA 12 km



WAQS 12 km



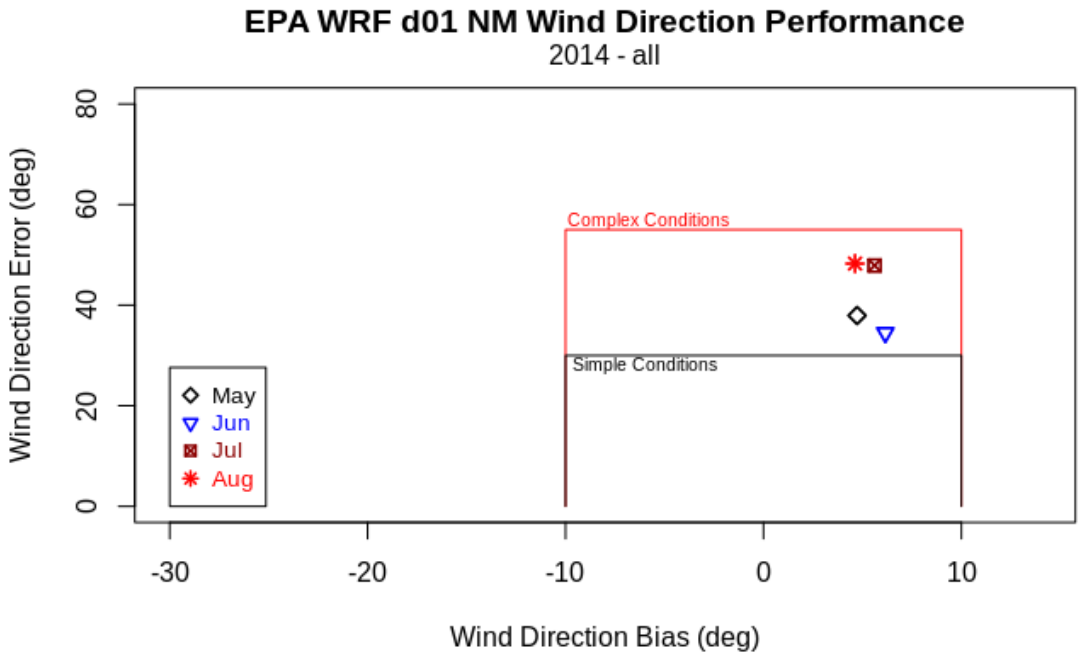
All months within complex conditions goal for both runs

Both runs have underprediction bias for all months; EPA slightly better

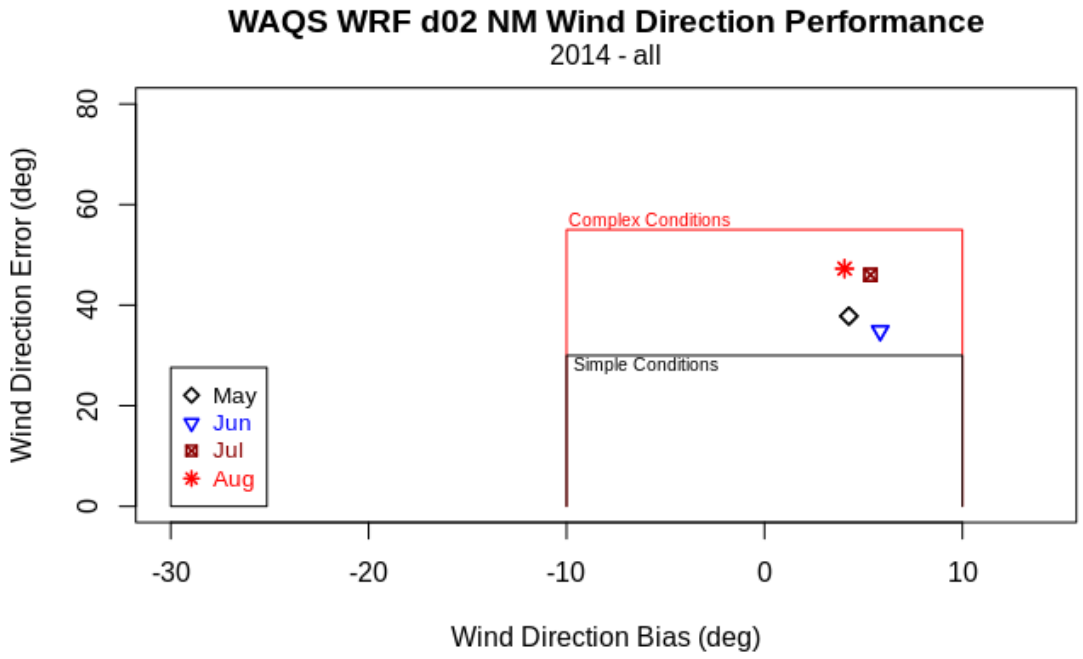
NMED Exhibit 18 - 0013

Soccer Plots – Wind Direction for all NM sites

EPA 12 km



WAQS 12 km

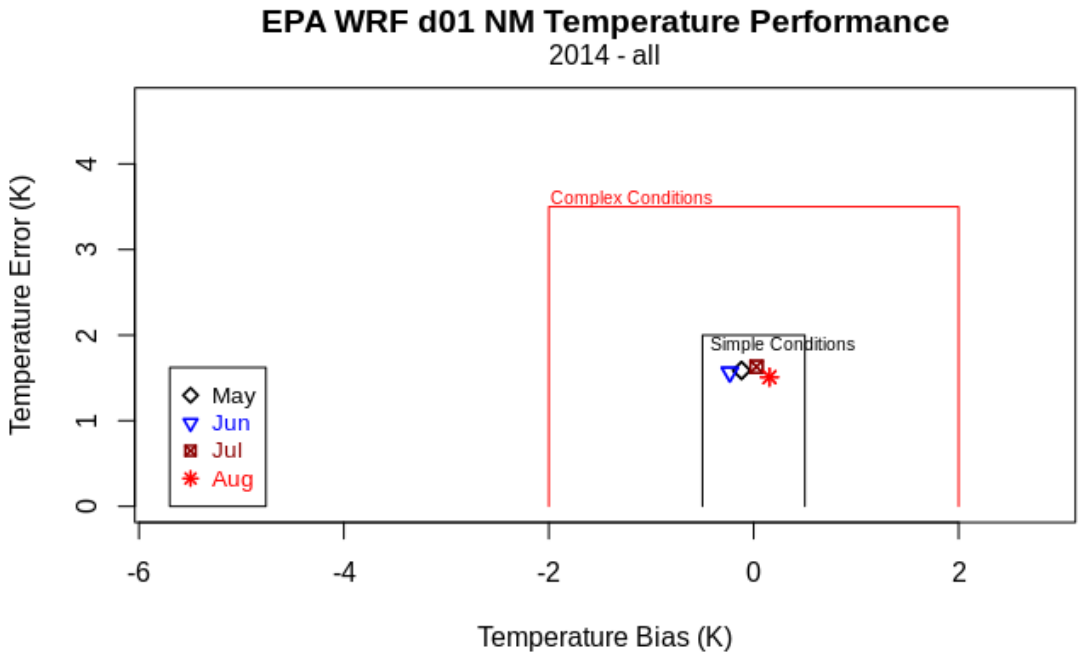


WAQS and EPA performance nearly identical

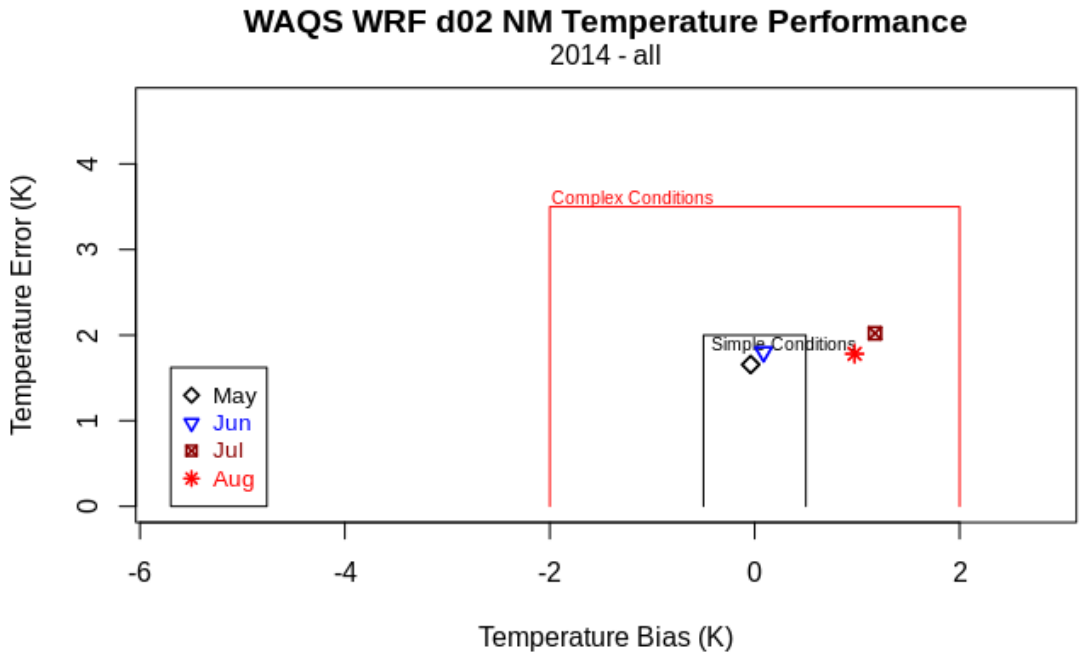
NMED Exhibit 18 - 0014

Soccer Plots – Temperature for all NM sites

EPA 12 km



WAQS 12 km



EPA run outperforms WAQS

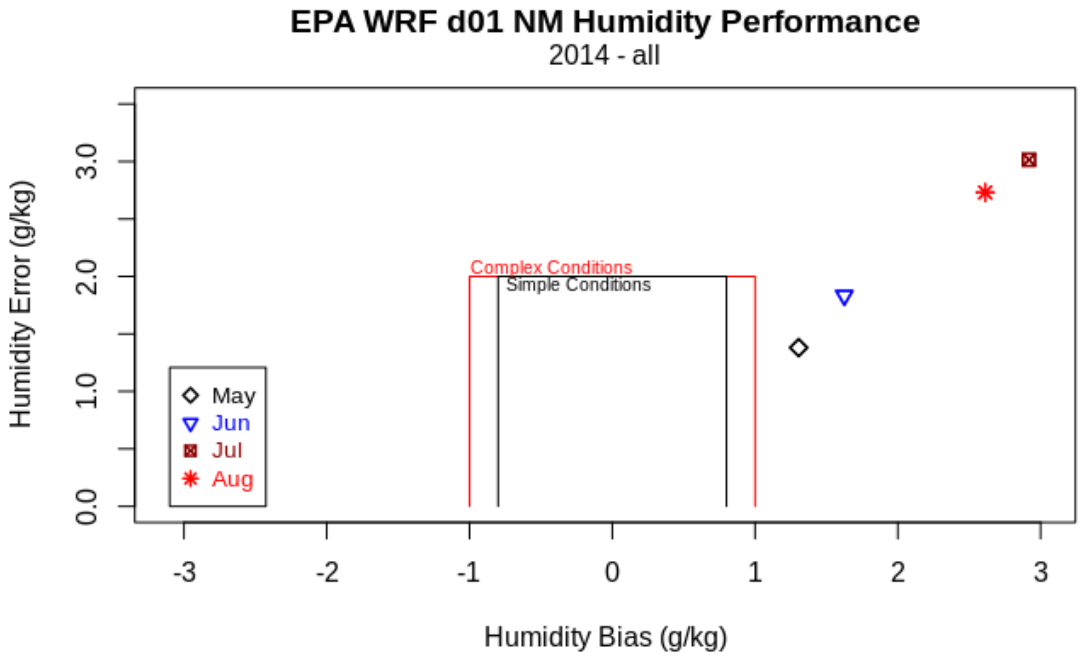
WAQS temperature poorest for Jul-Aug with warm bias

RAMBOLL

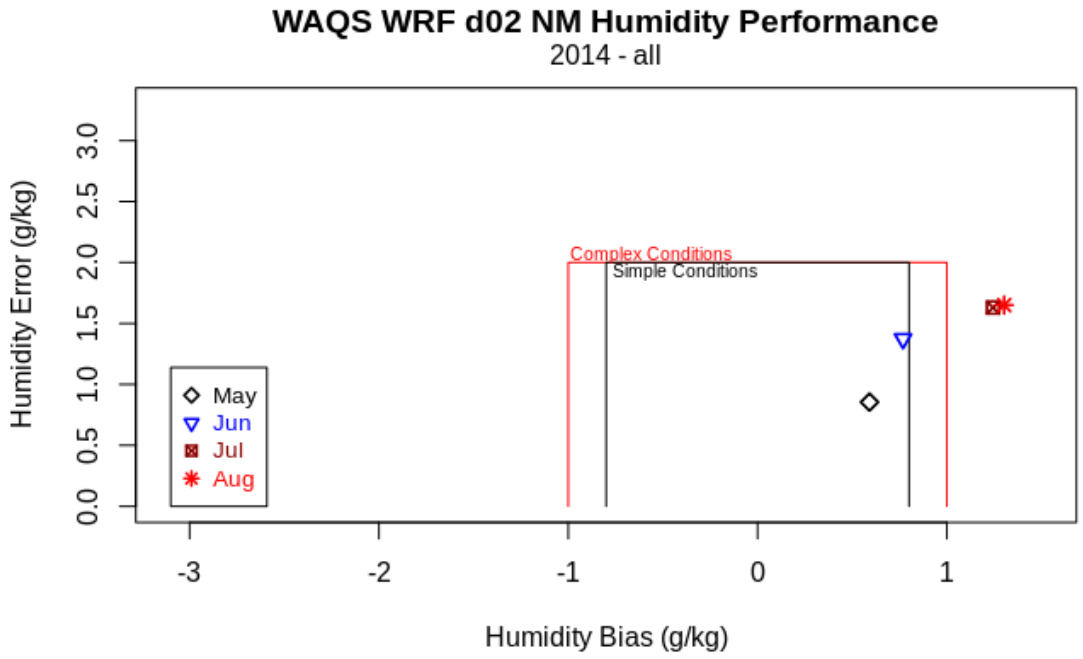
NMED Exhibit 18 - 0015

Soccer Plots – Humidity for all NM sites

EPA 12 km



WAQS 12 km



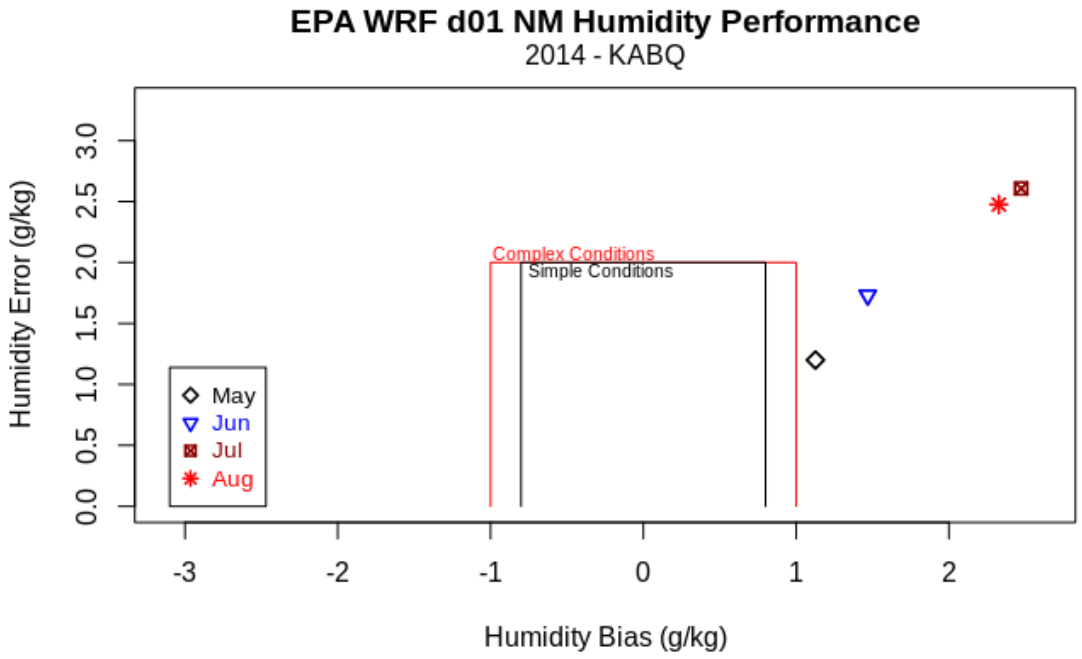
WAQS run outperforms EPA; both runs have positive (wet) bias for all months

EPA performance poorest for Jul-Aug: overactive convection?

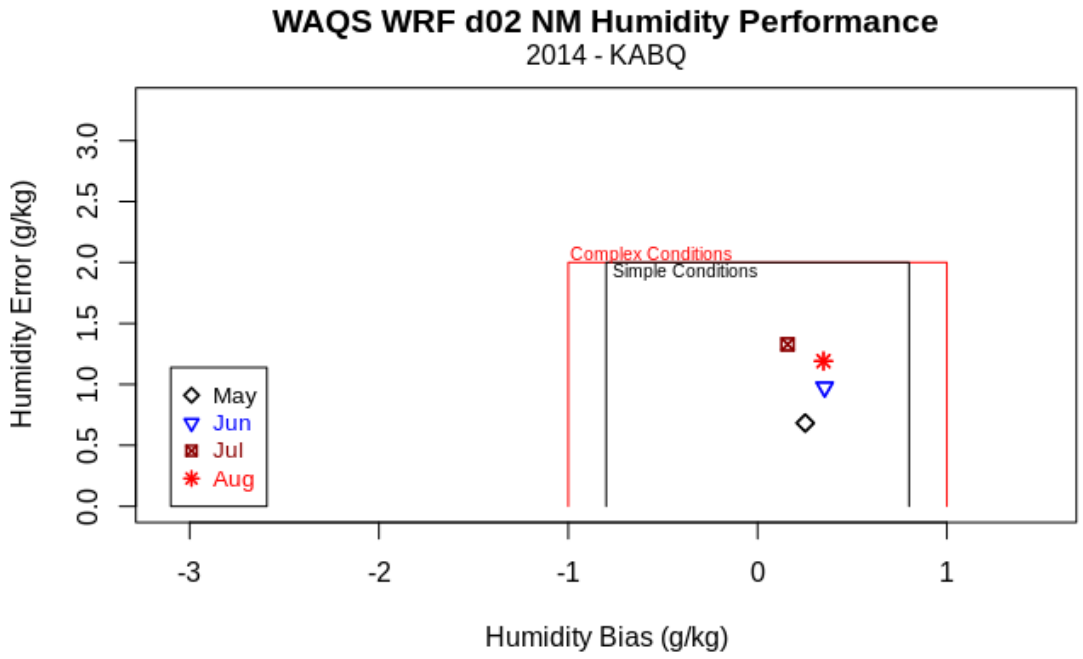
NMED Exhibit 18 - 0016

Soccer Plots – Humidity for KABQ

EPA 12 km



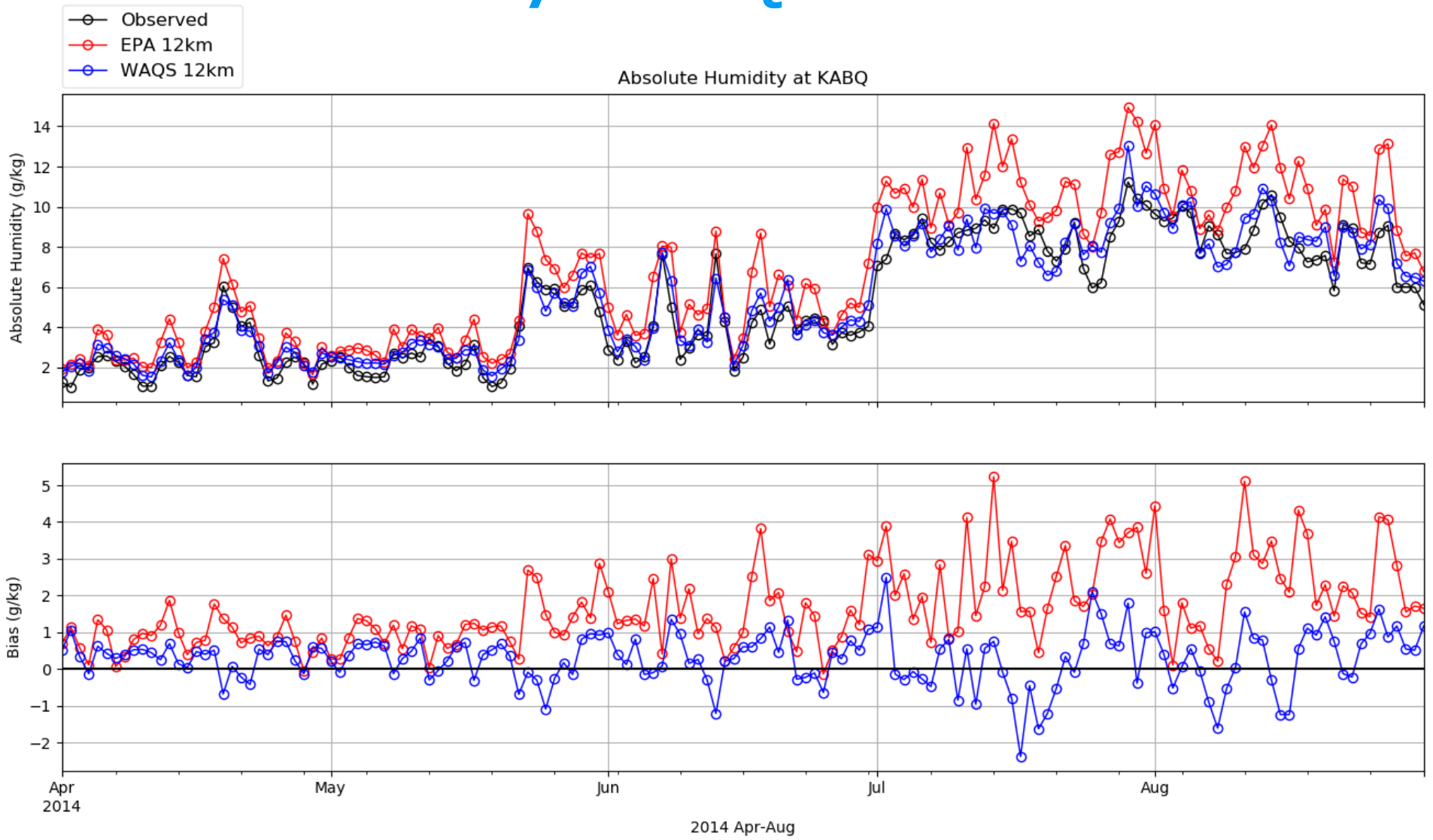
WAQS 12 km



WAQS run outperforms EPA; much smaller wet bias for all months

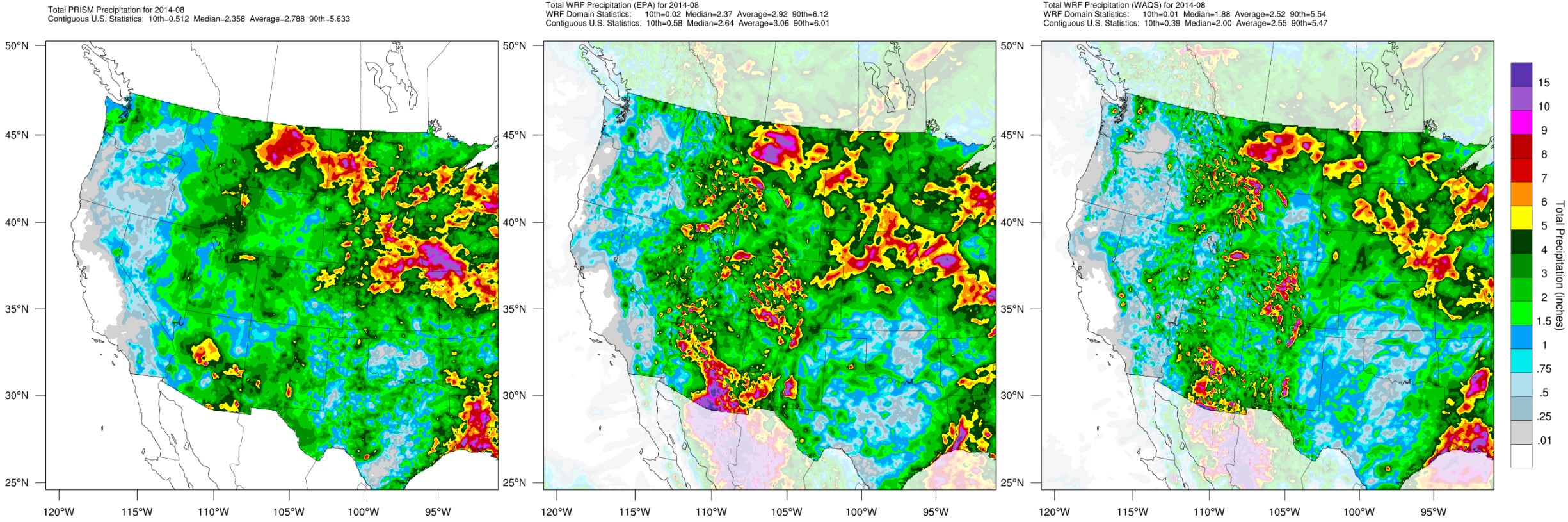
NMED Exhibit 18 - 0017

Time Series – Humidity at KABQ



Monthly Precipitation Plots – Aug 2014

PRISM Obs



EPA 12 km

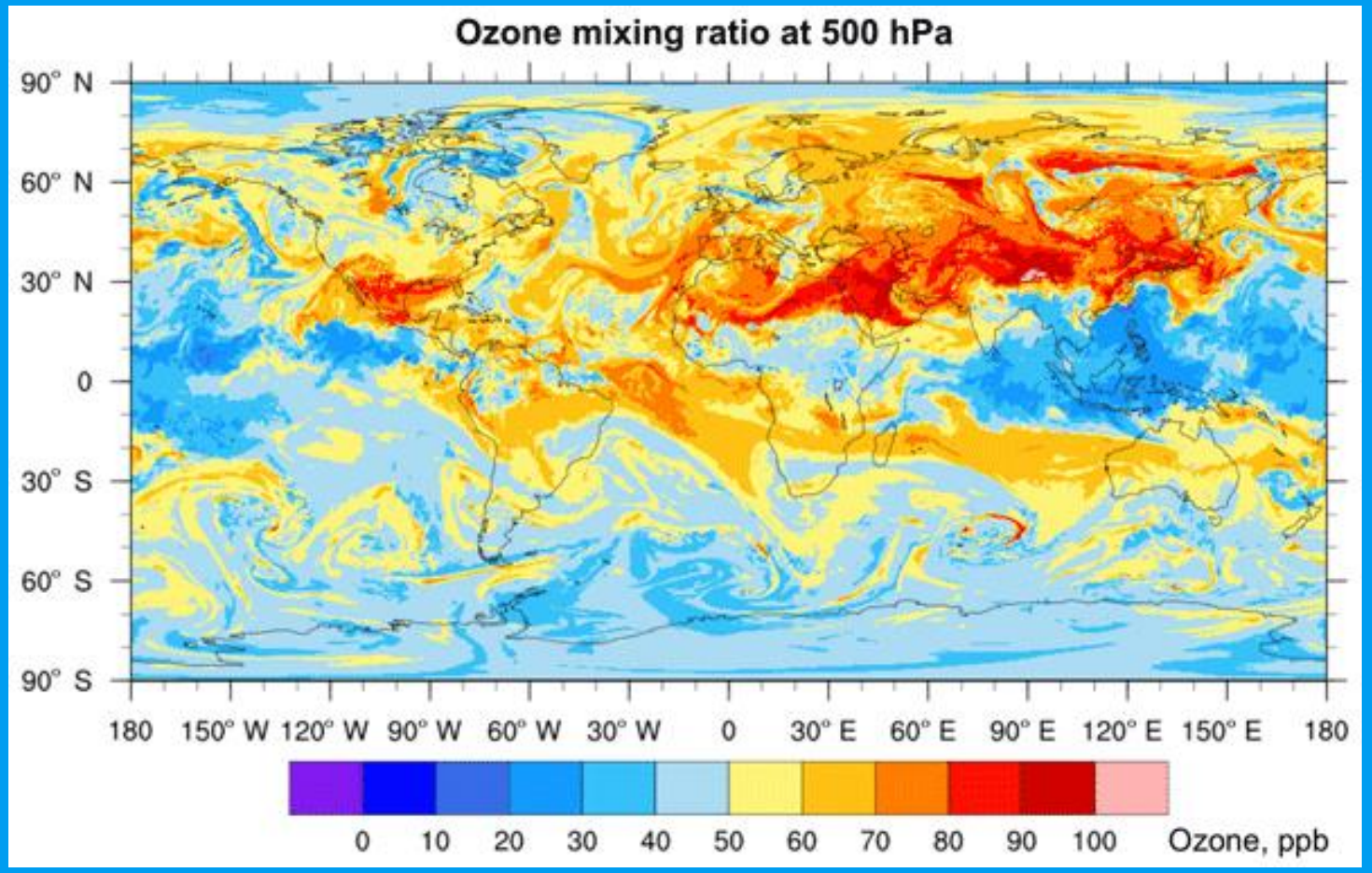
WAQS 12 km

NMED Exhibit 18 - 0019

Existing 2014 WRF MPE Summary and Conclusions

- WRF performance reasonable for both simulations outside of humidity/precipitation
- EPA wet bias in summer months associated with overactive summer convection
- WAQS smaller wet bias
- NM OAI proposed WRF configuration aligns closely with WAQS to avoid overactive summer convection in New Mexico, with these differences
  - Reposition 4 km domain to encompass all of New Mexico
  - Use hybrid vertical coordinate to improve representation of upper troposphere/lower stratosphere
  - Add second simulation driven by ERA5 analysis
  - No observation nudging
- Two NM OAI WRF simulations (WRF/NAM12 and WRF/ERA5) currently running
- Present evaluation of these two simulations in June webinar

Task 3: Evaluate 2014 Boundary Conditions Based on WRAP 2014 GEOS-Chem



RAMBOLL

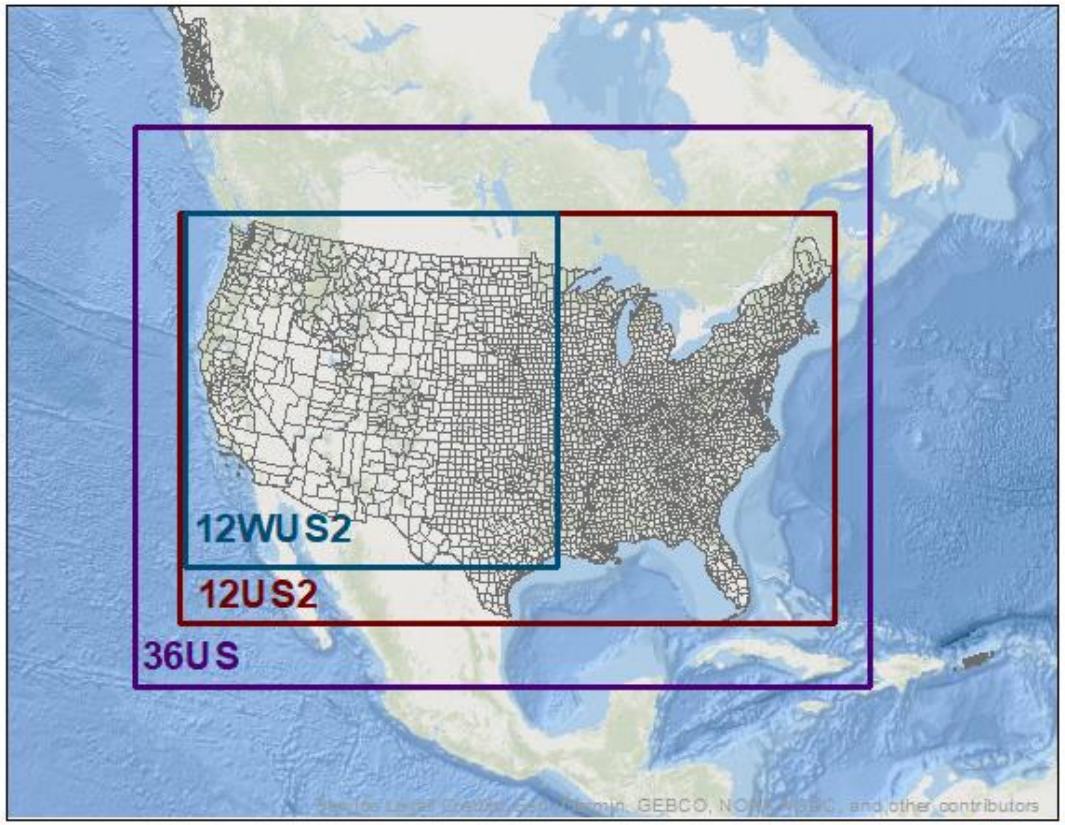
Overview of 2014 BC Evaluation

- Overview of WAQS-WRAP 2014 GEOS-Chem modeling
- Overview of WAQS 2014 Representative Base case Scenario
- Analysis of WAQS 2014 modeling results and BC contributions

NMED Exhibit 18 - 0022

Background

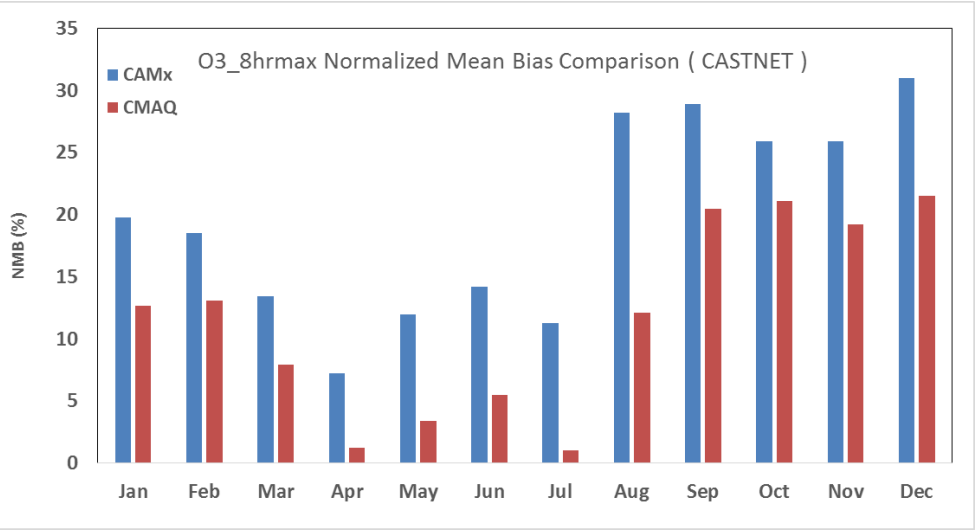
- Phase I and II of WRAP 2014 Shake-Out study developed a 2014v1 PGM modeling platform:
  - 36-km 36US and 12-km 12WUS2 domains
  - CMAQ and CAMx PGMs
  - **EPA 2014 GEOS-Chem BCs**
  - 2014v1 Emissions
    - 2014NEIv2 with western state updates
  - BEIS Biogenic Emissions

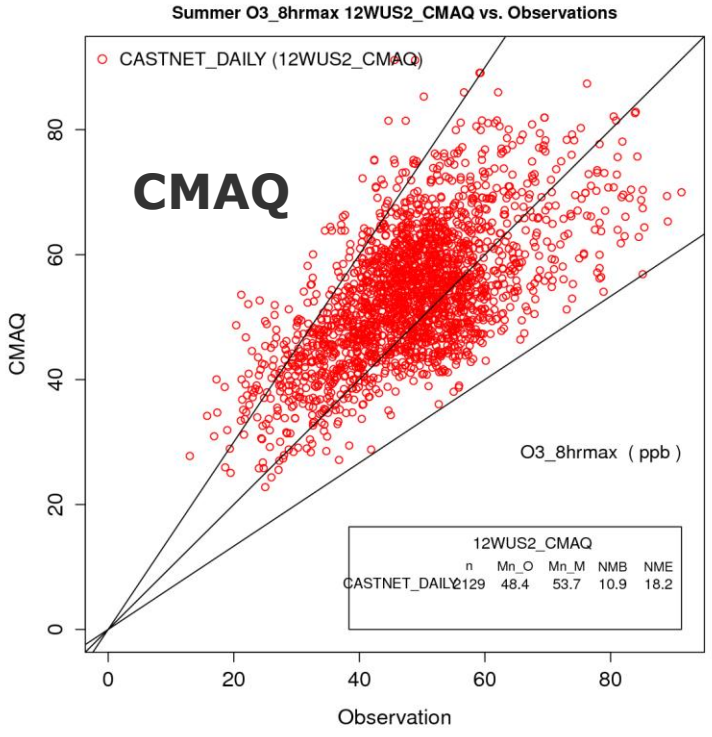


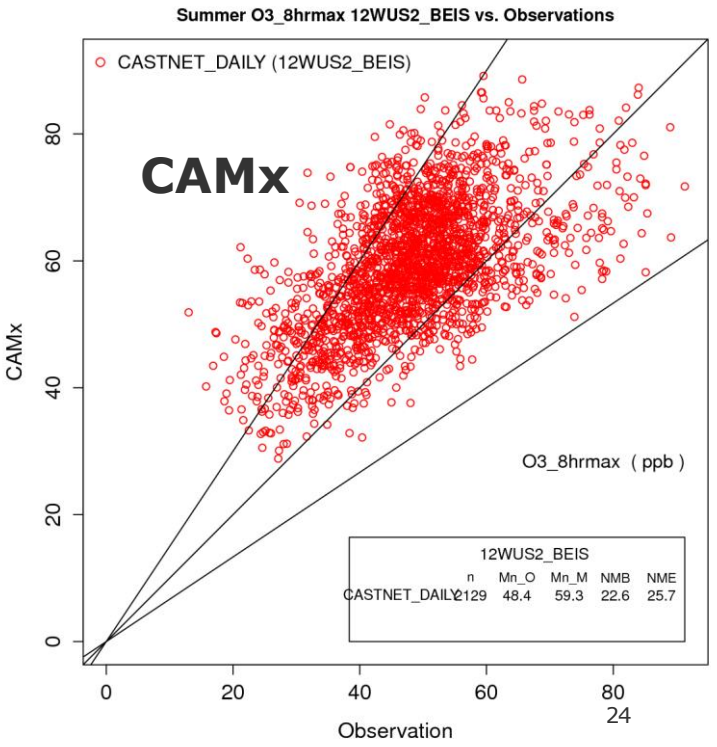
RAMBOLL

BCs Based on EPA 2014 GEOS-Chem had issues

- Year-round ozone overestimation bias
  - In both CMAQ and CAMx, but more pronounced in CAMx
- Maybe some SO4 overestimation, even after eliminating volcano eruptions and DMS emissions







RAMBOLL

NMED Exhibit 18 - 0024

Revised 2014 GEOS-Chem simulation

- WRAP elected to conduct a revised 2014 GEOS-Chem simulation
  - Use updated emissions, newer GEOS-Chem version and other updates as used by EPA and Ramboll in their 2016 GEOS-Chem runs that produced BCs without the large ozone overestimation bias in the CMAQ and CAMx simulations.

Science Options	WRAP 2014 Basecase	EPA 2014 Basecase	EPRI 2016 Basecase
Version	Version 12.2.0 (2019-02-19)	Version 11-01 (2017-02-01)	Version 11-02r (2018-06-22)
Vertical Grid Mesh	72 Layers	47 Layers	72 Layers
Chemistry mechanism	standard chemistry with complex SOA option	tropospheric chemistry with complex SOA option	standard chemistry with complex SOA option
Horizontal Grids	2x2.5 degree (Nx, Ny = 144, 91)	4x5 degree (Nx, Ny = 72, 46)	2x2.5 degree (Nx, Ny = 144, 91)
Initial Conditions	6-month spin-up	1-year spin-up	6-month spin-up
Meteorology	2014 GEOS-FP meteorology	2014 GEOS-5 meteorology	2016 GEOS-FP meteorology
Photolysis	Default (FAST-J)	Default (FAST-J)	Default (FAST-J)
Advection Scheme	Default (TPCORE)	Default (TPCORE)	Default (TPCORE)
Cloud Convection	On/Relaxed Arakawa-Schubert	On/Relaxed Arakawa-Schubert	On/Relaxed Arakawa-Schubert
PBL	Lin and McElroy	Lin and McElroy	Lin and McElroy
Dry Deposition	Default (Wesely)	Default (Wesely)	Default (Wesely)
Chemistry Solver	Default (FLEXCHEM)	Default (FLEXCHEM)	Default (FLEXCHEM)
Parallelization	Open Multi-Processing (OMP)	Open Multi-Processing (OMP)	Open Multi-Processing (OMP)

RAMBOLL

NMED Exhibit 18 - 0025

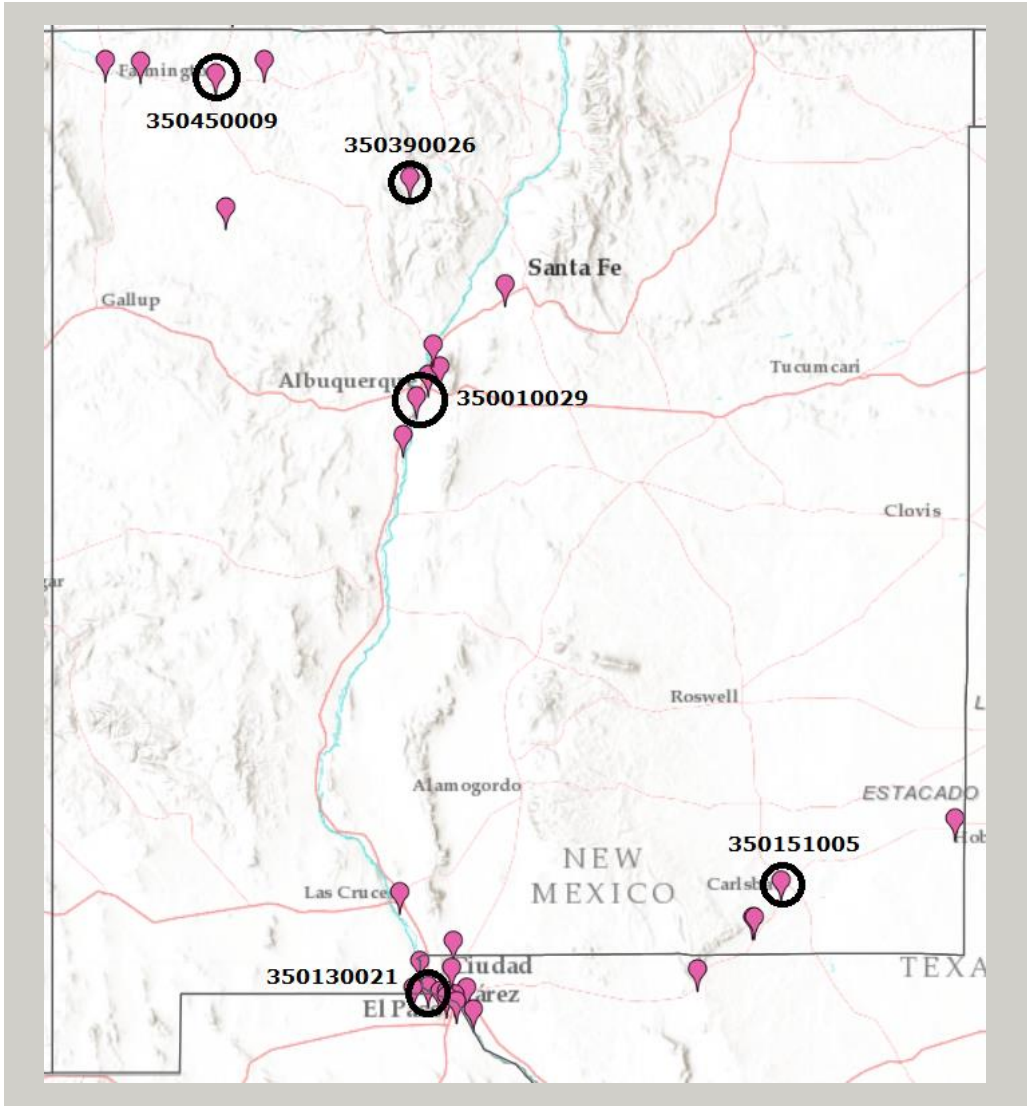
Representative Base Case Simulation Description

- WRAP 2014 GEOS-Chem used to derive Boundary conditions for 2014v2 and Representative Baseline (RepBase)
- Two additional GEOS-Chem simulations were performed to separate the Natural, Anthropogenic International and US contributions in the boundary conditions themselves:
  - Natural (NAT) and Zero-Rest-Of-the-World (ZROW)
- RepBase was instrumented in CAMx with source apportionment technology to track the ozone and PM contributions from the following 14 categories including boundary conditions:

Source Group Number	Brief Description
1	Natural Emissions
2	U.S. Wildfires (WF)
3	U.S. Prescribed Burns (Rx)
4	U.S. Agricultural Burning (Ag)
5	U.S. Anthropogenic Emissions (USAnthro)
6	Mexico Anthropogenic Emissions
7	Canada Anthropogenic Emissions
8	Off-Shore Commercial Marine Vessel (CMV) C3 Ocean Going Vessels (OGV) within 200 nautical miles of the coast (i.e., within the Emissions Control Area, ECA)
9	Remainder off-shore anthropogenic emissions that includes CMV C3 OGV outside of the ECA and non-U.S. O&G
10	Boundary Conditions: International contributions (BC_Intl)
11	Boundary Conditions: Natural contributions (BC_Nat)
12	Boundary Conditions: US contributions (BC_US)
13	Initial Conditions contributions
14	Top Boundary Concentrations contributions (top of the model)

RAMBOLL

Boundary Conditions Analysis Sites



- Compared MDA8 ozone from WRAP Representative Base scenario (RepBase) source apportionment with a few selected and representative AQS sites in NM

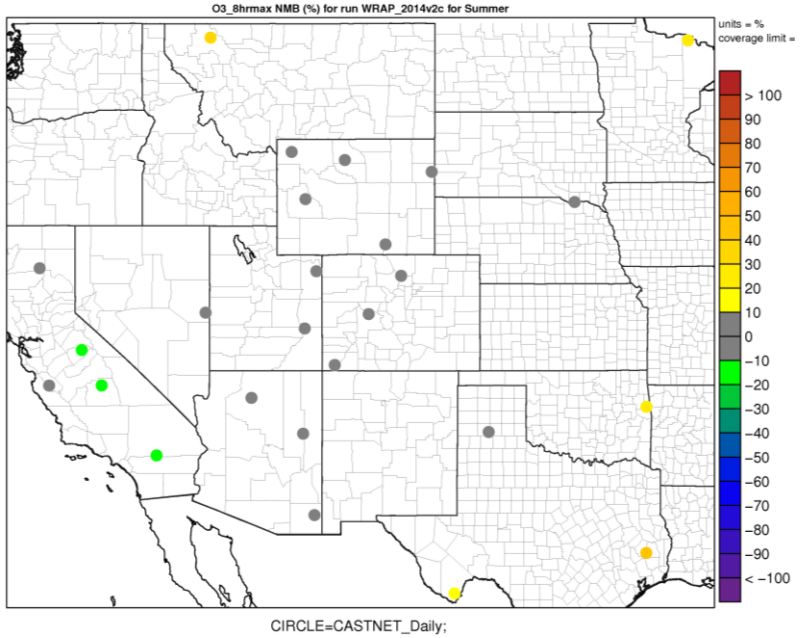
Site ID	County	Latitude	Longitude
350450009	San_Juan	36.74	-107.98
350390026	Rio_Arriba	36.19	-106.70
350010029	Bernalillo	35.02	-106.66
350130021	Dona_Ana	31.80	-106.58
350151005	Eddy	32.38	-104.26

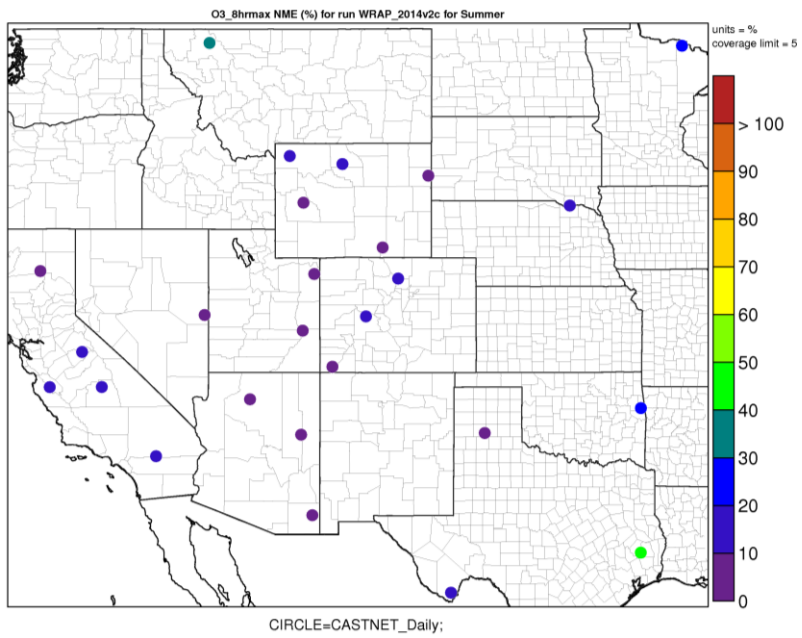
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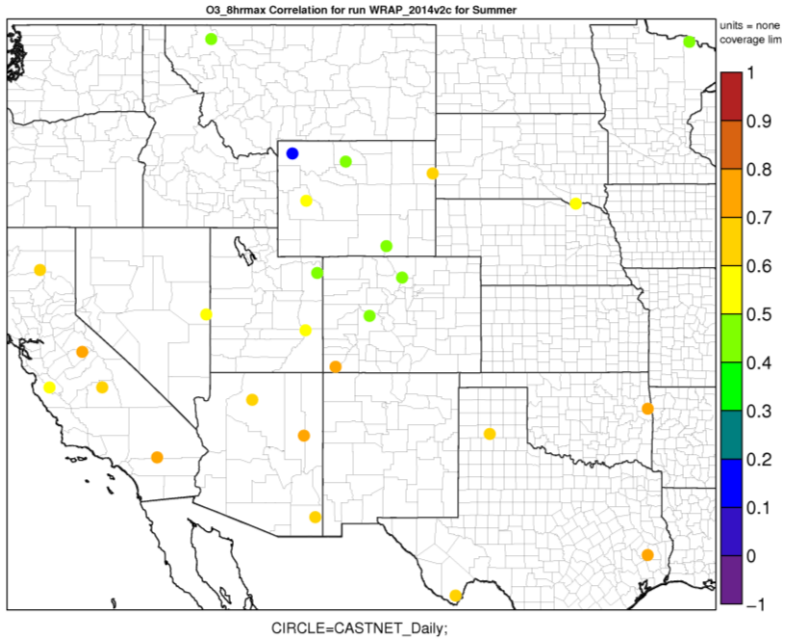
Selected Sites Ozone Model Performance

- RepBase does not have year specific emissions and is not meant to represent 2014. Fires contributions have been removed from this analysis
- RepBase statistics indicate performance for scenario in these sites are almost all within the goals for NMB and NME, within criteria for r
- Consistent with 2014v2 AZ, UT, CO ozone **NMB**, **NME** and **r** in the Summer (no CASTNET sites in NM)

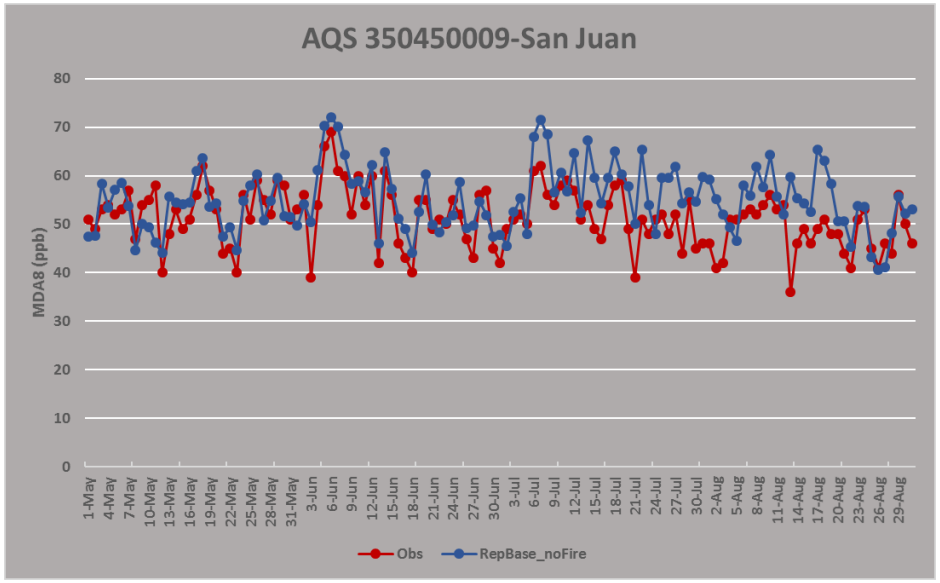
Site ID	County	NMB (%)	NME (%)	r
350450009	San_Juan	7.36	10.36	0.63
350390026	Rio_Arriba	3.24	8.62	0.57
350010029	Bernalillo	1.34	8.10	0.66
350130021	Dona_Ana	0.26	8.03	0.72
350151005	Eddy	-4.33	9.45	0.72

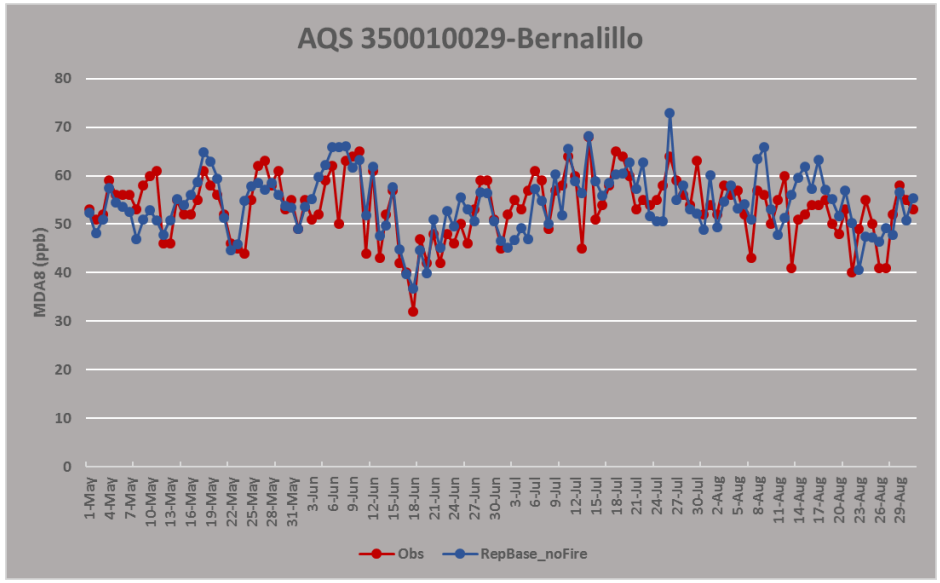


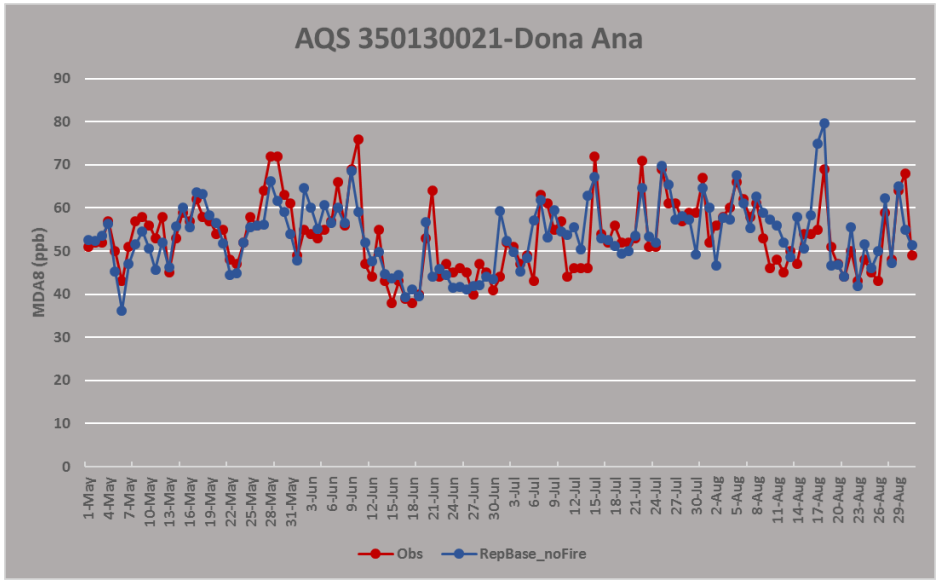


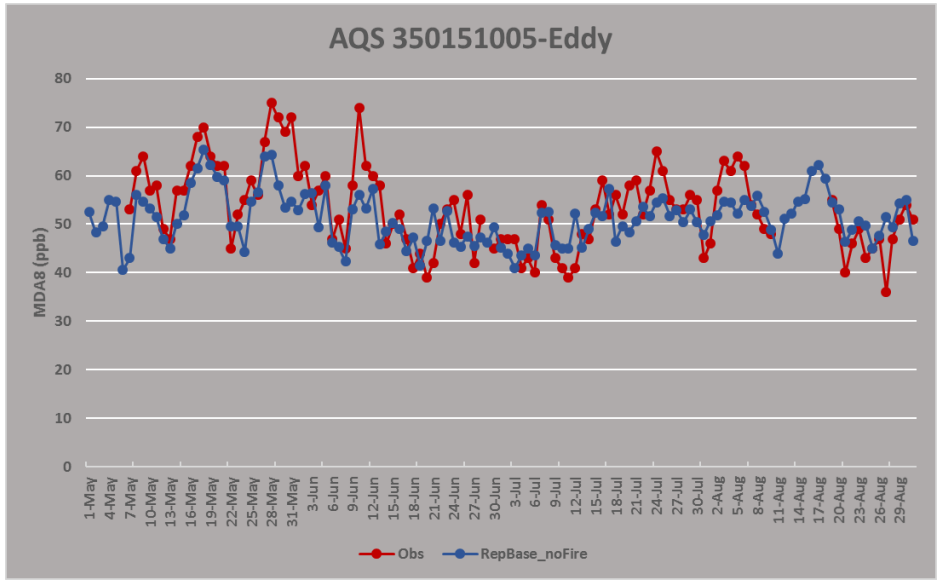


Selected Sites Time Series



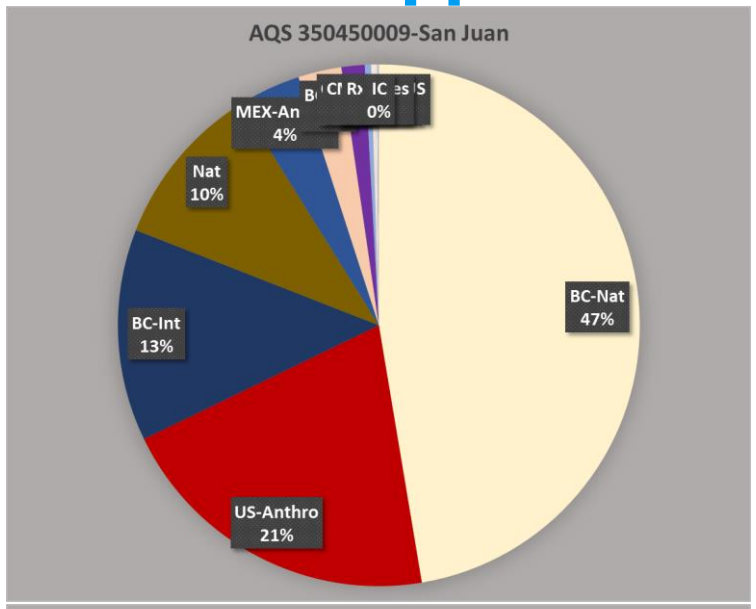


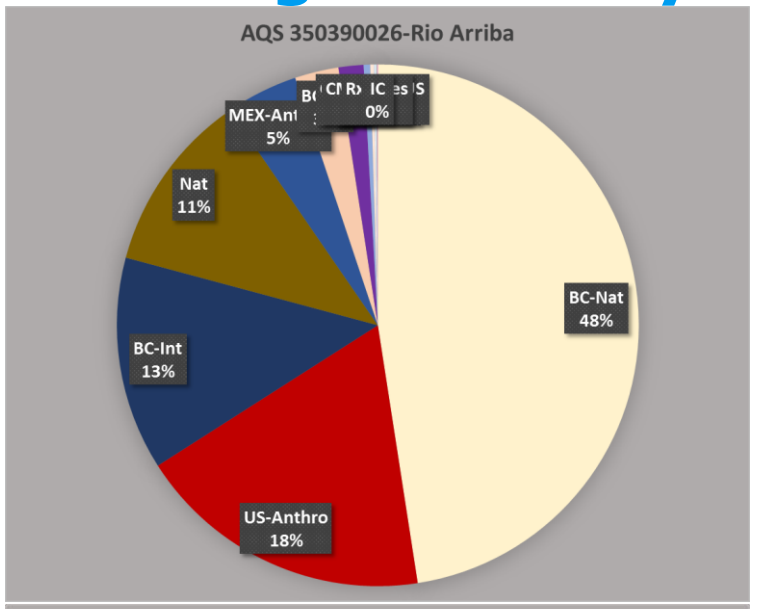


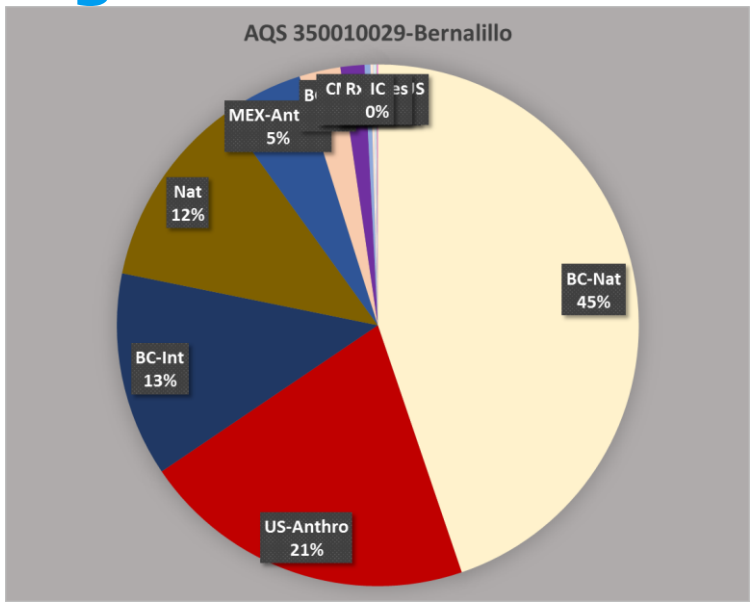


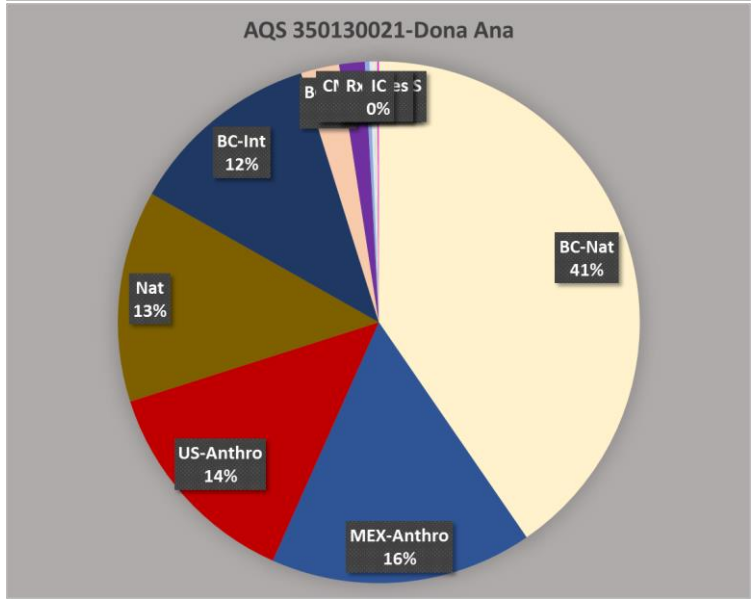
- RepBase statistics and time series suggest that is reasonable to use Source Apportionment results to understand sources of ozone at these sites

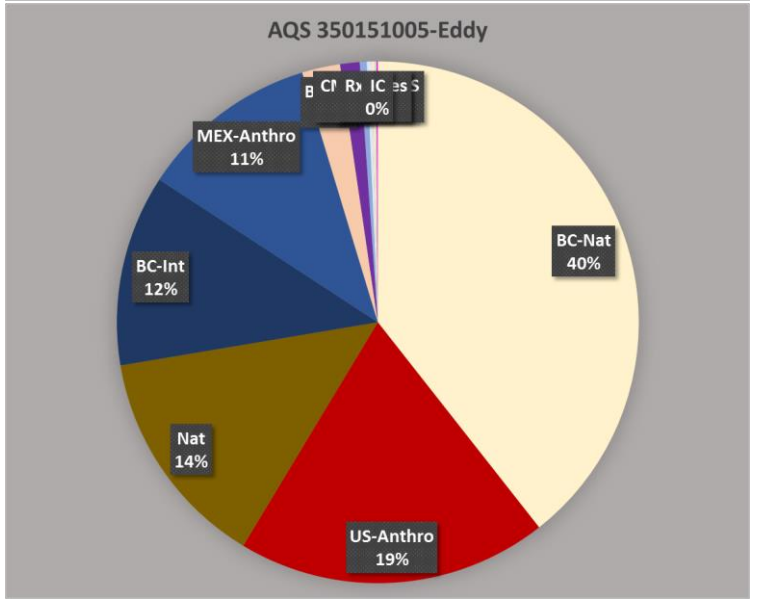
Source Apportionment Average over May to August







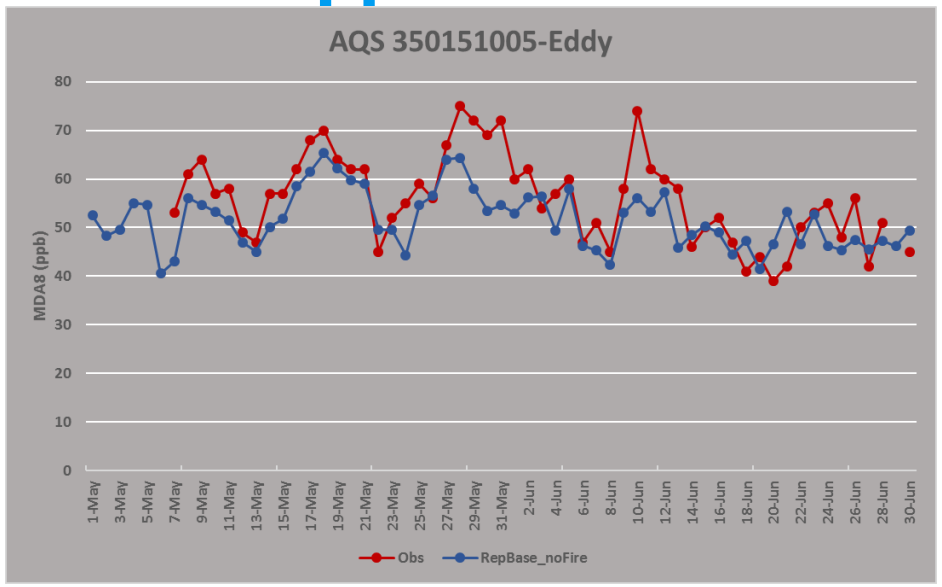


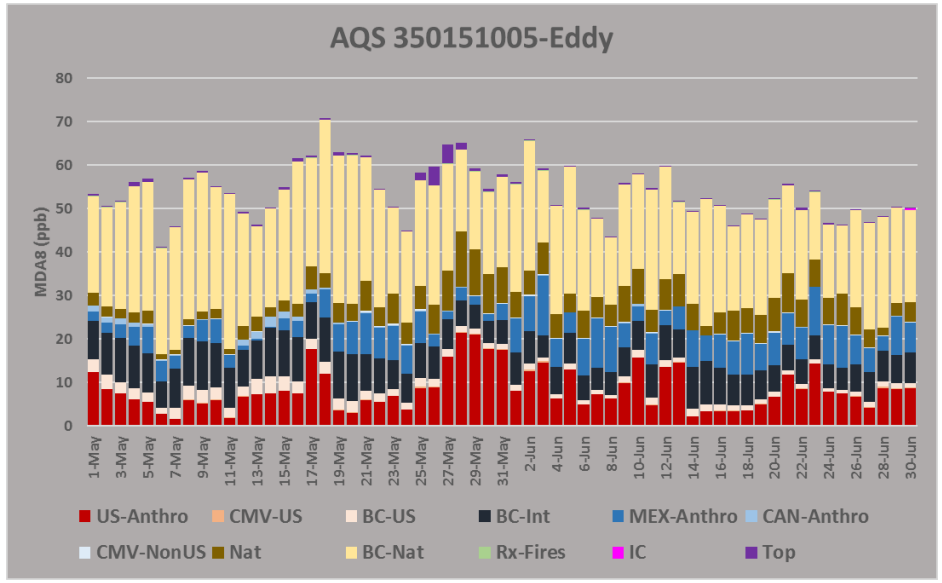


- Natural contribution from the GEOS-Chem Boundary Conditions ~ 40% to 48% of the ozone
- US Anthro ~ 14% to 21%
- International BC ~13%
- Mexican Anthro ~5%. Largest at Dona Ana county at 16%

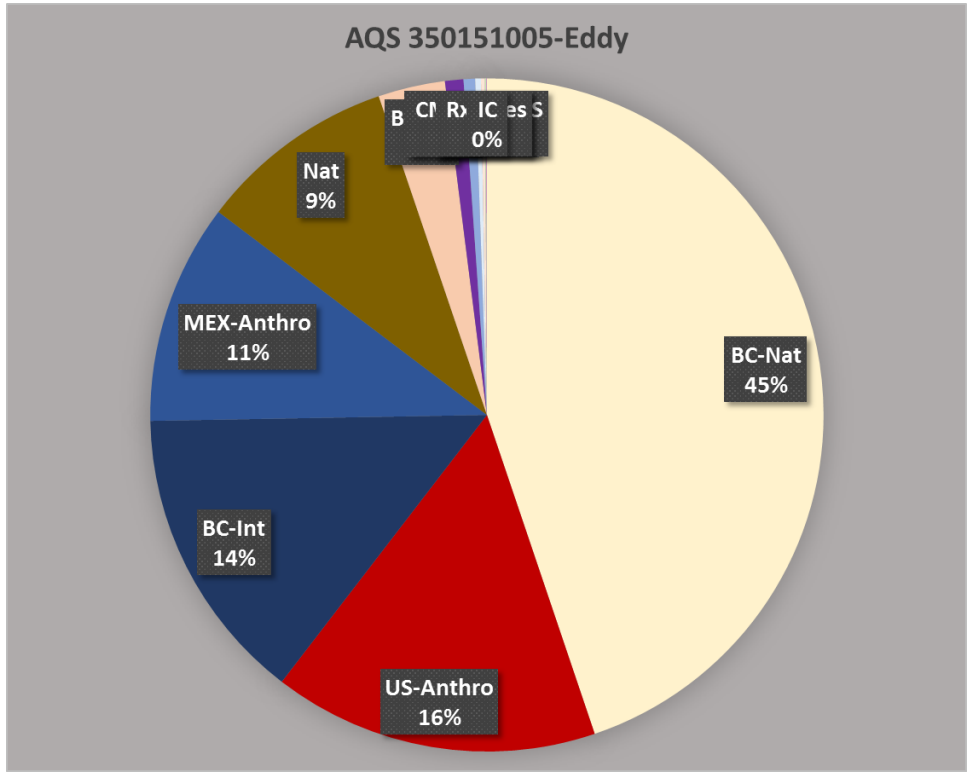
RAMBOLL

Source Apportionment: Eddy County



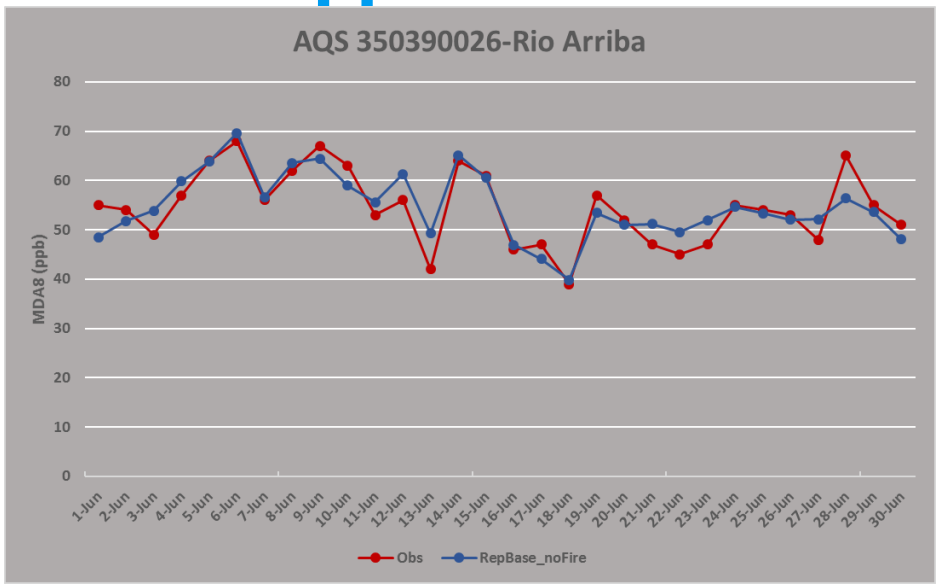


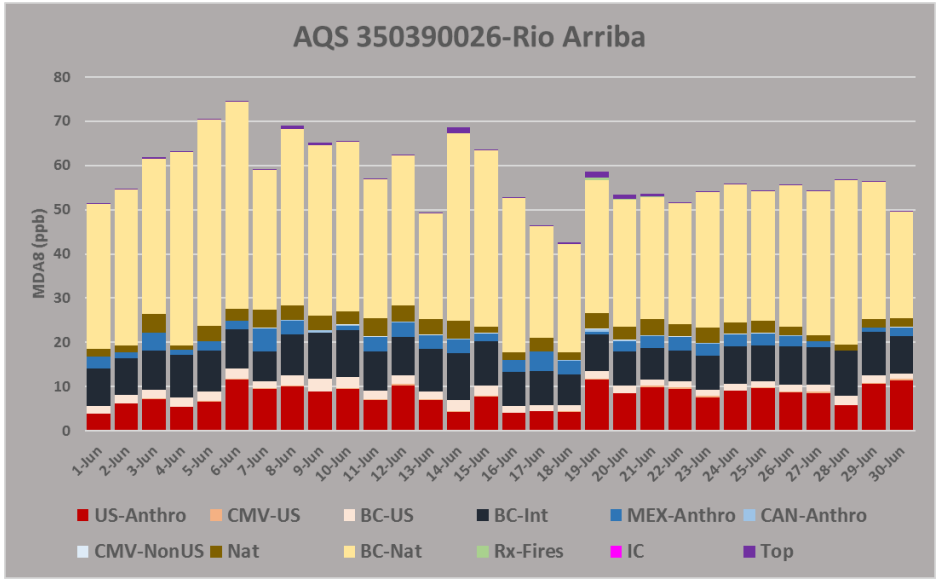
- Obs in Eddy County Site in May-Jun show multiple days with MDA8>70 ppb
- US Anthro and International BC contributions show equivalent contributions (16 and 14%)
- Peak on May 25 to 27 has some influence from the top of the model



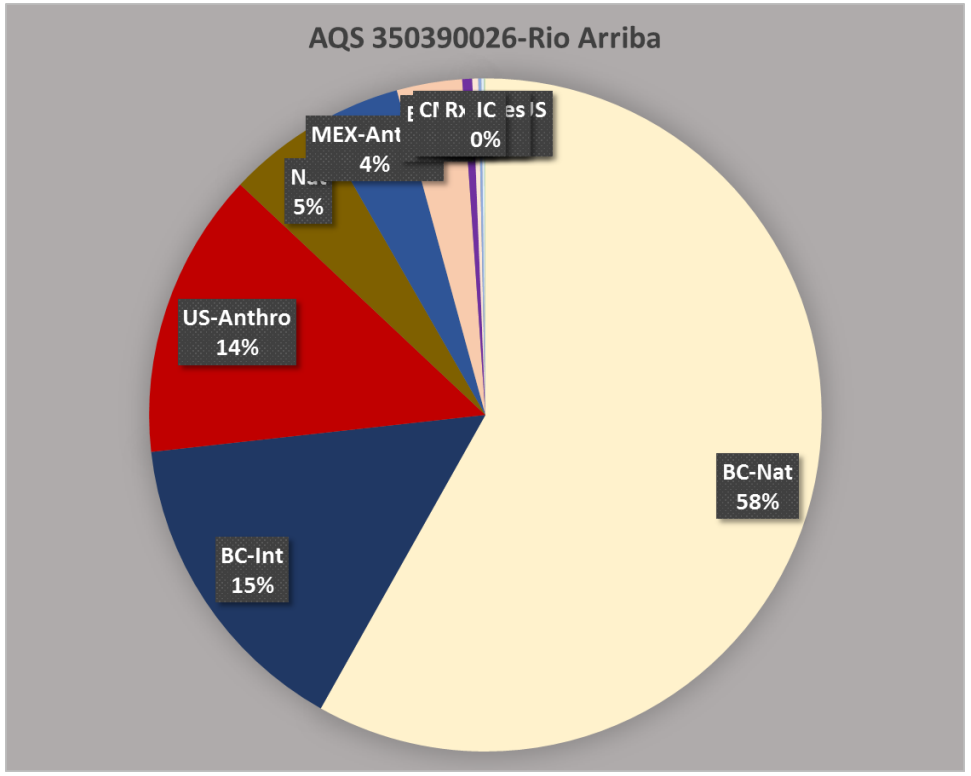
RAMBOLL

Source Apportionment: Rio Arriba county



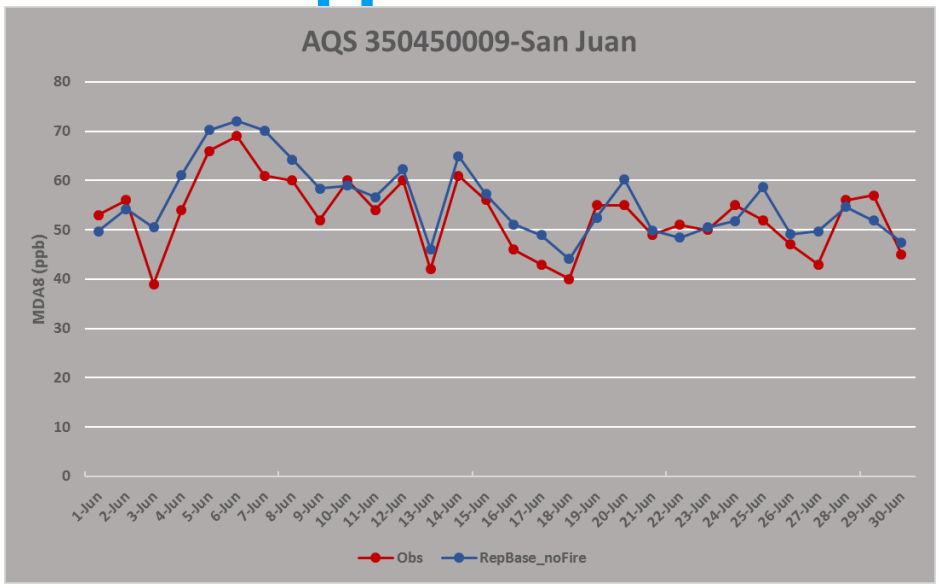


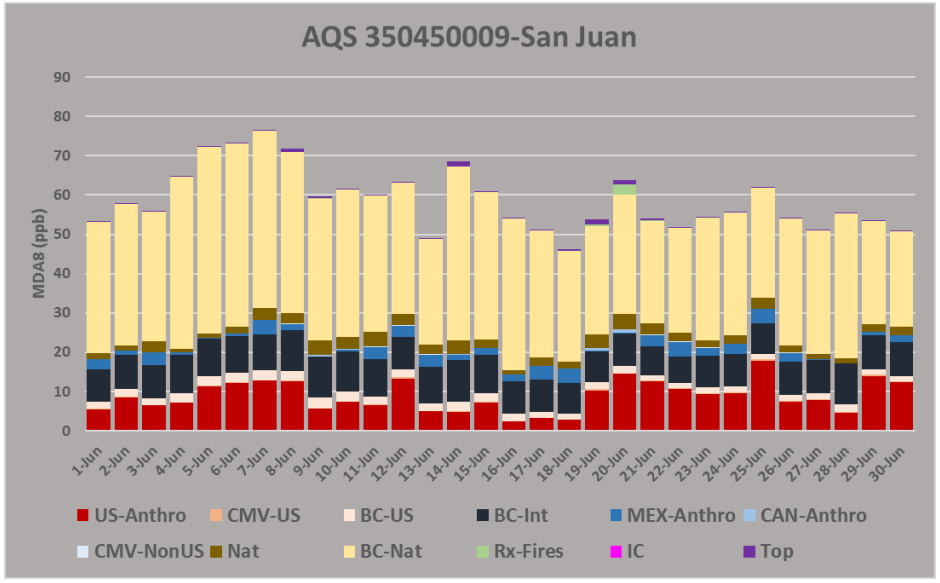
- International BC and US Anthro contributions show equivalent contributions (15 and 14%)
- Peak on June 6 dominated by Natural contributions from the Boundary



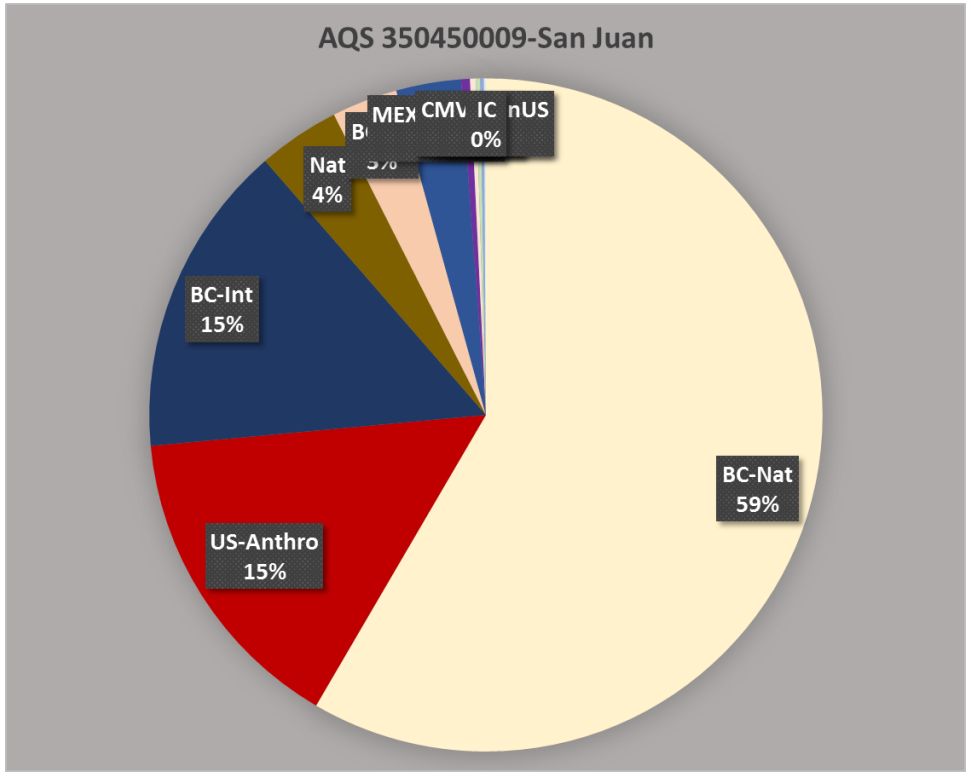
RAMBOLL

Source Apportionment: San Juan county



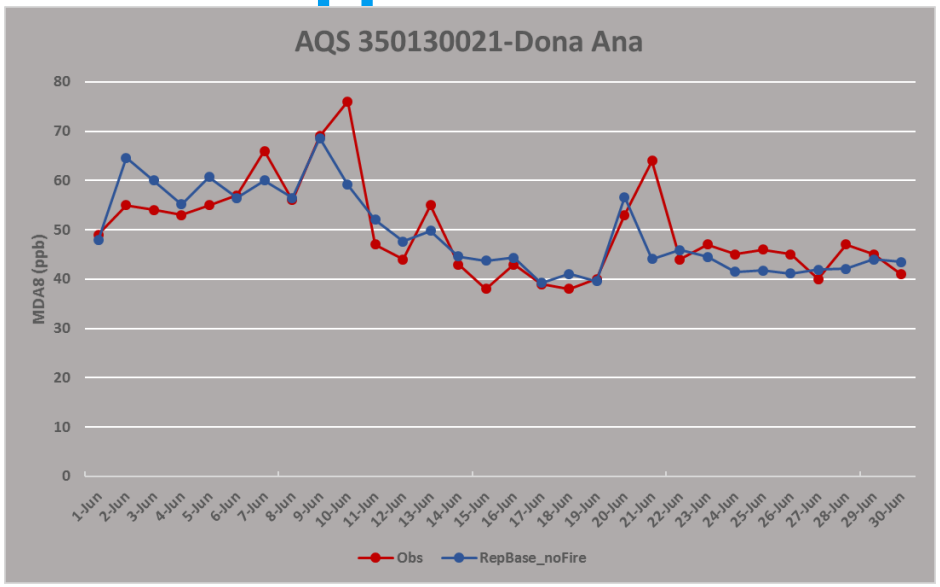


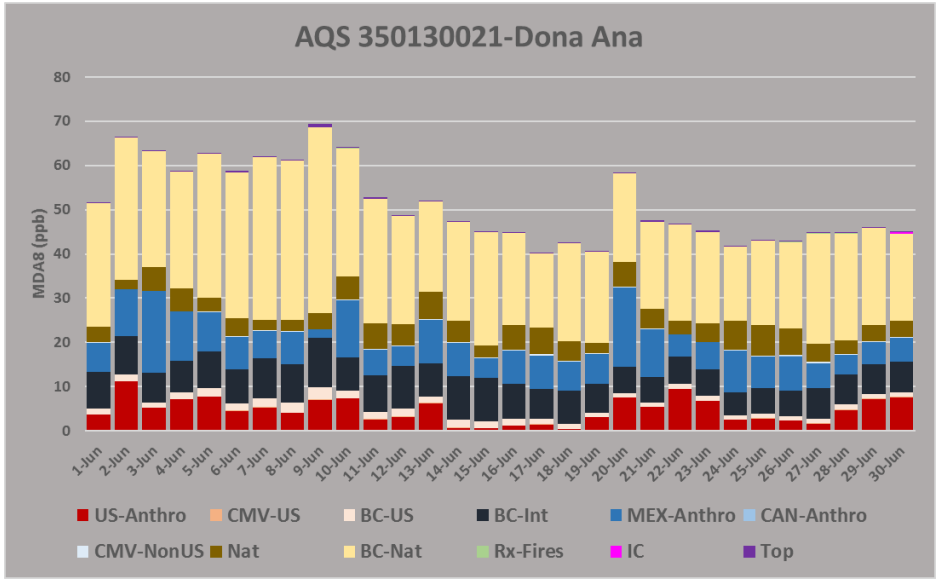
- International BC and US Anthro contributions show equivalent contributions (15%)
- Peak on June 7 dominated by Natural contributions from the Boundary



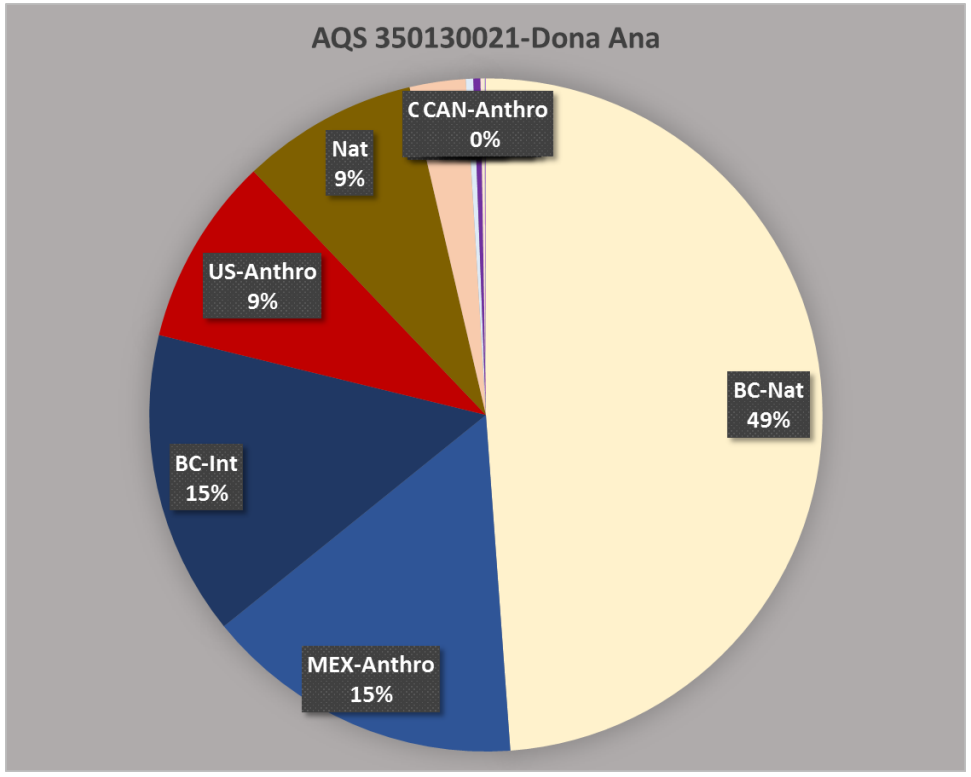
RAMBOLL

Source Apportionment: Dona Ana county



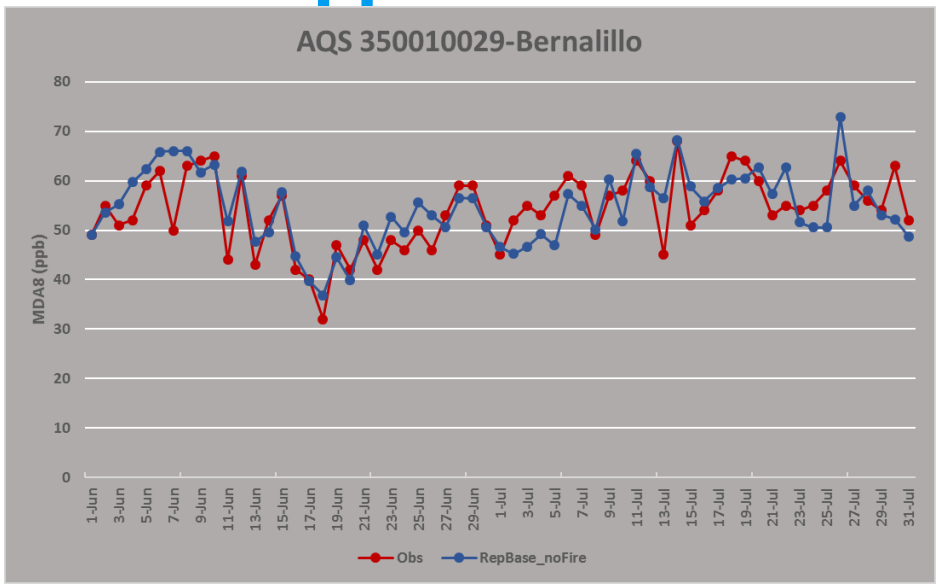


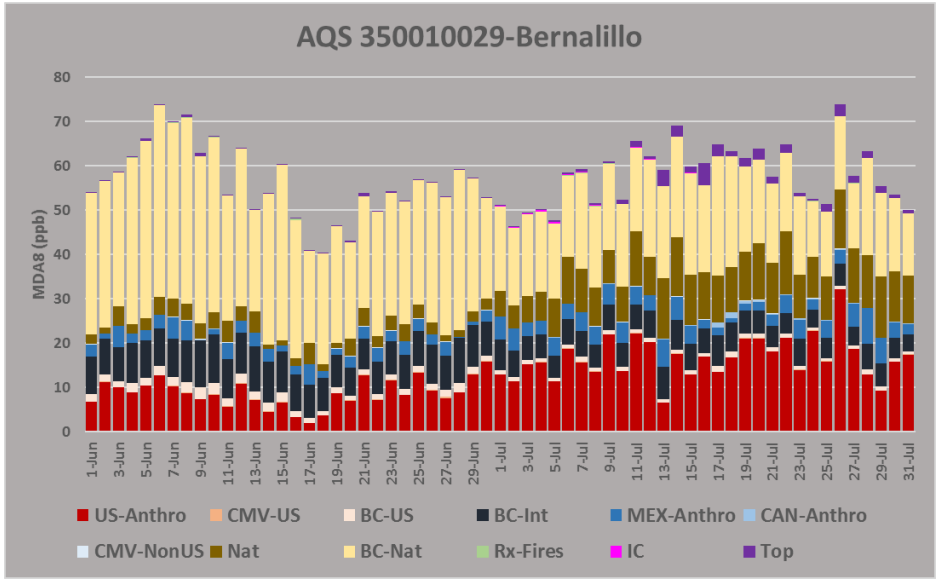
- International BC and Mexican Anthro contributions show equivalent contributions (15%)
- Peak on June 9 dominated by Natural contributions from the Boundary



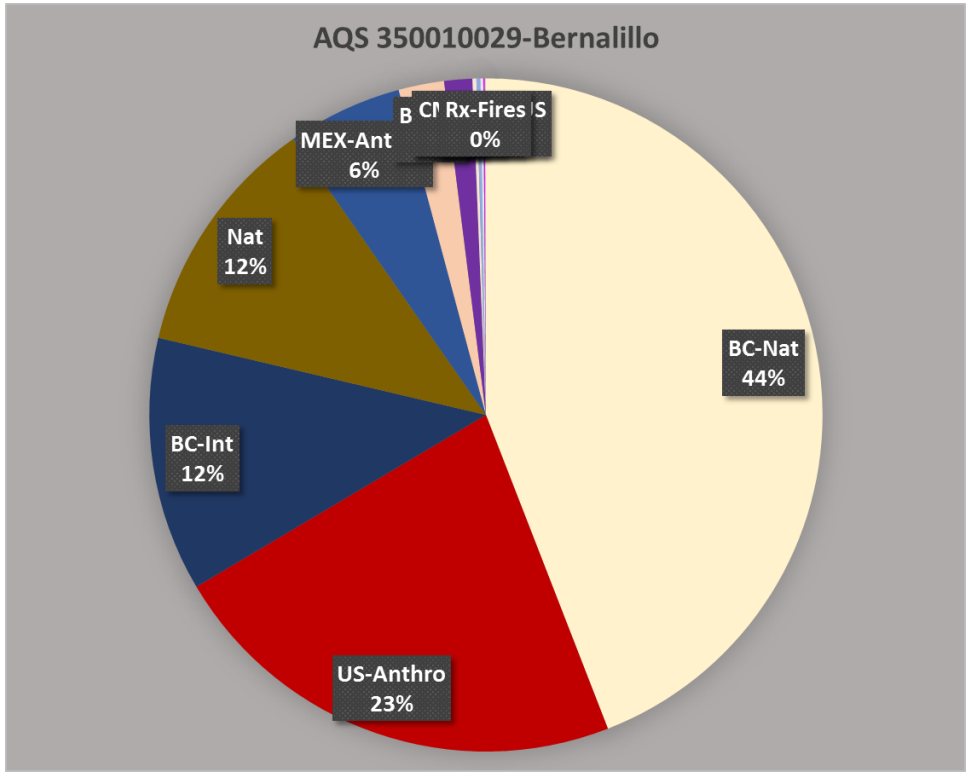
RAMBOLL

Source Apportionment: Bernalillo county





- US Anthro is almost twice as large as International BC contributions
- First peak in June has large US and International contributions, second peak in July more dominated by US natural sources



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GEOS-Chem Summary of Recent Updates

- WRAP 2014 Base Case used GEOS-Chem version 12.2.0 released 2019-02-19
- Current GC stable version is 12.8.2 released 2020-05-27
- Cumulative updates relevant for ozone :

Feature	Type	Version
Grid independent lighting NOx, biogenic and soil NOx emissions	Science	12.4.0
Updated offline biogenic emissions generated with GC 12.3.0	Science	12.5.0
Small alkyl nitrate chemistry	Science	12.7.0
Ozone deposition to the ocean	Science	12.8.0

http://wiki.seas.harvard.edu/geos-chem/index.php/GEOS-Chem_12#12.8.1

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NMED Exhibit 18 - 0036

Conclusions: BCs from WRAP 2014 GEOS-Chem

- Initial WRAP 2014v1 CAMx and CMAQ simulations using EPA 2014 GEOS-Chem BCs exhibited large ozone overestimation bias year-round
  - Made it difficult to evaluate other model options (e.g., biogenic emissions)
- WRAP elected to conduct their own 2014 GEOS-Chem using new versions of the model and emission inventories in CAMx 2014v2 and RepBase simulation
  - Much better ozone model performance across the western states
- We more closely examined WRAP CAMx 2014v2 ozone model performance in New Mexico
  - CAMx 2014v2 ozone performance in New Mexico good mostly achieving ozone performance goals
- We examined WRAP CAMx RepBase ozone source apportionment at sites in New Mexico
  - Found approximately 60%-75% of ozone was due to BCs, BCs from natural sources higher (40-50%)
  - Higher BC ozone contribution in northwest than southeast Counties in New Mexico
- Few recent updates to GEOS-Chem could affect ozone but would likely not significantly affect ozone BCs and would affect costs and schedule

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Task 1: Overview of Modeling Protocol



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Modeling Protocol – 1. Introduction

1.1 New Mexico OAI Project Genesis

1.2 Overview of NM OAI Study Modeling Approach

1.3 Related Studies

1.4 Conceptual Models for High Ozone in New Mexico

1.5 Overview of the Modeling Approach

1.6 Project Participants and Contacts

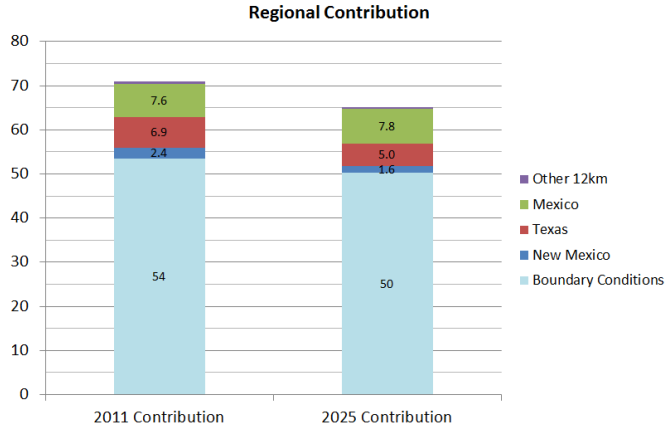
1.7 Communication

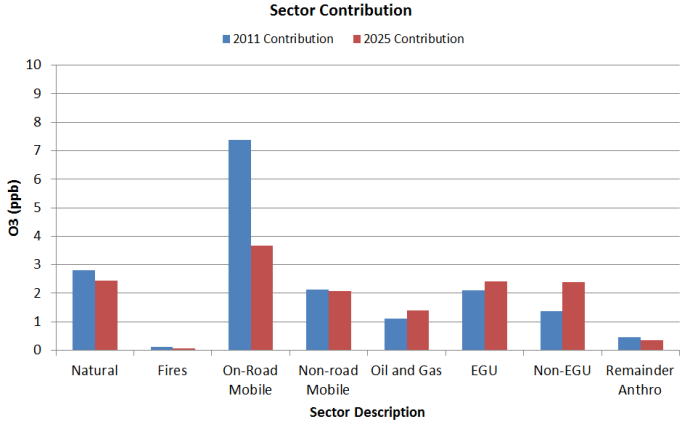
1.8 Schedule

RAMBOLL

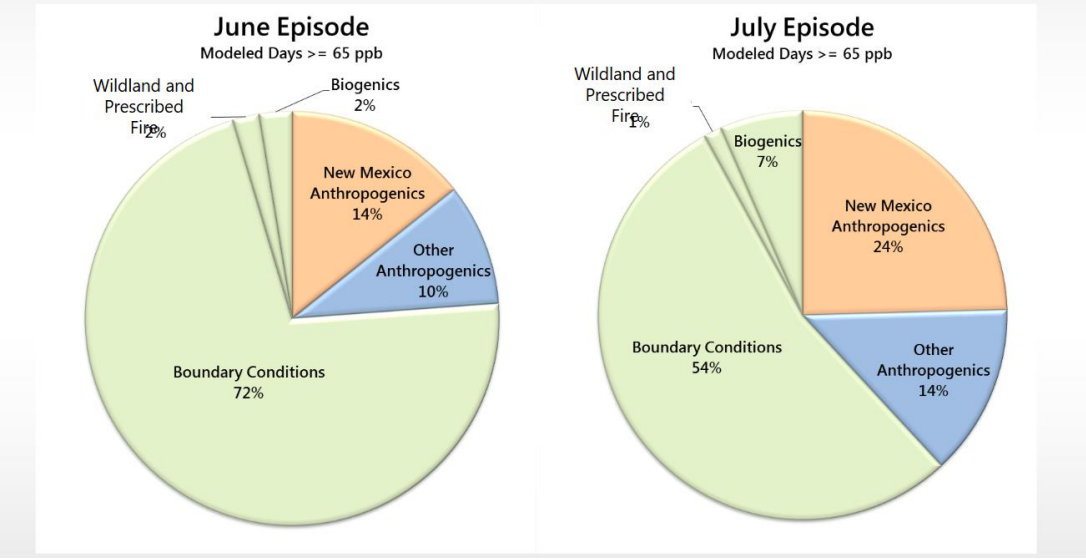
Modeling Protocol – 1. Introduction – 1.3 Related Studies

- Southern New Mexico Ozone Study (SNMOS)
  - Contributions to 2011 and 2025 Ozone Design Values at Desert View (2-3% due to NM)





- City of Albuquerque Ozone Study – Contributions to Ozone in Albuquerque



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Modeling Protocol – Model and Episode Selection

2. Model Selection

- Mainly Consistent with WRAP/WAQS 2014v2 and EPA 2016v1 modeling platforms
- CAMx – Photochemical
  - Used in WRAP, SNMOS, EPA, Denver SIP, etc.
- WRF – Meteorological
  - Current state-of-science
- SMOKE – Emissions Processor
  - Most widely used Emissions Model
- MEGAN – Biogenic Emissions
  - Selected over BEIS used in WRAP 2014v2
- GEOS-Chem – Global
  - For 36-km domain Boundary Conditions (BCs)

3. Episode Selection – May-Aug 2014

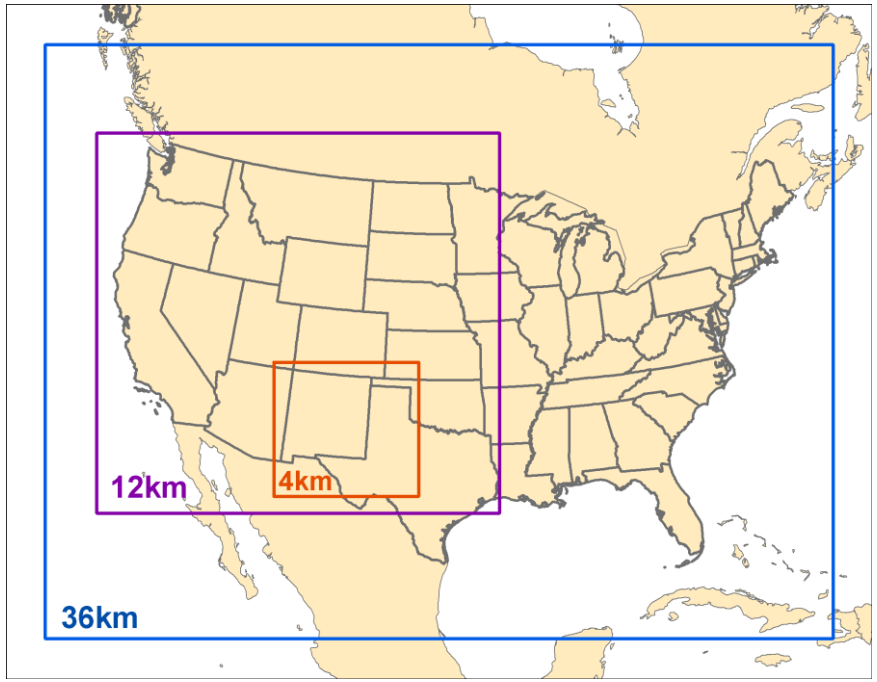
- Need to leverage existing photochemical modeling database so choose between 2014 or 2016
- Select 2014 because:
  - Coincides with an NEI Year
  - Higher quality emissions with updates from western states (WRAP 2014v2)
  - Observed ozone close to ozone DVs
  - 2014 has more ozone exceedance days (8) than 2016 (3)

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Modeling Protocol – Domain Selection and WRF Modeling

4. Domain Selection

- 36/12/4-km domains
- 4-km domain include New Mexico and O&G production areas in San Juan and Permian Basin



5. WRF Modeling

WRF Option	NM OAI Study	2014 WAQS	2014/2015 EPA
Vertical Coordinate	Hybrid	eta	eta
Domains run	36/12/4-km	36/12/4-km	12-km
Microphysics	Thompson	Thompson	Morrison 2
LW Radiation	RRTMG	RRTMG	RRTMG
SW Radiation	RRTMG	RRTMG	RRTMG
LSM	Noah	Noah	Pleim-Xiu
PBL scheme	YSU	YSU	ACM2
Sfc Layer Physics	MM5 similarity	MM5 similarity	MM5 similarity
Cumulus	36/12/4-km Multi-scale Kain Fritsch	36/12-km Multi-scale Kain Fritsch	Kain-Fritsch
BC, IC Analysis Nudging Source	12-km NAM/ERA5	12-km NAM	12-km NAM
Analysis Nudging Grids	36/12-km	36/12-km	12-km
Obs Nudging	None	4-km	None
Sea Sfc Temp	FNMOC	FNMOC	FNMOC

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Modeling Protocol – 2014 Base Case & Model Performance Evaluation

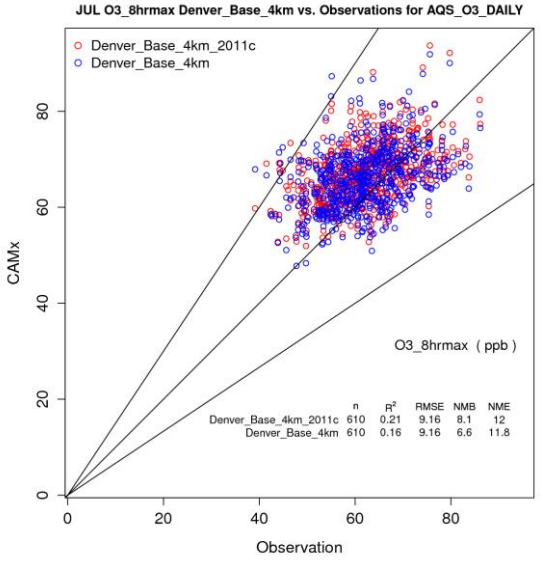
6. CAMx 2014 Inputs Preparation

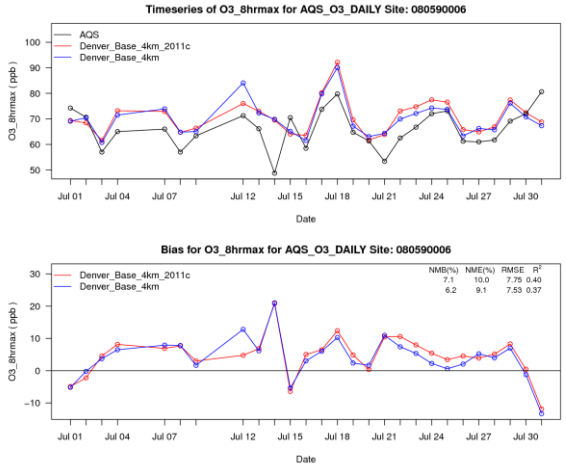
- CAMx Configuration and Options

Science Options	CAMx	Comment
Model Codes	CAMx v7.0	Latest version of CAMx used in WRAP/WAQS 2014v2 and EPA Regional Haze modeling
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes buffer cells
4-km grid	245 x 227 cells	New Mexico 4-km domain. Includes buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 thickness ~20 m. Model top at 50 mb (~19 km)
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 17, 2014
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain
Emissions		
Baseline Emissions Processing	SMOKE, SMOKE-MOVES2014, MEGAN	WRAP/WAQS 2014v2 emissions and EPA 2023fh for future year
Sub-grid-scale Plumes	Plume-in-Grid for major NO_X sources in New Mexico	Keep same PiG sources in 2014 and 2023 emission years
Chemistry		
Gas Phase Chemistry	CB6r4	Latest chemical reactions and kinetic rates with halogen chemistry (Yarwood et al., 2010)
Meteorological Processor	WRFCAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh grid size dependence
Vertical Diffusion	CMAQ-like Kv	Evaluate YSU Kv scheme
Diffusivity Lower Limit	Kv-min = 0.1 to 1.0 m^2/s in lowest 100 m	Depends on urban land use fraction
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	rain/snow/graupel
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative(EBI)	EBI fast and accurate solver
Vertical Advection Scheme	Implicit scheme w/ vertical velocity update	Emery et al., (2009a,b; 2011)
Horizontal Advection Scheme	Piecewise Parabolic Method (PPM) scheme	Colella and Woodward (1984)
Integration Time Step	Wind speed dependent	~0.5-1 min (4-km), 1-5 min (12-km), 5-15 min (36-km)

7. 2014 Base/Model Performance Evaluation

- Focus on ozone performance in NM 4-km Domain
- Ozone Performance Goals and Criteria
  - NMB < 5% & NMB < 15%
- AMET evaluation tool
- Diagnostic Sensitivity Tests:
  - WRF/NAM vs. WRF/ERA5
  - YSU vs. CMAQ-like Kv
- MPE Graphical Displays





Modeling Protocol – Future Year Modeling

8. 2023 CAMx Modeling

- EPA 2023fh Emission Projections
- Natural Emissions at 2016 Levels
- 2023 Control Measure Sensitivity Modeling
  - Control assumptions to be provided by NMED
- 2023 Ozone Source Apportionment
  - Design Document to be reviewed by NMED
  - Geographic Regions
    - NM, TX, OK, CO, AZ, CA, Mex, Can
  - Source Sectors
    - Upstream Oil and Gas, Midstream Oil and Gas, EGU Point, Non-EGU Point, On-Road Mobile, Non-Road Mobile, Other Anthropogenic, Fires (WF, Rx and Ag), Natural, BC from International Anthropogenic Emissions, BC from US Anthropogenic Emissions, BC from Natural Sources, Initial Concentrations

9. Ozone Design Value (DV) Projections

- EPA recommended ozone DV projection approach uses the model in a relative sense to scale the observed ozone DVB

$$DVF_{2023} = DVB_{2014} \times RRF$$

$$RRF = \sum MDA8\ Ozone_{2023} / \sum MDA8\ Ozone_{2014}$$

$$DVB_{2014} = (DV_{2012\text{-}2014} + DV_{2013\text{-}2015} + DV_{2014\text{-}2016}) / 3$$

10. Quality Assurance Project Plan (QAPP)

- Elements of QAPP built into sections of Modeling Protocol
- QA/QC critical component of all aspects of PGM modeling

11. References

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New Mexico 2014 and 2023 Emissions



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New Mexico Emissions Data

- 2014 base year anthropogenic emissions inventory for New Mexico will be based on the WAQS 2014v2 emissions
  - NMED will review the WAQS 2014v2 emissions and provide updates as needed
- 2023 anthropogenic emissions will be based on the EPA 2016v1 platform
- Onroad emissions based on SMOKE-MOVES processing with 2014 activity data and day-specific hourly gridded 2014 WRF meteorology
- O&G emissions based on state-of-the-science O&G emissions estimates from the IWDW-WAQS platform

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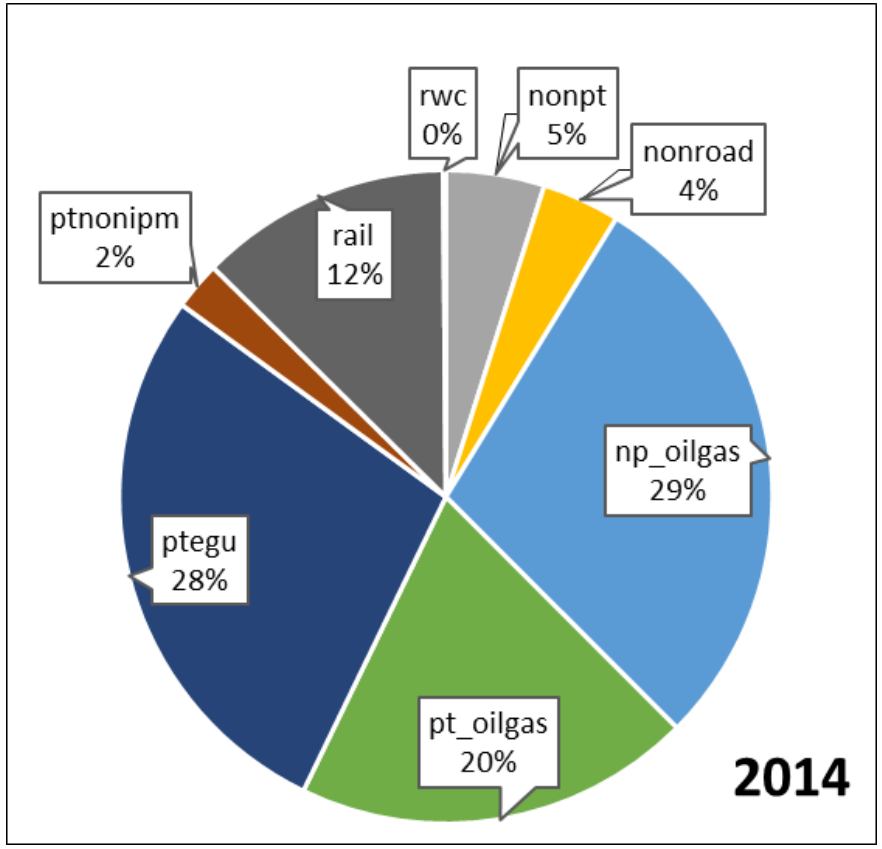
Emission Modeling
Sector Description

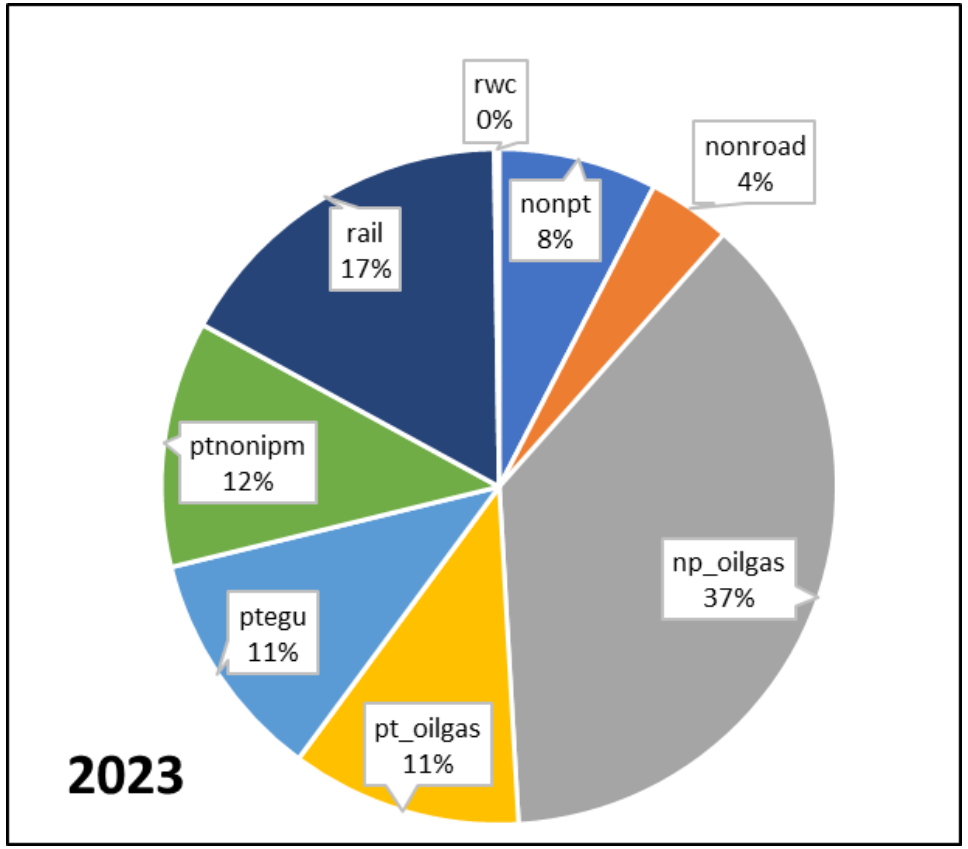
Sector	Description
afdust_adj	Area fugitive dust
ag	Agricultural ammonia sources
cmv_c1c2	Category 1 & 2 Marine Vessels
cmv_c3	Category 3 Marine Vessels
nonpt	Other nonpoint sources
np_oilgas	Non-point Oil and Gas
nonroad	Non-road mobile
onroad	On-road mobile
ptegu	EGU point sources
ptnonipm	Non-EGU point sources
pt_oilgas	Point Oil and Gas
rail	Locomotive
rwc	Residential Wood Combustion

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New Mexico Emissions: 2023 vs. 2014 NOx

All anthro source categories except onroad





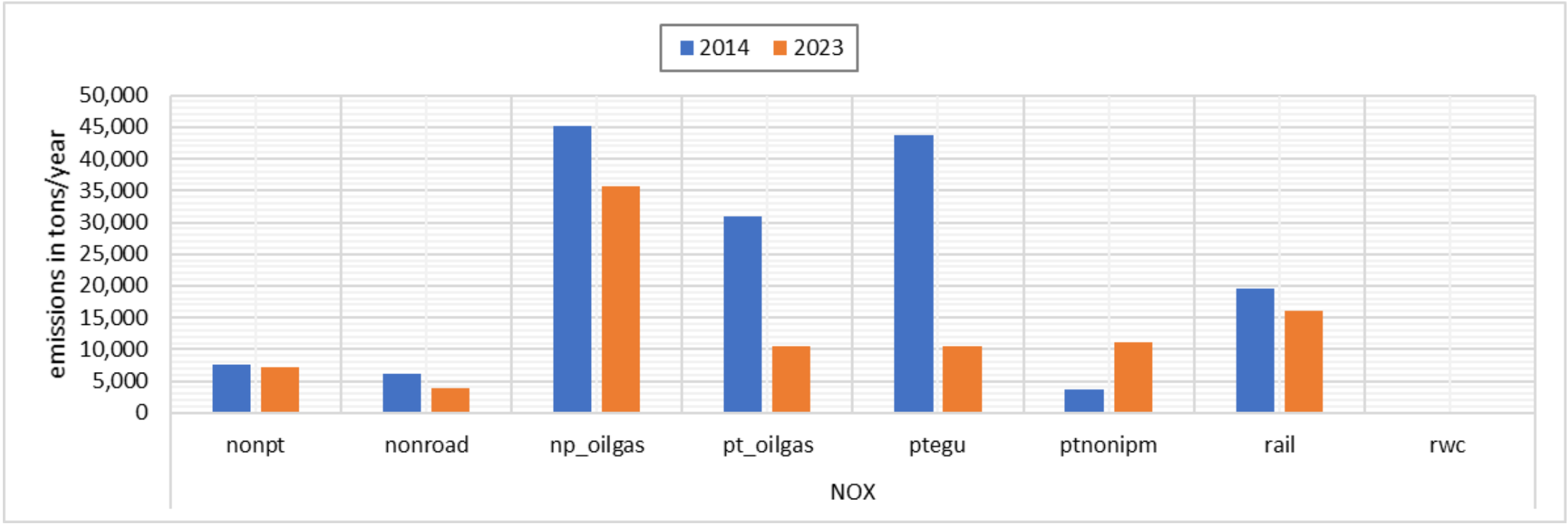
157,415 TPY

95,157 TPY

-62,258 TPY (40%) Reduction

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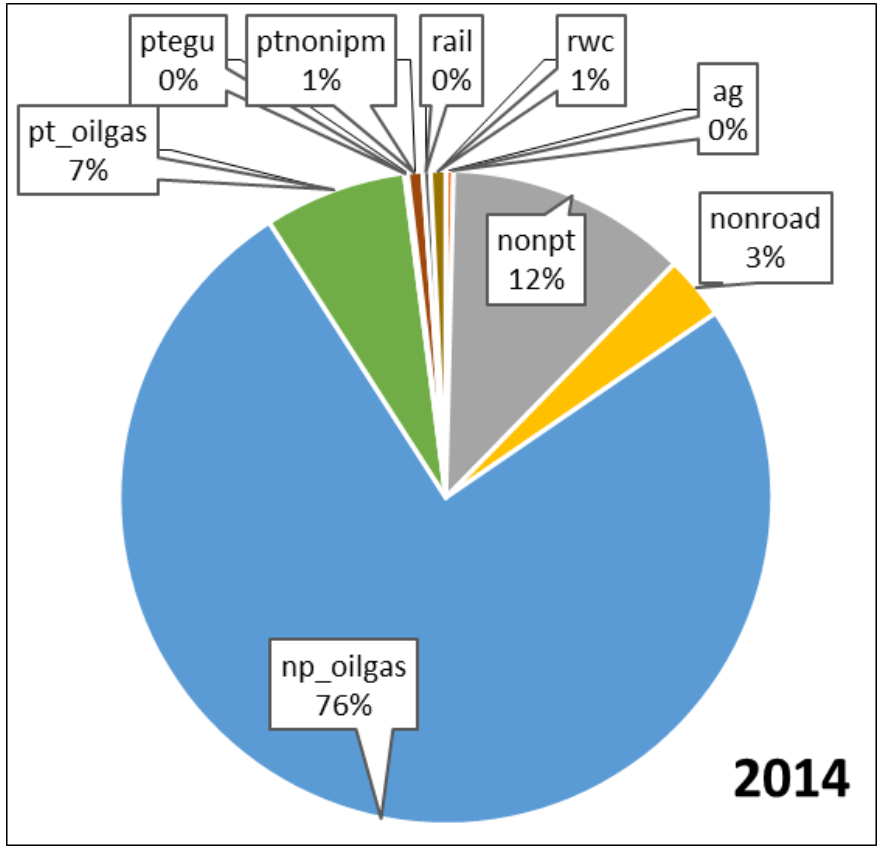
New Mexico Emissions: 2023 vs. 2014 NOx by Source Category



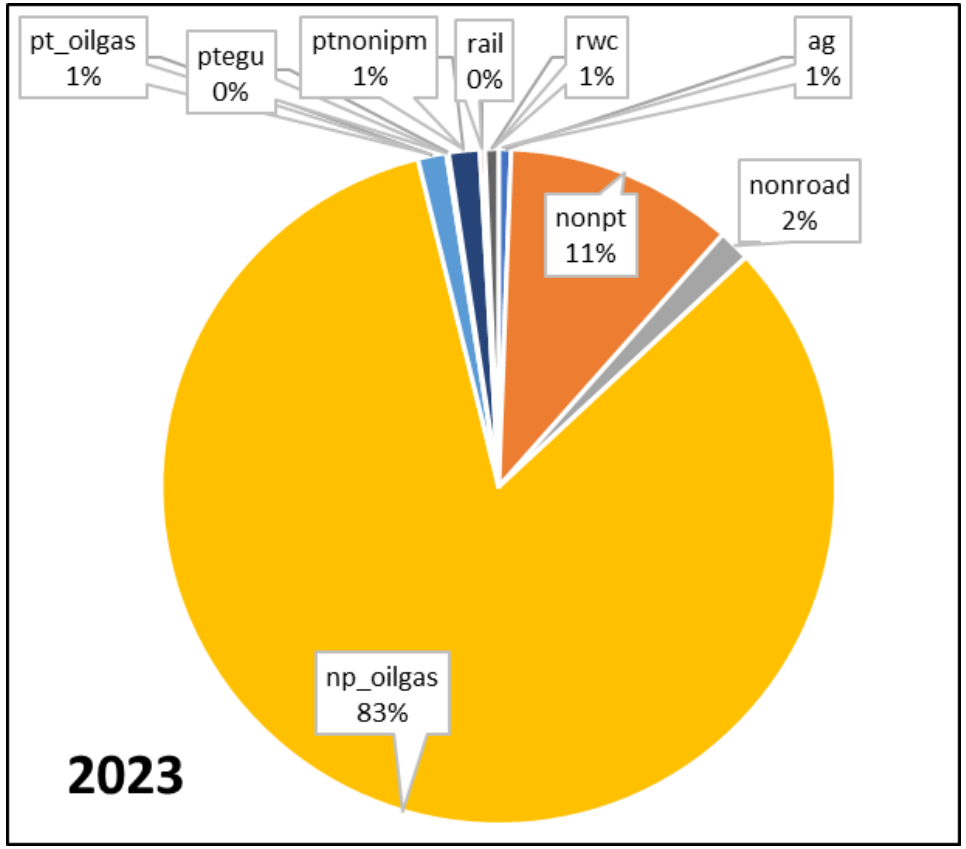
RAMBOLL

New Mexico Emissions: 2023 vs. 2014 VOC

All anthro source categories except onroad



255,765 TPY

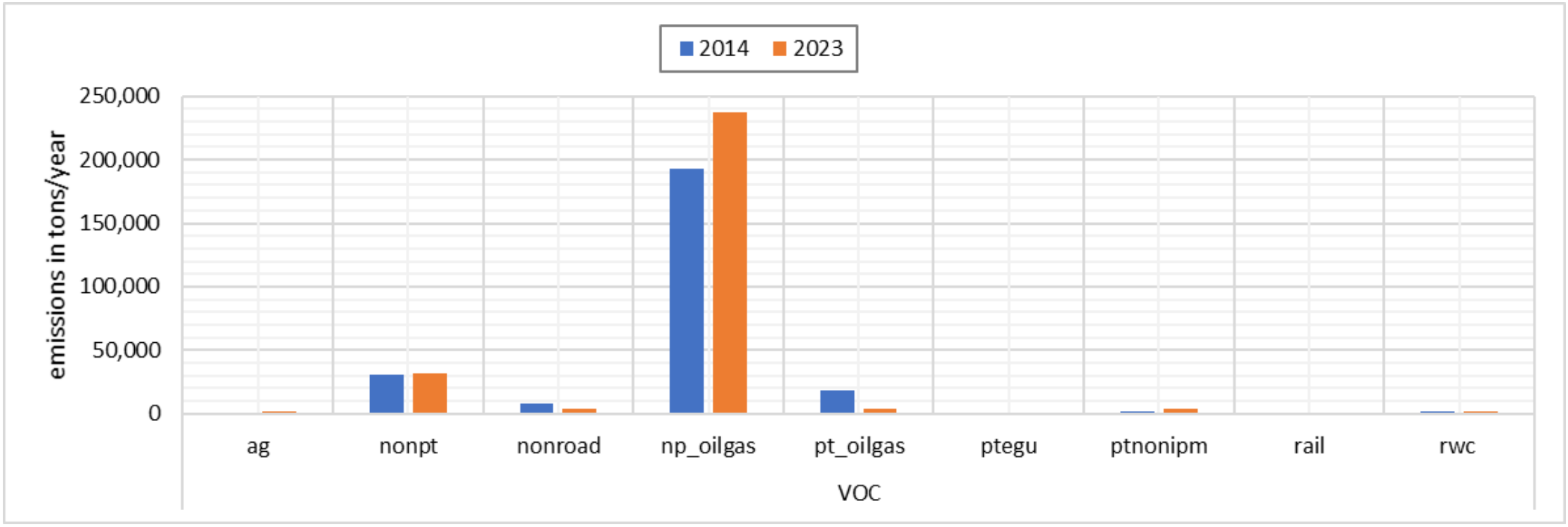


285,240 TPY

+29,475 TPY (12%) Increase

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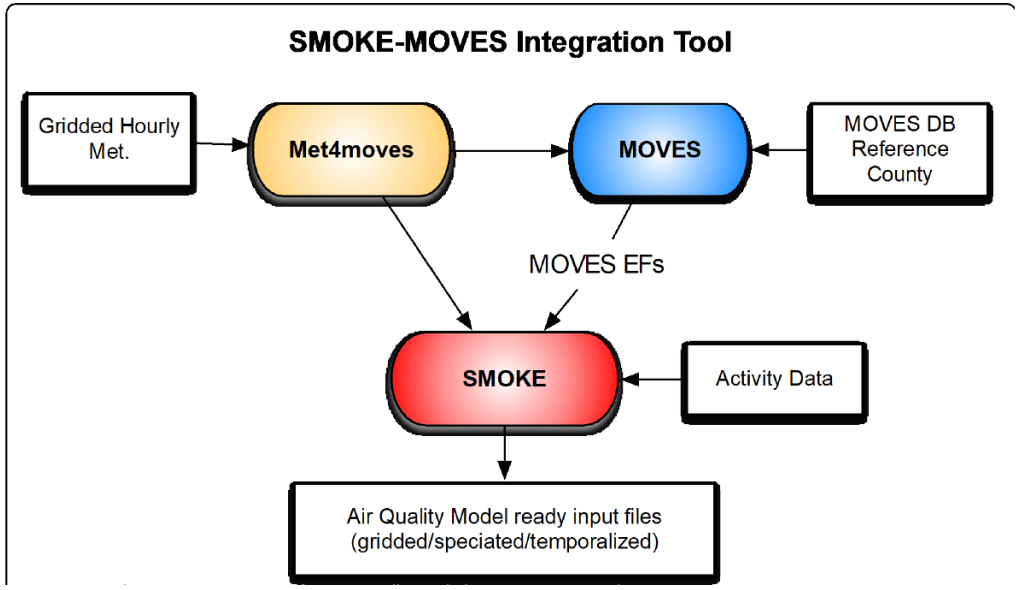
New Mexico Emissions: 2023 vs. 2014 VOC by Source Category



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Overview of SMOKE-MOVES Processing

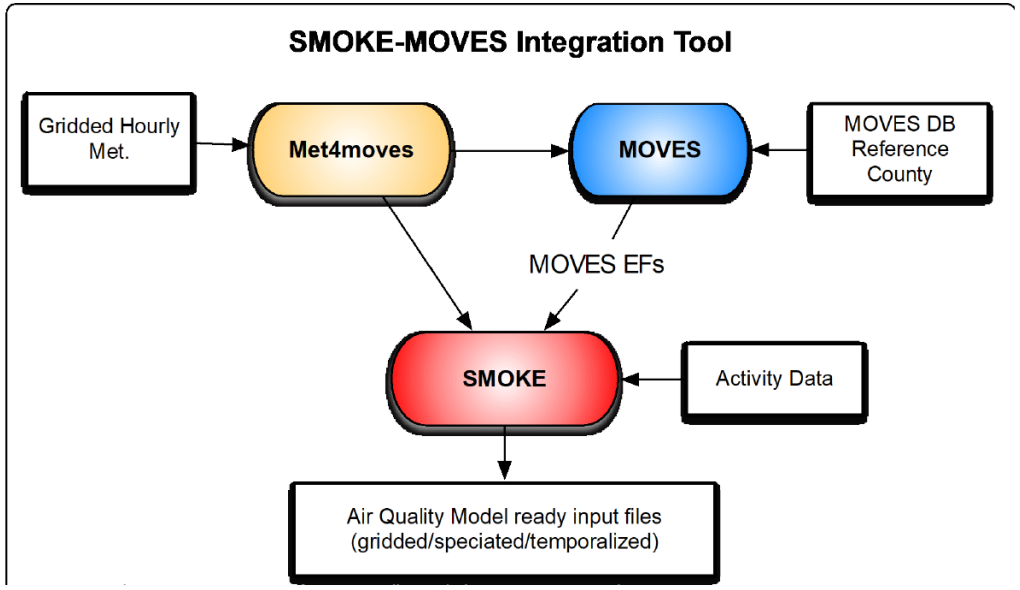
- Requires emission rate "lookup" tables generated by MOVES
  - EPA generated 2014 and 2023 MOVES "lookup" tables for modeling platform
- Uses gridded, hourly, day-specific temperatures
- Emission factors by temperature bin and speed for a series of "representative counties", to which every other county is mapped



NMED Exhibit 18 - 0052

Creating Onroad Emissions using SMOKE-MOVES

- Met4MOVES: Meteorological data preprocessor
- SMOKE processing applies the emission factors to the activity data to compute grid-cell emissions
- Activity Data
  - Vehicle Miles Travelled (VMT)
  - Vehicle Population
  - Extended Idling Hours



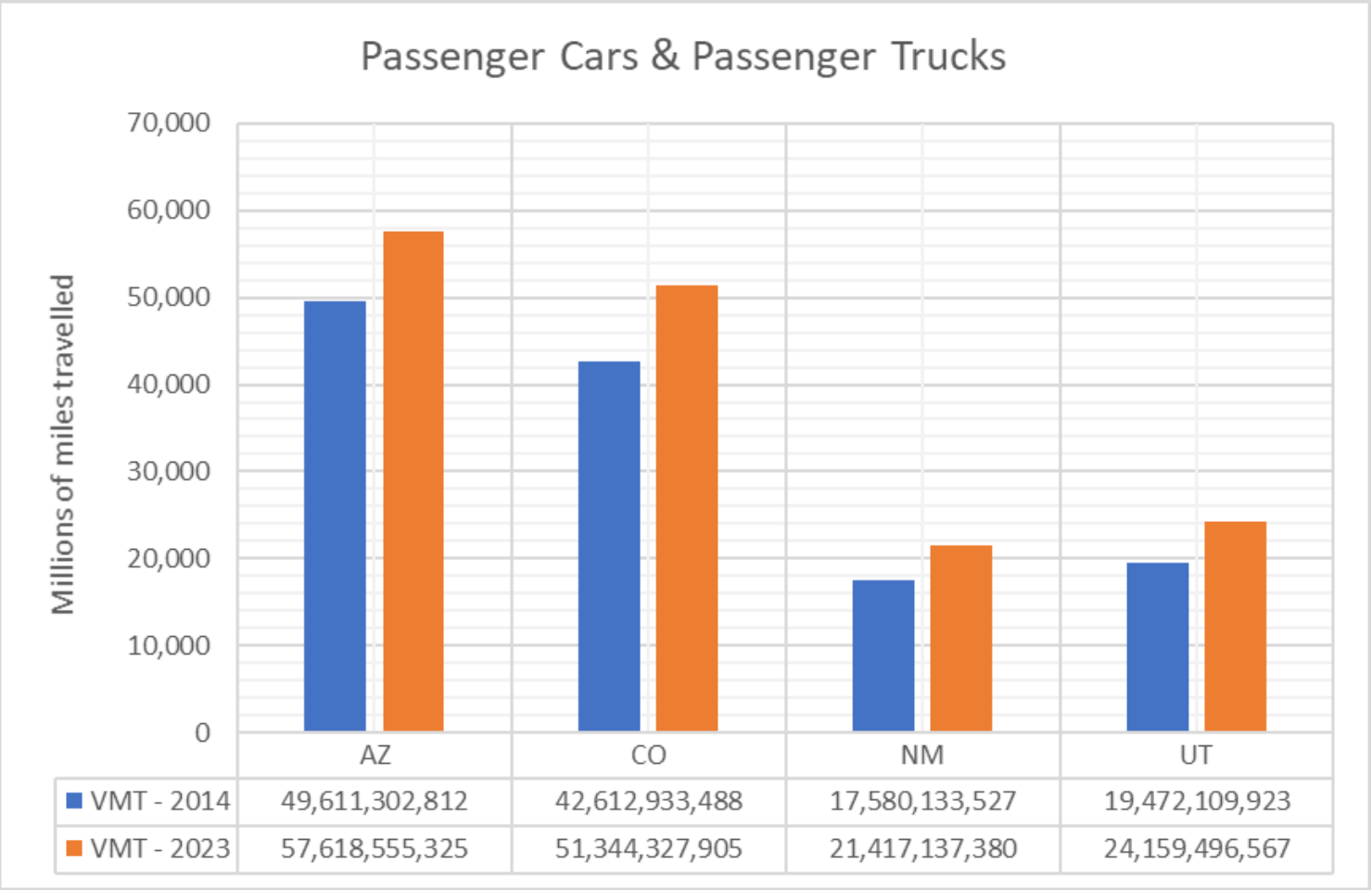
NMED Exhibit 18 - 0053

Review of On-Road Mobile Source Activity Data

- Activity data from EPA emission modeling platform
- Developed a spreadsheet tool to assist NMED to review activity data for 13 WRAP states
  - Show 2014 and 2023 population and activity of on-road vehicles
- The tab "Dashboard" shows comparisons of vehicle population and VMT by state, vehicle type, fuel type and road type.
- The tab "Scaling_factor" provides ratio of future year/base year activities by state, vehicle type and fuel type.

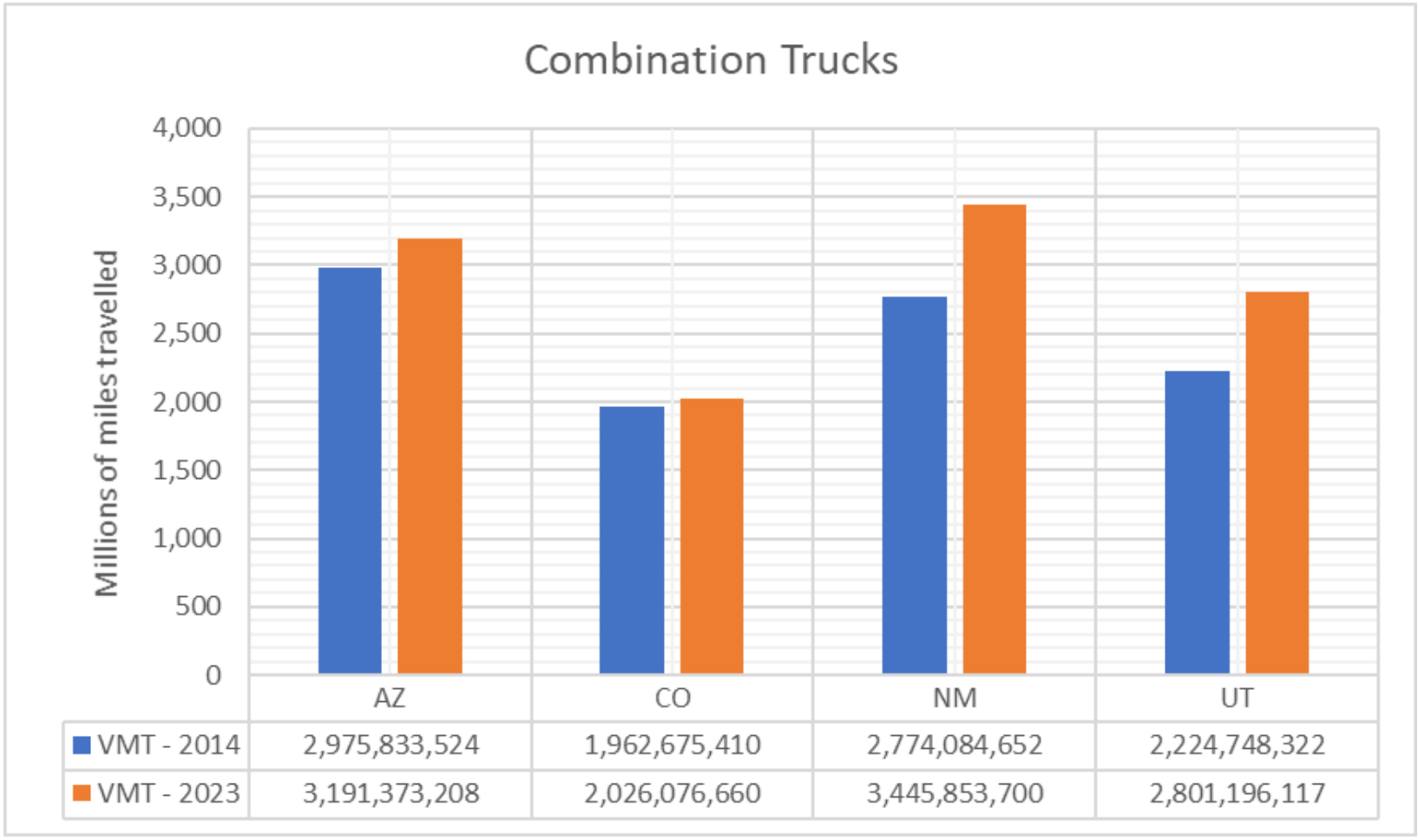
Gasoline Vehicles VMT for NM and Neighboring States

- Gasoline passenger vehicles
- Overall EPA projected 21% VMT increase in 2023 from 2014 for New Mexico



Heavy-Duty Diesel Trucks VMT for NM and Neighboring States

- Heavy-duty diesel truck VMT
- Overall EPA estimated 24% VMT increase in 2023 from 2014



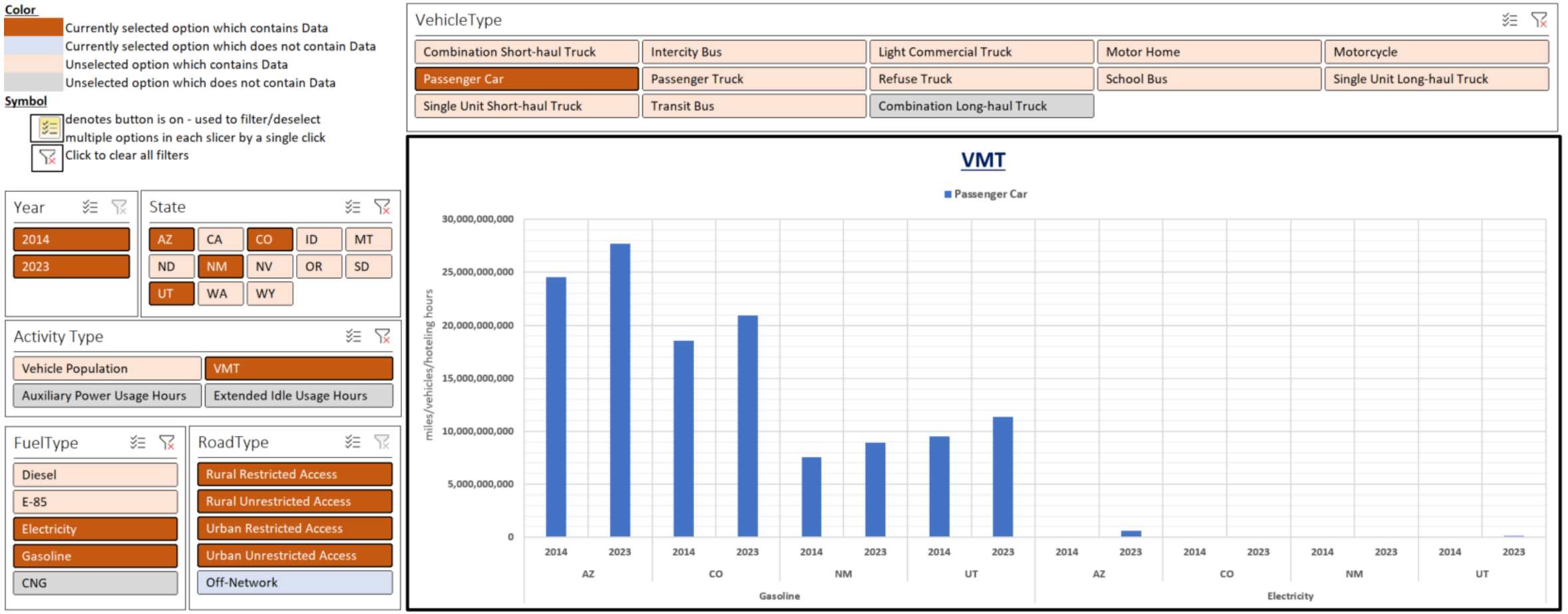
	AZ	CO	NM	UT
VMT - 2014	2,975,833,524	1,962,675,410	2,774,084,652	2,224,748,322
VMT - 2023	3,191,373,208	2,026,076,660	3,445,853,700	2,801,196,117

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NMED Exhibit 18 - 0056

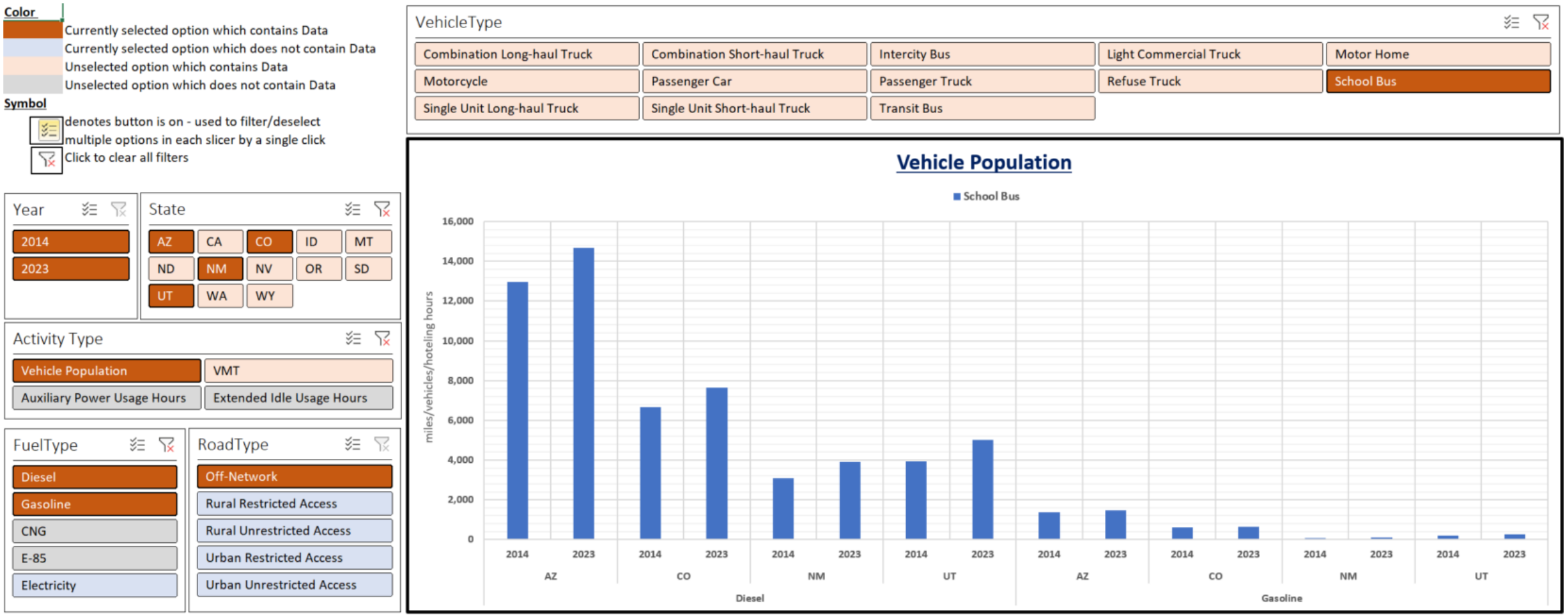
Example Plots that can be Created with the Tool

NMED Exhibit 18 - 0057



**Vehicle population data do not vary by road type. To show vehicle population, select Off-Network under road type.

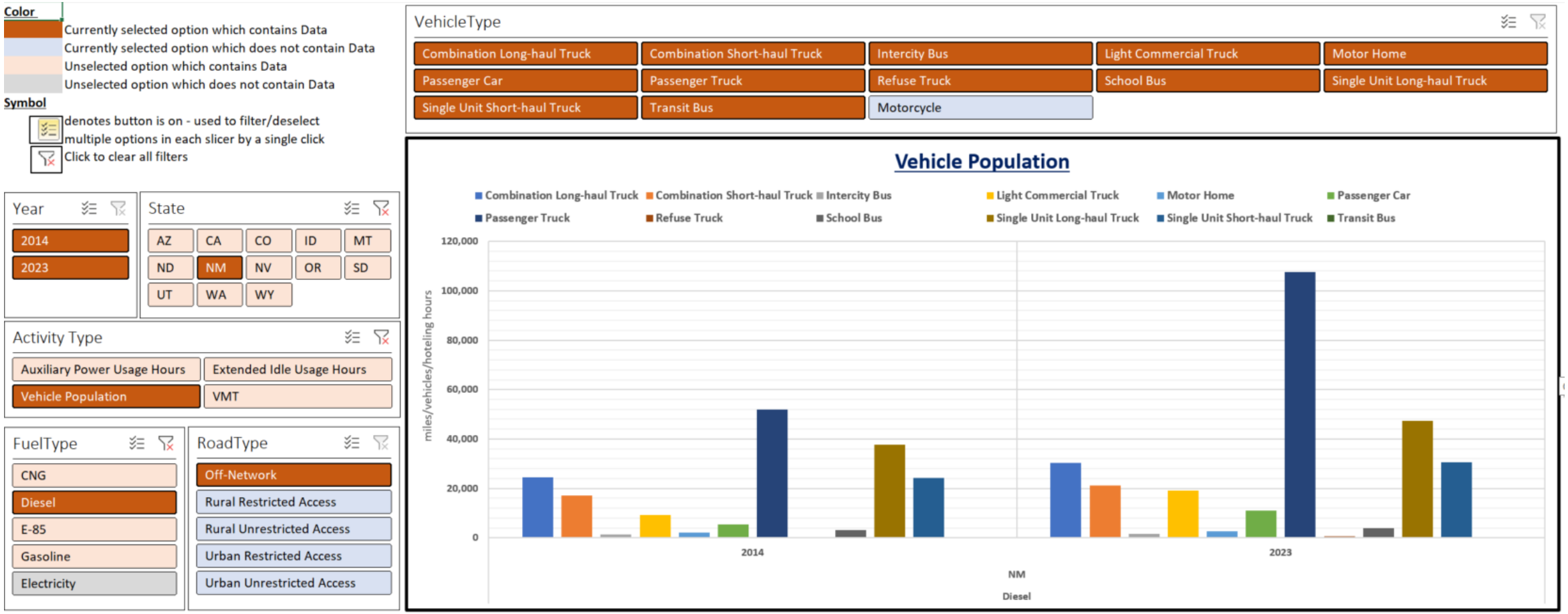
- Gasoline and Electric Passenger car VMT comparison for 2014 and 2023



**Vehicle population data do not vary by road type. To show vehicle population, select Off-Network under road type.

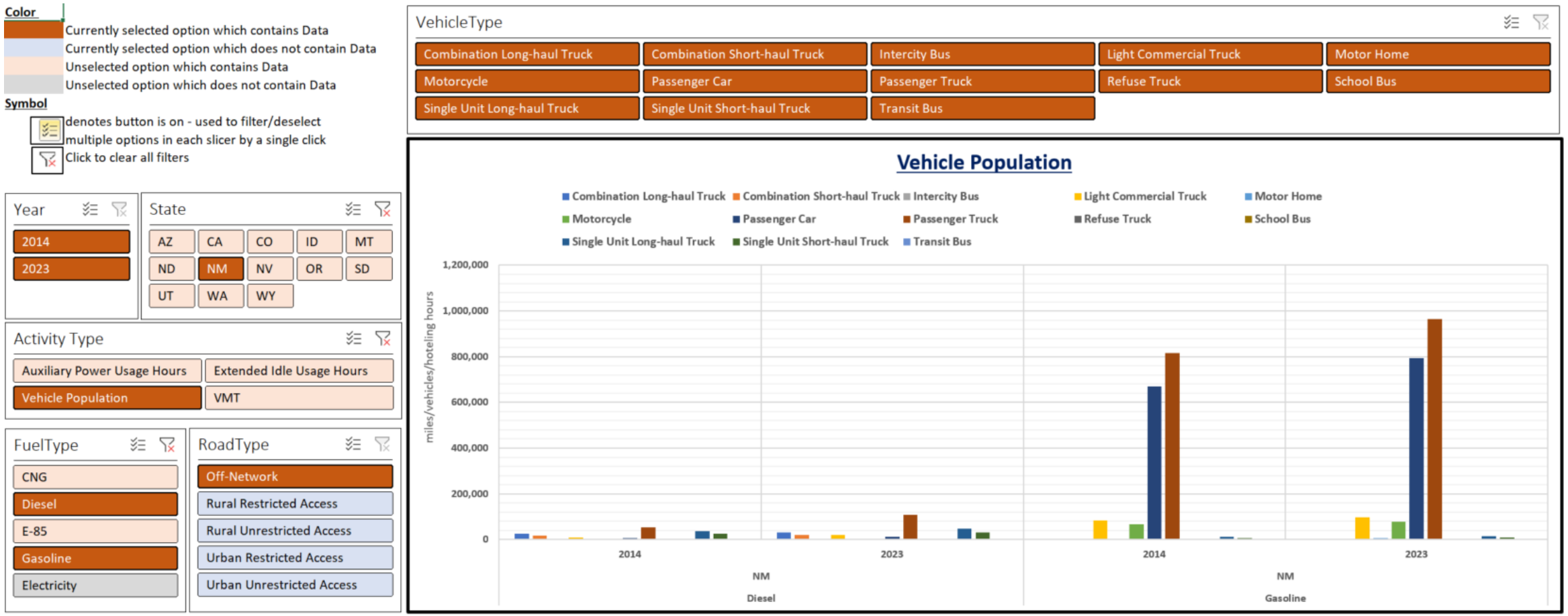
- School bus population comparison for NM, AZ, UT and CO by fuel type

NMED Exhibit 18 - 0059



**Vehicle population data do not vary by road type. To show vehicle population, select Off-Network under road type.

- NM diesel vehicle population by vehicle type

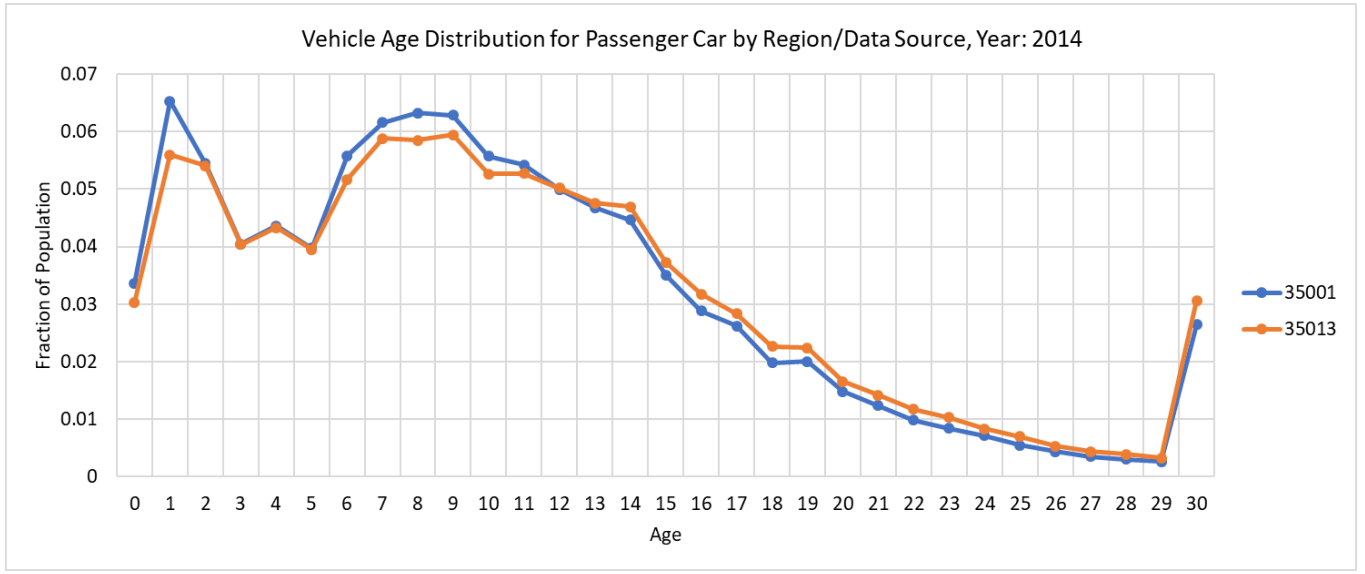


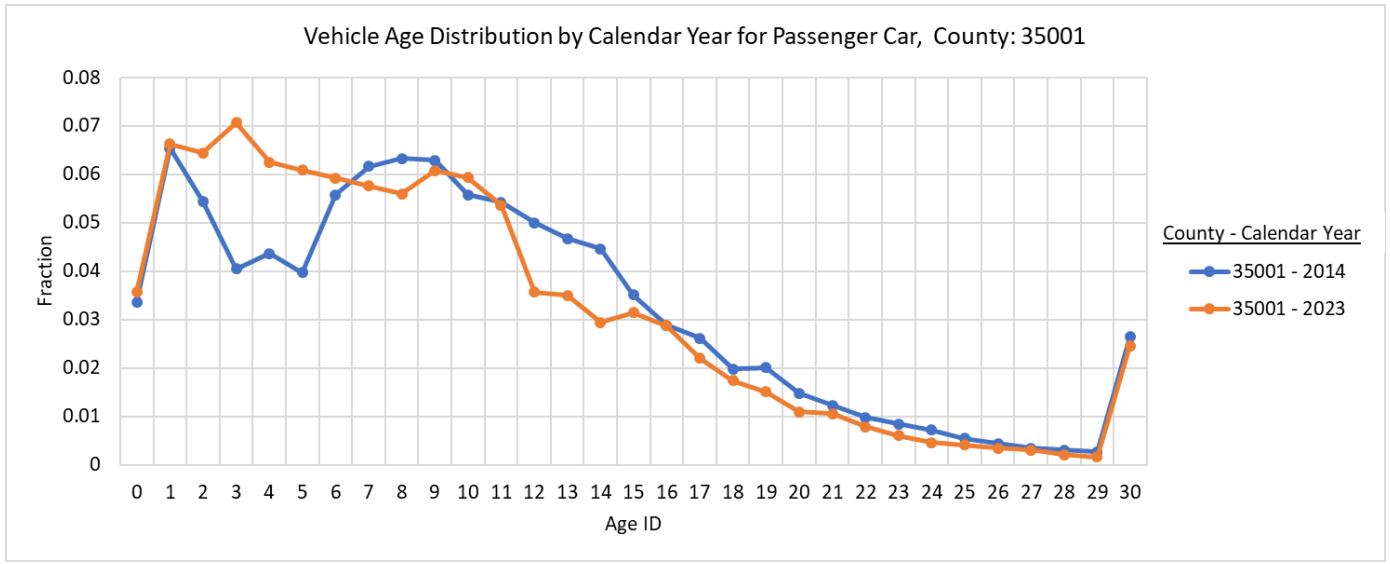
**Vehicle population data do not vary by road type. To show vehicle population, select Off-Network under road type.

- NM diesel and gasoline vehicle population by vehicle type

MOVES Inputs: Vehicle Age Distribution

- Vehicle age distribution for passenger cars
- The last bin of age distribution represents vehicles 30 year and older





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MOVES Inputs: I&M Coverage

Inspection and Maintenance Coverage (imcoverage table)

Source: MOVES2014b defaults

Rep county affected	Calendar Year	Program Test	Range of ModelYears affected	Pollutant_Emissions Process Affected	Compliance Factor (%)*							
					Passenger Car_Gasoline	Light Commercial Truck_Gasoline	Passenger Truck_Gasoline	Light Commercial Truck_Ethanol	Passenger Car_Ethanol	Passenger Truck_Ethanol	Single Unit Short-haul Truck_Gasoline	Single Unit Short-haul Truck_Ethanol
35001	2014	Exhaust OBD** Check	1996_2012	CO_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				CO_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				NOx_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				NOx_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
		Evaporative Gas Cap Check	1975_2006	THC_Evap Fuel Vapor Venting							93.1	93.1
			1975_1995	THC_Evap Fuel Vapor Venting	93.1	93.1	93.1	93.1	93.1	93.1		
		Two-mode, 2500 RPM/Idle Test	1975_1995	CO_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				CO_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
		Evaporative System OBD Check	1996_2012	THC_Evap Fuel Vapor Venting	93.1	93.1	93.1	93.1	93.1	93.1		
			2007_2012	THC_Evap Fuel Vapor Venting							93.1	93.1
	2023	Exhaust OBD Check	1996_2021	CO_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				CO_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				NOx_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				NOx_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
		Evaporative Gas Cap Check	1975_2006	THC_Evap Fuel Vapor Venting							93.1	93.1
			1975_1995	THC_Evap Fuel Vapor Venting	93.1	93.1	93.1	93.1	93.1	93.1		
		Two-mode, 2500 RPM/Idle Test	1975_1995	CO_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				CO_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Running Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
				THC_Start Exhaust	93.1	93.1	93.1	93.1	93.1	93.1	93.1	93.1
		Evaporative System OBD Check	1996_2021	THC_Evap Fuel Vapor Venting	93.1	93.1	93.1	93.1	93.1	93.1		
			2007_2021	THC_Evap Fuel Vapor Venting							93.1	93.1

Note: CDBs from 2016v1 and 2014v7.1 platforms did not include local/state IM coverage information. Platforms used MOVES defaults data where available.
MOVES2014b default database includes I/M coverage information only for Rep County 35001, other counties would be assumed to not have I/M program.
*The compliance factor represents the percentage of vehicles within a source type that actually receive the benefits of the program
**On-Board Diagnostics (OBD)

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NM OAI Study Next Steps



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Next Up in June 2020

- A little ahead of schedule (Task 3 completed month early)
- Need comments from NMED on Modeling Protocol and Work Plan
- Need approval from NMED to proceed with WRAP 2014v2 and EPA 2023 New Mexico emissions and mobile source assumptions
- Task 2.2 WRF modeling simulation will be finished in early June.
  - Conduct MPE and CAMx sensitivity test modeling
- Task 3 Evaluate BC data completed a month ahead of schedule (May instead of Jun)
- Task 4 -- Would like to start 2014 SMOKE and SMOKE-MOVES emissions modeling in June

RAMBOLL

New Mexico OAI Study Photochemical Modeling – 2nd Monthly Webinar June 2020



WESTAR and Ramboll

June 26, 2020

RAMBOLL Bright ideas. Sustainable change.

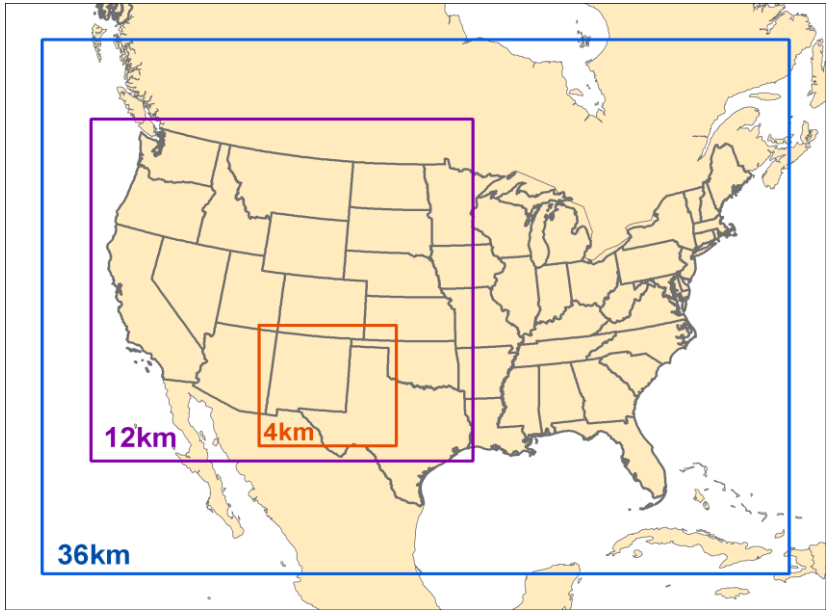
Content

- Introduction
- Overview of NMED OAI Modeling Project
- Summary of May 28, 2020 Webinar
- NMED OAI Modeling Study Website
  - https://www.wrapair2.org/NMOAI.aspx
- 2014 and 2023 New Mexico Emissions
- 2014 36/12/4-km WRF Meteorological Modeling and Model Evaluation
- Next Steps
- Discussion

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Overview of NMED OAI Modeling Study Tasks

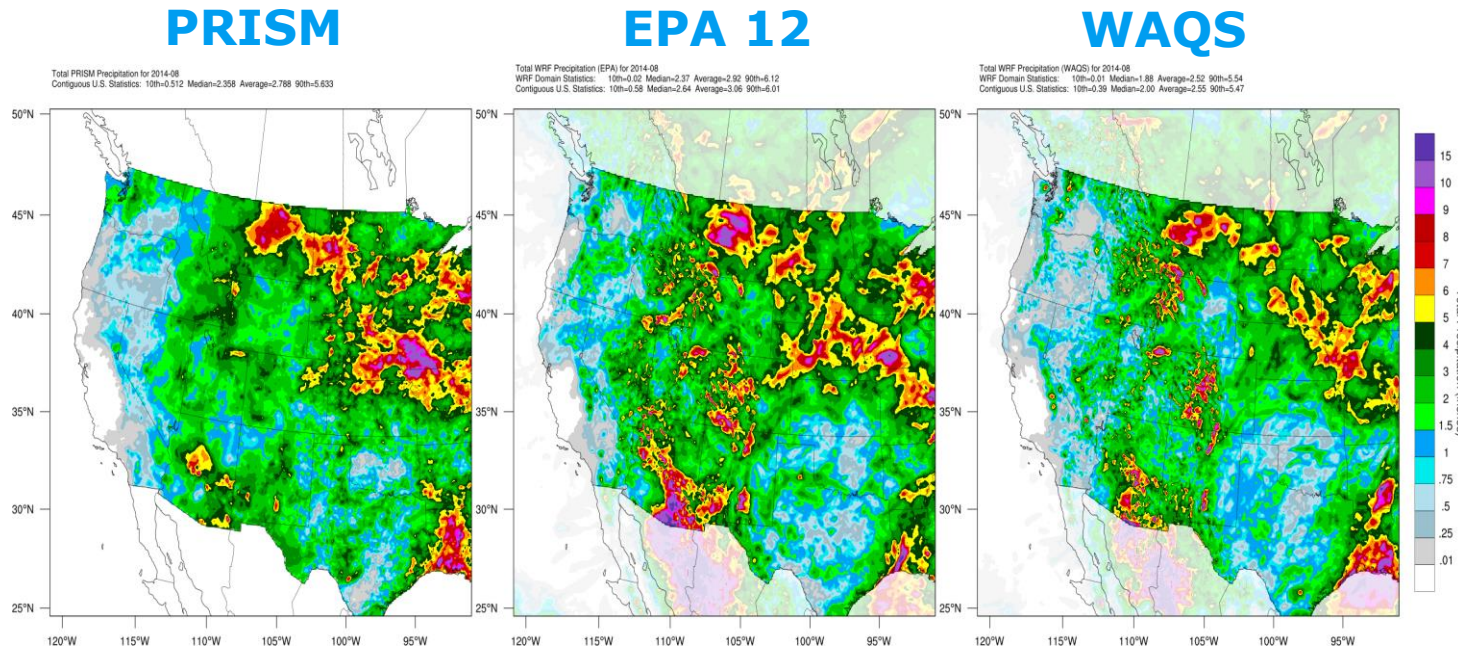
- Task 1: Development Modeling Protocol/QAPP and Work Plan -- Completed
- Task 2: WRF Meteorological Modeling -- Completed
- Task 3: Evaluate Boundary Condition Inputs – Completed
- Task 4: 2014 and 2023 Emissions Development
  - Sources of 2014 and 2023 Emissions -- Completed
  - Sources of Mobile Source Emissions -- Completed
  - Natural Emissions; SMOKE Emissions Modeling; 2023 Controls
- Task 5: CAMx 2014 Base Case Modeling
  - Formal 2014 Base Case and MPE Report
- Task 6: 2023 Future Year CAMx Modeling
  - 2023 Base, Source Apportionment and Control Measure Evaluation
- Task 7: Air Quality Technical Support Document (AQTSD)
  - Formal AQTSD; Transfer Data and Results to IWDW

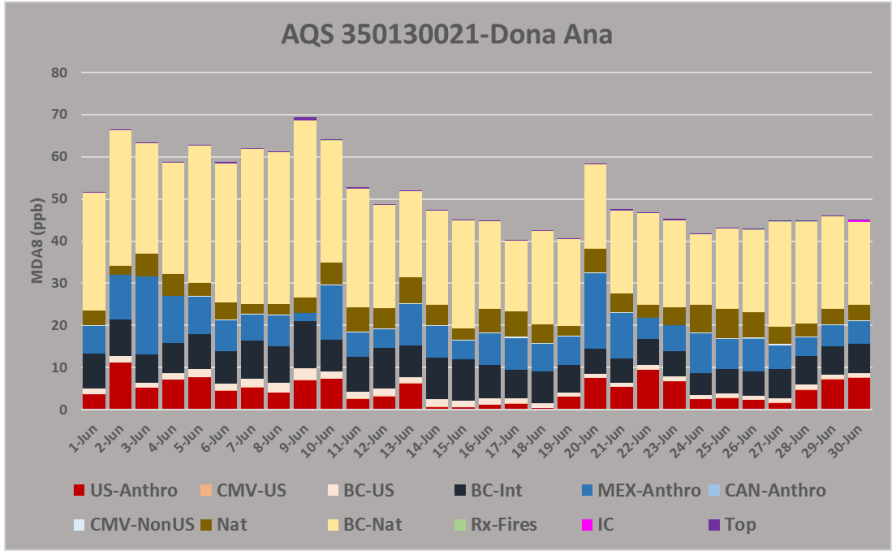


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OVERVIEW OF MAY 26, 2020 WEBINAR

- Evaluation of Existing 2014 WRF Meteorological Modeling
  - EPA vs. WAQS 2014 WRF Modeling
  - NMED 2014 WRF following WAQS
- Evaluation of 2014 GEOS-Chem BCs
  - Deemed adequate
- Overview of Modeling Protocol and Work Plan
- 2014 and 2023 New Mexico Emissions
  - Request comments by June 12
- Next Steps

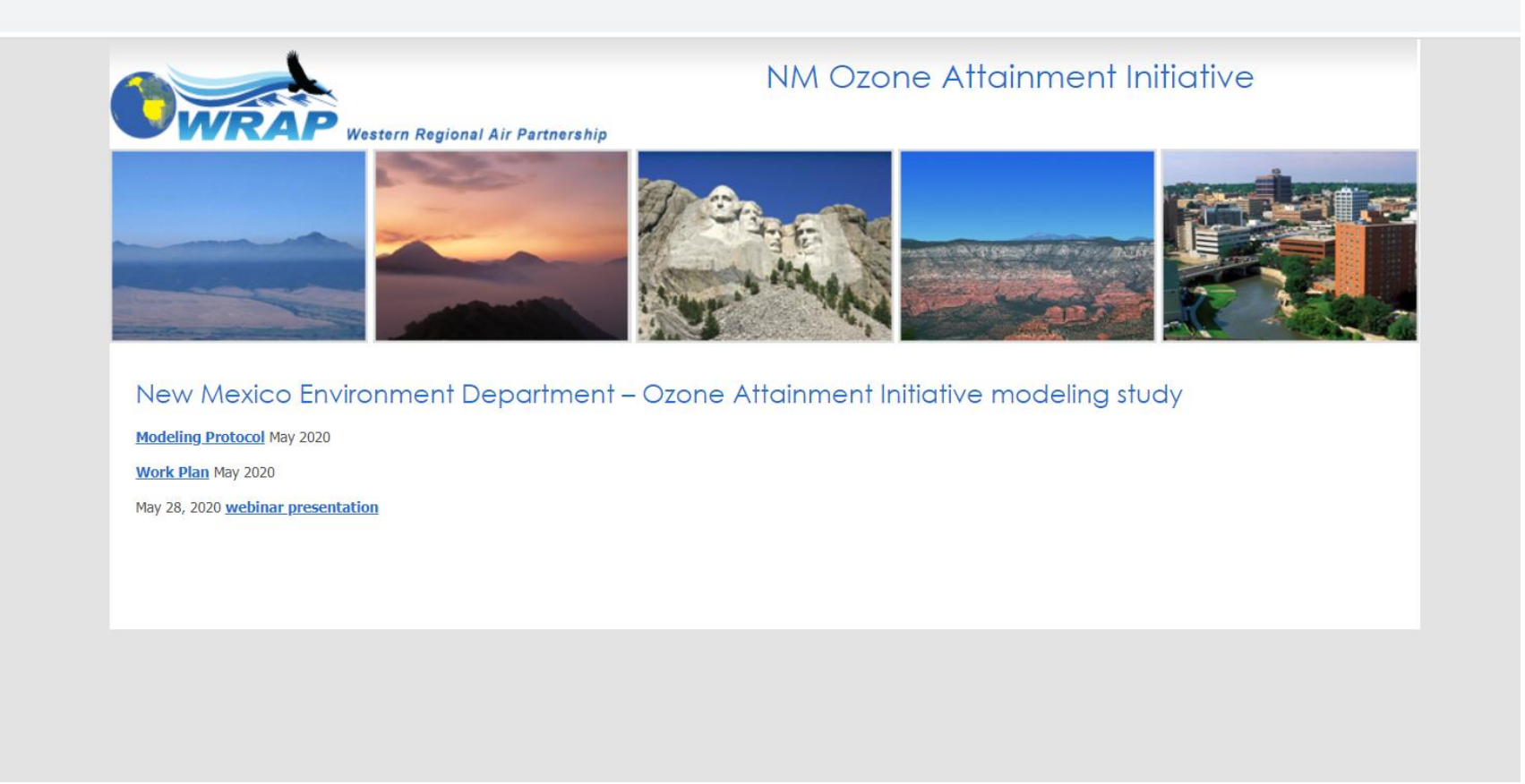




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NMED OAI MODELING STUDY WEBSITE

- https://www.wrapair2.org/NMOAI.aspx



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2014 AND 2023 EMISSIONS



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New Mexico Emissions Data

- 2014 anthropogenic emissions are based on the WAQS 2014v2
  - NMED provided information on a piece of equipment missing from the inventory (NOx 94 TPY and VOC 1 TPY)
  - Consistent emissions between Regional Haze and OAI studies
- 2023 anthropogenic emissions are based on the EPA 2016v1 platform
  - NMED updates: some Title V facilities are duplicates in the pt_oilgas and ptnonipm sectors
  - Added Lordsburg Generating Station missing from the 2023 inventory
- On-Road emissions based on SMOKE-MOVES processing with 2014/2023 activity data and day-specific hourly gridded 2014 WRF meteorology
- O&G emissions based on state-of-the-science O&G emissions estimates from the IWDW-WAQS platform

2014 update

facility_name	sector	CO	NOX	PM10	PM25	SO2	VOC
Saunders Gas Plant	pt_oilgas	6	94	0	0	0	1

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2023 NEW MEXICO EMISSIONS – DUPLICATE EMISSIONS

facility_name	sector	CO	NH3	NOX	PM10	PM25	SO2	VOC
Hope Pump Station	pt_oilgas	48	0	204	0	0	0	10
NuStar Logistics Operation LP - Hope Pump Station	ptnonipm	4	0	101	0	0	0	0
Durango Midstream - Empire Abo Gas Plant - CS	pt_oilgas	142	0	546	20	20	1,184	623
Empire Abo Gas Plant/Compressor Station	ptnonipm	12	0	84	0	0	162	42
Durango Midstream - Maljamar Gas Plant	pt_oilgas	239	0	305	14	14	417	250
Maljamar Gas Plant	ptnonipm	50	0	87	7	7	213	57
DCP - Linam Ranch Gas Plant	pt_oilgas	345	0	547	23	19	300	163
Linam Ranch Gas Plant	ptnonipm	449	0	692	28	28	109	103
DCP - Eunice Gas Plant	pt_oilgas	183	0	526	7	6	1,585	67
DCP Midstream - Eunice Gas Plant	ptnonipm	224	0	606	11	11	1,437	70
Mid-America Pipeline - San Luis Pump Station	pt_oilgas	4	0	8	0	0	0	8
San Luis Pump Station	ptnonipm	2	0	3	0	0	0	1
Huerfano Pump Station	ptnonipm	10	0	25	1	1	0	23
Mid-America Pipeline - Huerfano Pump Station	pt_oilgas	5	0	14	1	1	0	16
Lordsburg Generating Station	ptegu	2	0	3	0	0	0	1

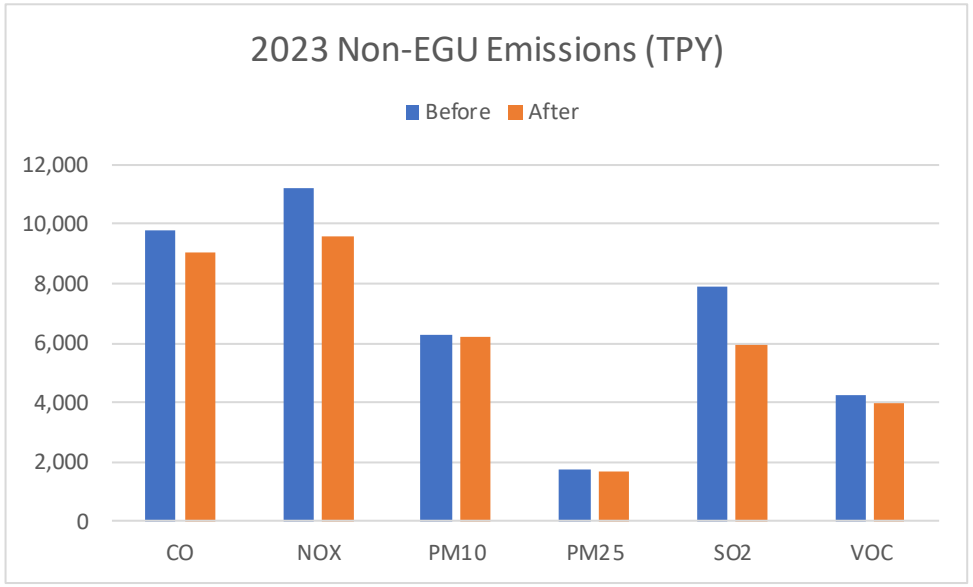
Some O&G sources not classified as O&G and incorrectly placed in Non-EGU Point Source Sector in EPA's 2023fh emission projections so got double counted when EPA 2023 O&G was replaced by WRAP 2023 O&G

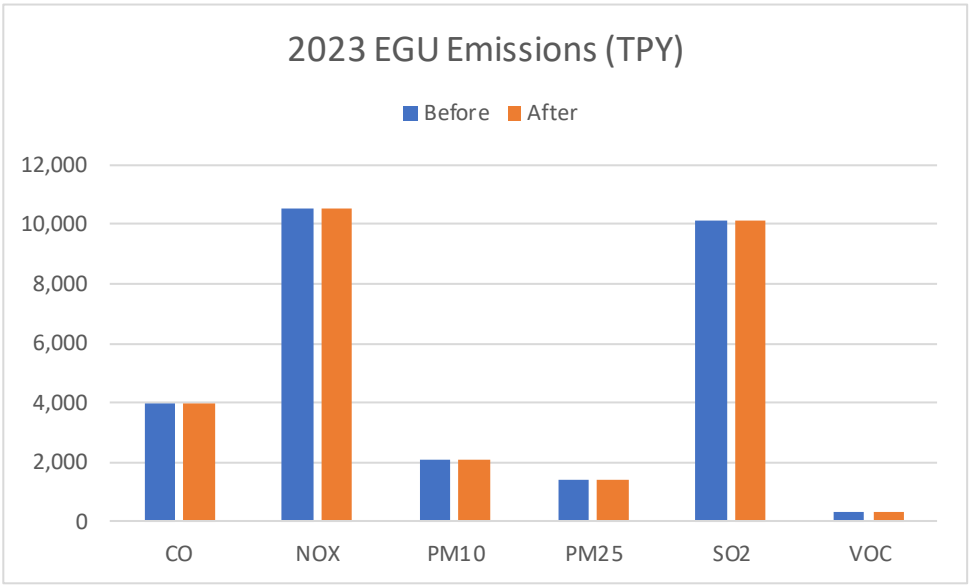
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NMED Exhibit 19 - 0008

2023 NM EMISSIONS UPDATES

Duplicate Sources						
	CO	NOX	PM10	PM25	SO2	VOC
Ptnonipm	751	1,599	48	48	1,921	297
Original inventory (total emissions)						
	CO	NOX	PM10	PM25	SO2	VOC
Pt_oilgas	38,732	44,062	1,150	1,104	12,864	32,934
Ptnonipm	9,774	11,208	6,273	1,744	7,881	4,232
Ptegu	3,963	10,516	2,040	1,365	10,122	312
Updated total emissions (removing duplicates)						
	CO	NOX	PM10	PM25	SO2	VOC
Pt_oilgas	38,732	44,062	1,150	1,104	12,864	32,934
Ptnonipm	9,023	9,609	6,225	1,696	5,960	3,936
Ptegu	3,965	10,519	2,040	1,365	10,122	312





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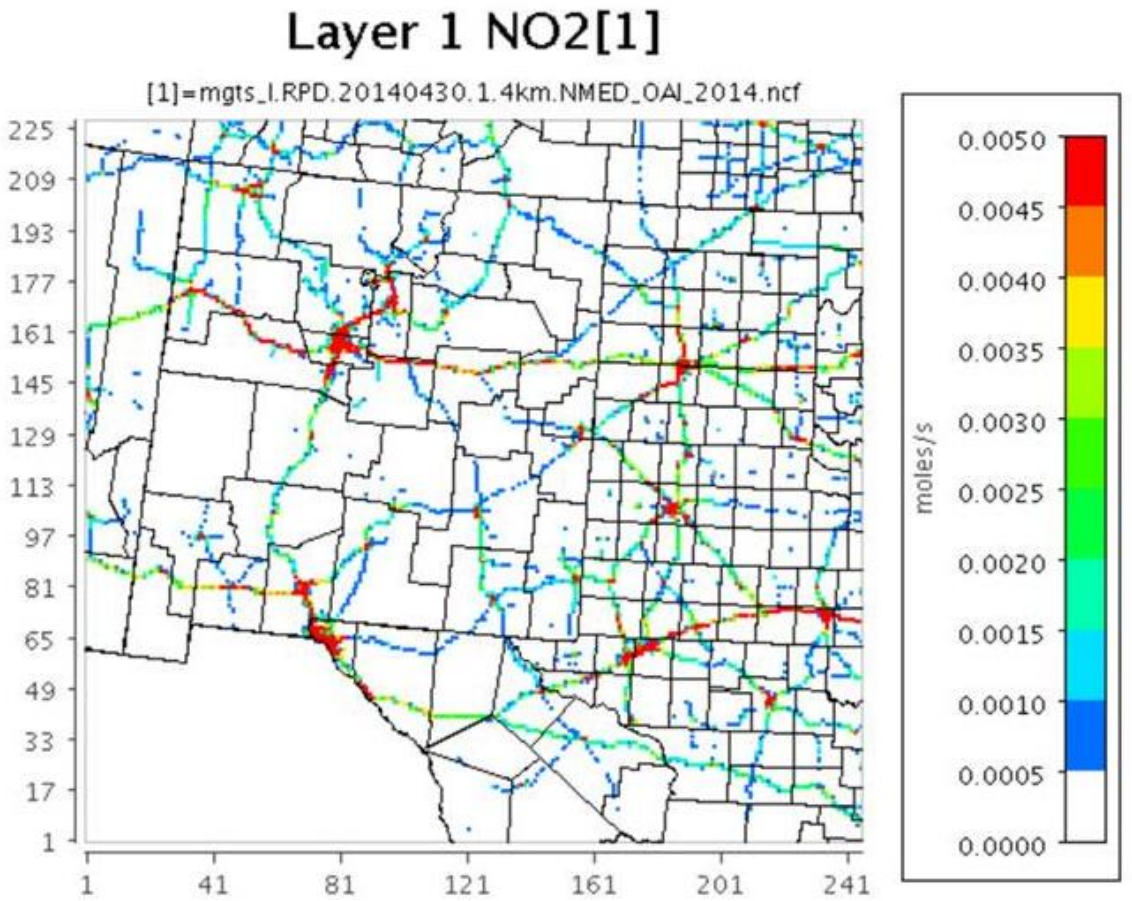
NMED Exhibit 19 - 0009

SMOKE PROCESSING

- SMOKE version 4.7

- Process 4 km emissions using spatial surrogates from EPA's emission modeling platform

- Began processing SMOKE-MOVES with 4-km MCIP data and 2014 MOVES lookup tables
  - rate-per-distance (RPD) (30 mins per day)
  - rate-per-vehicle (RPV) (10 mins per day)
  - rate-per-profile (RPP)
  - rate-per-hour (RPH)



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Emission Modeling Sector Description

Separate SMOKE emissions modeling of each Source Sector

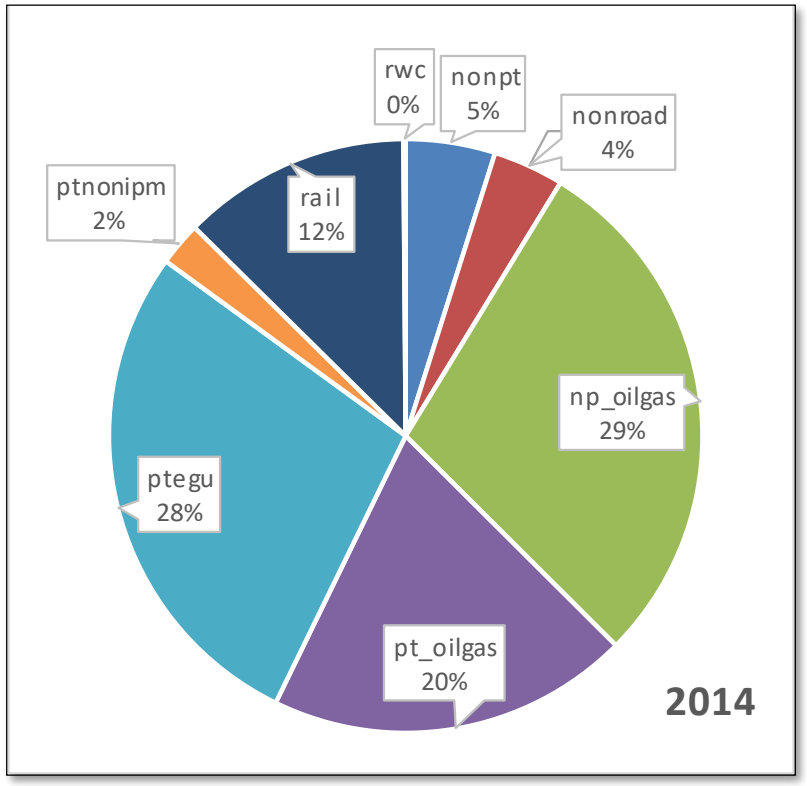
Sector	Description
afdust_adj	Area fugitive dust
ag	Agricultural ammonia sources
cmv_c1c2	Category 1 & 2 Marine Vessels
cmv_c3	Category 3 Marine Vessels
nonpt	Other nonpoint sources
np_oilgas	Non-point Oil and Gas
nonroad	Non-road mobile
onroad	On-road mobile
ptegu	EGU point sources
ptnonipm	Non-EGU point sources
pt_oilgas	Point Oil and Gas
rail	Locomotive
rwc	Residential Wood Combustion

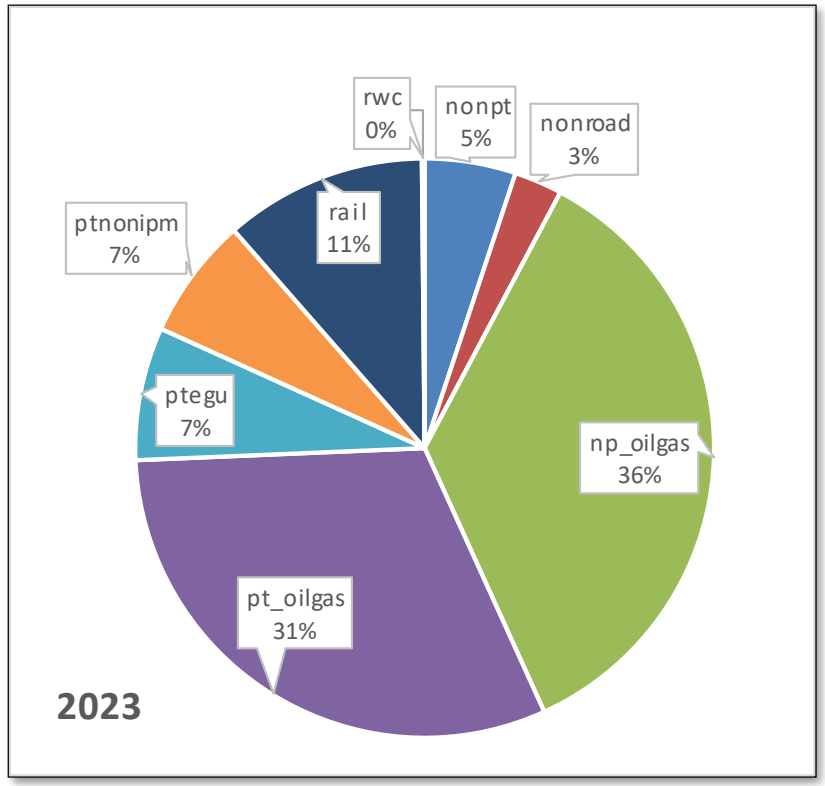
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NMED Exhibit 19 - 0011

Updated New Mexico Emissions: 2023 vs. 2014 NOx

All anthro source categories except onroad





157,534 TPY

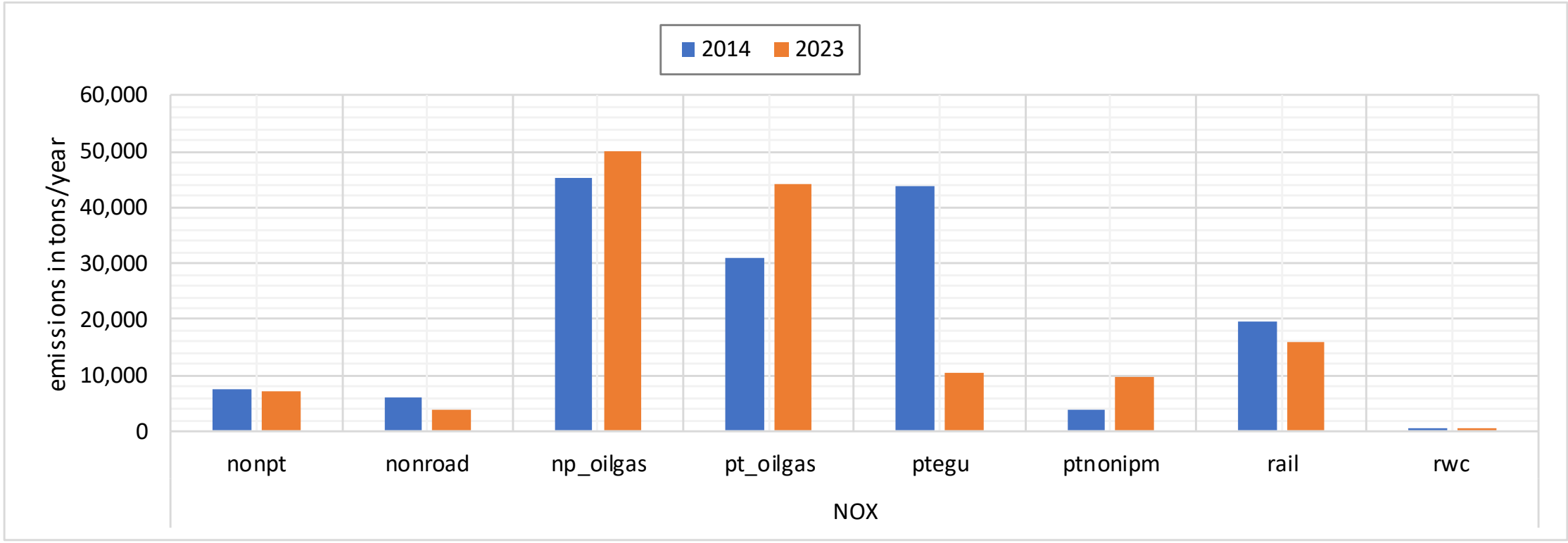
141,606 TPY

-15,928 TPY (10%) Reduction

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NMED Exhibit 19 - 0012

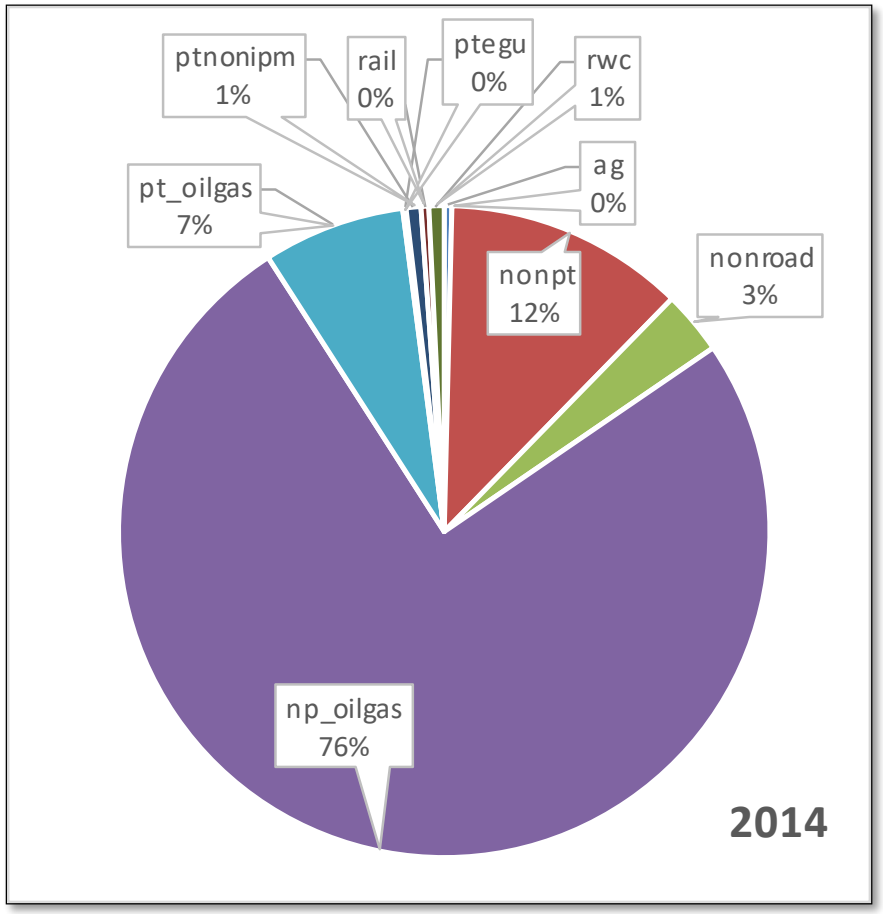
Updated New Mexico Emissions: 2023 vs. 2014 NOx by Source Category

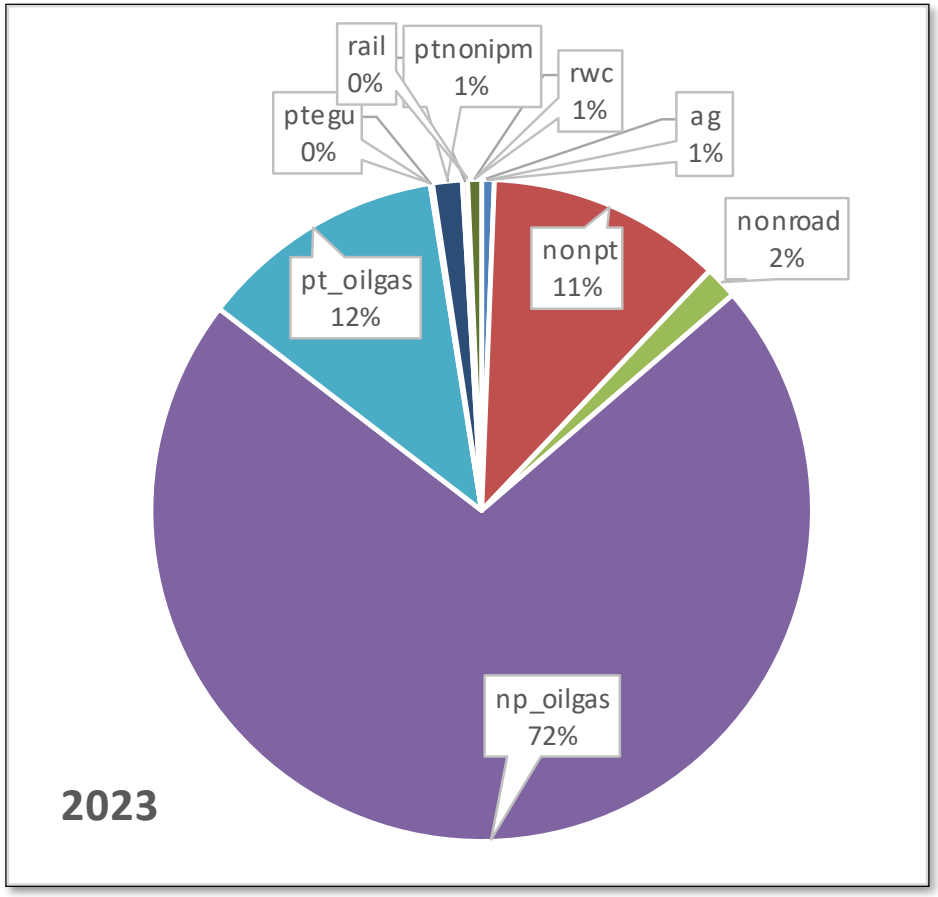


NMED Exhibit 19 - 0013

Updated New Mexico Emissions: 2023 vs. 2014 VOC

All anthro source categories except onroad





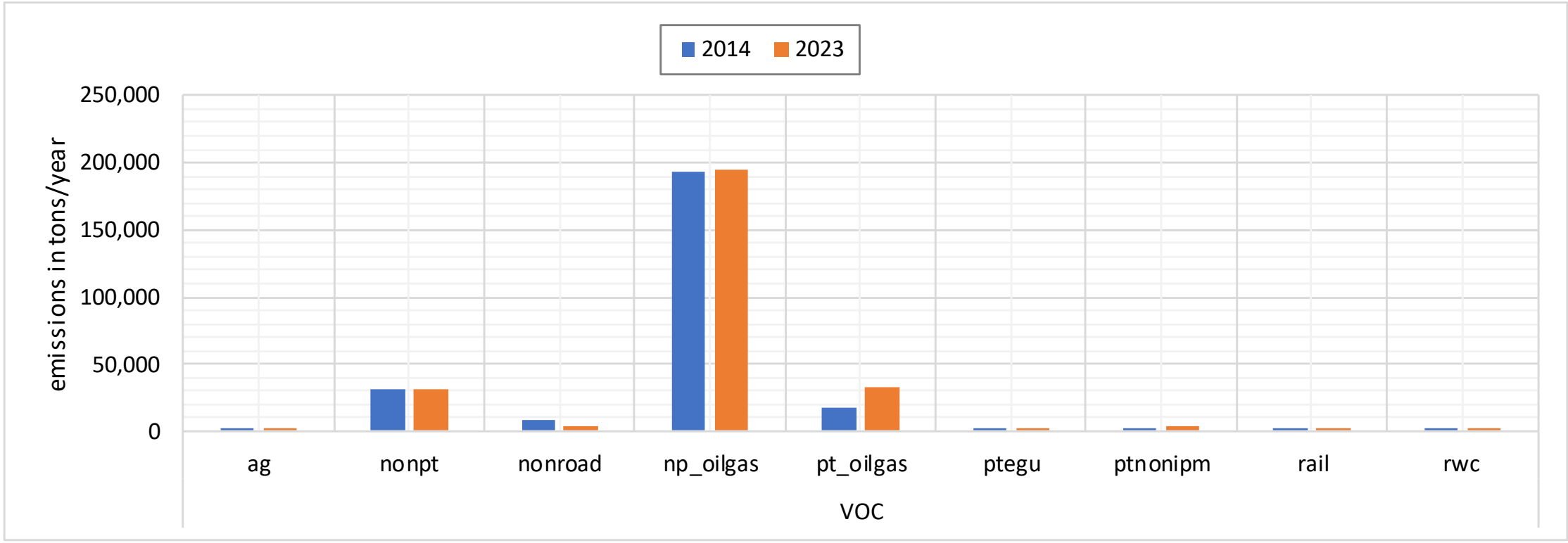
255,765 TPY

272,492 TPY

+16,727 TPY (7%) Increase

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Updated New Mexico Emissions: 2023 vs. 2014 VOC by Source Category



RAMBOLL

NMED Exhibit 19 - 0015

2014 36/12/4-KM WRF METEOROLOGICAL MODELING

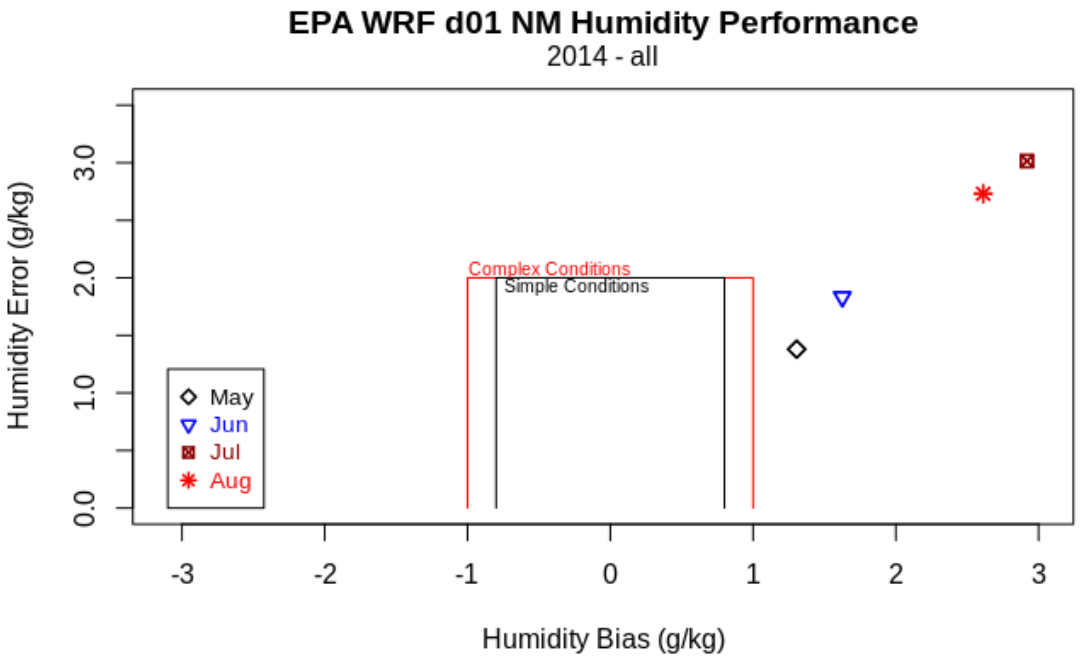


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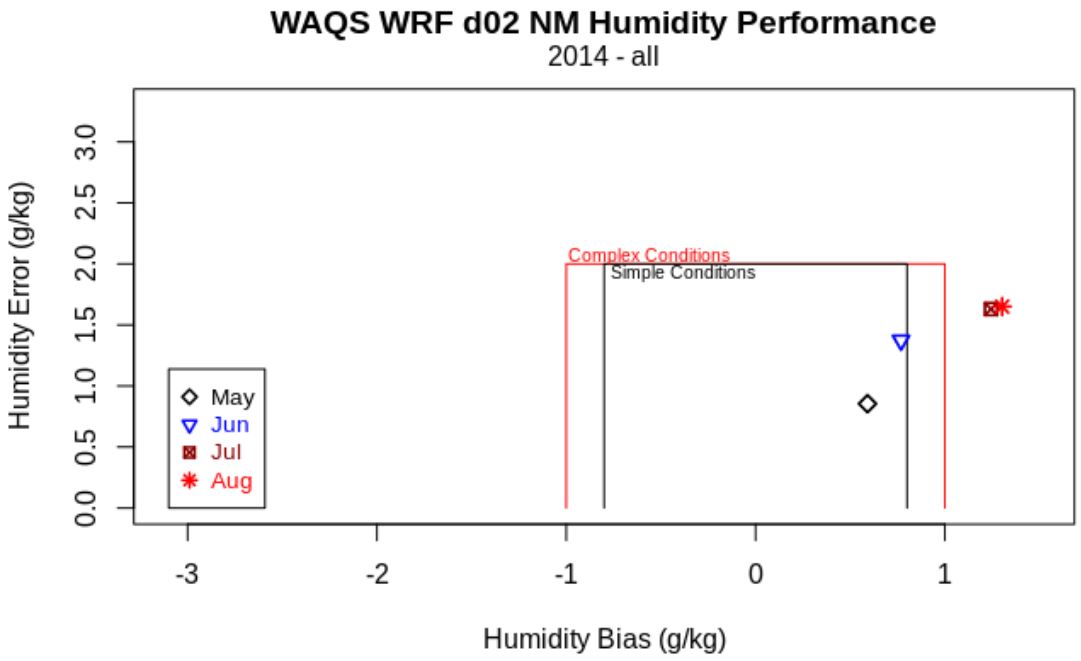
RECAP OF EPA/WAQS WRF EVALUATION

- Evaluated EPA 12US1 and WAQS 12WUS2 for May-August 2014
- EPA wet bias in summer months associated with overactive summer convection
- WAQS smaller wet bias

EPA 12 km



WAQS 12 km



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NMED Exhibit 19 - 0017

RECAP OF NM OAI WRF SETUP AND PROCEDURE

- NM OAI proposed WRF configuration aligns closely with WAQS to reduce overactive summertime convection in New Mexico, with these differences
  - Reposition 4 km domain to encompass all of New Mexico
  - Use hybrid vertical coordinate to improve representation of upper troposphere/lower stratosphere
  - Add second simulation driven by ERA5 analysis
  - No observation nudging
- Two NM OAI WRF simulations (NAM12/ERA5) completed and evaluated
- Present evaluation of these two simulations for this webinar

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NMED Exhibit 19 - 0018

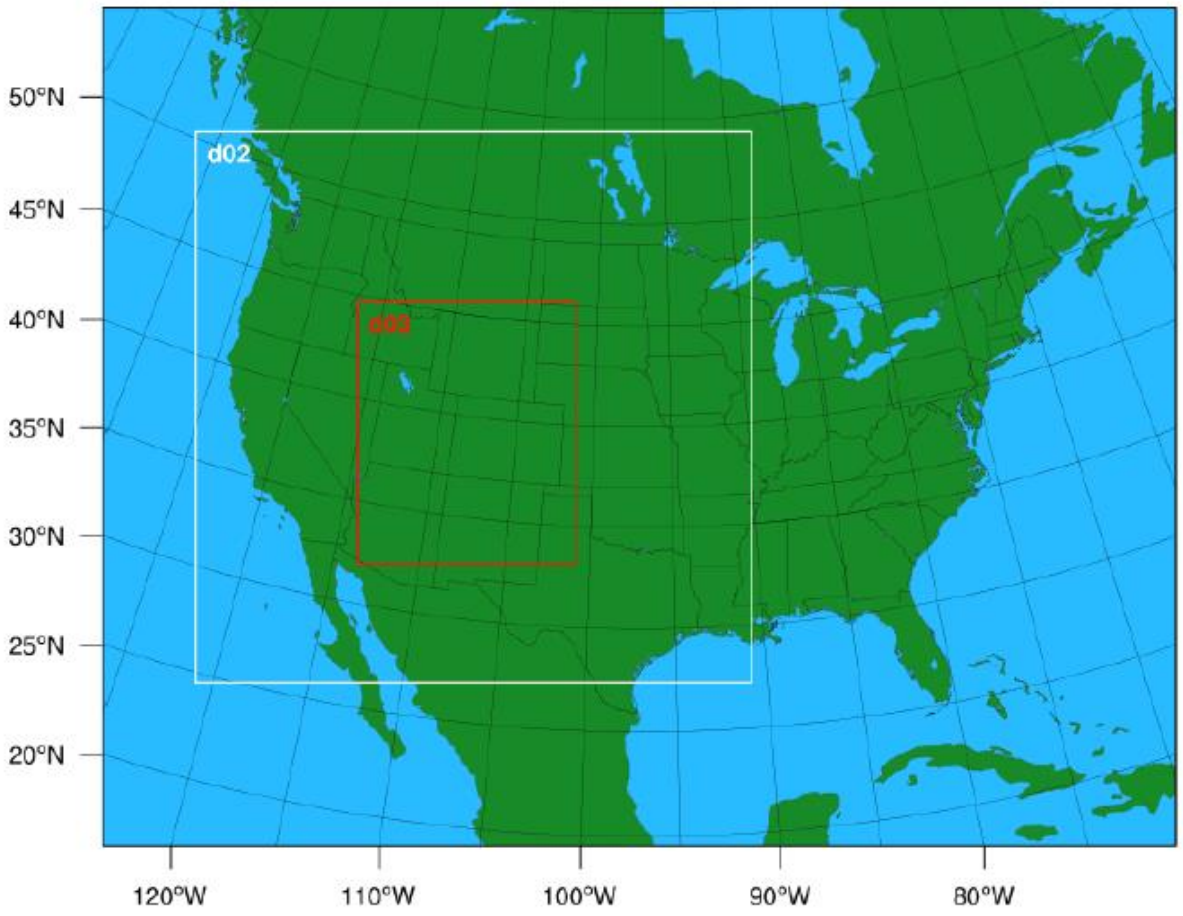
NM OAI VS WAQS WRF CONFIGURATION

WRF Option	NM OAI	2014 WAQS
Vertical Coordinate	hybrid sigma-pressure	sigma
Domains run	36/12/4-km	36/12/4-km
Microphysics	Thompson	Thompson
LW Radiation	RRTMG	RRTMG
SW Radiation	RRTMG	RRTMG
LSM	Noah	Noah
PBL scheme	YSU	YSU
Sfc Layer Physics	MM5 similarity	MM5 similarity
Cumulus	36/12/4-km Multi-scale Kain Fritsch	36/12-km Multi-scale Kain Fritsch
BC, IC Analysis Nudging Source	12-km NAM/ERA5	12-km NAM
Analysis Nudging Grids	36/12-km	36/12-km
Obs Nudging	None	4-km
Sea Sfc Temp	FNMOC	FNMOC

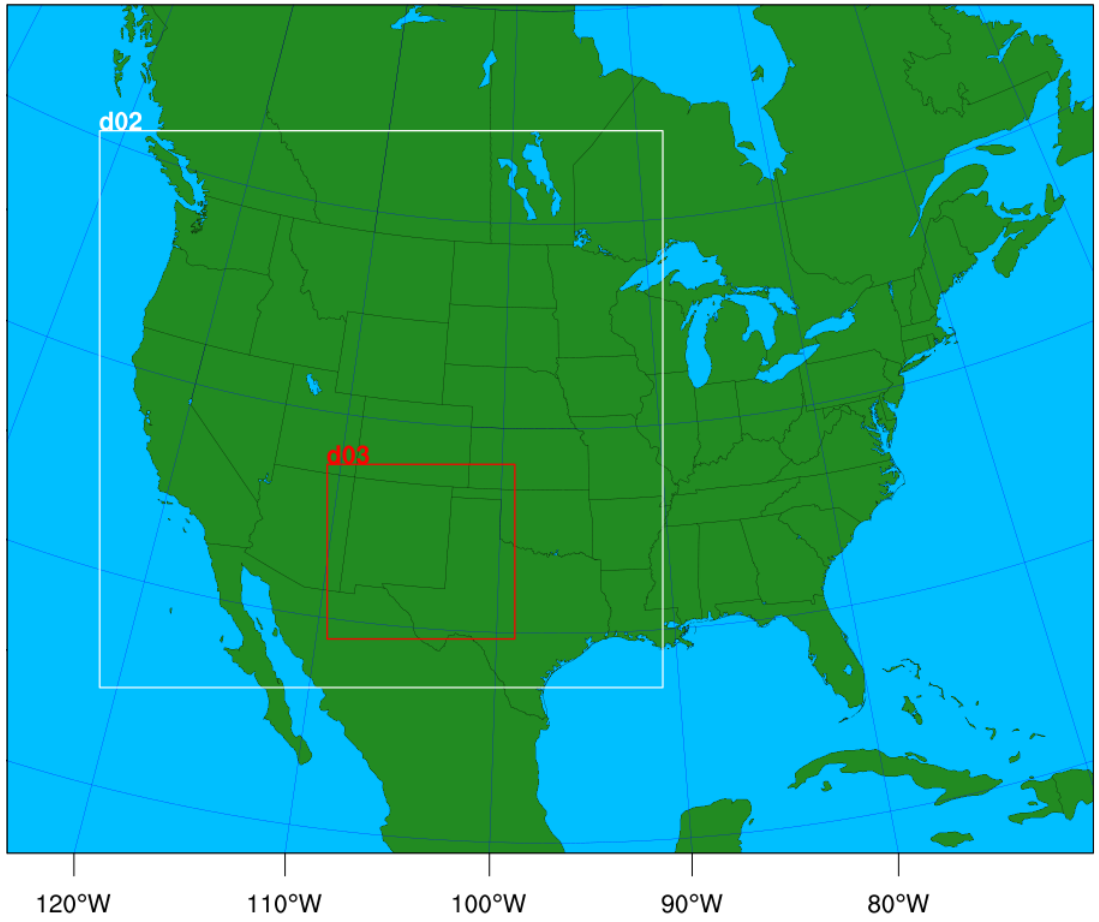
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NM OAI VS WAQS WRF DOMAINS

WAQS 36/12/4 km



NM OAI 36/12/4 km



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ERA5 VS NAM WRF MPE APPROACH

- Evaluate ERA5 and NAM WRF simulations for May-August 2014
  - ERA5 and NAM analysis field inputs are critical inputs to a WRF simulation as they define initial and boundary conditions (IC and BC) and are used in the Four Dimensional Data Assimilation (FDDA) to continuously nudge the WRF predictions to the analysis fields
  - Evaluation include observation sites within New Mexico only
- Quantitative Evaluation
  - METSTAT – model/obs pairing, bias/error statistics against NCAR ds3505 observations
    - Soccer plots – monthly stats
    - Time series – hourly and daily
    - Plots for all sites in NM, and each individual site within NM
- Qualitative Evaluation
  - PRISM precipitation spatial maps
    - Monthly and daily

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NMED Exhibit 19 - 0021

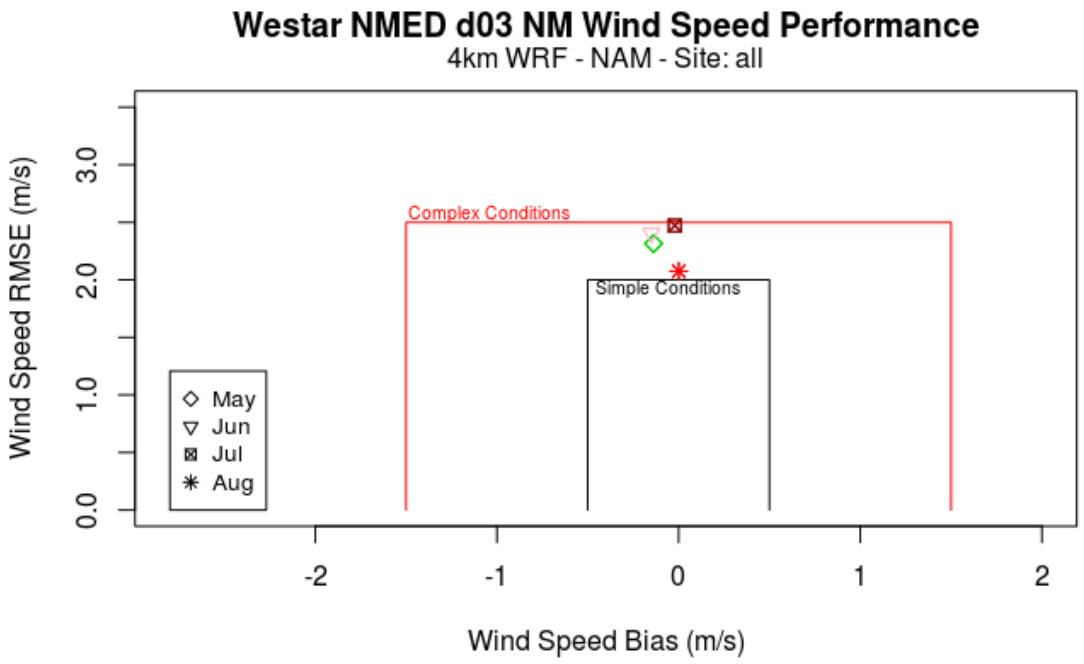
WRF STATISTICAL BENCHMARKS

Meteorological Variable	Simple Conditions		Complex Conditions	
	Bias	Error	Bias	Error
Temperature	< ±0.5 °C	< 2.0 °C	< ±2.0 °C	< 2.5 °C
Wind Speed	< ±0.5 m/s	< 2.0 m/s (RMSE)	< ±1.5 m/s	< 2.5 m/s (RMSE)
Wind Direction	< ±10 degrees	< 30 degrees	< ±10 degrees	< 50 degrees
Humidity	< ±0.8 g/kg	< 2.0 g/kg	< ±1.0 g/kg	< 2.0 g/kg

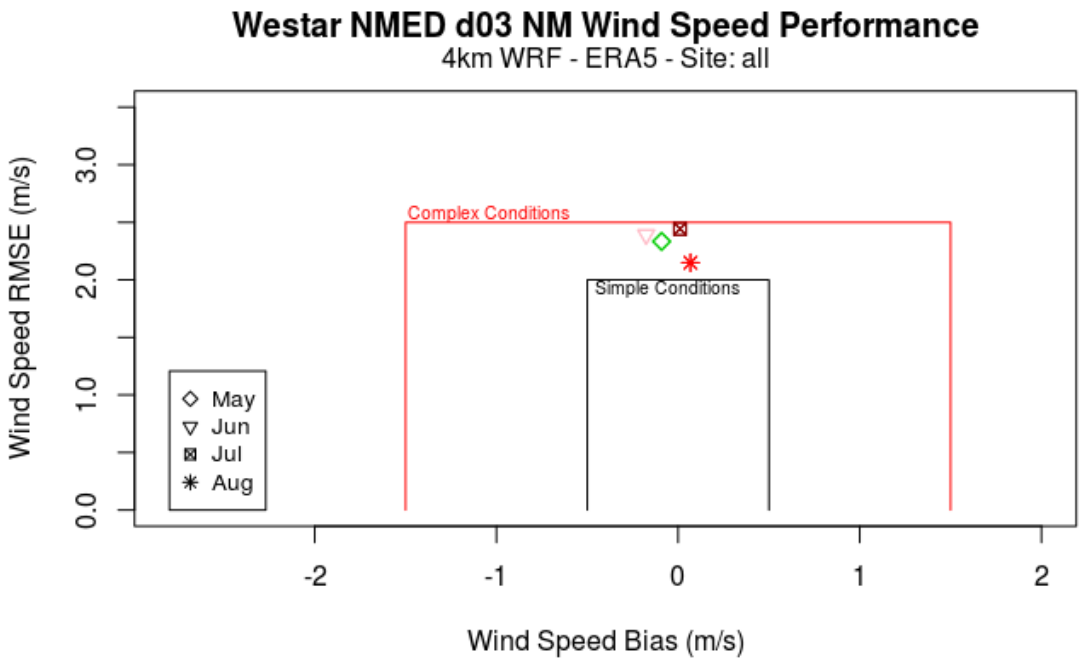
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SOCCER PLOTS – WIND SPEED FOR ALL NM SITES

NAM



ERA5



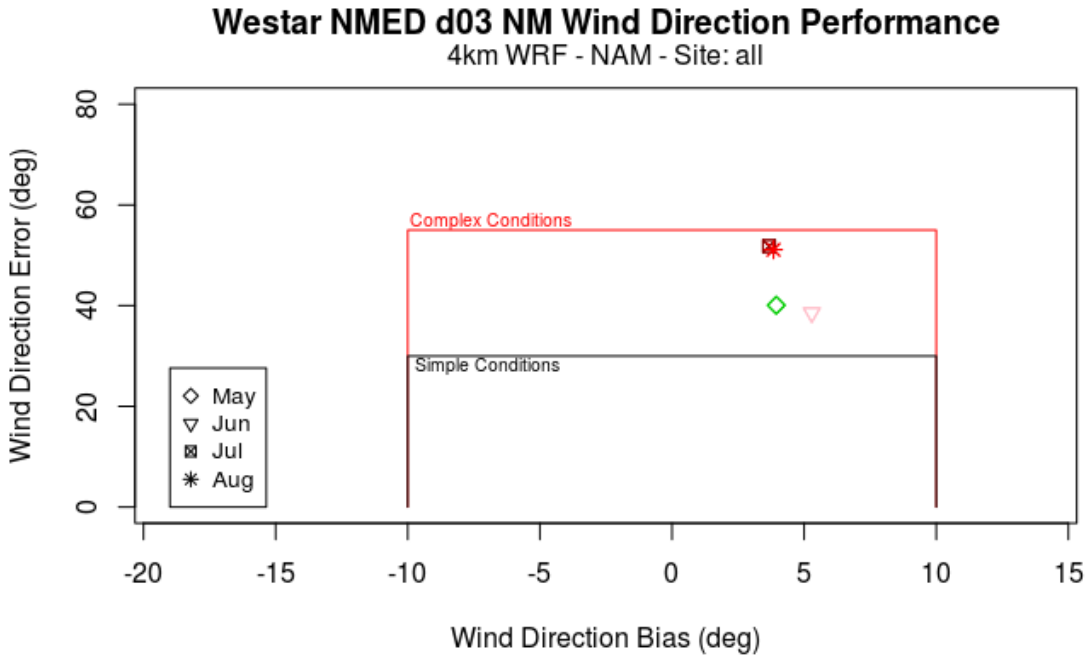
All months within complex conditions goal for both runs

NAM and ERA5 very similar; both runs' RMSE outside simple conditions goal for all months

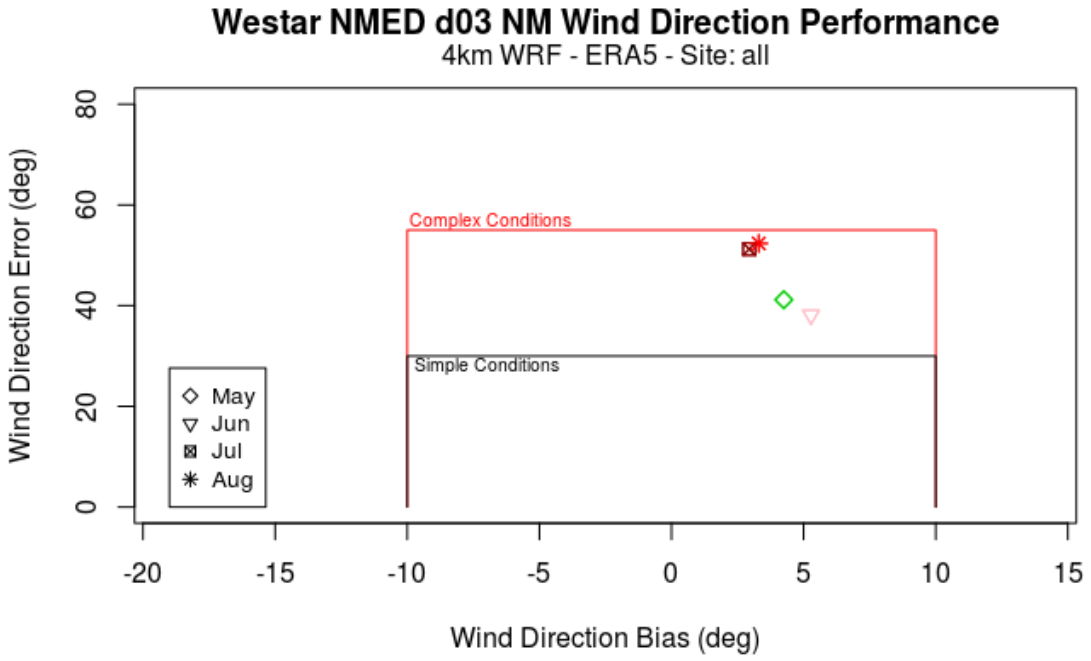
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SOCCER PLOTS – WIND DIRECTION FOR ALL NM SITES

NAM



ERA5

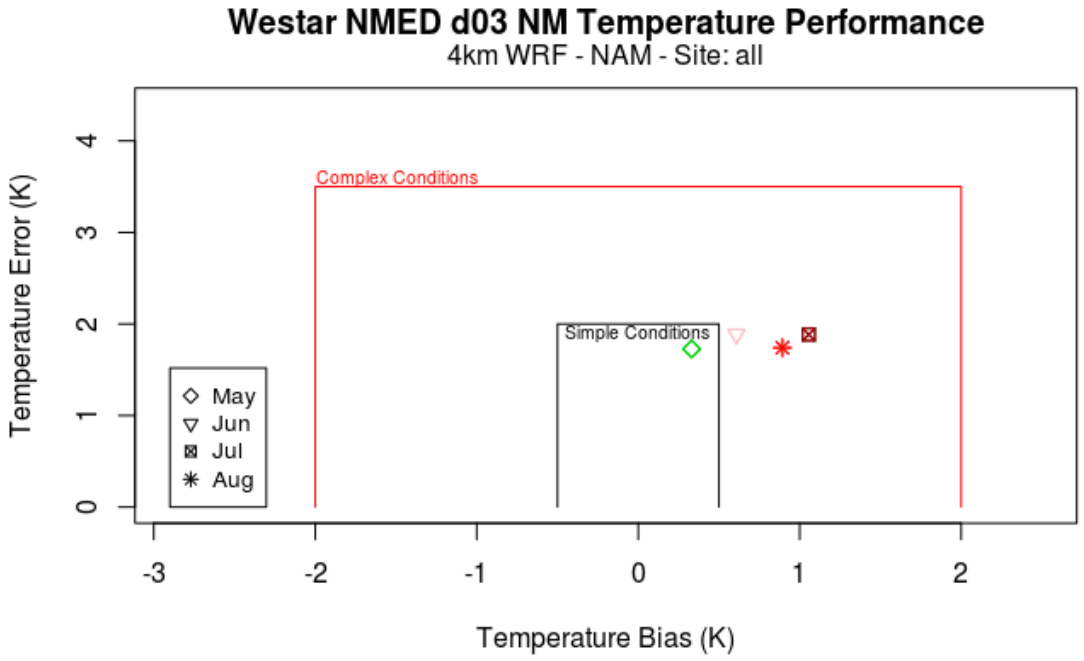


NAM and ERA5 performance nearly identical

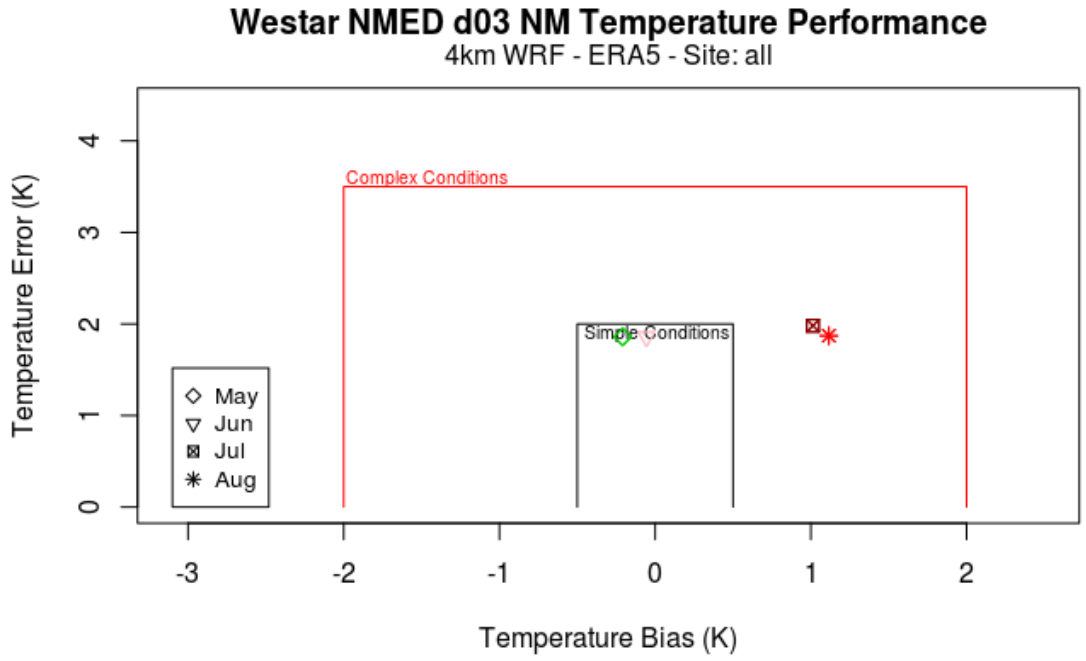
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SOCCER PLOTS – TEMPERATURE FOR ALL NM SITES

NAM



ERA5

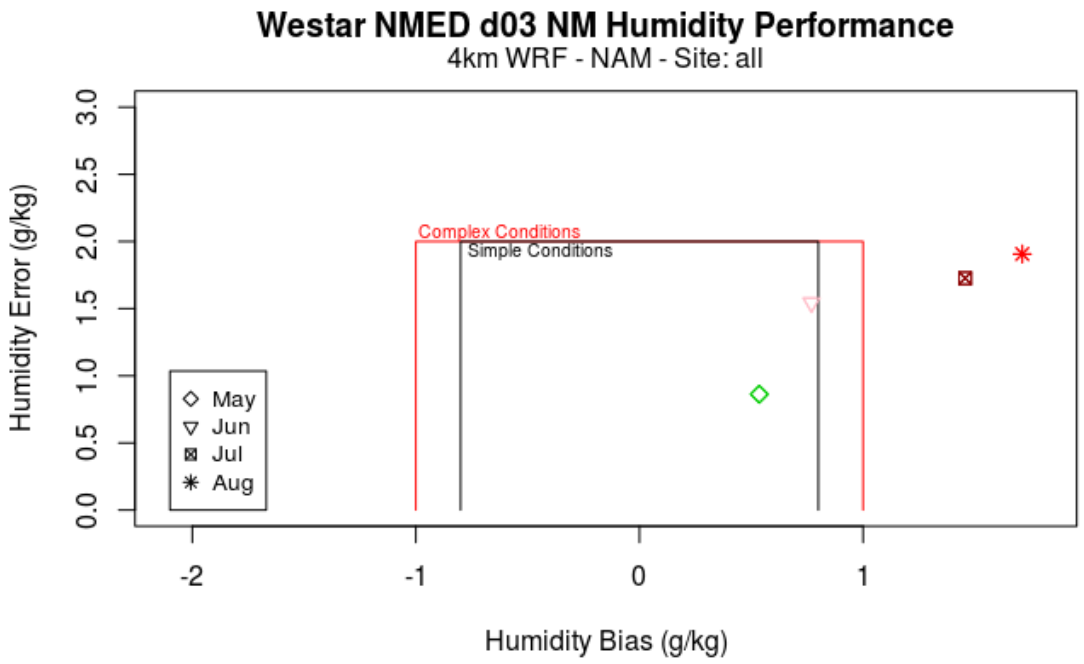


ERA5 run outperforms NAM for May-Jun; similar performance for Jul-Aug

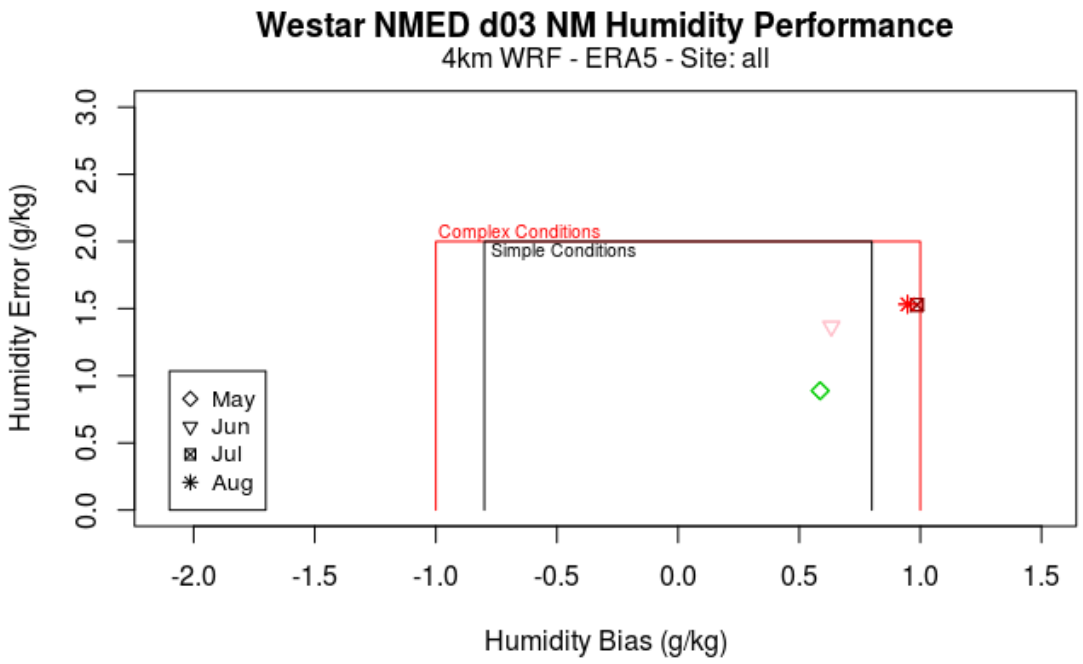
RAMBOLL

SOCCER PLOTS – HUMIDITY FOR ALL NM SITES

NAM



ERA5



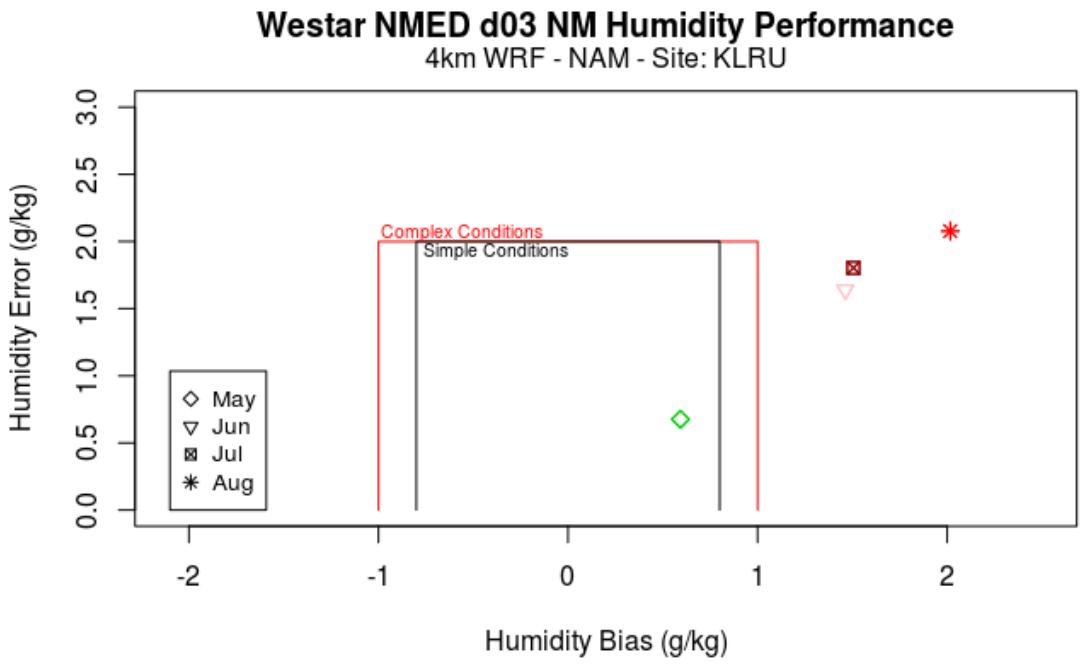
ERA5 run outperforms NAM; both runs have positive (wet) bias for all months

ERA5 considerably better performance for Jul-Aug

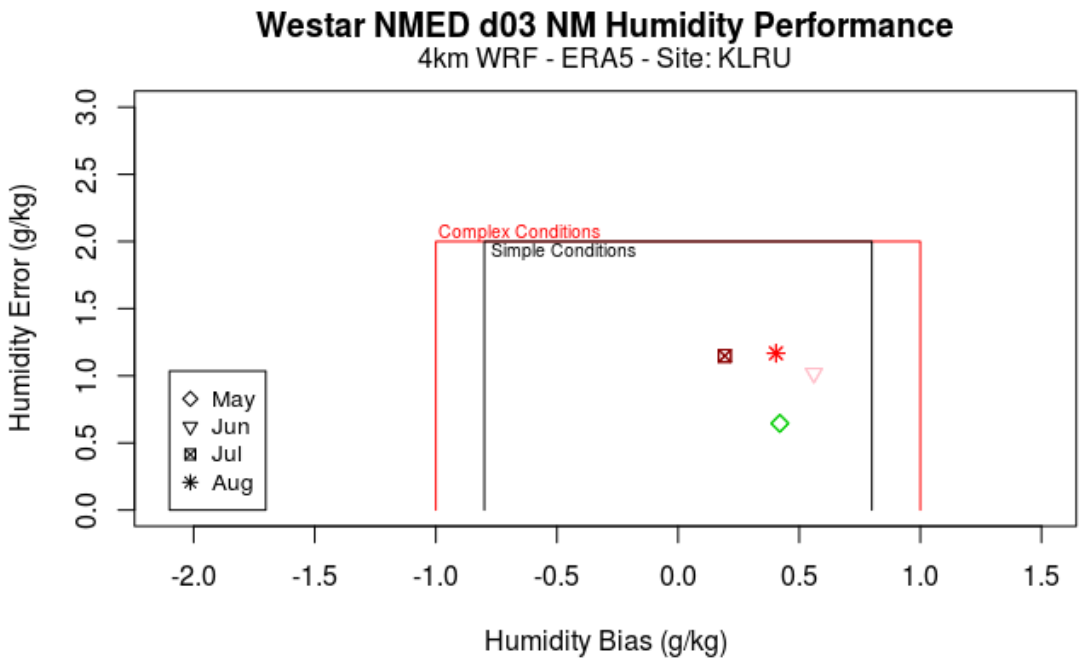
RAMBOLL

SOCCER PLOTS – HUMIDITY FOR KLRU

NAM



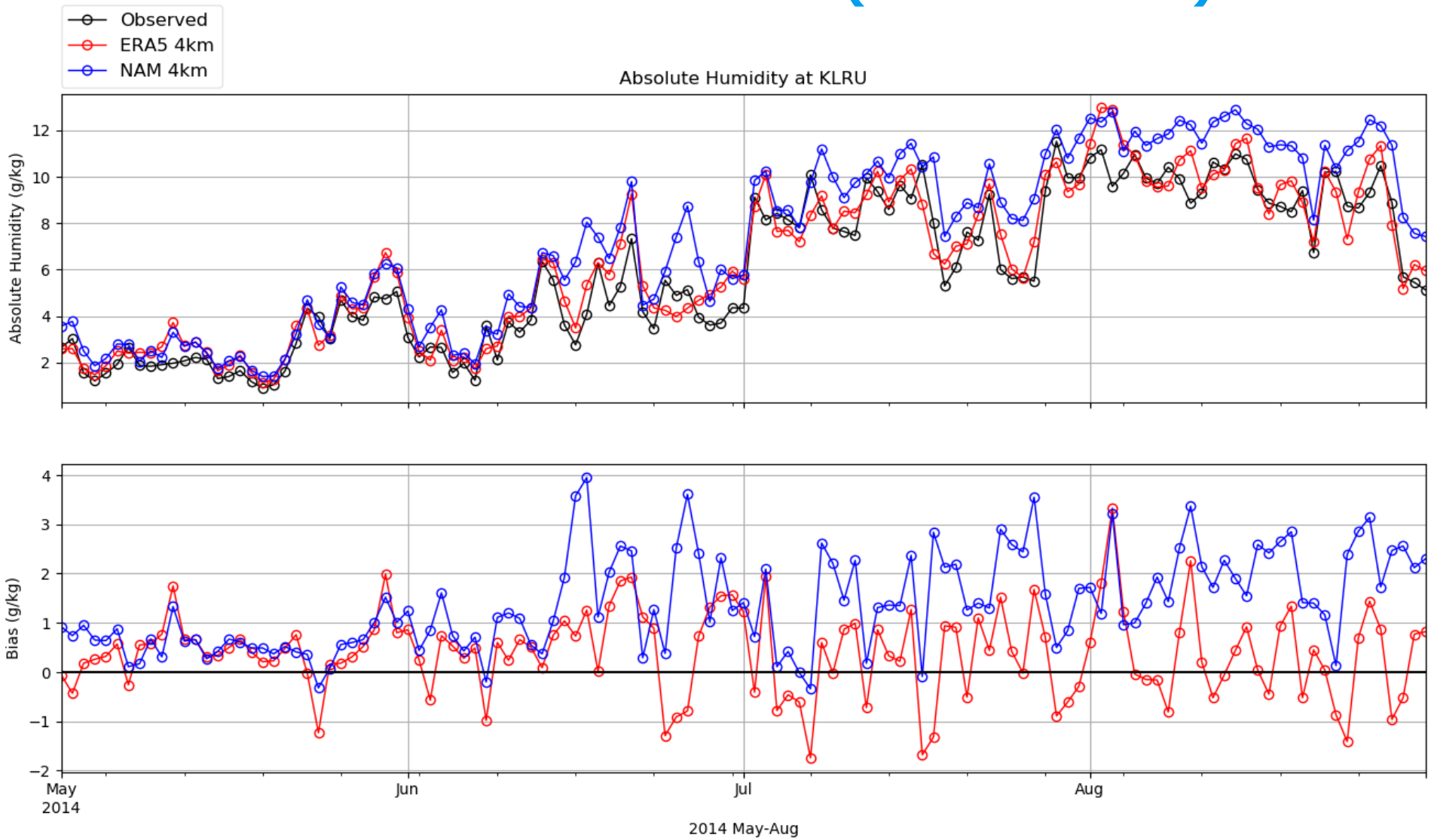
ERA5



ERA5 run outperforms NAM for all months

RAMBOLL

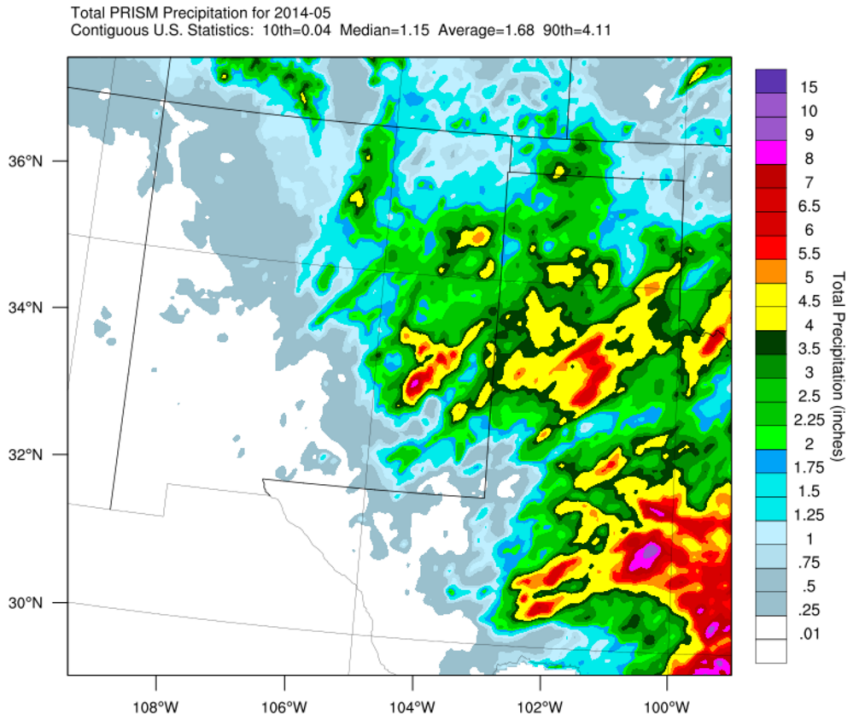
TIME SERIES – HUMIDITY AT KLRU (LAS CRUCES)



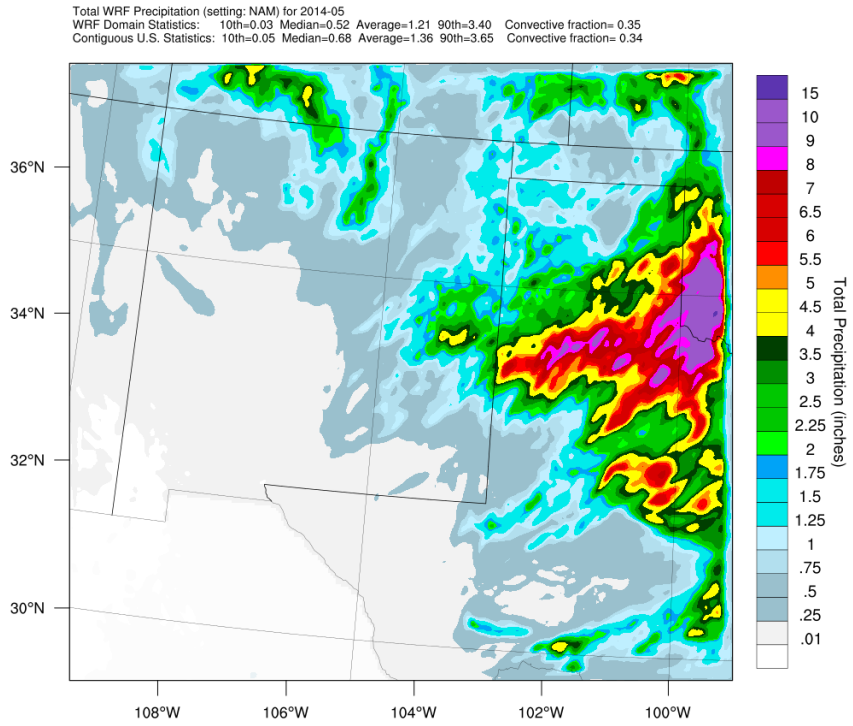
NMED Exhibit 19 - 0028

MONTHLY PRECIPITATION PLOTS – MAY 2014

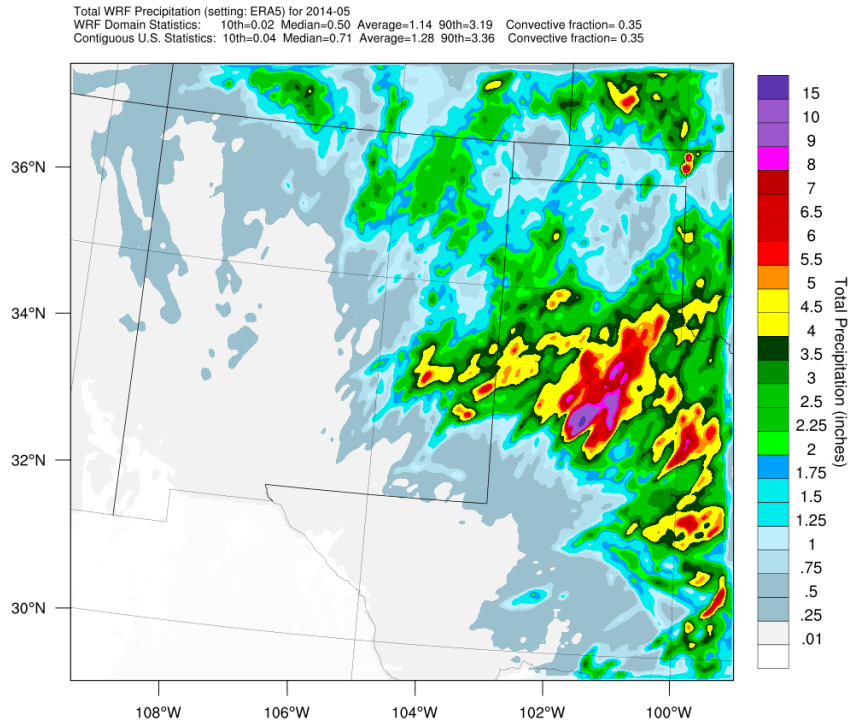
PRISM Obs



NAM



ERA5

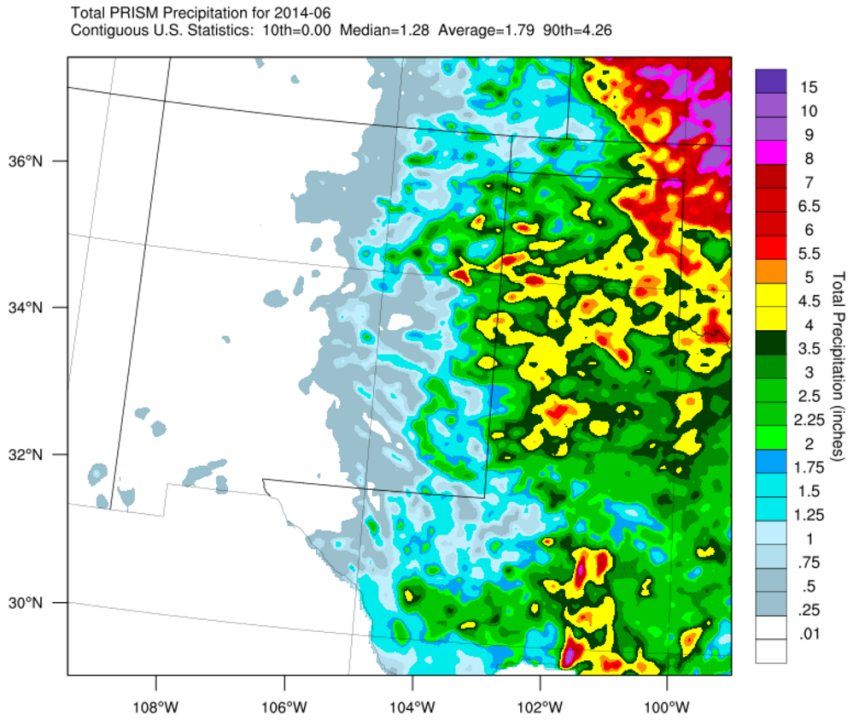


NAM and ERA5 are similar over New Mexico

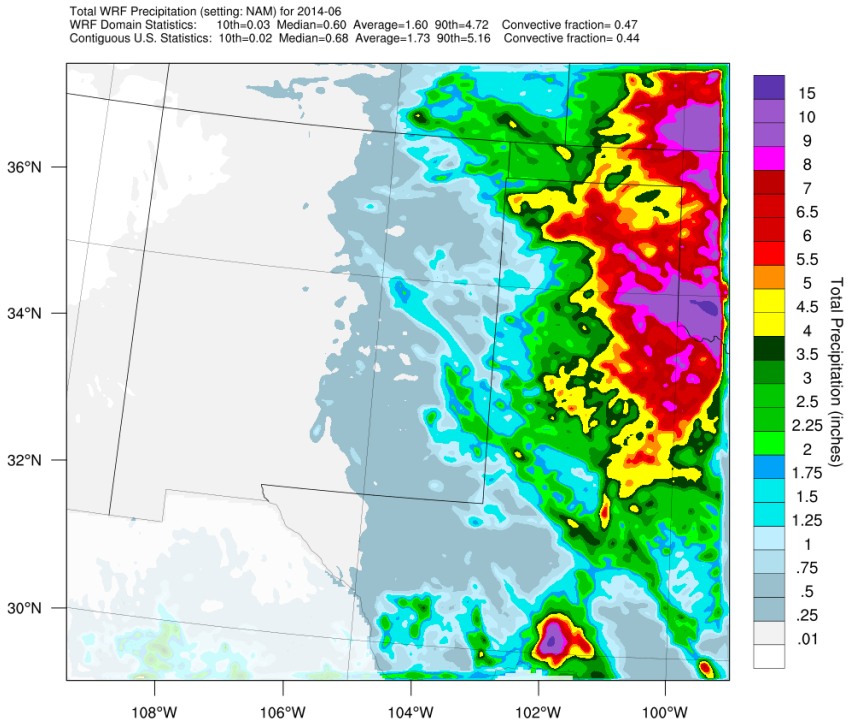
RAMBOLL

MONTHLY PRECIPITATION PLOTS – JUNE 2014

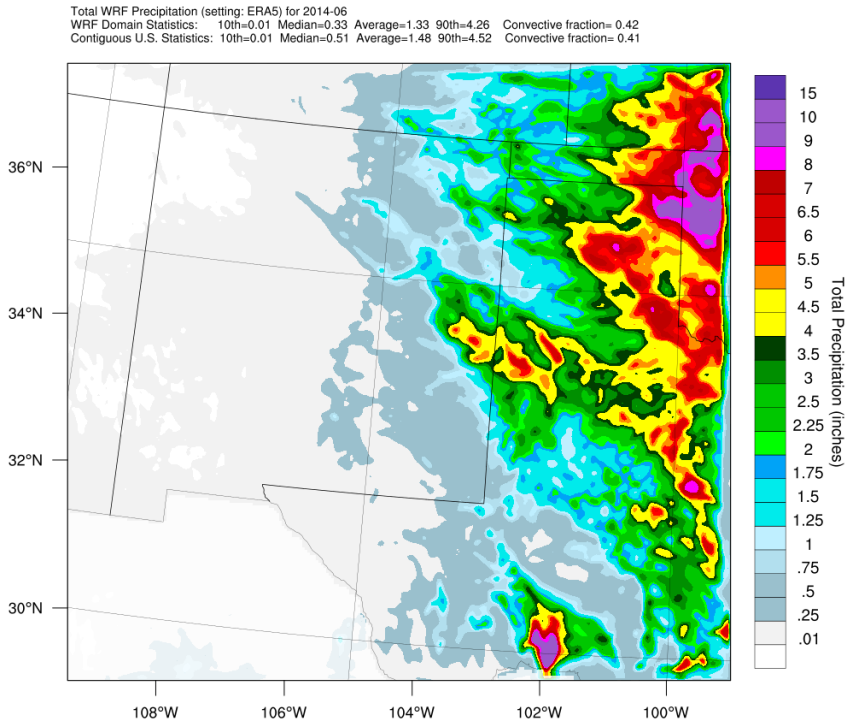
PRISM Obs



NAM



ERA5



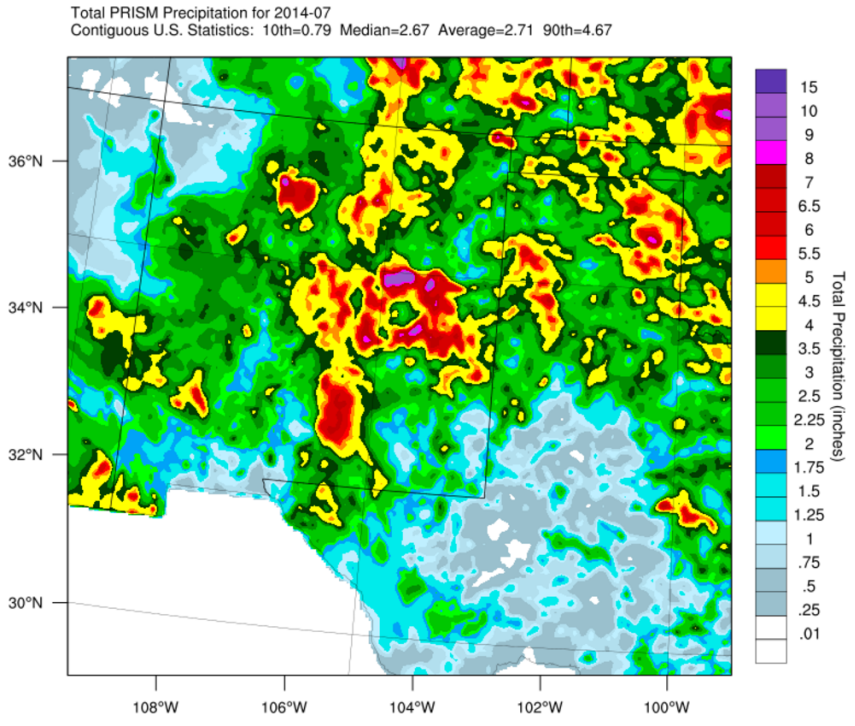
Both NAM and ERA5 are reasonable over NM; NAM overpredicts over North Texas

ERA5 slightly better

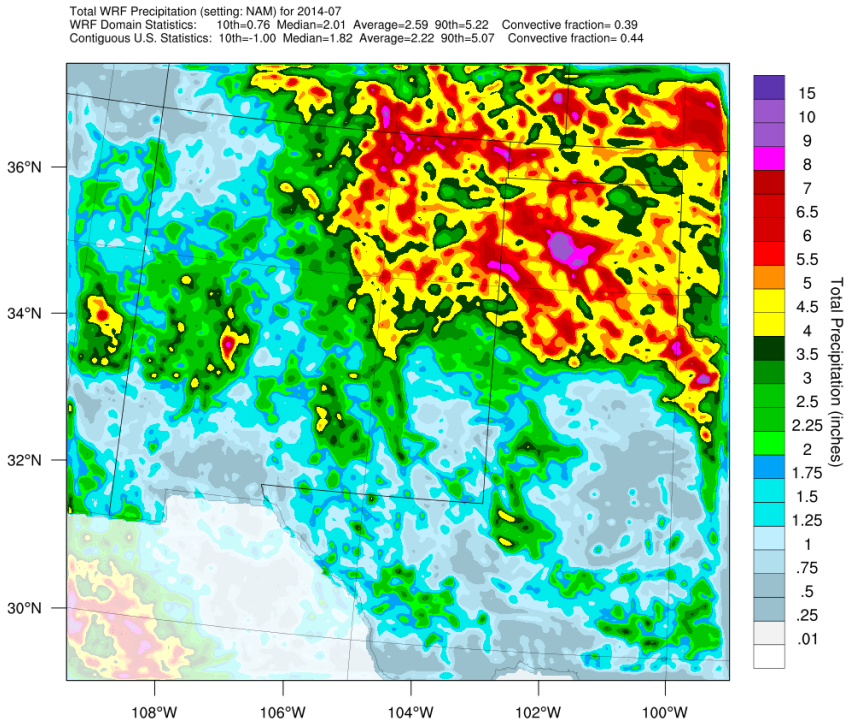
RAMBOLL

MONTHLY PRECIPITATION PLOTS – JULY 2014

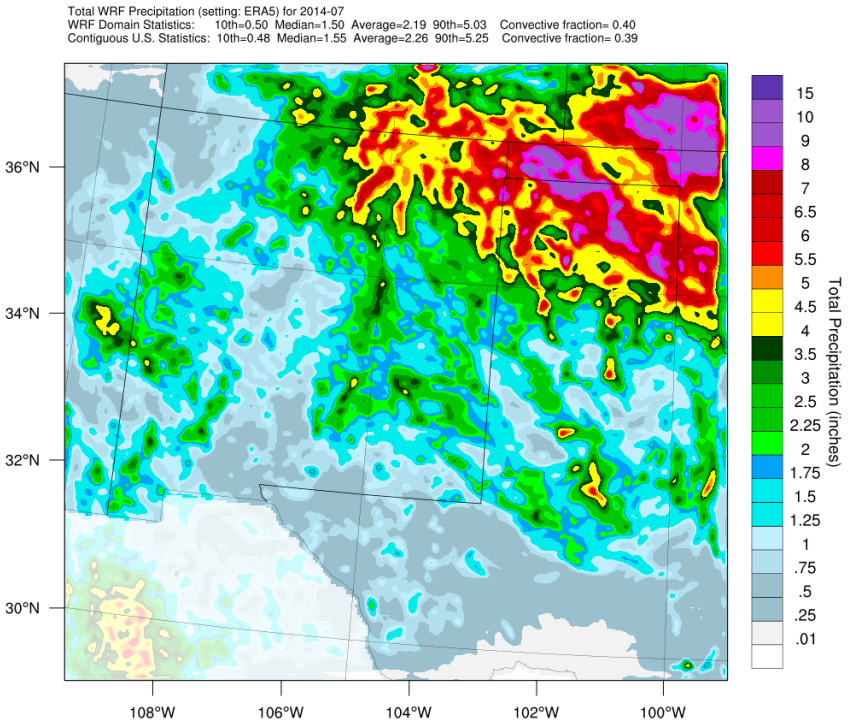
PRISM Obs



NAM



ERA5

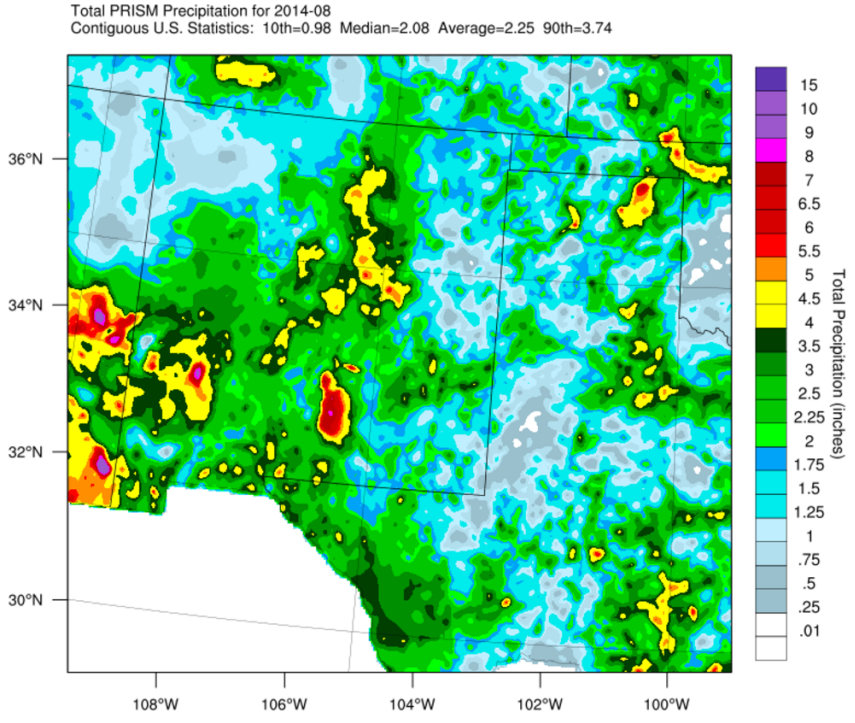


NAM overpredicts over NE New Mexico; both NAM and ERA5 show dry bias elsewhere in NM

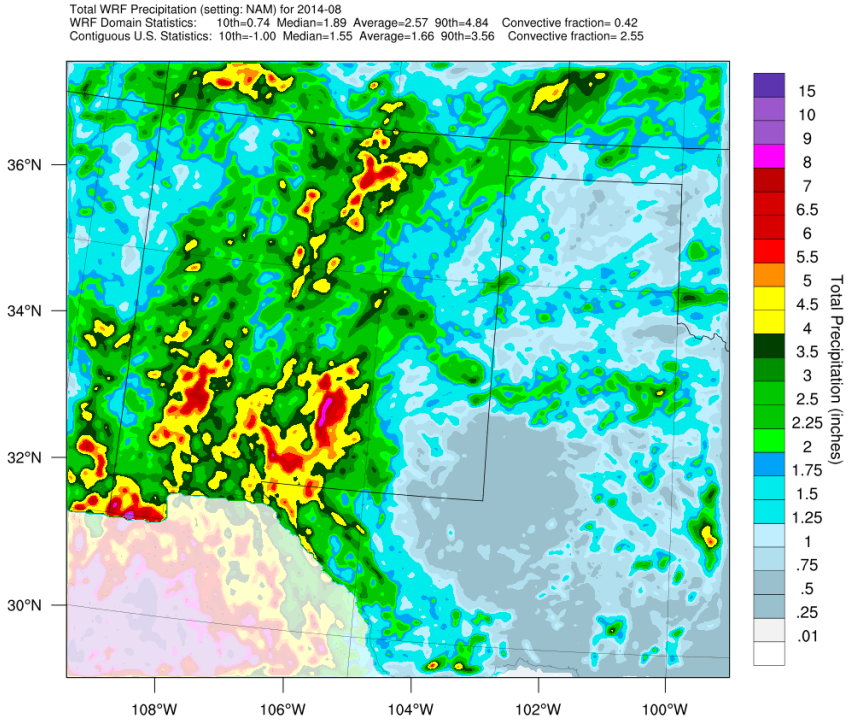
RAMBOLL

MONTHLY PRECIPITATION PLOTS – AUG 2014

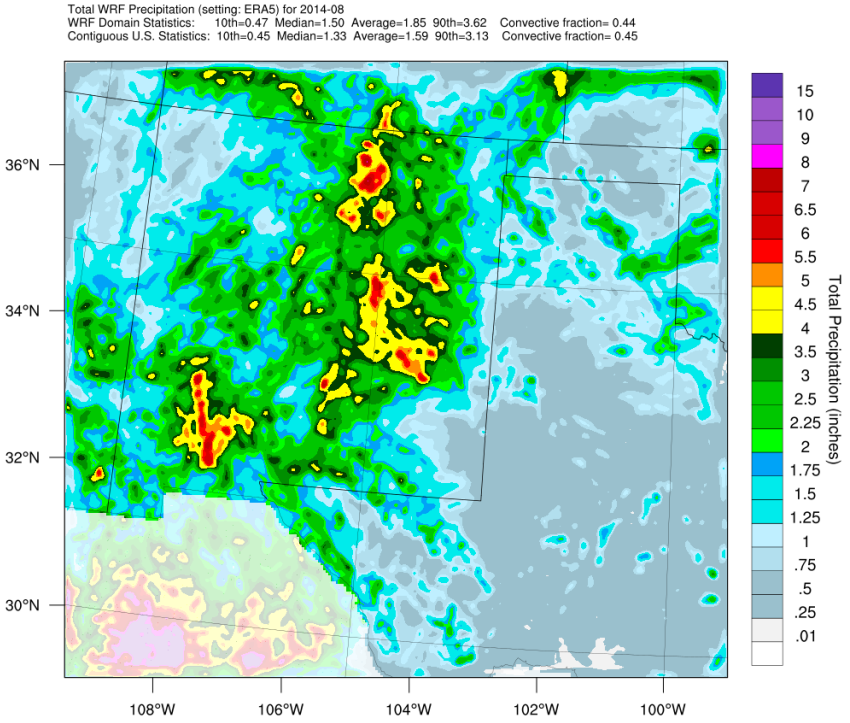
PRISM Obs



NAM



ERA5



ERA5 slightly better than NAM in matching location and magnitude of PRISM observations

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2014 WRF SUMMARY AND CONCLUSIONS

- WRF performance reasonable for both NAM and ERA5 simulations
- Differences between NAM and ERA5 are smaller in comparison to EPA/WAQS
- NAM wet bias in June-August may be partly associated with overactive summer convection
- ERA5 has smaller wet bias
- Not possible to know which WRF simulation will result in better in CAMx ozone performance
  - Relative performance varies across parameters/seasons/locations
  - Best (or worst) performing WRF days may have small (or large) influence on AQ concentrations
  - Other meteorological variables (vertical diffusion, PBL heights, etc.) may be more important than the ones we can easily evaluate (T, Q, winds, precip)
- Proceed with both WRF simulations through CAMx and select best ozone performance for final CAMx configuration

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NMED Exhibit 19 - 0033

NM OAI Study Next Steps



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Next Up in July 2020

- July 2020: Task 4 -- 2014 and 2023 Emissions
  - 2014 SMOKE-MOVES and SMOKE for 4-km New Mexico Domain
  - 2014 36/12/4-km MEGAN biogenic and LNOx emissions modeling
  - Start 2023 SMOKE modeling
- July 2020: Task 5 – CAMx 2014 36/12/4-km Base Case Modeling
  - CAMx meteorological input sensitivity modeling
    - May 1 – June 16, 2014; 4 configurations: WRF/NAM and WRF/ERA5 using CMAQ/YSU vertical diffusivities (Kv)
  - Start CAMx 2014 36/12/4-km final base case May - August
- July 2020: NMED OAI Webinar
  - 2014 SMOKE Results for 4-km New Mexico domain (Anthro & Natural)
  - CAMx WRF meteorology sensitivity modeling
  - CAMx 2014 36/12/4-km final base case configuration
- Expected progress in August 2020
  - 2014 CAMx base case and MPE Report
  - 2023 Base and Control Strategy SMOKE Modeling and 2023 CAMx base case

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DISCUSSION



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NEW MEXICO OZONE ATTAINMENT INITIATIVE

2014 and 2023 Emissions, CAMx WRF Sensitivity Tests and Selection of Final Model Configuration

Ralph Morris, Pradeepa Vennam,
Marco Rodriguez, Jeremiah Johnson,
Tejas Shah, Ramboll

Tom Moore and Mary Uhl, WESTAR

NM OAI Study Webinar#3

July 27, 2020

RAMBOLL Bright ideas. Sustainable change.



AGENDA – NMED OAI STUDY WEBINAR#3 – JULY 27, 2020

- Welcome and agenda review – Tom and all
- 2014 and 2023 emissions QA, updates and processing – Ramboll
  - 2014 and 2023 Emissions QA and identification of duplicate sources
  - 2014 SMOKE emissions processing and results
  - 2014 natural emissions
- CAMx meteorological sensitivity tests and CAMx final 2014 base case configuration – Ramboll
  - WRF NAM and ERA simulations
  - Ozone evaluation of CAMx four meteorological input sensitivity tests
  - Final CAMx 2014 36/12/4-km base case configuration
- Upcoming schedule, milestones when NMED needs support for EIB process - all

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2014 AND 2023 EMISSIONS

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NEW MEXICO EMISSIONS DATA

- 2014 anthropogenic emissions are based on the WAQS 2014v2
  - NMED found a generator engine missing in 2014v2 inventory (94 tpy NOx)
  - No double counting of sources in 2014v2 inventory
  - Consistent emissions data between the Regional Haze and OAI studies

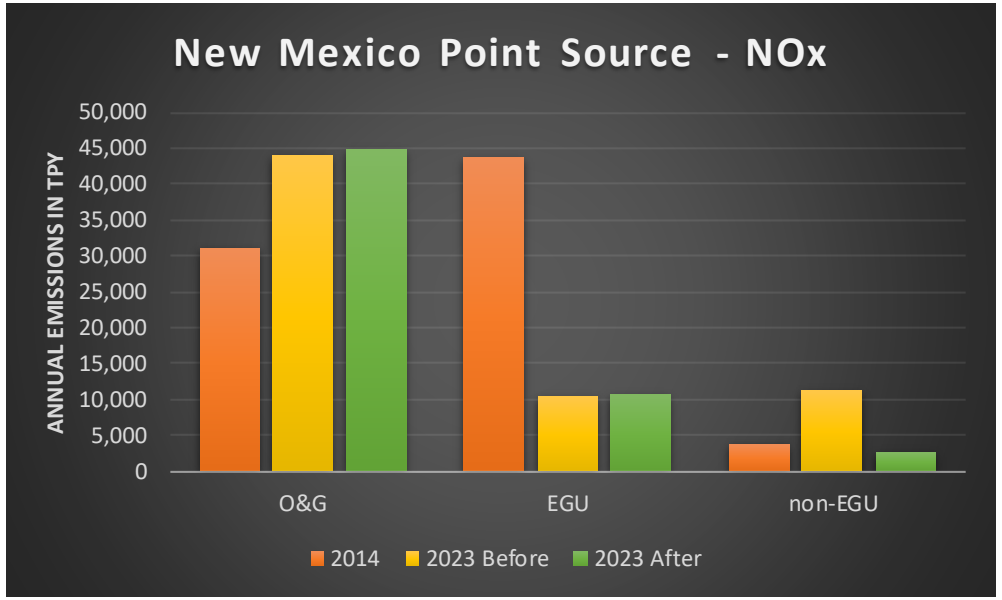
- 2023 anthropogenic emissions are based on the EPA 2016v1 platform
  - NMED found some point sources exist in both 2023 point O&G and non-EGU sectors
  - Found double counting of sources in WRAP O&G inventory: Title V and minor point sources
  - Found Lordsburg Generating Station is missing
  - Add two O&G sources: Chaco Gas Plant (NOx 2,053 tpy) and Mountainair CS (NOx 645 tpy)

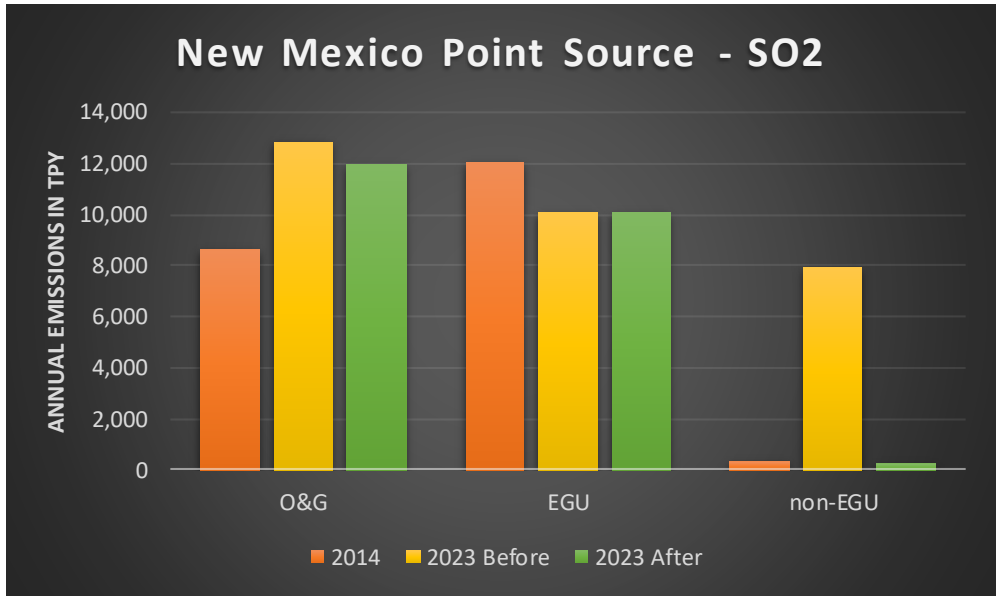
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NMED Exhibit 20 - 0004

DUPLICATE POINT SOURCES IN 2023

- NMED identified 21 facilities double counted in 2023 non-EGU and WRAP point O&G inventory
  - Double counted emissions: NOx 8,669 TPY and SO2 7,662 TPY
  - Represents approximately 9% (NOx) and 24% (SO2) of the New Mexico 2023 O&G emissions
- Duplicates in the WRAP O&G inventory: Some sources were present in Title V and minor point O&G sources datasets in the OGWG inventory.
  - Double counted emissions NOx: 1,927 TPY and SO2: 942 TPY





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NMED Exhibit 20 - 0005

O&G SOURCES IDENTIFIED IN NON-EGU INVENTORY BASED ON NAICS CODES

O&G NAICS found in ptnonipm but not duplicate

Duplicates found by EPA/NMED in pt_oilgas and ptnonipm sectors

Duplicates found based on NAICS

Sum of ann_value					poll						
region_cd	state	facility_name	facility_id	naics	CO	NH3	NOX	PM10	PM25	SO2	VOC
8123	CO	OVERLAND PASS - FT LUPTON METER NORTH	14794011	486990							1
8123	CO	OVERLAND PASS - FT LUPTON METER SOUTH	14919211	486990							3
8123	CO	OVERLAND PASS - FT LUPTON/DJ JUNCTION	14794111	486990							5
8123	CO	OVERLAND PASS - GROVER STATION	14794411	486990							10
8123	CO	OVERLAND PASS - LILLI METER	16286411	486990							3
8123	CO	OVERLAND PASS - LUCERNE METER	14793811	486990							4
8123	CO	OVERLAND PASS - LUCERNE/DJ JUNCTION	14919311	486990							7
8123	CO	OVERLAND PASS - MEWBOURN METER	14919411	486990							5
8123	CO	OVERLAND PASS - MEWBOURN/FT LUPTON	14919511	486990							8
8123	CO	OVERLAND PASS - OPPL/DJ JUNCTION &DJ PL	14793911	486990	0		0	1	1	1	9
8123	CO	OVERLAND PASS - PAWNEE CREEK	16203211	486990							2
35001	NM	Albuquerque Refined Products Terminal	12817711	48691	3		1				22
35005	NM	NuStar Logistics Operation LP - Hope Pump St	7565111	48691	4		101	0	0	0	0
35015	NM	Artesia Gas Plant	7411811	21112	380		351	11	11	19	73
35015	NM	Chaparral Gas Plant	17128911	21112	72		110	3	3	4	133
35015	NM	DCP Midstream - Pecos Diamond Gas Plant	7761811	21112	46		59	4	4	0	165
35015	NM	Empire Abo Gas Plant/Compressor Station	7584511	21112	12		84	0	0	162	42
35015	NM	Oxy - Indian Basin Gas Plant	7905211	21112	29		161	4	4	51	40
35025	NM	DCP Midstream - Eunice Gas Plant	5228911	21112	224		606	11	11	1,437	70
35025	NM	Denton Gas Plant	8091311	21112	32		26	2	2	952	28
35025	NM	Eunice Gas Processing Plant	8092311	21112	357		2,046	22	21	23	72
35025	NM	Jal No3 Gas Plant	5226911	21112	382		381	16	16	1,968	266
35025	NM	Linam Ranch Gas Plant	8241211	21112	449		692	28	28	109	103
35025	NM	Maljamar Gas Plant	5226611	21112	50		87	7	7	213	57
35025	NM	Saunders Gas Plant	8241411	21112	116		821	10	10	416	66
35025	NM	Targa - Monument Gas Plant	8241311	21112	195		361	17	5	1,953	89
35043	NM	San Luis Pump Station	6723811	48699	2		3	0	0		1
35043	NM	San Ysidro Pump Station GCP1-1145	6724211	48699	2		9	1	1	1	20
35045	NM	Harvest Pipeline - San Juan Gas Plant	7231911	21112	63		527	17	17	1	47
35045	NM	Huerfano Pump Station	6735511	48699	10		25	1	1	0	23
35045	NM	Kutz Canyon Processing Plant	7230311	21112	603		767	14	14	3	510
35045	NM	San Juan River Gas Plant	8091911	21112	92		137	4	4	143	78
35045	NM	Val Verde Treatment Plant	7992811	21112	107		139	25	25	43	156
38093	ND	Jamestown East Products Terminal	8012911	486910							39
46005	SD	NuStar PipeLine Operating Partnership	15648111	486910							41
46013	SD	NuStar Pipeline Operating Partnership LP	15646411	486910							73
46029	SD	Magellan Pipeline Company	15646511	486910							83
46035	SD	NuStar Pipeline Operatng Partnership	15646711	486910	0		0	0	0	0	14
46099	SD	Magellan Pipeline Company	15646311	486910	14		9	0	0	0	165
46099	SD	NuStar Pipeline Operating Partnership LP	2911811	486910	0		2	0	0	0	17
46135	SD	NuStar PipeLine Operating Partnership	15646611	486910							102
56025	WY	Casper Gas Plant	17924811	211130	41	0	32	2	2	0	10
56037	WY	Rock Springs Terminal	6939911	486910	0		0	0	0		33
Grand Total					3,284	0	7,537	199	186	7,500	2,698

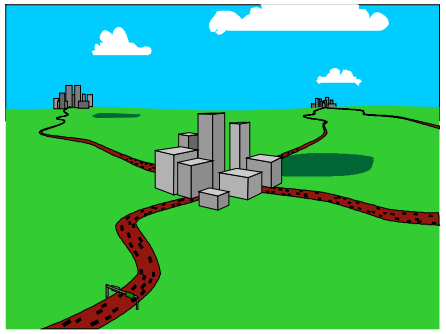
NMED Exhibit
20 - 0006

INTRODUCTION TO EMISSION PROCESSING

NMED Exhibit 20 - 0007

INTRODUCTION TO EMISSION PROCESSING

Start With

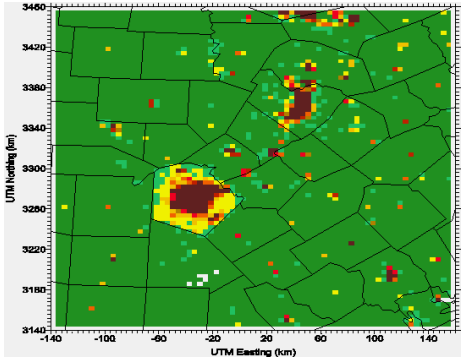


Annual Estimates (tons/year)

County Totals

Criteria Pollutants (NOx, CO, VOC)

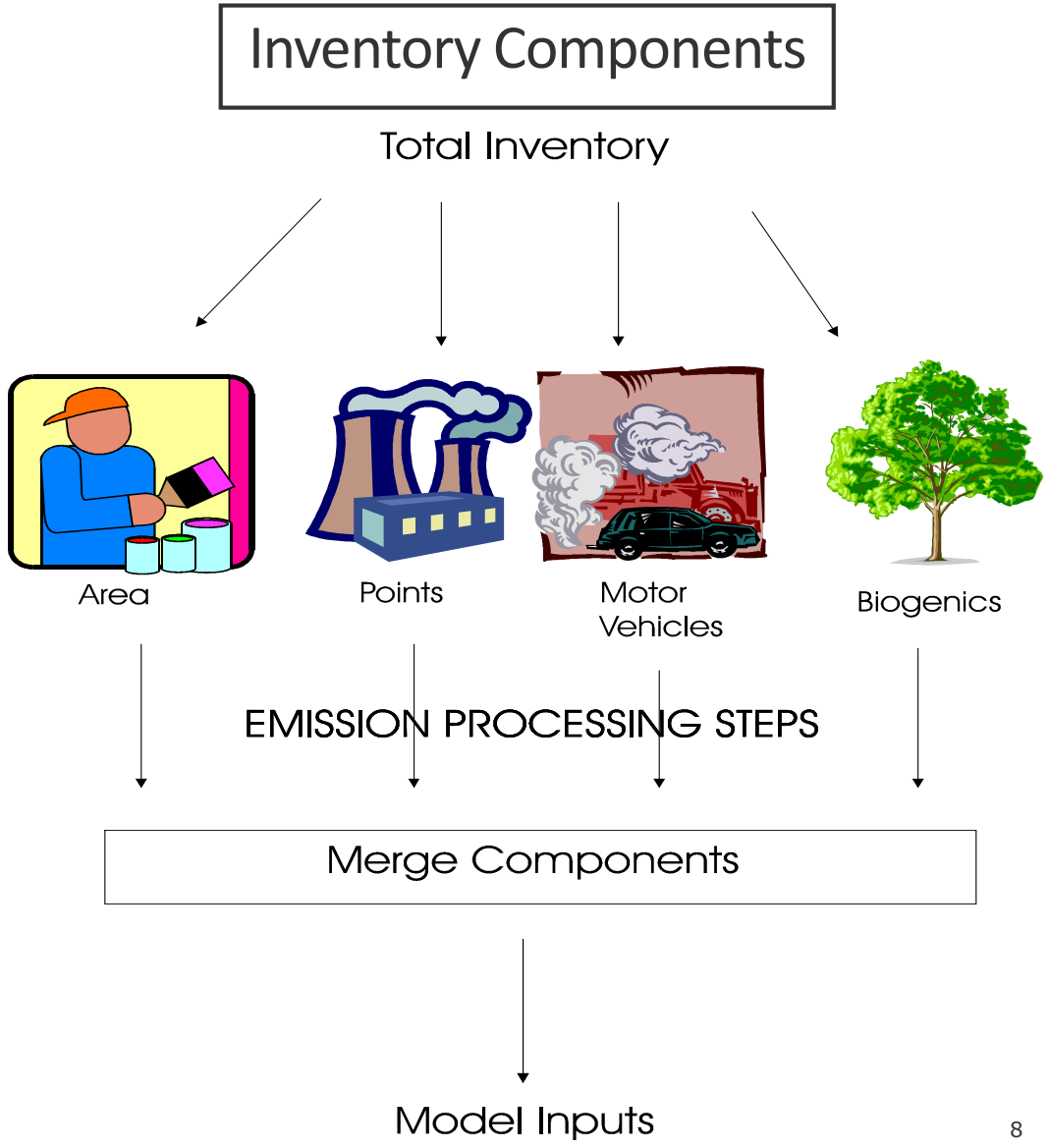
Model Ready



Hourly

Gridded

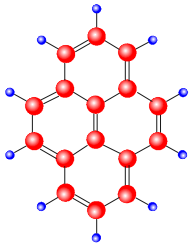
Speciated



NMED Exhibit 20 - 0008

INTRODUCTION TO EMISSION PROCESSING

Area source emission processing



Temporal Allocation



↓

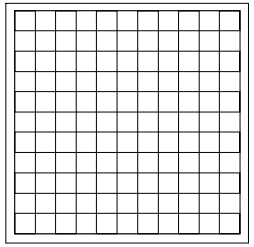
Speciation

↓

Growth/Controls

↓

Gridding



Point source emission processing

Temporal Allocation

↓

Speciation

↓

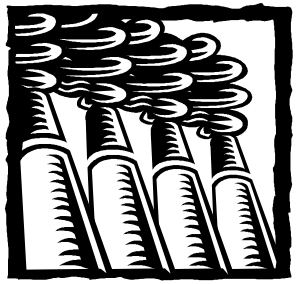


Growth/Controls



↓

Vertical Resolution

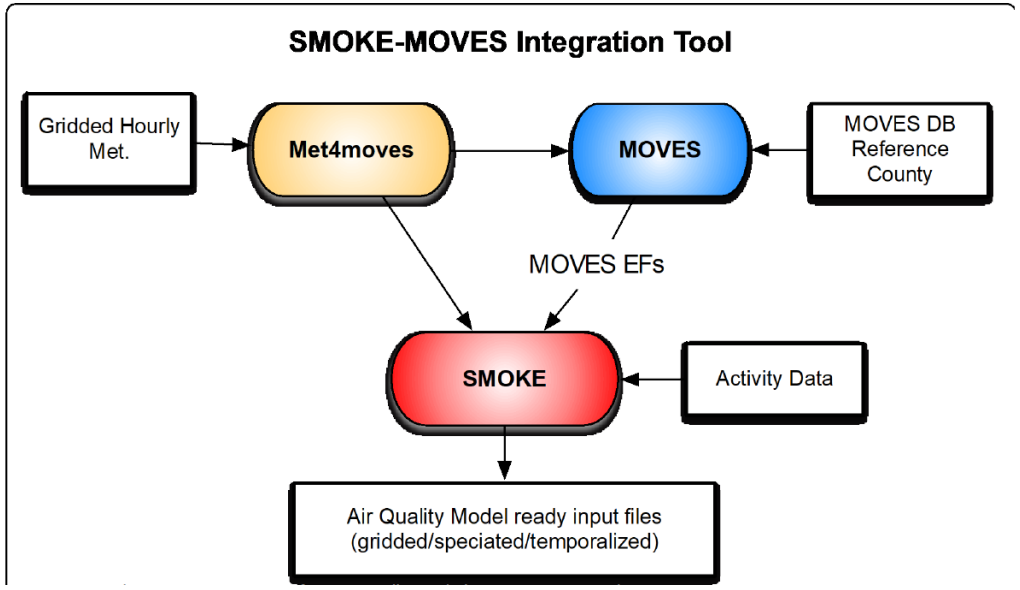


RAMBOLL

NMED Exhibit 20 - 0009

OVERVIEW OF SMOKE-MOVES PROCESSING

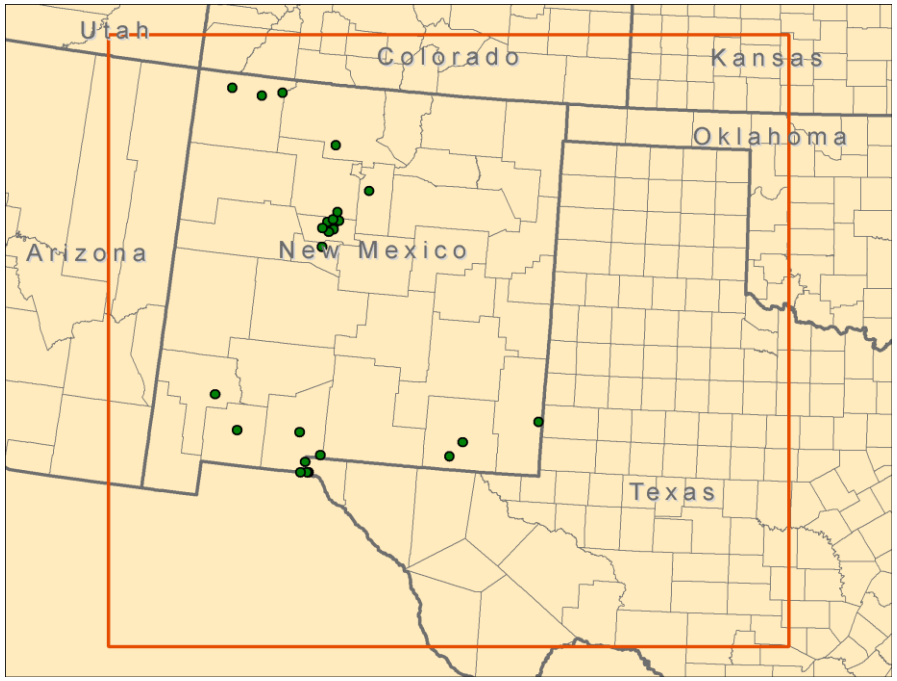
- Requires emission rate "lookup" tables generated by MOVES
- Uses gridded, hourly, day-specific temperatures
- SMOKE processing applies the emission factors to the activity data to compute grid-cell emissions



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SMOKE PROCESSING OF 2014 EMISSIONS

- SMOKE version 4.7
- Process emissions for 4-km domain
- Spatial surrogates**:** O&G spatial surrogates are based on 2014 O&G activity data and other 4-km surrogates obtained from EPA's Emission Modeling Platform (EMP).
- Speciation for CB6r4 chemical mechanism in CAMx



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NMED Exhibit 20 - 0011

SMOKE PROCESSING SECTORS

2014 4-km emissions in average tons/day

Sector	CO	NOx	VOC
ag	0.0	0.0	43.4
nonpt	141.3	28.5	213.2
nonroad	570.3	133.4	73.2
np_oilgas	286.8	311.7	1,642.5
np_oilgas_wrap_only	237.7	157.8	567.3
onroad	1,476.2	444.5	150.6
onroad_mex	356.3	98.4	34.4
othar	19.9	42.2	103.3
othpt	28.4	20.2	8.3
ptegu	89.2	210.6	5.0
pt_oilgas	113.8	205.2	48.4
pt_oilgas_wrap_only	89.9	114.7	56.1
ptnonipm	74.4	47.5	24.4
rail	22.9	122.7	6.2
rwc	7.0	0.1	1.2
TOTAL	**3,513.9**	**1,937.6**	**2,977.3**

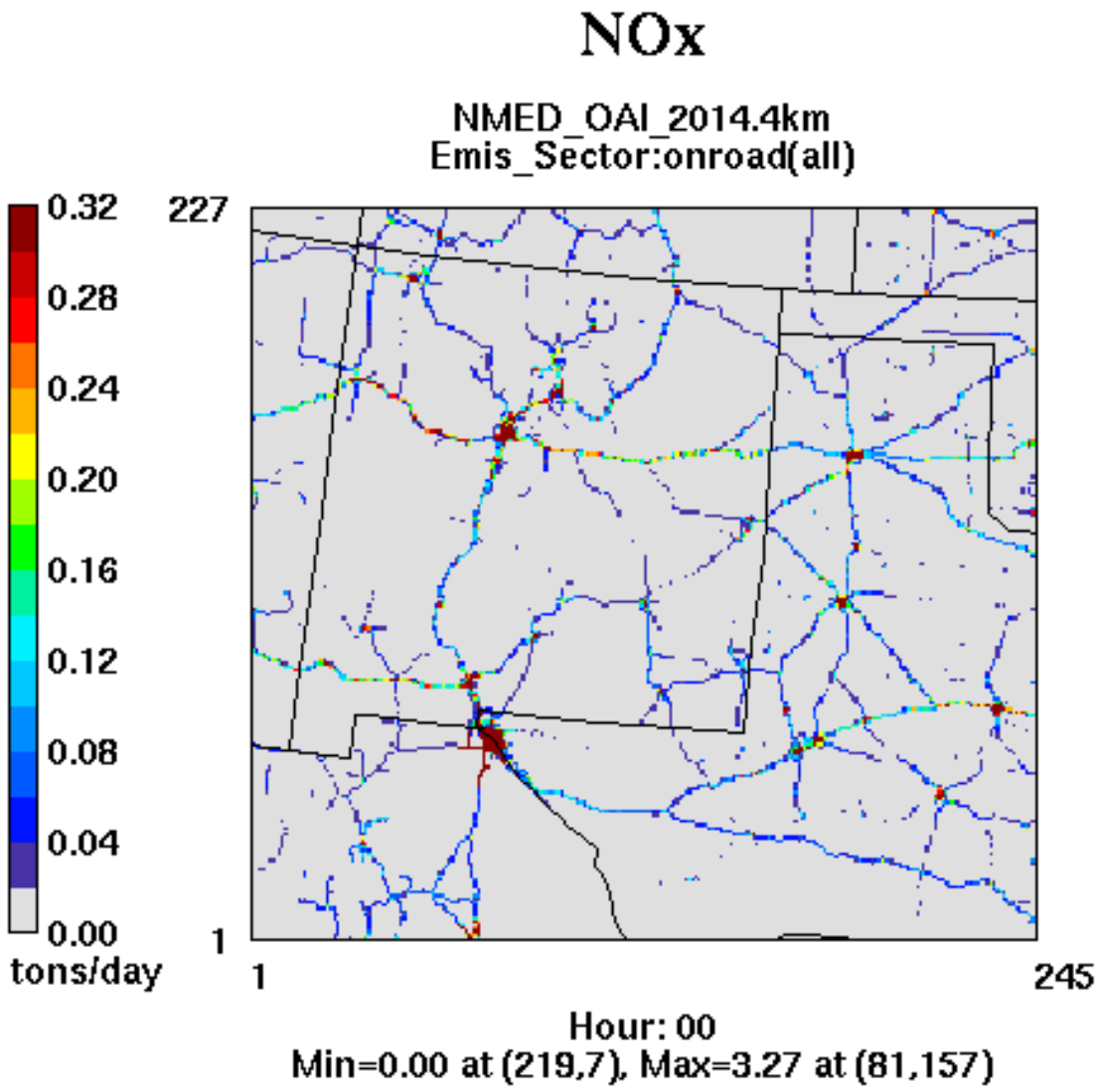
RAMBOLL

Sector	Description
afdust_adj	- Area fugitive dust
ag	- Agricultural ammonia sources
nonpt	- Other nonpoint sources
np_oilgas_wrap	- Non-point Oil and Gas for 7 WRAP states (CO, MT, NM, ND, SD, UT, WY)
np_oilgas	- Non-point Oil and Gas
nonroad	- Non-road mobile
rail	- Locomotive
onroad	- On-road mobile
ptegu	- EGU point sources
ptnonipm	- Non-EGU point sources
pt_oilgas_wrap	- Point Oil and Gas for 7 WRAP states (CO, MT, NM, ND, SD, UT, WY)
pt_oilgas	- Point Oil and Gas
rwc	- Residential Wood Combustion
onroad_mex	- Mexico onroad mobile
othar	- Mexico area
othpt	- Mexico point sources
MEGAN/BEIS	- Biogenic
LtNOx	- Lightning Nox
AG fire	- Ag Fire
RX fire	- Prescribed Fire
WF fire	- Wild Fire
Ptfire_othna	- Mexico fire
WBD	- Windblown Dust

NMED Exhibit
20 - 0012

ONROAD EMISSIONS

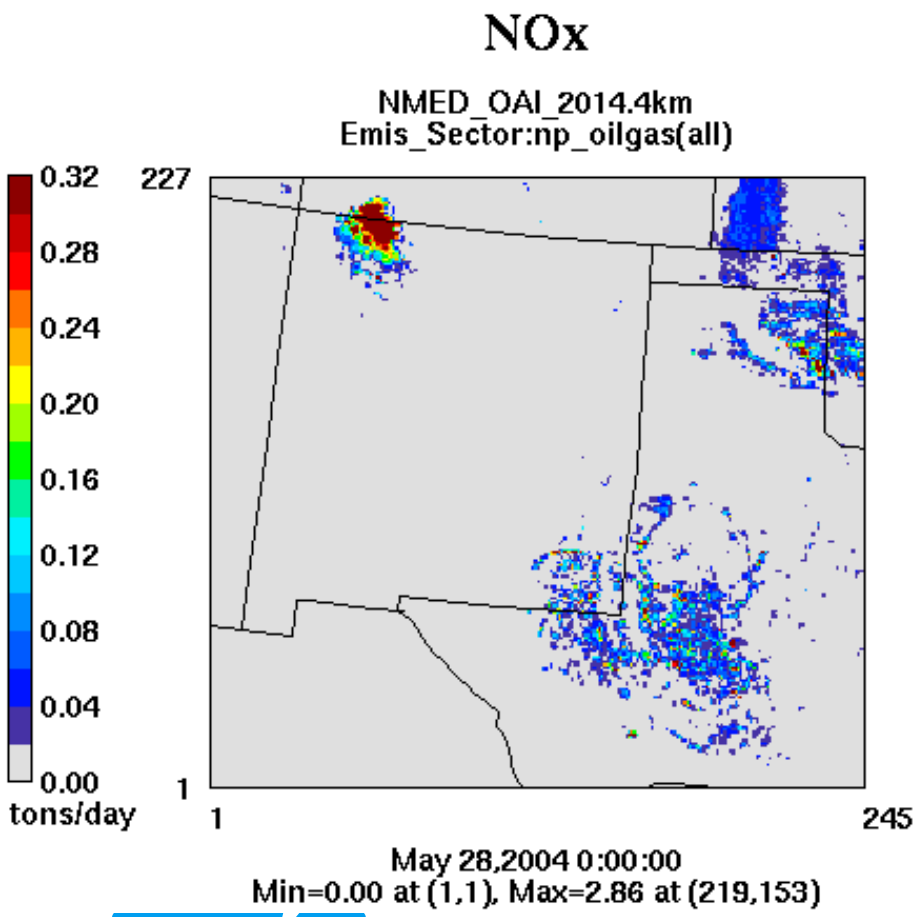
- On-road emissions developed using SMOKE-MOVES processing with 2014/2023 activity data and day-specific hourly gridded 2014 WRF meteorology
  - 2014 MOVES lookup tables and 4-km MCIP data
- SMOKE-MOVES processing:
  - rate-per-distance (RPD) (30 mins per day)
  - rate-per-vehicle (RPV) (10 mins per day)
  - rate-per-profile (RPP)
  - rate-per-hour (RPH)

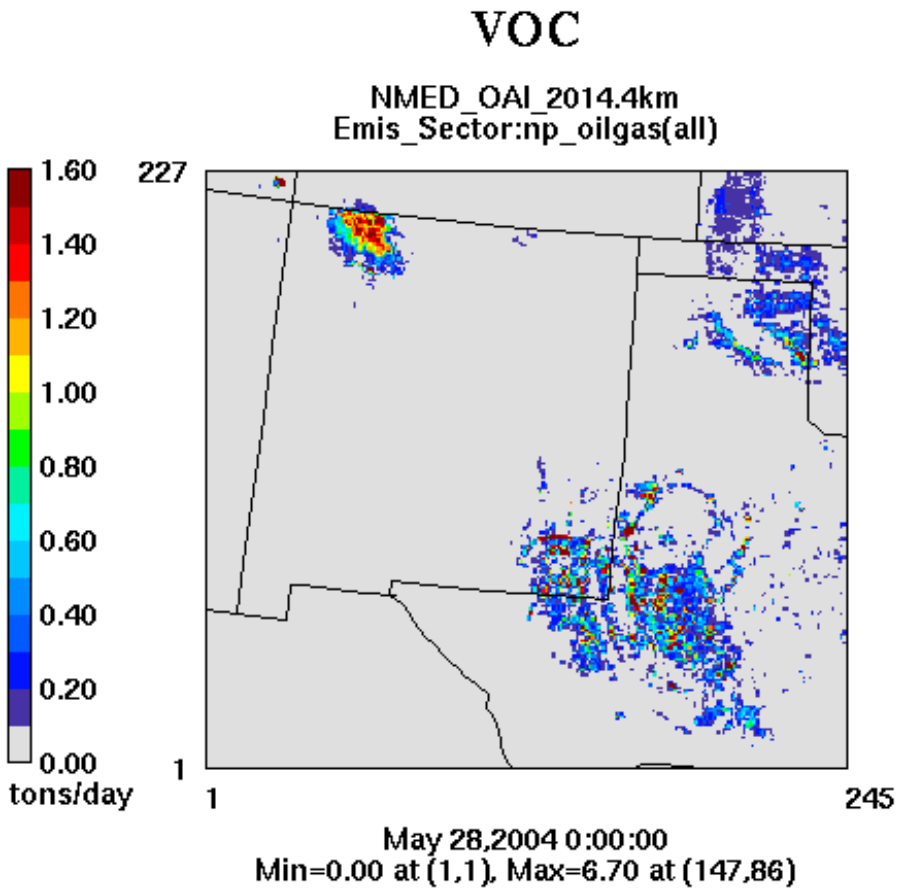


RAMBOLL

NON-POINT O&G EMISSIONS

Basin-specific speciation profiles



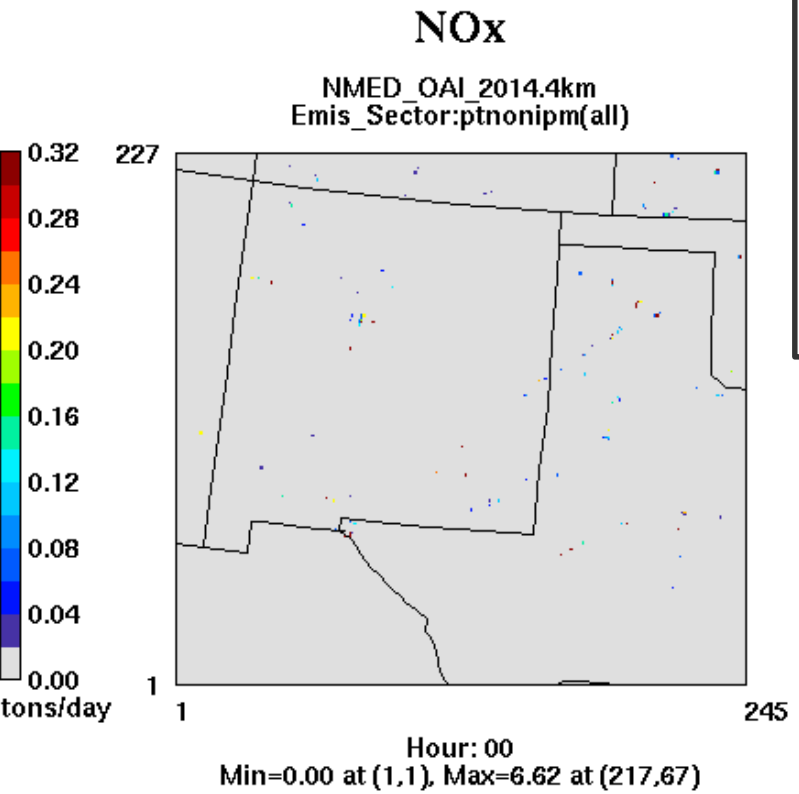


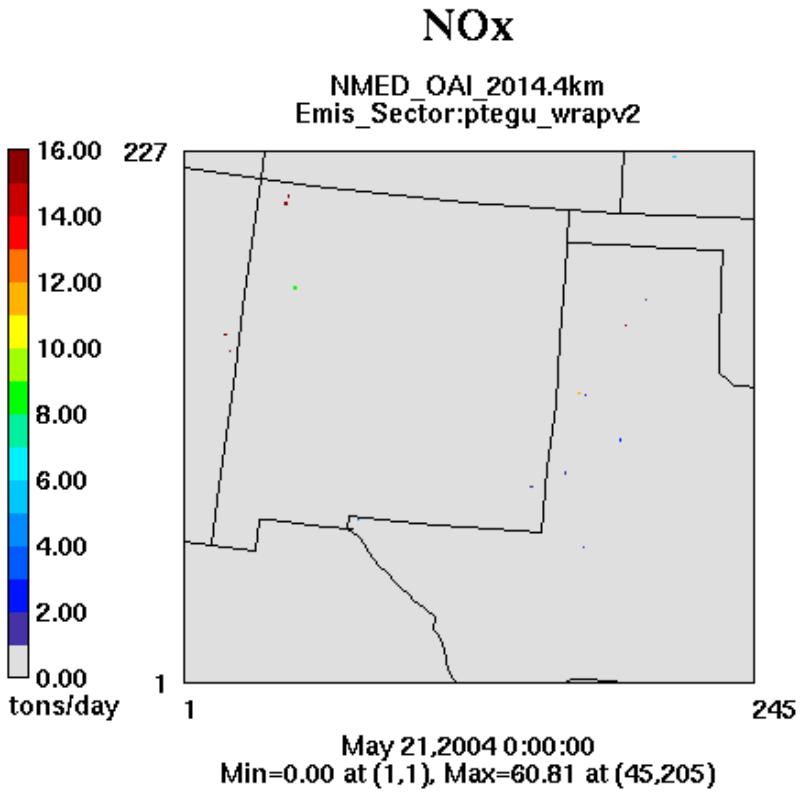
Surrogate	Surrogate Description
688	Gas production at oil wells
689	Gas production at all wells
690	Oil production at all wells
691	Well count - CBM wells
692	Spud count
693	Well count - all wells
694	Oil production at Oil wells
695	Well count - oil wells
696	Gas production at gas wells
697	Oil production at gas wells
698	Well count - gas wells
699	Gas production at CBM wells

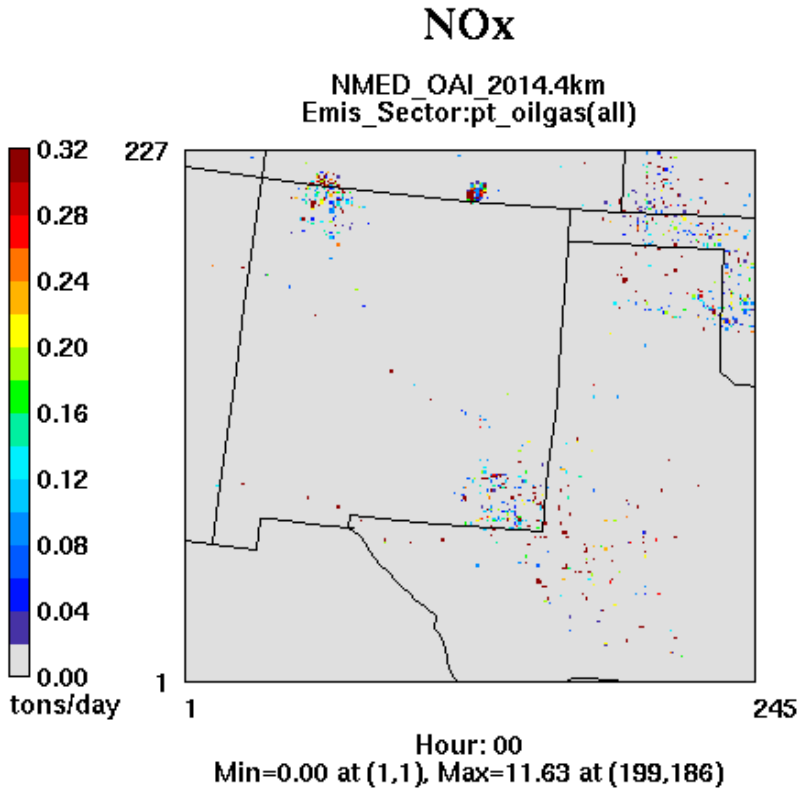
RAMBOLL

POINT SOURCE EMISSIONS

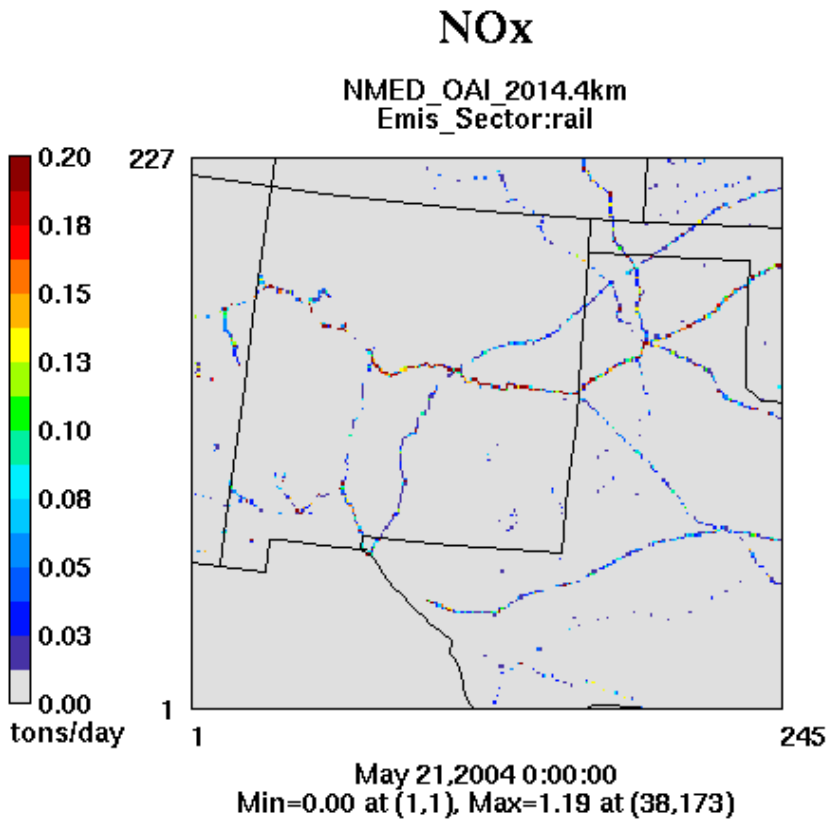
Point source processing generates elevated and low-level gridded files. Elevated files contain x/y coordinates for each point source so they are not domain dependent.

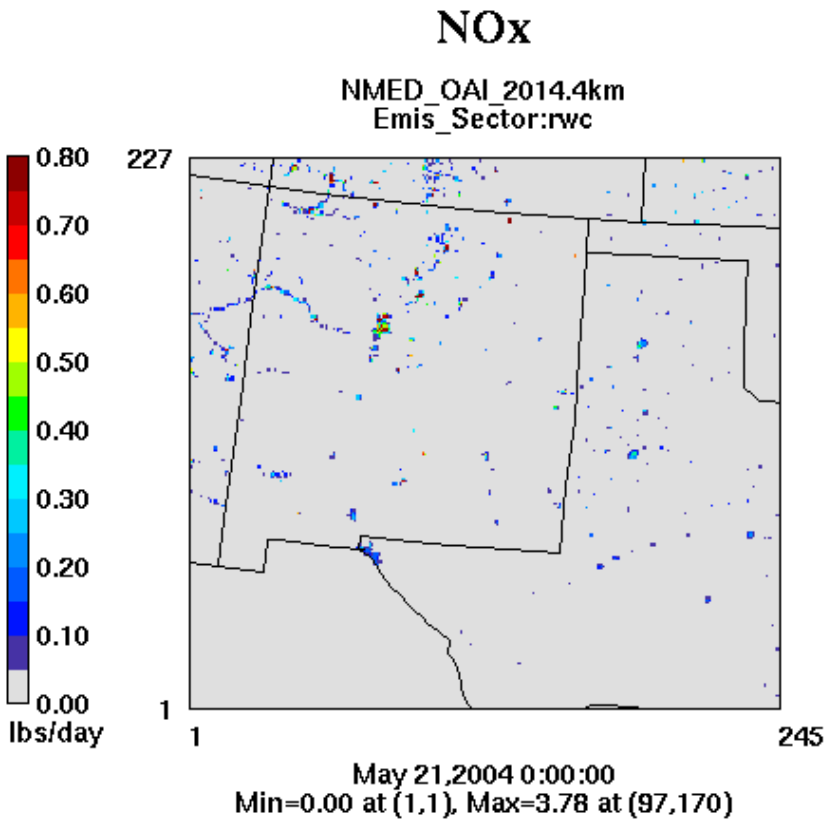






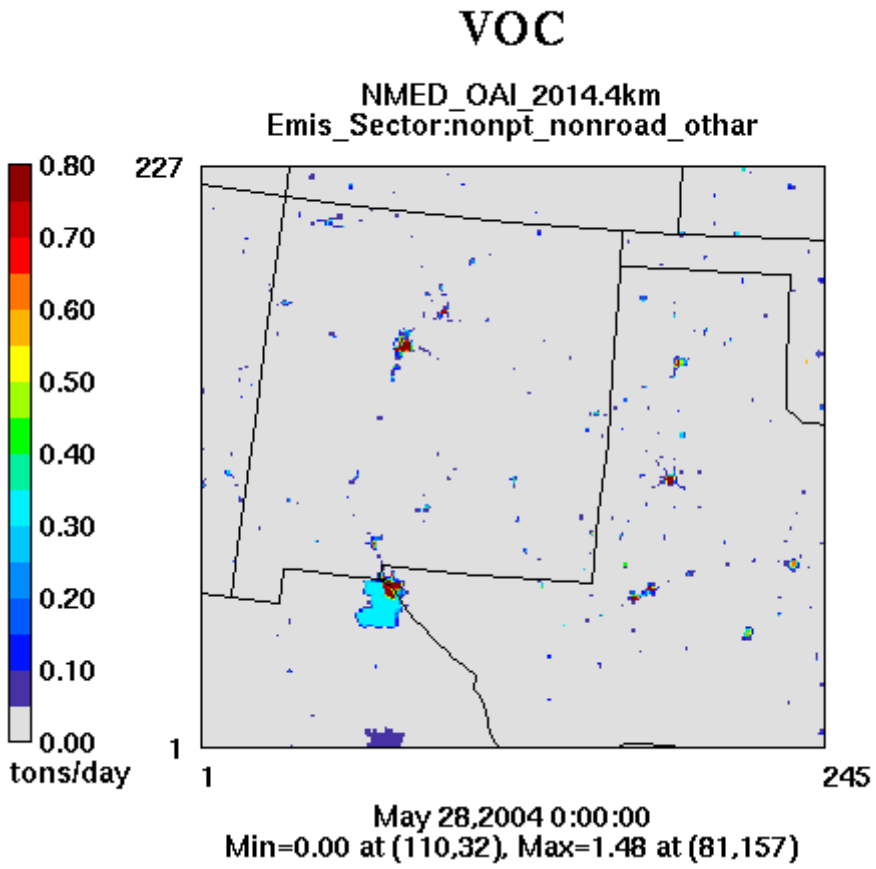
RAIL AND RWC EMISSIONS

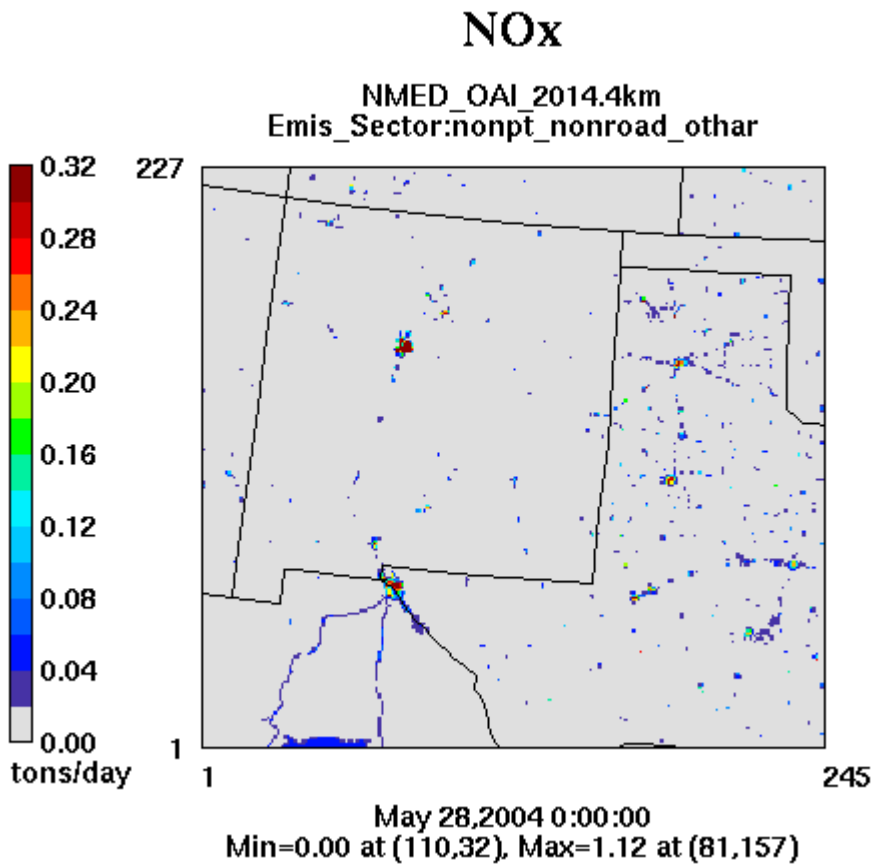




RAMBOLL

NONPOINT AND NONROAD EMISSIONS





RAMBOLL

NATURAL EMISSIONS

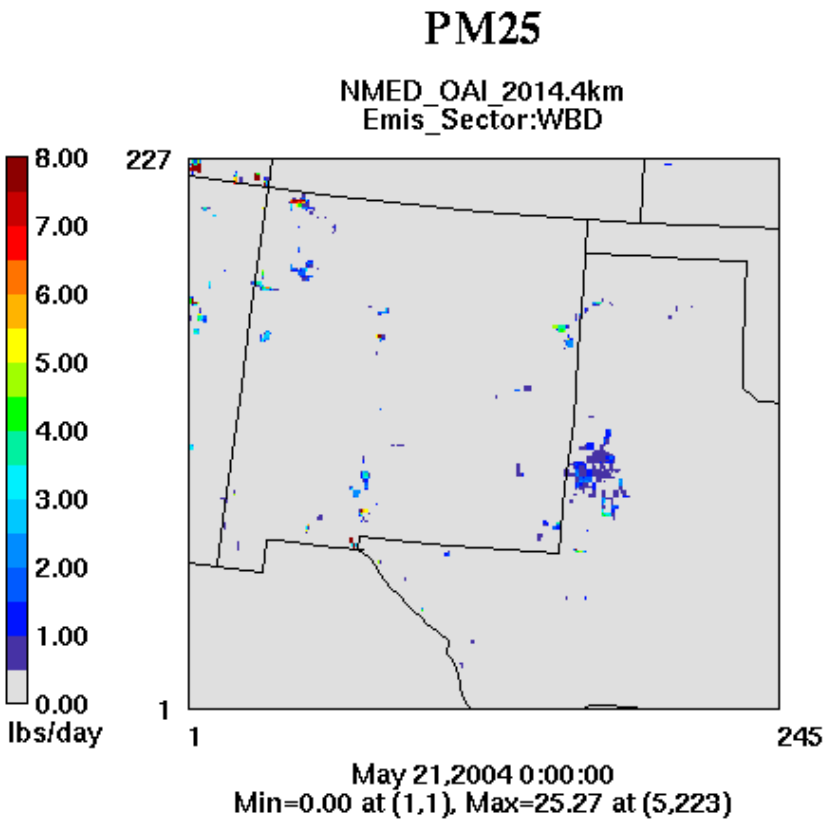
- Lightening NOx: Lightning NOx (LNOx) emissions processor with 2014 WRF meteorological data to generate CAMx-ready emissions
- Oceanic Emissions: OCEANIC emissions processor was used to generate sea salt and dimethyl sulfide (DMS) emissions
- Fire Emissions: Agricultural, prescribed burn and wildfire emissions from WRAP 2014v2 modeling developed by WRAP Smoke and Fire Workgroup
- Windblown dust: CAMx windblown dust (WBD) processor
- Biogenic Emissions: MEGAN or BEIS biogenic emissions model

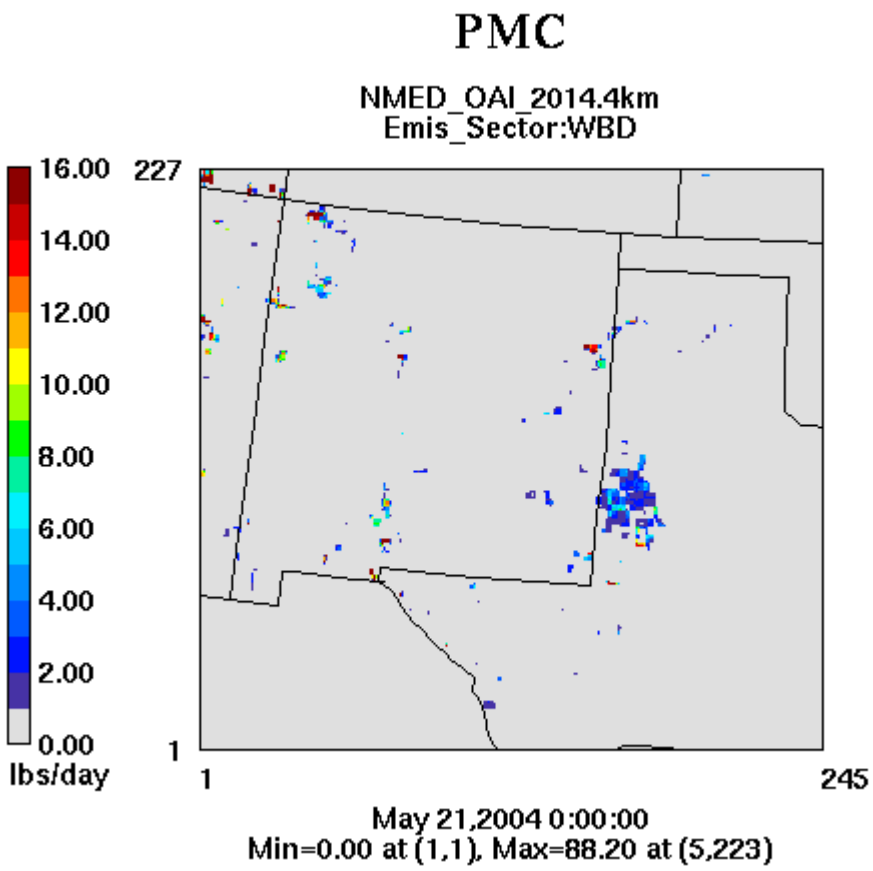
RAMBOLL

NMED Exhibit 20 - 0018

WINDBLOWN DUST EMISSIONS

	Emissions (tons/day)	
Year	PM2_5	CPRM
2014	20.9	80.2

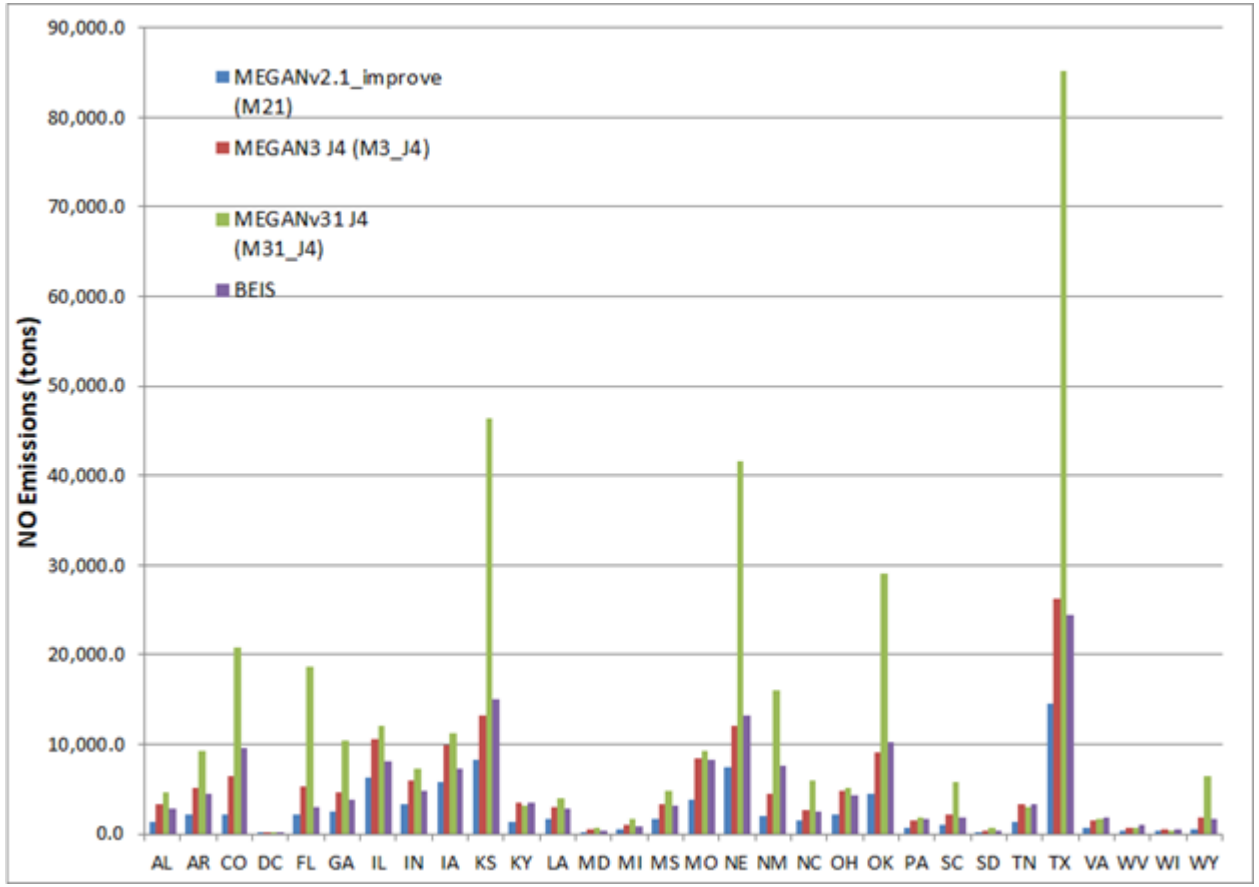




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BIOGENIC EMISSIONS

- MEGAN3.1 improvement: Replaced soil NO code (Yienger and Levy approach) used by MEGAN3.0 (and BEIS) with state-of-the-art BDSNP approach. This model was already available to the community in GEOS-chem and WRF-CMAQ but required on-line AQ model.
- Summer soil NOx (June 1-July 15, 2013 period) for New Mexico estimated using different biogenic models.
- Agricultural regions with high fertilizer application rates have large NO emissions
- Will use MEGAN v3.1 emissions as latest data



Reference: Guenther, A. et al (2018). Final Report For Project 18-005: Next steps for improving Texas biogenic VOC and NO emission estimates. Prepared for Air Quality Research Program (AQRP).

RAMBOLL

CAMX METEOROLOGICAL SENSITIVITY TESTS AND FINAL CONFIGURATION

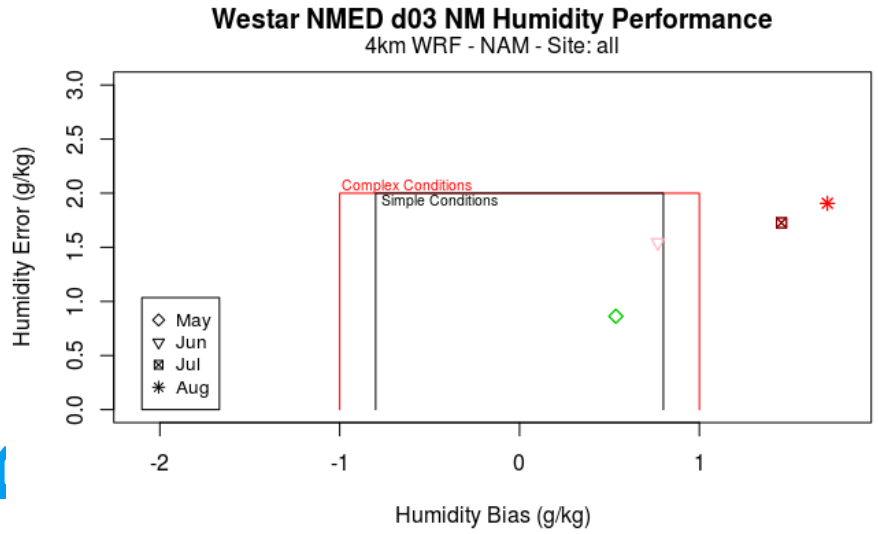
RAMBOLL

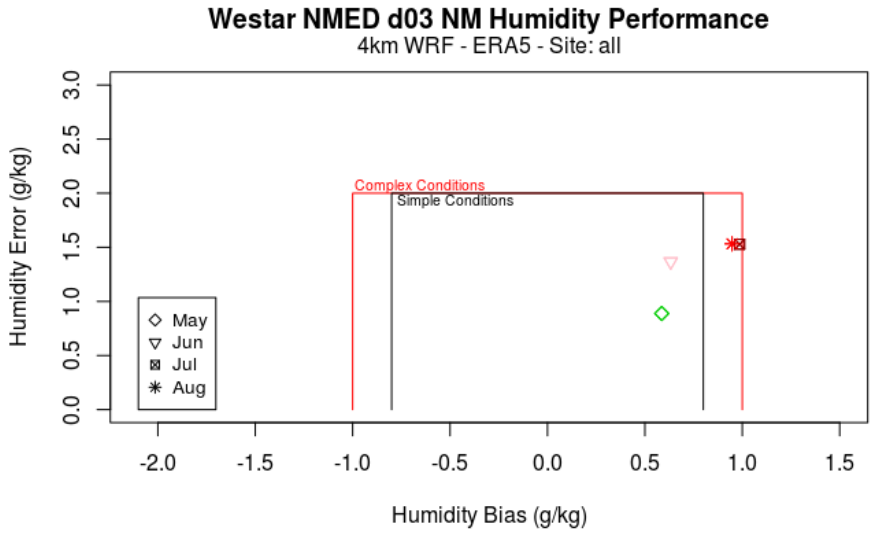
OVERVIEW

- Explore CAMx model performance using various WRF simulations presented on June 26, 2020 webinar (WRF sensitivities)
- CAMx model configurations used for WRF sensitivities
- Determine the WRF input and model configuration that best performs on selected period to use for 2014 CAMx base case

2014 WRF PERFORMANCE SUMMARY (JUNE 26 WEBINAR)

- WRF summer 2014 simulations using NAM and ERA5 analysis fields
  - Analysis fields used for initialization and boundary conditions (BCs) and for 36/12-km four-dimensional data assimilation (FDDA/nudging)
- WRF model performance reasonable for both NAM and ERA5 simulations
  - Surface meteorology (WS, WD, T, Q) and precipitation (PRISM)
- Differences between NAM and ERA5 are smaller in comparison to EPA/WAQS
- NAM wet bias in Jun-Aug may be partly associated with overactive summer convection
  - ERA5 has smaller wet bias

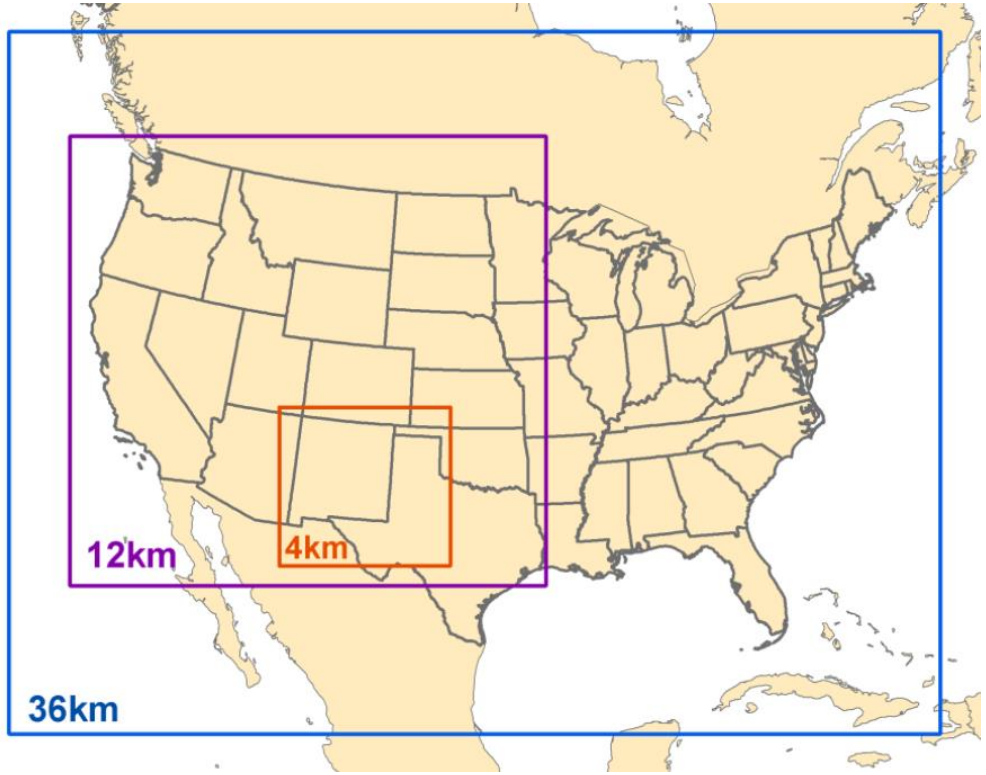




RAMBOLL

MODELING DOMAIN AND CONFIGURATION

- Performed CAMx simulations using 36/12/4-km nested domains with available WRF met (NAM and ERA5) for selected period: May 15 to Jun 5
- Emissions and other inputs identical on all sensitivities.
- CAMx flexi-nesting used for 4 km domain emissions
- Tested two types of vertical diffusivities (Kv): CMAQ and YSU
- Total of four CAMx sensitivities:
  1. **NAM CMAQ**
  2. **NAM YSU**
  3. **ERA5 CMAQ**
  4. **ERA5 YSU**

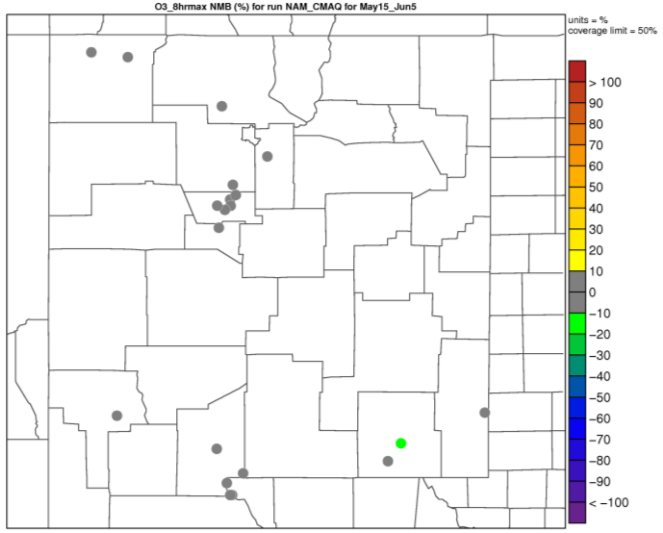


RAMBOLL

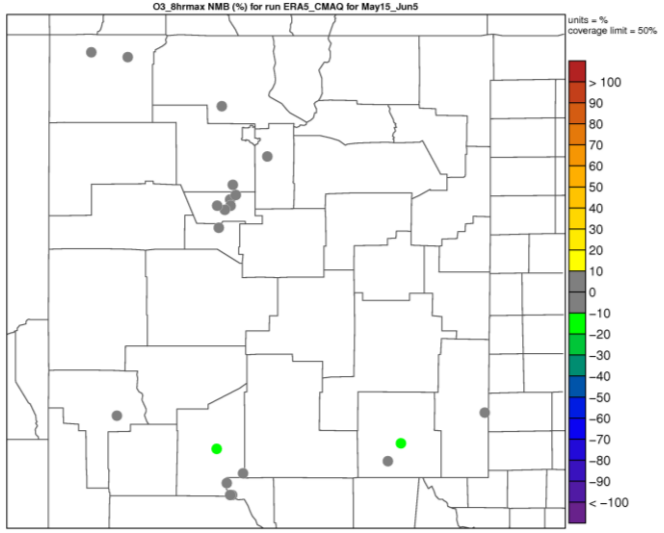
NMED Exhibit 20 - 0024

OZONE BIAS COMPARISON: NMB WITH 60 PPB CUT-OFF

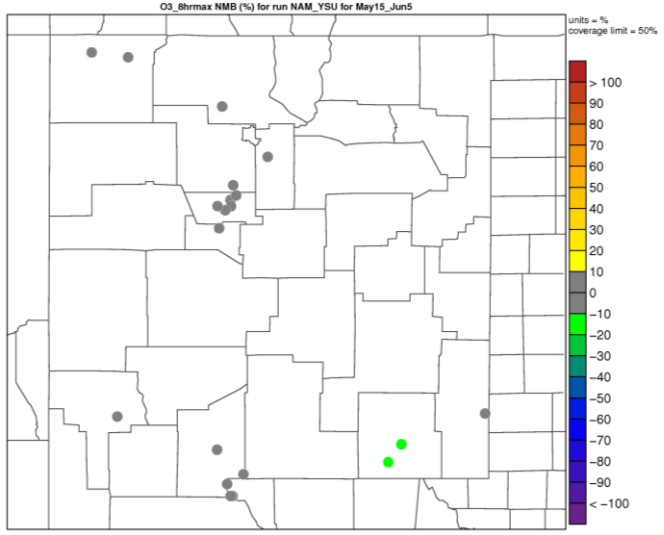
NAM CMAQ



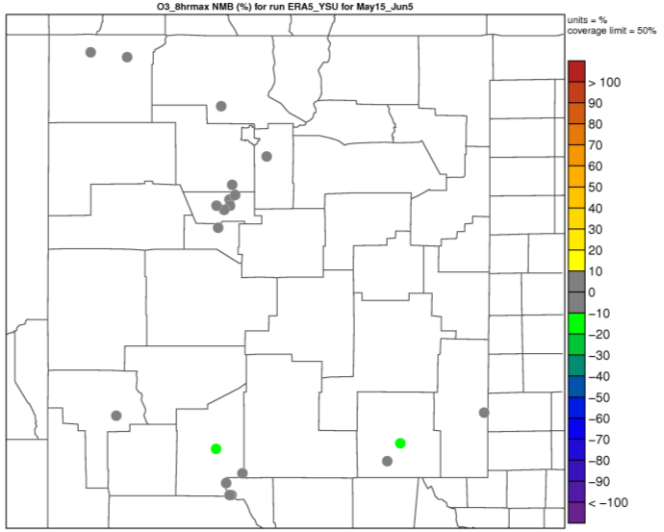
ERA5 CMAQ



NAM YSU



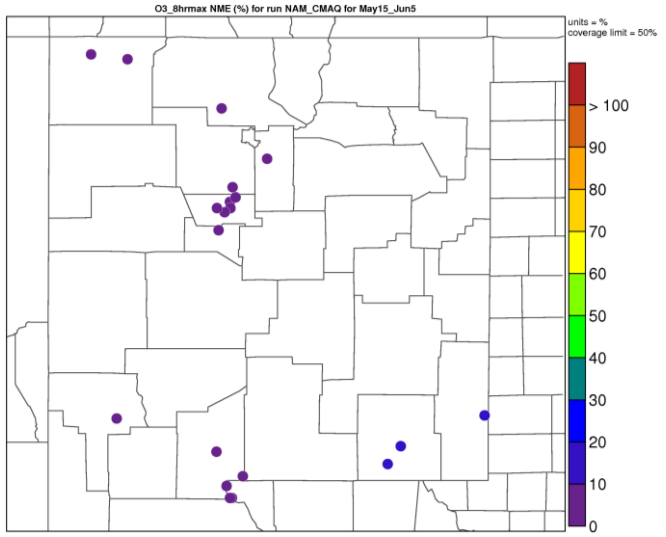
ERA5 YSU



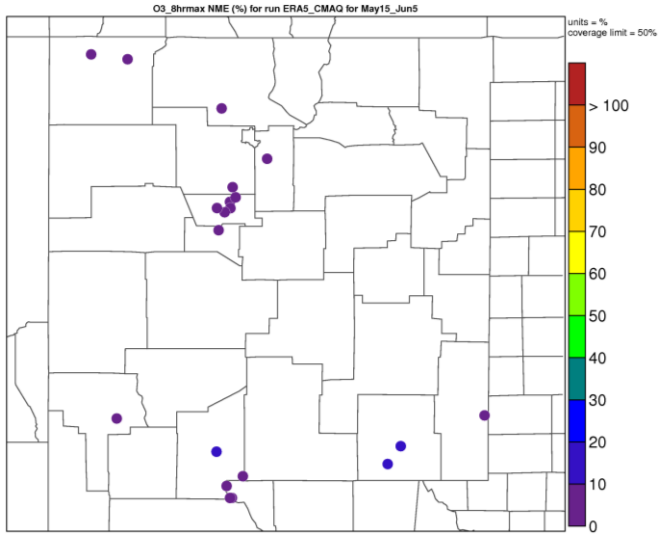
- NMB for all sensitivities generally within Performance Goal
  - Goal: NMB < ±5%
  - Criteria: NMB < ±15%
- Worst performance occurs in Southern portion of NM
- Based on NMB, NAM CMAQ is the configuration with best performance

OZONE ERROR COMPARISON: NME WITH 60 PPB CUT-OFF

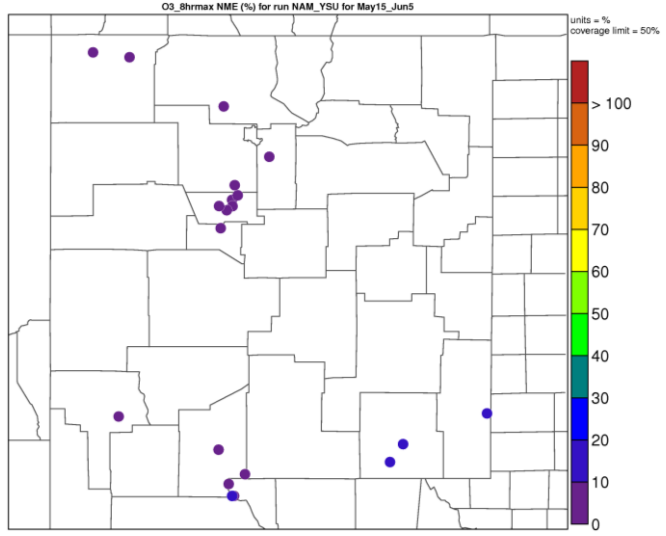
NAM CMAQ



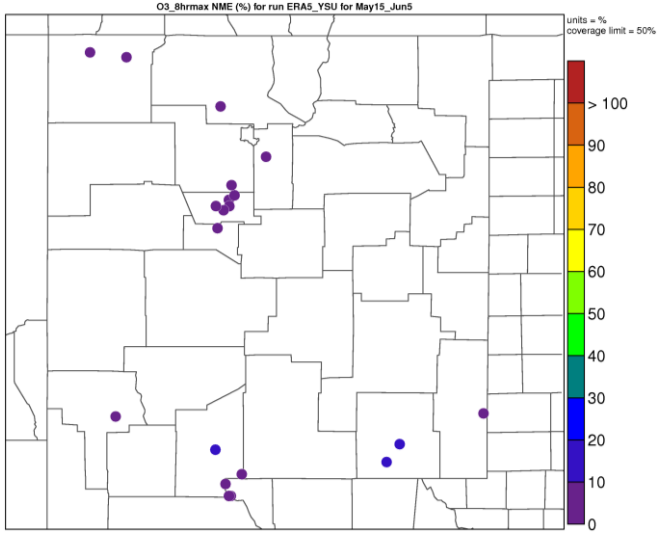
ERA5 CMAQ



NAM YSU

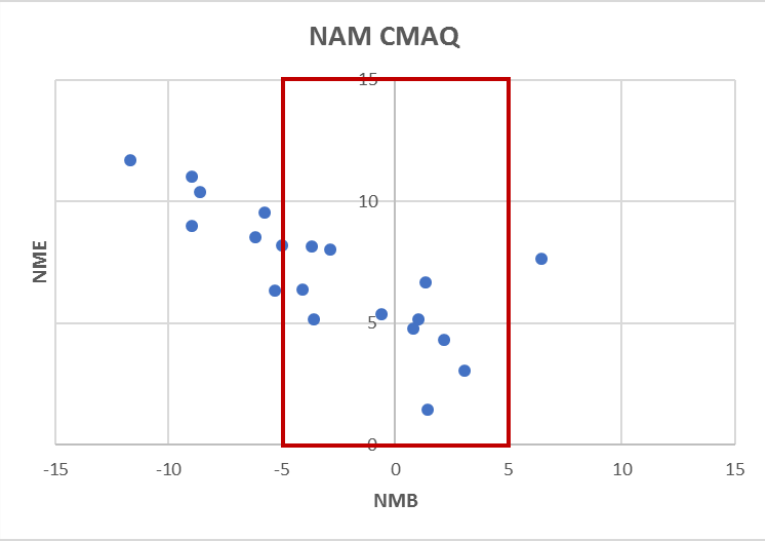


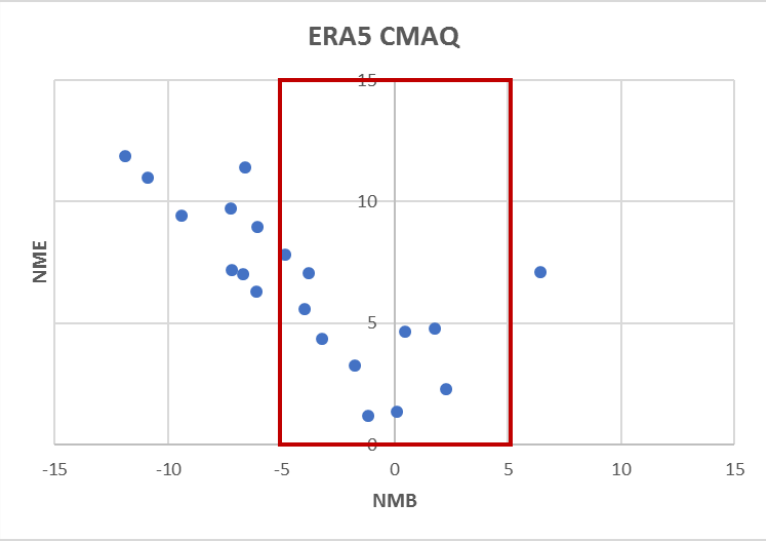
ERA5 YSU

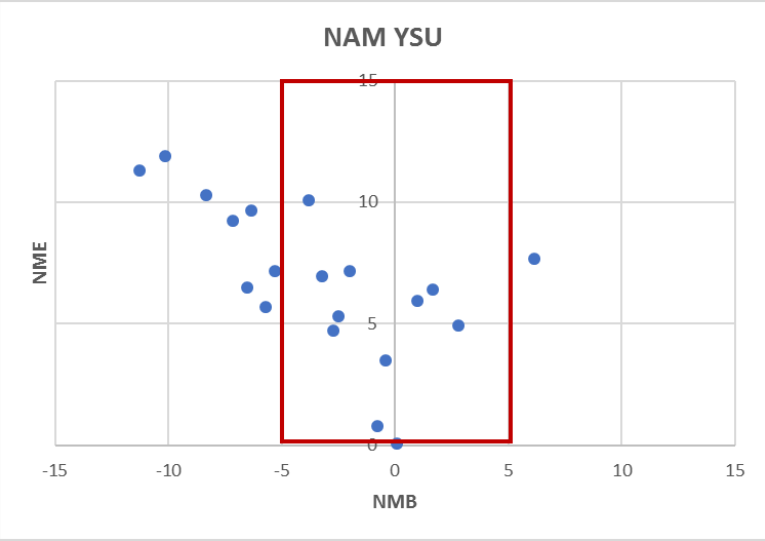


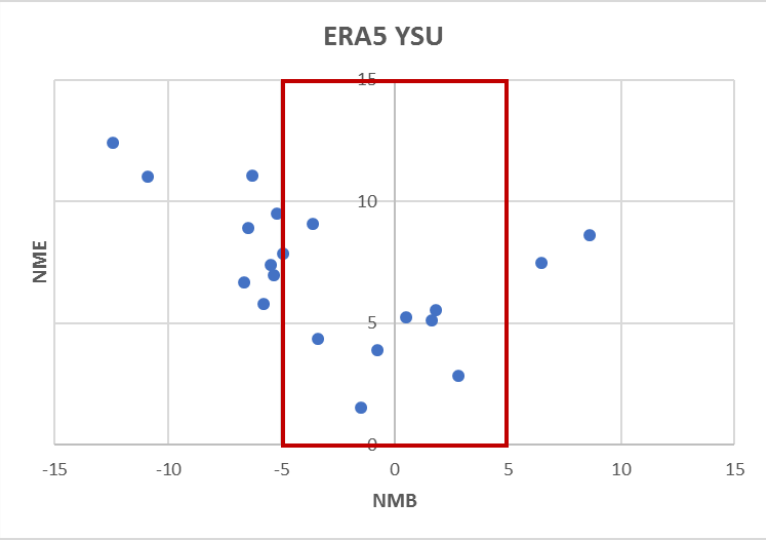
- NME for all sensitivities generally within Performance Goal
  - Goal: NME < 15%
  - Criteria: NMB < 25%
- Worst performance occurs in Southern portion of NM
- Based on NME, NAM meteorology is the best performing

SITE-SPECIFIC COMPARISON: SOCCER PLOTS 60 PPB CUT-OFF







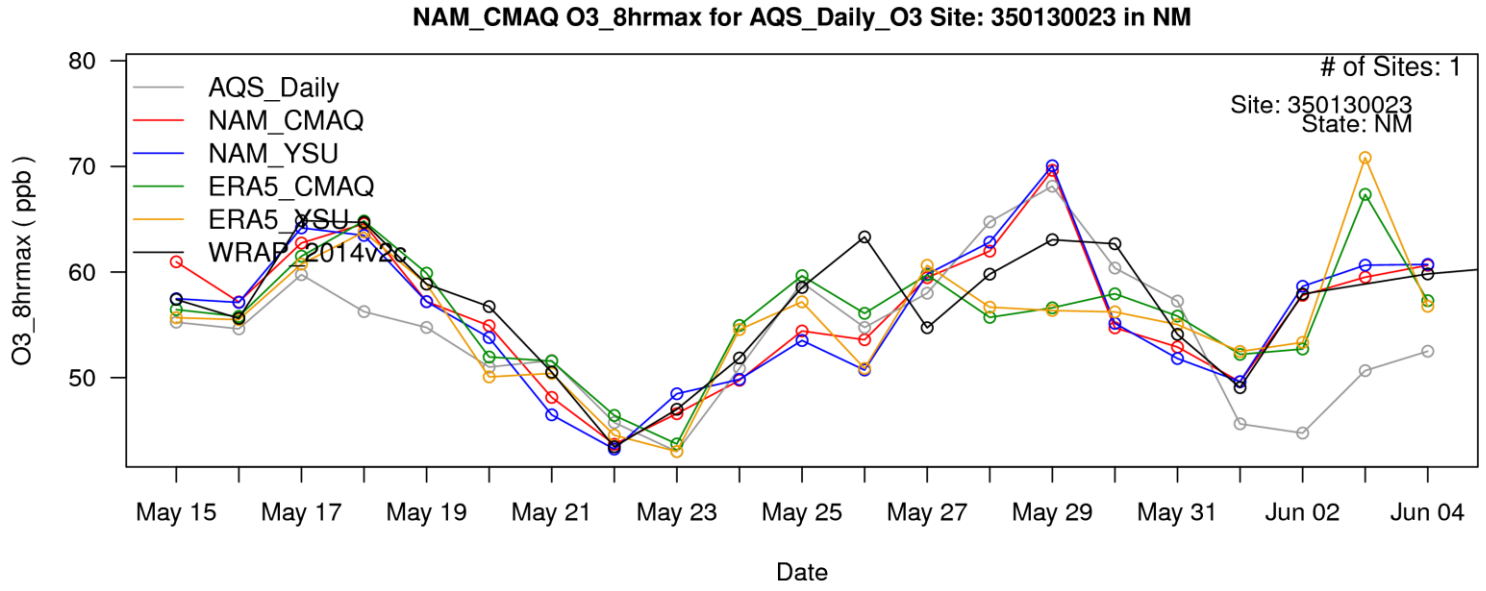


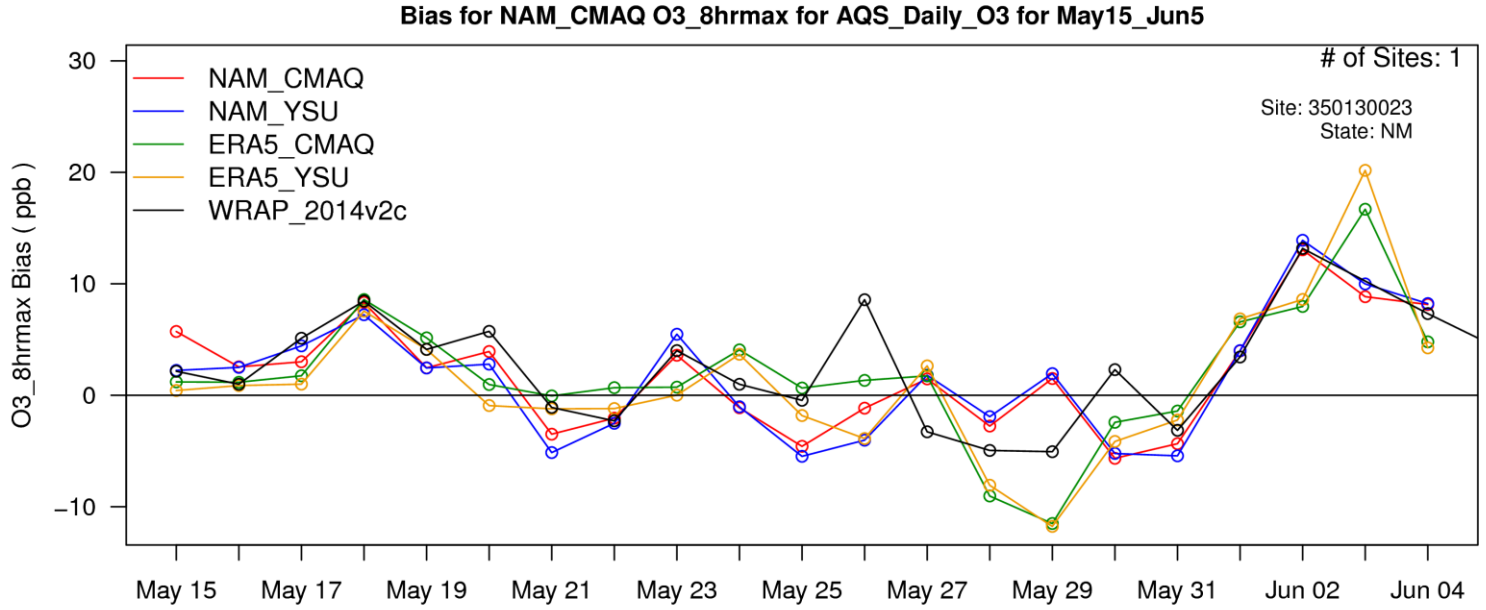
- With a 60 ppb cut-off all sensitivities show CAMx tends to underpredict ozone peaks
- Still all sensitivities within Performance Criteria
- NAM shows slightly better performance than ERA5
  - More sites achieve Performance Goals
- NAM CMAQ shows sites with smaller NME compared to NAM YSU

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NMED Exhibit 20 - 0027

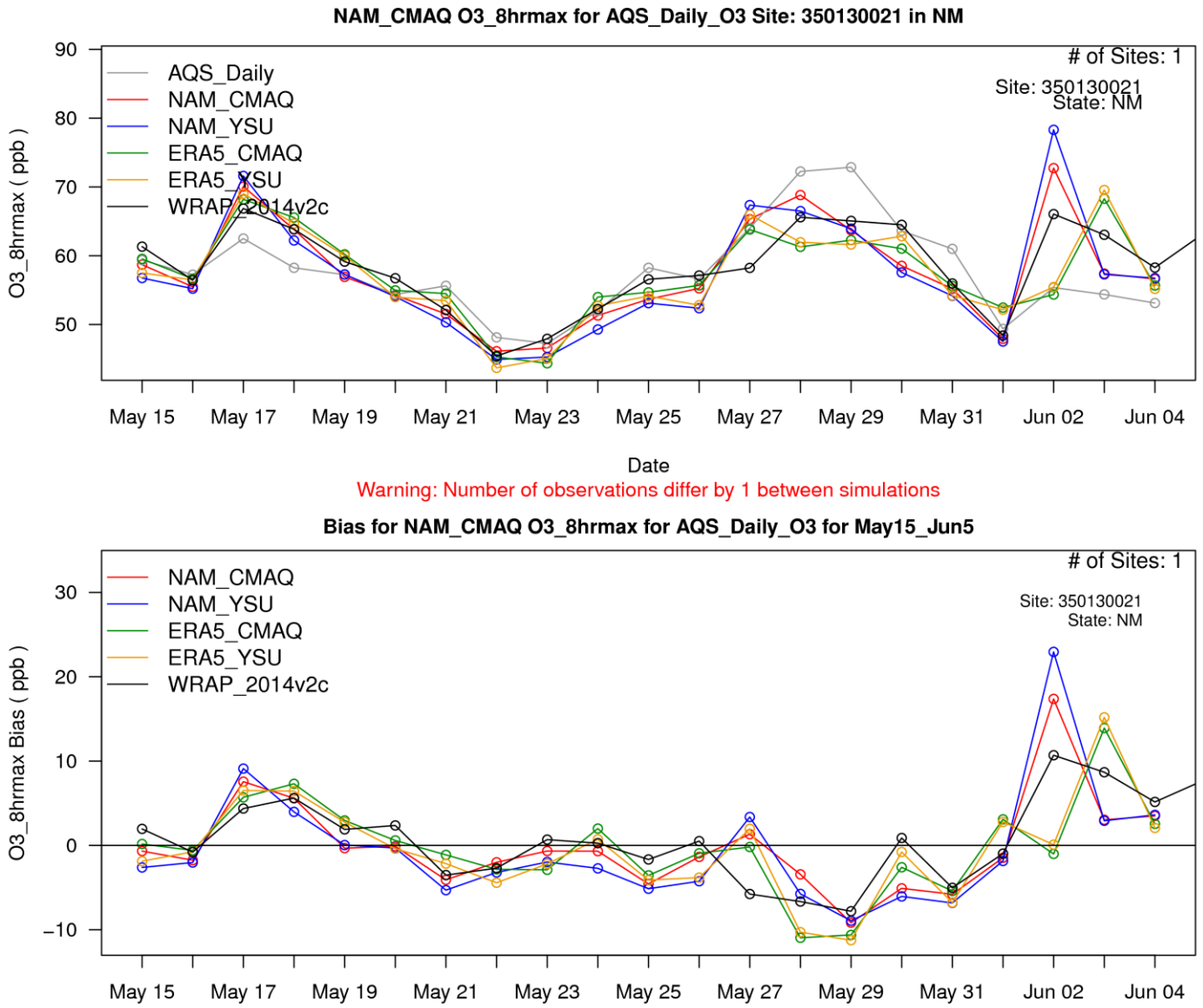
SELECTED SITES TIMESERIES: SOLANO RD (DONA ANA COUNTY)





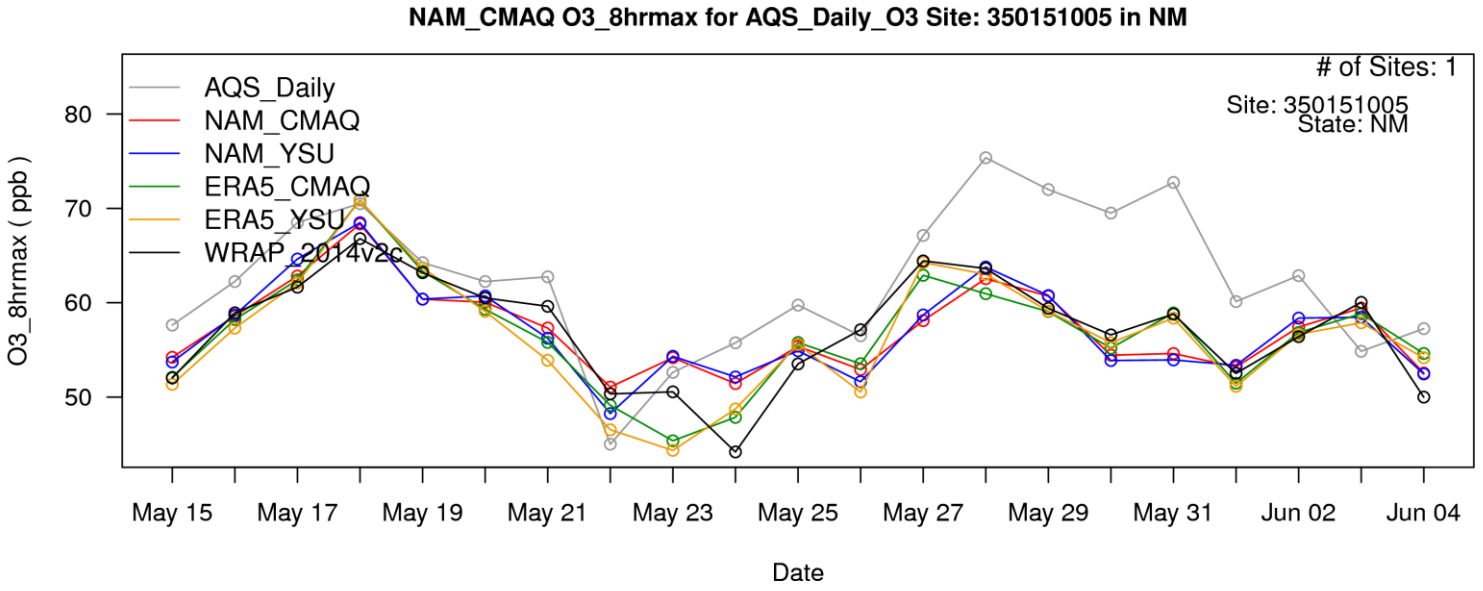
- NAM sensitivities better capture peak on May 29

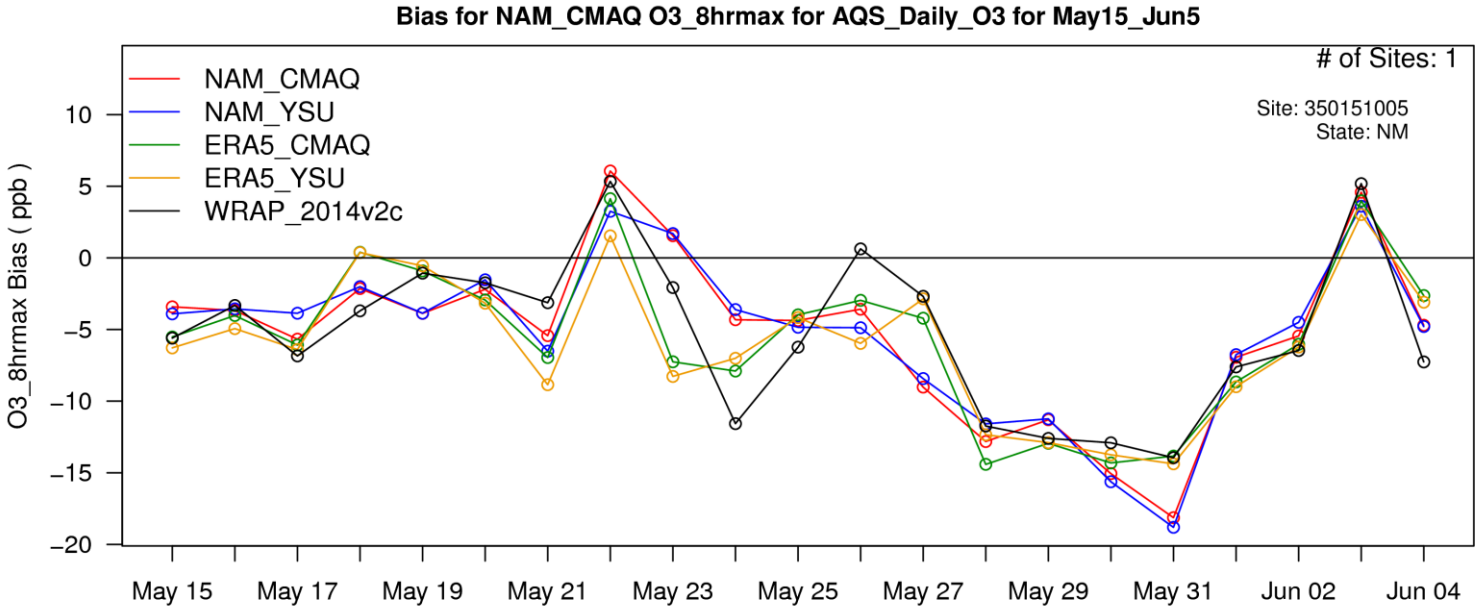
SELECTED SITES TIMESERIES: DESERT VIEW (DONA ANA COUNTY)



- Underestimate observed peaks May 28-29
- WRF/NAM better than other WRF

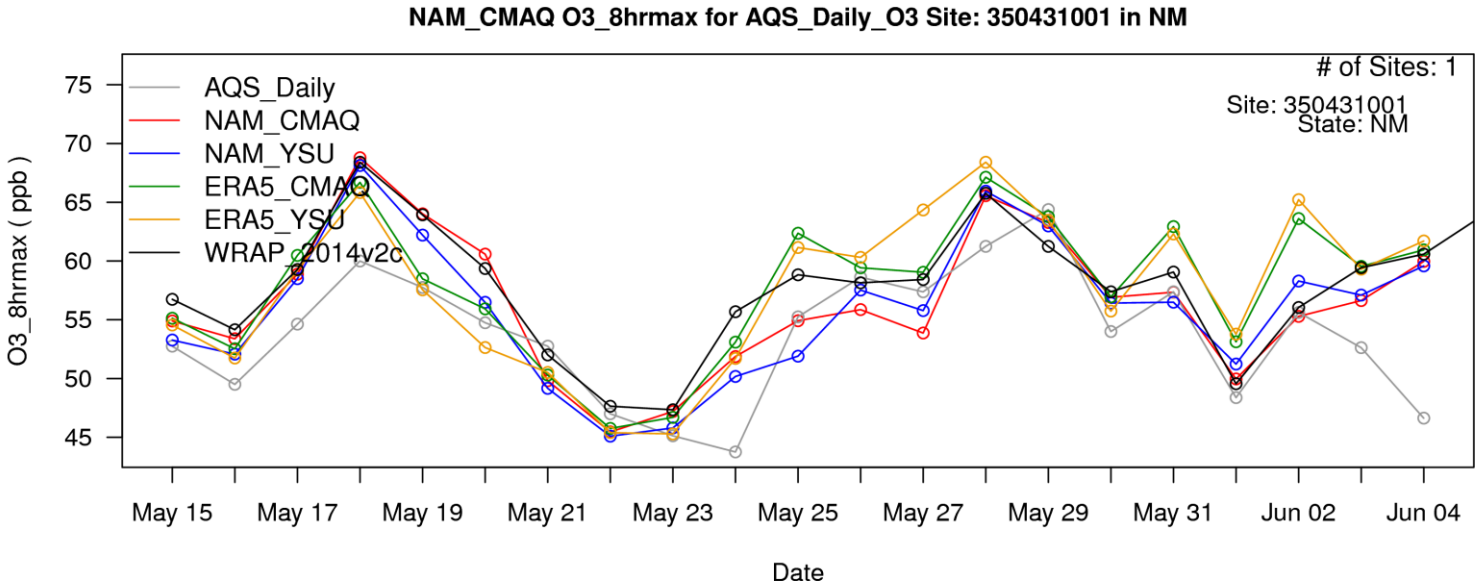
SELECTED SITES TIMESERIES: CARLSBAD (EDDY COUNTY)

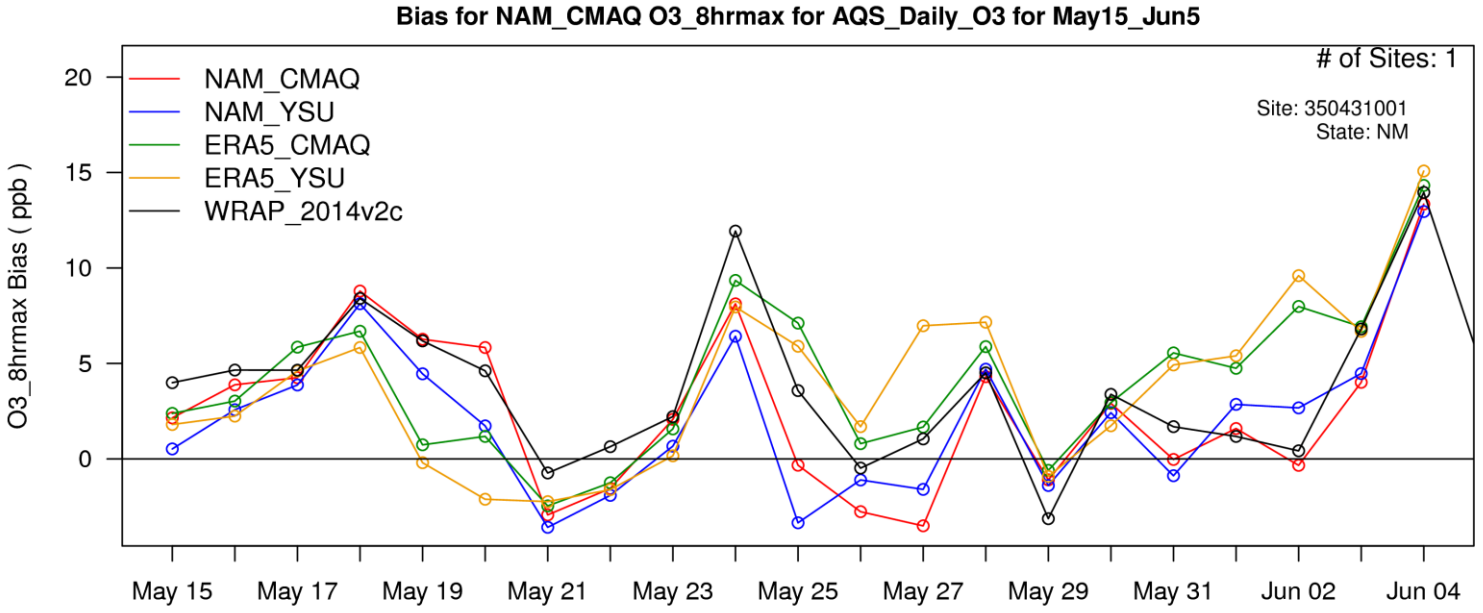




- All sensitivities miss high ozone on May 27 to May 31

SELECTED SITES TIMESERIES: SANDOVAL COUNTY





- All sensitivities get high ozone on May 29. NAM CMAQ has lower bias

CAMX SENSITIVITIES SUMMARY

- All sensitivities have NMB and NME values that are within Performance Criteria, most sites within Performance Goals
- Differences between all sensitivities are relatively small among each other
- NAM meteorology captures peak ozone concentrations better than ERA5
- Caveats:
  - WRF sensitivities run for May-Jun so they may not reflect the observed precipitations biases in WRF for Jun-Aug
  - WRF performance showed that precipitation biases could occur over NE NM where there are no ozone monitors, so performance is unknown there
- NAM with CMAQ Kv treatment selected to simulate 2014 base case based on slightly better performance on NMB

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NMED Exhibit 20 - 0032

FINAL CAMX 2014 BASE CASE CONFIGURATION

- CAMx summer 2014 36/12/4-km meteorological inputs based on WRF simulation using NAM analysis fields processed with WRFCAMx with CMAQ Kv option
  - Same WRF/NAM configuration as used by WRAP-WAQS CAMx 2014 base case

Science Options	CAMx	Comment
Model Codes	CAMx v7.0 (May 2020)	Latest version of CAMx used i WRAP/WAQS 2014v2 and EPA Haze modeling
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes bu
4-km grid	245 x 227 cells	New Mexico 4-km domain. In buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 thickness ~20 m. Mo 50 mb (~19 km)
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 1
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain
Emissions		
Baseline Emissions Processing	SMOKE, SMOKE-MOVES2014, MEGAN	WRAP/WAQS 2014v2 emissio EPA 2023fh for future year
Sub-grid-scale Plumes	Plume-in-Grid for major NO_X sources in New Mexico	Keep same PiG sources in 20 2023 emission years
Chemistry		
Gas Phase Chemistry	CB6r4	Latest chemical reactions and rates with halogen chemistry et al., 2010)
Meteorological Processor	WRFCAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh grid size de
Vertical Diffusion	CMAQ-like Kv	Evaluate YSU Kv scheme
Diffusivity Lower Limit	Kv-min = 0.1 to 1.0 m^2/s in lowest 100 m	Depends on urban land use fr
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	rain/snow/graupel
Numerics		

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CURRENT STATUS AND NEXT STEPS

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CURRENT STATUS/NEXT STEPS

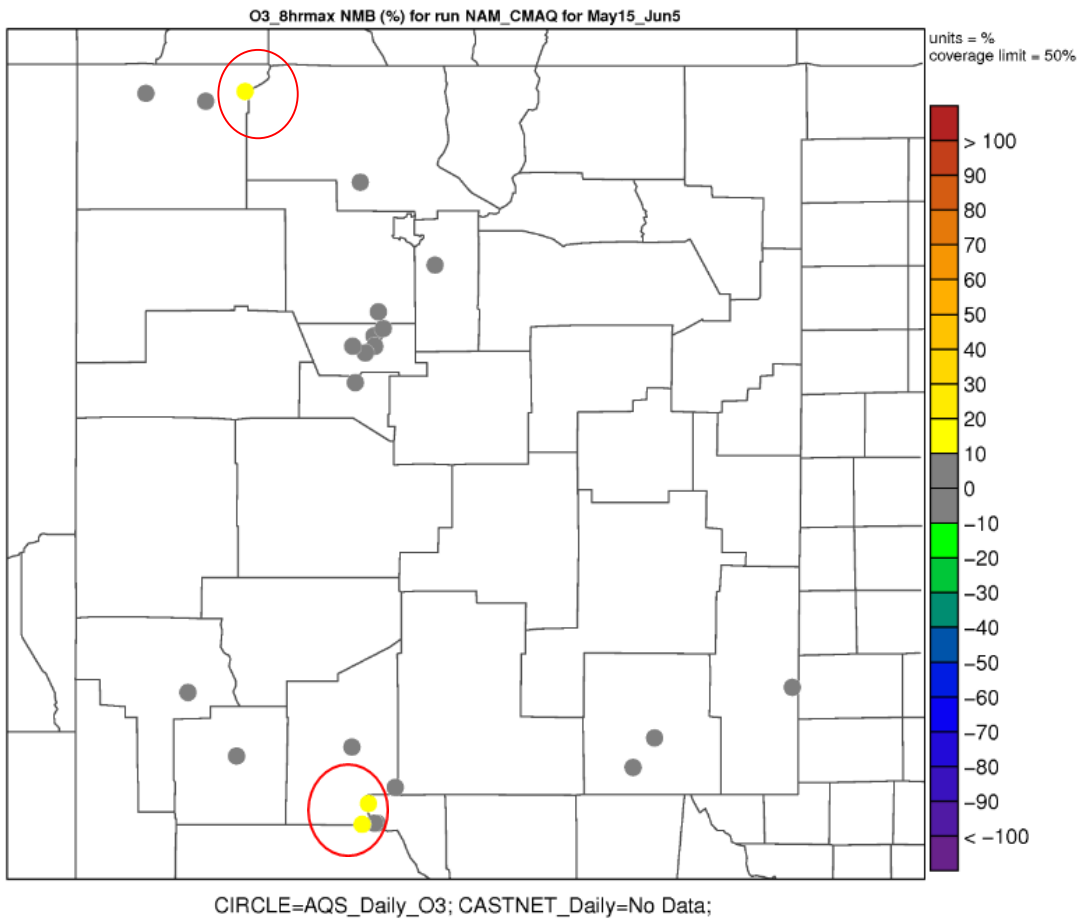
- CAMx Summer 2014 36/12/4-km base case simulation in August 2020
  - Model Performance Evaluation
  - Task 5 2014 Base Case and MPE Report
- 2023 SMOKE Emissions Processing in August

Webinar Number	Webinar Topics by Task	Date	Status
1.	1. Modeling Protocol and Work Plan 2.1 Evaluate Existing Met 4.1 Recommend 2014 and 2023 Emissions 4.2.1 Recommend 2014 & 2023 Mobile Source Emissions	May 2020	• Done • Done • Done • Done
2.	2.2 Additional Met Modeling 3.1 Evaluate BC Data 4.1 Summary of 2014 and 2023 Emissions	Jun 2020	• Done • Done • Done
3.	4.2.1 Summary of 2014 and 2023 Mobile Source Emissions 4.3 2014 Natural Emissions Results (e.g., Biogenic & LNOx)	Jul 2020	• Done • In Progress
4.	4.2.3 2014 & 2023 SMOKE-MOVES Results 4-km NM Domain 4.4 2014 & 2023 SMOKE Emissions Modeling Results	Aug 2020	• Partly Done • Partly Done
5.	4.5 FY Emissions Strategy Results 5. 2014 CAMx Base Case Modeling and MPE	Sep 2020	
6.	6.1 2023 CAMx Modeling Results 6.2 2023 Ozone Design Value Projections	Oct 2020	
7.	6.3 2023 Control Strategy Results 6.4 2023 Source Apportionment Modeling Results	Nov 2020	

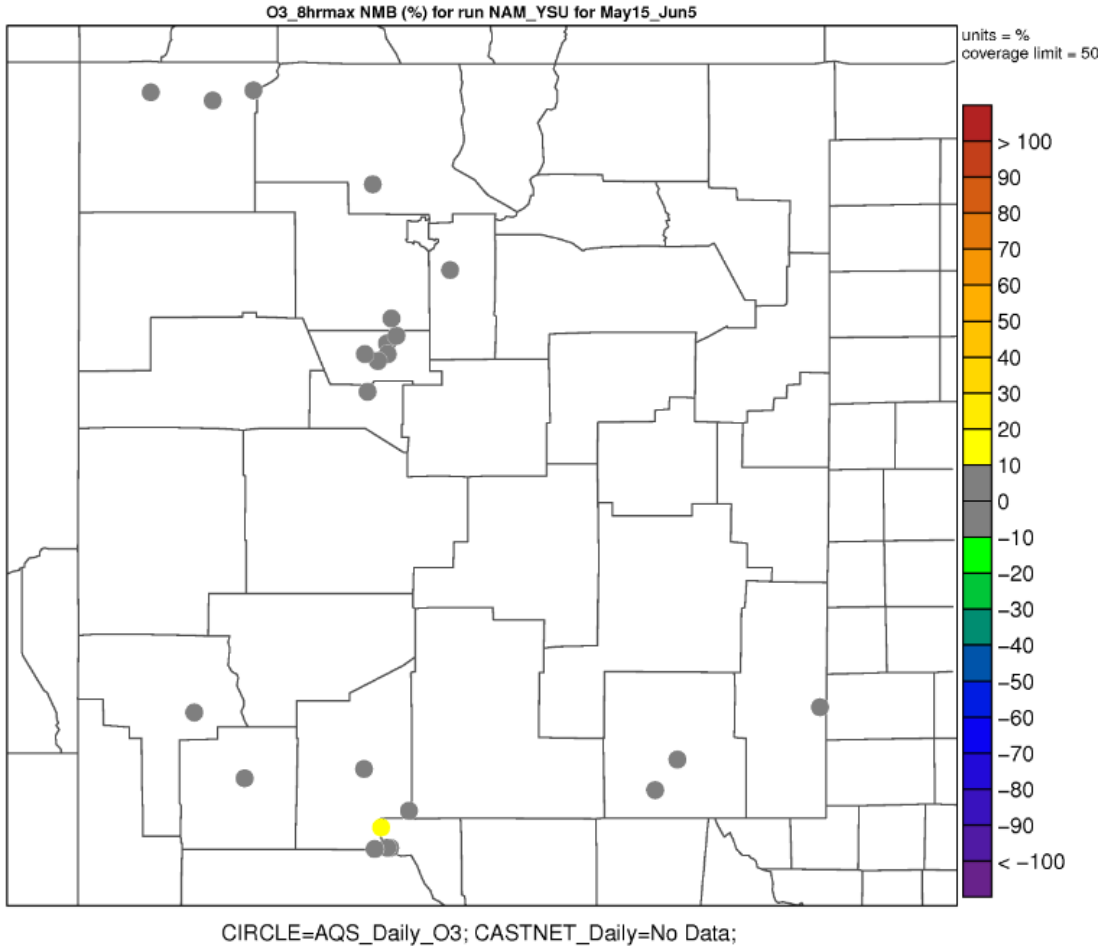
RAMBOLL

ADDITIONAL SLIDES

NAM_CMAQ with no 60ppb cut-off

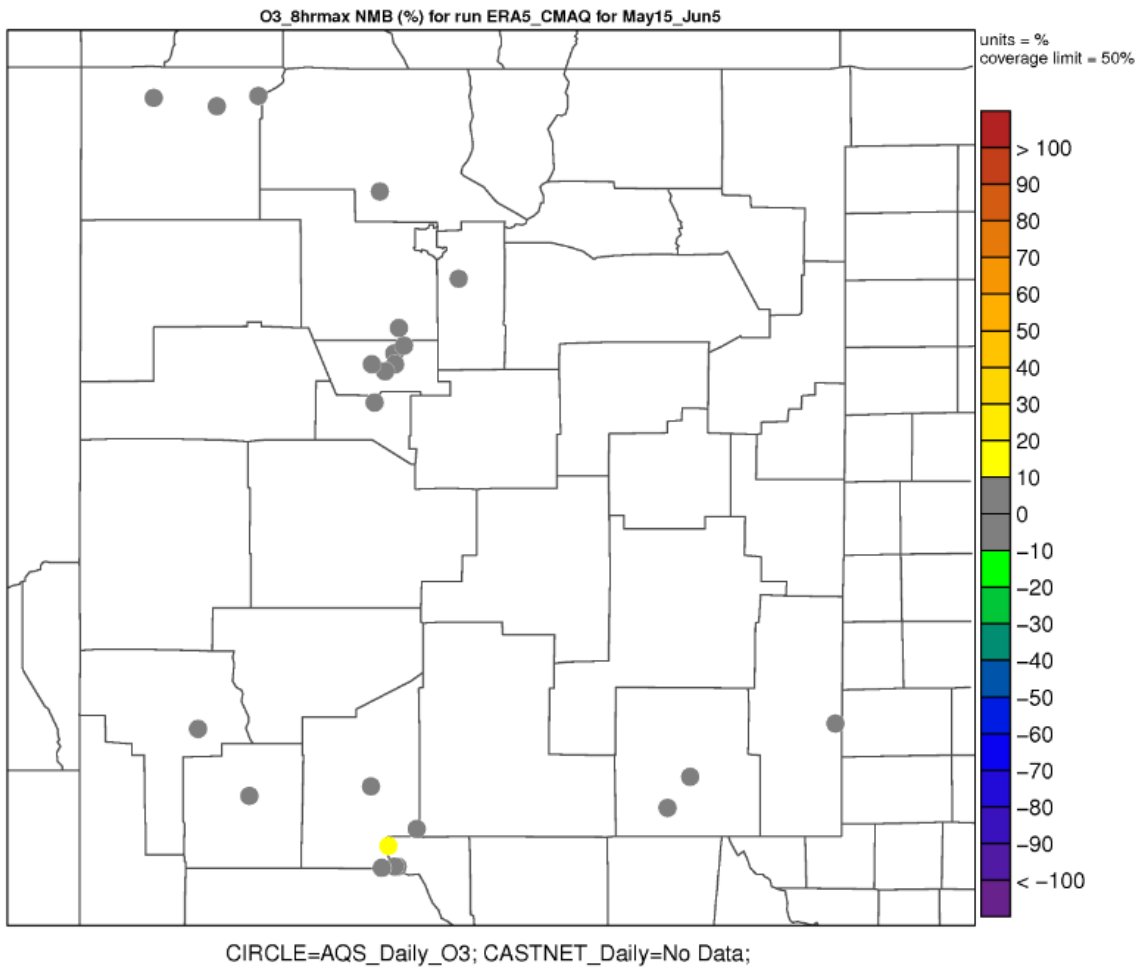


NAM_YSU with no 60ppb cut-off

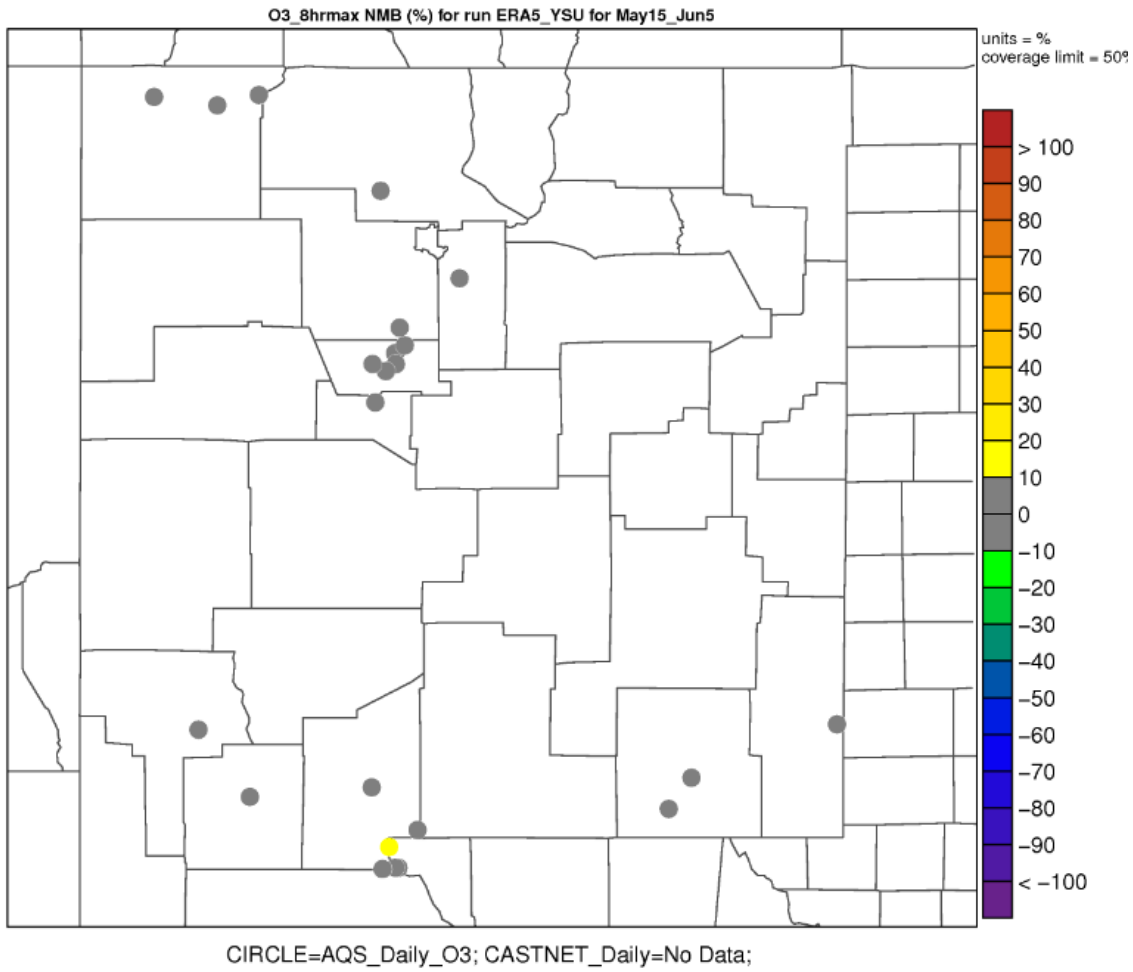


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ERA5_CMAQ with no 60ppb cut-off



ERA5_YSU with no 60ppb cut-off



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NEW MEXICO OZONE ATTAINMENT INITIATIVE

1. 2014 and 2023 Emissions
2. CAMx 2014 Base and Model Performance
3. 2023 CAMx Modeling Status
4. Next Steps -- Future Year Control Strategy

Ralph Morris, Pradeepa Vennam, Marco Rodriguez, Jeremiah Johnson, Chao-Jung Chien and Tejas Shah, Ramboll

Tom Moore and Mary Uhl, WESTAR

NM OAI Study Webinar#4

August 31, 2020

RAMBOLL Bright ideas. Sustainable change.

AGENDA – NMED OAI STUDY WEBINAR#4 – AUGUST 31, 2020

- 2014 and 2023 Emissions
  - Natural Emissions for 2014
  - Updates to 2023 Emissions to Remove Duplicates and Other Updates
  - SMOKE Emissions Modeling for 2014 and 2023
  - Summary of 2014 and 2023 Emissions
- CAMx 2014 36/12/4-km Base Case Modeling
  - Final CAMx Configuration for 2014 Base Case
  - CAMx 2014 Base Case Ozone Model Performance Evaluation
  - Status of Task 5 2014 Base Case and Model Evaluation Report
- Next Steps

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OVERVIEW OF NM OAI PHOTOCHEMICAL MODELING STUDY

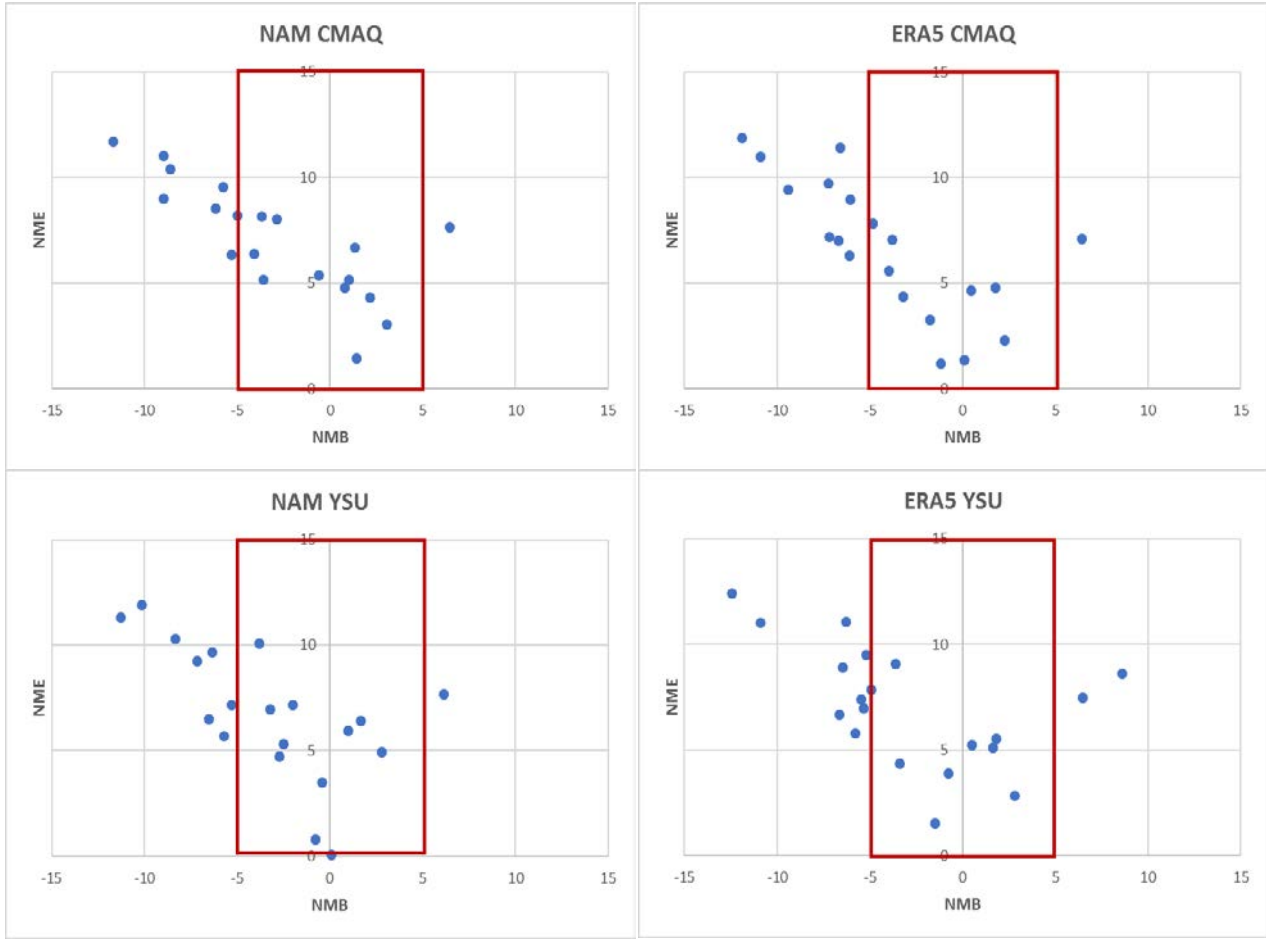
- *Task 1: Modeling Protocol, QAPP and Work Plan – Completed May 2020*
- *Task 2: Meteorological Modeling – Completed June 2020*
- *Task 3: Boundary Conditions – Completed June 2020*
- *Task 4: 2014 and 2023 Emissions – 2014 Completed June 2020*
  - *2023 Almost Completed August 2020 –* **only 2023 SMOKE-MOVES for 12-km 12WUS2 left**
- *Task 5: CAMx 2014 Base Case and Model Performance Evaluation – Work done August 2020*
  - **Working on Task 5 2014 Base Case and MPE report done in early September**
- **Task 6: Future Year (2023) Modeling**
  - **6.1: CAMx 2023 Base Case Modeling – Set-up ready to start (need 2023 12-km mobile)**
  - **6.2: Model Attainment Test – Not Started**
  - **6.3: Source Apportionment Modeling – Not Started**
  - **6.4: Emissions Sensitivity/Control Modeling – Not Started**
- **Task 7: Technical Support Document and Technology Transfer – Not Started**

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PREVIOUS WEBINAR HIGHLIGHTS (JULY 27, 2020)

- 2014 and 2023 Emissions
  - Summary of SMOKE processing
  - Identification & elimination of duplicate sources
  - Preliminary results
- CAMx 2014 Meteorological Sensitivity Runs
  - WRF/NAM and WRF/ERA5 simulations
  - Kv = CMAQ-like and Kv = YSU
  - Four CAMx WRF sensitivity simulations
  - WRF/NAM w/ Kv=CMAQ selected
    - Ozone performance for all four runs close
    - WRF/NAM w/ Kv=CMAQ had slightly lower bias and better performance on some observed ozone peaks

Site-Specific Bias/Error Soccer Plots for Four CAMx WRF Sensitivity Tests



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2014 AND 2023 EMISSIONS

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NEW MEXICO EMISSIONS DATA

- 2014 anthropogenic emissions are based on the WRAP/WAQS 2014v2
  - Onroad emissions based on SMOKE-MOVES processing with 2014 activity and WRF meteorology
  - O&G emissions based on state-of-the-science WRAP OGWG emission estimates
  - NMED found a generator engine missing in 2014v2 inventory (94 tpy NOx)
  - Consistent emissions data between the Regional Haze and OAI studies
- 2023 anthropogenic emissions are based on the EPA 2016v1 platform
  - Like 2014, onroad emissions created using SMOKE-MOVES and O&G emissions based on WRAP OGWG
  - NMED found duplicate sources between WRAP O&G and EPA non-EGU sectors
  - Found double counting of NM sources in WRAP O&G inventory: Title V and minor point sources
  - Updated San Juan Generating Station (NOx 7,059 TPY) and added Lordsburg Generating Station
  - Updated three O&G sources: Chaco Gas Plant (NOx 2,053 tpy), Carlsbad CS, and Mountainair CS (NOx 645 tpy)

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NMED Exhibit 21 - 0006

NATURAL EMISSIONS

Remained the same between 2014 and 2023

- Lightening NOx: Lightning NOx (LNOx) emissions processor with 2014 WRF meteorological data to generate CAMx-ready emissions
- Oceanic Emissions: OCEANIC emissions processor was used to generate sea salt and dimethyl sulfide (DMS) emissions
- Fire Emissions: Agricultural, prescribed burn and wildfire emissions from WRAP 2014v2 modeling developed by WRAP Smoke and Fire Workgroup
- Windblown dust: CAMx windblown dust (WBD) processor
- Biogenic Emissions: MEGAN v3.1 biogenic emissions model

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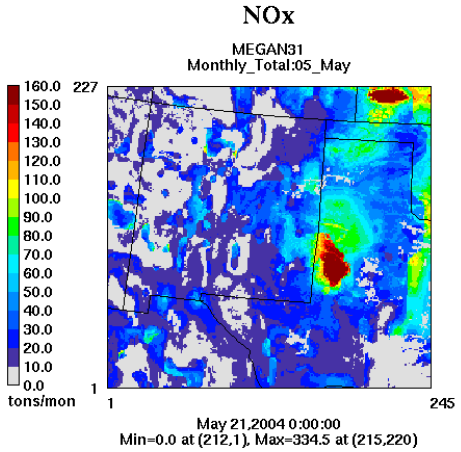
MEGAN V3.1 EMISSIONS

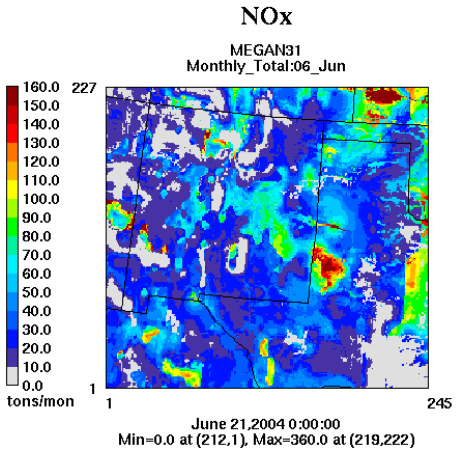
- Soil NOx

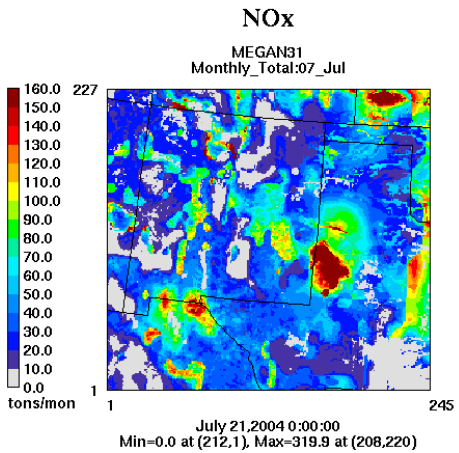
Month	tons/day	
	NOx	VOC
May	1,131	4,139
Jun	1,369	8,615
Jul	1,666	10,248
Aug	1,323	11,438

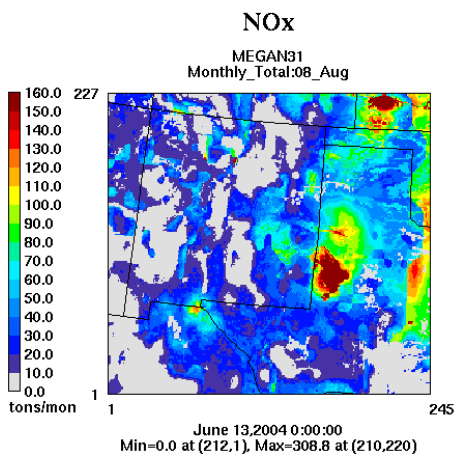
May June July August

NOx

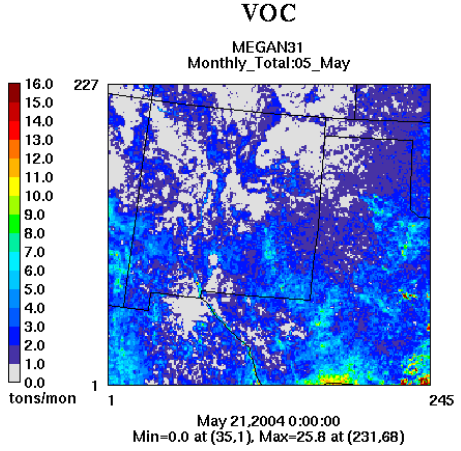


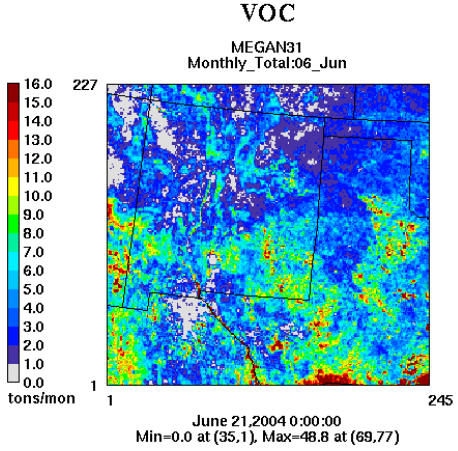


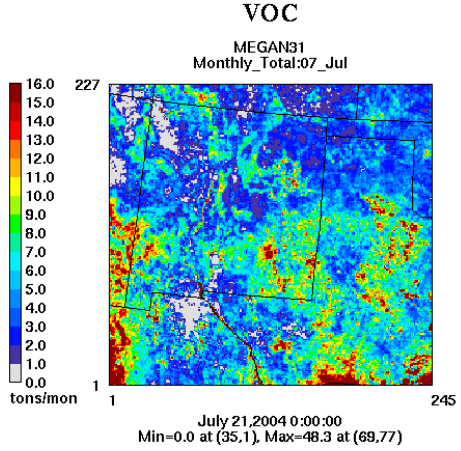


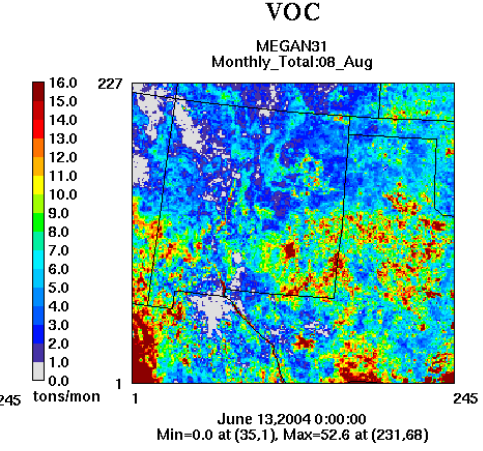


VOC





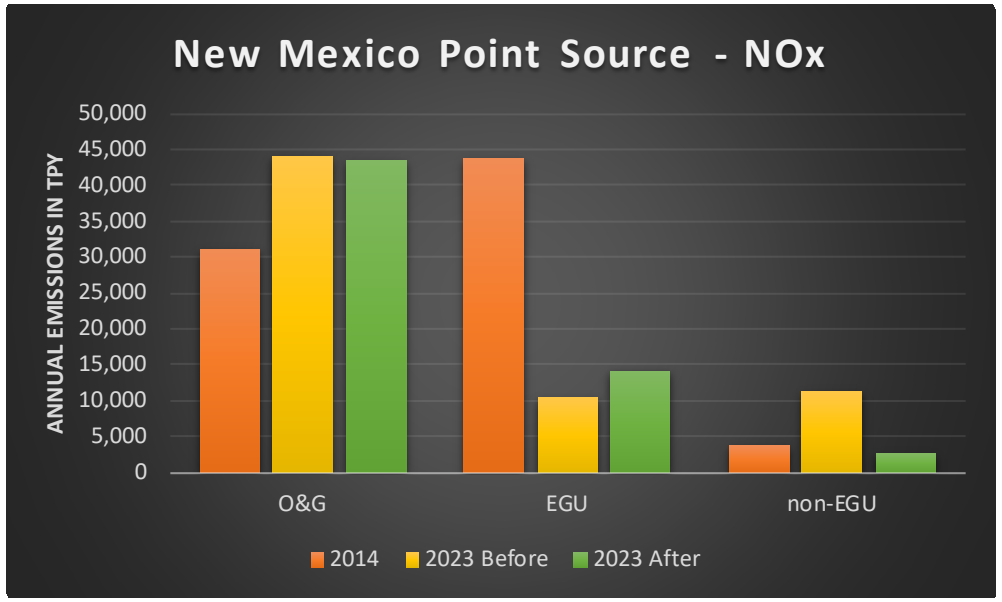


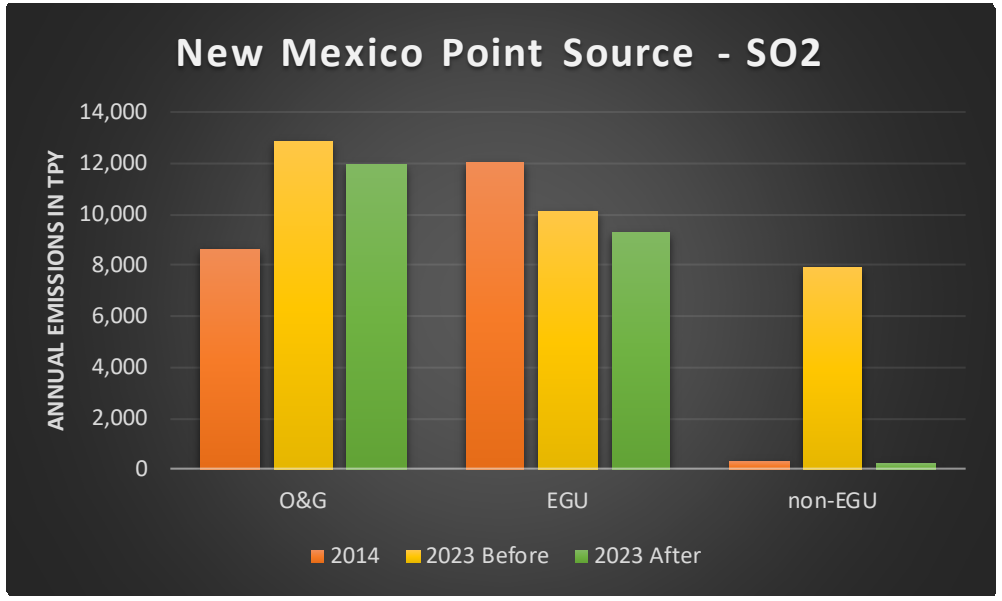


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DUPLICATE POINT SOURCES IN 2023

- NMED identified 21 facilities double counted in 2023 non-EGU and WRAP point O&G inventory
  - Double counted emissions: NOx 8,669 TPY and SO2 7,662 TPY
  - Represents approximately 9% (NOx) and 24% (SO2) of the New Mexico 2023 O&G emissions
- Duplicates in the WRAP O&G inventory: Some sources were present in Title V and minor point O&G sources datasets in the OGWG inventory.
  - Double counted emissions NOx: 1,927 TPY and SO2: 942 TPY





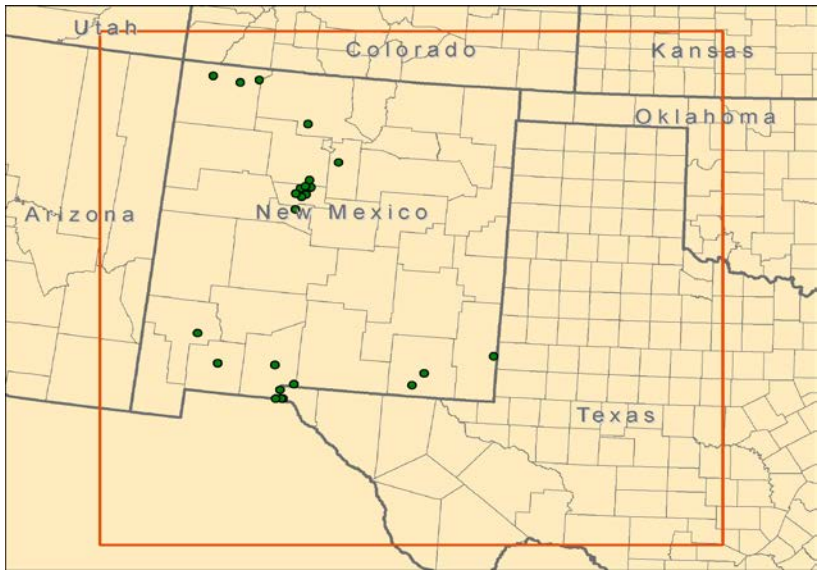
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NMED Exhibit 21 - 0009

SMOKE PROCESSING SECTORS

US-Anthro

Sector	Description
afdust_adj	- Area fugitive dust
ag	- Agricultural ammonia sources
nonpt	- Other nonpoint sources
np_oilgas_wrap	- Non-point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)
np_oilgas	- Non-point Oil and Gas
nonroad	- Non-road mobile
rail	- Locomotive
onroad	- On-road mobile
ptegu	- EGU point sources
ptnonipm	- Non-EGU point sources
pt_oilgas_wrap	- Point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)
pt_oilgas_wrap	- Point Oil and Gas
rwc	- Residential Wood Combustion



New Mexico 4-km Domain

Non-US Anthro & Natural

Sector	Description
onroad_mex	- Mexico onroad mobile
othar	- Mexico area
othpt	- Mexico point sources
MEGAN/BEIS	- Biogenic
LtNOx	- Lightning Nox
AG fire	- Ag Fire
RX fire	- Prescribed Fire
WF fire	- Wild Fire
Ptfire_othna	- Mexico fire
WBD	- Windblown Dust

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NEW MEXICO 4-KM DOMAIN EMISSIONS (ANTHRO ONLY)

2014 in average tons/day

Sector	CO	NOx	VOC
ag	0.0	0.0	43.4
nonpt	141.3	28.5	213.2
nonroad	570.3	133.4	73.2
np_oilgas	286.8	311.7	1,642.5
np_oilgas_wrap_only	237.7	157.8	567.3
onroad	1,476.2	444.5	150.6
onroad_mex	356.3	98.4	34.4
othar	19.9	42.2	103.3
othpt	28.4	20.2	8.3
ptegu	89.2	210.6	5.0
pt_oilgas	113.8	205.2	48.4
pt_oilgas_wrap_only	89.9	114.7	56.1
ptnonipm	74.4	47.5	24.4
rail	22.9	122.7	6.2
rwc	7.0	0.1	1.2
TOTAL	**3,513.9**	**1,937.6**	**2,977.3**

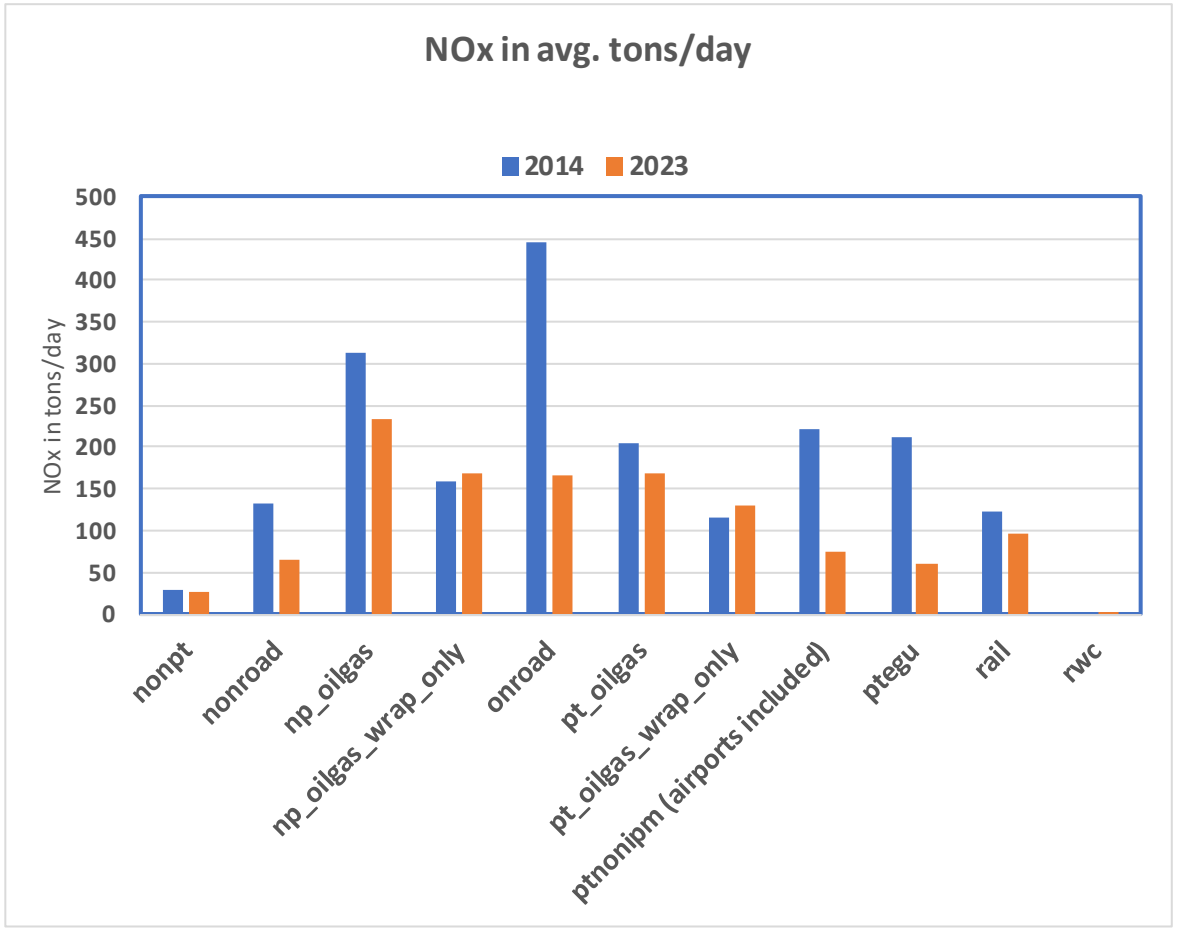
2023 in average tons/day

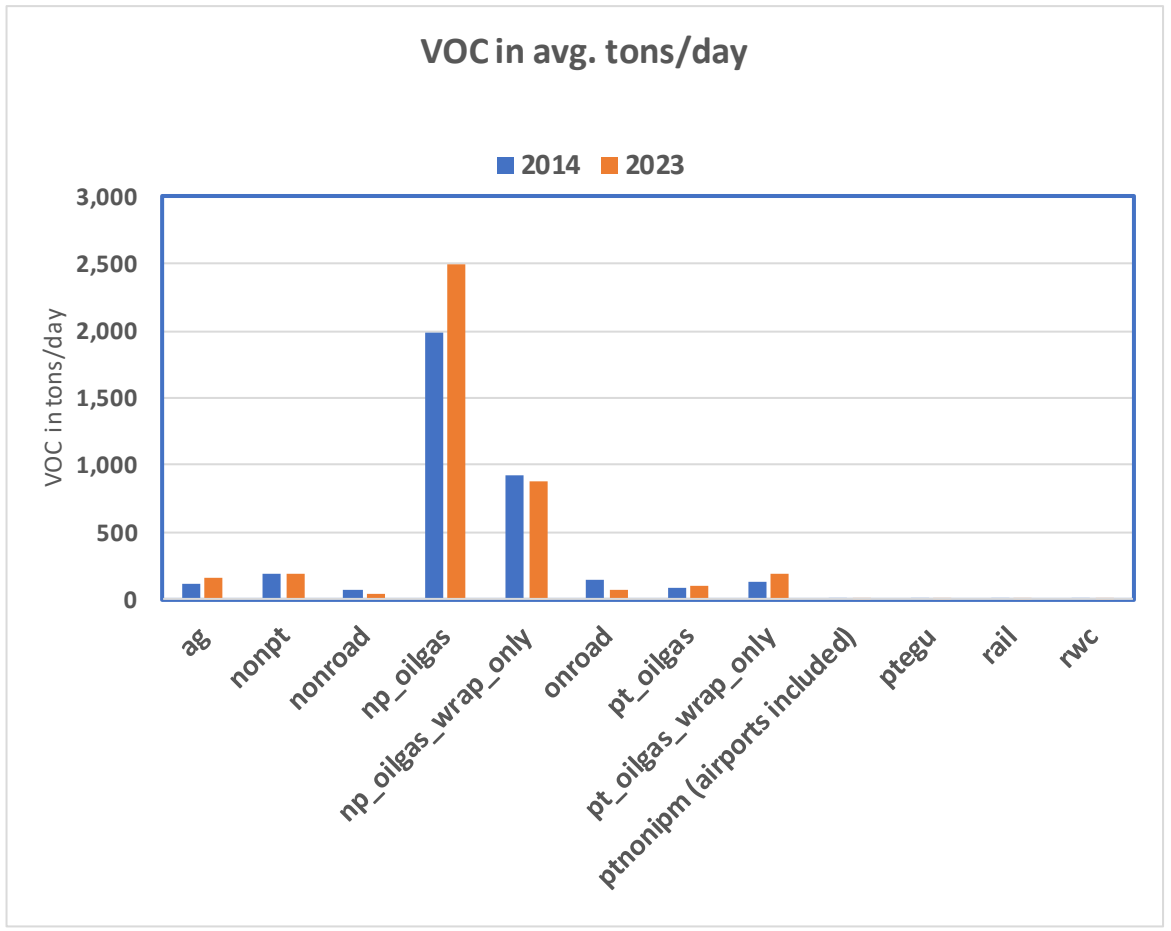
Sector	CO	NOX	VOC
ag	0.0	0.0	65.7
nonpt	141.9	27.3	217.0
nonroad	504.9	64.1	39.3
np_oilgas	298.3	234.3	2,124.5
np_oilgas_wrap_only	267.4	169.0	559.6
onroad	841.8	166.6	0.0
onroad_mex	336.3	98.0	35.0
othar	21.6	44.1	121.8
othpt	32.8	19.1	11.3
ptegu	34.0	60.6	1.6
pt_oilgas	99.0	169.1	57.9
pt_oilgas_wrap_only	111.4	130.5	86.5
ptnonipm	55.9	43.9	20.2
rail	22.1	96.4	4.2
rwc	7.0	0.1	1.1
TOTAL	**2,774.2**	**1,323.1**	**3,345.6**

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NMED Exhibit 21 - 0011

NEW MEXICO 4-KM EMISSIONS COMPARISON: 2014 VS. 2023



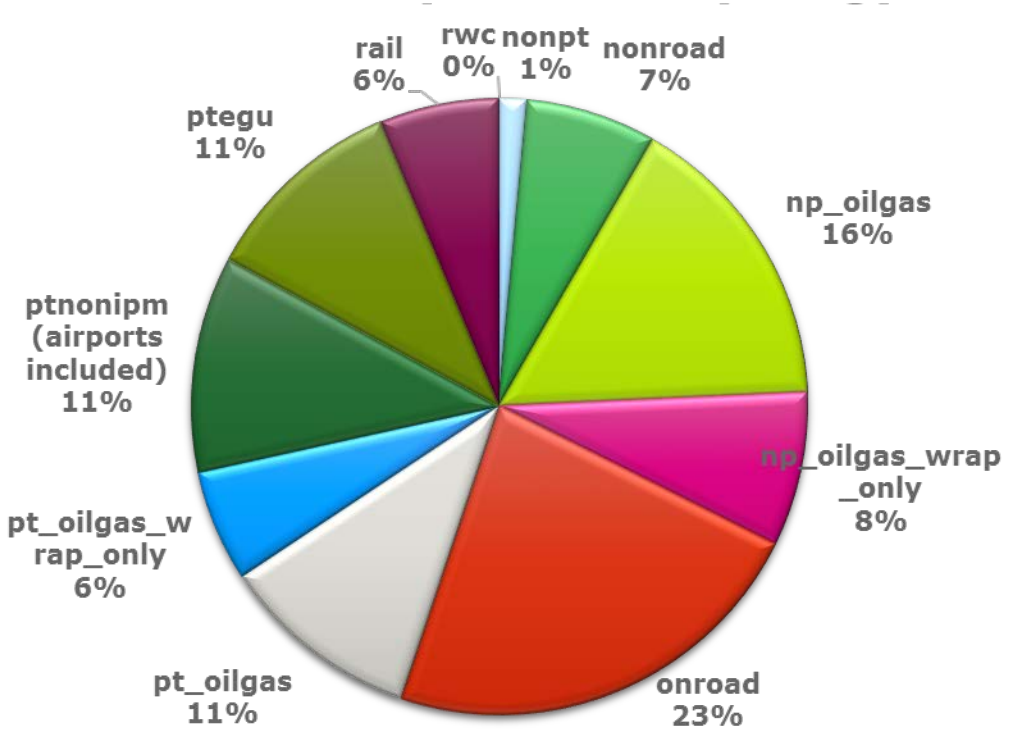


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NMED Exhibit 21 - 0012

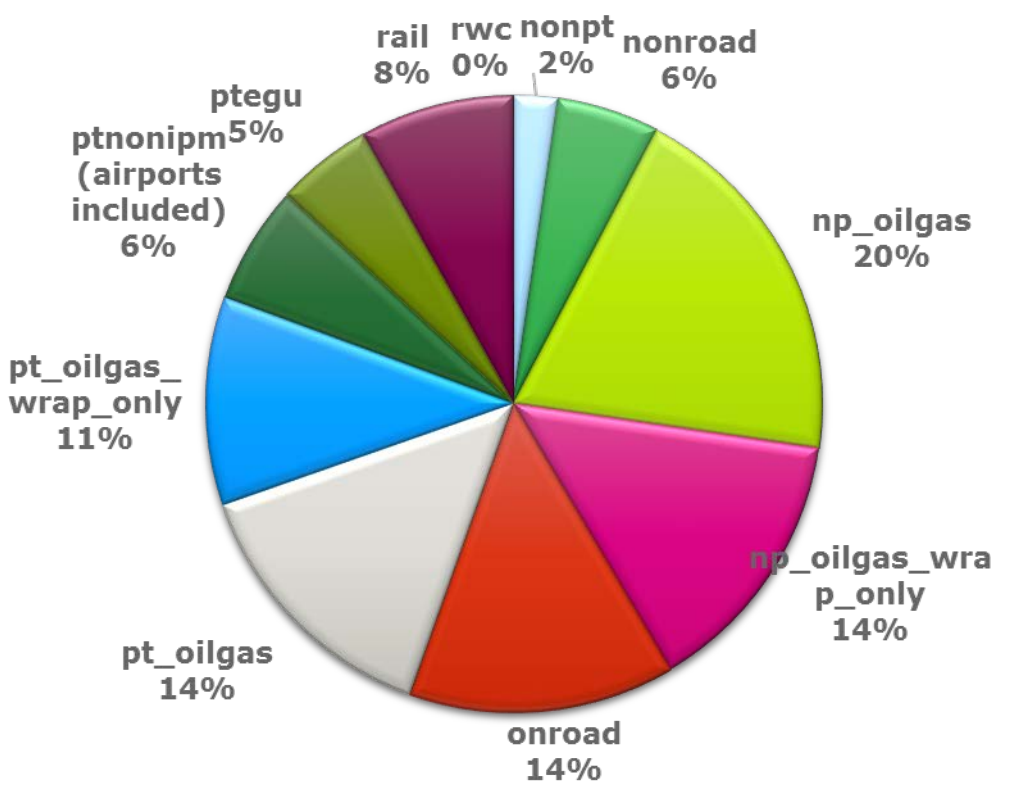
NEW MEXICO 4-KM NOX COMPARISON

2014 NOx



1,938 TPD

2023 NOx



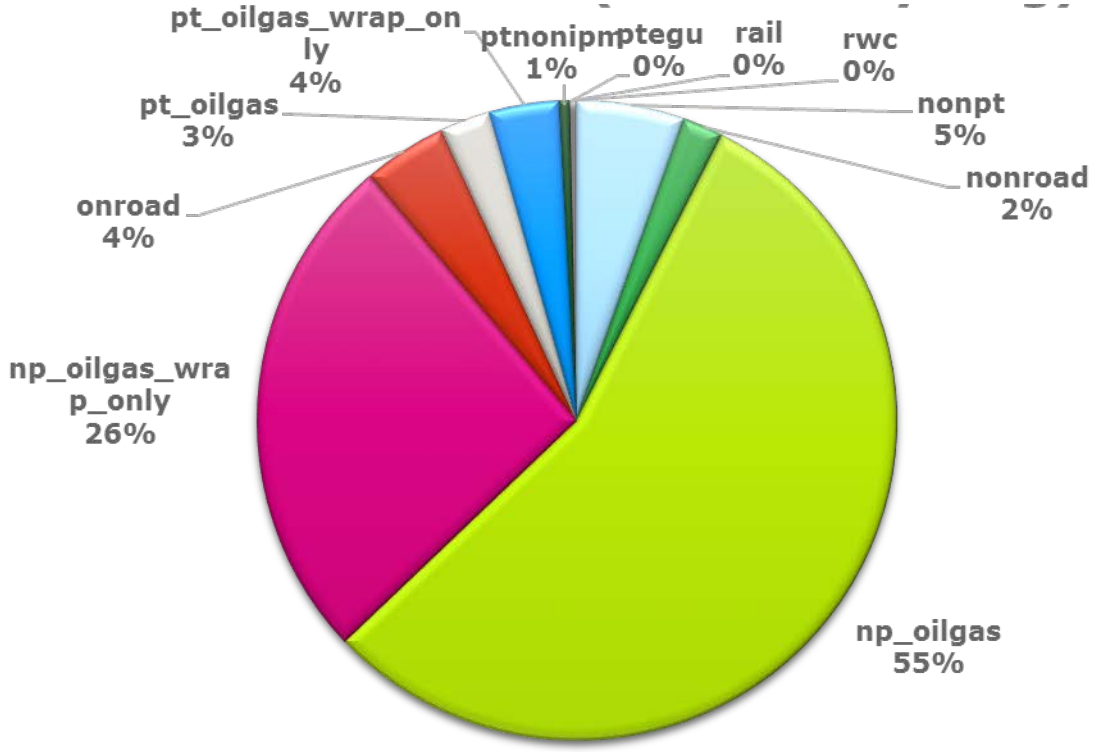
1,323 TPD

-615 TPD (32%) Reduction

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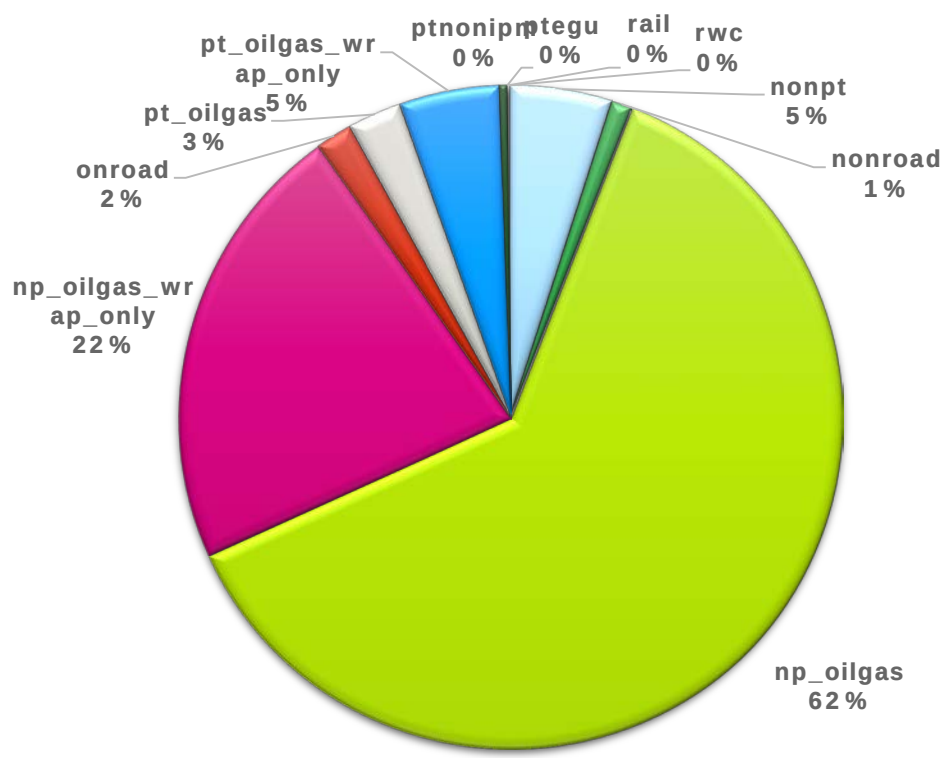
NEW MEXICO 4-KM VOC COMPARISON

2014 VOC



2,977 TPD

2023 VOC

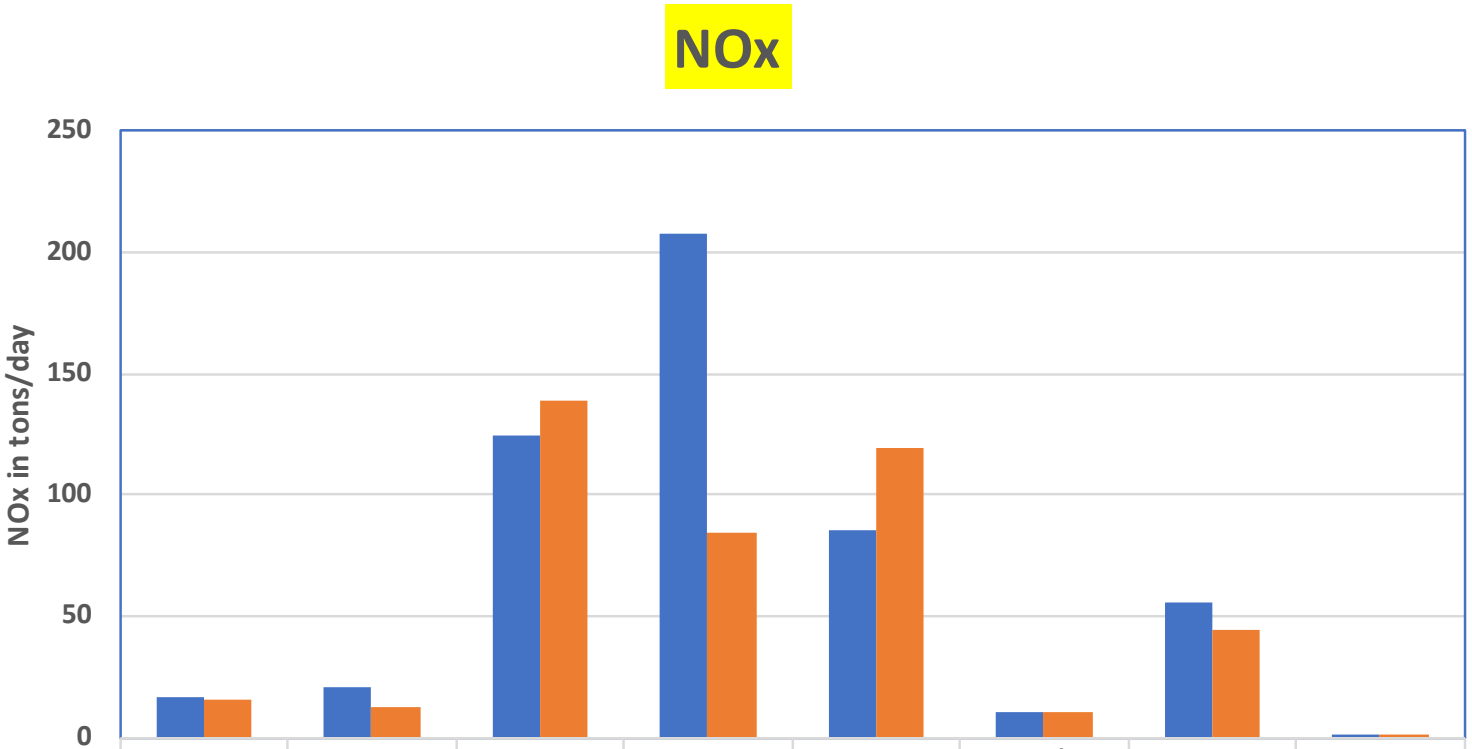


3,346 TPD

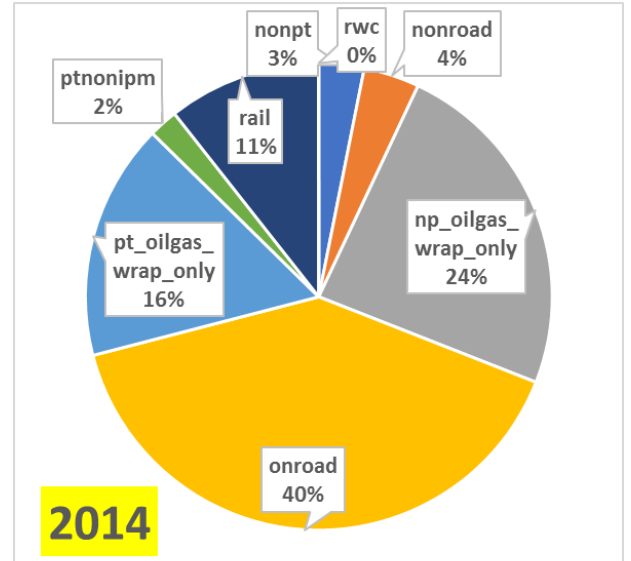
+369 TPD (12%) Increase

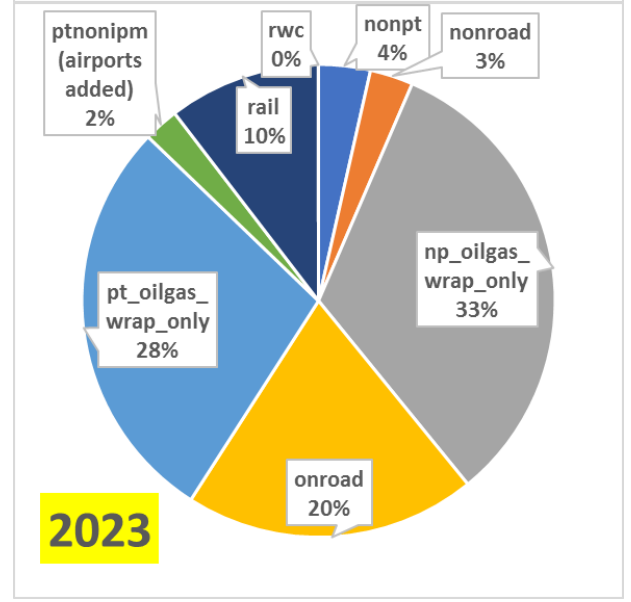
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NEW MEXICO NOX SUMMARY

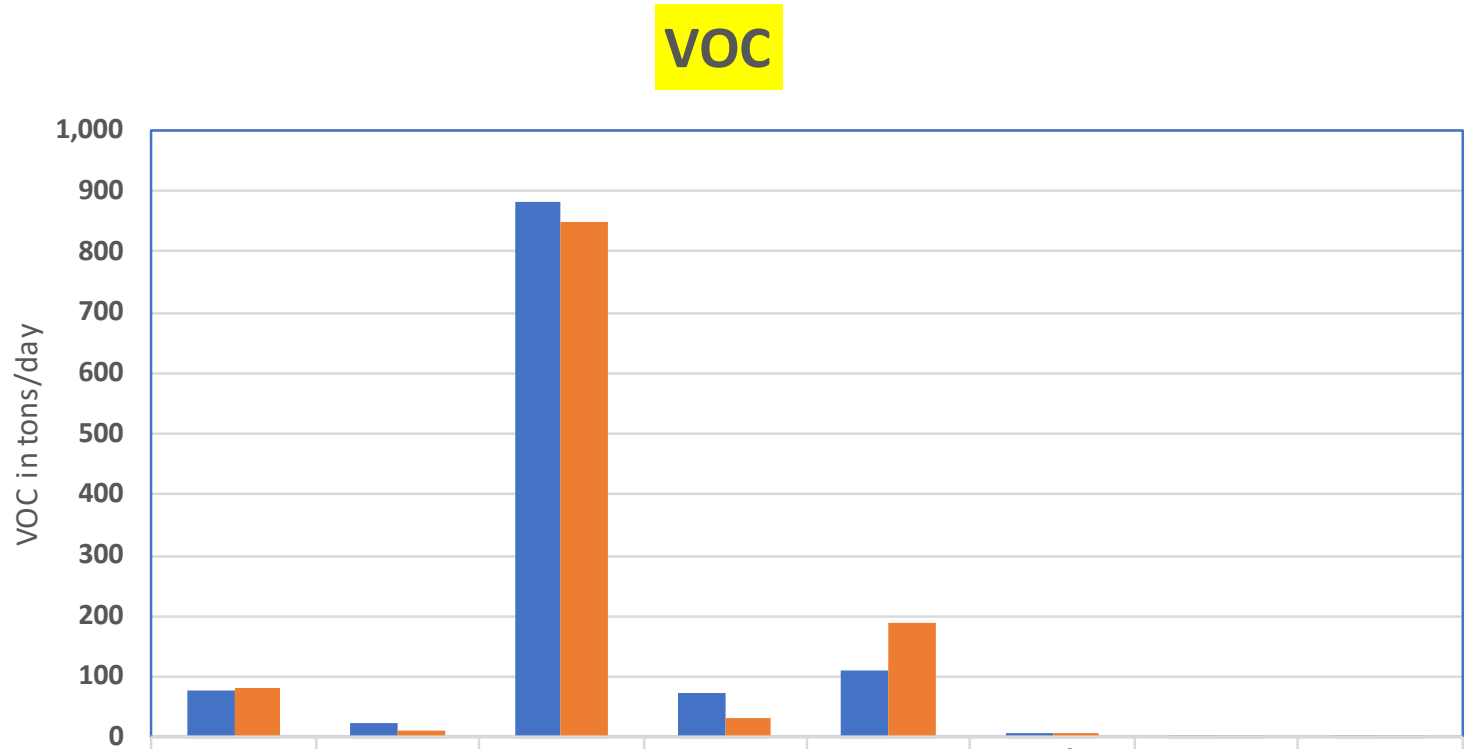


	nonpt	nonroad	np_oilgas_wrap_only	onroad	pt_oilgas_wrap_only	ptnonipm (airports added)	rail	rwc
2014	16	20	125	208	85	10	55	0
2023	15	12	138	85	119	10	44	0

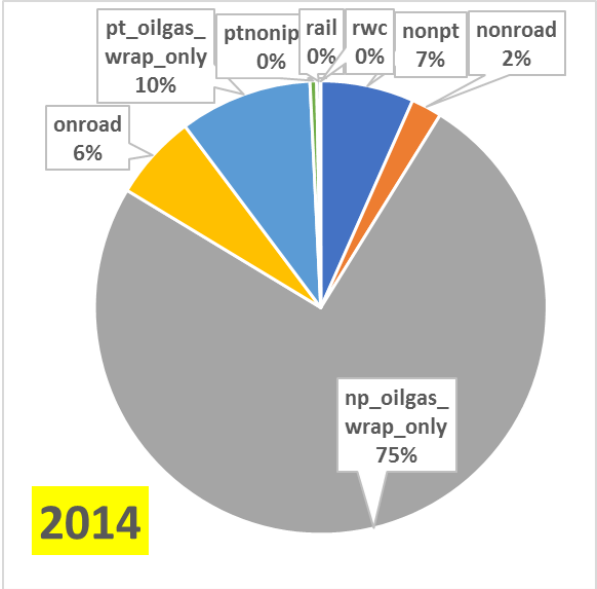


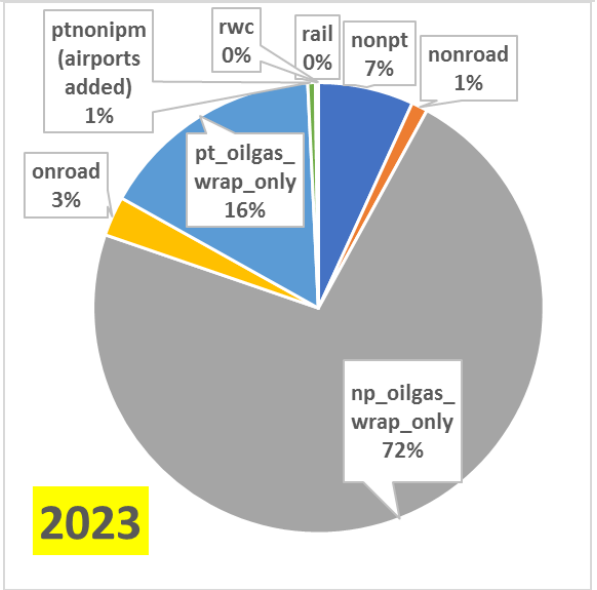


NEW MEXICO VOC SUMMARY



	nonpt	nonroad	np_oilgas_ wrap_only	onroad	pt_oilgas_ wrap_only	ptnonipm (airports added)	rail	rwc
2014	78	26	881	72	112	6	3	1
2023	80	14	849	33	189	6	2	1

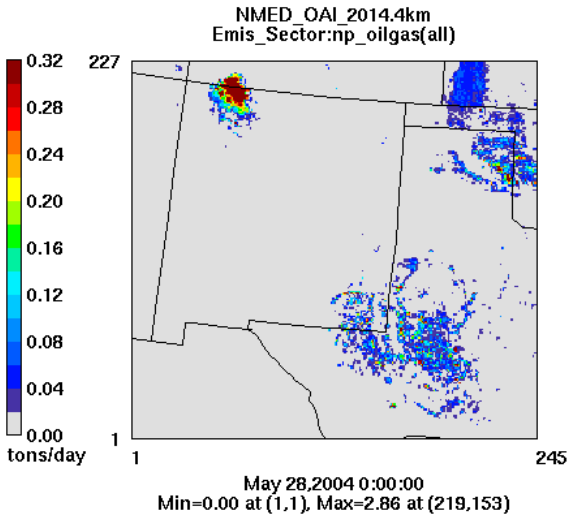




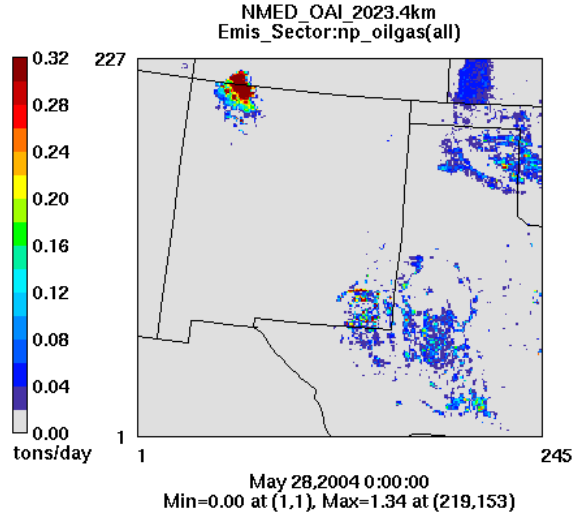
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NON-POINT O&G EMISSIONS: NOX

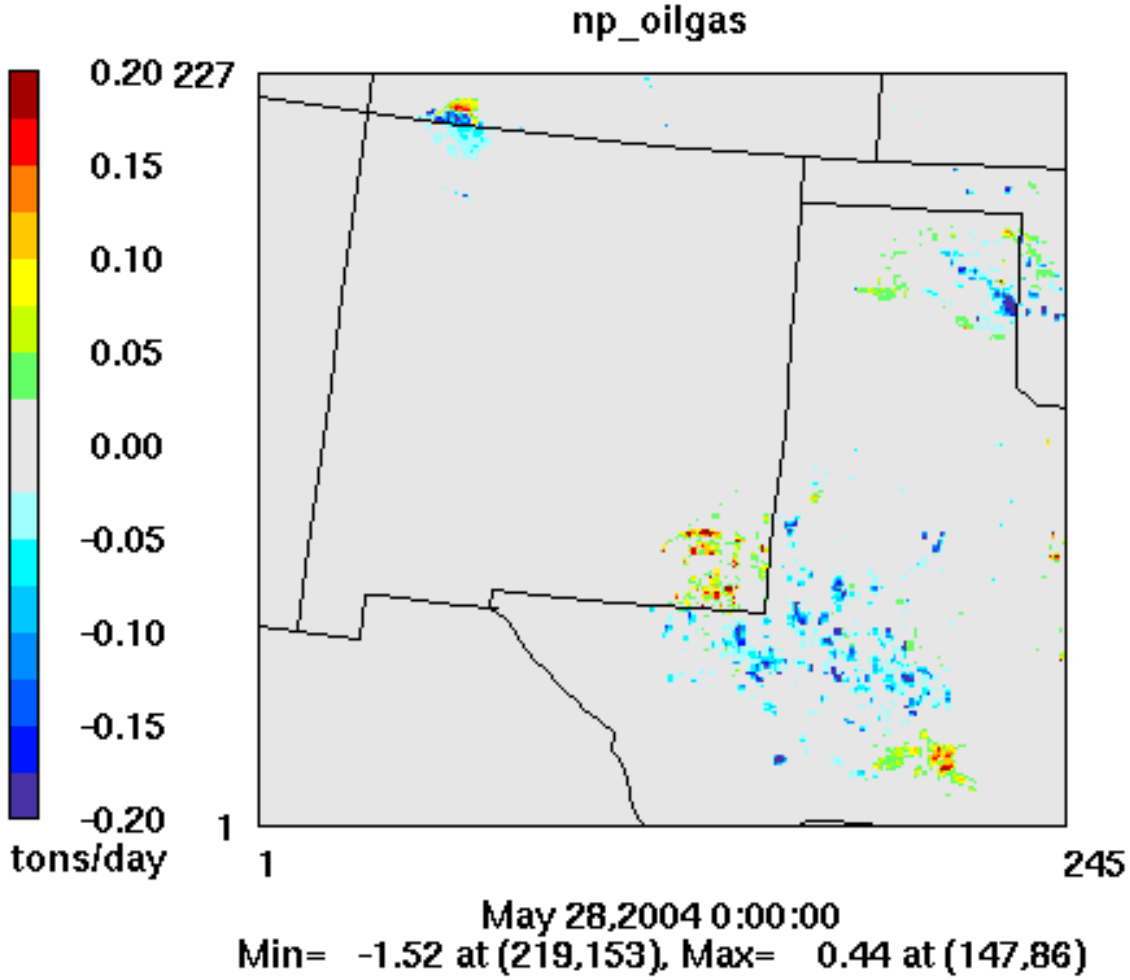
2014



2023



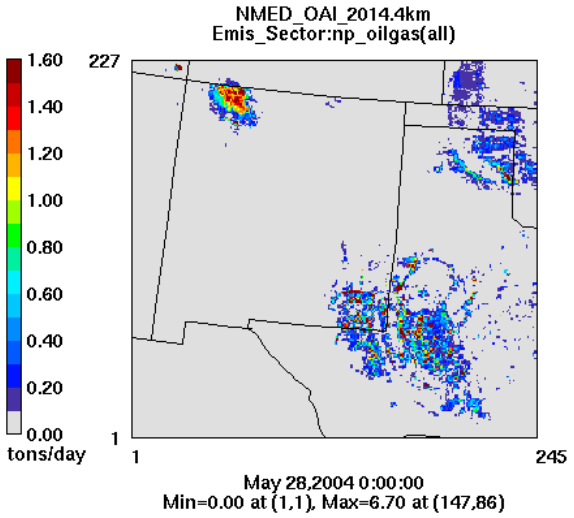
Delta NOx (2023 – 2014)



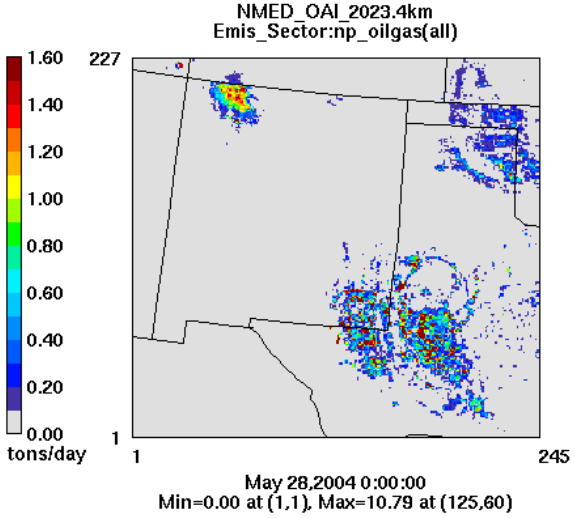
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NON-POINT O&G EMISSIONS: VOC

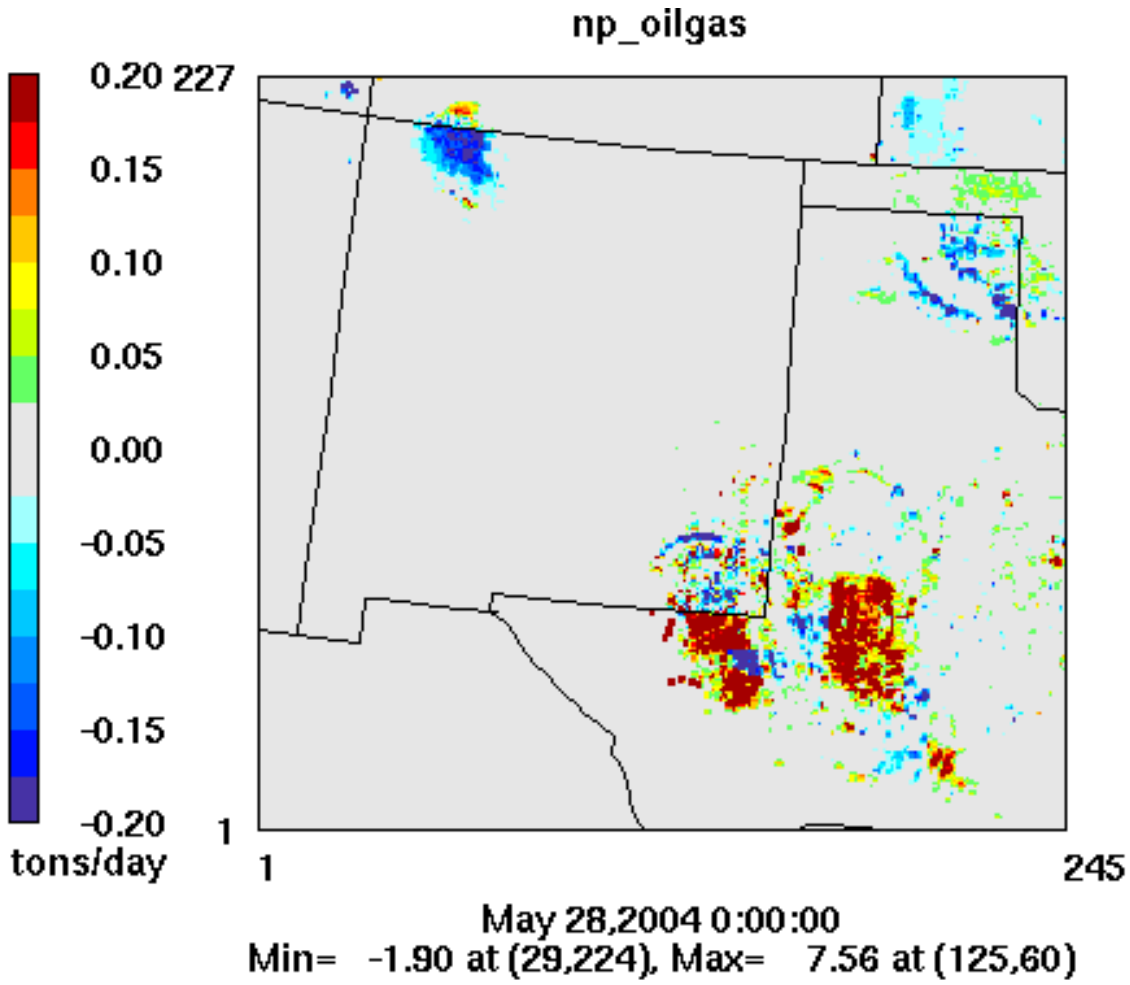
2014



2023



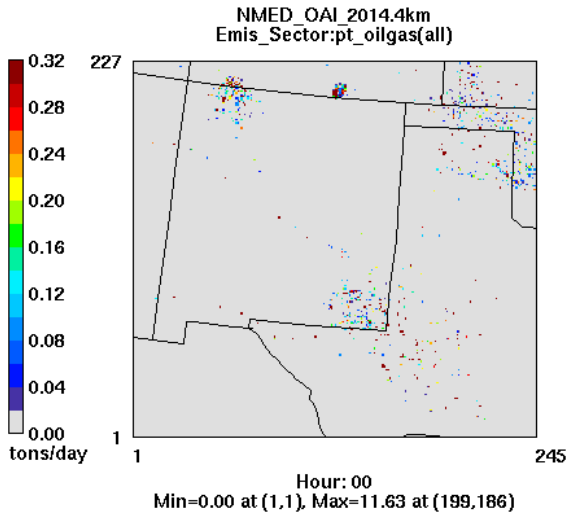
Delta VOC (2023 – 2014)



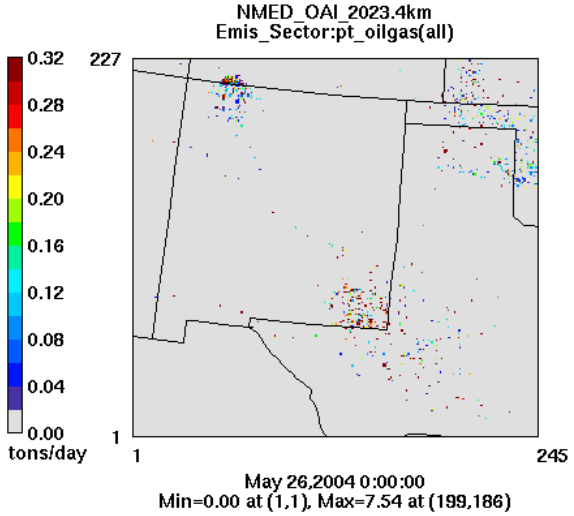
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POINT O&G EMISSIONS: NOX

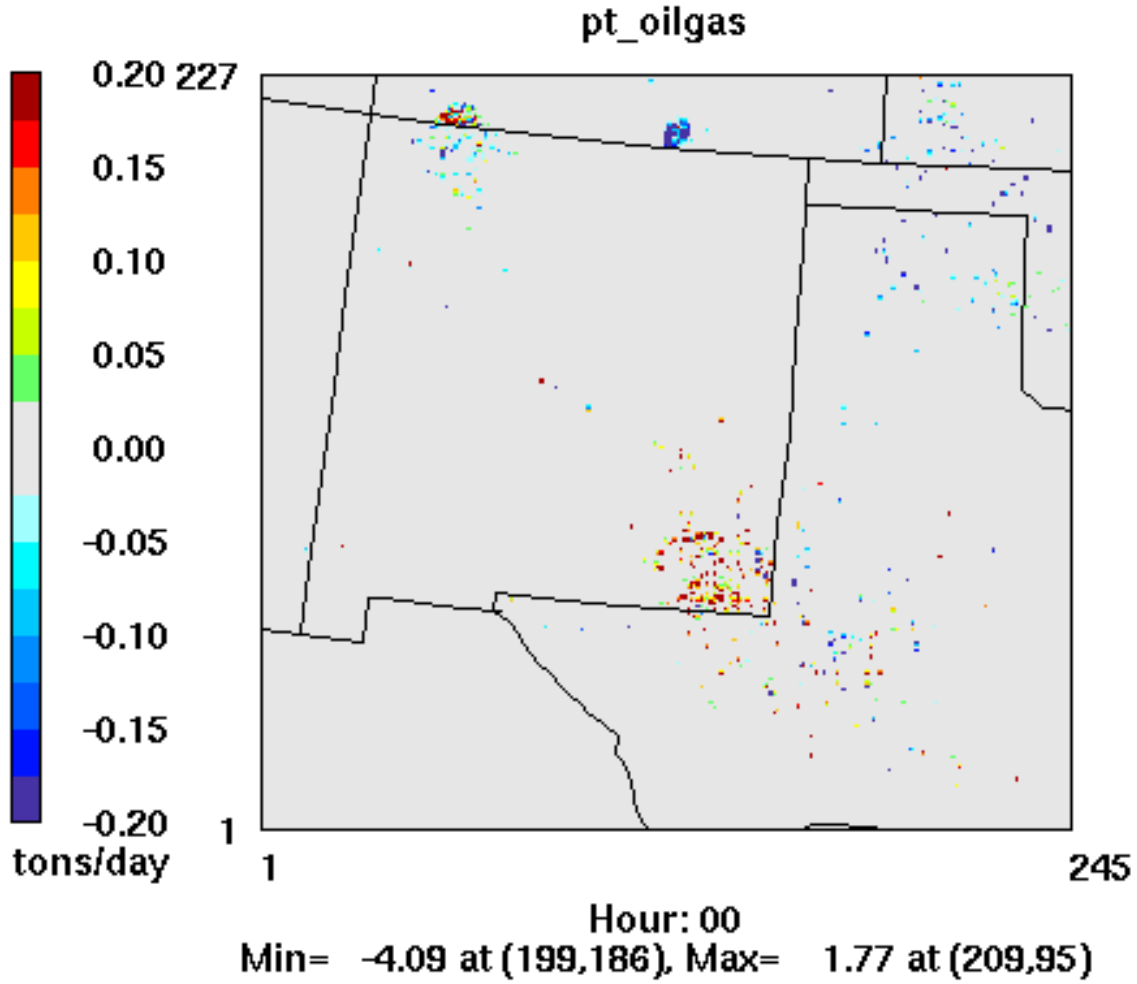
2014



2023



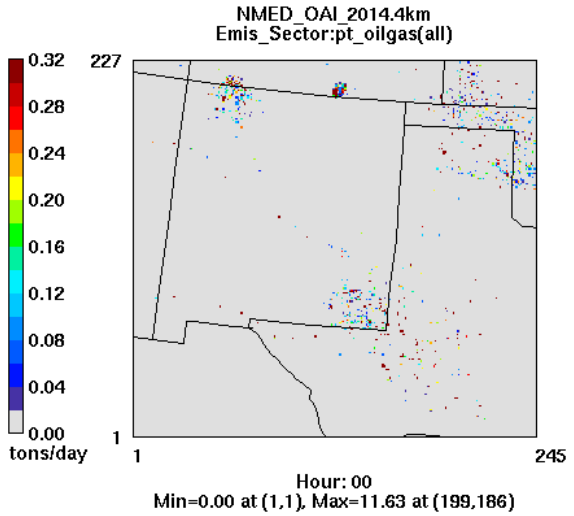
Delta NOx (2023 – 2014)



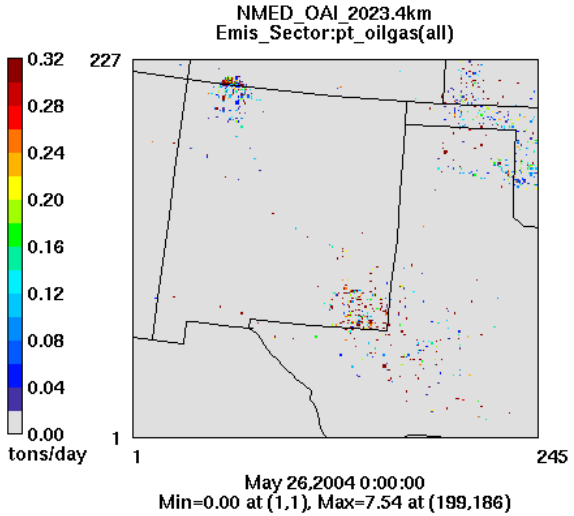
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POINT O&G EMISSIONS: VOC

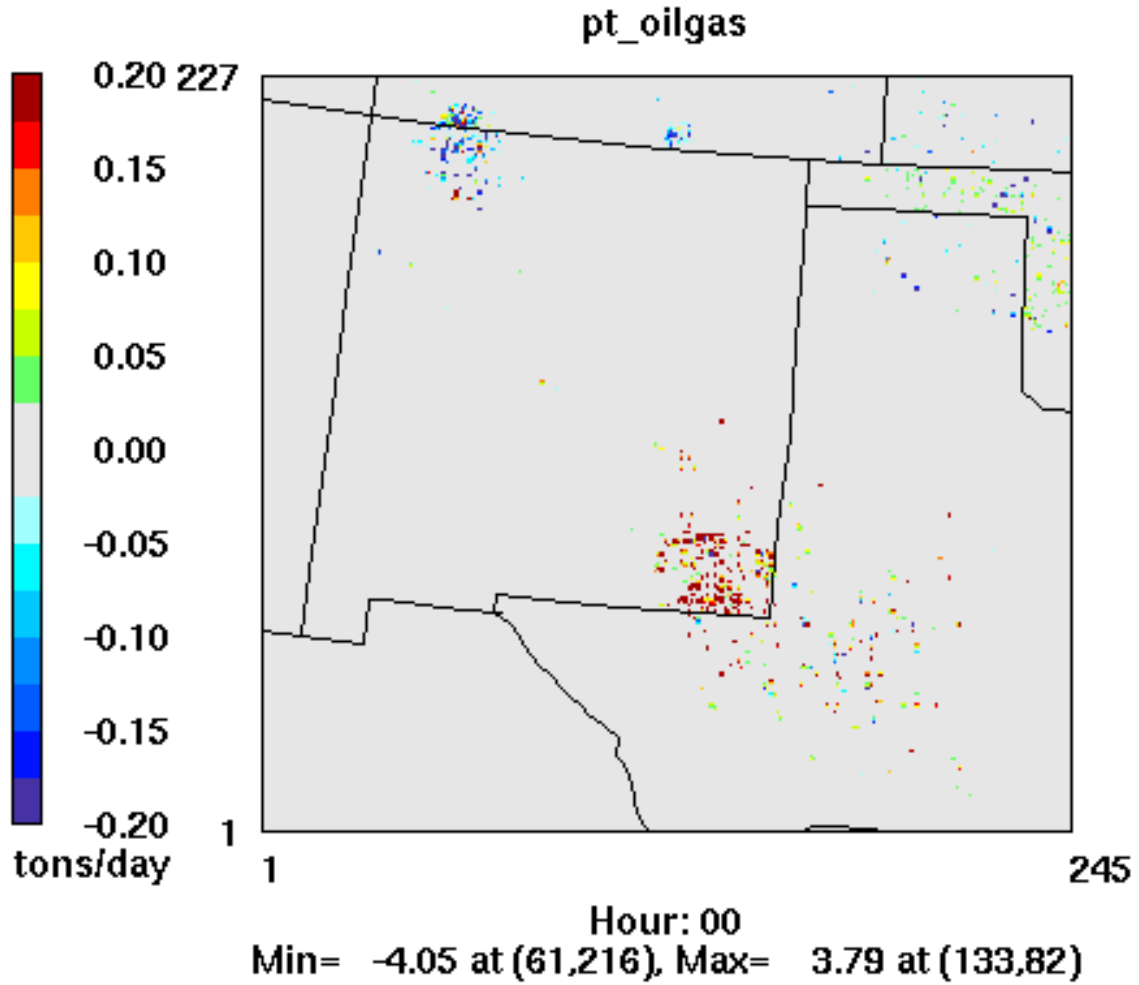
2014



2023



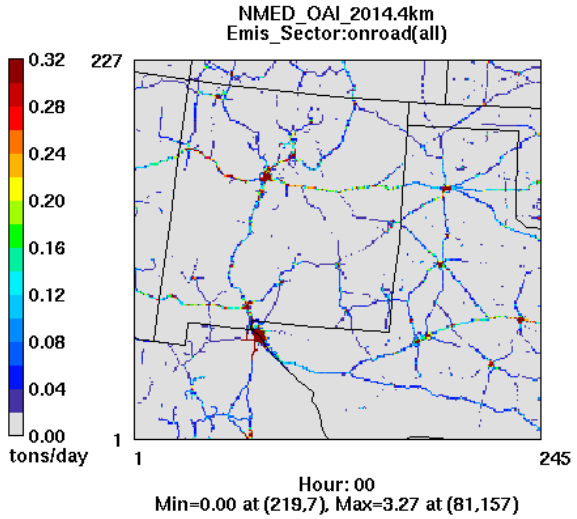
Delta VOC (2023 – 2014)



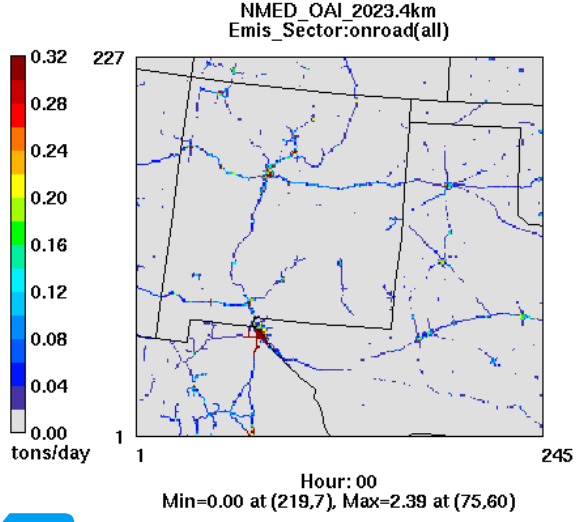
RAMBOLL

ONROAD EMISSIONS: NOX

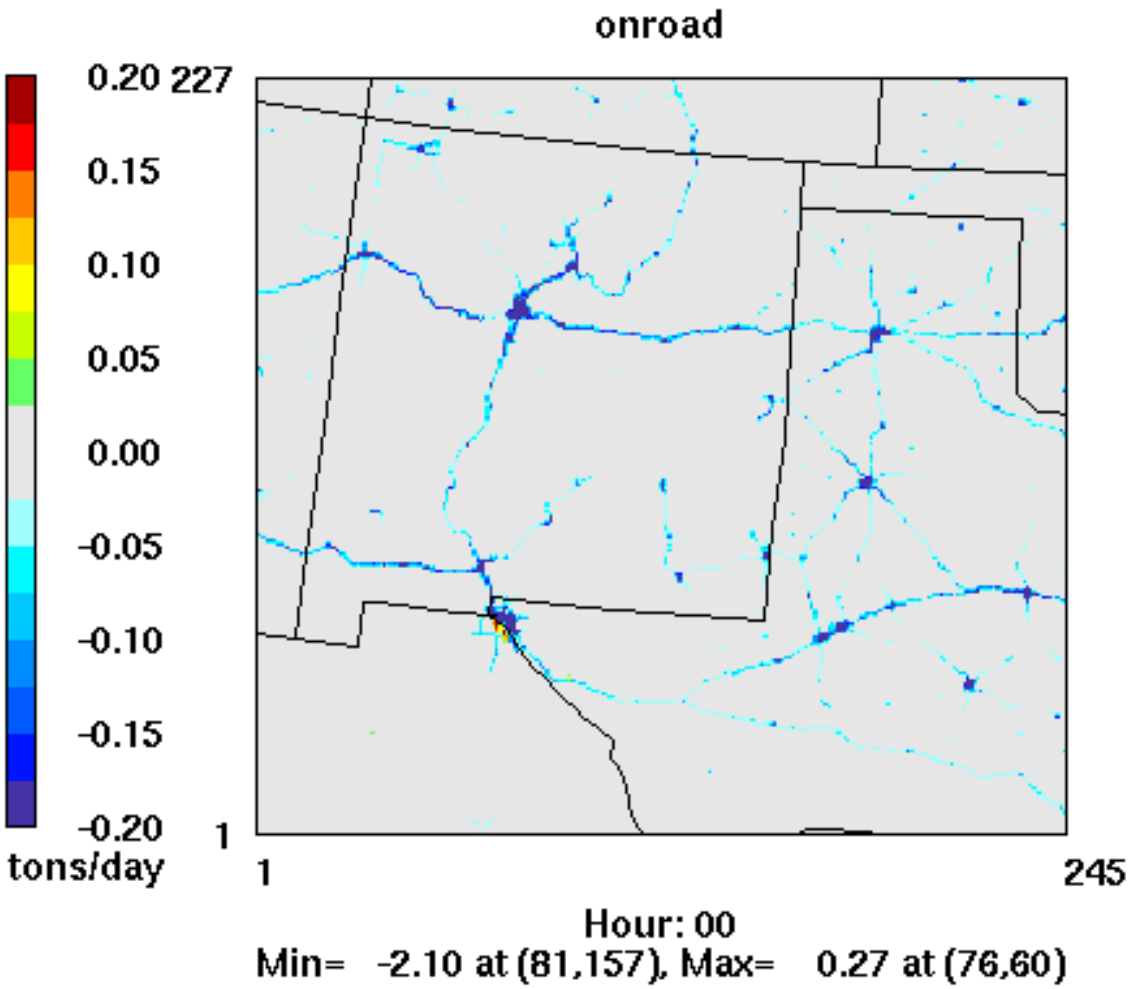
2014



2023



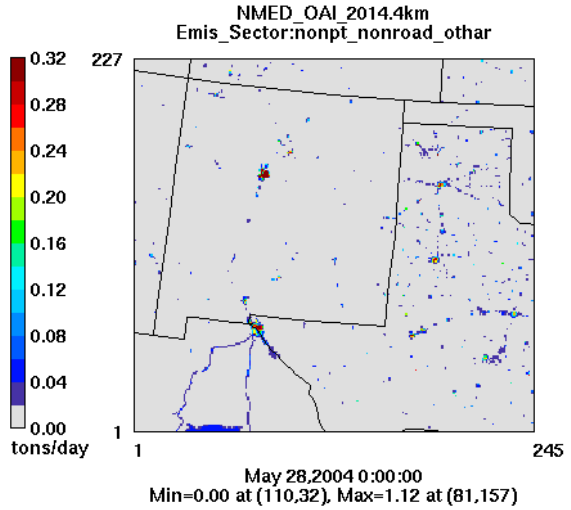
Delta NOx (2023 – 2014)



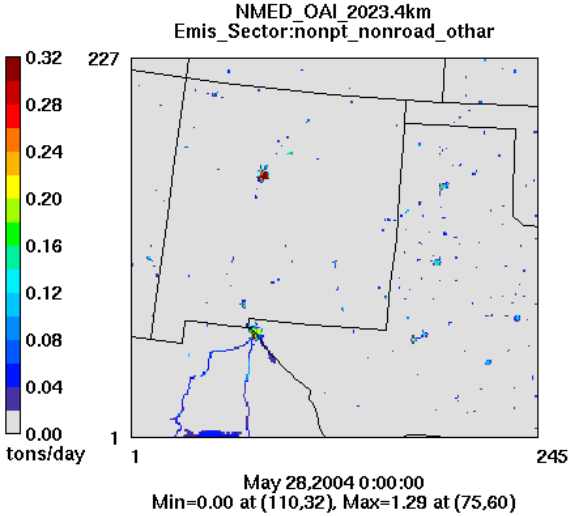
RAMBOLL

NONPOINT AND NONROAD EMISSIONS: NOX

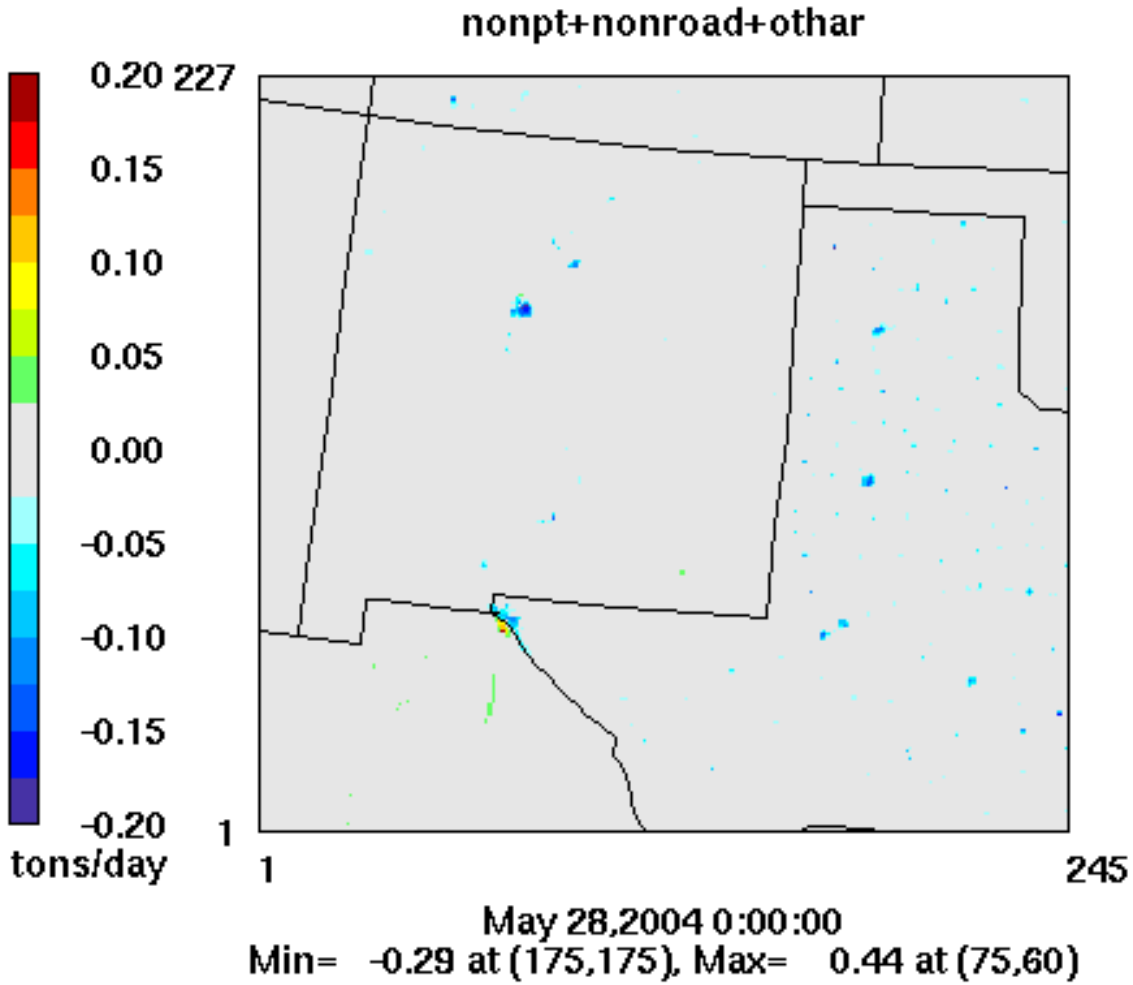
2014



2023



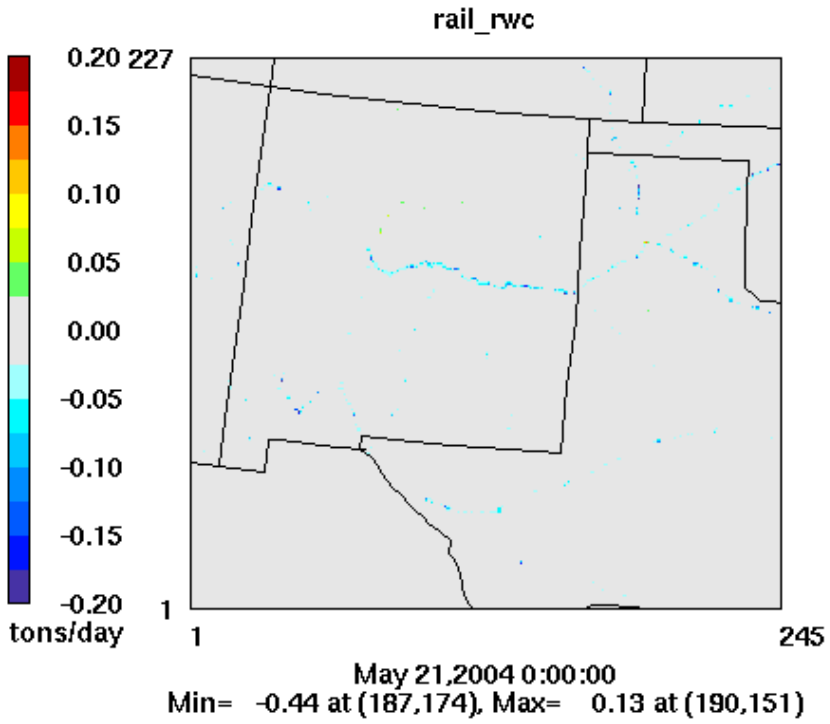
Delta NOx (2023 – 2014)



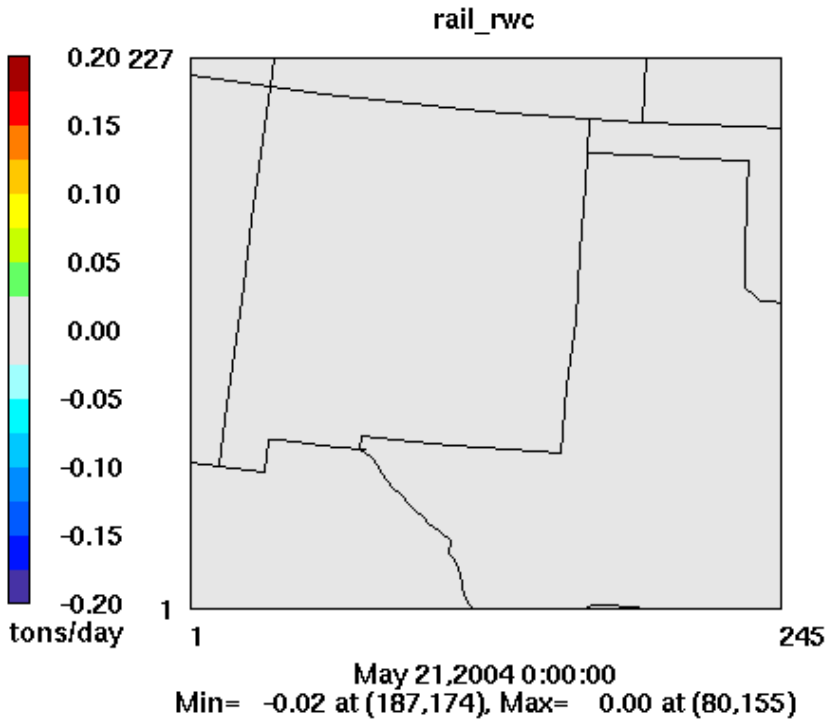
RAMBOLL

RAIL AND RWC EMISSIONS

Delta NOx (2023 – 2014)



Delta VOC (2023 – 2014)



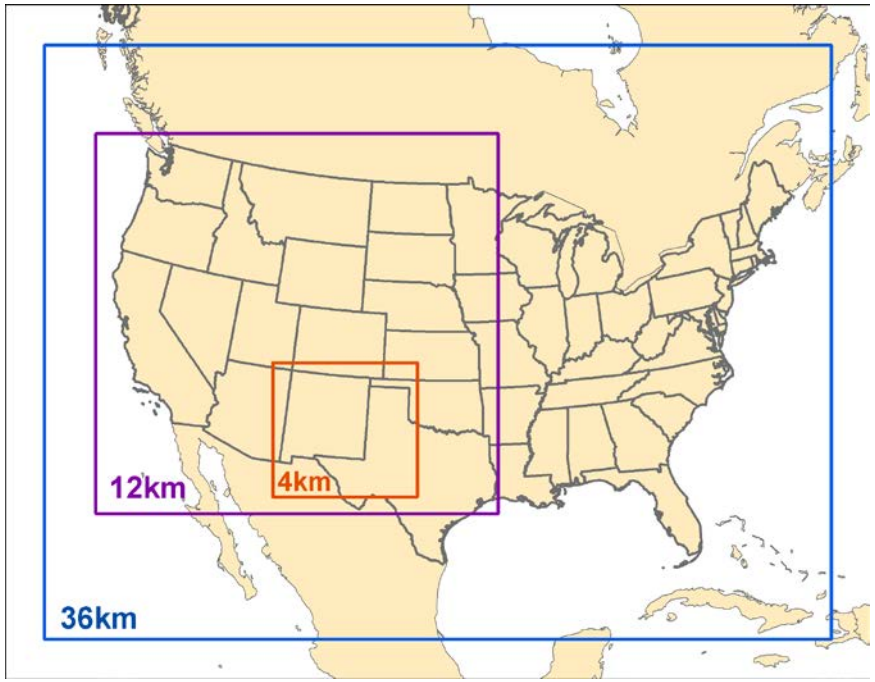
RAMBOLL

CAMX 2014 BASE CASE MODELING AND MODEL PERFORMANCE EVALUATION

RAMBOLL

CAMX 2014 BASE CASE – FINAL MODEL CONFIGURATION

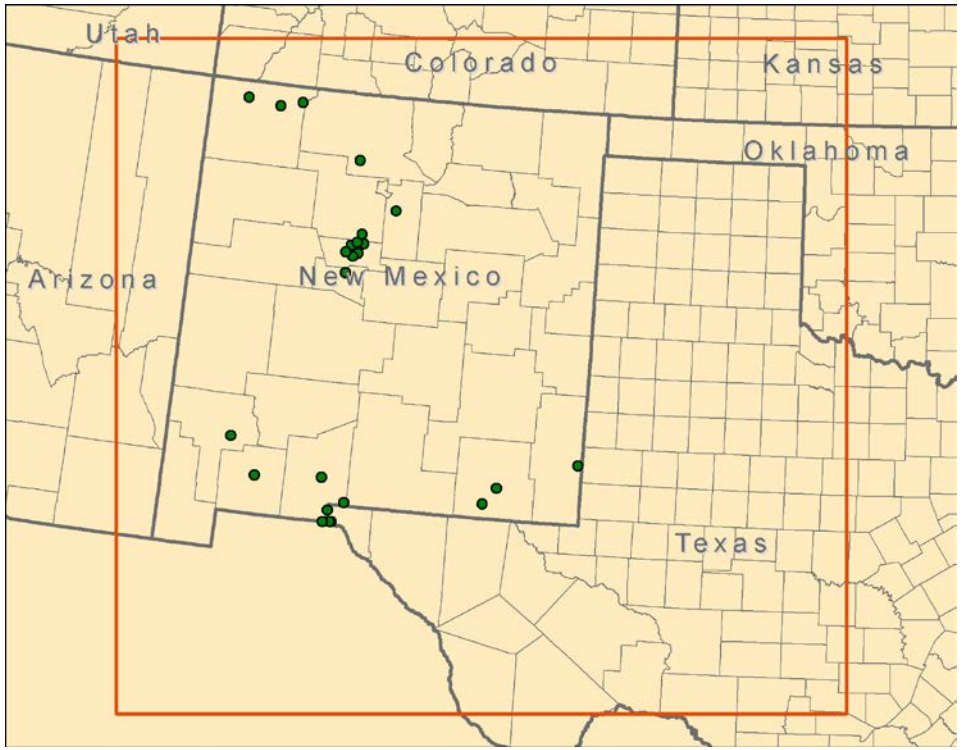
- Episode: May-August 2014
  - 16-day spin-up before first high ozone day in NM
    - 68 ppb on May 17
- 36/12/4-km Modeling Domains
  - 36/12-km domains same as WRAP Regional Haze
  - New 4-km New Mexico domain
- Boundary Conditions (BC) from WRAP 2014 GEOS-Chem
- Four Meteorological Diagnostic Sensitivity tests
  - Selected WRF/NAM with Kv=CMAQ
- WRAP 2014v2 base year emissions
  - EPA NEI2014v2 w/ western state updates
- EPA 2016v1 platform 2023fh emissions for Future Year



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CAMX CONFIGURATION

- Very similar to WRAP CAMx 36/12-km Regional Haze set-up
  - o Addition of 4-km NM Domain



Science Options	CAMx	Comment
Model Codes	CAMx v7.0	Latest version of CAMx made publicly available May 2020 (www.camx.com)
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes buffer cells
4-km grid	245 x 227 cells	New Mexico 4-km domain. Includes buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 ~20 m. Model top at 50 mb (~19 km). Layer collapsing from 35 vertical layers in WRF
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 17, 2014
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain lateral boundaries
Emissions		
Emissions Processing	SMOKE, SMOKE-MOVES2014, MEGAN	WRAP/WAQS 2014v2 emissions and EPA 2023fh for future year
Sub-grid-scale	Plume-in-Grid (PiG)	NOx > threshold
Chemistry		
Gas Phase	CB6r4	(Yarwood et al., 2010)
Meteorological Processor	WRFCAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh dependence
Vertical Diffusion	CMAQ-like Kv	Evaluated YSU Kv scheme
Diffusivity Min	Kv-min = 0.1 to 1.0 m^2/s in lowest 100 m	Urban land use fraction
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)
Wet Deposition	CAMx -specific formulation	rain/snow/graupel
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative(EBI)	EBI fast and accurate solver
Vertical Advection	Implicit scheme ate	Emery et al., (2009a,b; 2011)
Horizontal Advection	Piecewise Parabolic	Colella and Woodward (1984)

NMED Exhibit 21 - 0026

2014 BASE CASE MPE

- Used AMETv1.4 MPE tool
- Model evaluated against EPA AQS Surface Air Quality Data for 2014
- Model performance compared with standard PGM goals and criteria values (Emery et al., 2016)
- “Goals” : statistical value that the best model can be expected to achieve
- “Criteria” : statistical value that majority of models have achieved

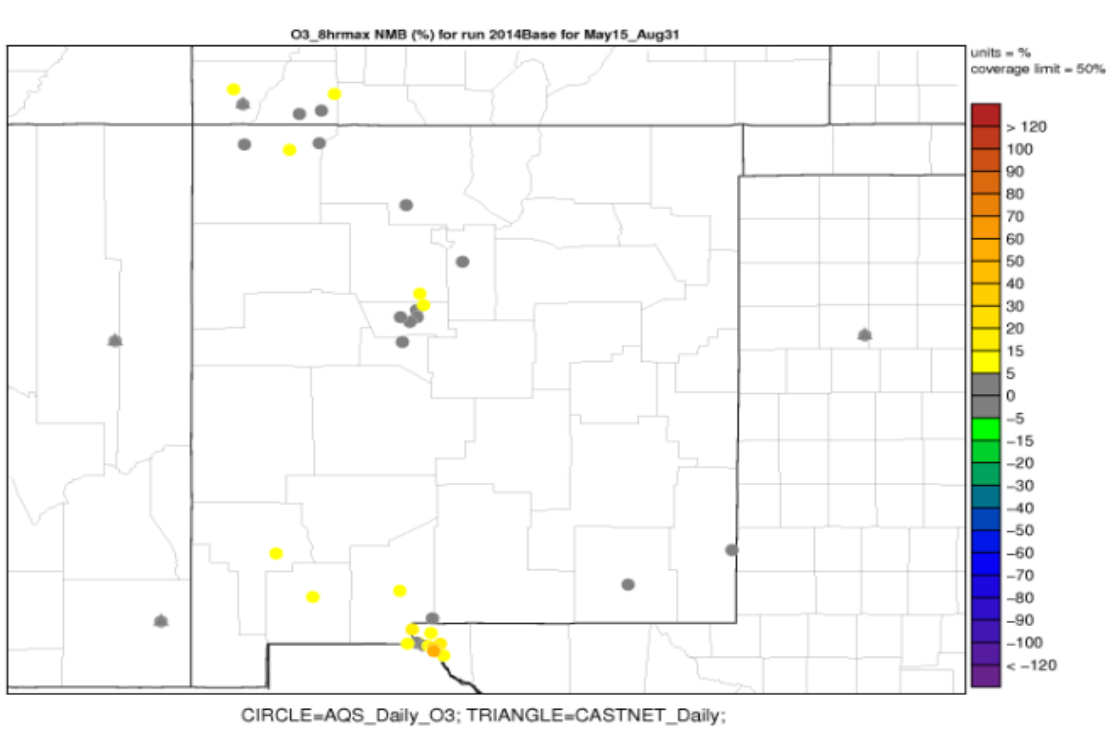
Species	NMB		NME	
	Goal	Criteria	Goal	Criteria
1-hr & MDA8 Ozone	<±5%	<±15%	<15%	<25%

RAMBOLL

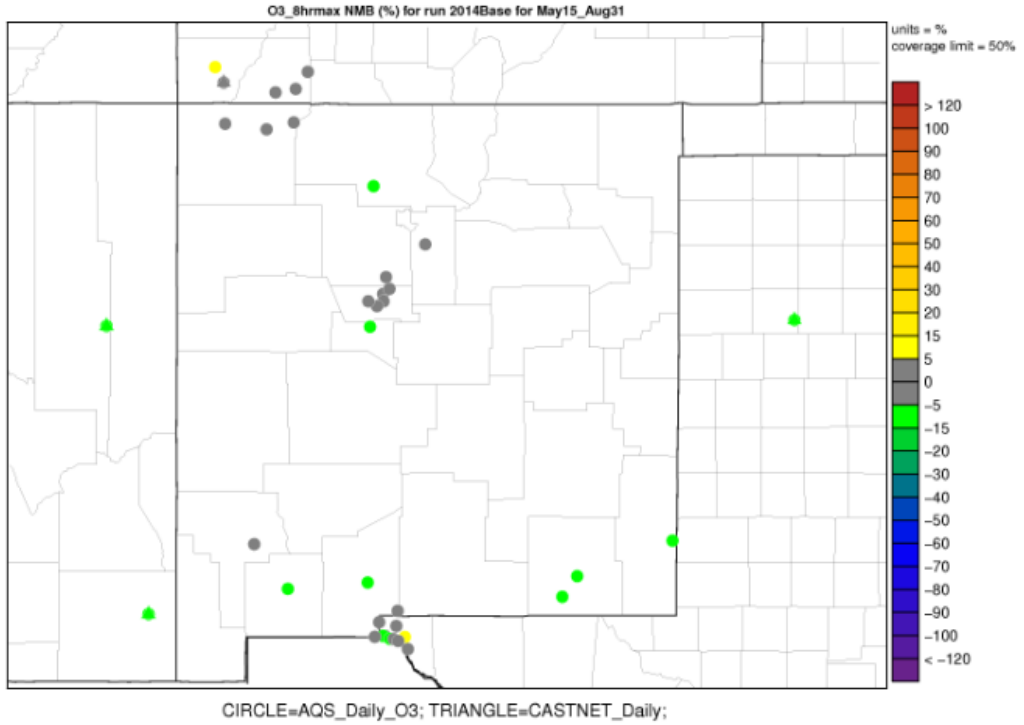
OZONE EVALUATION ACROSS 4KM DOMAIN

- Throughout the domain at most of the sites model is achieving performance goal with NMB <±5%.
- Few remaining sites are within the performance criteria with NMB <±15%, where model is overpredicting lower concentrations and underpredicting higher concentrations.

MDA8 O3 no cut-off



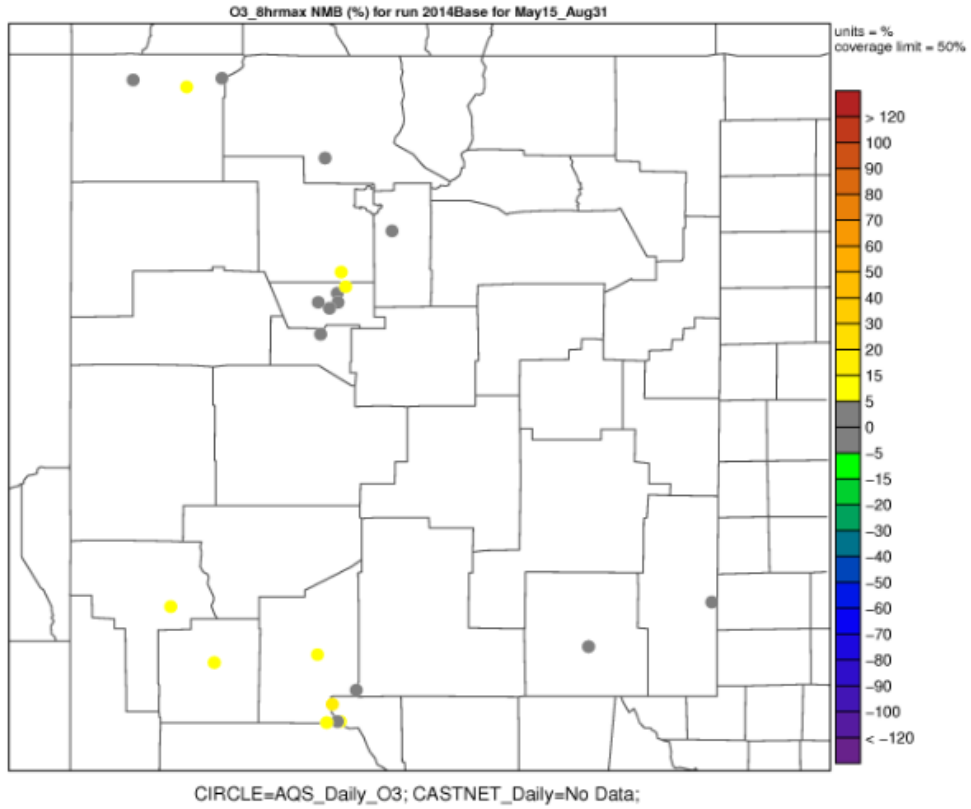
MDA8 O3 with 60 ppb cut-off



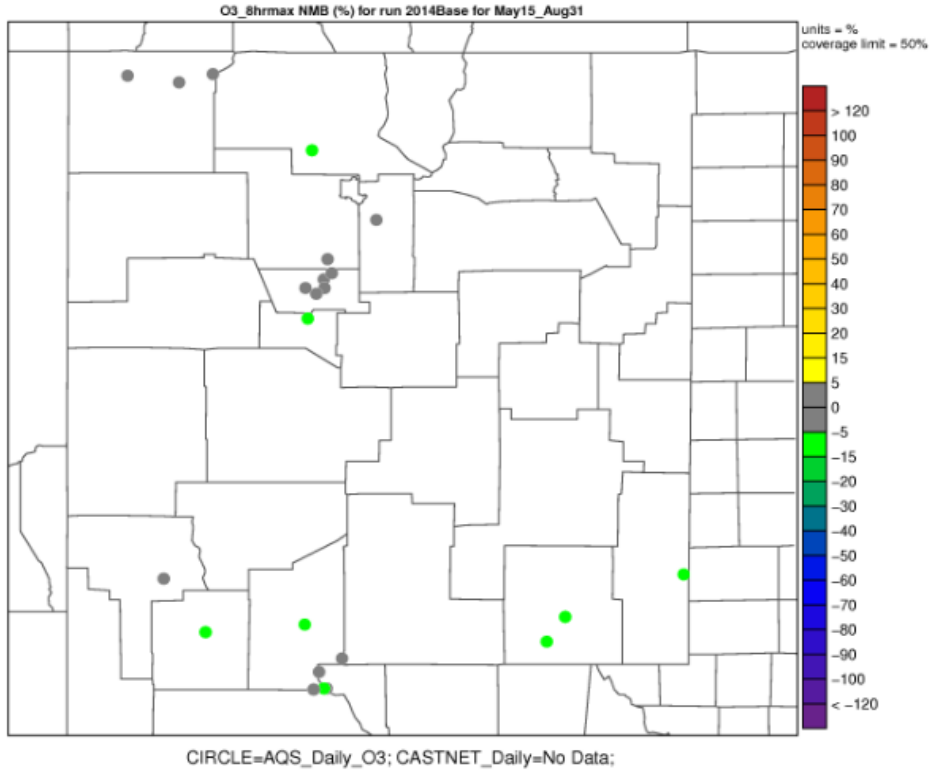
OZONE EVALUATION ACROSS NM DOMAIN

- Overall majority of sites in New Mexico are achieving performance goal (< ±5%) and criteria (< ±15%)
- Most of the southern New Mexico sites are underpredicting MDA8 concentrations higher than 60 ppb

MDA8 O3 no cut-off



MDA8 O3 with 60 ppb cut-off



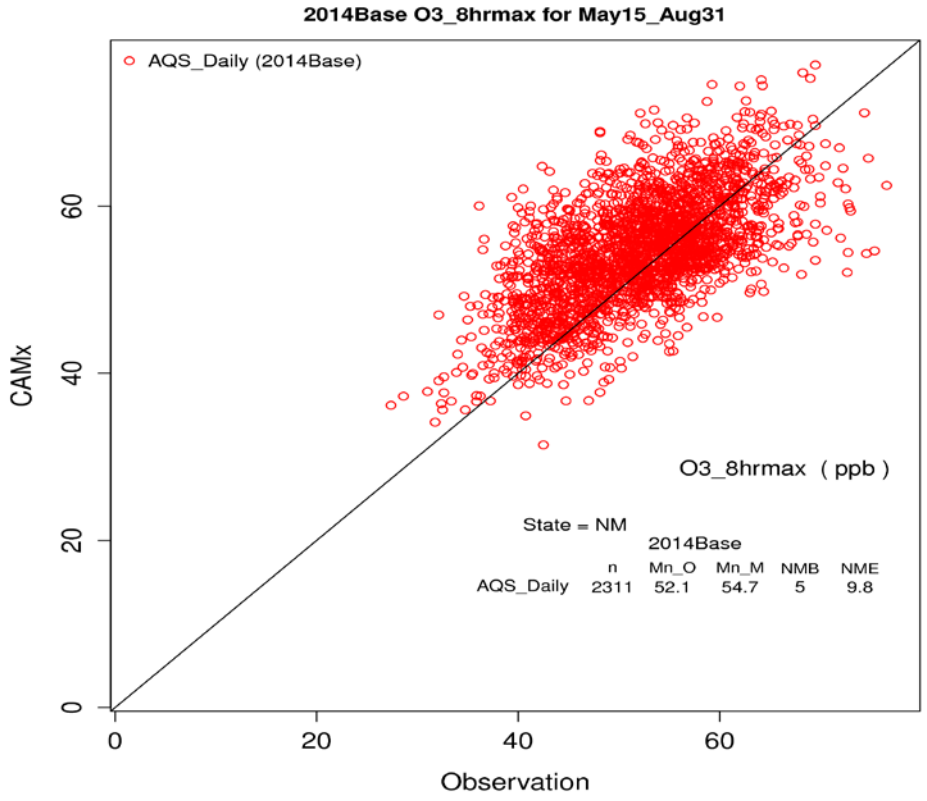
RAM

NMED Exhibit
21 - 0029

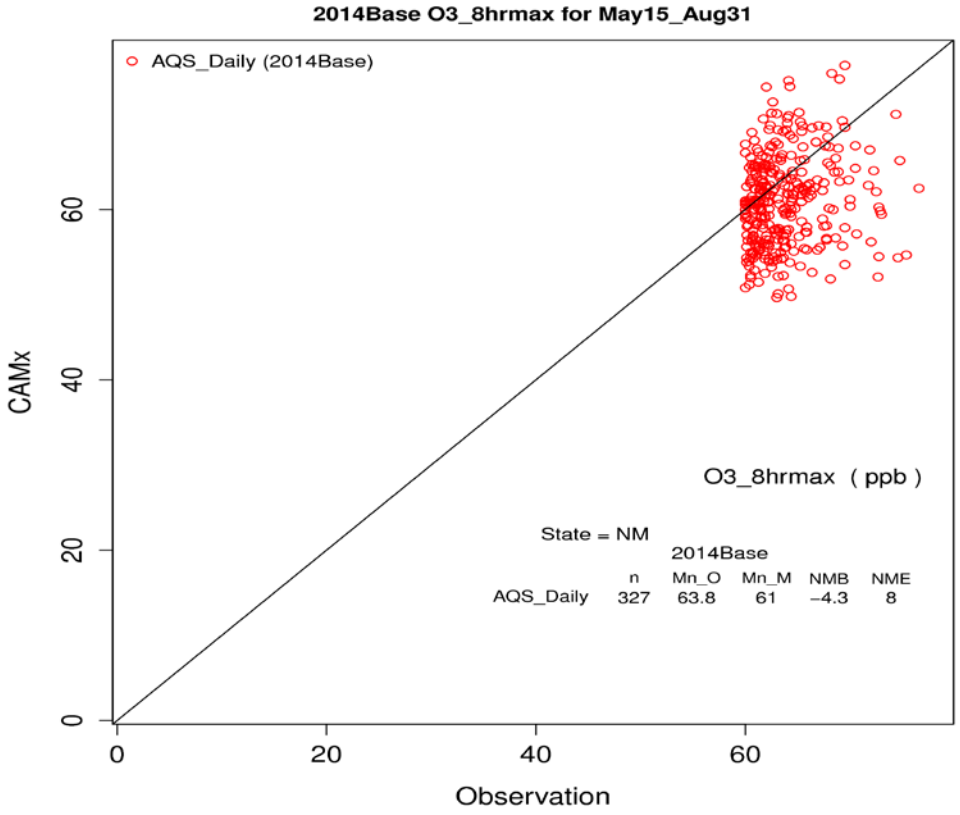
SCATTER PLOTS ACROSS AQS SITES IN NM

Domain wide all AQS sites MPE statistics w/ and w/o 60 ppb cut-off NMB (5.0%, -4.3%) and NME (9.8%, 8.0%) metrics are within performance goals (NMB<±5% and NME<15%).

MDA8 O3 without cut-off



MDA8 O3 with 60 ppb cut-off

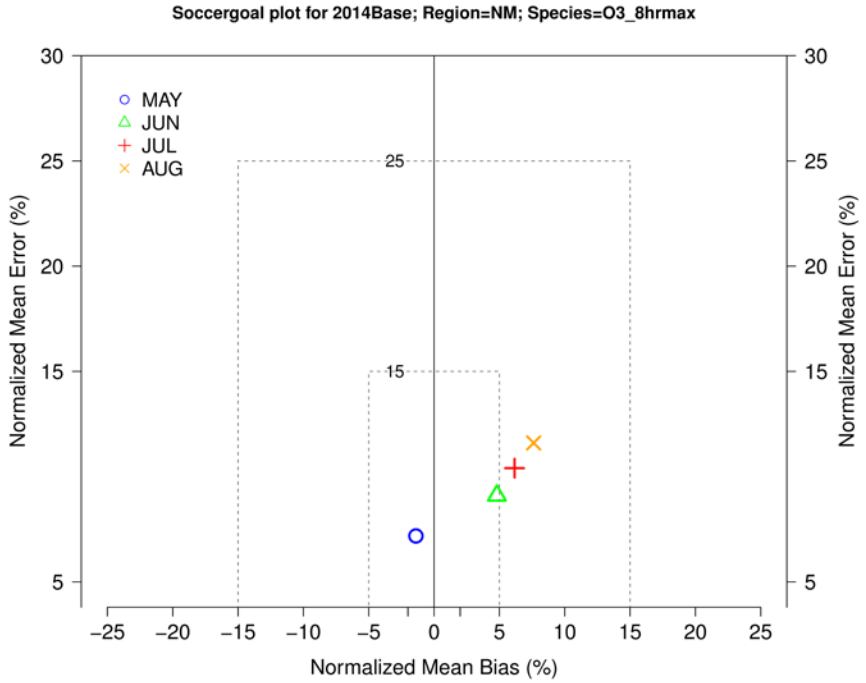


NMED Exhibit
21 - 0030

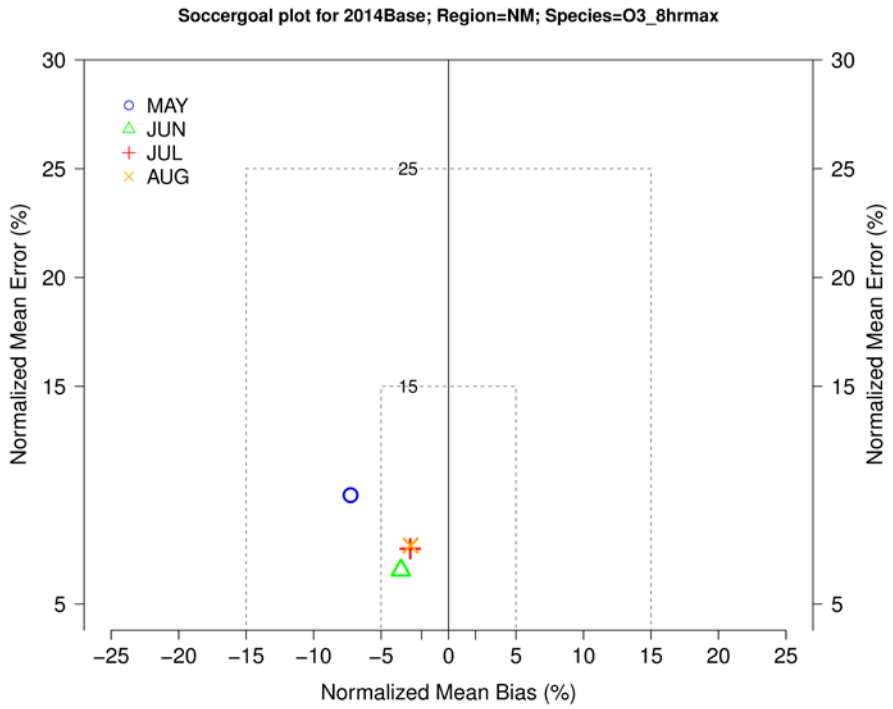
MONTHLY SOCCER PLOT FOR ALL NM AQS SITES

- May only includes only 15 days (i.e., May 15 -30) and has higher underestimation
- Using all ozone data slight overestimation with Jul and Aug bias falling between goal and criteria
- With 60 ppb observed MDA8 ozone cut-off slight underestimation bias that achieved goal in Jun-Jul-Aug
- All monthly average error metrics are within performance goal.

MDA8 O3 without cut-off

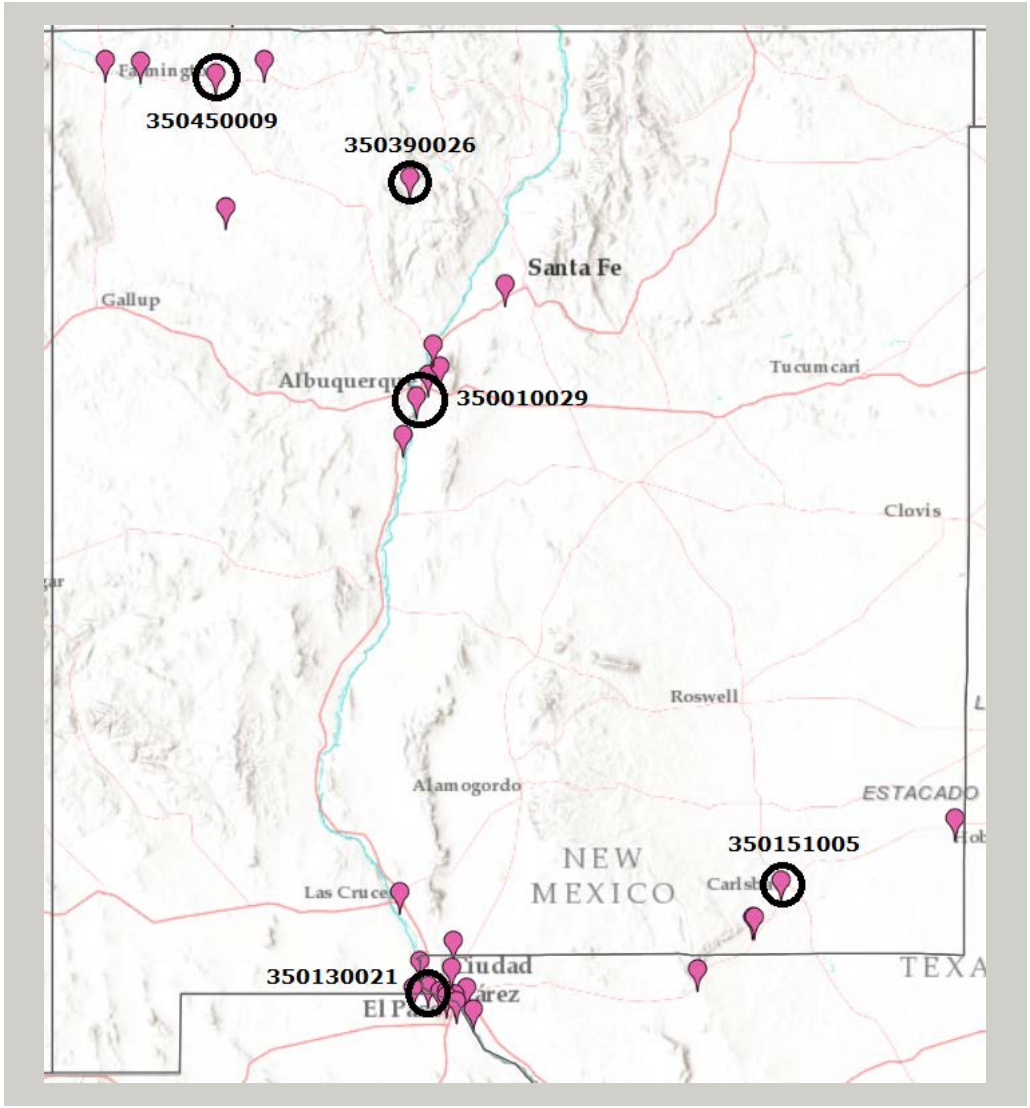


MDA8 O3 with 60 ppb cut-off



NMED Exhibit
21 - 0031

NM Analysis Sites



- Compared MDA8 ozone from 2014Base case modeling with a few selected AQS sites in NM

Site ID	Site Name	County	Latitude	Longitude
350450009	Bloomfield	San_Juan	36.74	-107.98
350390026	Coyote Ranger	Rio_Arriba	36.19	-106.70
350010029	South Valley	Bernalillo	35.02	-106.66
350130021	Desert View	Dona_Ana	31.80	-106.58
350151005	Carlsbad	Eddy	32.38	-104.26

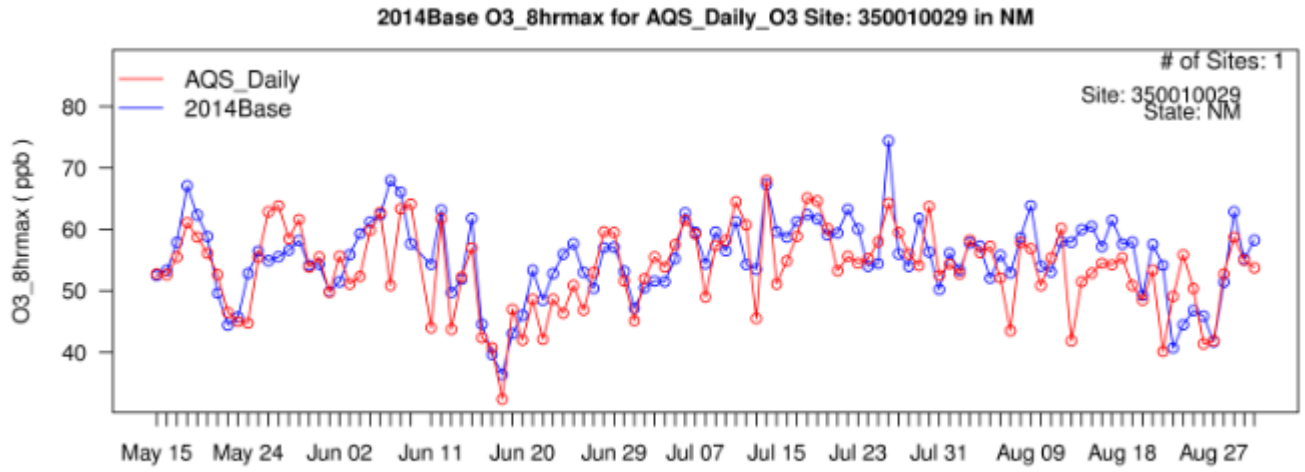
RAMBOLL

OZONE EVALUATION ACROSS NM DOMAIN

350010029

Bernalillo

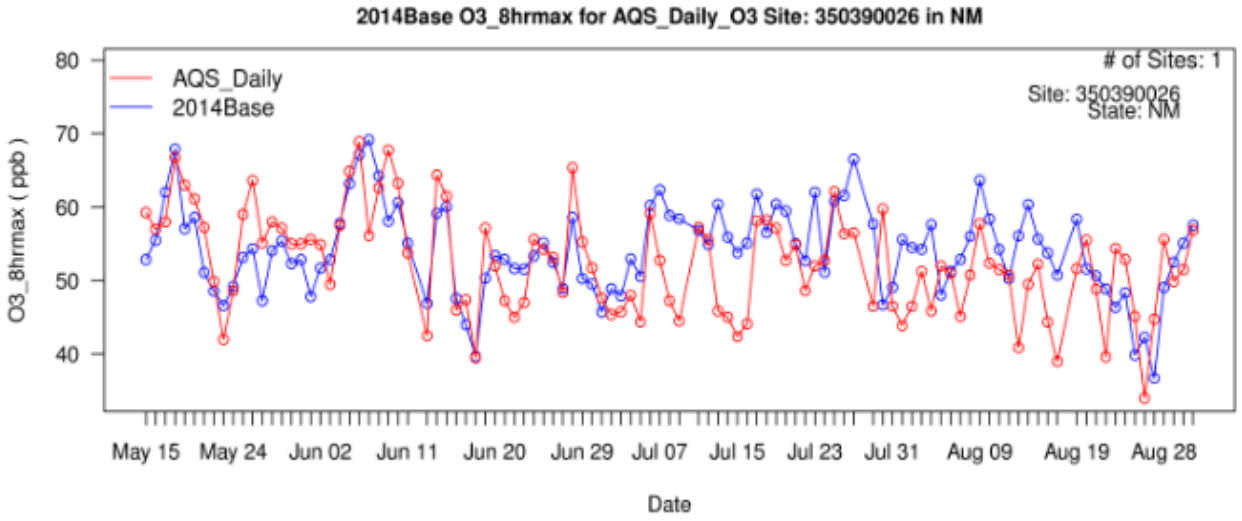
South Valley



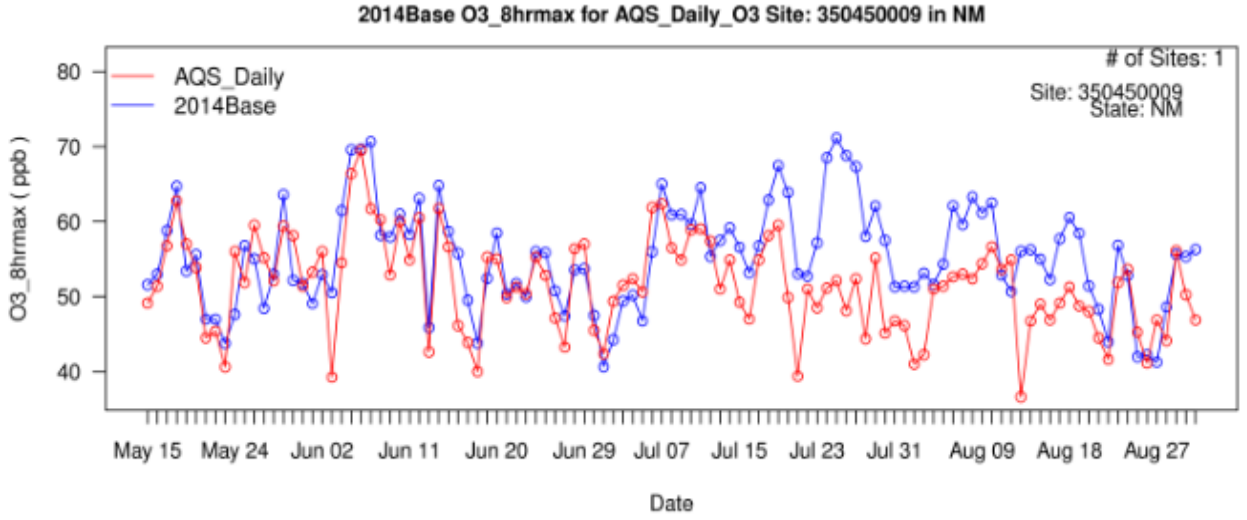
Model performing well at Bernalillo county site.

Model overpredicting lower concentrations at both Rio Arriba and San Juan county sites.

350390026, Rio Arriba, Coyote Ranger



350450009, San Juan, Bloomfield

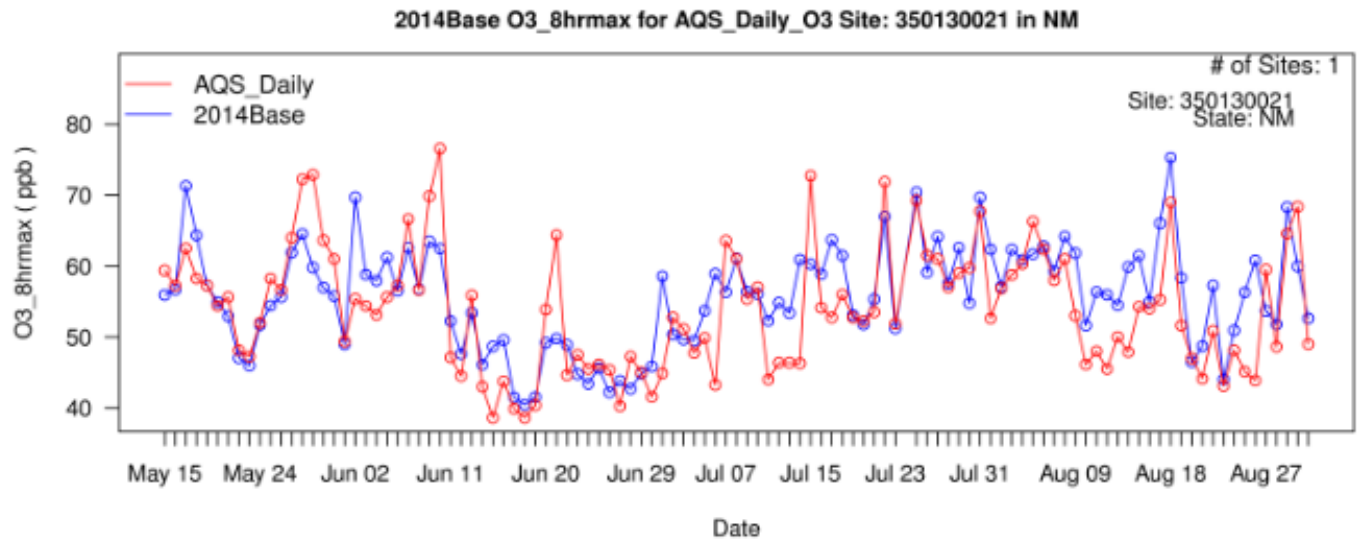


OZONE EVALUATION ACROSS NM DOMAIN

350130021

Dona Ana

Desert View

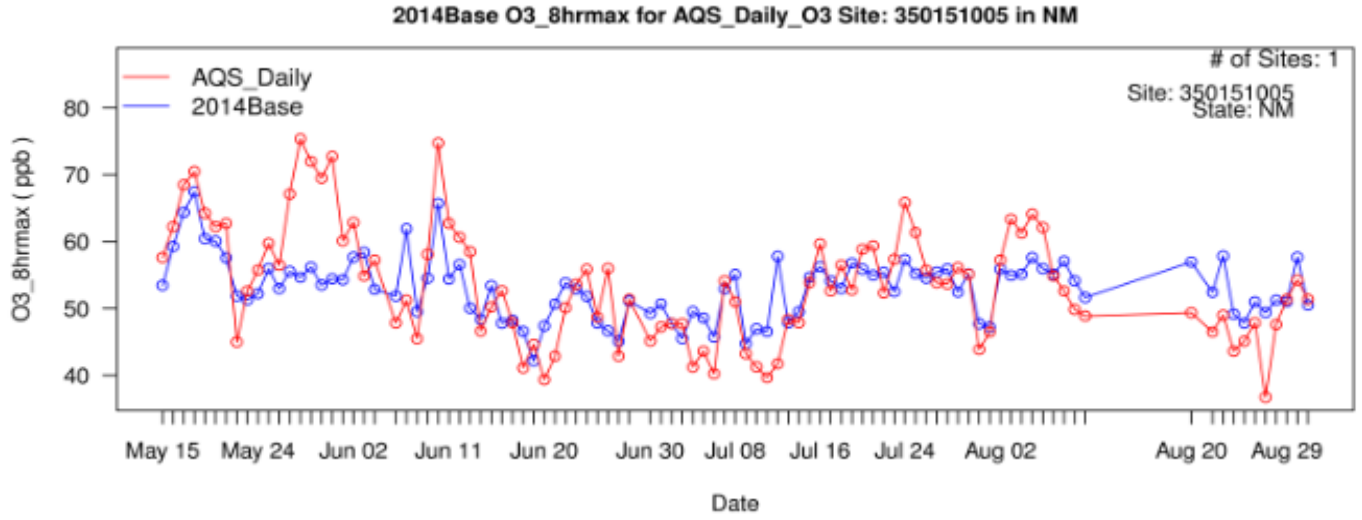


Model able to predict peaks during August month.

350151005

Eddy

Carlsbad



Model underpredicting the May 27-31st exceedance event.

RAMBOLL

SITE SPECIFIC METRICS

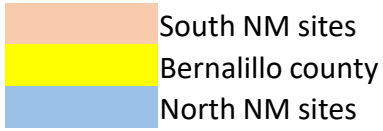
Site ID	Site Names	NMB No Cut-Off	NMB w/ 60 ppb Cut-Off
350010023	Del Norte	1.7	-3.88
350010024	South East Heights	3.1	-2.37
350010029	South Valley	3.1	-2.79
350010032	Westside	1.1	-3.4
350011012	Foot Hills	13.6	1.98
350130008	La Union	17.4	-1.56
350130017	Sunland Park Yard	9.0	-3.55
350130020	Chaparral	4.8	-4.65
350130021	Desert View	3.2	-5.11
350130022	Santa Teresa	8.2	0.14
350130023	Solano	6.1	-6.47
350151005	Carlsbad	-1.1	-12.3
350171003	Chino Copper Smelter	9.1	-0.99
350250008	Hobbs Jefferson	2.1	-9.87
350290003	Deming Airport	6.2	-5.04
350390026	Coyote Ranger District	3.3	-5.43
350431001	Bernalillo	8.1	3.84
350450009	Bloomfield	7.2	2.47
350450018	Navajo Lake	2.2	-0.61
350451005	Sub Station	1.4	3.28
350490021	Santa Fe Airport	3.8	-1.69
350610008	Los Lunas	0.8	-6.53

	Below Performance Goal
	Between Performance Goal and Criteria
	Exceeds Performance Criteria

RAMBOLL

NEW MEXICO REGIONAL EVALUATION REGIONS

Site ID	Site Name	County	Lat	Lon
350130022	Santa Teresa	Dona Ana	31.79	-106.68
350130017	Sunland Park Yard	Dona Ana	31.80	-106.56
350130021	Desert View	Dona Ana	31.80	-106.58
350130008	La Union	Dona Ana	31.93	-106.63
350130020	Chaparral	Dona Ana	32.04	-106.41
350290003	Deming Airport	Luna	32.26	-107.72
350130023	Solano	Dona Ana	32.32	-106.77
350151005	Carlsbad	Eddy	32.38	-104.26
350171003	Chino Copper Smelter	Grant	32.69	-108.13
350250008	Hobbs Jefferson	Lea	32.73	-103.12
350610008	Los Lunas	Valencia	34.81	-106.74
350010029	South Valley	Bernalillo	35.02	-106.66
350010024	South East Heights	Bernalillo	35.06	-106.58
350010032	Westside	Bernalillo	35.06	-106.76
350010023	Del Norte	Bernalillo	35.13	-106.59
350011012	Foot Hills	Bernalillo	35.19	-106.51
350431001	Bernalillo	Sandoval	35.30	-106.55
350490021	Santa Fe Airport	Santa Fe	35.62	-106.08
350390026	Coyote Ranger District	Rio Arriba	36.19	-106.70
350450009	Bloomfield	San Juan	36.74	-107.98
350451005	Sub Station	San Juan	36.80	-108.47
350450018	Navajo Lake	San Juan	36.81	-107.65

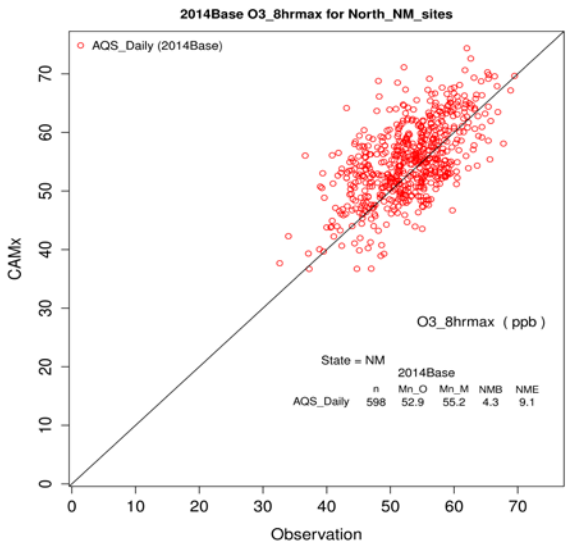


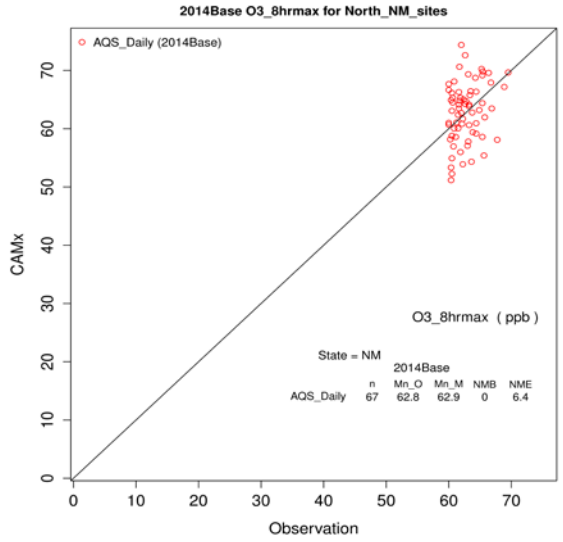
	No Cut-Off		With Cut-Off	
Region	NMB(%)	NME(%)	NMB(%)	NME(%)
North NM	4.3	9.1	0	6.4
Bernalillo	4.3	9.4	-2.8	7.1
South NM	5.8	10.5	-6.1	8.5

RAMBOLL

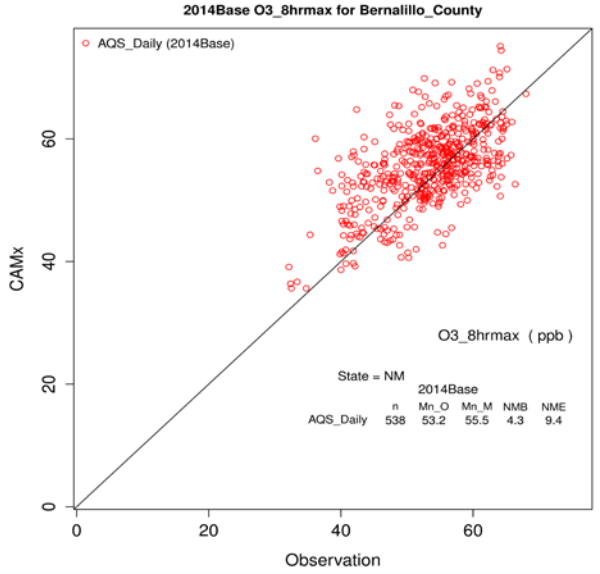
REGION BASED SCATTER PLOTS

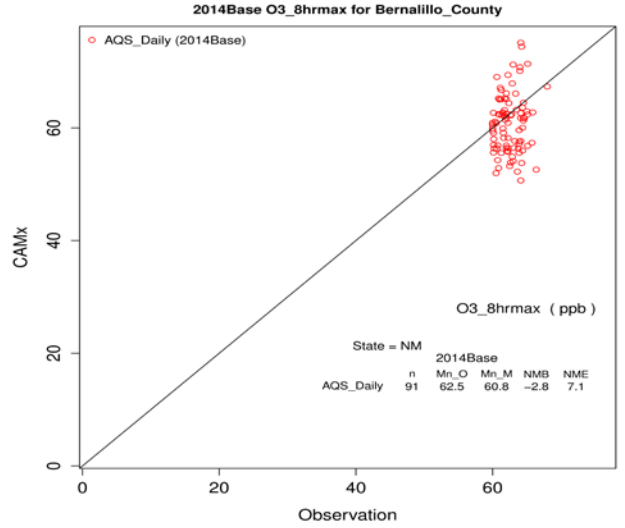
North NM



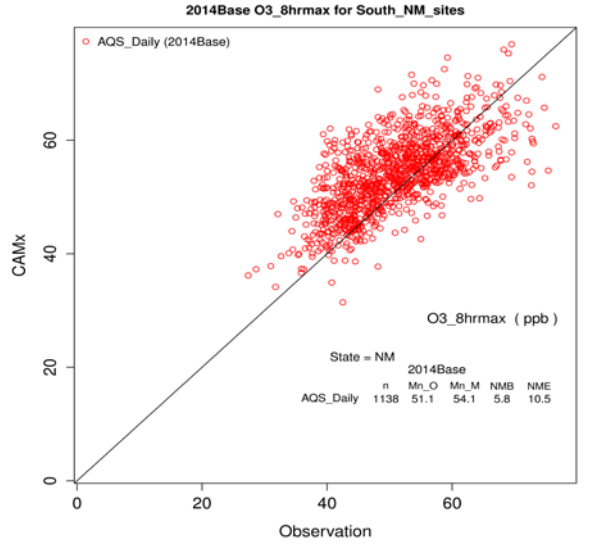


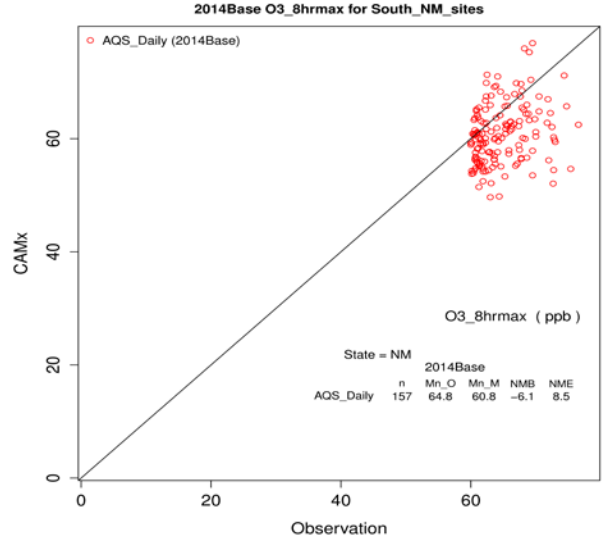
Bernalillo





South NM





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NMED Exhibit
21 - 0037

MPE FOR OZONE DESIGN VALUE PROJECTION

- EPA-recommended approach for making future year ozone Design Value (DV) projections uses the PGM base year top 10 highest MDA8 ozone concentrations to develop Relative Response Factors (RRF)
- The RRF is applied to the measured base year (BY) ozone design value (DVb) to projected a future year (FY) ozone design value (DVf)

$$RRF = \sum Model_{FY} / \sum Model_{BY}$$

$$DVf = DVb \times RRF$$

- The ozone model performance for the 10 highest modeled base year MDA8 ozone is therefore important
  - An alternative projection approach to the EPA-default is to use the top 10 highest modeled base year MDA8 ozone that meet a MPE requirement (e.g., within ±10%)

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EVALUATION FOR TOP 10 HIGHEST MODELED MDA8 OZONE

Desert View	Obs	Prd	Bias	%
8/18/2014	69.0	75.3	6.3	9.1%
5/17/2014	62.5	71.3	8.8	14.1%
7/25/2014	69.3	70.4	1.2	1.7%
6/2/2014	55.4	69.7	14.3	25.8%
7/31/2014	67.7	69.7	2.0	2.9%
8/29/2014	64.6	68.3	3.7	5.8%
7/22/2014	71.9	67.0	-4.9	-6.8%
8/17/2014	55.3	66.0	10.8	19.5%
5/28/2014	72.3	64.5	-7.7	-10.7%
5/18/2014	58.3	64.3	6.1	10.4%
8/8/2014	61.0	64.2	3.2	5.2%
7/27/2014	61.0	64.1	3.1	5.2%
7/17/2014	52.8	63.7	10.9	20.7%
6/9/2014	69.9	63.5	-6.4	-9.2%
8/6/2014	62.4	62.8	0.4	0.7%
7/29/2014	59.0	62.6	3.6	6.1%
6/7/2014	66.6	62.6	-4.0	-6.1%
6/10/2014	76.6	62.5	-14.1	-18.4%
8/1/2014	52.6	62.4	9.7	18.5%
8/3/2014	58.8	62.3	3.6	6.1%

Carlsbad	Obs	Prd	Bias	%
5/18/2014	70.5	67.5	-3.0	-4.3%
6/10/2014	74.8	65.7	-9.0	-12.1%
5/17/2014	68.5	64.4	-4.1	-6.0%
6/7/2014	51.3	61.9	10.7	20.8%
5/19/2014	64.3	60.5	-3.8	-5.9%
5/20/2014	62.3	60.1	-2.2	-3.5%
5/16/2014	62.3	59.3	-3.0	-4.8%
6/3/2014	54.9	58.4	3.5	6.5%
8/23/2014	49.0	57.9	8.9	18.1%
7/12/2014	41.8	57.8	16.1	38.5%
6/2/2014	62.9	57.7	-5.2	-8.3%
8/30/2014	54.3	57.7	3.4	6.3%
8/5/2014	64.1	57.6	-6.5	-10.1%
5/21/2014	62.8	57.6	-5.2	-8.2%
7/24/2014	65.9	57.3	-8.5	-13.0%
8/8/2014	52.6	57.1	4.5	8.5%
8/20/2014	49.4	57.0	7.6	15.4%
7/19/2014	52.8	56.8	4.1	7.7%
6/12/2014	60.7	56.6	-4.1	-6.7%
7/16/2014	59.7	56.3	-3.4	-5.7%

Bloomfield	Obs	Prd	Bias	%
7/25/2014	52.1	71.1	19.0	36.4%
6/7/2014	61.7	70.6	8.9	14.4%
6/6/2014	69.5	69.7	0.2	0.2%
6/5/2014	66.4	69.6	3.2	4.8%
7/26/2014	48.1	68.8	20.7	42.9%
7/24/2014	51.1	68.5	17.4	34.0%
7/19/2014	59.5	67.5	8.0	13.4%
7/27/2014	52.4	67.3	14.9	28.5%
7/7/2014	62.4	65.0	2.6	4.2%
6/14/2014	61.8	64.8	3.0	4.9%
5/18/2014	62.8	64.7	2.0	3.1%
7/11/2014	59.0	64.5	5.5	9.3%
7/20/2014	49.9	63.9	14.0	28.1%
5/29/2014	59.4	63.6	4.2	7.1%
8/8/2014	52.4	63.3	10.9	20.8%
6/12/2014	60.5	63.1	2.6	4.3%
7/18/2014	58.1	62.9	4.7	8.2%
8/10/2014	56.6	62.5	5.9	10.4%
8/6/2014	52.6	62.1	9.5	18.0%
7/29/2014	55.1	62.1	6.9	12.6%

Yellow = 20 highest observed MDA8 ozone (dark yellow top 10)
Red = bias greater than ±10%
Blue = Added model days using ±10% MPE criteria

RAMBOLL

CONCLUSIONS CAMX 2015 36/12/4-KM BASE CASE MPE

- Across all sites in New Mexico ozone performance meets the bias and error Performance Goals
  - Across all observations there is a slight overestimation but still meet bias goal (≤±5%)
  - Using just observed ozone above a 60 ppb cut-off, the goal is still met with an underestimation bias
- The northern NM and Bernalillo County subregions meet the ozone goals , but southern NM subregion bias falls between the performance goal and criterion
- Example evaluation for 10 highest modeled MDA8 ozone used to make ozone projections using EPA default approach found good overlap with observed highest MDA8 ozone:
  - At Desert View (Dona Ana County) 7 of top 10 modeled days were top 20 observed, 5 top 10 observed
  - At Carlsbad (Eddy County) 6 of top 10 modeled days were top 20 observed; 4 top 10 observed
  - At Bloomfield (San Juan County) 6 of top 10 modeled days were top 20 observed; 5 top 10 observed
- Although there were some periods of questionable model performance (e.g., late July in San Juan County and late May at Carlsbad), overall the model performance was quite reasonable and mostly achieved the performance goals and always achieved the performance criteria

RAMBOLL

CURRENT STATUS AND NEXT STEPS

RAMBOLL

CURRENT STATUS / NEXT STEPS

- Close to starting Task 6.1 CAMx 2023 Base Case Simulation
  - NMED asked us to pause the 2023 modeling on August 26, 2020

Original NM OAI Modeling Study Work Plan Webinar Schedule

Webinar Number	Webinar Topics by Task	Date	Status
1.	1. Modeling Protocol and Work Plan 2.1 Evaluate Existing Met 4.1 Recommend 2014 and 2023 Emissions 4.2.1 Recommend 2014 & 2023 Mobile Source Emissions	May 2020	• Done • Done • Done • Done
2.	2.2 Additional Met Modeling 3.1 Evaluate BC Data 4.1 Summary of 2014 and 2023 Emissions	Jun 2020	• Done • Done • Done
3.	4.2.1 Summary of 2014 and 2023 Mobile Source Emissions 4.3 2014 Natural Emissions Results (e.g., Biogenic & LNOx)	Jul 2020	• Done • Done
4.	4.2.3 2014 & 2023 SMOKE-MOVES Results 4-km NM Domain 4.4 2014 & 2023 SMOKE Emissions Modeling Results 5 CAMx 2014 Base Case and Model Evaluation	Aug 2020	• Done • 12-km SMK-MVS • MPE Report
5.	4.5 FY Emissions Strategy Results 5. 2014 CAMx Base Case Modeling and MPE	Sep 2020	• Need data NMED • Report early Sep
6.	6.1 2023 CAMx Modeling Results 6.2 2023 Ozone Design Value Projections	Oct 2020	• September? • September?
7.	6.3 2023 Control Strategy Results 6.4 2023 Source Apportionment Modeling Results	Nov 2020	• Need data NMED • Not Done

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NEXT STEPS

- NMED issues a stop work on 2023 modeling; redirect effort to 2028 modeling
- NMED requests WESTAR/Ramboll provide scope-of-work, cost estimate and schedule for three new tasks:
  - Develop 2028 base case O&G emissions for New Mexico
  - Develop CAMx 36/12/4-km 2028 emissions using WRAP 2028OTBa2 database with updated 2028 O&G emissions for New Mexico and run CAMx 2028 36/12/4-km base case simulation
  - Receive 2028 New Mexico O&G control strategy emissions from NMED and conduct CAMx 2028 36/12/4-km NM O&G control strategy simulation and provide ozone results to NMED

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NEW MEXICO OZONE ATTAINMENT INITIATIVE

2014 and 2028 Emissions Development

Tejas Shah, Chao-Jung Chien, Sai Sreedhar Varada, John Grant, Marco Rodriguez, and Ralph Morris, Ramboll

Tom Moore and Mary Uhl, WESTAR

NM OAI Study Webinar

February 1, 2021

RAMBOLL Bright ideas. Sustainable change.

DEVELOPMENT OF 2028 MODELING EMISSIONS

01 Natural Emissions

02 Anthropogenic Emission Data Sources

03 SMOKE Emissions Modeling

04 Summary of 2014 and 2028 Emissions

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NATURAL EMISSIONS

Remained the same between 2014 and 2028



Fire

- Agricultural
- Prescribed burn
- Wildfire
- WRAP Smoke and Fire Workgroup inventory for 2014v2

CO, NO_x, VOC, SO_2, PM



Biogenic

- Soil NOx
- BVOC
- MEGAN v3.1
- BEIS v3.7 biogenic emissions model

VOC, NO_x



Oceanic

- Sea-salt
- Dimethyl sulfide (DMS)
- OCEANIC emissions processor

SO_2, PM

Wind-blown dust

- Wind stress initiating the saltation process
- CAMx windblown dust (WBD) processor

PM



Lightning

- Flash rate and NO yield per flash
- Lightning NOx emissions processor with 2014 WRF

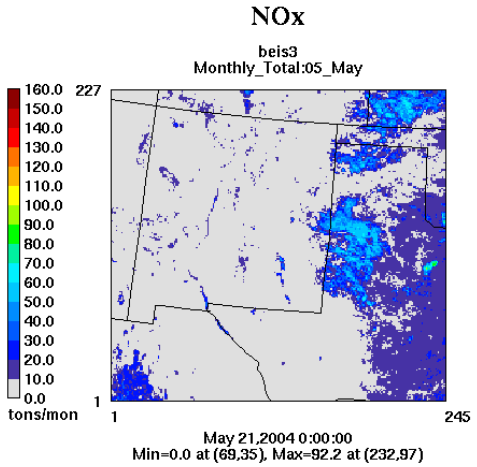
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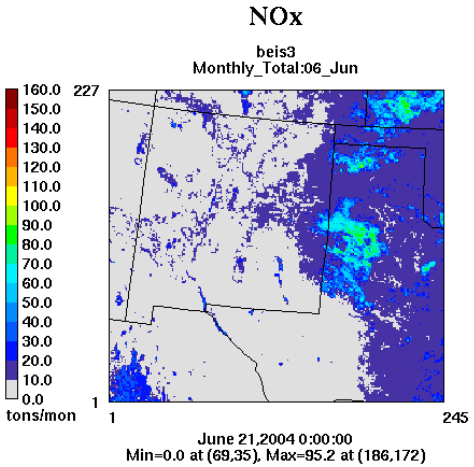
RAMBOLL

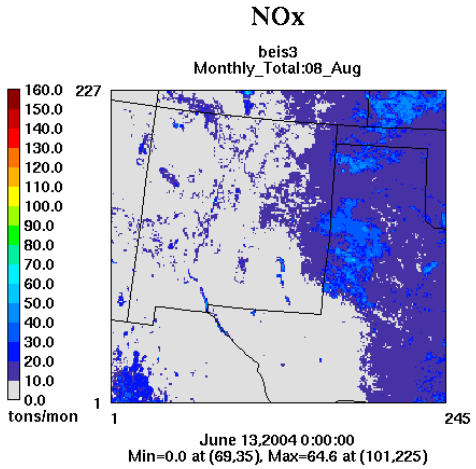
NMED Exhibit 22 - 0003

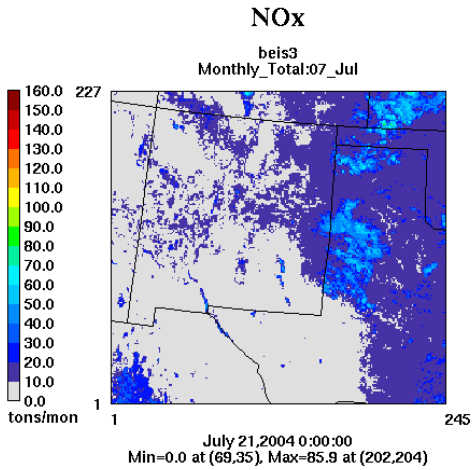
BEIS V3.7 EMISSIONS

Tons/month		MEGAN	BEIS3	Abs Diff (BEIS3-MEGAN)	Ratio (BEIS3/MEGAN)
May	NOX	35,050	10,602	-24,448	0.30
	VOC	128,323	159,809	31,486	1.25
Jun	NOX	42,445	13,134	-29,311	0.31
	VOC	267,055	256,379	-10,676	0.96
Jul	NOX	51,639	12,838	-38,801	0.25
	VOC	317,697	251,562	-66,135	0.79
Aug	NOX	41,002	11,923	-29,079	0.29
	VOC	354,570	216,032	-138,538	0.61

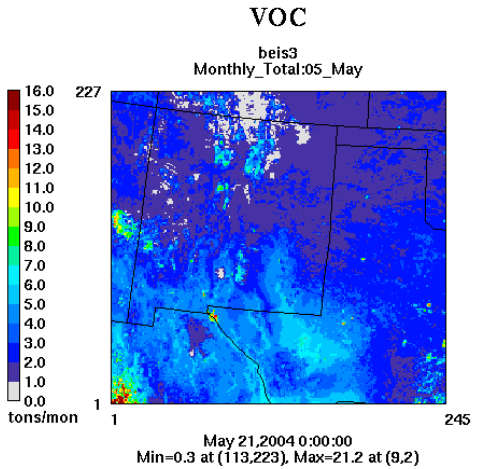


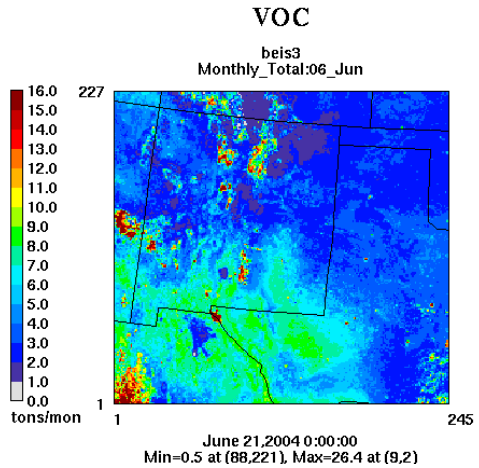


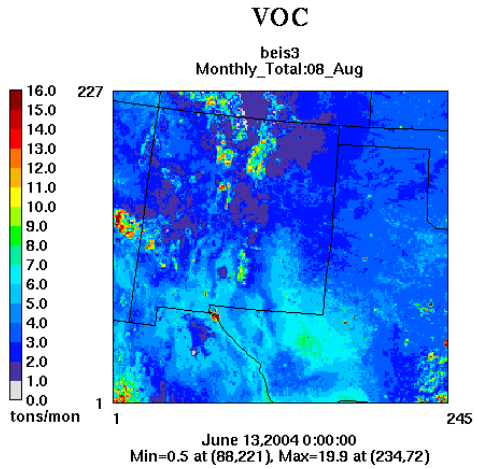


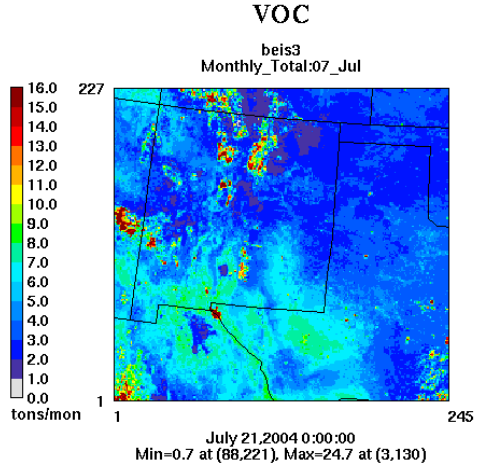


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NMED Exhibit
22 - 0004

ANTHRO EMISSION DATA SOURCES

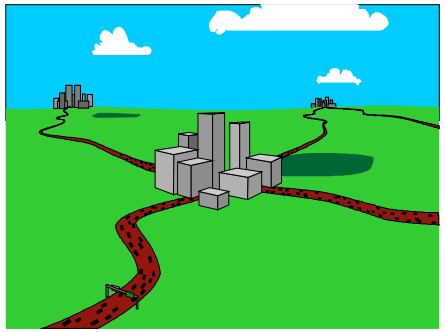
- 2014 anthropogenic emissions from 2014v2 scenario of the WRAP/WAQS RH modeling
  - Onroad emissions generated using SMOKE-MOVES processing for the 4-km domain
  - O&G emissions based on state-of-the-science WRAP OGWG emission estimates
  - NMED found a generator engine missing in 2014v2 inventory (94 tpy NOx)
  - Consistent emissions data between the Regional Haze and OAI studies
- 2028 anthropogenic emissions based on the WRAP/WAQS 2028 on-the-books scenario (2028OTBa2 only with actual 2014 fires)
  - O&G emissions based on inventory developed by Ramboll (presented in Jan 11th meeting)
  - Onroad emissions created using SMOKE-MOVES
  - Fixed double counting of NM sources
  - Updated San Juan Generating Station (NOx 7,391 TPY) and added Lordsburg Generating Station
  - Updated three O&G sources: Chaco Gas Plant (NOx 2,053 tpy), Carlsbad CS, and Mountainair CS (NOx 645 tpy)

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NMED Exhibit 22 - 0005

EMISSION PROCESSING FOR AQM

Start With

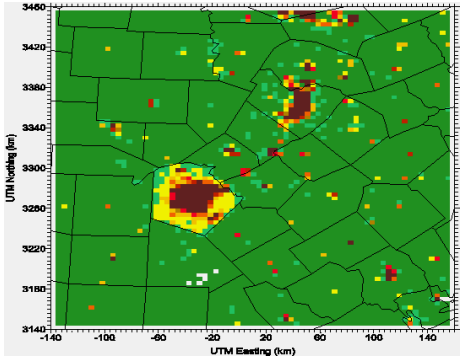


Annual Estimates (tons/year)

County Totals

Criteria Pollutants (NOx, CO, VOC)

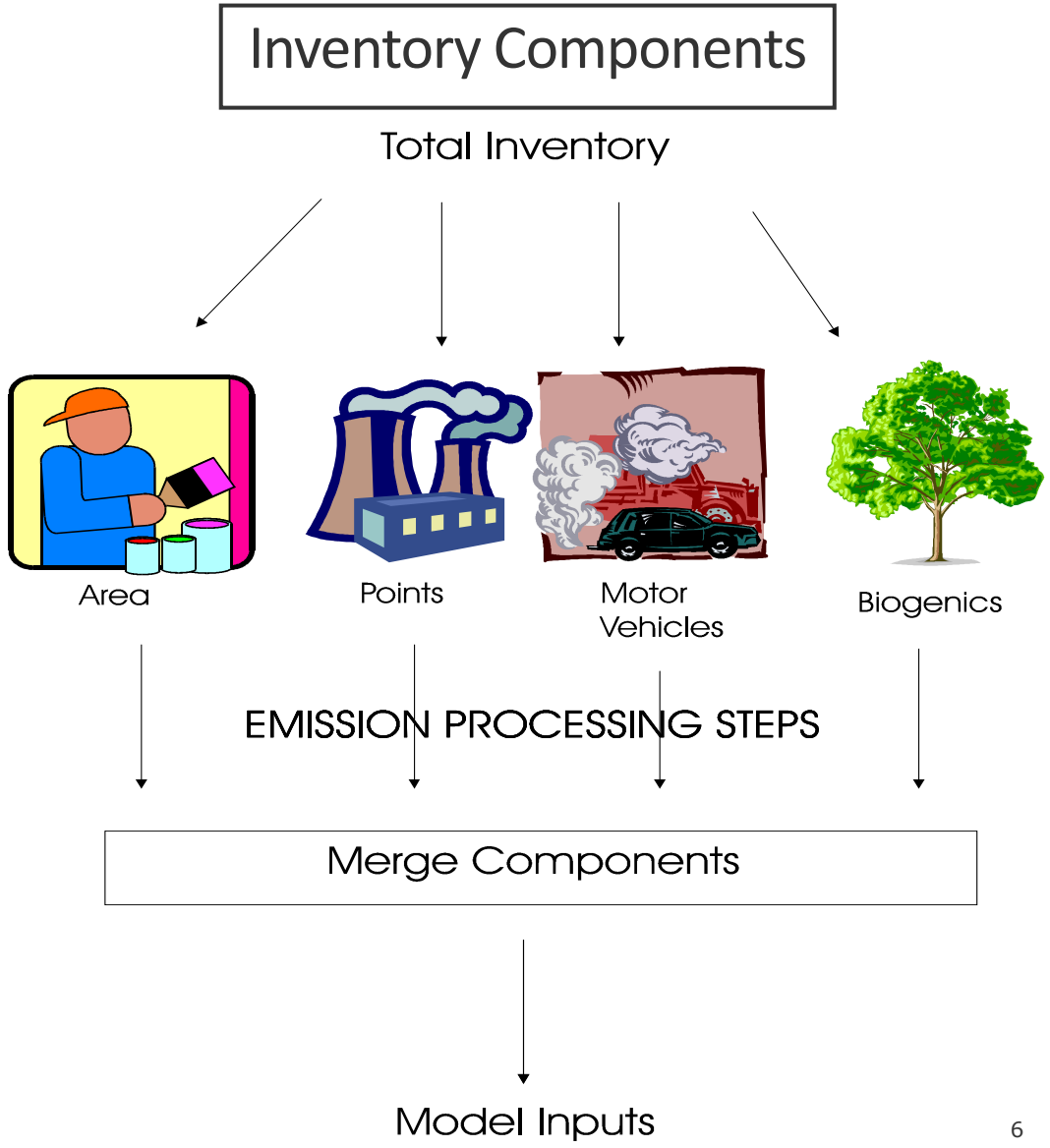
Model Ready



Hourly

Gridded

Speciated

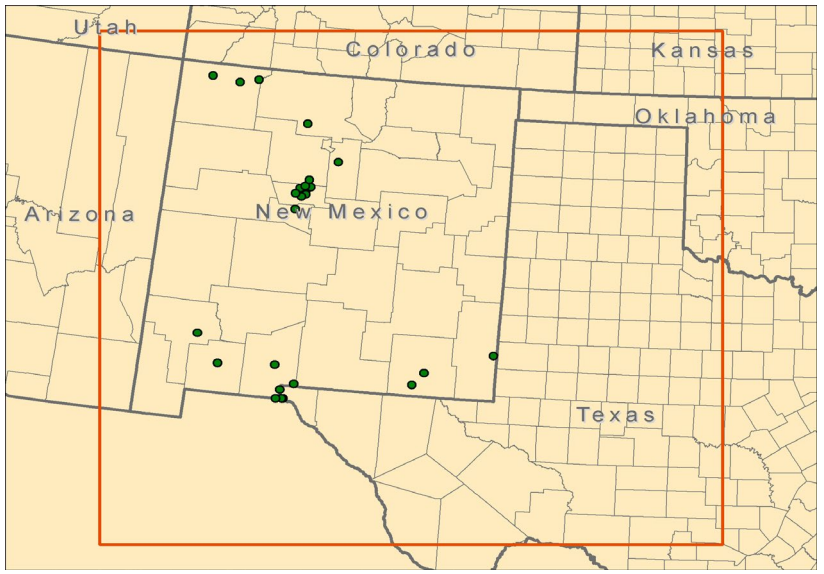


NMED Exhibit 22 - 0006

SMOKE PROCESSING SECTORS

US-Anthro

Sector	Description
afdust_adj	- Area fugitive dust
ag	- Agricultural ammonia sources
nonpt	- Other nonpoint sources
np_oilgas_wrap	- Non-point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)
np_oilgas	- Non-point Oil and Gas
nonroad	- Non-road mobile
rail	- Locomotive
onroad	- On-road mobile
ptegu	- EGU point sources
ptnonipm	- Non-EGU point sources
pt_oilgas_wrap	- Point Oil and Gas for 7 WRAP States (CO, MT, NM, ND, SD, UT, WY)
pt_oilgas_wrap	- Point Oil and Gas
rwc	- Residential Wood Combustion



New Mexico 4-km Domain

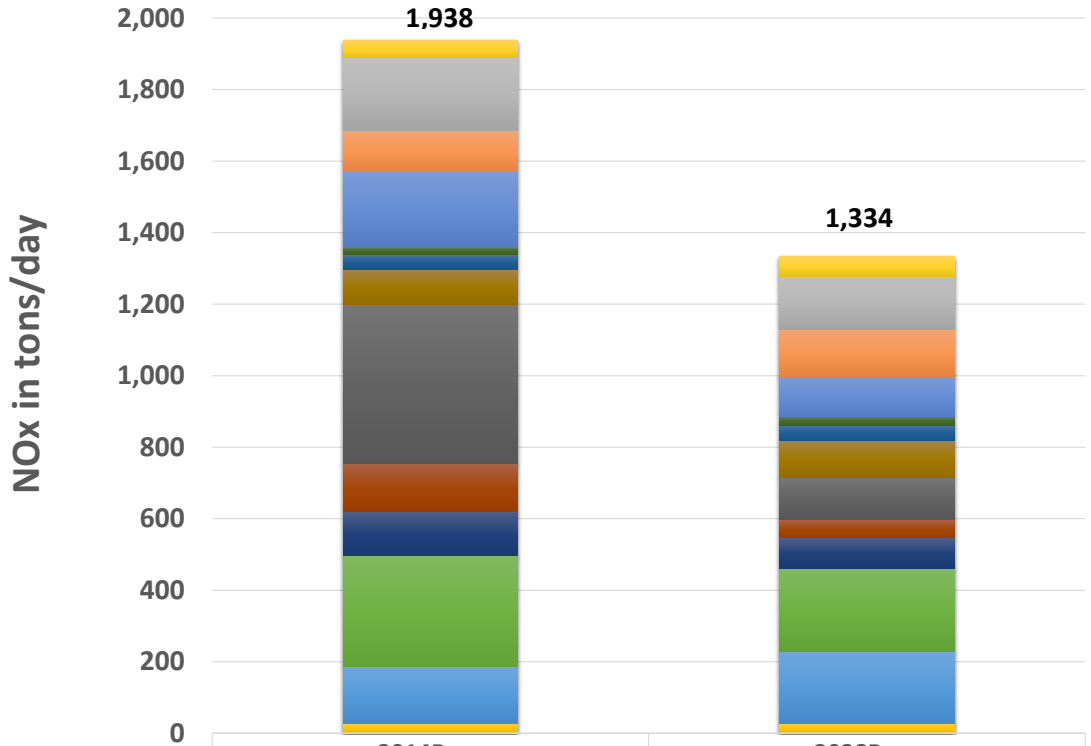
Non-US Anthro & Natural

Sector	Description
onroad_mex	- Mexico onroad mobile
othar	- Mexico area
othpt	- Mexico point sources
MEGAN/BEIS	- Biogenic
LtNOx	- Lightning Nox
AG fire	- Ag Fire
RX fire	- Prescribed Fire
WF fire	- Wild Fire
Ptfire_othna	- Mexico fire
WBD	- Windblown Dust

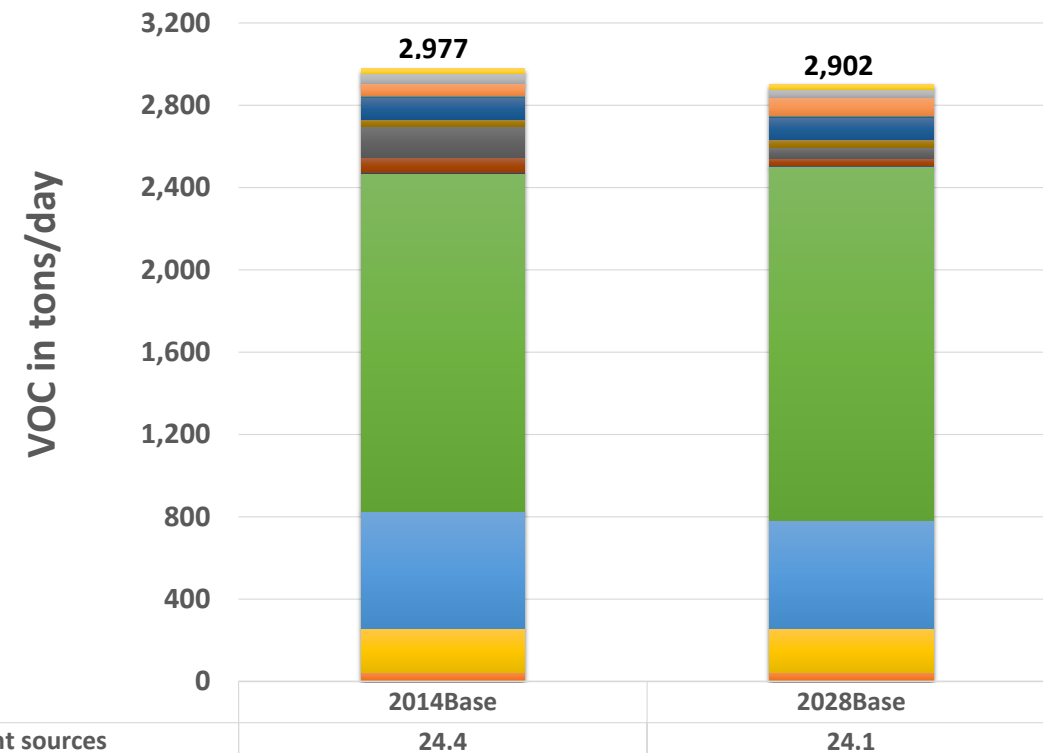
RAMBOLL

NMED Exhibit 22 - 0007

NEW MEXICO 4-KM EMISSIONS COMPARISON:



	2014Base	2028Base
Non-EGU point sources	47.5	55.9
Point O&G other states	205.2	150.3
Point O&G for 7 WRAP States	114.7	130.4
EGU	210.6	112.9
Mexico point sources	20.2	23.1
Mexico area	42.2	42.0
Mexico onroad mobile	98.4	104.0
Onroad-mobile	444.5	117.6
Non-road mobile	133.4	50.4
Rail	122.7	87.1
Non-point O&G other states	311.7	231.7
Non-point O&G for 7 WRAP States	157.8	200.4
Other nonpoint sources	28.5	28.5
Residential Wood Combustion	0.1	0.1

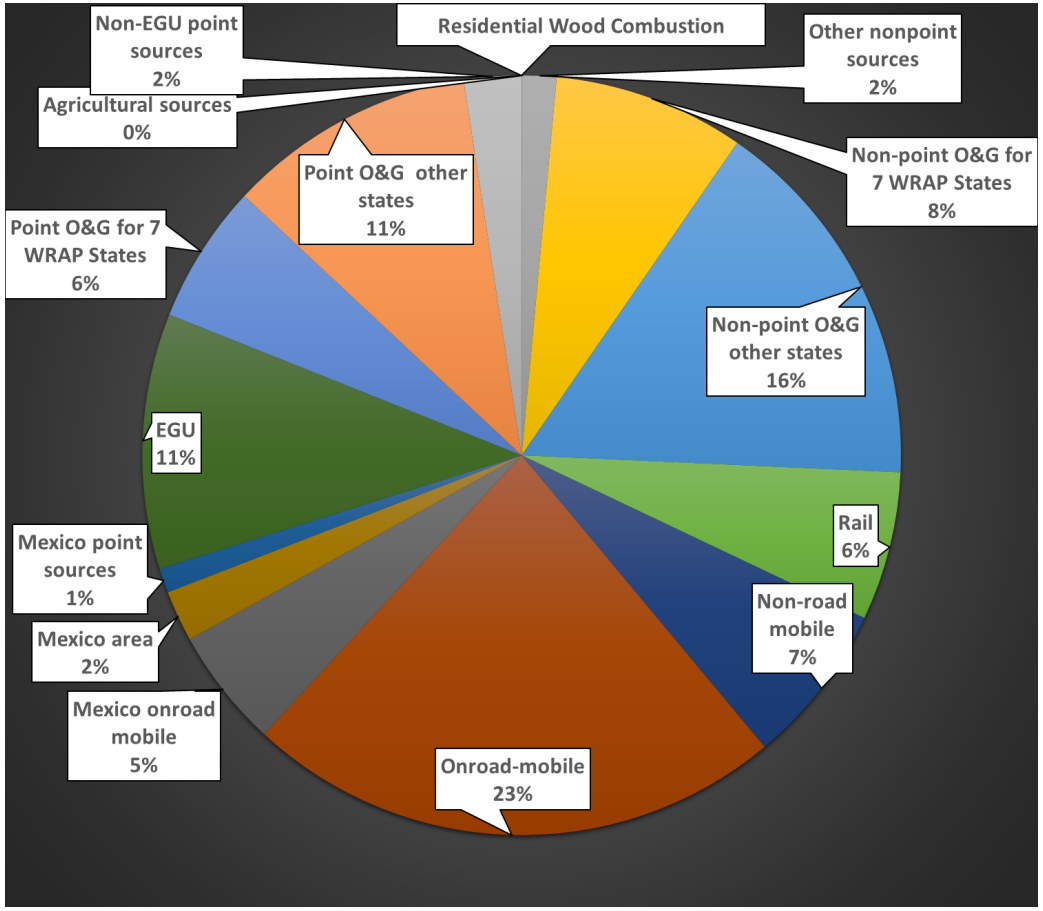


	2014Base	2028Base
Non-EGU point sources	24.4	24.1
Point O&G other states	48.4	41.0
Point O&G for 7 WRAP States	56.1	86.5
EGU	5.0	2.9
Mexico point sources	8.3	8.2
Mexico area	103.3	107.0
Mexico onroad mobile	34.4	37.1
Onroad-mobile	150.6	52.5
Non-road mobile	73.2	37.5
Rail	6.2	3.6
Non-point O&G other states	1,642.5	1,719.7
Non-point O&G for 7 WRAP States	567.3	524.4
Other nonpoint sources	213.2	213.2
Residential Wood Combustion	1.2	1.2
Agricultural sources	43.4	43.4

NMED Exhibit 22 - 0008

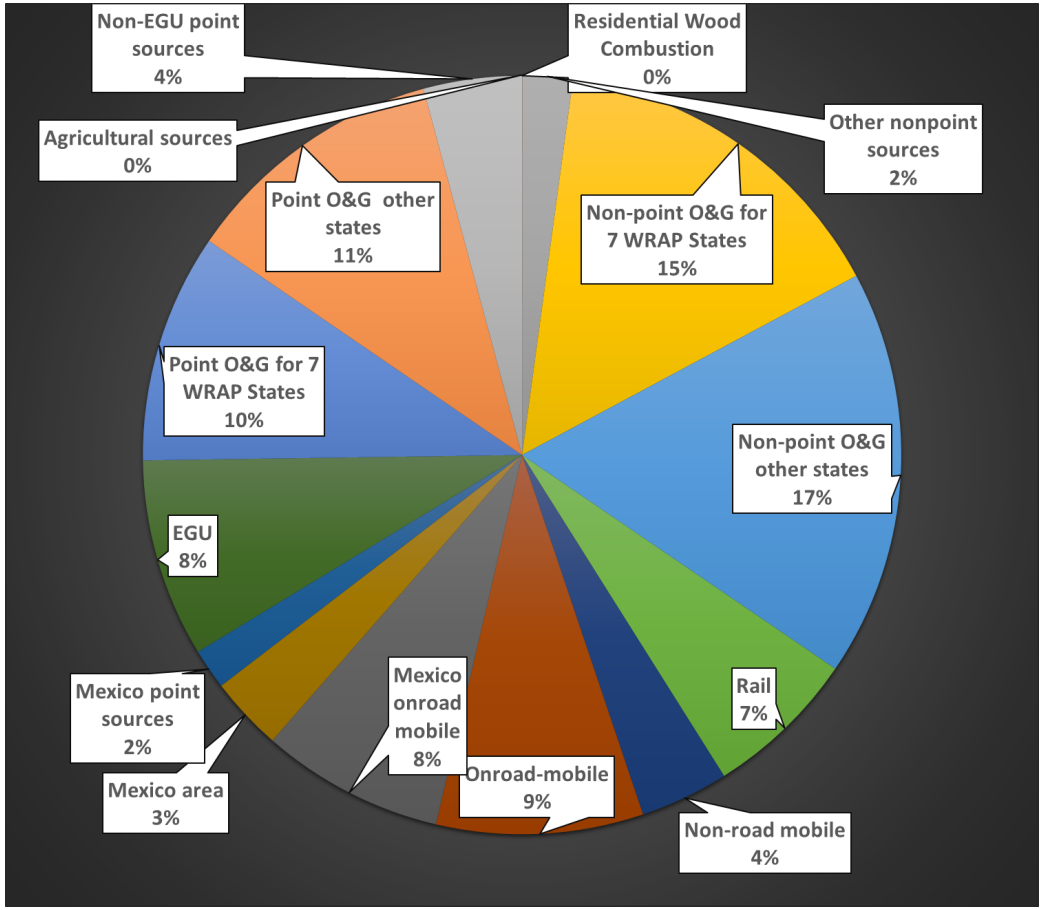
NEW MEXICO 4-KM NOX COMPARISON

2014 NOx



1,938 TPD

2028 NOx



1,334 TPD

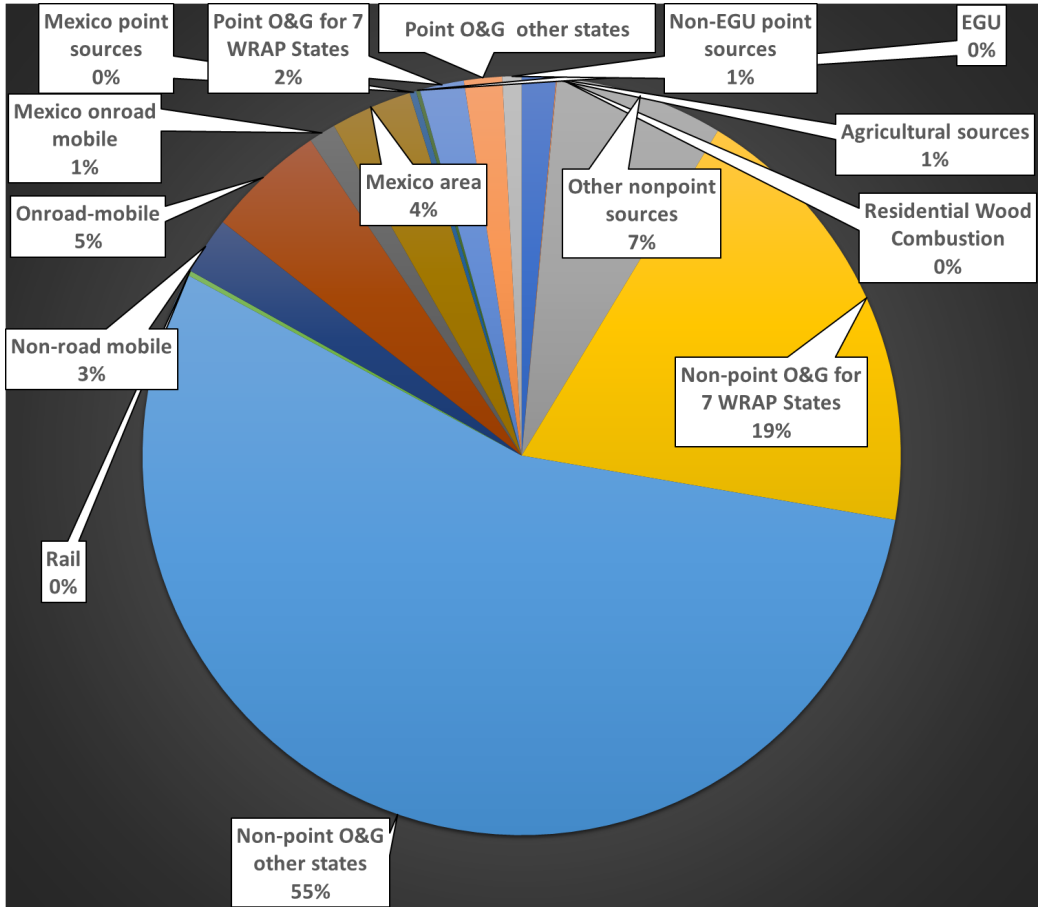
-604 TPD (31.1%) Reduction

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NMED Exhibit 22 - 0009

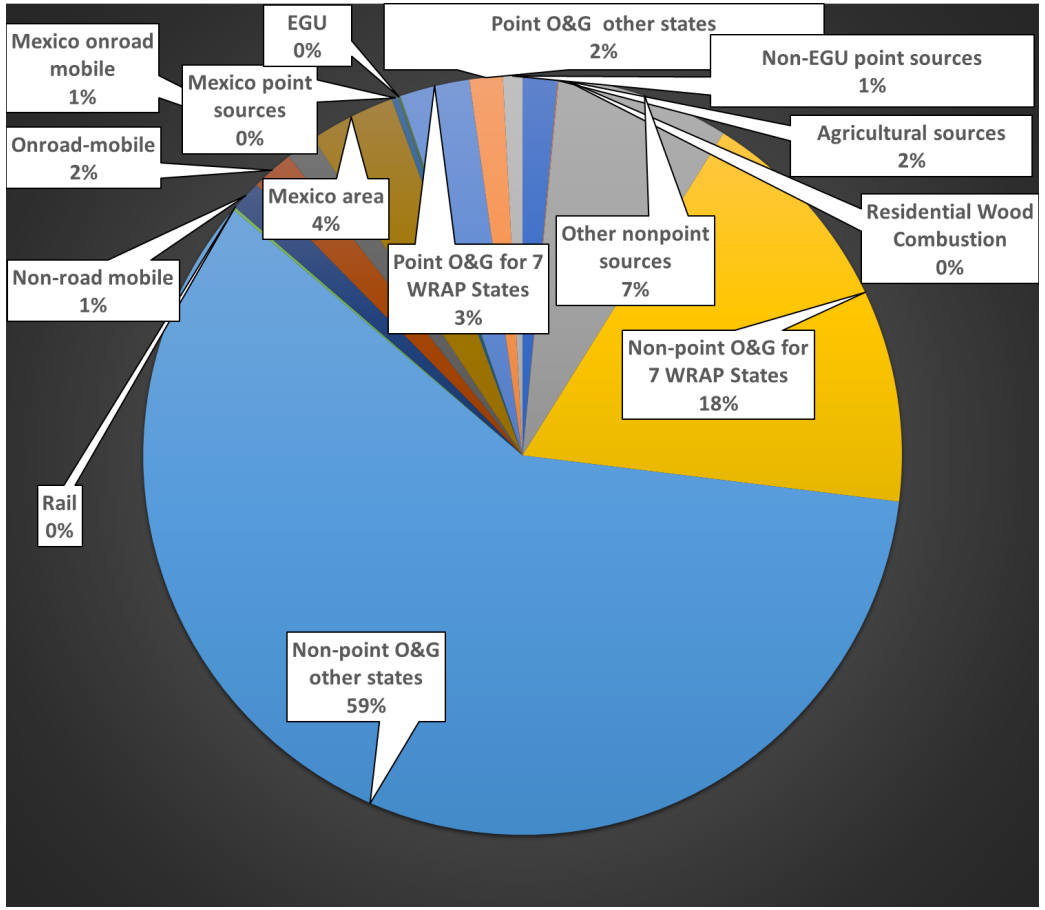
NEW MEXICO 4-KM VOC COMPARISON

2014 VOC



2,977 TPD

2028 VOC



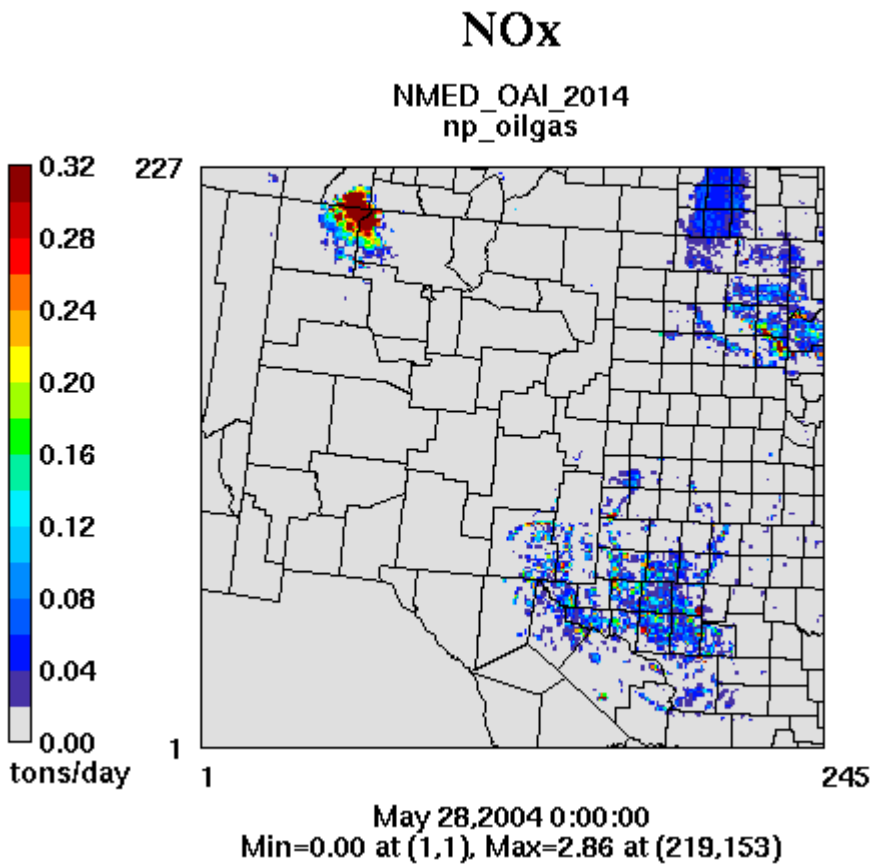
2,902TPD

-75 TPD (2.5%) Reduction

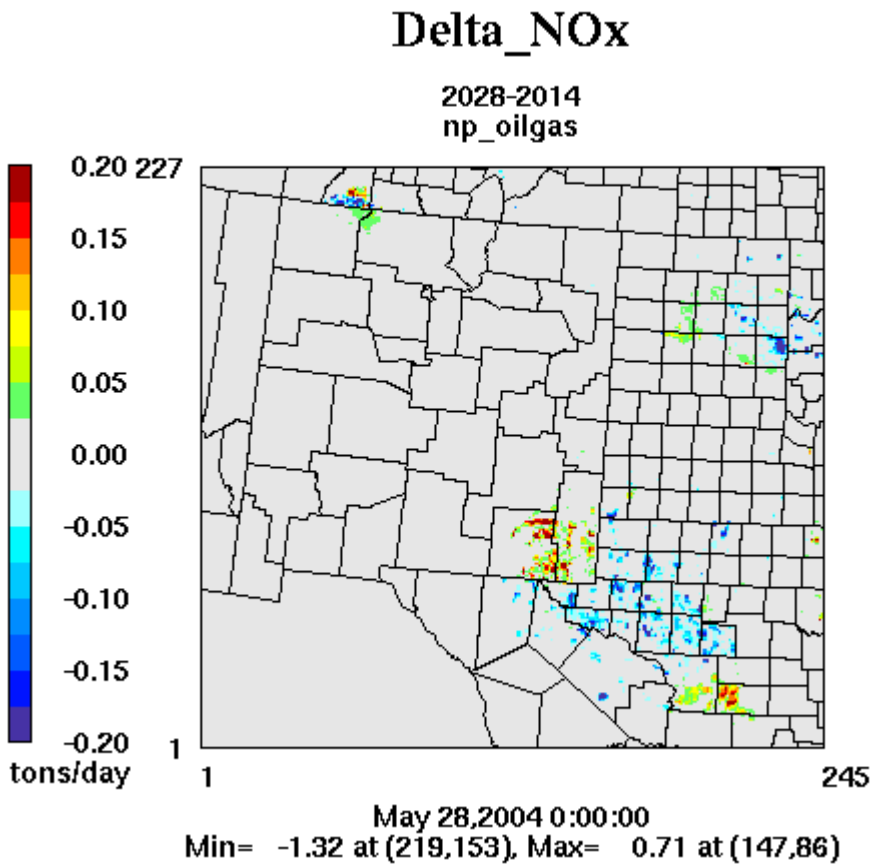
RAMBOLL

NON-POINT O&G EMISSIONS: NOX

2014



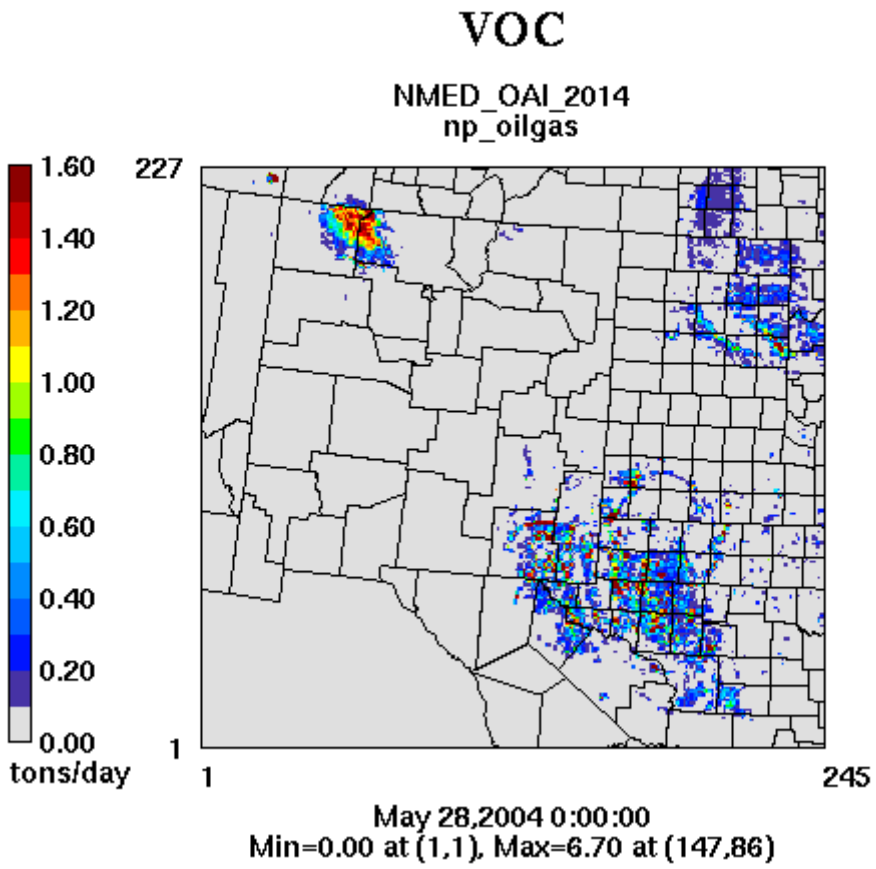
Difference plot (2028 – 2014)



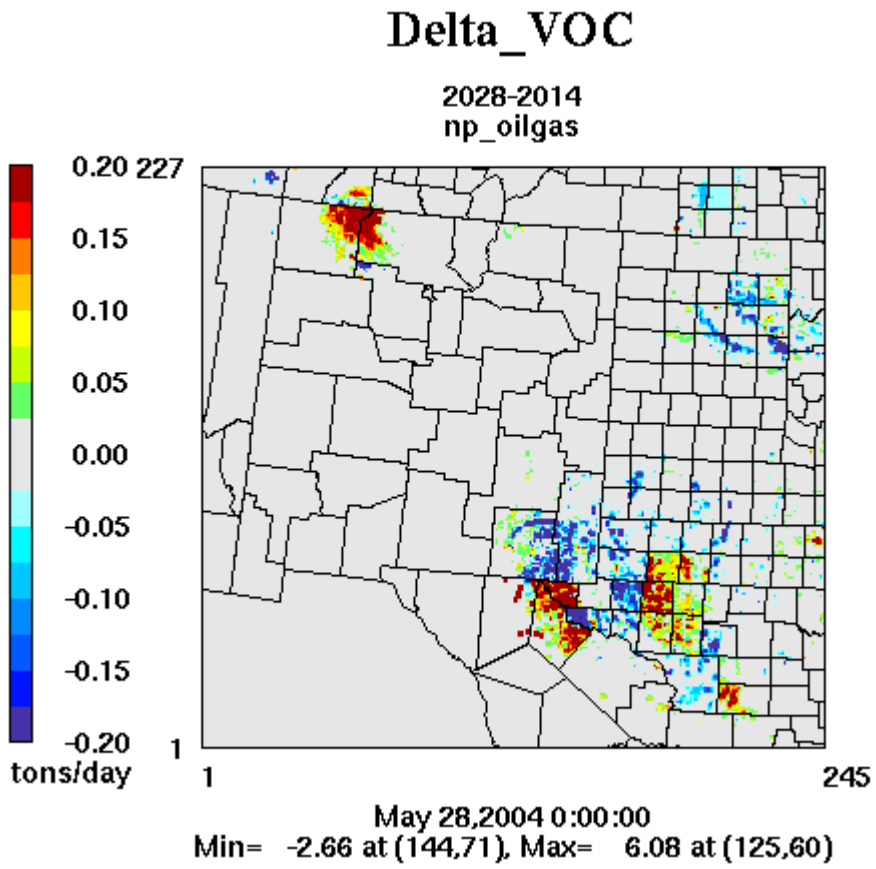
RAMBOLL

NON-POINT O&G EMISSIONS: VOC

2014



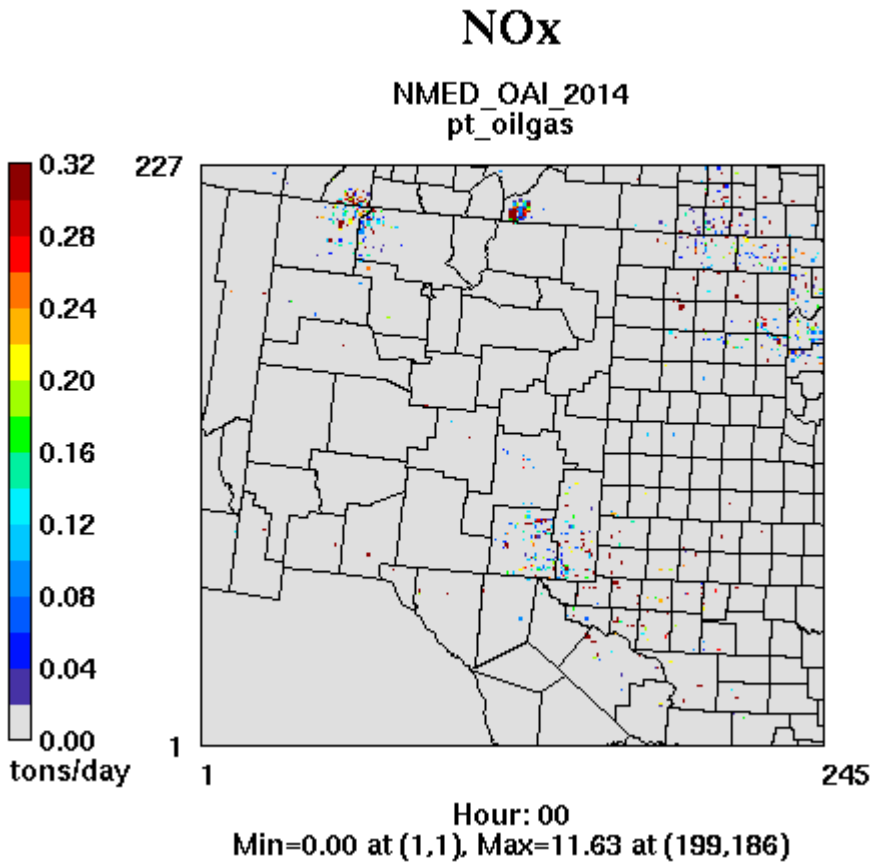
Difference plot (2028 – 2014)



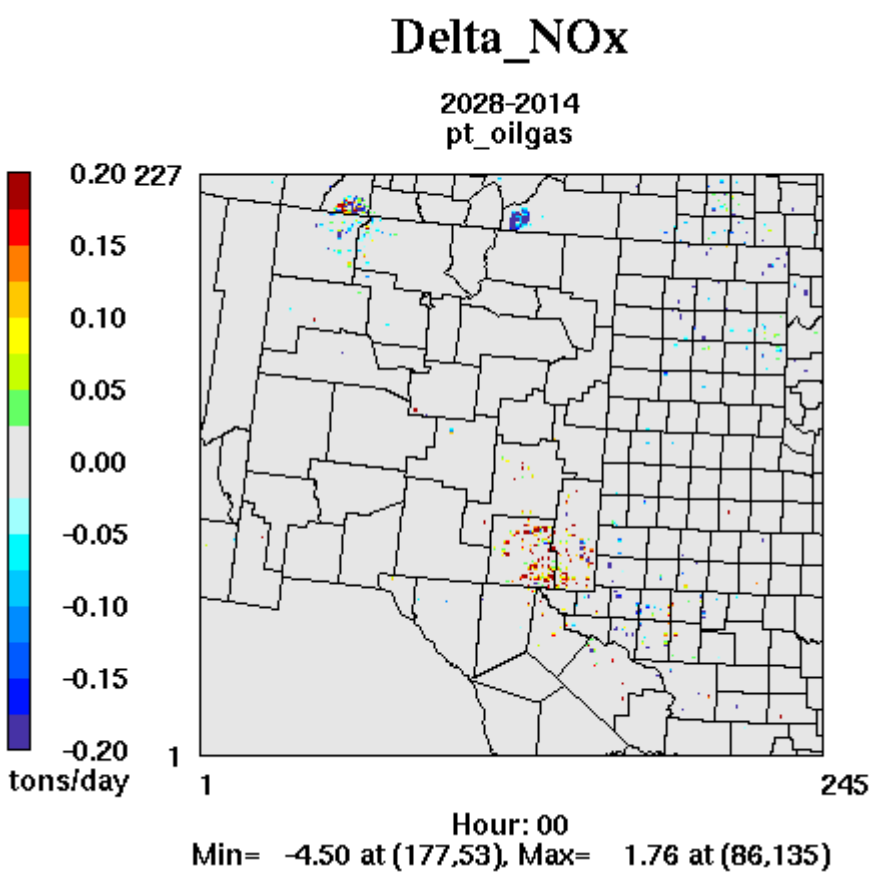
RAMBOLL

POINT O&G EMISSIONS: NOX

2014



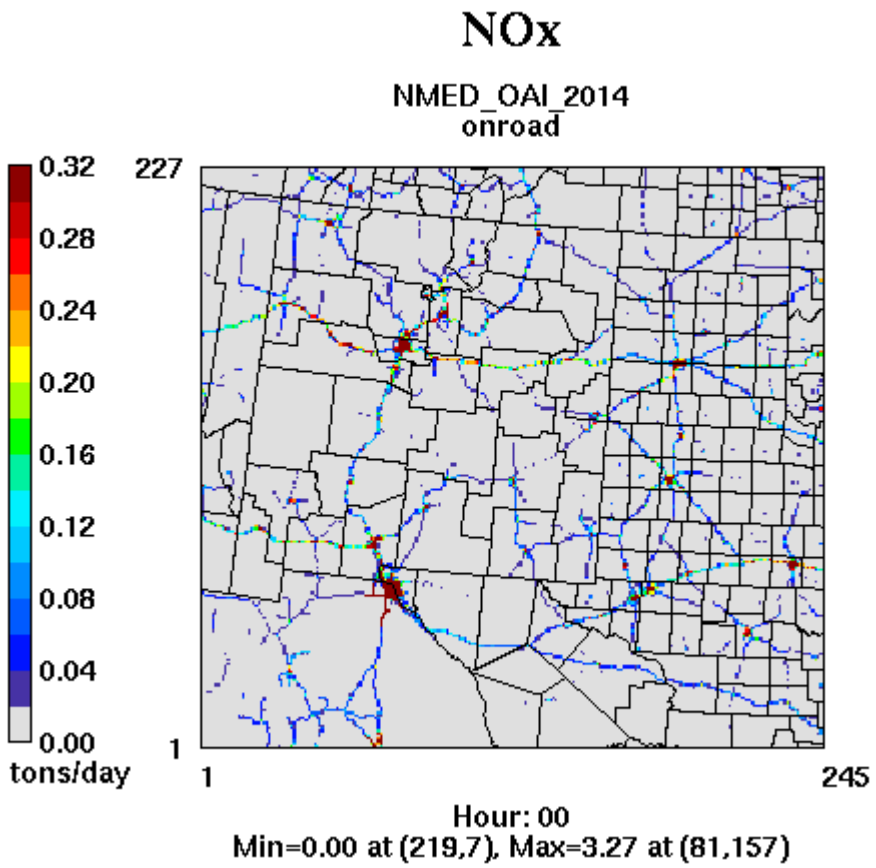
Difference plot (2028 – 2014)



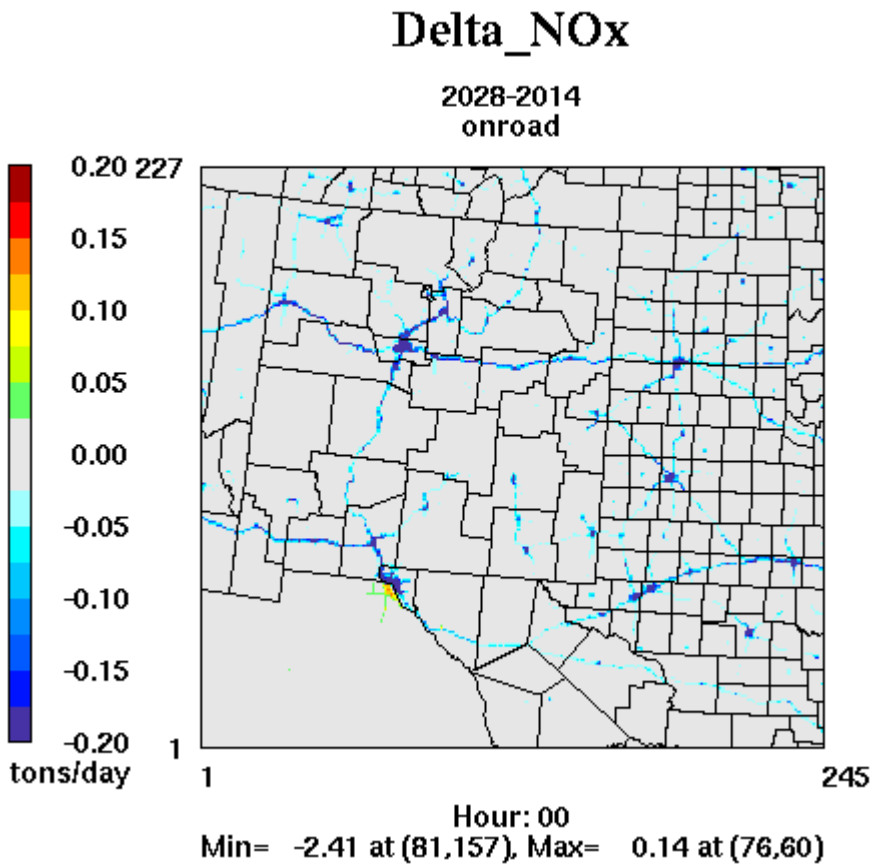
RAMBOLL

ONROAD EMISSIONS: NOX

2014



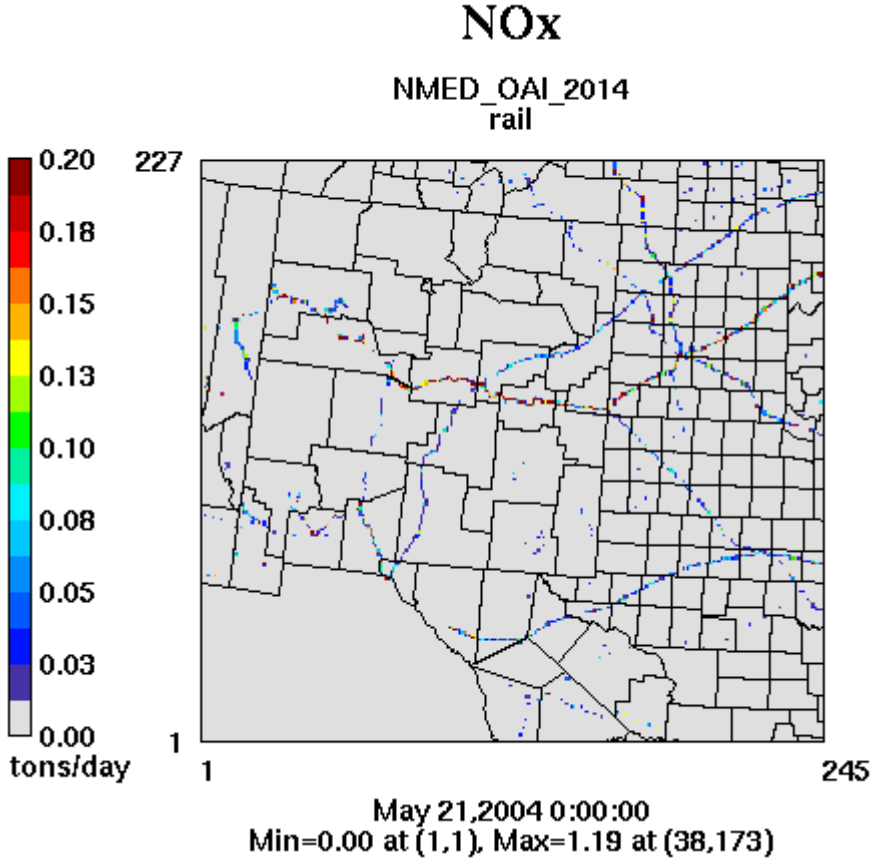
Difference plot (2028 – 2014)



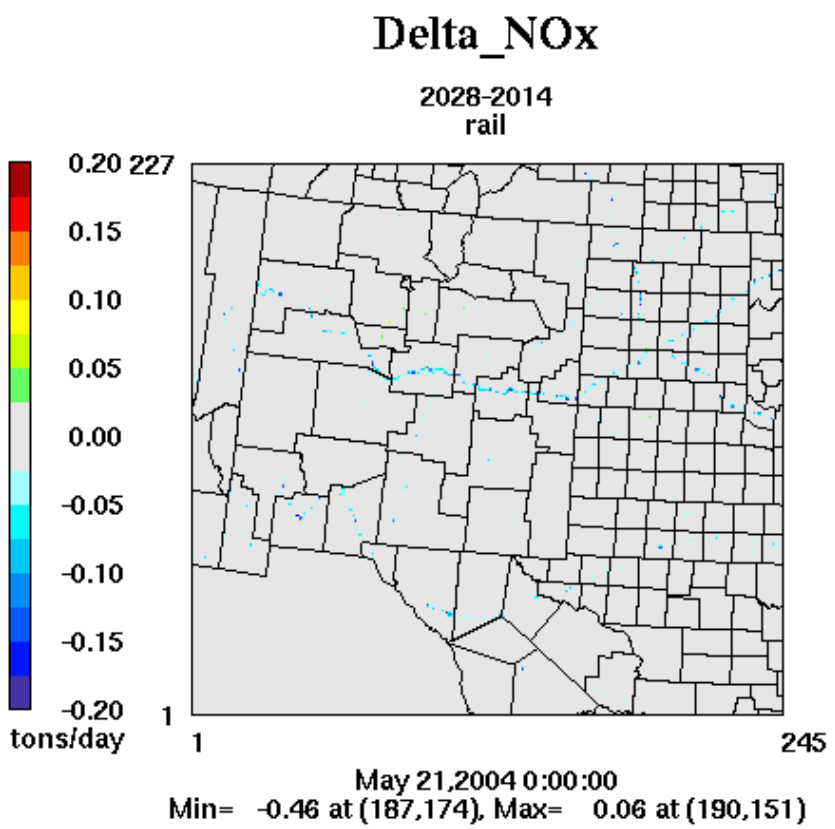
RAMBOLL

RAIL EMISSIONS: NOX

2014



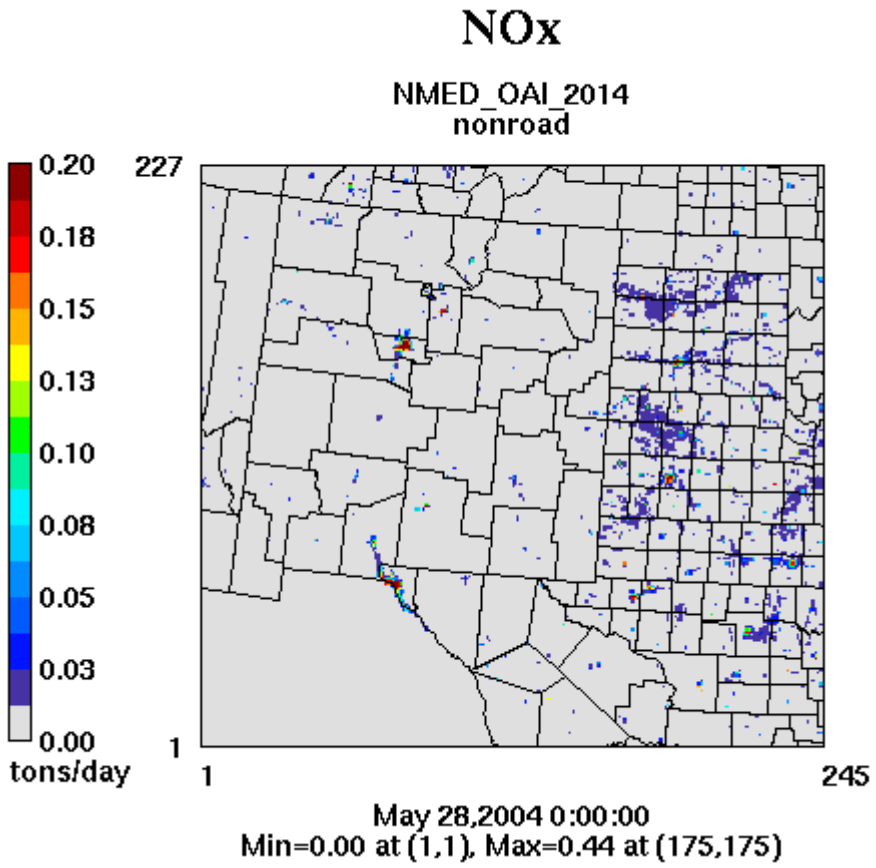
Difference plot (2028 – 2014)



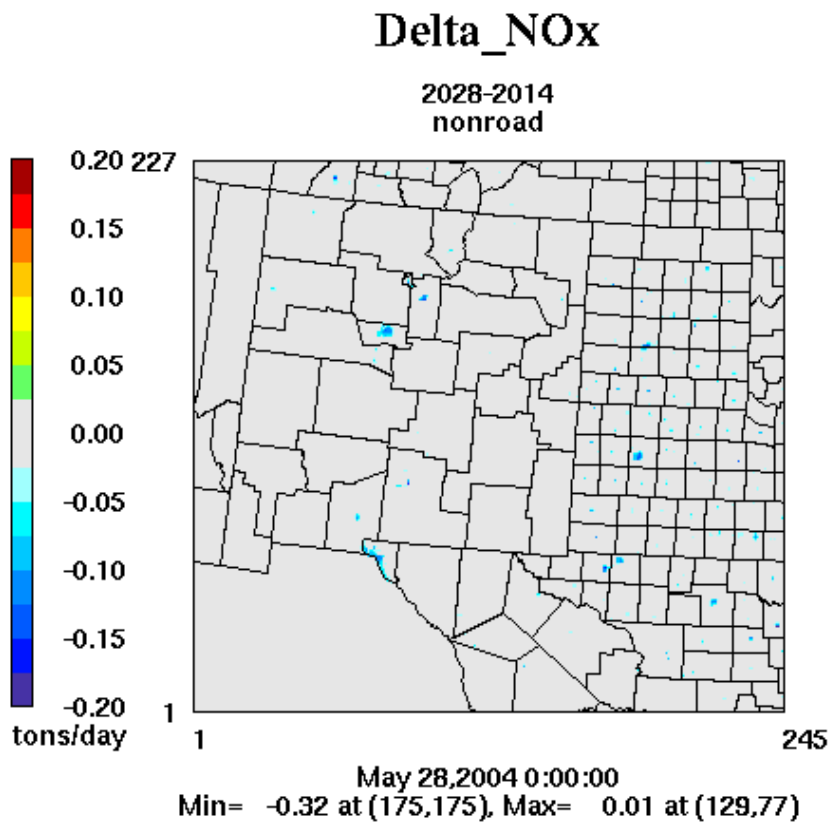
RAMBOLL

NONROAD EMISSIONS: NOX

2014



Difference plot (2028 – 2014)



RAMBOLL

CURRENT STATUS AND NEXT STEPS

- Completed 36/12/4-km 2028 emissions with updated 2028 O&G emissions for New Mexico and started CAMx runs
- Process 2028 O&G emissions for NM O&G Control Scenario
- Conduct CAMx 2028 36/12/4-km NM O&G control strategy simulation and provide ozone results to NMED

RAMBOLL

2028 O&G CONTROL SCENARIO EMISSIONS – PRELIMINARY ANALYSIS

RAMBOLL

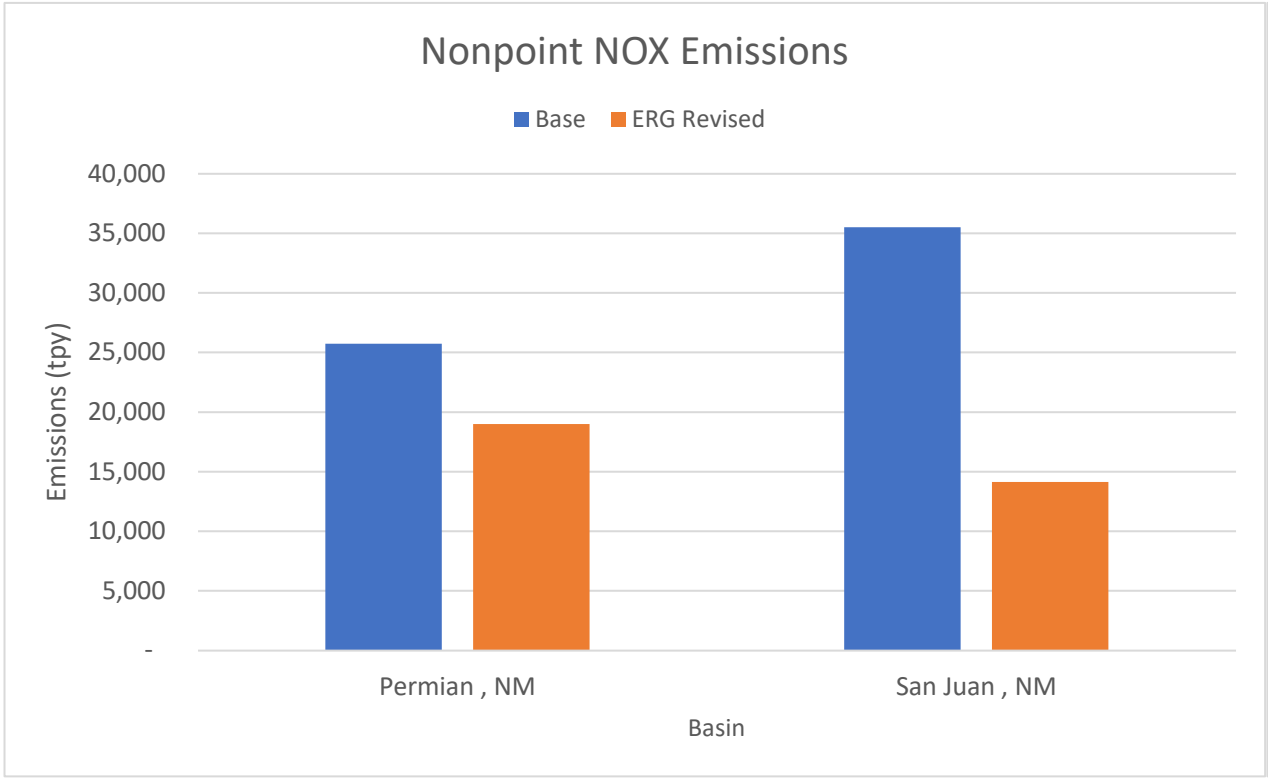
2028 O&G CONTROL SCENARIO EMISSIONS

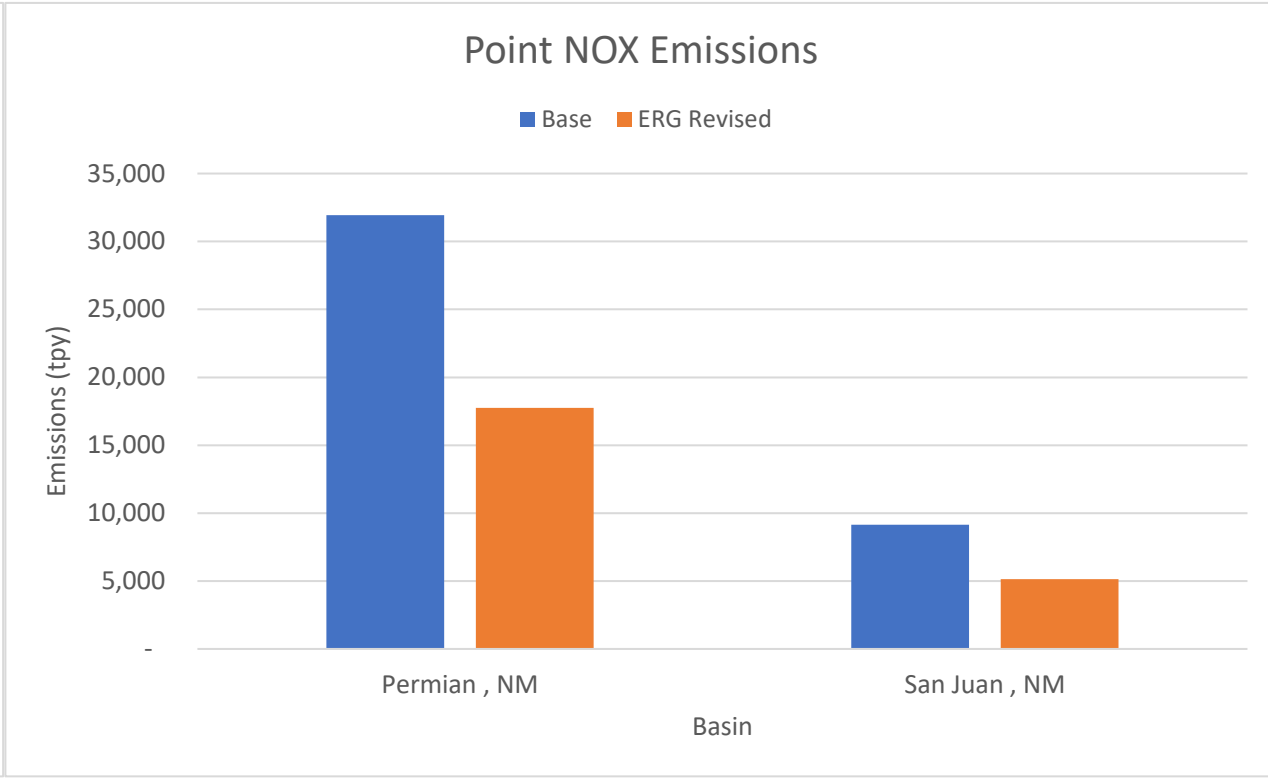
- ERG provided revised point and nonpoint NM emissions for affected counties/SCCs/pollutants.
- 7 NM counties included in ERG's inventory
  - San Juan Basin (4 counties)
  - Permian Basin (3 counties)
- Bar chart displays by Pollutant, Basin and Source Categories (in tons/year)

	Source	Base	ERG Revised	Change	Percent Change
NOx	Nonpoint	61,245	33,144	(28,101)	-46%
	Point	41,066	22,872	(18,195)	-44%
	Total	102,311	56,015	(46,296)	-45%
	Source	Base	ERG Revised	Change	Percent Change
VOC	Nonpoint	181,252	85,564	(95,688)	-53%
	Point	30,340	19,608	(10,732)	-35%
	Total	211,592	105,173	(106,420)	-50%

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2028 O&G CONTROL SCENARIO NOX EMISSIONS



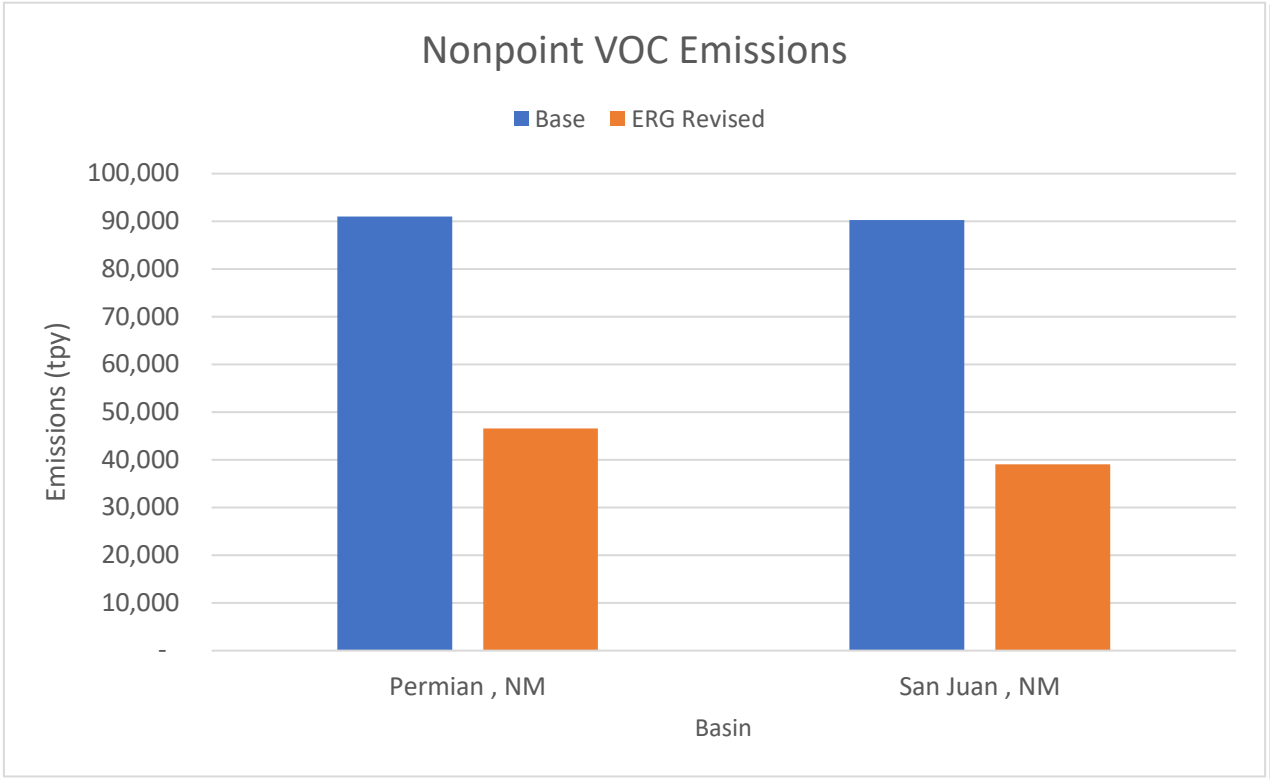


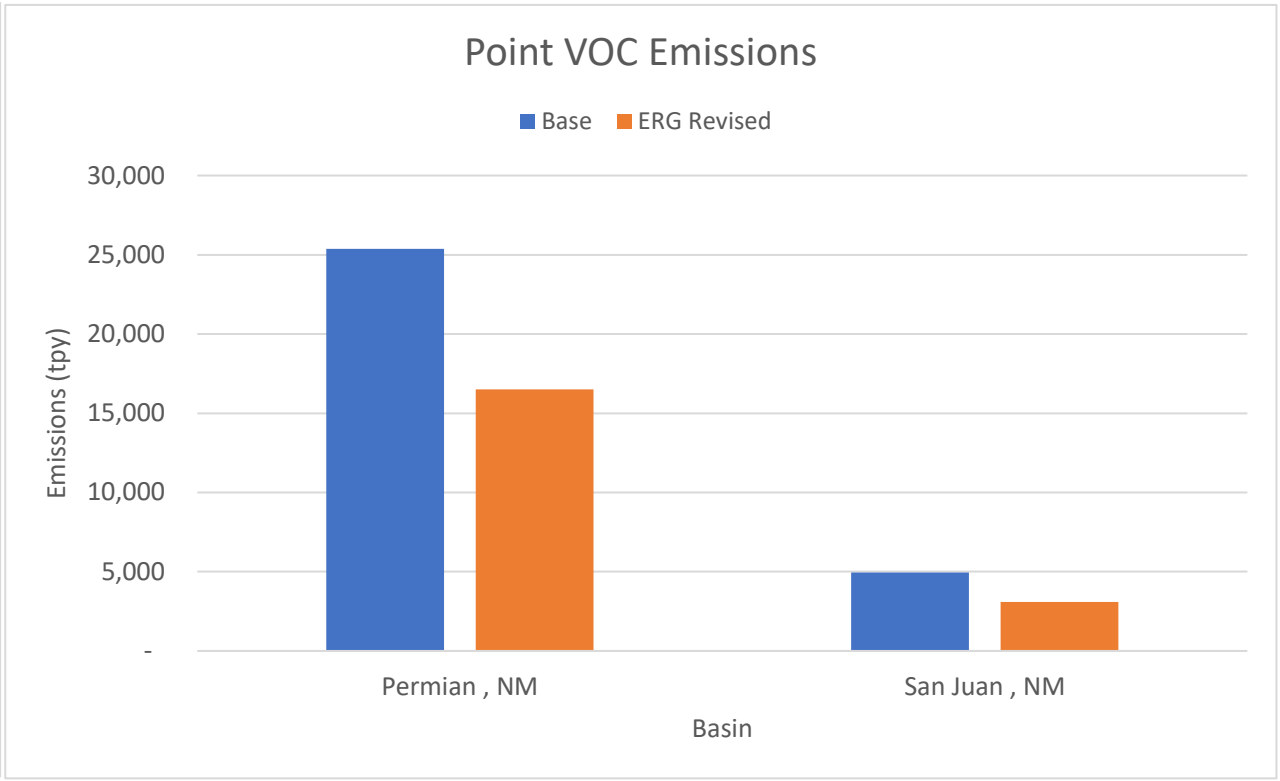
- 26% NOx reduction for Permian
- 60% NOx reduction for San Juan

- 44% NOx reduction for Permian
- 44% NOx reduction for San Juan

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2028 O&G CONTROL SCENARIO VOC EMISSIONS



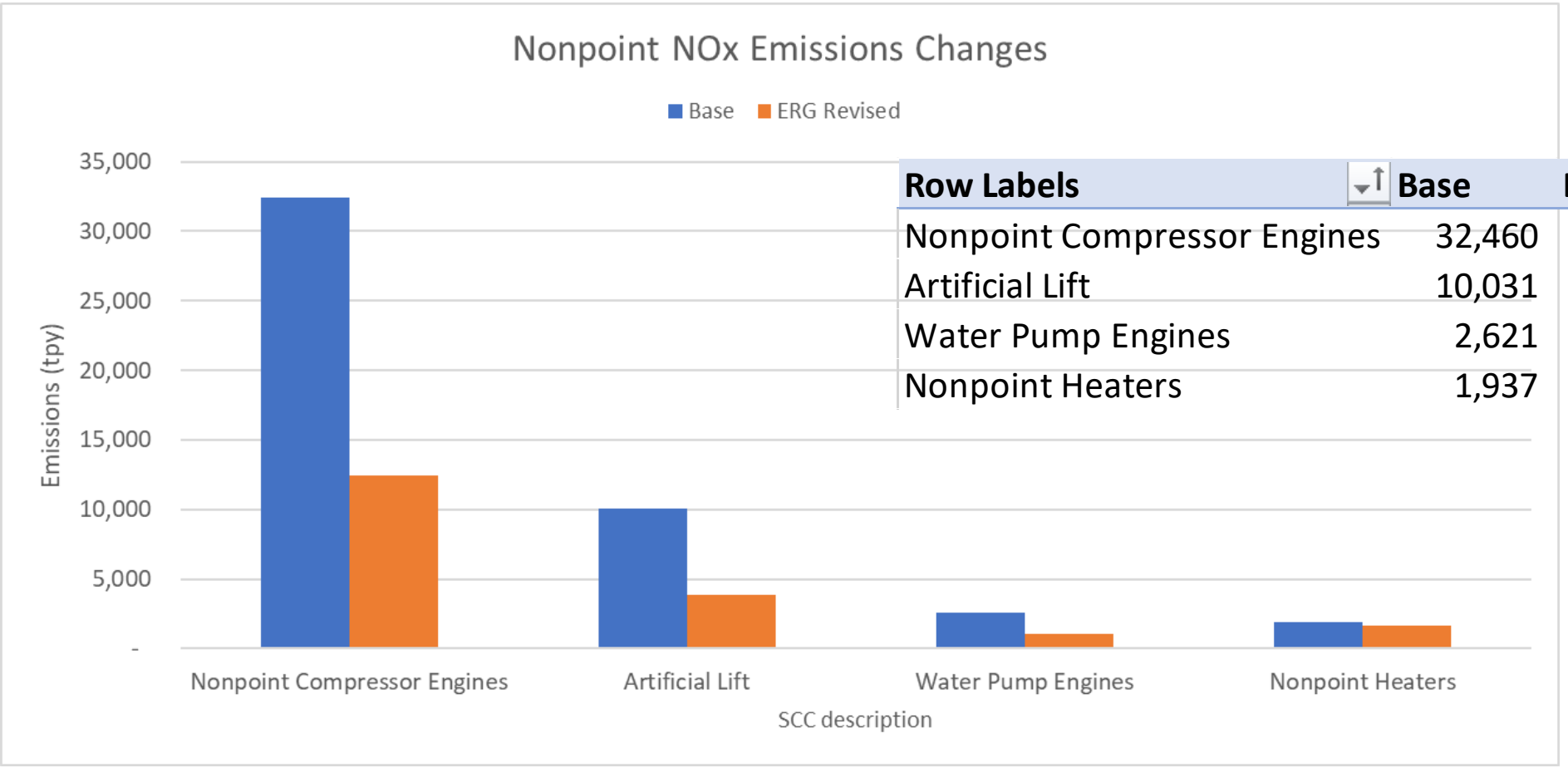


- 49% VOC reduction in Permian
- 57% VOC reduction in San Juan

- 35% VOC reduction for Permian
- 38% VOC reduction for San Juan

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NONPOINT O&G NOX CHANGE

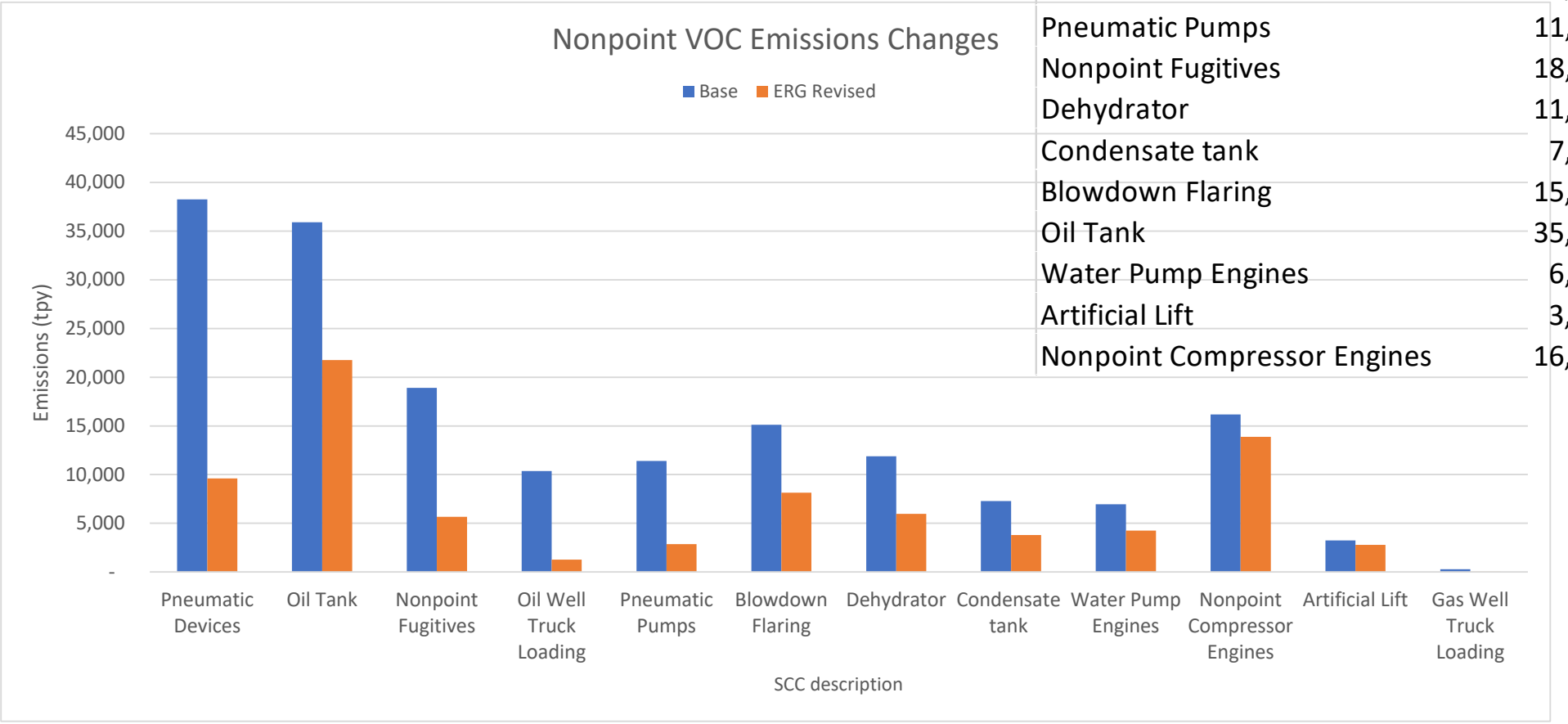


Row Labels	Base	ERG Revis	Sum of dif	Sum of pe
Nonpoint Compressor Engines	32,460	12,432	(20,028)	-62%
Artificial Lift	10,031	3,842	(6,189)	-62%
Water Pump Engines	2,621	1,030	(1,591)	-61%
Nonpoint Heaters	1,937	1,643	(294)	-15%

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NONPOINT O&G VOC CHANGE

Row Labels	Base	ERG Revis	Sum of dif	Sum of pe
Oil Well Truck Loading	10,353	1,273	(9,080)	-88%
Gas Well Truck Loading	292	36	(256)	-88%
Pneumatic Devices	38,240	9,598	(28,641)	-75%
Pneumatic Pumps	11,404	2,862	(8,541)	-75%
Nonpoint Fugitives	18,894	5,668	(13,225)	-70%
Dehydrator	11,870	5,964	(5,905)	-50%
Condensate tank	7,289	3,809	(3,480)	-48%
Blowdown Flaring	15,110	8,135	(6,975)	-46%
Oil Tank	35,889	21,747	(14,141)	-39%
Water Pump Engines	6,962	4,252	(2,710)	-39%
Artificial Lift	3,232	2,776	(455)	-14%
Nonpoint Compressor Engines	16,162	13,885	(2,277)	-14%



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NEW MEXICO OZONE ATTAINMENT INITIATIVE

Revised 2014v2 Base Case, 2028 Base Case Modeling and 2028 NM O&G Control Strategy

Tejas Shah, Chao-Jung Chien, Sai Sreedhar Varada, John Grant, Marco Rodriguez, Pradeepa Vennam and Ralph Morris, Ramboll

Tom Moore and Mary Uhl, WESTAR

NM OAI Study Webinar

February 10, 2021

RAMBOLL Bright ideas. Sustainable change.

REVISED 2014V2 BASE CASE AND 2028 BASE CASE MODELING

01 Revised 2014v2 Base Case Modeling

02 2028 Base Case Modeling and Ozone DV Projections

03 2028 New Mexico O&G Control Scenario

04 Design of 2028 State/Category APCA Source Apportionment

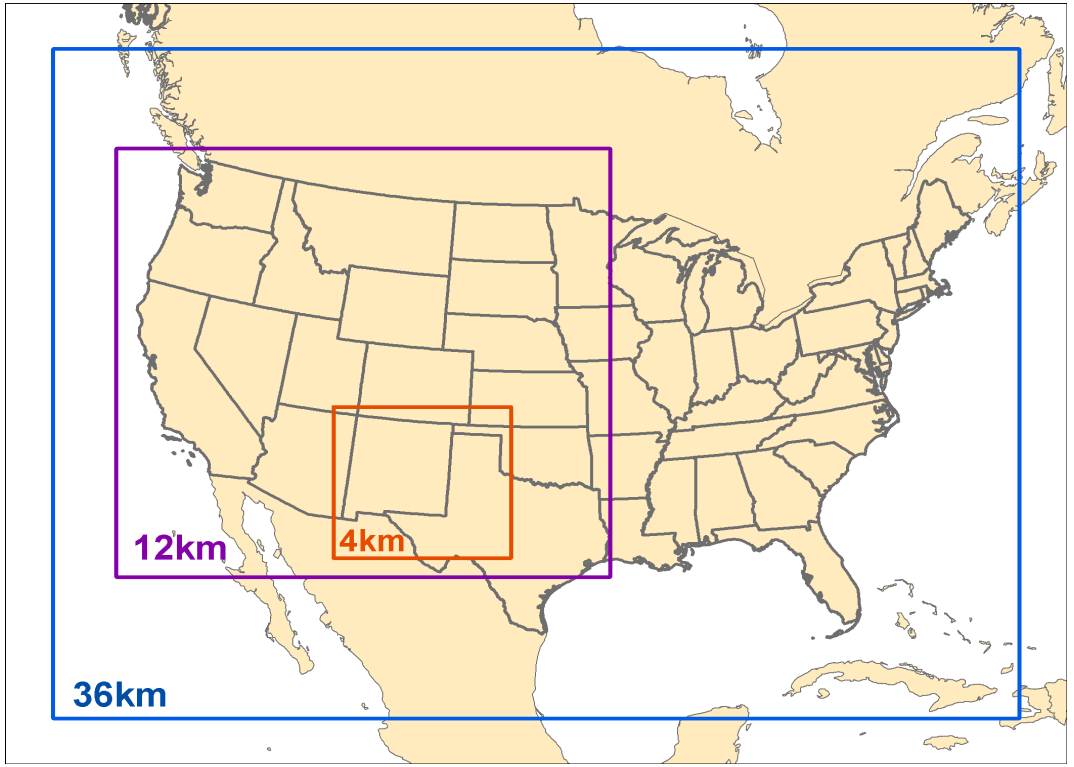
05 Design of 2028 VOC- & NOx-limited OSAT Source Apportionment

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NMED Exhibit 23 - 0002

CAMX 2014 NM OAI STUDY MODEL CONFIGURATION

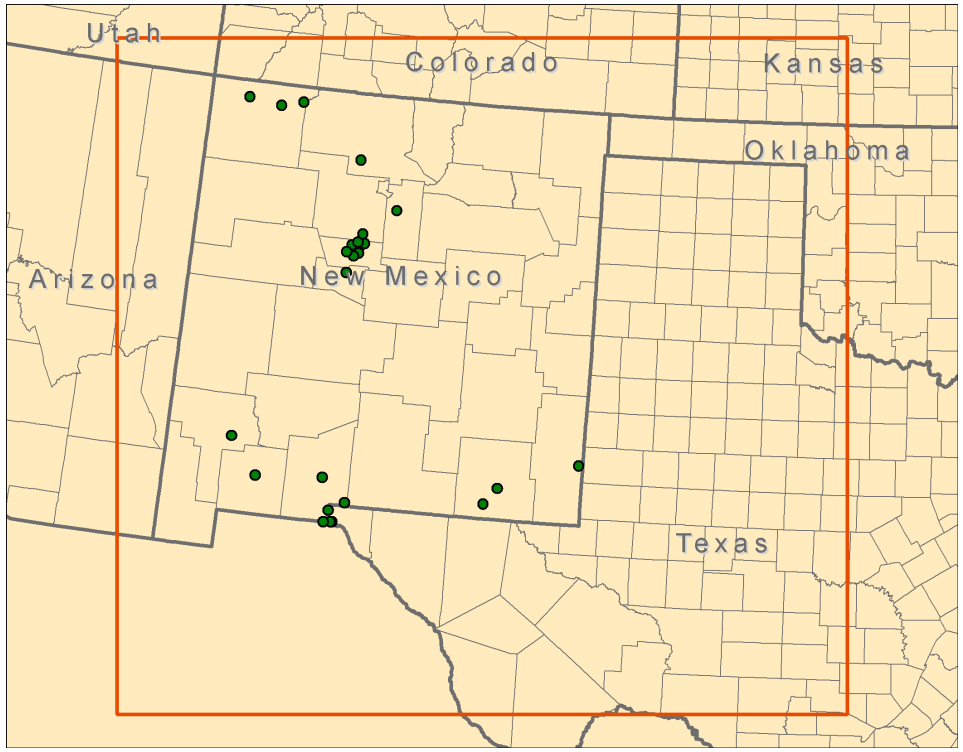
- Episode: May-August 2014
  - 16-day spin-up before first high ozone day in NM
    - 68 ppb on May 17
- 36/12/4-km Modeling Domains
  - 36/12-km domains same as WRAP Regional Haze
  - New 4-km New Mexico domain
- Boundary Conditions (BC) WRAP 2014 GEOS-Chem
- Four Meteorological Diagnostic Sensitivity tests
  - Selected WRF/NAM with Kv=CMAQ
- WRAP 2014v2 base year emissions
  - EPA NEI2014v2 w/ western state updates
- WRAP 2028OTBa2 for future year w/ 2014 actual fires and new 2028 NM O&G



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ORIGINAL CAMX CONFIGURATION

- Similar to WRAP CAMx 36/12-km Regional Haze set-up w/ 4-km NM domain added
- Two changes in revised 2014v2 Base Case:
  - Use CAMx v7.1
  - Use BEIS biogenic emissions



Science Options	CAMx	Comment
Model Codes	CAMx v7.0	Latest version of CAMx made publicly available May 2020 (www.camx.com)
Horizontal Grid Mesh	36/12/4-km	
36-km grid	148 x 112 cells	36US domain
12-km grid	227 x 215 cells	12WUS2 domain. Includes buffer cells
4-km grid	245 x 227 cells	New Mexico 4-km domain. Includes buffer cells
Vertical Grid Mesh	25 vertical layers, defined by WRF	Layer 1 ~20 m. Model top at 50 mb (~19 km). Layer collapsing from 35 vertical layers in WRF
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions	Start on May 1, 2014	First high ozone day is May 17, 2014
Boundary Conditions	WRAP 2014 GEOS-Chem	For 36US domain lateral boundaries
Emissions		
Emissions Processing	SMOKE, SMOKE-MOVES2014, MEGAN	WRAP/WAQS 2014v2 emissions and EPA 2023fh for future year
Sub-grid-scale	Plume-in-Grid (PiG)	NOx > threshold
Chemistry		
Gas Phase	CB6r4	(Yarwood et al., 2010)
Meteorological Processor	WRFCAMx	Compatible with CAMx v7.0
Horizontal Diffusion	Spatially varying	K-theory with Kh dependence
Vertical Diffusion	CMAQ-like Kv	Evaluated YSU Kv scheme
Diffusivity Min	Kv-min = 0.1 to 1.0 m^2/s in lowest 100 m	Urban land use fraction
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	(Zhang et. al, 2001; 2003)

NMED Exhibit 23 - 0004

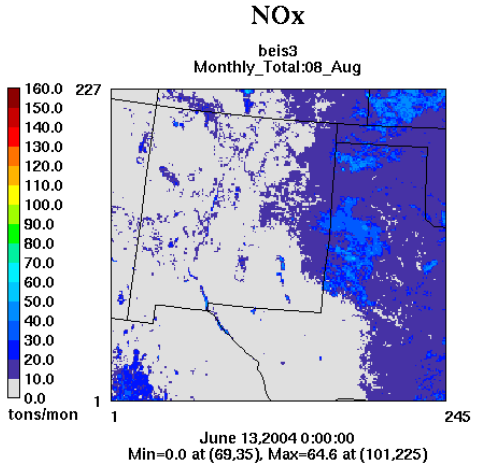
REVISED CAMx 2014v2 BASE CASE SIMULATION

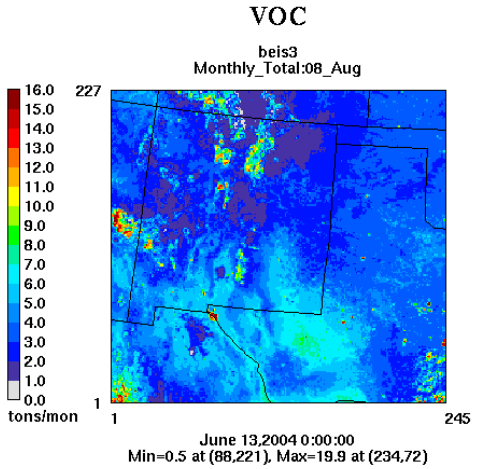
RAMBOLL

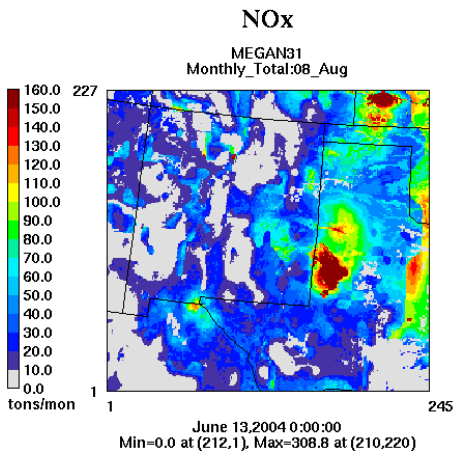
REVISED CAMX 2014V2 36/12/4-KM BASE CASE AND MPE

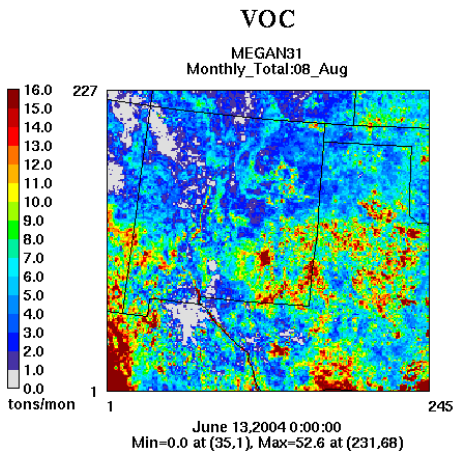
- Two changes between original CAMx 36/12/4-km 2014 and revised 2014v2 base cases
  - Use CAMx v7.1 instead of CAMx v7.0
    - Bugs in source apportionment tools in CAMx v7.0 necessitated change
    - Little change expected in ozone results due to model version
  - Switched from MEGAN v3.1 to BEIS biogenic emissions in 4-km domain
    - MEGAN v3.1 very new and turned out to be not ready to run out of the box
    - MEGAN v3.1 missing LAI in urban areas so has zero biogenic emissions unless extra work is performed to do data filling
    - MEGAN v3.1 has much higher (~3x) biogenic NOx than BEIS, and previous versions of MEGAN
    - WRAP 2014/RepBase/2028 regional haze modeling is using BEIS
    - Denver 2020 Serious ozone SIP used MEGAN but for follow-on 2023 and 2026 modeling switched to BEIS because of zero urban biogenic emissions and biogenic NOx that seemed high

BEIS V3.7 VS. MEGAN V3.1 BIOGENIC EMISSIONS - AUGUST









BEIS

Tons/month		MEGAN	BEIS3	Abs Diff (BEIS3-MEGAN)	Ratio (BEIS3/MEGAN)
May	NOX	35,050	10,602	-24,448	0.30
	VOC	128,323	159,809	31,486	1.25
Jun	NOX	42,445	13,134	-29,311	0.31
	VOC	267,055	256,379	-10,676	0.96
Jul	NOX	51,639	12,838	-38,801	0.25
	VOC	317,697	251,562	-66,135	0.79
Aug	NOX	41,002	11,923	-29,079	0.29
	VOC	354,570	216,032	-138,538	0.61

MEGAN

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2014 (MEGAN) AND 2014V2 (BEIS) BASE CASE MPE

- Used EPA's AMETv1.4 MPE tool
- Model evaluated against EPA AQS and CASTNet Surface Air Quality Data for 2014
- Model performance compared with standard PGM goals and criteria values (Emery et al., 2016)
- "Goals" - statistical value that the best model can be expected to achieve
- "Criteria" - statistical value that majority of models have achieved

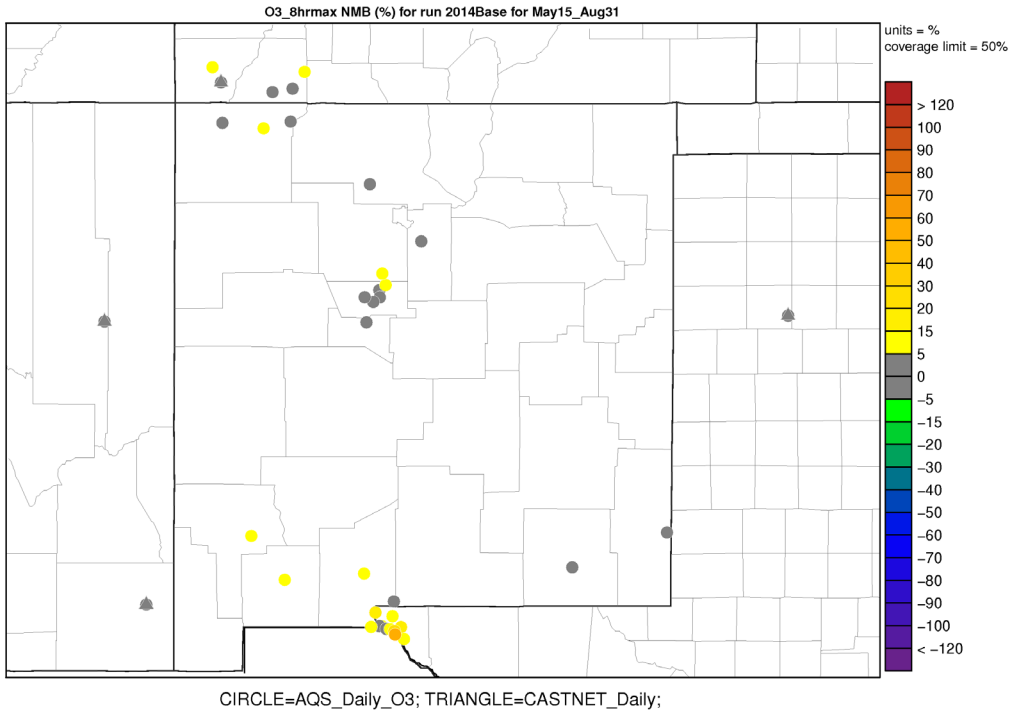
Species	NMB		NME	
	Goal	Criteria	Goal	Criteria
1-hr & MDA8 Ozone	<±5%	<±15%	<15%	<25%

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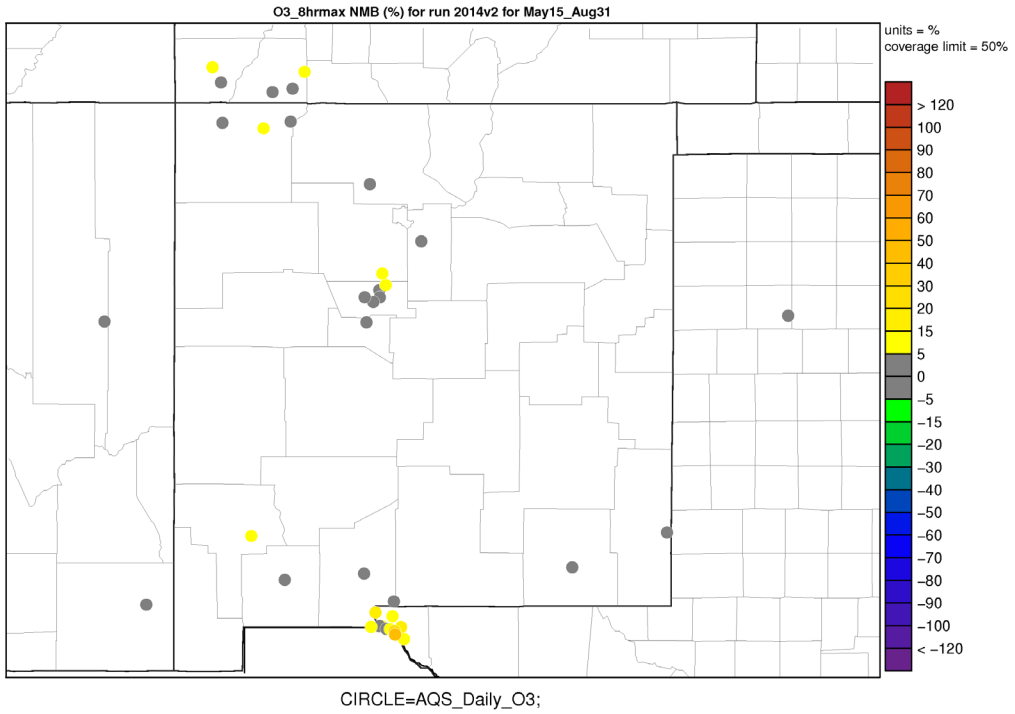
NMED Exhibit 23 - 0008

NMB (BIAS) WITHOUT 60 PPB CUTOFF

2014Base (MEGAN)



2014v2 (BEIS)



Both 2014 Base and 2014v2 meet ozone Performance Criteria at all sites but one in El Paso

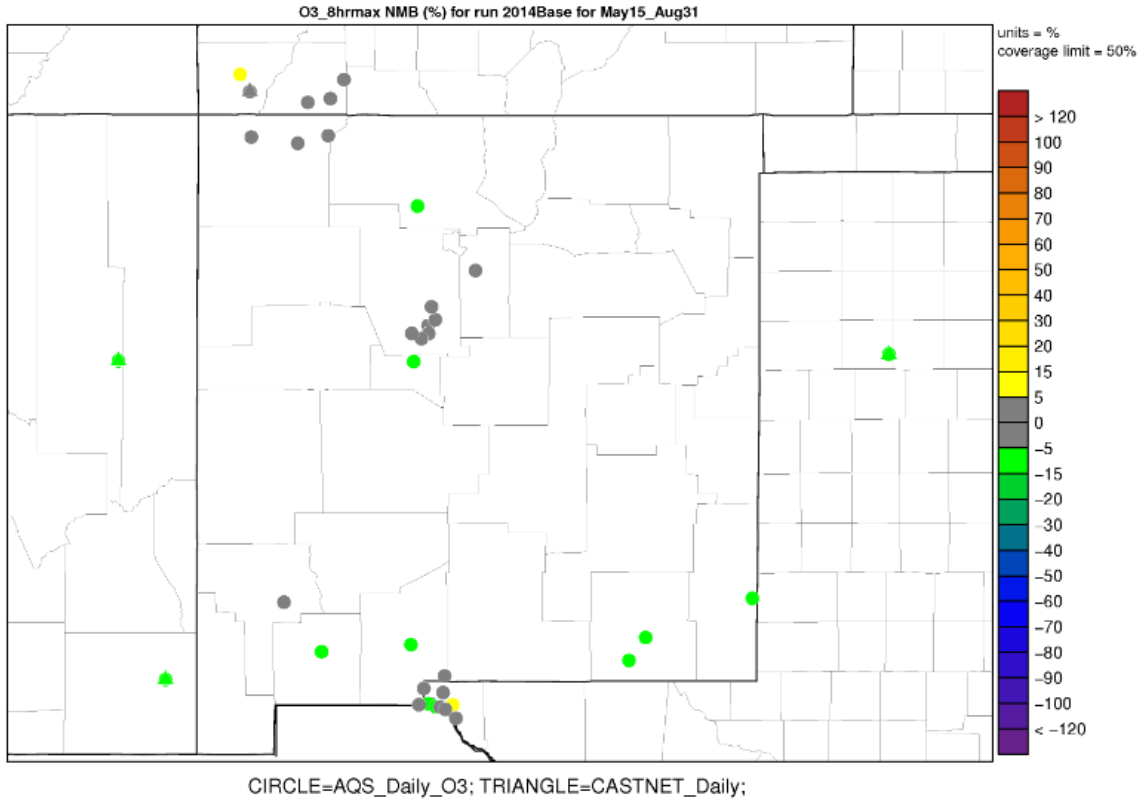
2014v2 has more sites achieving Performance Goals (grey)

RAMBOLL

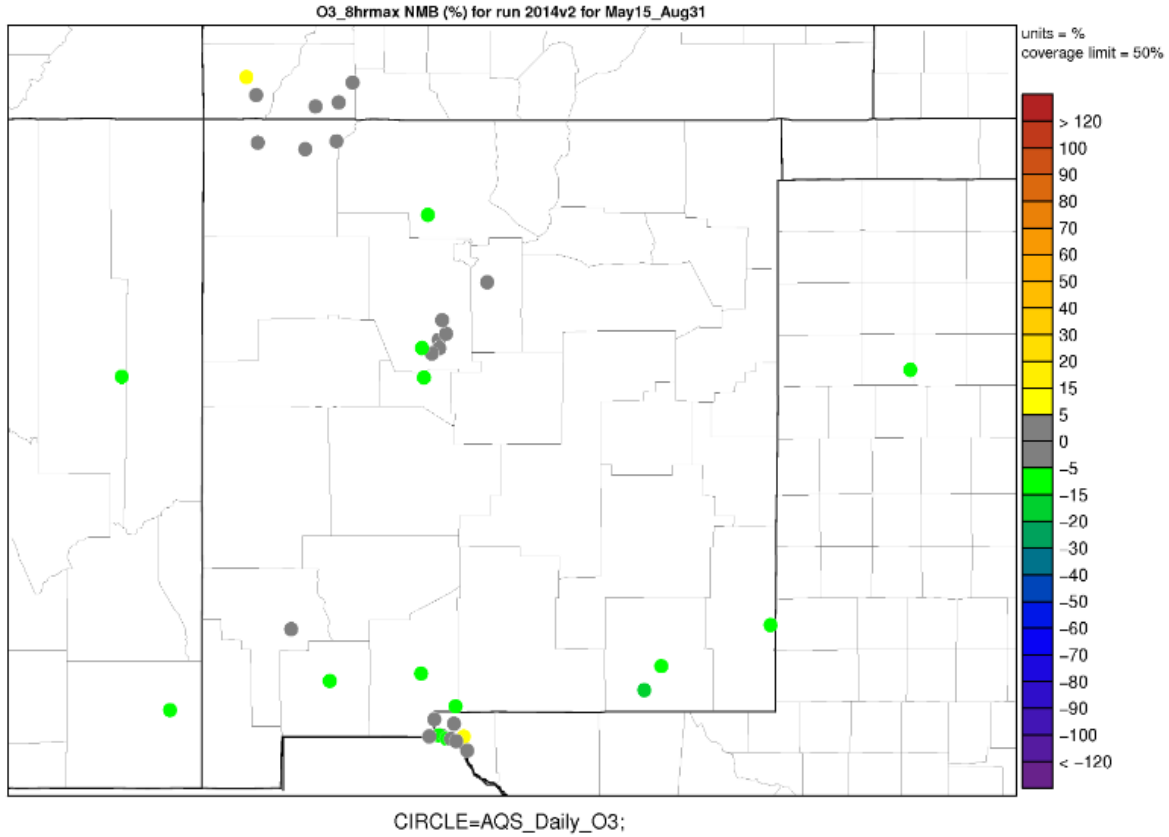
NMED Exhibit 23 - 0009

NMB (BIAS) WITH 60 PPB CUTOFF

2014Base (MEGAN)



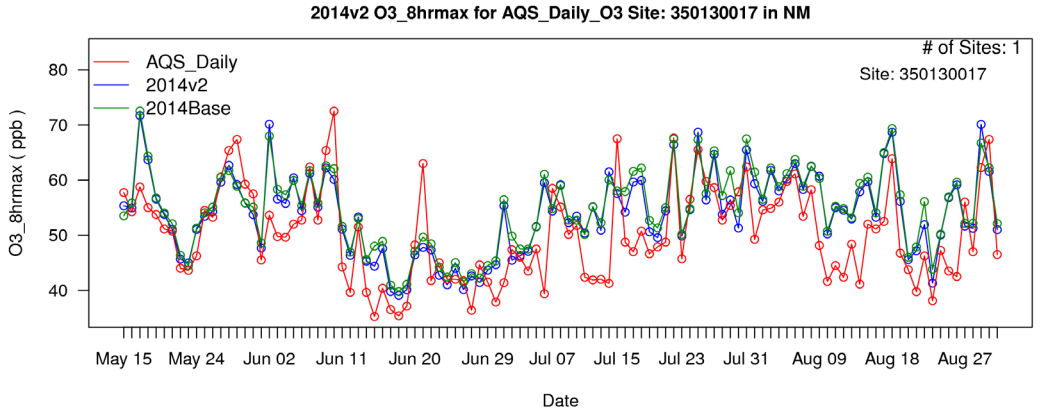
2014v2 (BEIS)

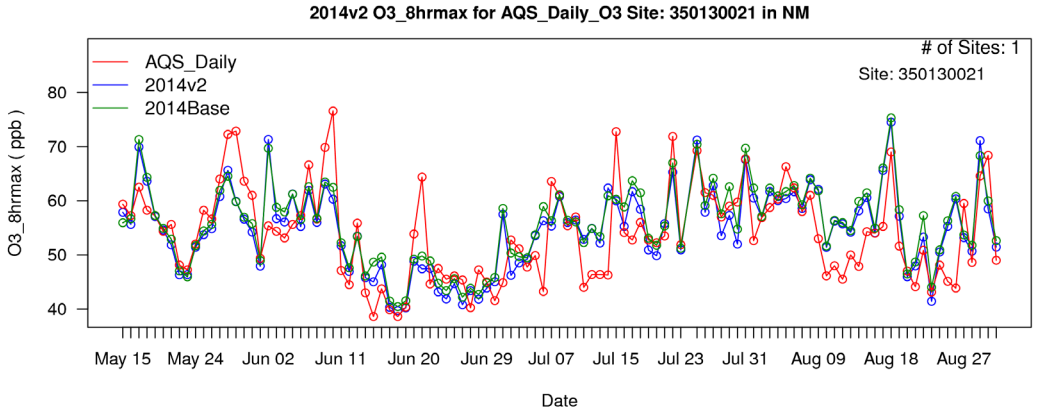


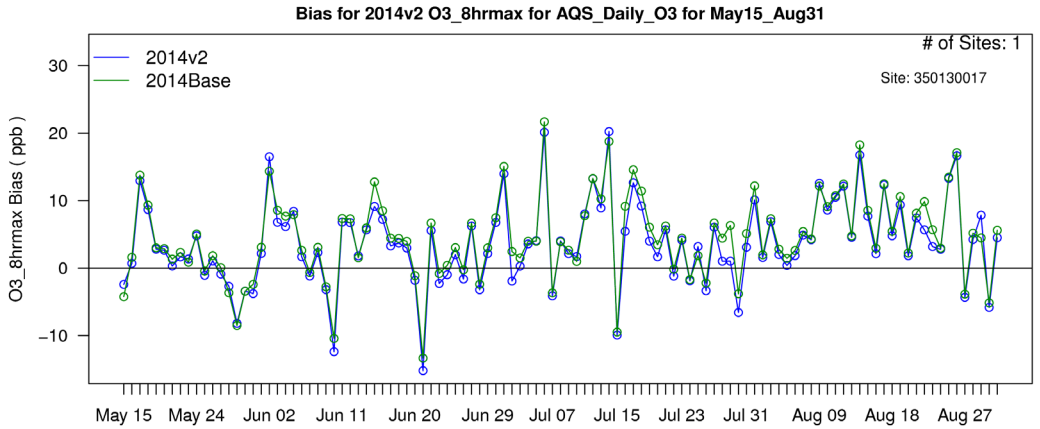
2014v2 larger underestimation at a few sites with 60ppb cutoff compared to 2014Base but still achieves Performance Criteria

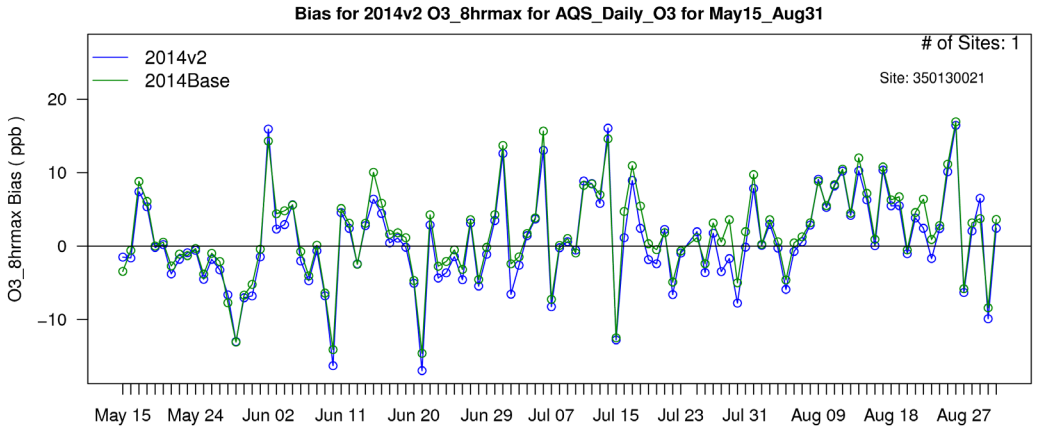
RAMBOLL

SUNLAND PARK AND DESERT VIEW (DONA ANA COUNTY)



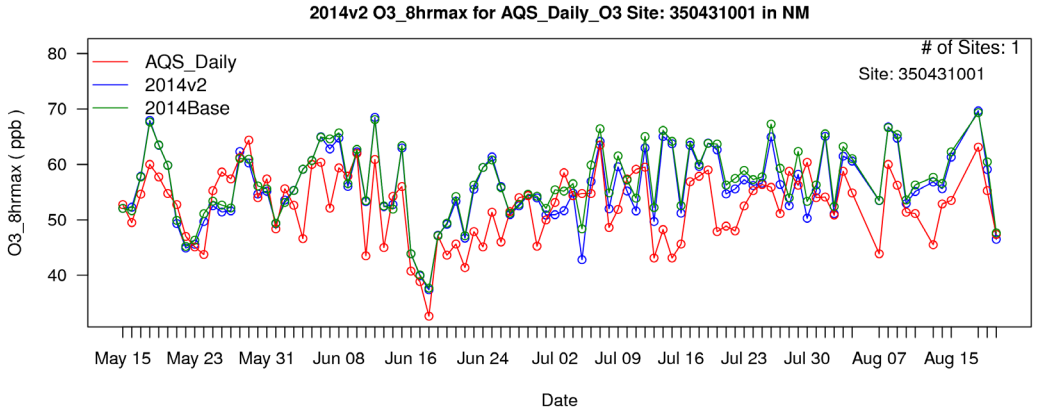


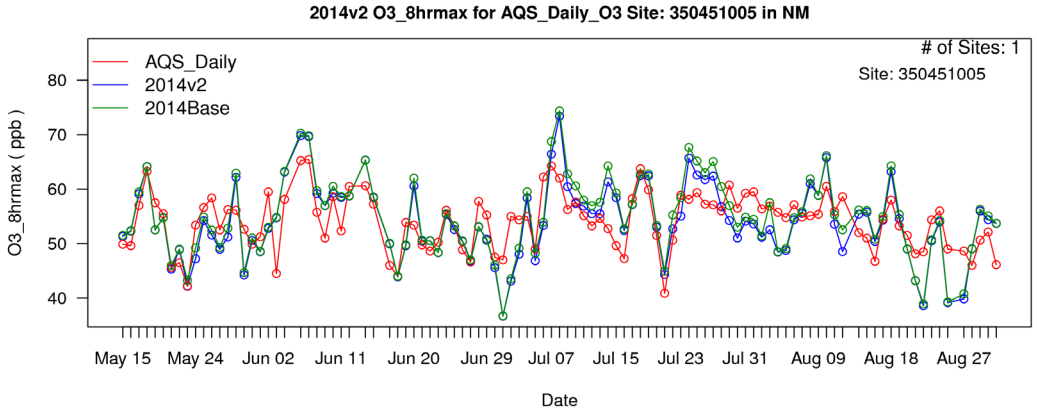


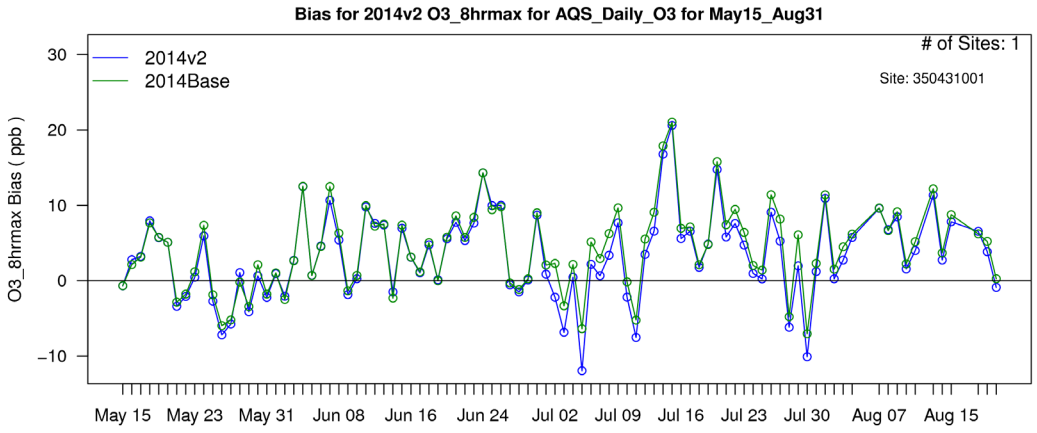


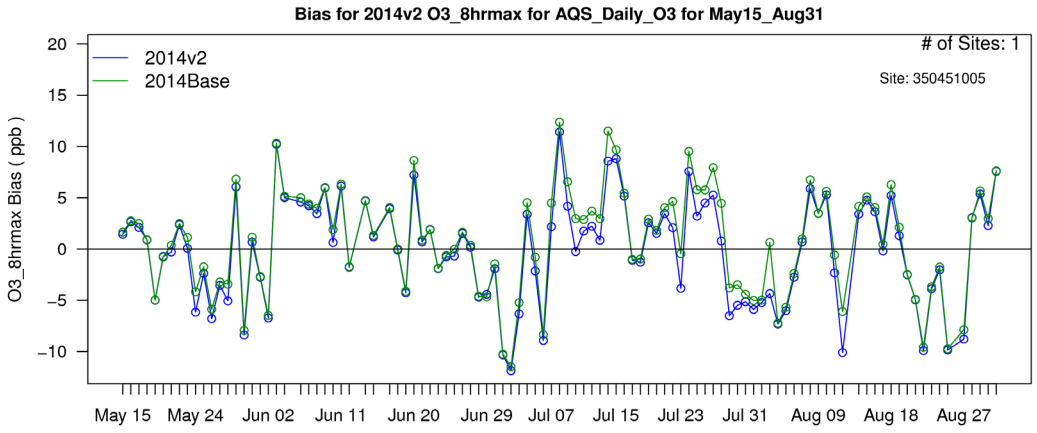
RAMBOLL

BERNALILLO (SANDOVAL CTY) & SUB STATION (SAN JUAN CTY)









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OZONE MPE BY NEW MEXICO SUBREGIONS

- Original 2014 Base Case

	Nocutoff		Withcutoff	
Region	**NMB(%)**	**NME(%)**	**NMB(%)**	**NME(%)**
North NM	4.3	9.1	0	6.4
Bernalillo	4.3	9.4	-2.8	7.1
South NM	5.8	10.5	-6.1	8.5

- Revised 2014v2 Base Case

	Nocutoff		Withcutoff	
Region	**NMB(%)**	**NME(%)**	**NMB(%)**	**NME(%)**
North NM	2.6	8.6	-1.0	6.6
Bernalillo	2.6	9.6	-4.3	8.5
South NM	3.5	10.2	-7.8	9.9

- Consistent with MEGAN v3.1 having higher NOx emissions than BEIS v3.7, CAMx revised 2014v2 base has slight lower ozone than original 2014 base
  - Also consistent with time series plots
- Results in slight improvement in ozone performance statistics when no cutoff is used
- Results in a slight degradation in ozone performance statistics when 60 ppb observed ozone cutoff is used
- Very similar ozone model performance

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NMED Exhibit 23 - 0013

OZONE MPE BY NEW MEXICO MONITORING SITE

2014Base (with MEGAN)			
SiteID	SiteNames	NMB No Cutoff	NMB 60 ppb Cutoff
350010023	Del Norte	1.7	-3.9
350010024	South East Heights	3.1	-2.4
350010029	South Valley	3.1	-2.8
350010032	Westside	1.1	-3.4
350011012	Foot Hills	13.6	2.0
350130008	La Union	17.4	-1.6
350130017	Sunland Park Yard	9.0	-3.6
350130020	Chaparral	4.8	-4.7
350130021	Desert View	3.2	-5.1
350130022	Santa Teresa	8.2	0.1
350130023	Solano	6.1	-6.5
350151005	Carlsbad	-1.1	-12.3
350171003	Chino Copper	9.1	-1.0
350250008	Hobbs Jefferson	2.1	-9.9
350290003	Deming Airport	6.2	-5.0
350390026	Coyote Ranger	3.3	-5.4
350431001	Bernalillo	8.1	3.8
350450009	Bloomfield	7.2	2.5
350450018	Navajo Lake	2.2	-0.6
350451005	Sub Station	1.4	3.3
350490021	Santa Fe Airport	3.8	-1.7
350610008	Los Lunas	0.8	-6.5

2014v2 (with BEIS)			
SiteID	SiteNames	NMB No Cutoff	NMB 60 ppb Cutoff
350010023	Del Norte	0.5	-4.9
350010024	South East Heights	1.3	-3.6
350010029	South Valley	0.9	-4.4
350010032	Westside	-1.0	-5.4
350011012	Foot Hills	11.9	0.8
350130008	La Union	15.0	-3.0
350130017	Sunland Park Yard	7.4	-4.1
350130020	Chaparral	2.8	-5.8
350130021	Desert View	1.4	-6.3
350130022	Santa Teresa	5.8	-1.8
350130023	Solano	3.9	-8.2
350151005	Carlsbad	-4.3	-14.5
350171003	Chino Copper	7.0	-1.8
350250008	Hobbs Jefferson	-1.2	-12.6
350290003	Deming Airport	3.8	-8.6
350390026	Coyote Ranger	1.2	-5.6
350431001	Bernalillo	6.4	3.3
350450009	Bloomfield	6.0	1.7
350450018	Navajo Lake	0.5	-3.6
350451005	Sub Station	-0.1	2.2
350490021	Santa Fe Airport	1.5	-2.5
350610008	Los Lunas	-1.7	-9.0

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CONCLUSIONS: REVISED CAMX 2014V2 BASE CASE

- With lower biogenic emissions, the CAMx revised 2014v2 base case (BEIS) produces slightly lower ozone concentrations that the original CAMx 2014 base case (MEGAN)
  - Slightly improves ozone performance when overestimated (e.g., when not using ozone cutoff)
  - Slightly degrades ozone performance when underestimated (e.g., when using 60 ppb ozone cutoff)
  - Overall ozone model performance is comparable and basic MPE features nearly identical
- How to document in the NMED OAI Study?
  - 2014 database development and model evaluation report for original CAMx 2014 base case posted to NMED OAI website
    - https://www.wrapair2.org/pdf/NM_OAI_2014_BaseCase_MPE_v3.pdf
  - Ozone performance not appreciably changed

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CAMX 2028 BASE CASE RESULTS

NMED Exhibit 23 - 0016

SMAT CONFIGURATION

- SMAT run with "default" options except where highlighted:
  - Request spatial field output
    - Ozone DV spatial interpolation performed with and without using concentration gradients
  - Updated SMAT ozone observations file
  - Base year design values calculated centered on 2014 (i.e., 2012-2016)

Option	Main category	Setting	Default	This Study
Desired Output	Project Name			NMED_OAI
	Point Estimates Forecast	Forecast Ozone DV at monitors	Yes	Yes
	Quarterly model data	output used model data file	Yes	Yes
	Spatial Field	Interpolate monitor data to spatial field	No	Yes
	Neighbor File	Spatial Field	No	No
	Actions on run completion	Extract all selected output files	Yes	Yes
	Design Value Periods	output all DV periods	No	No
	Base an Future DV	Output Max DV	No	No
Data Input	Monitor Data	Ozone Data	SMAT_OZONE_MAX4DV_STD70_2002_2015.CSV	SMAT_OZONE_MAX4DV_STD70_2002_2018.CSV
	Model Data	Baseline File	EPA_test	2014v2.csv
		Forecast File	EPA_test	2028.csv
	Using Model Data	Temporal adjustment at monitor	3x3	3x3
			Max-paired in space	Max-paired in space
Filtering/ Interpolation	Choose Ozone DV	Start Year	2009-2011	2012-2014
		End Year	2011-2013	2014-2016
	Valid ozone monitors	Minimum number of DV	1	1
		Required DV	None selected	None selected
	Default interpolation method	Inverse Distance Weights	Yes	Yes
		check to set max interpolation distance	not checked	not checked
RRF/ Spatial Gradient	RRF setup	Top x modeled ozone days	10	10
		Initial threshold value (ppb)	not checked	not checked
		Minimum number days in baseline above threshold	NA	NA
		Minimum allowable threshold value (ppb)	60	60
		Min number of days above min allowable threshold	5	5
		Enable backstop minimum threshold for spatial fields	not checked	not checked
		subrange first day ozone used in RRF	-	-
		subrange last day ozone used in RRF	-	-
		paired days based on high concentration instead of date	not checked	not checked
	Spatial Gradient Setup	Start Value	1	1
		End Value	5	5

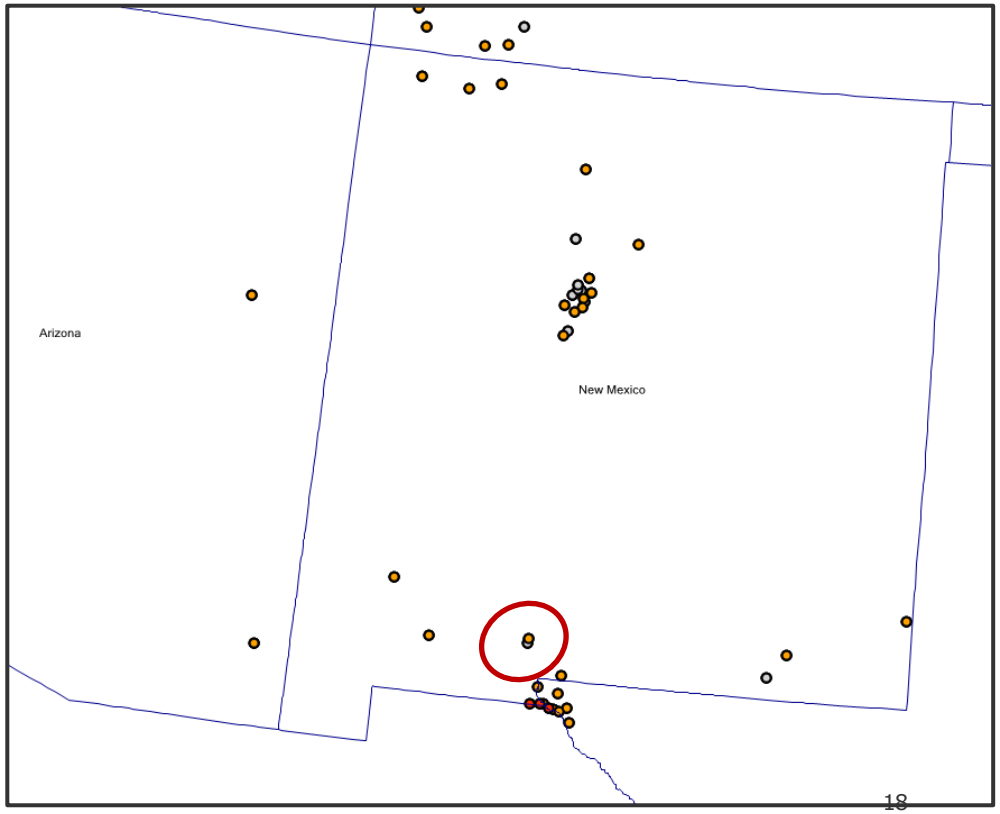
RAMBOLL

NMED Exhibit 23 - 0017

SMAT DESIGN VALUES NEW MEXICO

AQS ID	DVC: 2014 (ppb)	DVF: 2028 (ppb)	DVF – DVC (ppb)	County
350010023	66.3	60.9	-5.4	Bernalillo
350010024	68.0	62.3	-5.7	Bernalillo
350010029	66.0	61.0	-5.0	Bernalillo
350010032	67.0	62.6	-4.4	Bernalillo
350011012	65.0	59.1	-5.9	Bernalillo
350130008	66.3	60.0	-6.3	Dona Ana
350130017	67.0	61.9	-5.1	Dona Ana
350130020	67.0	62.3	-4.7	Dona Ana
350130021	72.0	67.0	-5.0	Dona Ana
350130022	71.3	66.1	-5.2	Dona Ana
350130023	65.0	60.3	-4.7	Dona Ana
350151005	69.0	66.7	-2.3	Eddy
350171003	62.0	59.0	-3.0	Grant
350290003	66.0	62.7	-3.3	Luna
350390026	64.0	60.8	-3.2	Rio Arriba
350431001	64.0	58.4	-5.6	Sandoval
350450009	64.3	61.0	-3.3	San Juan
350450018	67.0	64.8	-2.2	San Juan
350451005	63.7	60.8	-2.9	San Juan
350490021	64.3	60.6	-3.7	Santa Fe
350610008	66.3	62.2	-4.1	Valencia

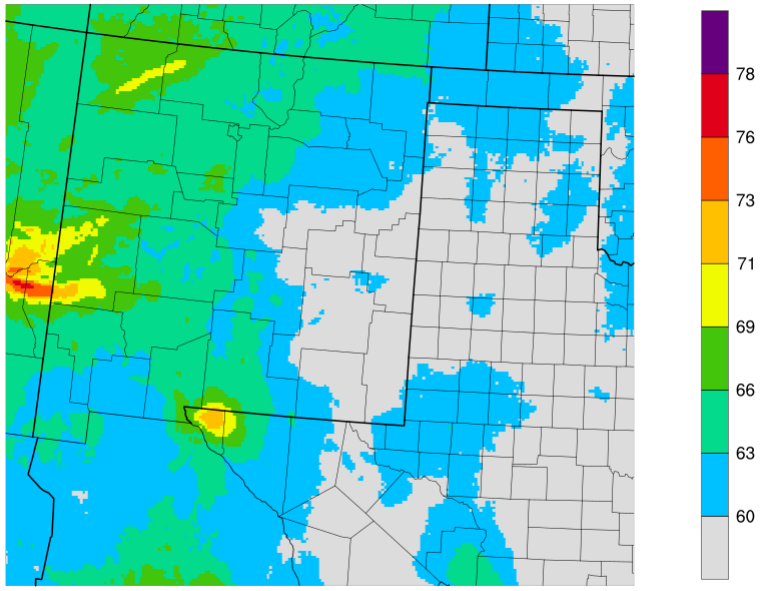
- Only two sites in NM have DV over 71 in the base case period (2012-2016)
  - Desert View and Santa Teresa



RAMBOLL

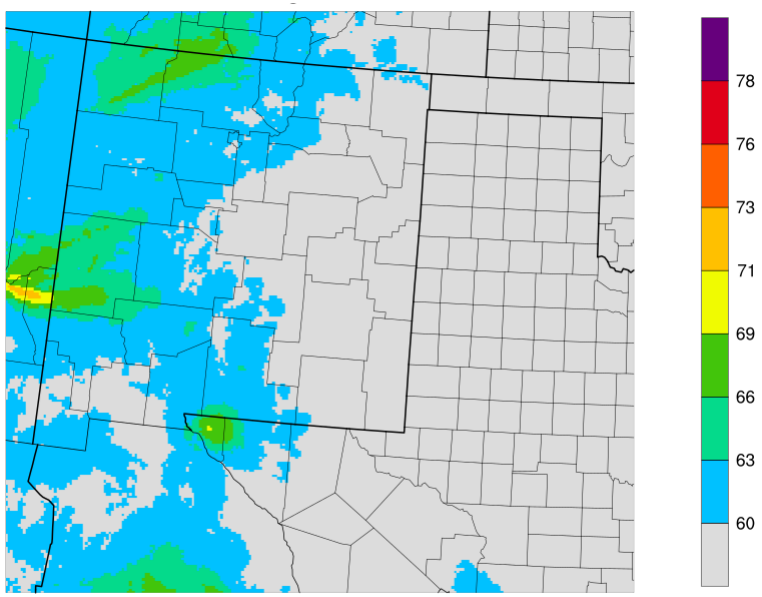
UNMONITORED AREA ANALYSIS USING MODELED GRADIENTS IN 2012-2014 OZONE DV SPATIAL INTERPOLATION

DVC: 2014



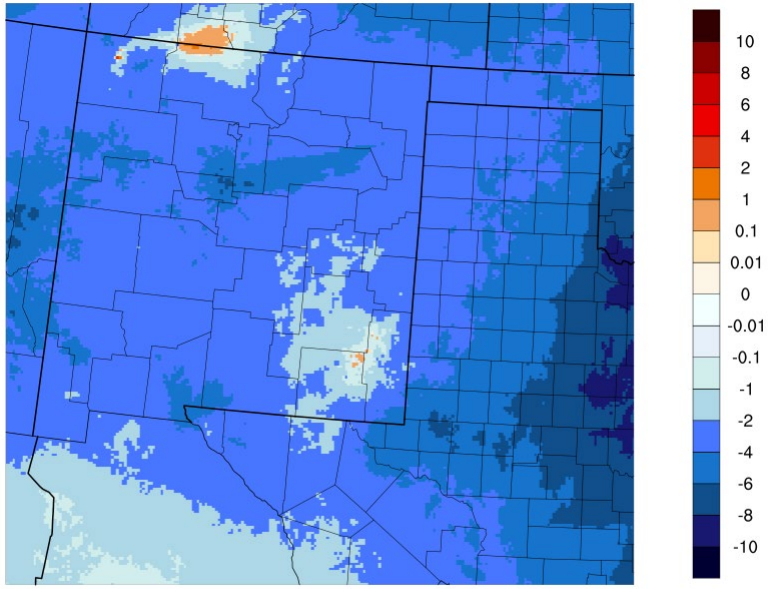
max(7,117) = 77.4 ppb
min(238,27) = 55.2 ppb

DVF: 2018



max(7,117) = 72.6 ppb
min(241,28) = 47.7 ppb

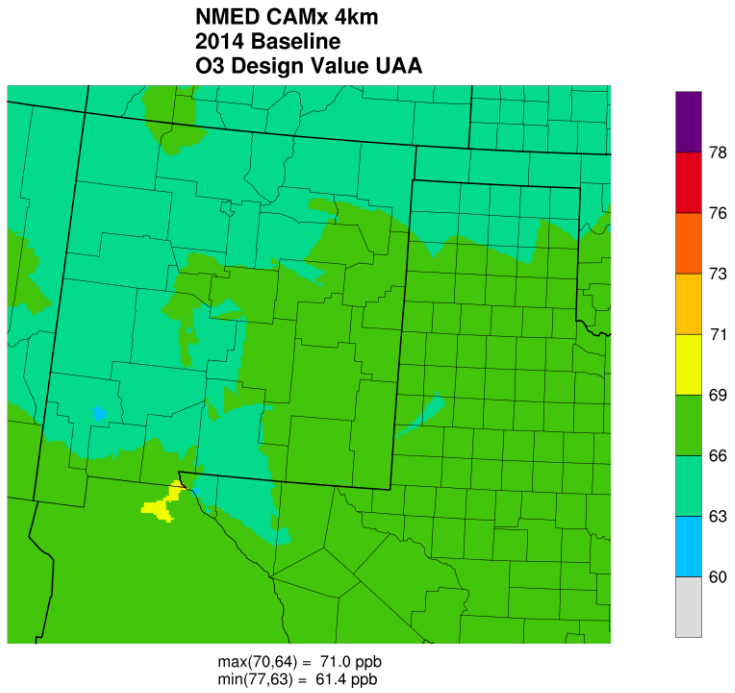
DVF - DVC



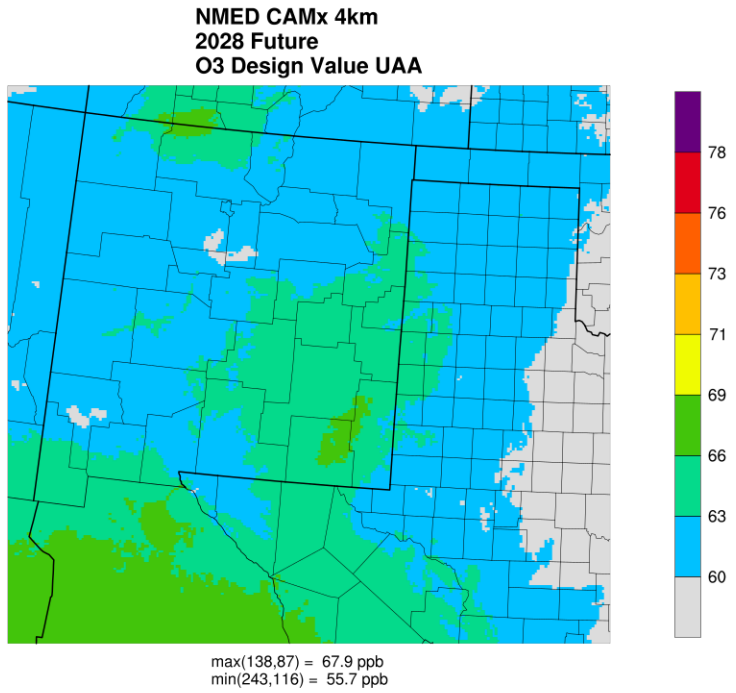
RAMBOLL

UNMONITORED AREA ANALYSIS NOT USING MODELED GRADIENTS IN 2012-2014 OZONE DV SPATIAL INTERPOLATION

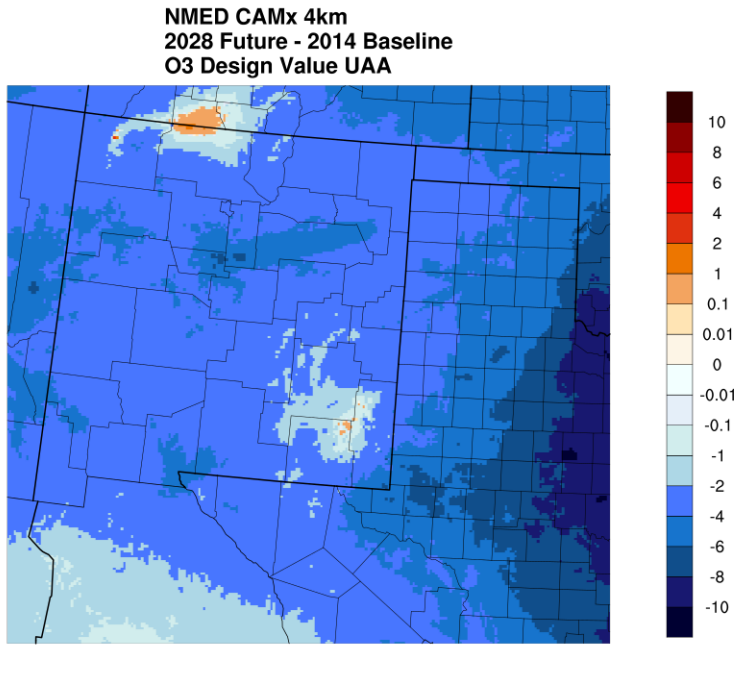
DVC: 2014



DVF: 2018



DVF - DVC

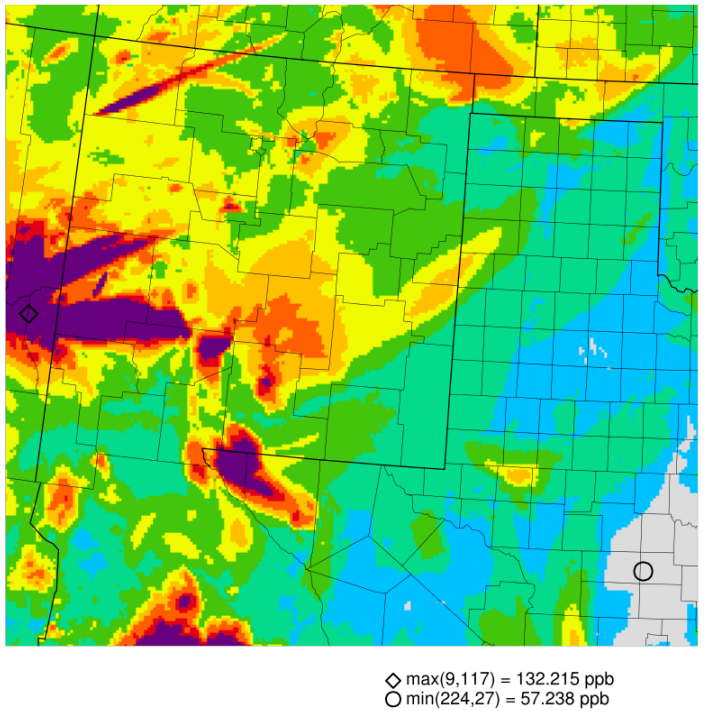


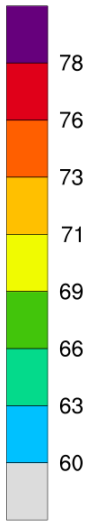
RAMBOLL

MODEL MDA8 RESULTS

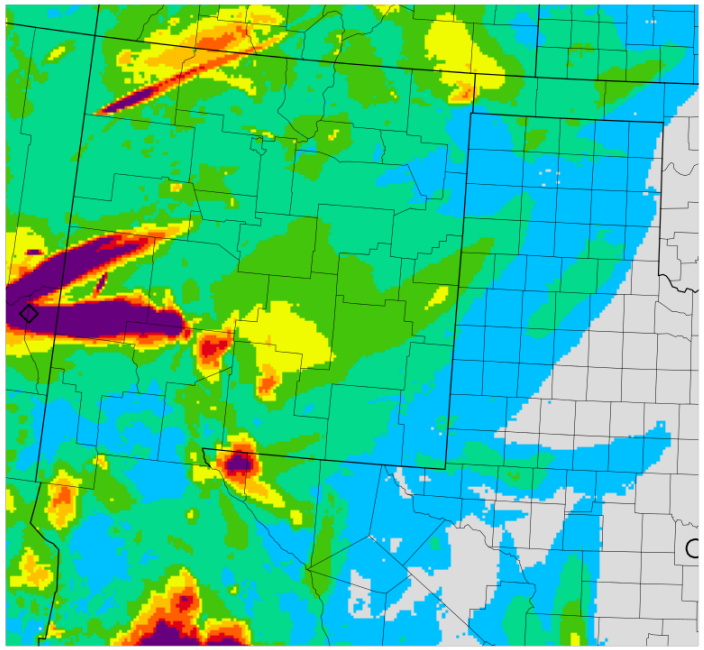
EPISODE MAXIMUM MDA8 AND DIFFERENCE

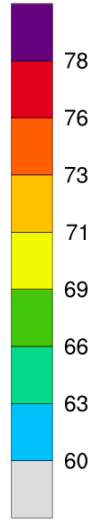
Max(2014)



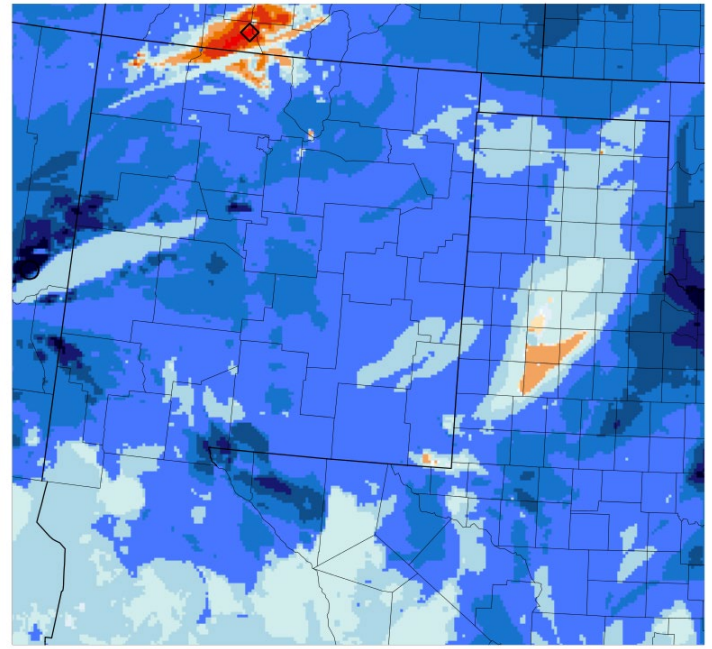


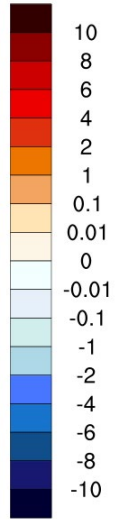
Max(2028)





Max(2028) – Max(2014)



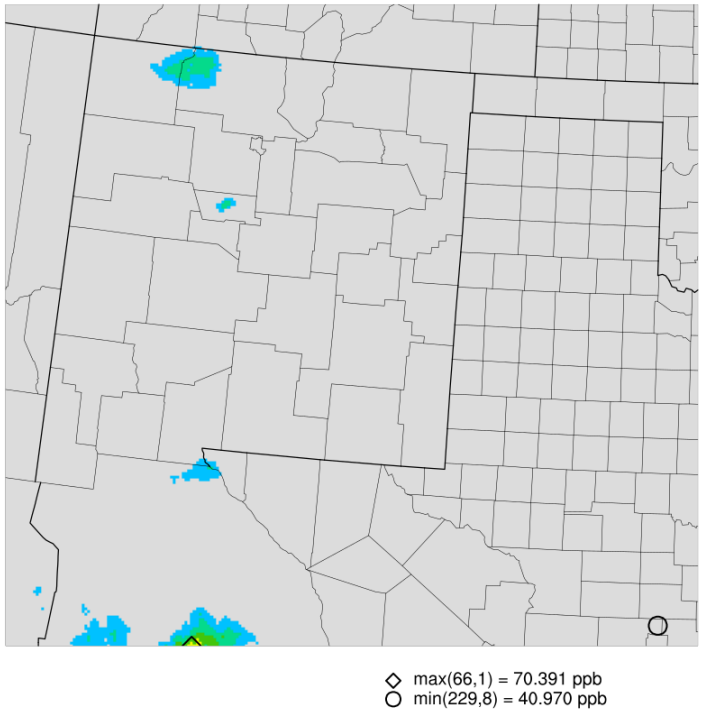


- Maximum values and differences are unpaired in time.
- High concentrations tend to occur on western part of the domain where there are no monitors

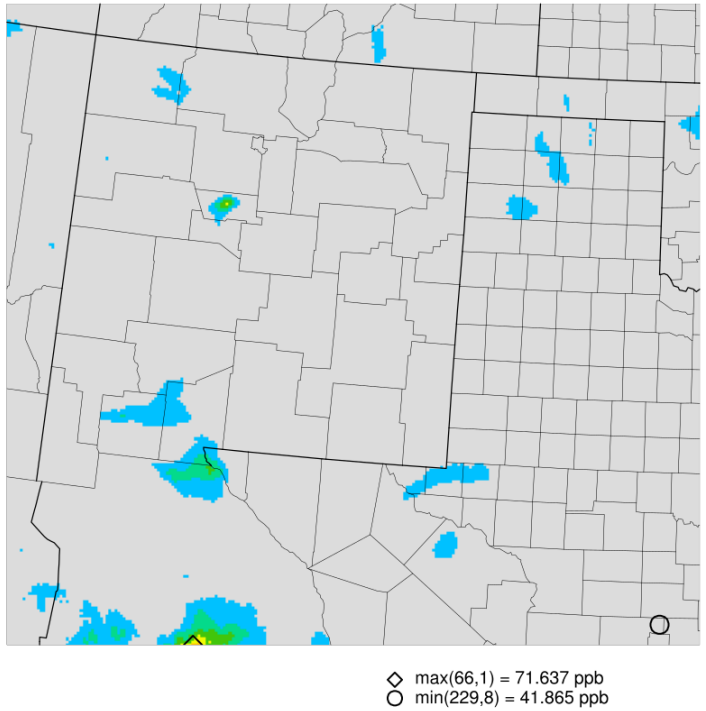
RAMBOLL

MAXIMUM ONE DAY DIFFERENCE: AUG 17

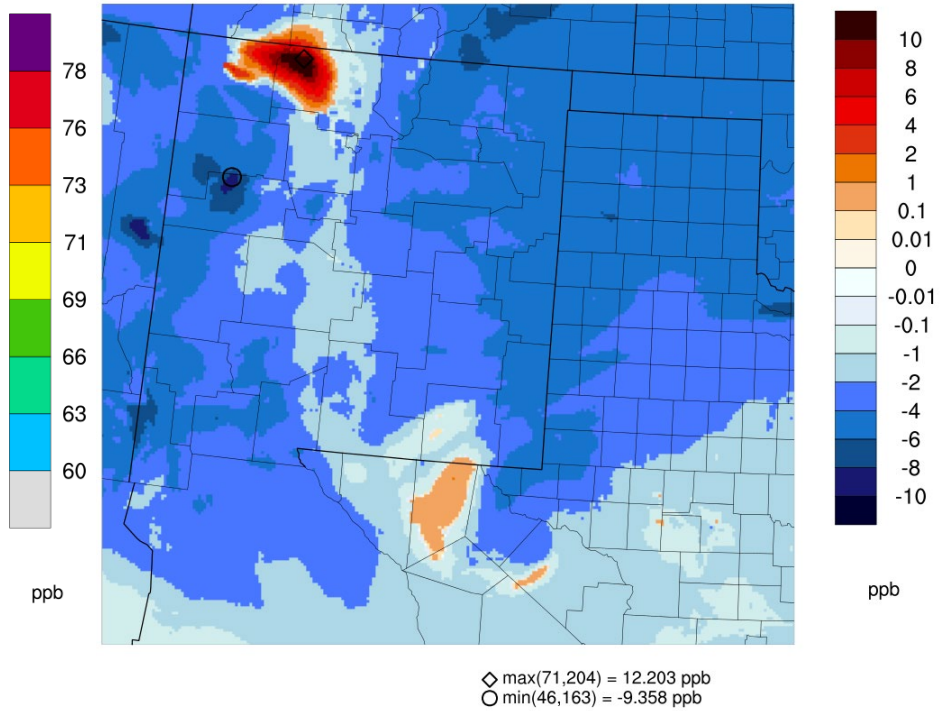
2028



2014



2028 - 2014



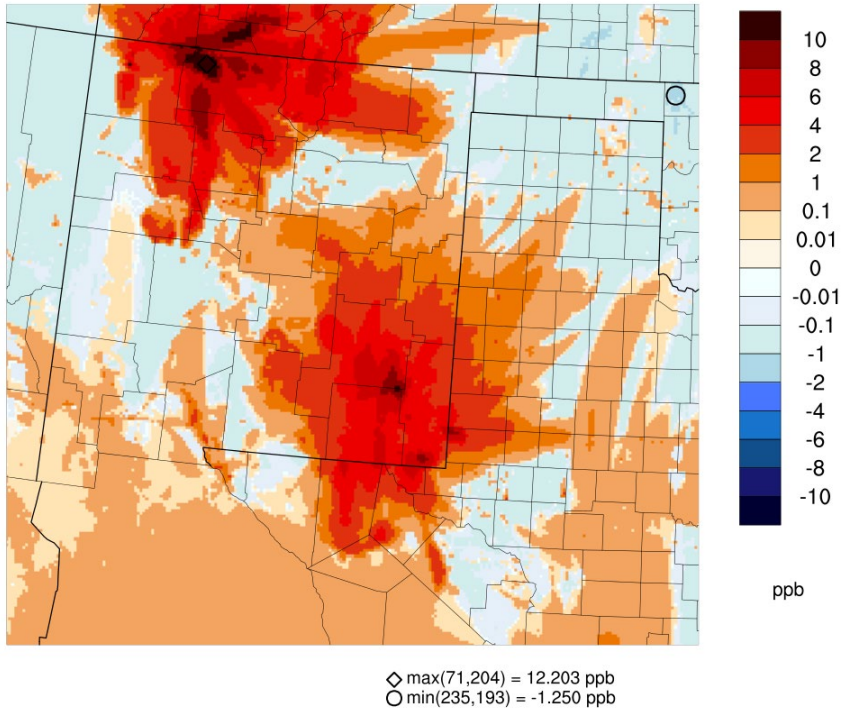
- Maximum difference (12.2 ppb) occurs in NW part of the domain in a day with low ozone concentrations

RAMBOLL

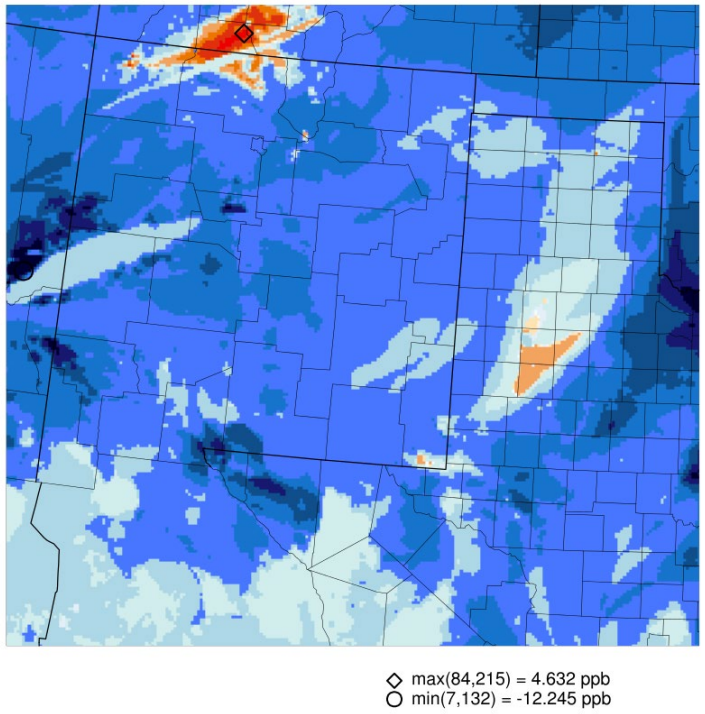
NMED Exhibit 23 - 0023

COMPARISON AMONG DIFFERENCES

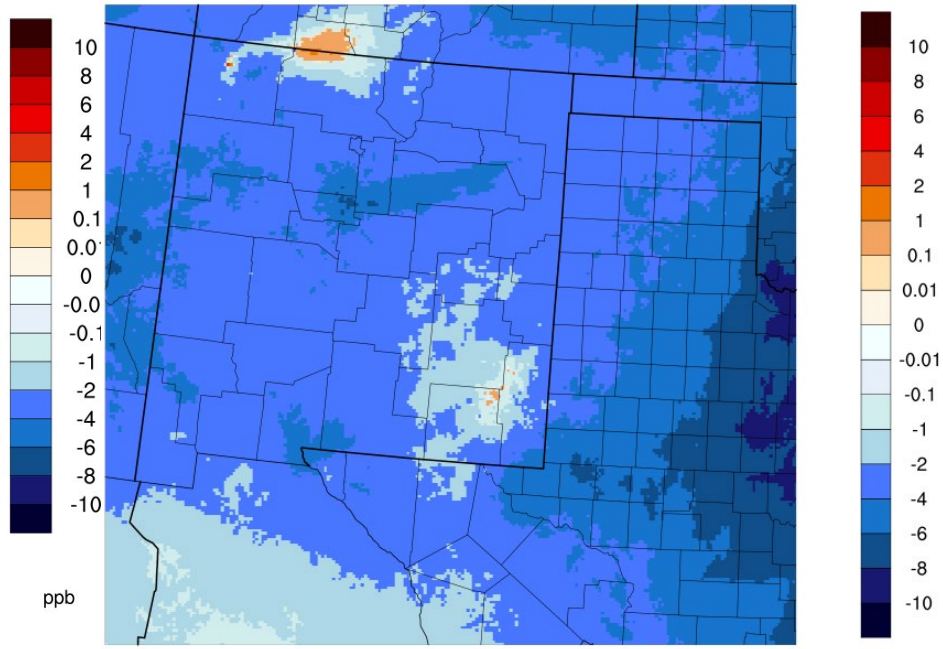
MAX (DIFF)



DIFF (MAX)



UAA DIFF



- Feature with increased ozone in 2028 over northern NM appears in all figures

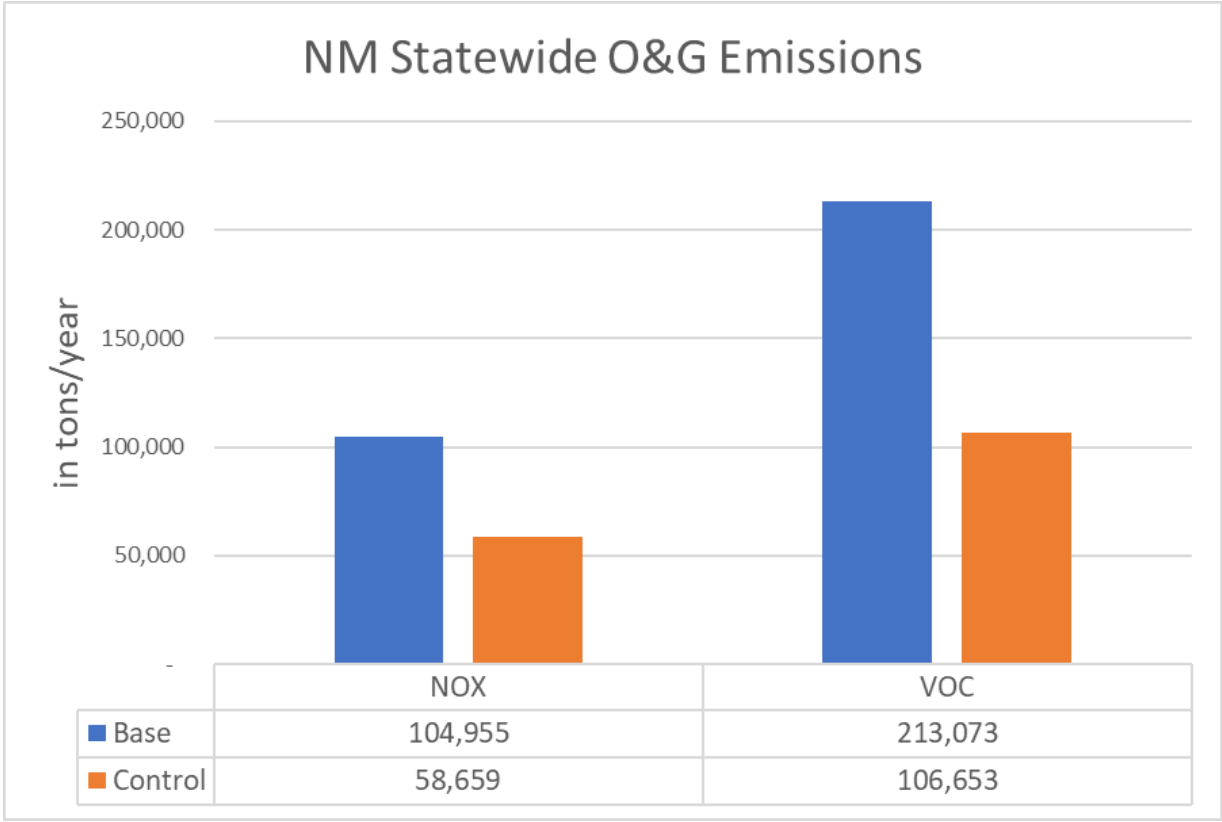
RAMBOLL

STATUS OF 2028 NEW MEXICO OIL AND GAS (O&G) CONTROL STRATEGY (CS) MODELING

RAMBOLL

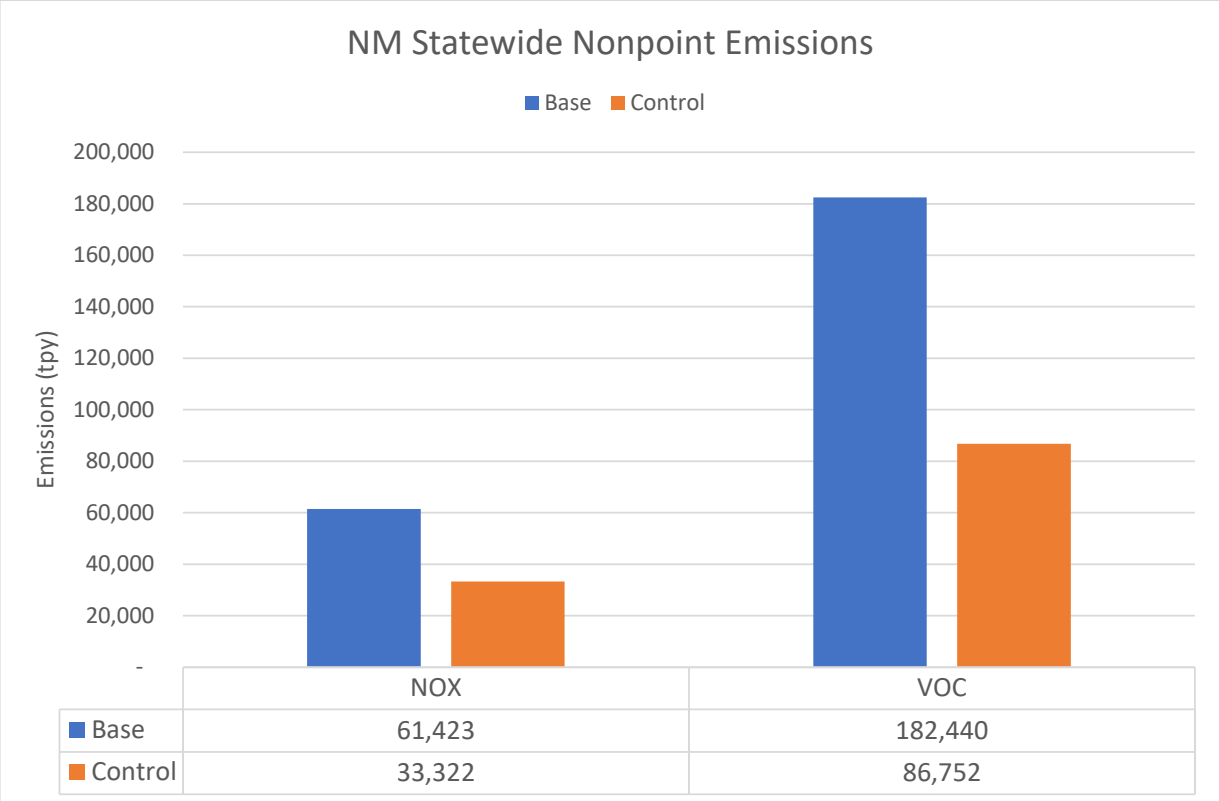
2028 O&G CONTROL SCENARIO EMISSIONS

- ERG provided revised point and nonpoint NM emissions for affected counties/SCCs/pollutants.
- 7 NM counties included in ERG's inventory
  - San Juan Basin (4 counties)
  - Permian Basin (3 counties)
- Bar chart display to show comparisons between 2028 Base and Control Scenario O&G emissions for NM
- 44% NOx and 50% VOC reductions in total O&G emissions

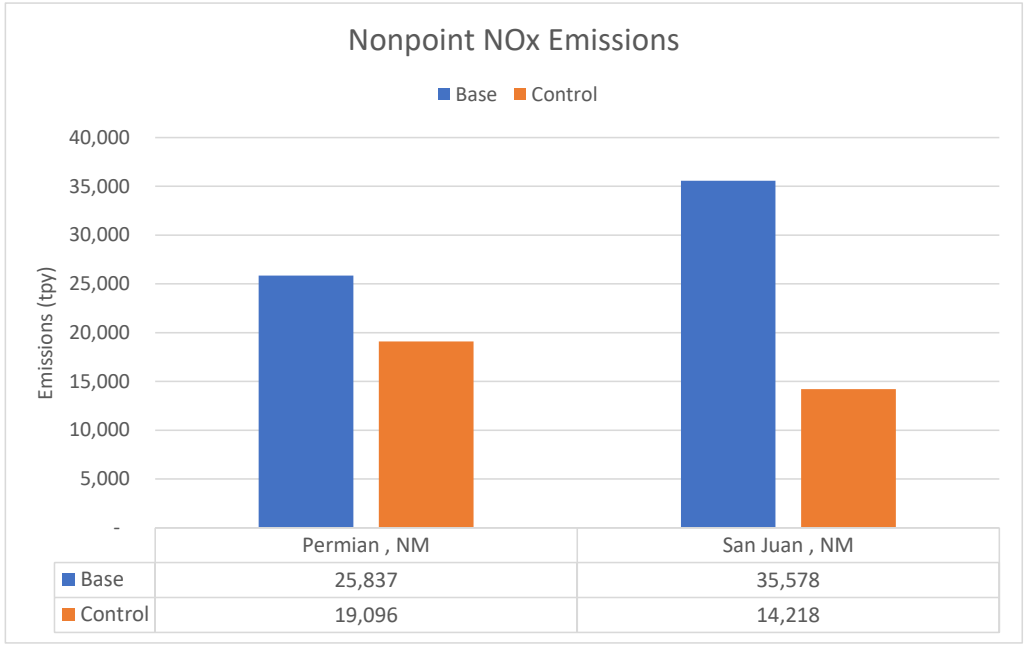


NMED Exhibit 23 - 0026

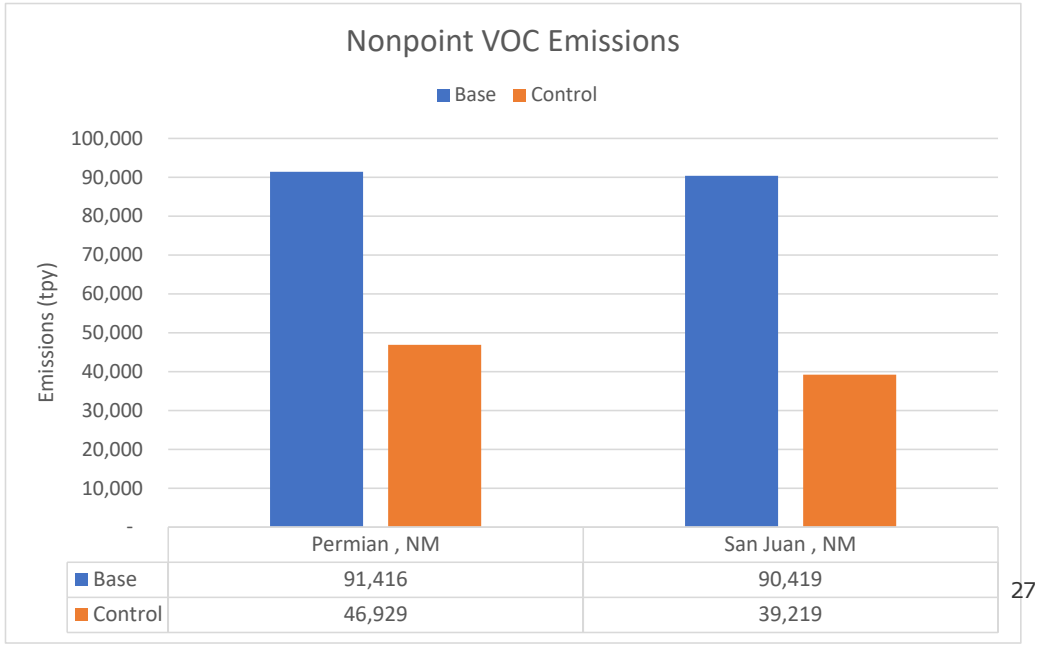
NEW MEXICO NONPOINT O&G



	NOX	VOC
Base	61,423	182,440
Control	33,322	86,752



	Permian , NM	San Juan , NM
Base	25,837	35,578
Control	19,096	14,218

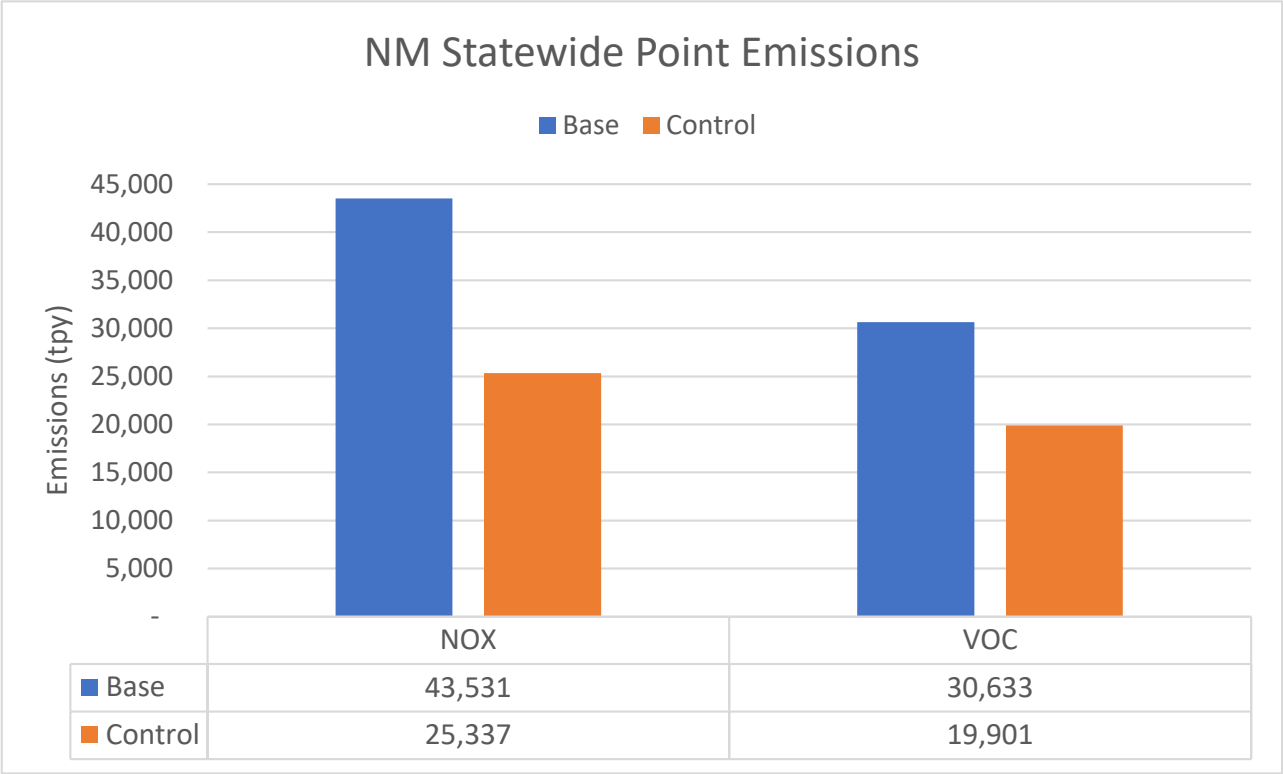


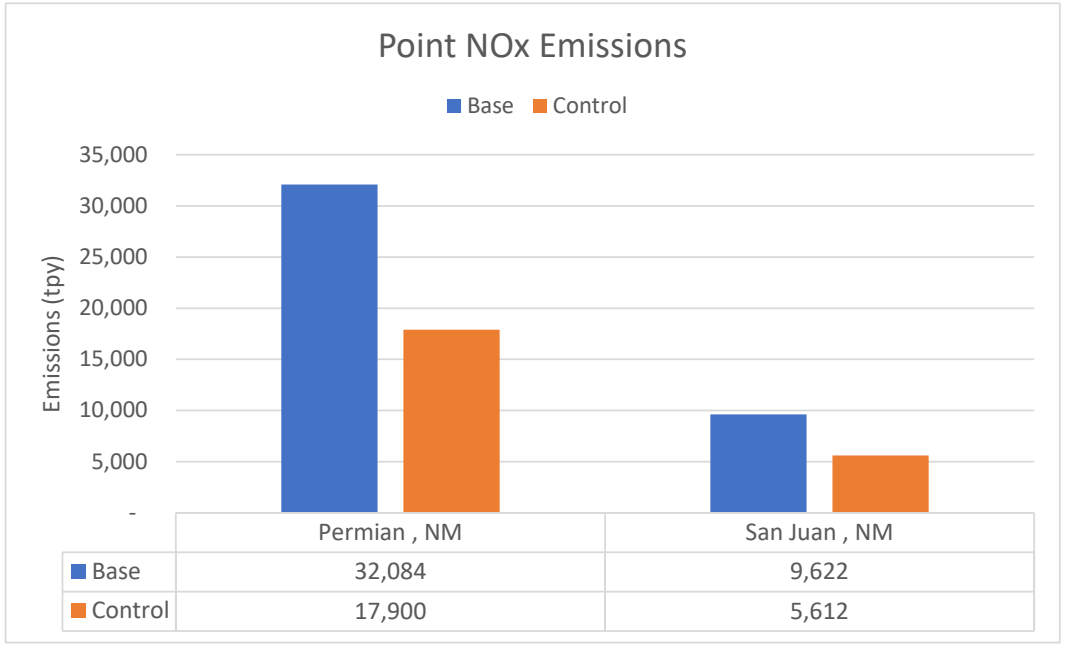
	Permian , NM	San Juan , NM
Base	91,416	90,419
Control	46,929	39,219

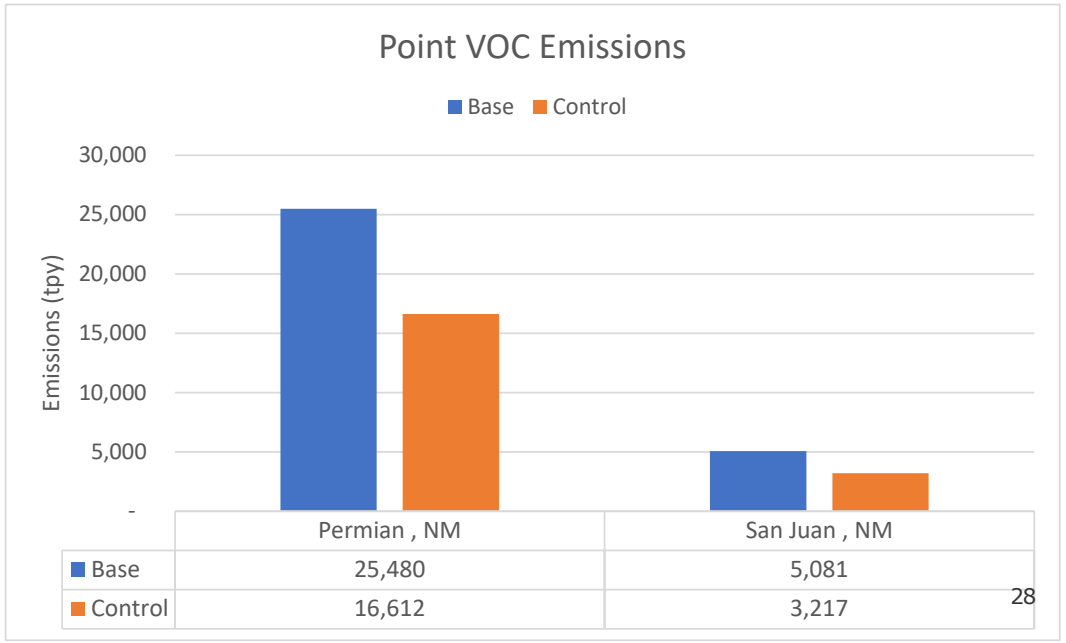
- 46% NOx reduction in nonpoint O&G
- 52% VOC reduction in nonpoint O&G

RAMBOLL

NEW MEXICO POINT O&G



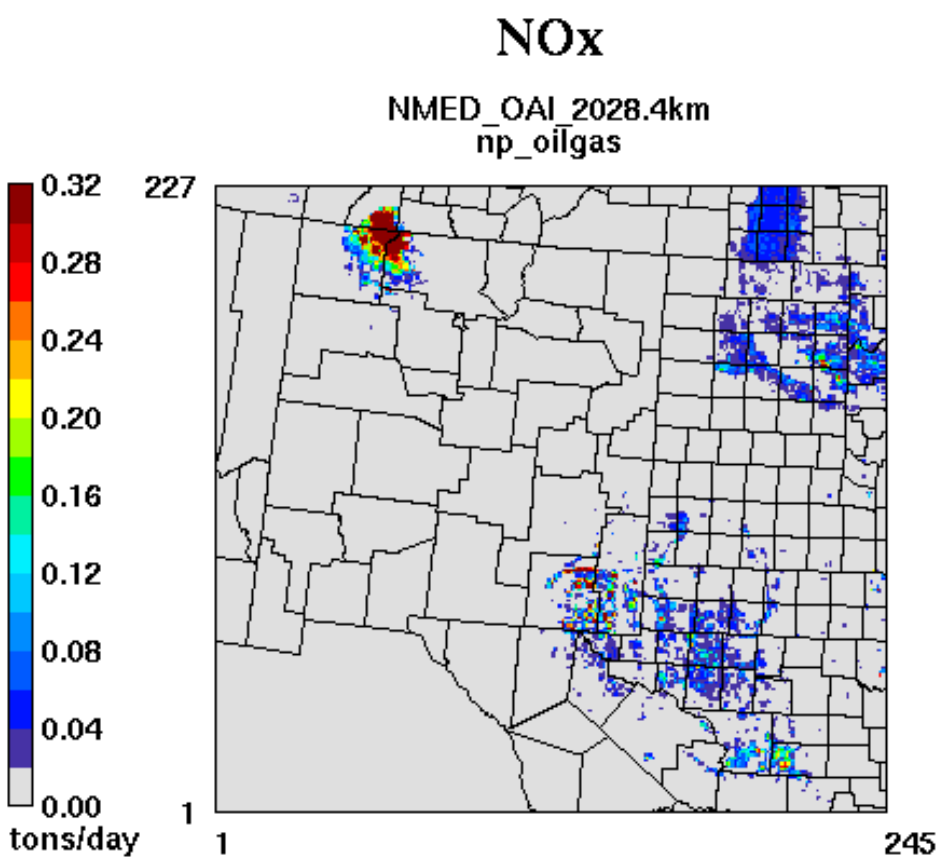


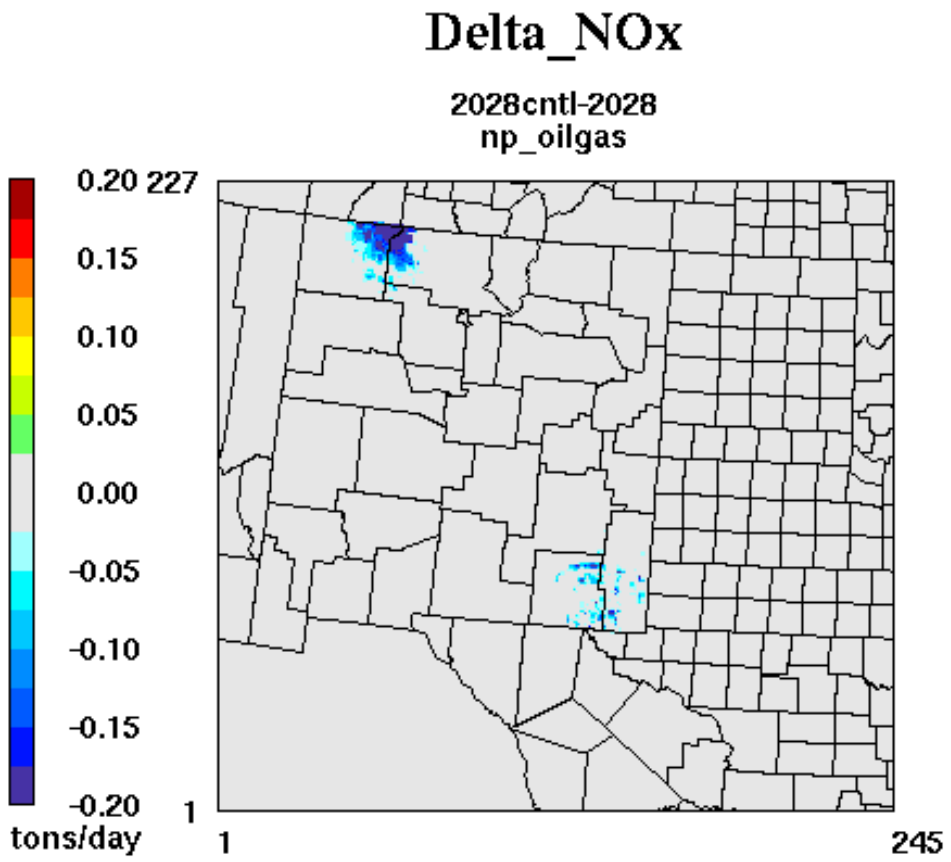


- 42% NOx reduction in point O&G
- 35% VOC reduction in point O&G

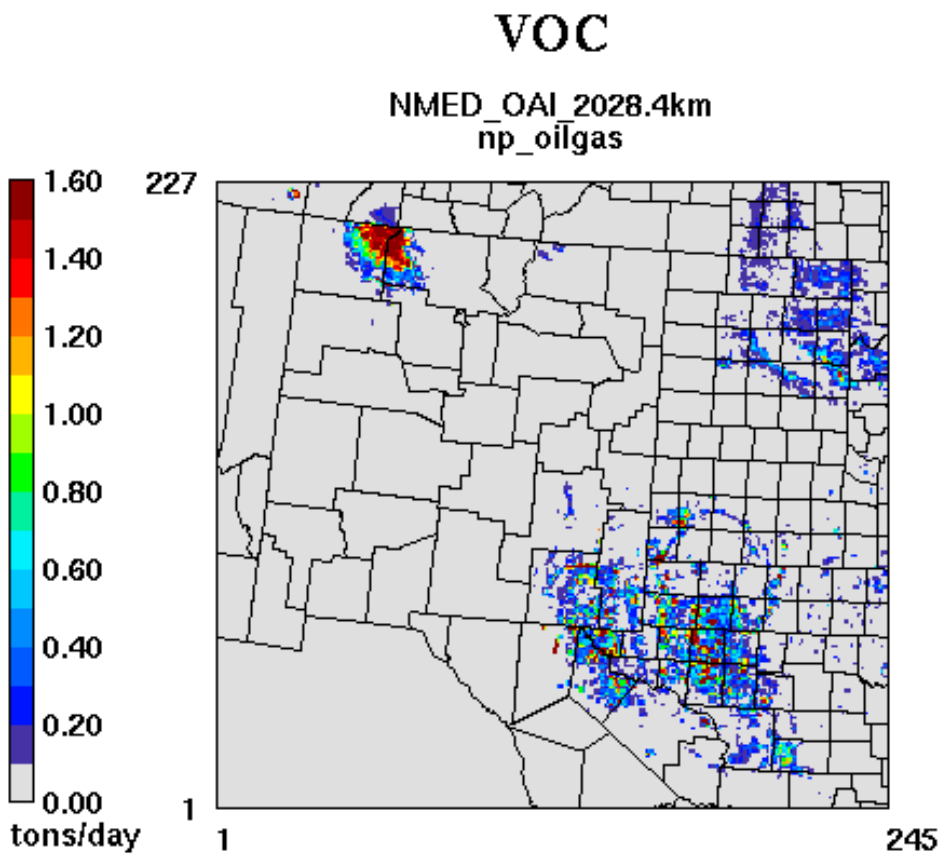
RAMBOLL

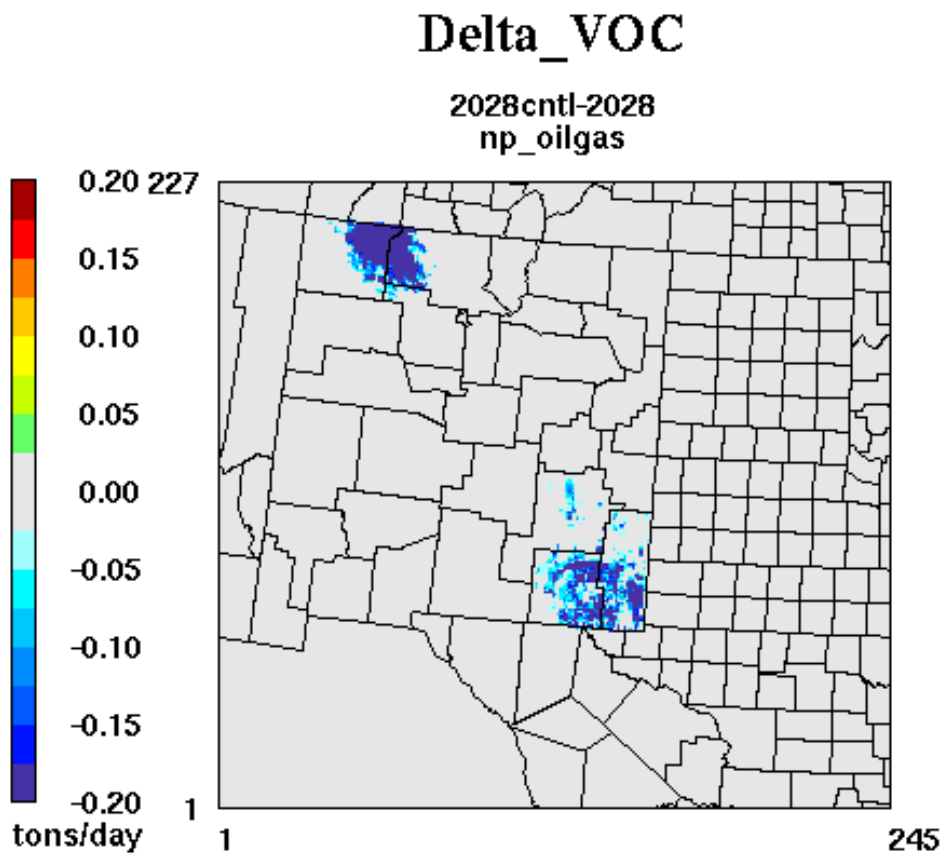
NONPOINT O&G COMPARISON: NOX



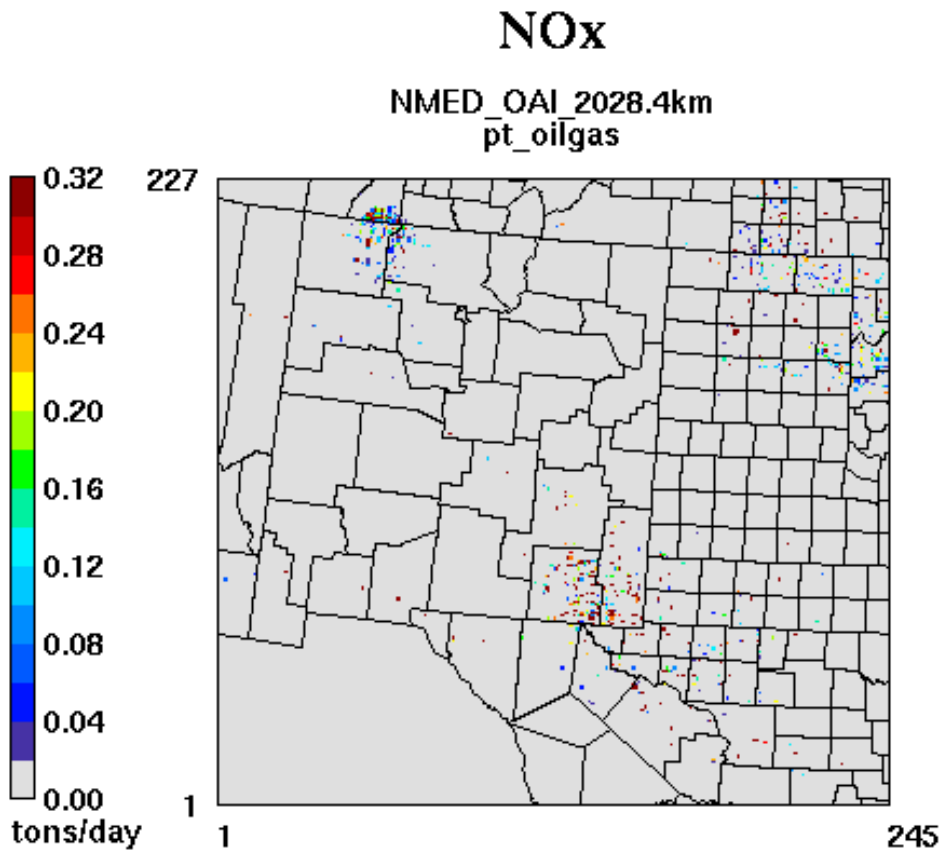


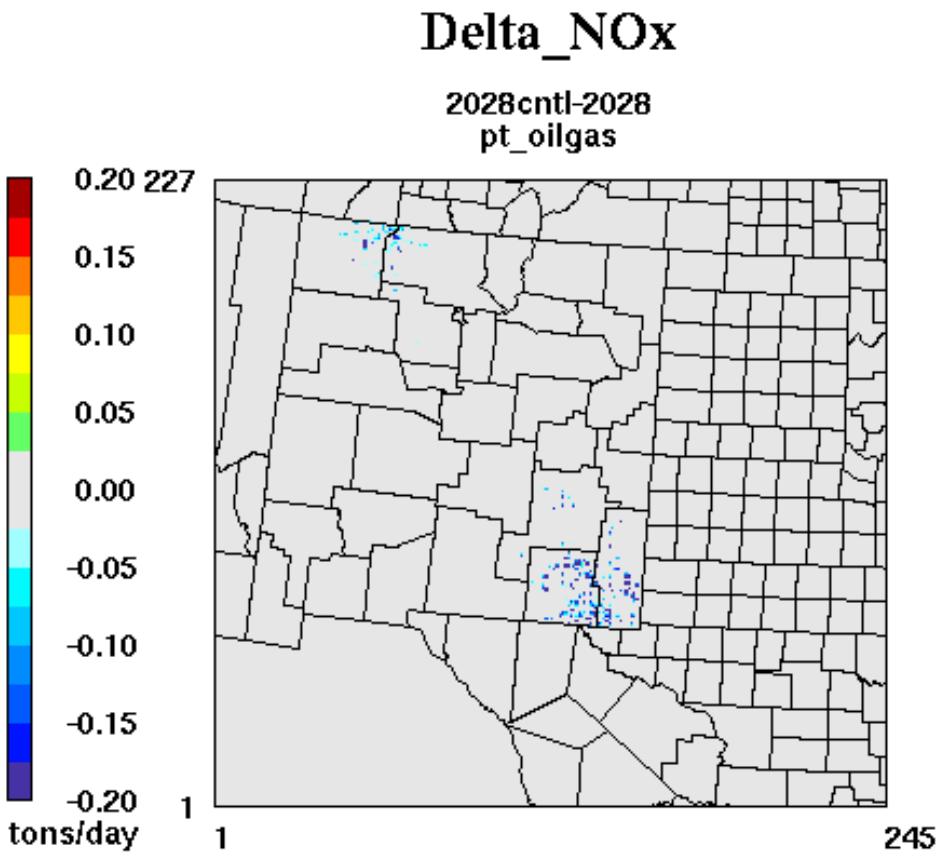
NONPOINT O&G COMPARISON: VOC



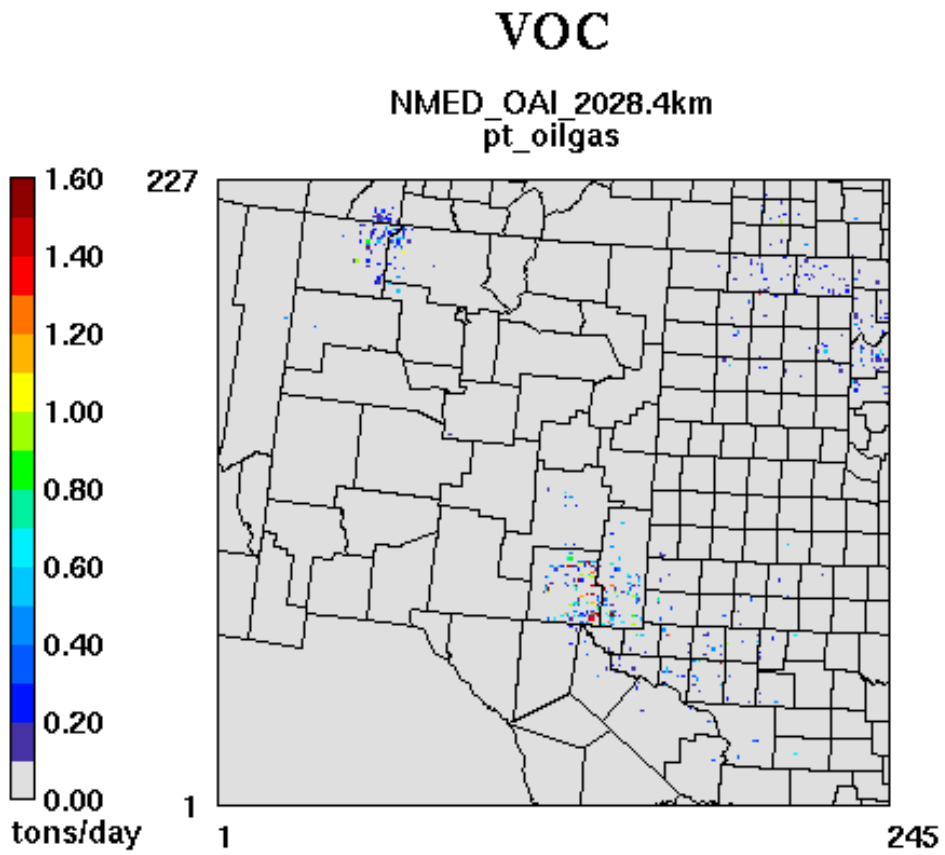


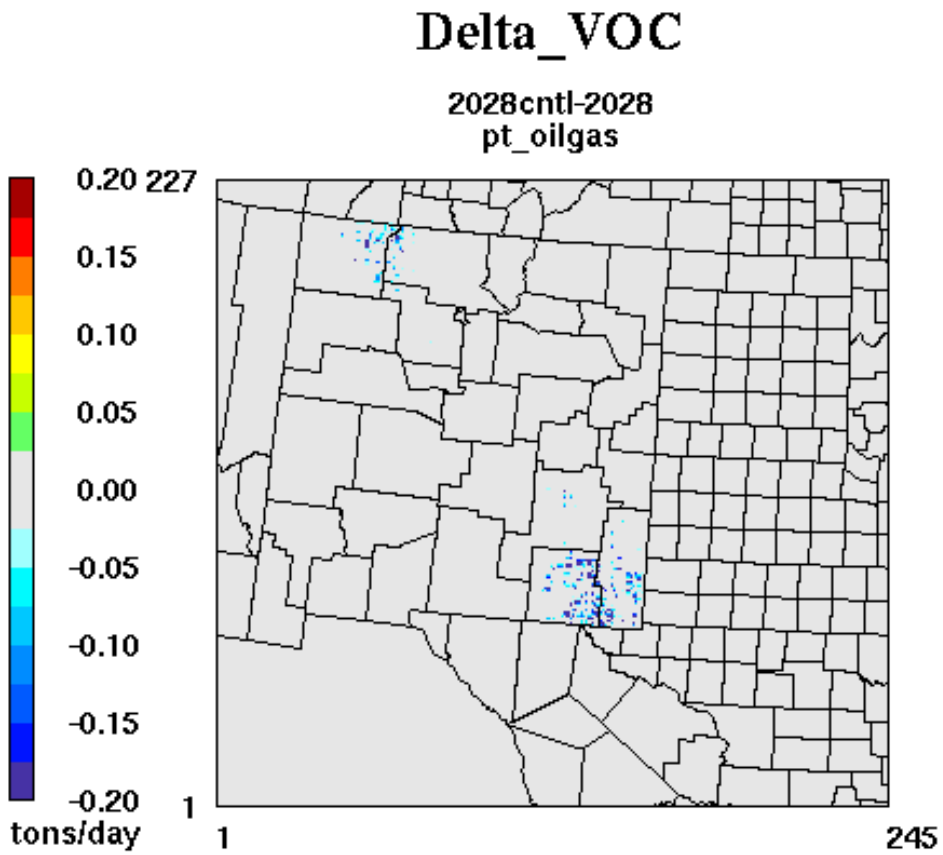
POINT O&G COMPARISON: NOX





POINT O&G COMPARISON: VOC





CURRENT STATUS AND NEXT STEPS

- Completed processing of 2028 O&G emissions for New Mexico O&G Control Scenario
- Started 2028 CAMx runs for O&G Control Scenario last Friday (2/5)
- Analyze CAMx outputs and provide ozone results to NMED

RAMBOLL

NMED Exhibit 23 - 0033

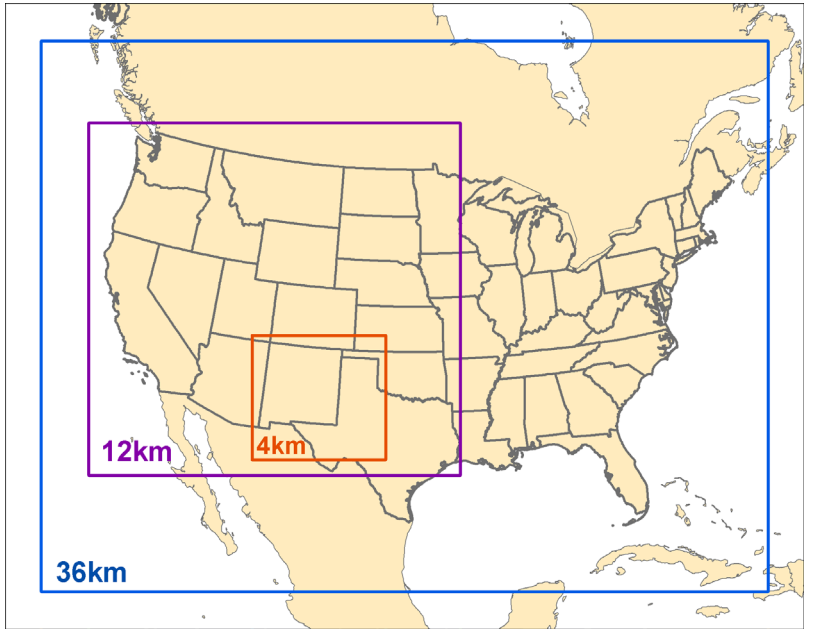
DESIGN OF 2028 NM O&G CS SOURCE REGION AND CATEGORY APCA OZONE SOURCE APPORTIONMENT

RAMBOLL

NMED Exhibit 23 - 0034

CAMX 2028 NM O&G CS APCA OZONE SOURCE APPORTIONMENT

- Purpose: To determine contributions of 9 Source Categories within New Mexico and rest of U.S. as well as international anthropogenic emissions to ozone concentrations in New Mexico under the 2028 NM O&G CS emissions scenario.
- Approach:
  - Model: CAMX version 7.1 (released December 2020)
  - Domains: NMED OAI Study 36/12/4-km
  - Period: May – August 2014
  - Boundary Conditions: WRAP 2014 GEOS-Chem
  - Emissions Scenario: WRAP 2028OTBa2 except:
    - Actual 2014 Fire Emissions (U.S. WF, Rx and Ag)
    - 2028 New Mexico Oil and Gas Control Strategy (2028 NM O&G CS)
  - Source Apportionment: Anthropogenic Precursor Culpability Assessment (APCA) version of CAMx ozone source apportionment tool.



RAMBOLL

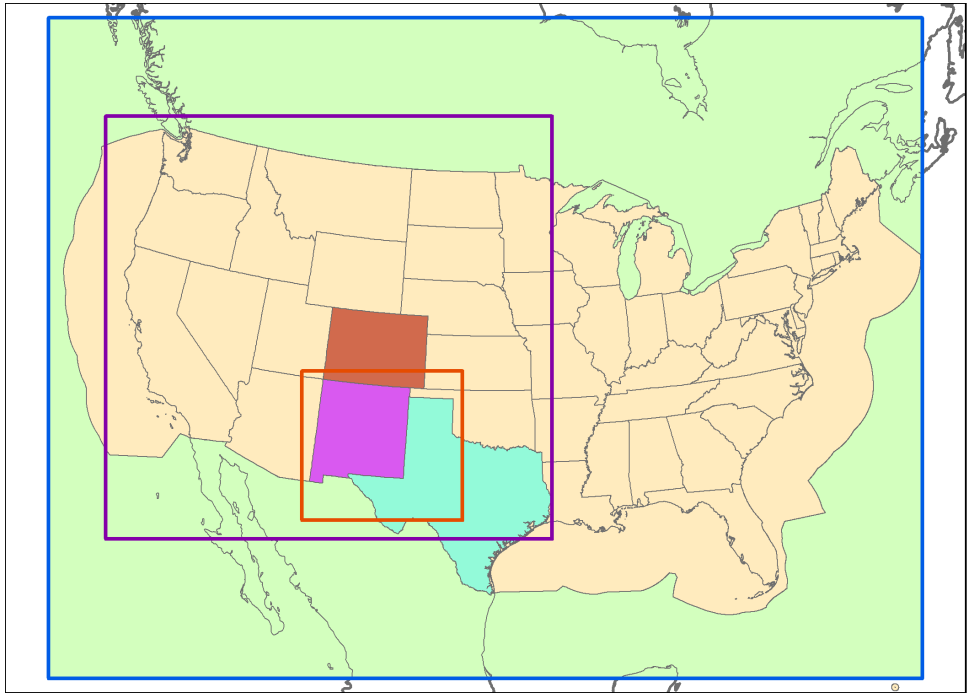
CAMX 2028 NM O&G CS APCA OZONE SOURCE APPORTIONMENT

- CAMx Ozone Source Apportionment Technology (OSAT) ozone source apportionment tool:
  - Ozone contributions are obtained for user-defined Source Groups:
    - A Source Group typically consists of a Source Category emitting from a geographic Source Region
    - For example, on-road mobile source emissions from New Mexico
  - OSAT uses reactive tracers for ozone (O3V and O3N) and precursors (e.g., VOC and NOx) and intermediate species (e.g., NO3 and PAN) that run in parallel to the host model
  - When ozone is formed in the host model, OSAT determines whether ozone formation is more VOC-limited or NOx-limited and assigns the ozone formed to Source Groups O3V or O3N based on the relative contribution of the Source Groups' limiting precursor to the total precursor concentration
- CAMx Anthropogenic Precursor Culpability Assessment (APCA) ozone source apportionment tool:
  - APCA differs from OSAT in that it recognizes that natural emissions are not controllable so only allocates ozone to natural emissions Source Groups when it is due to natural NOx interacting with natural VOC
  - When ozone is formed due to natural VOC and anthropogenic NOx under VOC-limited conditions, a case OSAT would assign to the natural Source Group, APCA redirects the ozone formed to the anthropogenic Source Group
  - APCA provides more control-strategy relevant information

RAMBOLL

CAMX 2028 NM O&G CS APCA OZONE SOURCE APPORTIONMENT

- **Definition of Source Groups**
  - Boundary Conditions (BCs) from 2014 GEOS-Chem runs:
    - BC_{Intl} - International anthropogenic emissions
    - BC_{USA} – U.S. anthropogenic emissions
    - $BC_{Natural}$ – Natural sources
    - BC_{Top} – BC above the top of domain
  - Source Categories (9):
    1. Natural (biogenic, lightning NOx, etc.);
    2. Fires (WF, Rx, Ag, other);
    3. Oil and gas point sources (surrogate for midstream);
    4. Oil and gas non-point sources (surrogate for upstream;
    5. EGU point;
    6. Non-EGU point;
    7. On-road mobile;
    8. Non-road mobile; and
    9. Remainder anthropogenic.
  - Source Regions (5):
    - New Mexico
    - Texas
    - Colorado
    - Remainder U.S.
    - International (Mex, Can, CMV > 200 nmi)
  - 50 Source Groups (50 = 5 x 9 + 5)



RAMBOLL

NMED Exhibit 23 - 0037

CAMX 2028 NM O&G CS APCA OZONE SOURCE APPORTIONMENT

- Post-Processing of CAMx 2028 NM O&G CS APCA Source Apportionment Results
  - MDA8 Ozone Concentrations at the Monitoring Sites
    - Generate stacked Bar Charts and Pie Charts of source contributions using an Excel Dashboard
    - User select monitoring sites and group of 10 days to display, and stacked bar charts are generated for the 10 days and pie chart for the average of the 10 days (e.g., 10 days used in SMAT for 2028 ozone projections)
  - Spatial maps of MDA8 ozone for Source Categories within New Mexico across 4-km domain
    - Provides a footprint of New Mexico Source Category contributions
    - Other spatial maps of MDA8 ozone (e.g., Source Categories and State across Western U.S.)
  - International Anthropogenic Emission Contributions
    - Run SMAT removing contributions from International anthropogenic emissions (i.e., Mex/Can/CMV + BC_{Intl}) to obtain 2028 ozone DVs w/o International emissions and compare with 2028 NM O&G CS ozone DV projections

RAMBOLL

NMED Exhibit 23 - 0038

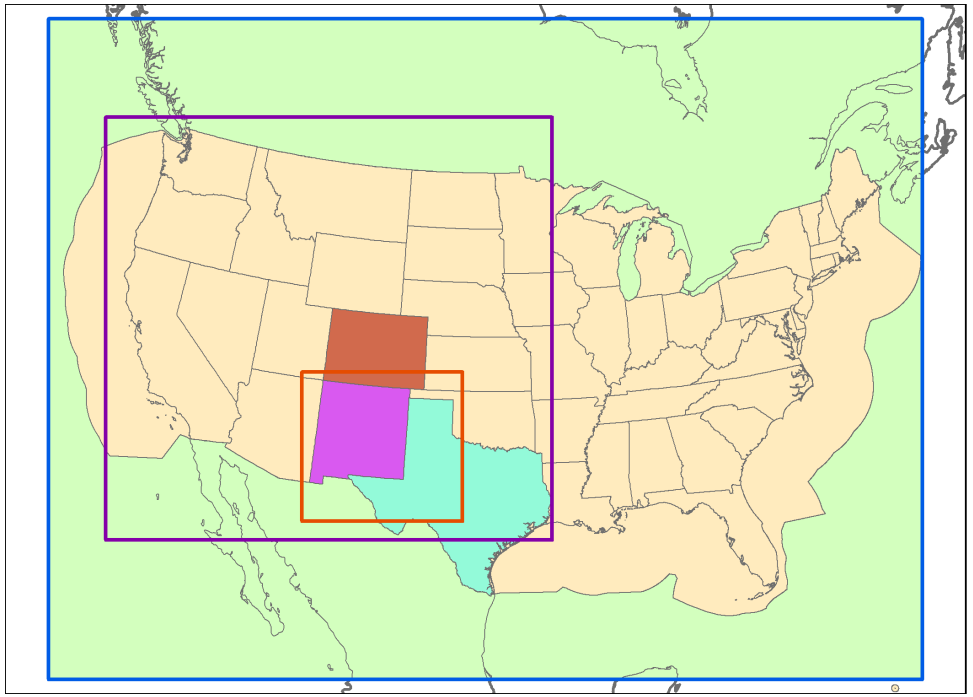
DESIGN OF 2028 NM O&G CS OSAT VOC-VS. NOX-LIMITED OZONE SOURCE APPORTIONMENT

RAMBOLL

NMED Exhibit 23 - 0039

CAMX 2028 NM O&G CS OSAT OZONE SOURCE APPORTIONMENT

- Purpose: To estimate relative amount of VOC-Sensitive vs. NOx-sensitive ozone formation within 2028 New Mexico.
- Use the OSAT version of CAMx ozone source apportionment tool
- Definition of Source Groups
  - Source Regions (5):
    - Use same 5 Source Regions as APCA SA run
  - Source Categories (2):
    - Anthropogenic Emissions
    - Natural and Fire Emissions
  - 12 Source Groups (5 x 2 + 2 [IC,BC])
    - Will run faster than CAMx APCA SA Run (50 Source Groups)



RAMBOLL

NMED Exhibit 23 - 0040

CAMX 2028 NM O&G CS OSAT OZONE SOURCE APPORTIONMENT

- Post-processing of CAMx 2028 NM O&G CS OSAT ozone source apportionment results
  - Monitoring site displays
    - Extract Hourly and MDA8 ozone at the monitoring sites and load in Excel Dashboard to display stacked Bar Charts and Pie Charts of IC/BC and VOC-sensitive vs. NOx-sensitive ozone formation contributions
  - Spatial maps across 4-km NM domain depicting fraction of MDA8 ozone formed under VOC-sensitive vs. NOx-sensitive formation conditions:
    - Total MDA8 ozone; BC ozone; O3V ozone; and O3N ozone
    - Ratio of O3V/O3N: When > 1 → more VOC-sensitive and when < 1 → more NOx sensitive
    - Percent NOx-sensitive ozone formation to total ozone without BC (i.e., 100 x ∑O3N /(∑O3N +∑O3V)

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NMED Exhibit 23 - 0041

NEW MEXICO OZONE ATTAINMENT INITIATIVE

Sensitivity of 2028 Ozone Projections to Current Year Ozone Design Values and Preliminary Draft Air Quality Technical Support Document

Marco Rodriguez, Pradeepa Vennam, Jung Chien, John Grant, Tejas Shah and Ralph Morris, Ramboll

Tom Moore and Mary Uhl, WESTAR

NM OAI Study Webinar

March 12, 2021

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SENSITIVITY OF 2028 OZONE PROJECTIONS TO DVC & AQTSD

01 Summary of 2028 Base and O&G Control Strategy Ozone Design Value Projections following EPA Guidance (from Feb 24, 2021)

02 Sensitivity of 2028 Ozone Projections to Current Year Ozone Design Values ($DVC_{2015\text{-}2019}$ and $DV_{2017\text{-}2019}$)

03 Preliminary Draft Air Quality Technical Support Document (AQTSD)

04 Status of 2028 O&G Control Strategy Source Sector APCA Ozone Source Apportionment Modeling

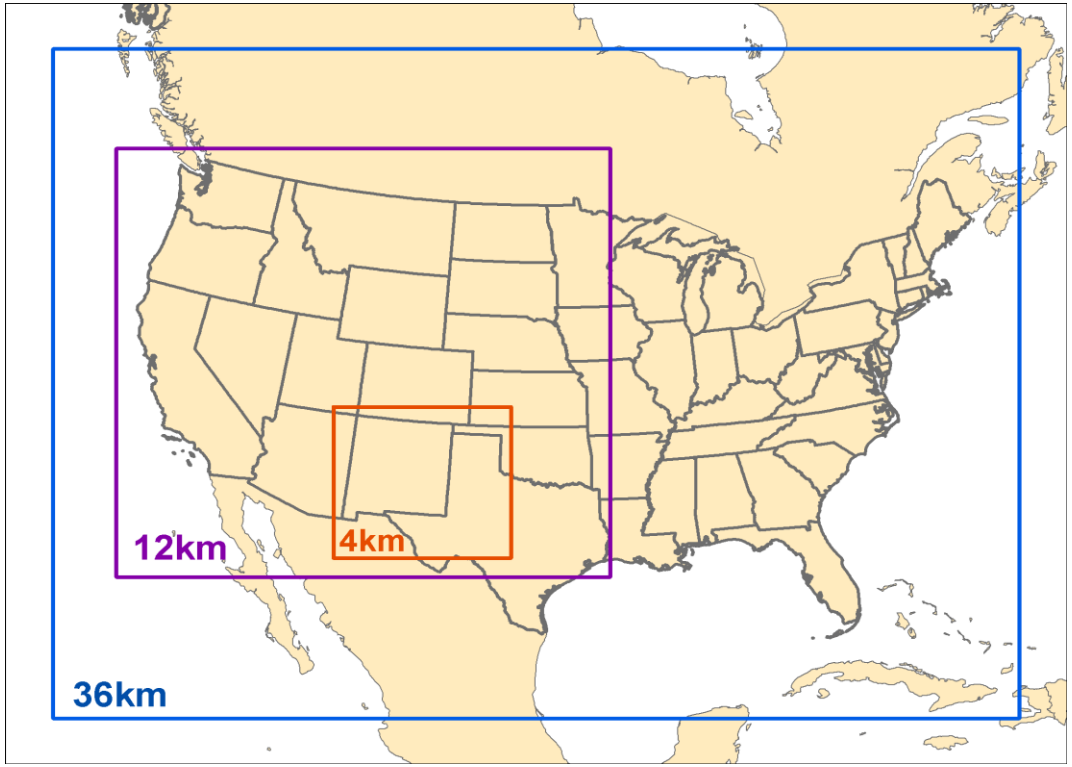
05 Status of 2028 O&G Control Strategy VOC/NOx Sensitivity OSAT Ozone Source Apportionment Modeling

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NMED Exhibit 24 - 0002

CAMX 2014 NM OAI STUDY MODEL CONFIGURATION

- Episode: May-August 2014
  - 16-day spin-up before first high ozone day in NM
    - 68 ppb on May 17
- 36/12/4-km Modeling Domains
  - 36/12-km domains same as WRAP Regional Haze
  - New 4-km New Mexico domain
- Boundary Conditions (BC) WRAP 2014 GEOS-Chem
- Four Meteorological Diagnostic Sensitivity tests
  - Selected WRF/NAM with Kv=CMAQ
- WRAP 2014v2 base year emissions
  - EPA NEI2014v2 w/ western state updates
- WRAP 2028OTBa2 for future year w/ 2014 actual fires and new 2028 NM O&G



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FUTURE YEAR OZONE DESIGN PROJECTION APPROACH

- EPA's Ozone Modeling Guidance (2018) recommends making future year ozone Design Value (DVF) projections using the relative change in modeling results between the base (2014) and future (2028) years to scale the current year ozone design value (DVC)
  - The model derived scaling factors are called Relative Response Factors (RRFs) and are the ratio of the future to current year CAMx modeling results averaged across the 10 highest modeled MDA8 ozone days > 60 ppb in the current (2014) year base case near the monitor:

$$RRF = \sum MDA8\ Ozone_{2028} / \sum MDA8\ Ozone_{2014}$$

$$DVF = RRF \times DVC$$

  - By "near the monitor," the maximum 2014 modeled MDA8 ozone within a 3x3 array of 4-km grid cells centered on the monitor from the 2014 is used
  - If there are not 10 modeled MDA8 ozone days in the 2014 base case > 60 ppb for the RRFs, then you can use less than 10 days, but EPA guidance recommends there be at least 5 days
  - EPA recommends that the observed current year design value (DVC) be based on the average of 3 years of ozone DVs over 5-years centered on the base modeling year (2014):

$$DVC_{2012\text{-}2016} = 1/3 \times (DV_{2012\text{-}2014} + DV_{2013\text{-}2015} + DV_{2014\text{-}2016})$$

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NMED Exhibit 24 - 0004

FUTURE YEAR OZONE DESIGN PROJECTION APPROACH

- EPA has codified their recommended future year ozone DVF projection technique in the Software for Modeled Attainment Test (SMAT)
- SMAT was applied using default settings, with one exception, and the 2014v2 and 2028 Base Case and 2028 O&G Control Strategy CAMx modeling results to obtain projected 2028 ozone DVF projections:
  - Use 3x3 array of 4-km cells centered on monitor for "near the monitor"
  - Use 10 days for RRFs with CAMx 2014 MDA8 ozone > 60 ppb
    - If less than 10 days with MDA8 ozone > 60 ppb use 4 days minimum (exception)
    - Default minimum number of days is 5, needed to relax to pick up Hobbs monitor in Lea County
  - Use current year design value based on average of 3 DVs centered on 2014
    - $DVC_{2012\text{-}2016}$
- SMAT Unmonitored Area Analysis (UAA) to obtain 2028 ozone DVF projections throughout 4-km New Mexico modeling domain
  - Recommend use spatial interpolation of monitoring site DVC without using modeled concentration gradients

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PROJECTED 2028 OZONE DVFS FOLLOWING EPA GUIDANCE

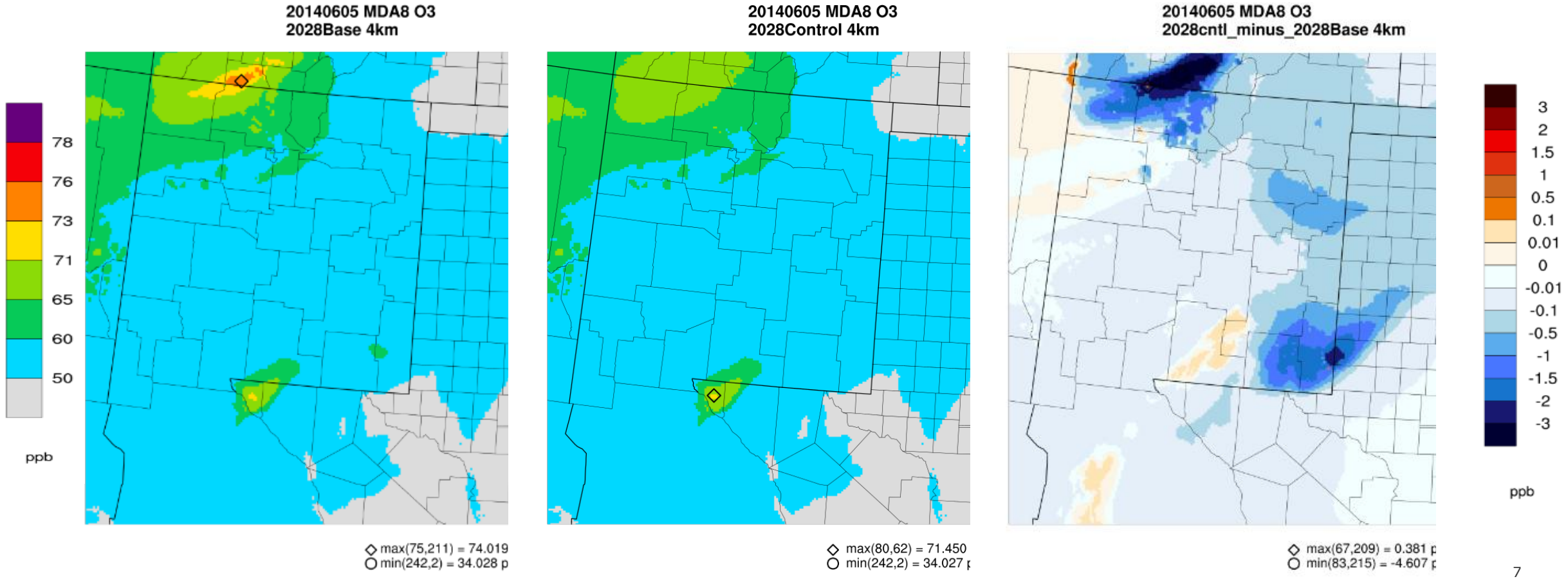
- Two sites have current year $DVC_{2012-2016}$ above the 2015 ozone NAAQS:
  - Desert View = 72.0 ppb
  - Santa Teresa = 71.3 ppb
- Using EPA guidance, all sites have 2028 ozone DVF below NAAQS
- 2028 O&G Control Strategy reduces 2028 ozone DVF by:
  - -0.3 to -1.5 ppb North NM Sites
  - -0.2 to -0.5 ppb Bernalillo County
  - -0.1 to -0.3 ppb South NM Sites

AQS_ID	2012-16	Projected 2028 DVF			Site Name	State
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
Northern New Mexico						
350390026	64.0	60.8	60.0	-0.8	Coyote Ranger District	NM
350431001	64.0	58.4	58.1	-0.3	Bernalillo (E Avenida)	NM
350450009	64.3	61.0	60.2	-0.8	Bloomfield	NM
350450018	67.0	64.8	63.3	-1.5	Navajo Lake	NM
350451005	63.7	60.8	59.6	-1.2	Substation	NM
350490021	64.3	60.6	60.4	-0.2	Santa Fe Airport	NM
Bernalillo County						
350010023	66.3	60.9	60.7	-0.2	Del Norte HS	NM
350010024	68.0	62.3	62.0	-0.3	South East Heights	NM
350010029	66.0	61.0	60.5	-0.5	South Valley	NM
350010032	67.0	62.6	62.1	-0.5	Westside	NM
350011012	65.0	59.1	58.8	-0.3	Foothills	NM
Southern New Mexico						
350130008	66.3	60.0	59.8	-0.2	La Union	NM
350130017	67.0	61.9	61.8	-0.1	Sunland Park City Yard	NM
350130020	67.0	62.3	62.2	-0.1	Chaparral	NM
350130021	72.0	67.0	66.8	-0.2	Desert View	NM
350130022	71.3	66.1	66.0	-0.1	Santa Teresa	NM
350130023	65.0	60.3	60.2	-0.1	Solano	NM
350151005	69.0	66.7	66.4	-0.3	Carlsbad	NM
350171003	62.0	59.0	58.9	-0.1	Chino Copper Smelter	NM
350250008	66.0	64.0	63.3	-0.7	Hobbs Jefferson	NM
350290003	66.0	62.7	62.5	-0.2	Deming Airport	NM
350610008	66.3	62.2	62.0	-0.2	Los Lunas (Los Lentes)	NM

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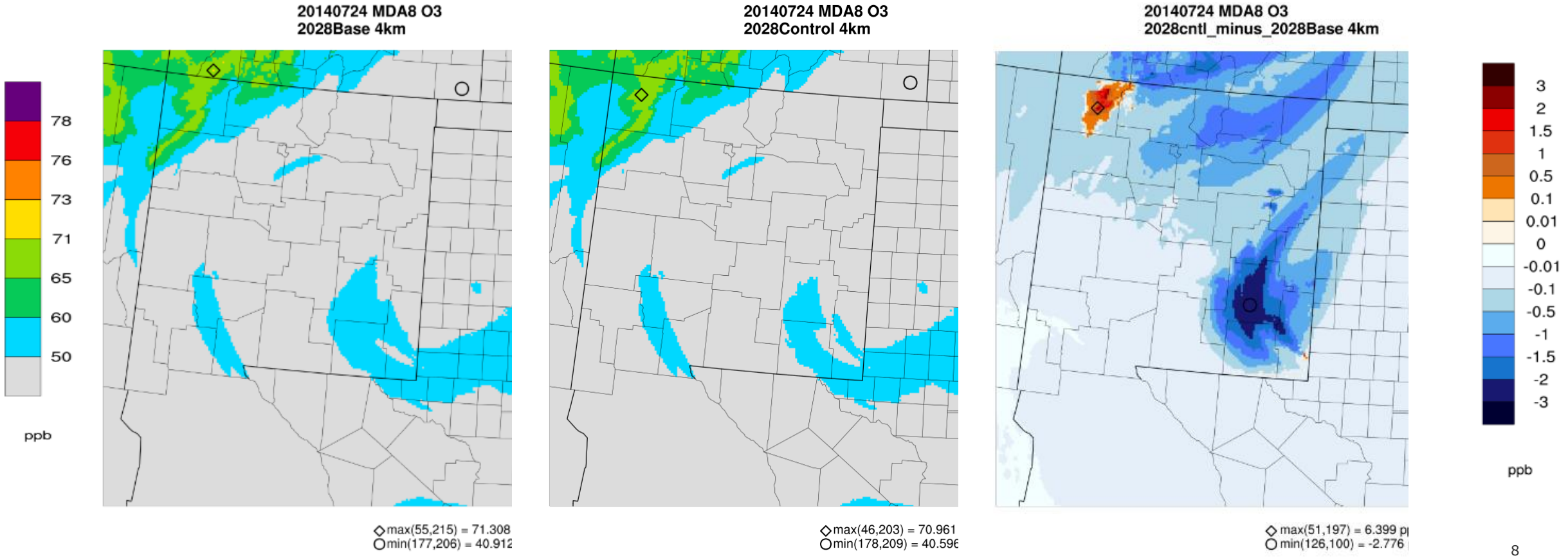
2028 BASE AND O&G CONTROL MDA8 OZONE ON JUNE 5, 2014

- Day with 2028 Base Case MDA8 ozone above 70 ppb 2015 ozone NAAQS in San Juan County that is reduced to below the NAAQS in 2028 O&G Control Strategy



2028 BASE AND O&G CONTROL MDA8 OZONE ON JULY 24, 2014

- Day in which NOx Disbenefits due to 2028 O&G Control Strategy is sufficient to increase a single 4-km grid cell in San Juan County that was below the ozone NAAQS in 2028 Base Case to barely above (71.0 ppb) the 2015 ozone NAAQS in 2028 O&G Control Strategy



INCREASING OZONE AT NEW MEXICO SITES

- More recent years have higher ozone DVs at some New Mexico sites:
  - Red > 75 ppb 2008 NAAQS
  - Yellow > 70 ppb 2015 NAAQS
  - Green > 67 ppb (95th percentile)
- Latest 2017-2019 ozone design value ($DV_{2017-2019}$) has 6 sites that exceed the 2015 ozone NAAQS:
  - Carlsbad = 79 ppb
  - Desert View = 77 ppb
  - Santa Teresa = 76 ppb
  - Chaparral = 73 ppb
  - Hobbs = 71 ppb
  - Foothills = 71 ppb

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Ozone Design Values 2010 to 2019

AQS Site ID	Local Site Name	County Name	2008-2010	2009-2011	2010-2012	2011-2013	2012-2014	2013-2015	2014-2016	2015-2017	2016-2018	2017-2019
350010023	Del Norte HS	Bernalillo	0.064	0.066	0.068	0.070	0.068	0.066	0.065	0.067	0.070	0.070
350010024	SE Heights	Bernalillo	0.066	0.068	0.070	0.070	0.068					
350010027	Westside	Bernalillo	0.067	0.068	0.071	0.071						
350010029	South Valley	Bernalillo	0.066	0.067	0.069	0.070	0.067	0.066	0.065	0.065	0.066	0.067
350010032	Westside	Bernalillo			0.070	0.070	0.067					
350011012	Foothills	Bernalillo	0.068	0.070	0.074	0.072	0.067	0.064	0.064	0.067	0.069	0.071
350011013	North Valley	Bernalillo	0.067	0.068	0.069	0.069						
350130008	La Union	Dona Ana	0.064	0.062	0.065	0.067	0.067	0.066	0.066	0.068	0.068	0.070
350130017	Sunland Park	Dona Ana	0.064	0.065	0.068	0.067	0.067					
350130020	Chaparral	Dona Ana	0.066	0.067	0.067	0.069	0.068	0.067	0.066	0.068	0.071	0.073
350130021	Desert View	Dona Ana	0.070	0.069	0.072	0.072	0.072	0.072	0.072	0.072	0.074	0.077
350130022	Santa Teresa	Dona Ana	0.067	0.066	0.070	0.075	0.074	0.072	0.068	0.072	0.074	0.076
350130023	Solano	Dona Ana	0.063	0.063	0.065	0.065	0.065	0.065	0.065	0.066	0.067	0.070
350151005	Carlsbad City	Eddy	0.067	0.068	0.071	0.071	0.071	0.069	0.067	0.068	0.074	0.079
350153001	Carlsbad Caverns	Eddy									0.071	
350171003	Chino Copper	Grant	0.063	0.065	0.067	0.063	0.062					
350250008	Hobbs Jefferson	Lea	0.059	0.061	0.061	0.066	0.065	0.067	0.066	0.067	0.070	0.071
350290003	Deming Airport	Luna	0.057	0.058	0.064	0.067	0.066					
350390026	Coyote Ranger District	Rio Arriba							0.064	0.065	0.067	0.067
350431001	Bernallilo	Sandoval	0.060	0.061	0.061	0.063	0.063	0.065	0.064	0.065	0.068	0.068
350439004	Pueblo Of Jemez	Sandoval		0.062								
350450009	Bloomfield	San Juan	0.060	0.061	0.067	0.068	0.067	0.064	0.062	0.064	0.069	0.068
350450018	Navajo Lake	San Juan			0.071	0.071	0.068	0.067	0.066	0.068	0.070	0.069
350451005	Substation	San Juan	0.063	0.063	0.067	0.068	0.066	0.063	0.062	0.064	0.069	0.069
350490021	Santa Fe Airport	Santa Fe	0.063	0.062	0.065	0.066	0.066	0.064	0.063	0.063	0.066	0.066
350610008	Los Lunas	Valencia			0.067	0.070	0.069	0.066	0.064	0.065	0.067	0.068

2028 OZONE PROJECTIONS SENSITIVITY ANALYSIS TO DVC

- Given increased ozone concentrations in more recent years, a sensitivity analysis of the 2028 ozone projections to current year ozone design value (DVC) starting point for the projections was conducted
- 2028 ozone DVF projection sensitivity analysis was conducted using two alternative definitions of current year design value (DVC):
  - $DVC_{2015\text{-}2019} = (DV_{2015\text{-}2017} + DV_{2016\text{-}2018} + DV_{2017\text{-}2019}) / 3$
    - Consistent with EPA guidance to use average of 3-years of ozone DVs for DVC to modulate year-to-year variability, but centered on 2017 instead of 2014
  - $DV_{2017\text{-}2019}$ (the latest design value based on validated data)
- Still using CAMx 2014v2 and 2028 modeling results, so not accounting for changes in emissions from 2014 to 2017-2019 in 2028 ozone projections:
  - Where emissions went down (e.g., mobile source dominated), may understate 2028 ozone DVFs
  - Where emissions went up (e.g., Permian Basin O&G), may overstate 2028 ozone DVFs

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2028 OZONE DVF SENSITIVITY TO DVC USING $DVC_{2015\text{-}2019}$

- Four monitoring sites have 2015-2019 current year $DVC_{2015\text{-}2019}$ greater than the 2015 ozone NAAQS:
  - Desert View = 74.3 ppb
  - Santa Teresa = 74.0 ppb
  - Carlsbad = 73.7 ppb
  - Carlsbad NP* = 71.0 ppb
- 2028 Base Case has one site with 2028 ozone DVF > NAAQS using $DVC_{2015\text{-}2019}$:
  - Carlsbad = 71.2 ppb
- 2028 O&G Control Strategy sufficient that all 2028 ozone DVFs are below the NAAQS when using $DVC_{2015\text{-}2019}$:
  - Carlsbad = 70.9 ppb

AQS_ID	2015-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	69.0	63.4	63.1	-0.3	Del Norte HS	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	Bernalillo
350011012	69.0	62.7	62.4	-0.3	Foothills	Bernalillo
350130008	68.7	62.1	62.0	-0.1	La Union	Dona Ana
350130020	70.7	65.7	65.7	0.0	Chaparral	Dona Ana
350130021	74.3	69.1	68.9	-0.2	Desert View	Dona Ana
350130022	74.0	68.6	68.5	-0.1	Santa Teresa	Dona Ana
350130023	67.7	62.9	62.7	-0.2	Solano	Dona Ana
350151005	73.7	71.2	70.9	-0.3	Carlsbad	Eddy
350153001	71.0	69.3	69.3	0.0	Carlsbad Caverns NP	Eddy
350250008	69.3	67.2	66.5	-0.7	Hobbs Jefferson	Lea
350390026	66.3	63.0	62.2	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	67.0	61.2	60.9	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	67.0	63.6	62.8	-0.8	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	67.3	64.2	62.9	-1.3	Substation	San Juan
350490021	65.0	61.2	61.0	-0.2	Santa Fe Airport	Santa Fe
350610008	66.7	62.6	62.3	-0.3	Los Lunas (Los Lentes)	Valencia

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* Carlsbad Caverns NP only has data for 2016-2018

NMED Exhibit 24 - 0011

2028 OZONE DVF SENSITIVITY TO DVC USING $DV_{2017-2019}$

- Six monitoring sites have $DV_{2017-2019}$ greater than the 2015 ozone NAAQS:
  - Carlsbad = 79.0 ppb
  - Desert View = 77.0 ppb
  - Santa Teresa = 76.0 ppb
  - Chaparral = 73.0 ppb
  - Hobbs = 71.0 ppb
  - Foothills = 71.0 ppb
- 2028 Base Case two sites DVF > NAAQS:
  - Carlsbad = 76.4 ppb
  - Desert View = 71.6 ppb
- 2028 O&G Control, both DVF > NAAQS:
  - Carlsbad = 76.0 ppb
  - Desert View = 71.4 ppb

AQS_ID	2017-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	70.0	64.3	64.0	-0.3	Del Norte HS	Bernalillo
350010029	67.0	61.9	61.4	-0.5	South Valley	Bernalillo
350011012	71.0	64.5	64.2	-0.3	Foothills	Bernalillo
350130008	70.0	63.3	63.2	-0.1	La Union	Dona Ana
350130020	73.0	67.8	67.8	0.0	Chaparral	Dona Ana
350130021	77.0	71.6	71.4	-0.2	Desert View	Dona Ana
350130022	76.0	70.5	70.3	-0.2	Santa Teresa	Dona Ana
350130023	70.0	65.0	64.8	-0.2	Solano	Dona Ana
350151005	79.0	76.4	76.0	-0.4	Carlsbad	Eddy
350250008	71.0	68.9	68.1	-0.8	Hobbs Jefferson	Lea
350390026	67.0	63.6	62.8	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	68.0	62.1	61.8	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	68.0	64.6	63.7	-0.9	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	69.0	65.8	64.5	-1.3	Substation	San Juan
350490021	66.0	62.2	62.0	-0.2	Santa Fe Airport	Santa Fe
350610008	68.0	63.8	63.5	-0.3	Los Lunas (Los Lentes)	Valencia

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NMED Exhibit 24 - 0012

PRELIMINARY DRAFT AQTSD

1. Introduction
2. 2014 WRF Meteorological Modeling
3. Boundary Condition Inputs
4. 2014 Emission Inputs
5. Diagnostic Sensitivity Tests
6. 2014 Base Case Modeling and Model Performance Evaluation
7. 2028 Base Case Modeling and Ozone Design Value Projections
8. 2028 Oil and Gas Control Strategy Modeling and Ozone Design Value Projections
9. Sensitivity of 2028 Ozone Design Value Projections to Current Year Design Values
10. Summary and Conclusions
11. References

To Come:

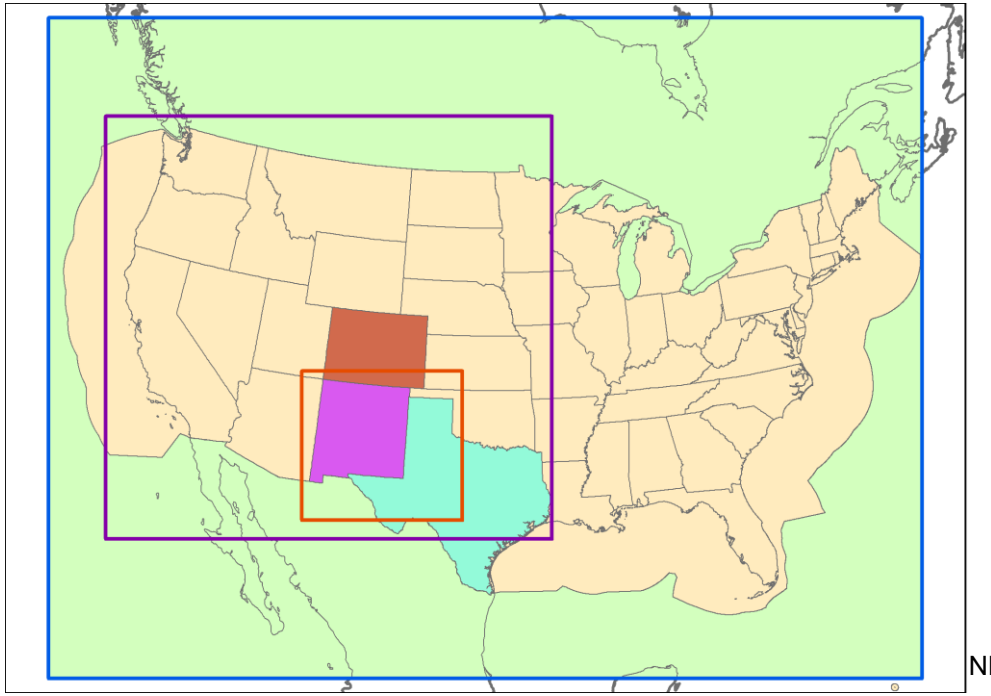
10. APCA Source Sector Ozone Source Apportionment Modeling
11. OSAT VOC/NOx Sensitivity Ozone Source Apportionment Modeling

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NMED Exhibit 24 - 0013

CAMX 2028 O&G CS APCA OZONE SOURCE APPORTIONMENT

- **Definition of Source Groups**
  - Boundary Conditions (BCs) from 2014 GEOS-Chem runs:
    - BC_{Intl} - International anthropogenic emissions
    - BC_{USA} – U.S. anthropogenic emissions
    - $BC_{Natural}$ – Natural sources
    - BC_{Top} – BC above the top of domain
  - Source Categories (9):
    1. Natural (biogenic, lightning NOx, etc.);
    2. Fires (WF, Rx, Ag, other);
    3. Oil and gas point sources (surrogate for midstream);
    4. Oil and gas non-point sources (surrogate for upstream;
    5. EGU point;
    6. Non-EGU point;
    7. On-road mobile;
    8. Non-road mobile; and
    9. Remainder anthropogenic.
  - Source Regions (5):
    - New Mexico
    - Texas
    - Colorado
    - Remainder U.S.
    - International (Mex, Can, CMV > 200 nmi)
  - 50 Source Groups (50 = 5 x 9 + 5)

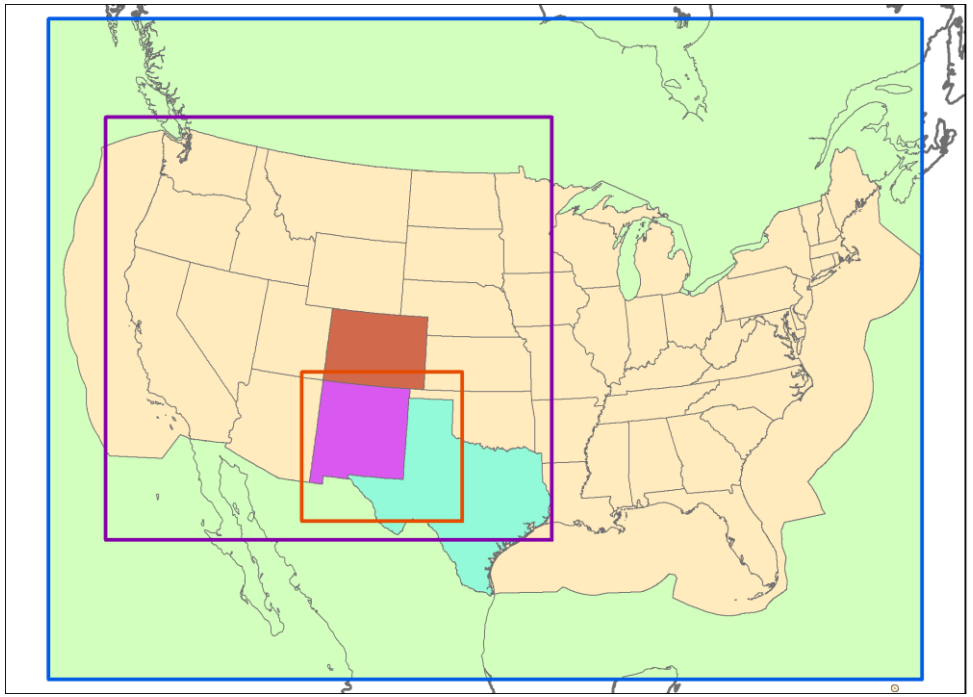


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NMED Exhibit 24 - 0014

CAMX 2028 O&G CS OSAT OZONE SOURCE APPORTIONMENT

- Use the OSAT version of CAMx ozone source apportionment tool
  - OSAT O3V and O3N tracers give indication of amount of VOC-limited and NOx-limited ozone formation
- Definition of Source Groups
  - Source Regions (5):
    - Use same 5 Source Regions as APCA SA run
  - Source Categories (3):
    - Anthropogenic Emissions
    - Natural (Biogenic, lightning NOx, WBD, oceanic)
    - Fires (WF, Rx, Ag and other)
  - 17 Source Groups (5 x 3 + 2 [IC,BC])
    - Will run faster than CAMx APCA SA Run (50 Source Groups)



Start March 12, 2021

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NEW MEXICO OZONE ATTAINMENT INITIATIVE

2028 Source Sector APCA Ozone Source Apportionment Modeling and Revised Draft Air Quality Technical Support Document

Marco Rodriguez, Pradeepa Vennam, Jung Chien, John Grant, Tejas Shah and Ralph Morris, Ramboll

Tom Moore and Mary Uhl, WESTAR

NM OAI Study Webinar

April 2, 2021

RAMBOLL Bright ideas. Sustainable change.

2028 SOURCE SECTOR APCA OZONE SOURCE APPORTIONMENT

01 Summary of 2028 Ozone Design Value Projections Following EPA Guidance and Sensitivity Analysis to Current Year DVC

02 2028 O&G CS Source Sector APCA Ozone Source Apportionment Modeling Results

03 Second Draft Air Quality Technical Support Document (AQTSD)

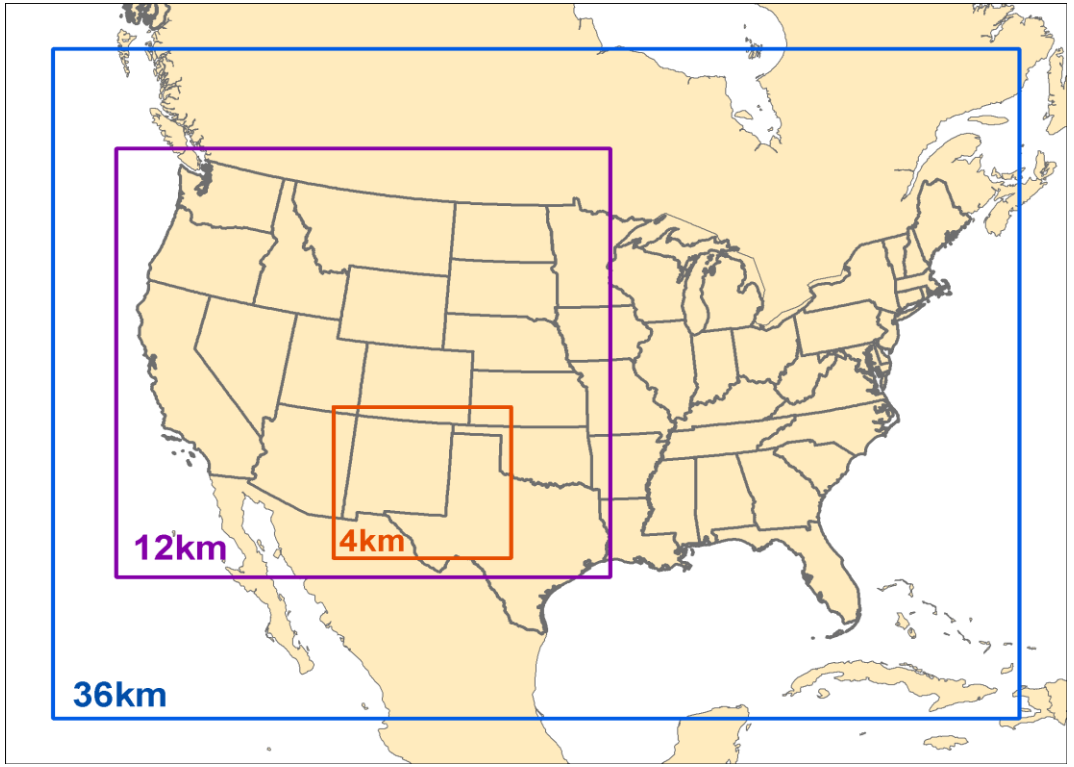
04 Status of 2028 OSAT VOC/NOx Formation Sensitivity Ozone Source Apportionment Modeling

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NMED Exhibit 25 - 0002

CAMX 2014 NM OAI STUDY MODEL CONFIGURATION

- Episode: May-August 2014
  - 16-day spin-up before first high ozone day in NM
    - 68 ppb on May 17
- 36/12/4-km Modeling Domains
  - 36/12-km domains same as WRAP Regional Haze
  - New 4-km New Mexico domain
- Boundary Conditions (BC) WRAP 2014 GEOS-Chem
- Four Meteorological Diagnostic Sensitivity tests
  - Selected WRF/NAM with Kv=CMAQ
- WRAP 2014v2 base year emissions
  - EPA NEI2014v2 w/ western state updates
- WRAP 2028OTBa2 for future year w/ 2014 actual fires and new 2028 NM O&G



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PROJECTED 2028 OZONE DVFS FOLLOWING EPA GUIDANCE

- Future Year 2028 ozone design value (DVF) projections following EPA guidance using 2012-2016 DVC:
  - 2028 DVF = RRF x $DVC_{2012\text{-}2016}$
- Two sites have current year $DVC_{2012\text{-}2016}$ above the 2015 ozone NAAQS:
  - Desert View = 72.0 ppb
  - Santa Teresa = 71.3 ppb
- Using EPA guidance, all sites have 2028 ozone DVF below NAAQS for both 2028 Base and 2028 O&G Control Strategy:
  - Desert View = 67.0 and 66.8 ppb
  - Santa Teresa = 66.1 and 66.0 ppb

AQS_ID	2012-16 DVC (ppb)	Projected 2028 DVF Base (ppb)	Projected 2028 DVF Cntl (ppb)	Projected 2028 DVF Cntl - Base	Site Name	State
Northern New Mexico						
350390026	64.0	60.8	60.0	-0.8	Coyote Ranger District	NM
350431001	64.0	58.4	58.1	-0.3	Bernalillo (E Avenida)	NM
350450009	64.3	61.0	60.2	-0.8	Bloomfield	NM
350450018	67.0	64.8	63.3	-1.5	Navajo Lake	NM
350451005	63.7	60.8	59.6	-1.2	Substation	NM
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350010032	67.0	62.6	62.1	-0.5	Westside	NM
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350130008	66.3	60.0	59.8	-0.2	La Union	NM
350130017	67.0	61.9	61.8	-0.1	Sunland Park City Yard	NM
350130020	67.0	62.3	62.2	-0.1	Chaparral	NM
350130021	72.0	67.0	66.8	-0.2	Desert View	NM
350130022	71.3	66.1	66.0	-0.1	Santa Teresa	NM
350130023	65.0	60.3	60.2	-0.1	Solano	NM
350151005	69.0	66.7	66.4	-0.3	Carlsbad	NM
350171003	62.0	59.0	58.9	-0.1	Chino Copper Smelter	NM
350250008	66.0	64.0	63.3	-0.7	Hobbs Jefferson	NM
350290003	66.0	62.7	62.5	-0.2	Deming Airport	NM
350610008	66.3	62.2	62.0	-0.2	Los Lunas (Los Lentes)	NM

RAMBOLL

INCREASING OZONE AT NEW MEXICO SITES

- More recent years have higher ozone DVs at some New Mexico sites:
  - Red > 75 ppb 2008 NAAQS
  - Yellow > 70 ppb 2015 NAAQS
  - Green > 67 ppb (95th percentile)
- Latest 2017-2019 ozone design value ($DV_{2017-2019}$) has 6 sites that exceed the 2015 ozone NAAQS
- Conducted sensitivity analysis of 2028 ozone DVF projections to current year DVC
  - $DVC_{2015-2019}$
  - $DVC_{2017-2019}$

Ozone Design Values 2010 to 2019

AQS Site ID	Local Site Name	County Name	2008-2010	2009-2011	2010-2012	2011-2013	2012-2014	2013-2015	2014-2016	2015-2017	2016-2018	2017-2019
350010023	Del Norte HS	Bernalillo	0.064	0.066	0.068	0.070	0.068	0.066	0.065	0.067	0.070	0.070
350010024	SE Heights	Bernalillo	0.066	0.068	0.070	0.070	0.068					
350010027	Westside	Bernalillo	0.067	0.068	0.071	0.071						
350010029	South Valley	Bernalillo	0.066	0.067	0.069	0.070	0.067	0.066	0.065	0.065	0.066	0.067
350010032	Westside	Bernalillo			0.070	0.070	0.067					
350011012	Foothills	Bernalillo	0.068	0.070	0.074	0.072	0.067	0.064	0.064	0.067	0.069	0.071
350011013	North Valley	Bernalillo	0.067	0.068	0.069	0.069						
350130008	La Union	Dona Ana	0.064	0.062	0.065	0.067	0.067	0.066	0.066	0.068	0.068	0.070
350130017	Sunland Park	Dona Ana	0.064	0.065	0.068	0.067	0.067					
350130020	Chaparral	Dona Ana	0.066	0.067	0.067	0.069	0.068	0.067	0.066	0.068	0.071	0.073
350130021	Desert View	Dona Ana	0.070	0.069	0.072	0.072	0.072	0.072	0.072	0.072	0.074	0.077
350130022	Santa Teresa	Dona Ana	0.067	0.066	0.070	0.075	0.074	0.072	0.068	0.072	0.074	0.076
350130023	Solano	Dona Ana	0.063	0.063	0.065	0.065	0.065	0.065	0.065	0.066	0.067	0.070
350151005	Carlsbad City	Eddy	0.067	0.068	0.071	0.071	0.071	0.069	0.067	0.068	0.074	0.079
350153001	Carlsbad Caverns	Eddy									0.071	
350171003	Chino Copper	Grant	0.063	0.065	0.067	0.063	0.062					
350250008	Hobbs Jefferson	Lea	0.059	0.061	0.061	0.066	0.065	0.067	0.066	0.067	0.070	0.071
350290003	Deming Airport	Luna	0.057	0.058	0.064	0.067	0.066					
350390026	Coyote Ranger District	Rio Arriba							0.064	0.065	0.067	0.067
350431001	Bernallilo	Sandoval	0.060	0.061	0.061	0.063	0.063	0.065	0.064	0.065	0.068	0.068
350439004	Pueblo Of Jemez	Sandoval		0.062								
350450009	Bloomfield	San Juan	0.060	0.061	0.067	0.068	0.067	0.064	0.062	0.064	0.069	0.068
350450018	Navajo Lake	San Juan			0.071	0.071	0.068	0.067	0.066	0.068	0.070	0.069
350451005	Substation	San Juan	0.063	0.063	0.067	0.068	0.066	0.063	0.062	0.064	0.069	0.069
350490021	Santa Fe Airport	Santa Fe	0.063	0.062	0.065	0.066	0.066	0.064	0.063	0.063	0.066	0.066
350610008	Los Lunas	Valencia			0.067	0.070	0.069	0.066	0.064	0.065	0.067	0.068

RAMBOLL

2028 OZONE DVF SENSITIVITY TO $DVC_{2015\text{-}2019}$ AND $DVC_{2017\text{-}2019}$

AQS_ID	2015-19 DVC (ppb)	Projected 2028 DVF Base (ppb)	Projected 2028 DVF Cntl (ppb)	Projected 2028 DVF Cntl - Base	Site Name	County
350010023	69.0	63.4	63.1	-0.3	Del Norte HS	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	Bernalillo
350011012	69.0	62.7	62.4	-0.3	Foothills	Bernalillo
350130008	68.7	62.1	62.0	-0.1	La Union	Dona Ana
350130020	70.7	65.7	65.7	0.0	Chaparral	Dona Ana
350130021	74.3	69.1	68.9	-0.2	Desert View	Dona Ana
350130022	74.0	68.6	68.5	-0.1	Santa Teresa	Dona Ana
350130023	67.7	62.9	62.7	-0.2	Solano	Dona Ana
350151005	73.7	71.2	70.9	-0.3	Carlsbad	Eddy
350153001	71.0	69.3	69.3	0.0	Carlsbad Caverns NP	Eddy
350250008	69.3	67.2	66.5	-0.7	Hobbs Jefferson	Lea
350390026	66.3	63.0	62.2	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	67.0	61.2	60.9	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	67.0	63.6	62.8	-0.8	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	67.3	64.2	62.9	-1.3	Substation	San Juan
350490021	65.0	61.2	61.0	-0.2	Santa Fe Airport	Santa Fe
350610008	66.7	62.6	62.3	-0.3	Los Lunas (Los Lentes)	Valencia

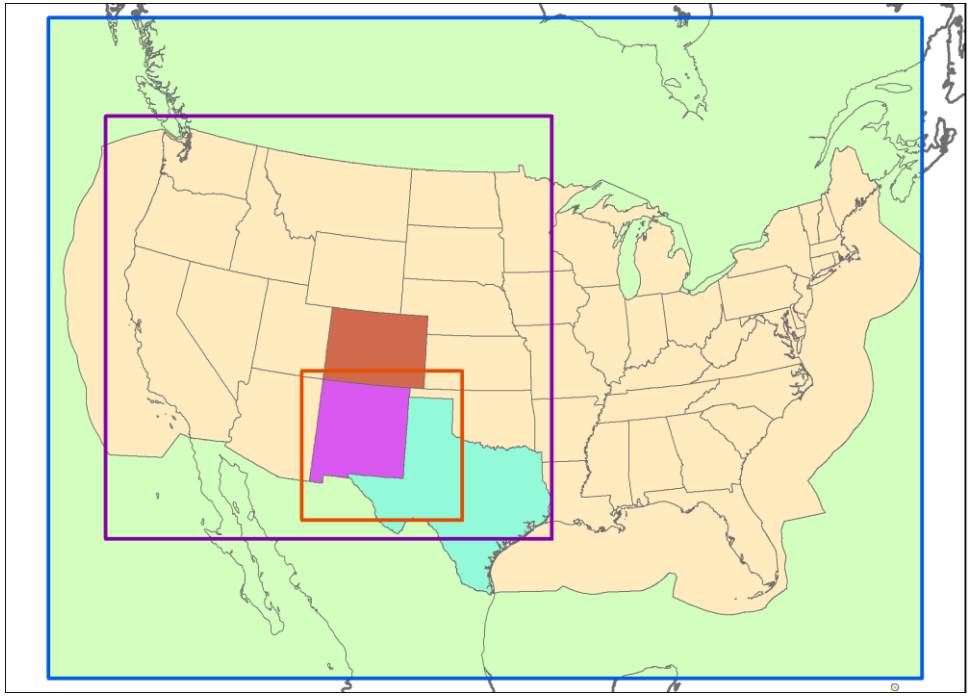
AQS_ID	2017-19 DVC (ppb)	Projected 2028 DVF Base (ppb)	Projected 2028 DVF Cntl (ppb)	Projected 2028 DVF Cntl - Base	Site Name
350010023	70.0	64.3	64.0	-0.3	Del Norte HS
350010029	67.0	61.9	61.4	-0.5	South Valley
350011012	71.0	64.5	64.2	-0.3	Foothills
350130008	70.0	63.3	63.2	-0.1	La Union
350130020	73.0	67.8	67.8	0.0	Chaparral
350130021	77.0	71.6	71.4	-0.2	Desert View
350130022	76.0	70.5	70.3	-0.2	Santa Teresa
350130023	70.0	65.0	64.8	-0.2	Solano
350151005	79.0	76.4	76.0	-0.4	Carlsbad
350250008	71.0	68.9	68.1	-0.8	Hobbs Jefferson
350390026	67.0	63.6	62.8	-0.8	Coyote Ranger Dist
350431001	68.0	62.1	61.8	-0.3	Bernalillo (E Avenida)
350450009	68.0	64.6	63.7	-0.9	Bloomfield
350450018	69.0	66.7	65.2	-1.5	Navajo Lake
350451005	69.0	65.8	64.5	-1.3	Substation
350490021	66.0	62.2	62.0	-0.2	Santa Fe Airport
350610008	68.0	63.8	63.5	-0.3	Los Lunas (Los Lentes)

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NMED Exhibit 25 - 0006

CAMX 2028 O&G CS SOURCE SECTOR APCA OZONE SA

- **Definition of Source Groups**
  - Boundary Conditions (BCs) from WRAP 2014 GEOS-Chem runs:
    - BC_{Intl} - International anthropogenic emissions
    - BC_{USA} – U.S. anthropogenic emissions
    - $BC_{Natural}$ – Natural sources
    - BC_{Top} – BC above the top of domain
  - Source Categories (9):
    1. Natural (biogenic, lightning NOx, etc.);
    2. Fires (WF, Rx, Ag, other);
    3. Oil and gas point sources (surrogate for midstream);
    4. Oil and gas non-point sources (surrogate for upstream;
    5. EGU point;
    6. Non-EGU point;
    7. On-road mobile;
    8. Non-road mobile; and
    9. Remainder anthropogenic.
  - Source Regions (5):
    - New Mexico
    - Texas
    - Colorado
    - Remainder U.S.
    - International (Mex, Can, CMV > 200 nmi)
  - 50 Source Groups (50 = 5 x 9 + 5)



RAMBOLL

NMED Exhibit 25 - 0007

SOURCE SECTOR CONTRIBUTIONS TO 2028 OZONE DVFS

1. NEW MEXICO SOURCE SECTOR CONTRIBUTIONS TO 2028 OZONE DVF AT MONITORS
2. SPATIAL DISTRIBUTION OF NEW MEXICO SOURCE SECTOR CONTRIBUTIONS TO 2028 DVFS
3. UNITED STATES SOURCE SECTOR CONTRIBUTIONS TO 2028 OZONE DVF AT MONITORS

RAMBOLL

NMED Exhibit 25 - 0008

REDUCTIONS 2028 OZONE DVFS NEW MEXICO SOURCE SECTORS

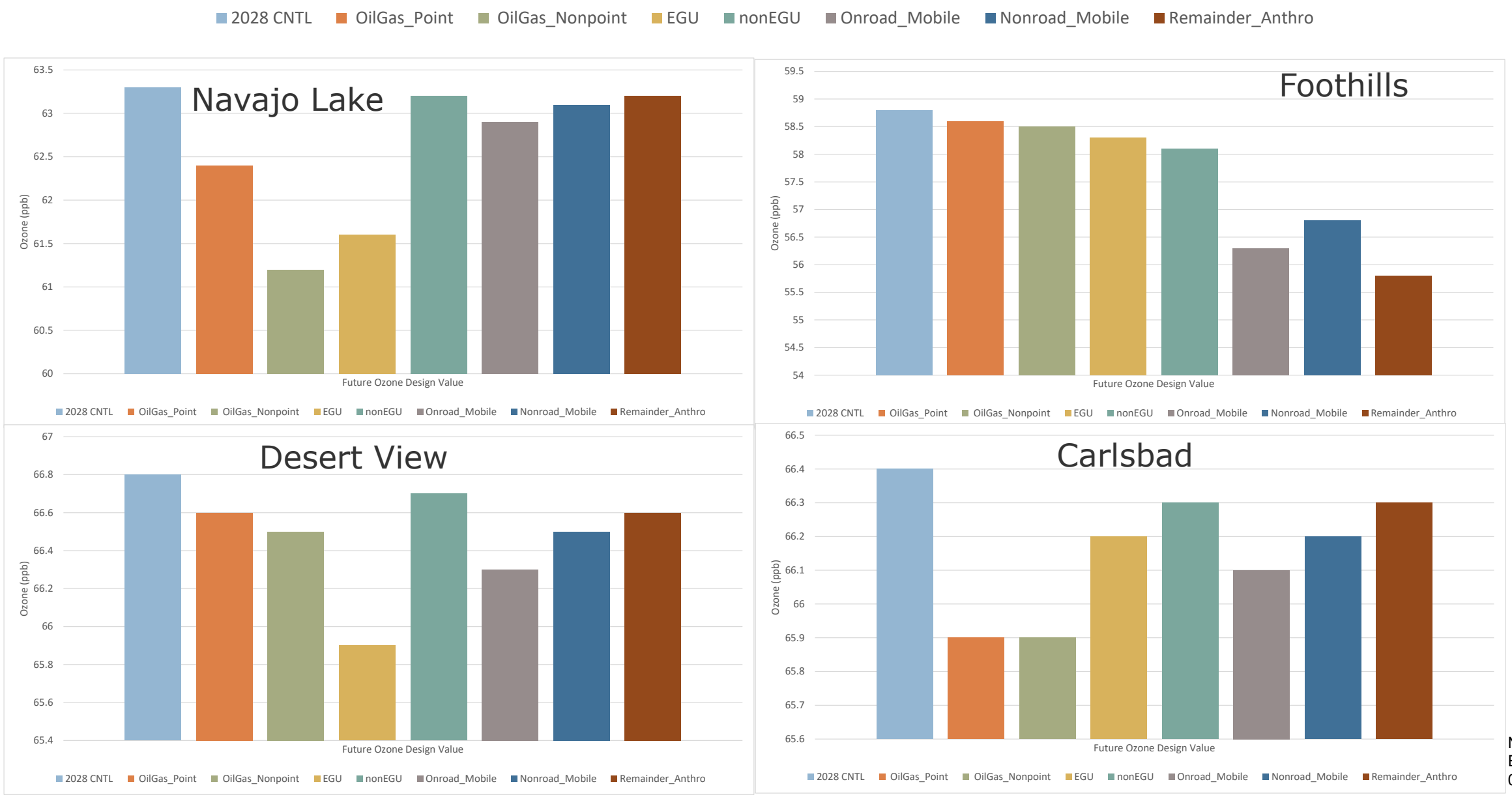
- 2028 ozone DVF Reductions from New Mexico Source Sectors
  - O&G Point: -0.1 to -0.9 ppb
  - O&G Non-Pt: -0.1 to -2.1 ppb
  - EGU Point: 0.0 to -3.1 ppb
  - Non-EGU Pt: 0.0 to -1.1 ppb
  - On-Road: -0.1 to -2.7 ppb
  - Non-Road: -0.1 to -1.9 ppb
  - Other Anthro: 0.0 to -3.6 ppb

AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	OnRoad	NonRoad	OAnth
350010023	NORTE	66.3	60.7	-0.2	-0.3	-0.5	-1.0	-2.7	-2.0	-3.6
350010024	SEHGS	68.0	62.0	-0.2	-0.3	-0.5	-1.1	-2.5	-1.9	-3.2
350010029	STHVA	66.0	60.5	-0.3	-0.5	-0.5	-1.0	-2.2	-1.7	-2.4
350010032	WSTSD	67.0	62.1	-0.2	-0.4	-0.4	-0.4	-1.6	-1.2	-1.8
350011012	FTHIL	65.0	58.8	-0.2	-0.3	-0.5	-0.7	-2.5	-2.0	-3.0
350130008	UNION	66.3	59.8	-0.2	-0.2	-0.7	0.0	-0.5	-0.3	-0.1
350130017	SPARK	67.0	61.8	-0.2	-0.2	-0.9	0.0	-0.4	-0.2	-0.2
350130020	CHAPA	67.0	62.2	-0.1	-0.1	-0.3	0.0	-0.2	-0.1	-0.1
350130021	DSVIE	72.0	66.8	-0.2	-0.3	-0.9	-0.1	-0.5	-0.3	-0.2
350130022	TERES	71.3	66.0	-0.3	-0.3	-0.7	-0.1	-0.5	-0.3	-0.2
350130023	SOLAN	65.0	60.2	-0.2	-0.2	-0.2	-0.2	-1.2	-0.7	-0.3
350151005	CARLS	69.0	66.4	-0.5	-0.5	-0.2	-0.1	-0.3	-0.2	-0.1
350171003	GRANT	62.0	58.9	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0
350250008	HOBBS	66.0	63.3	-0.9	-1.1	-0.2	0.0	-0.3	-0.2	-0.1
350290003	DEAIR	66.0	62.5	-0.2	-0.1	-0.2	0.0	-0.6	-0.4	0.0
350390026	COYOT	64.0	60.0	-0.2	-0.5	-0.5	0.0	-0.2	-0.1	0.0
350431001	BERNA	64.0	58.1	-0.1	-0.2	-0.4	-0.4	-2.1	-1.5	-1.9
350450009	BLOOM	64.3	60.2	-0.7	-1.4	-1.9	0.0	-0.4	-0.1	-0.1
350450018	NAVAJ	67.0	63.3	-0.9	-2.1	-1.7	-0.1	-0.4	-0.2	-0.1
350451005	SUBST	63.7	59.6	-0.6	-1.5	-3.1	-0.1	-0.5	-0.2	-0.2
350490021	SNTFE	64.3	60.4	-0.2	-0.3	-0.2	-0.3	-1.2	-0.7	-0.8
350610008	LUNAS	66.3	62.0	-0.2	-0.3	-0.3	-0.3	-1.1	-1.0	-0.4

RAMBOLL

NMED Exhibit 25 - 0009

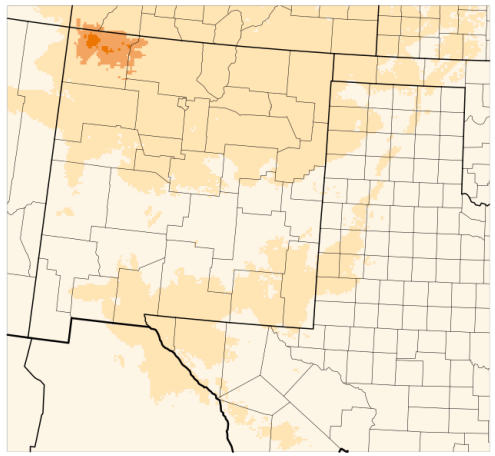
2028 OGCS OZONE DVF & W/ NM SOURCE SECTORS REMOVED



NMED Exhibit 25 - 0010

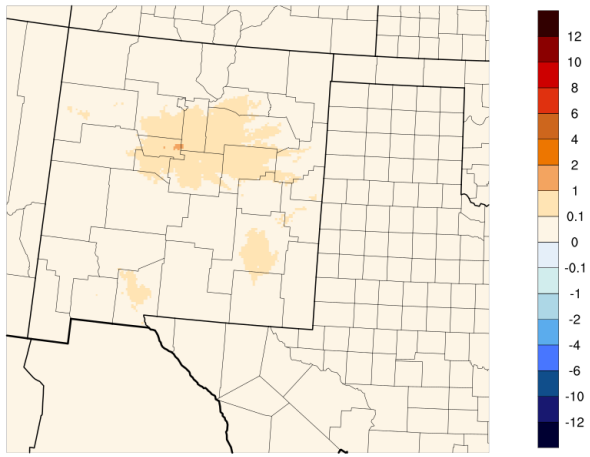
SMAT UAA ($DVC_{2012-2016}$) 2028 DVF SOURCE CONTRIBUTIONS

2028 Contributions
EGU point
O3 Design Value UAA



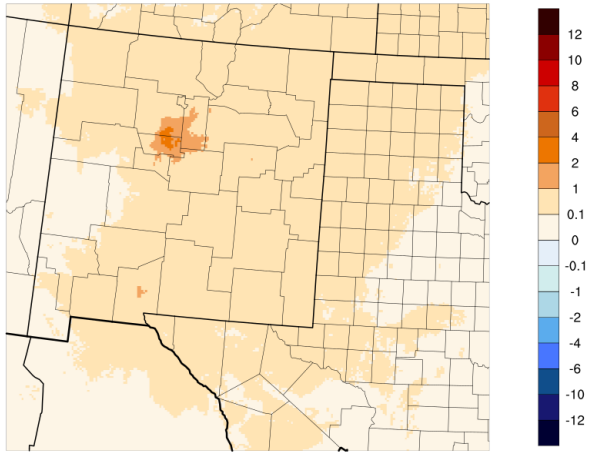
max(44,208) = 3.105 ppb
min(1,215) = 0.006 ppb

2028 Contributions
NonEGU point
O3 Design Value UAA



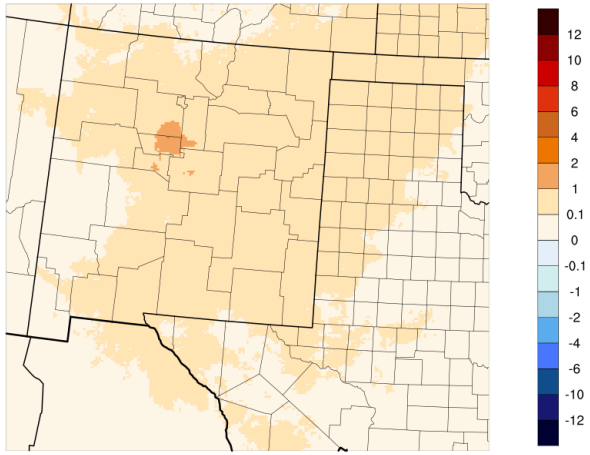
max(86,154) = 1.283 ppb
min(32,1) = 0.000 ppb

2028 Contributions
On-road mobile
O3 Design Value UAA



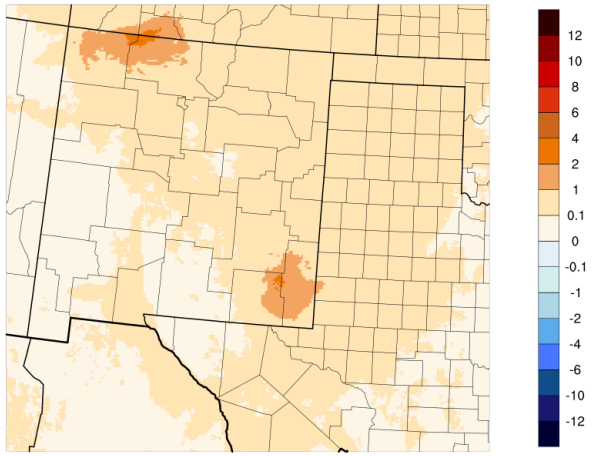
max(82,158) = 2.598 ppb
min(19,189) = 0.006 ppb

2028 Contributions
Non-road mobile
O3 Design Value UAA



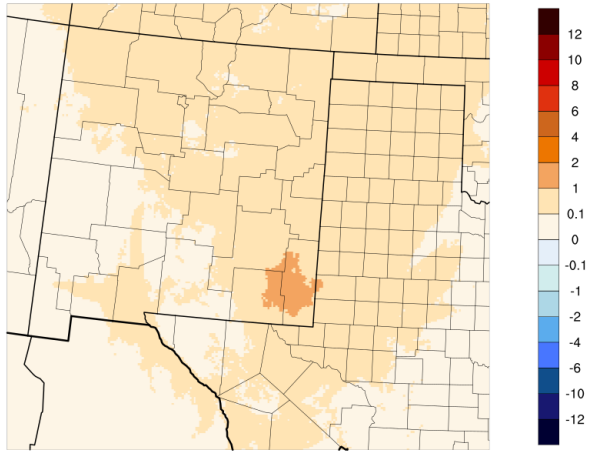
max(82,158) = 2.103 ppb
min(22,200) = 0.006 ppb

2028 Contributions
OilandGas non-point
O3 Design Value UAA



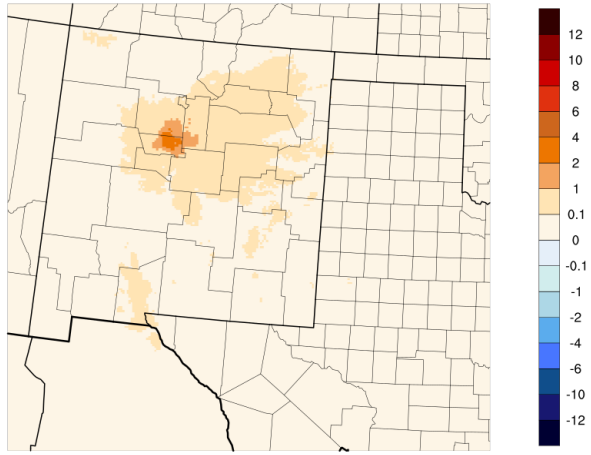
max(67,209) = 2.986 ppb
min(18,192) = 0.006 ppb

2028 Contributions
OilandGas point
O3 Design Value UAA



max(139,86) = 1.889 ppb
min(12,165) = 0.000 ppb

2028 Contributions
Remainder Anthro
O3 Design Value UAA



max(82,156) = 3.094 ppb
min(9,122) = 0.000 ppb

NMED Exhibit 25 - 0011

REDUCTIONS 2028 O3 DVFS U.S. ANTHROPOGENIC SOURCE SECTORS

- 2028 ozone DVF Reductions from All U.S. Anthro Source Sectors
  - O&G Point: -0.2 to -1.6 ppb
  - O&G Non-Pt: -0.3 to -2.7 ppb
  - EGU Point: -0.4 to -3.6 ppb
  - Non-EGU Pt: -0.6 to -1.7 ppb
  - On-Road: -1.3 to -3.9 ppb
  - Non-Road: -0.9 to -3.0 ppb
  - Other Anthro: -0.6 to -4.2 ppb

AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	OnRoad	NonRoad	OAnth
350010023	NORTE	66.3	60.7	-0.5	-0.7	-1.1	-1.7	-3.9	-3.0	-4.2
350010024	SEHGS	68.0	62.0	-0.5	-0.7	-1.0	-1.7	-3.6	-2.8	-3.7
350010029	STHVA	66.0	60.5	-0.6	-0.9	-1.0	-1.6	-3.3	-2.5	-2.9
350010032	WSTSD	67.0	62.1	-0.4	-0.7	-0.9	-1.0	-2.7	-2.0	-2.4
350011012	FTHIL	65.0	58.8	-0.5	-0.7	-1.1	-1.4	-3.8	-3.0	-3.7
350130008	UNION	66.3	59.8	-0.8	-0.9	-1.6	-1.5	-3.2	-2.3	-1.5
350130017	SPARK	67.0	61.8	-0.7	-1.0	-1.8	-1.5	-3.0	-2.1	-1.7
350130020	CHAPA	67.0	62.2	-0.6	-0.8	-1.3	-1.4	-2.3	-1.7	-1.3
350130021	DSVIE	72.0	66.8	-0.8	-1.1	-1.8	-1.6	-3.1	-2.2	-1.8
350130022	TERES	71.3	66.0	-0.8	-1.1	-1.6	-1.5	-2.9	-2.1	-1.5
350130023	SOLAN	65.0	60.2	-0.7	-1.0	-0.9	-1.1	-2.7	-1.8	-1.1
350151005	CARLS	69.0	66.4	-0.8	-1.1	-0.5	-0.8	-1.3	-0.9	-0.7
350171003	GRANT	62.0	58.9	-0.2	-0.3	-0.4	-0.7	-1.3	-1.0	-0.7
350250008	HOBBS	66.0	63.3	-1.6	-2.2	-0.7	-0.6	-1.4	-1.0	-0.7
350290003	DEAIR	66.0	62.5	-0.4	-0.5	-0.6	-0.7	-1.7	-1.2	-0.7
350390026	COYOT	64.0	60.0	-0.5	-0.9	-0.8	-0.7	-1.5	-1.0	-0.7
350431001	BERNA	64.0	58.1	-0.4	-0.6	-0.8	-1.1	-3.4	-2.5	-2.6
350450009	BLOOM	64.3	60.2	-1.1	-2.1	-2.3	-0.7	-1.7	-1.1	-0.6
350450018	NAVAJ	67.0	63.3	-1.3	-2.7	-2.0	-0.8	-1.7	-1.2	-0.8
350451005	SUBST	63.7	59.6	-1.1	-2.5	-3.6	-0.8	-1.7	-1.2	-0.7
350490021	SNTFE	64.3	60.4	-0.5	-0.7	-0.7	-0.7	-2.0	-1.4	-1.3

RAMBOLL

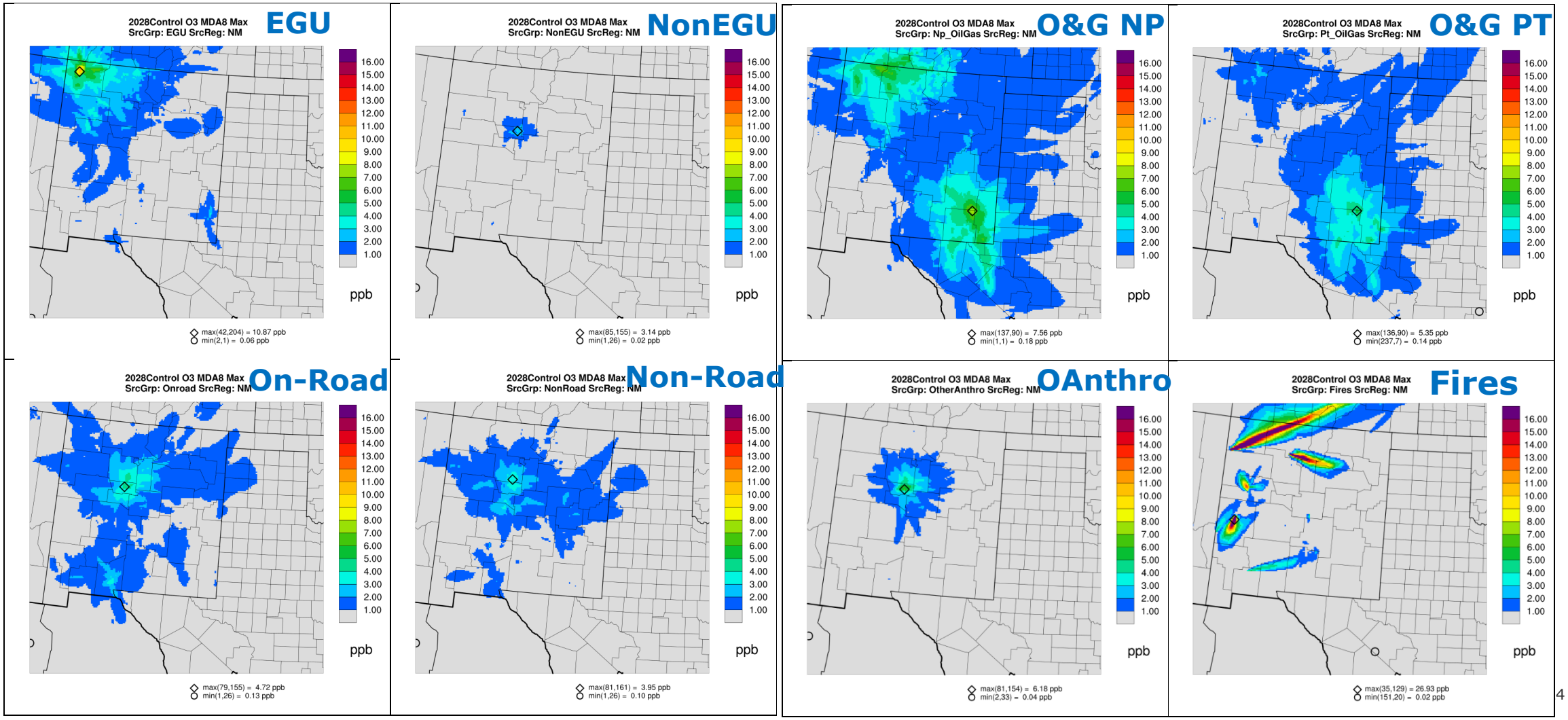
SOURCE SECTOR CONTRIBUTIONS TO MODELED 2028 OZONE

1. HIGHEST NEW MEXICO SOURCE SECTOR CONTRIBUTIONS TO DAILY MDA8 OZONE DURING EPISODE
2. DETAILS OF SOURCE SECTOR CONTRIBUTIONS TO MODELED 2028 MDA8 OZONE ON 10 SMAT DAYS USED TO MAKE 2028 OZONE DVF PROJECTIONS
3. SPATIAL DISTRIBUTION OF NEW MEXICO AND ALL UNITED STATES SOURCE SECTOR CONTRIBUTIONS ON SIX EXAMPLE DAYS

RAMBOLL

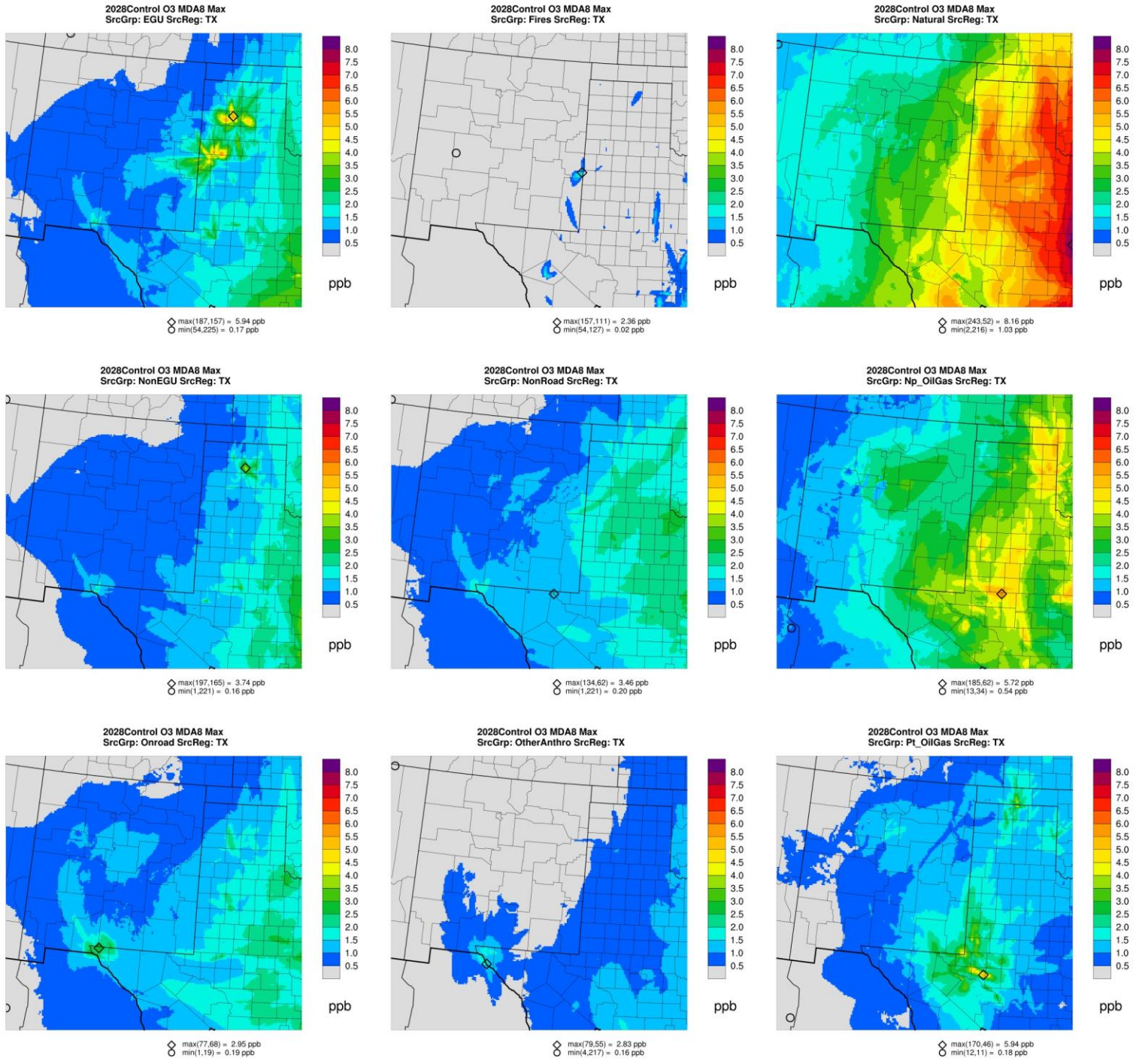
NMED Exhibit 25 - 0013

HIGHEST NEW MEXICO SOURCE SECTOR OZONE CONTRIBUTIONS TO MDA8 OZONE DURING EPISODE



HIGHEST TEXAS SOURCE SECTOR OZONE CONTRIBUTIONS TO MDA8 OZONE DURING EPISODE

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

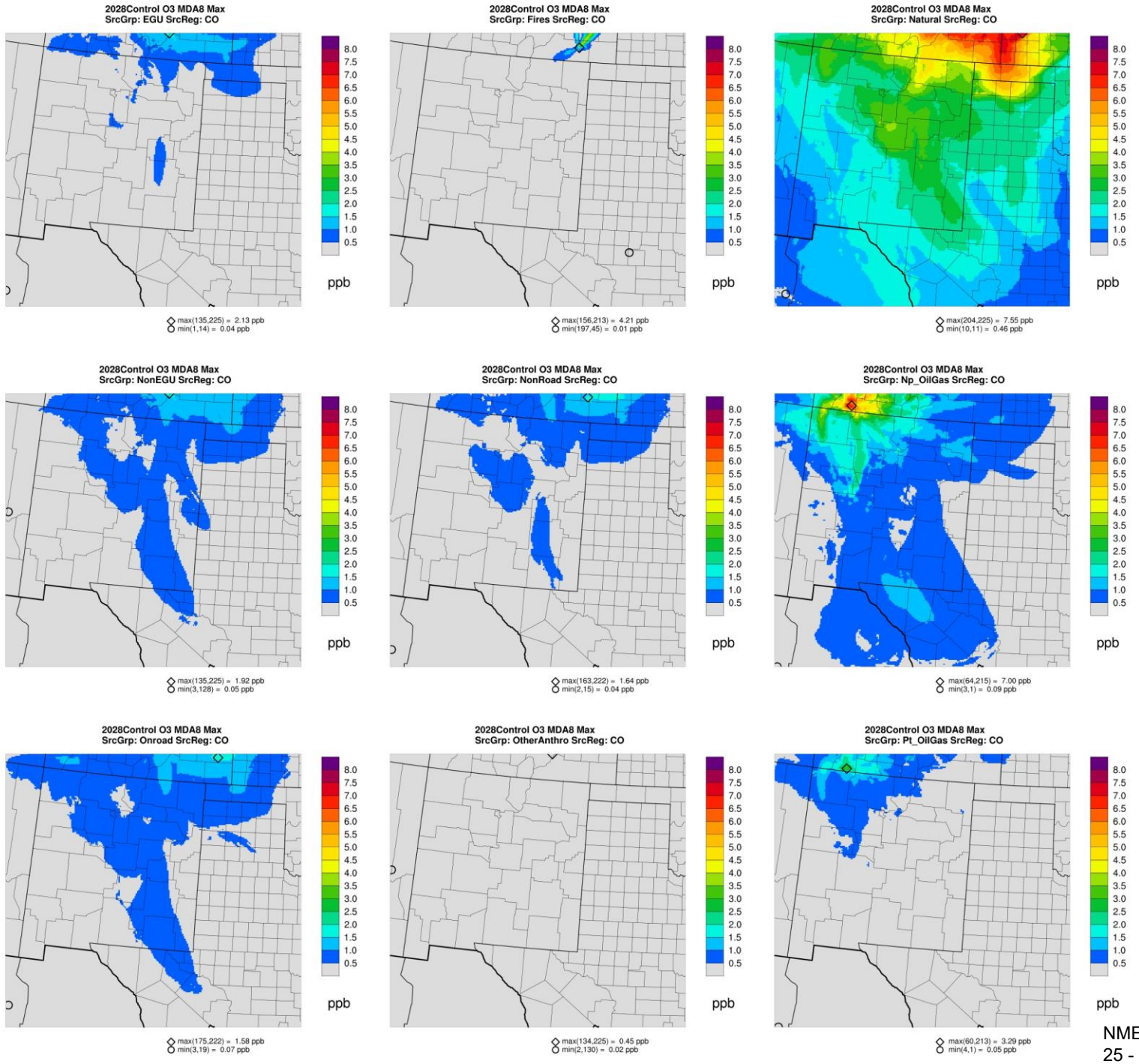


RAMBOLL

NMED Exhibit
25 - 0015

HIGHEST COLORADO SOURCE SECTOR OZONE CONTRIBUTIONS TO MDA8 OZONE DURING EPISODE

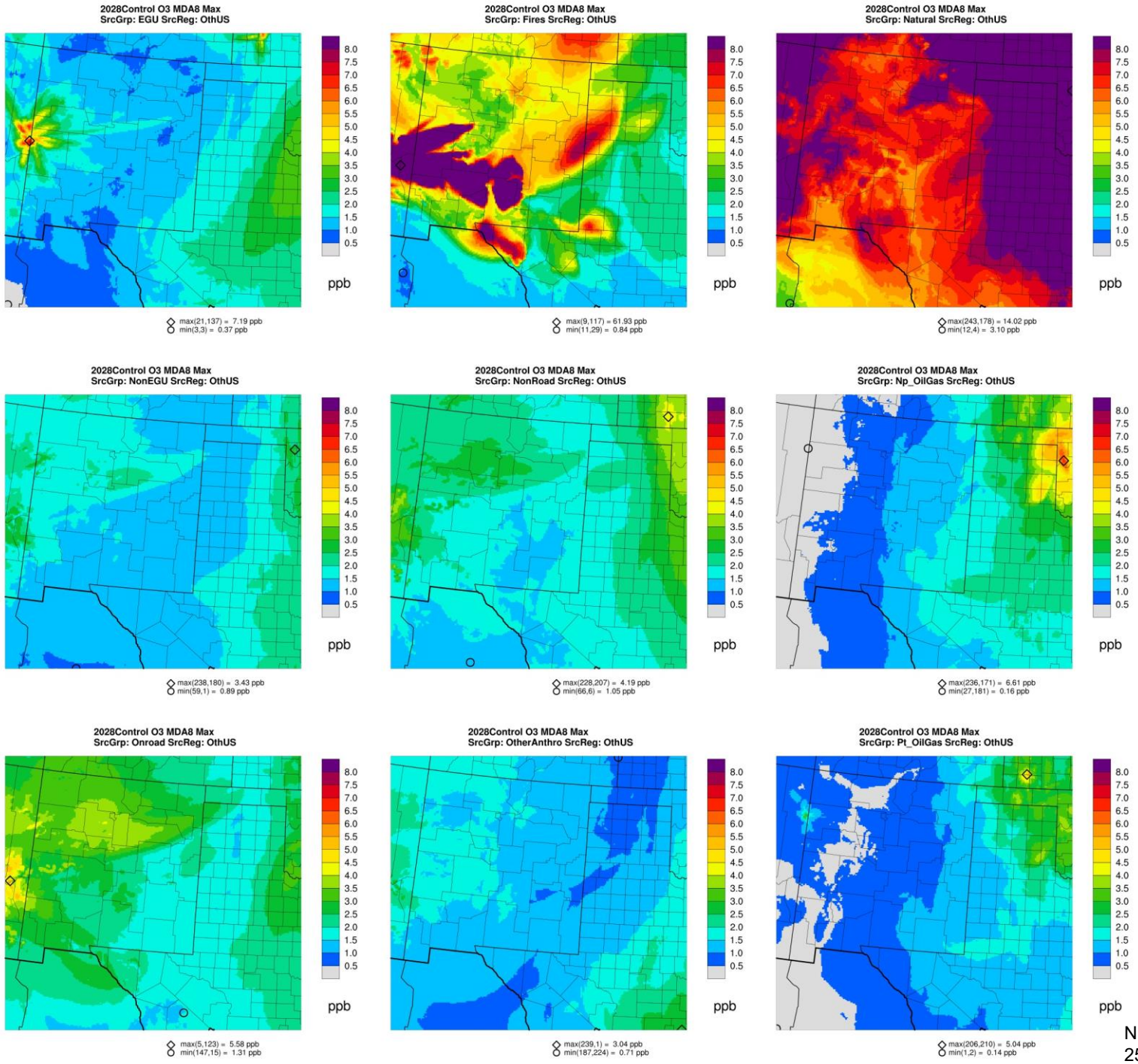
EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT



NMED Exhibit
25 - 0016

HIGHEST REMAINING U.S. SOURCE SECTOR OZONE CONTRIBUTIONS TO MDA8 OZONE DURING EPISODE (EXCLUDES NM, TX AND CO)

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

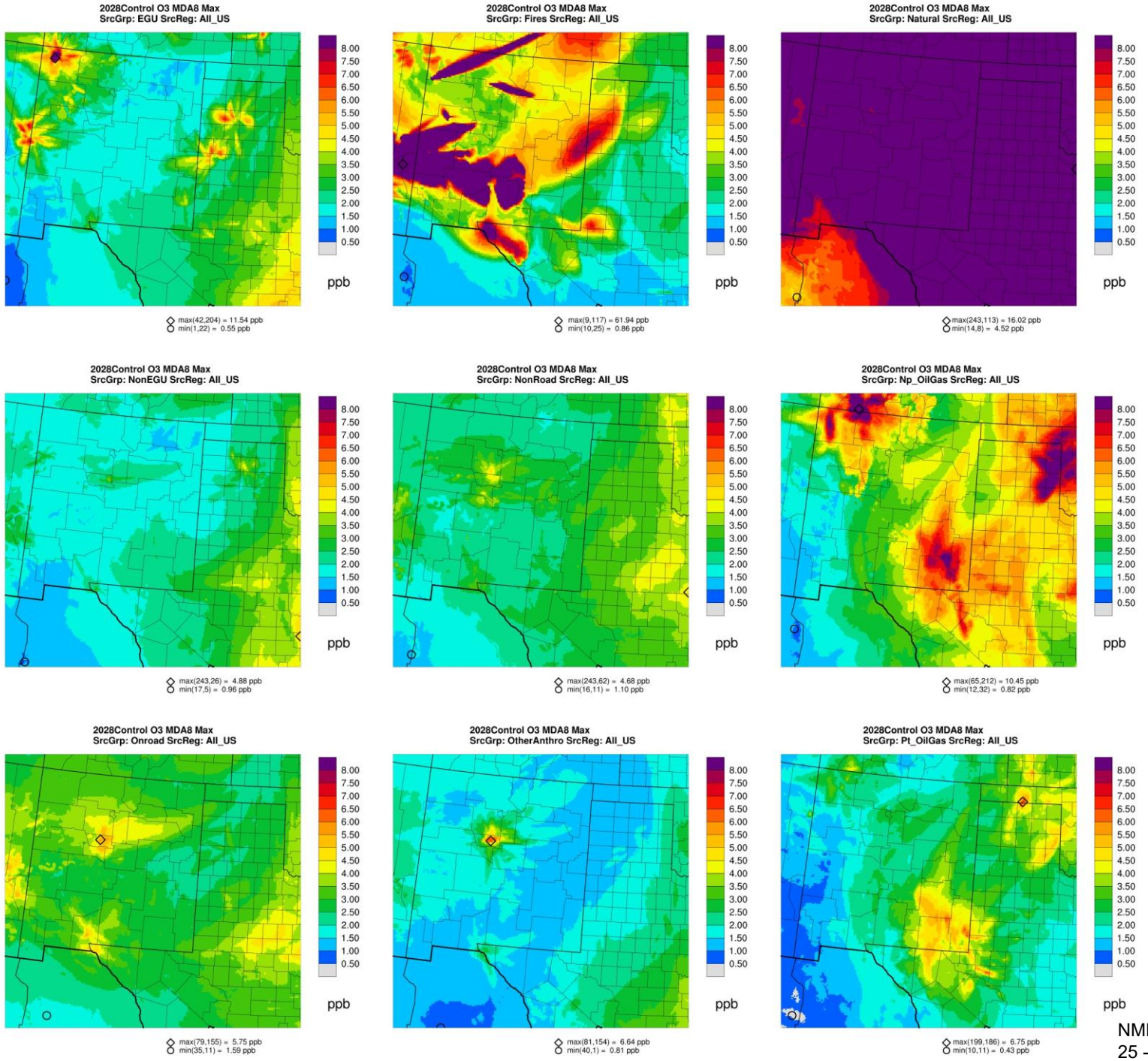


RAMBOLL

NMED Exhibit
25 - 0017

HIGHEST ALL U.S. SOURCE SECTOR OZONE CONTRIBUTIONS TO MDA8 OZONE DURING EPISODE

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

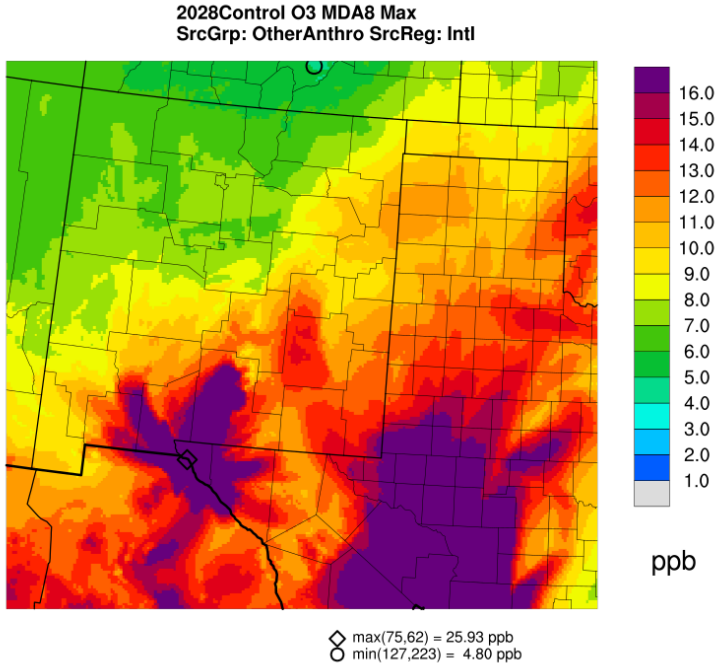


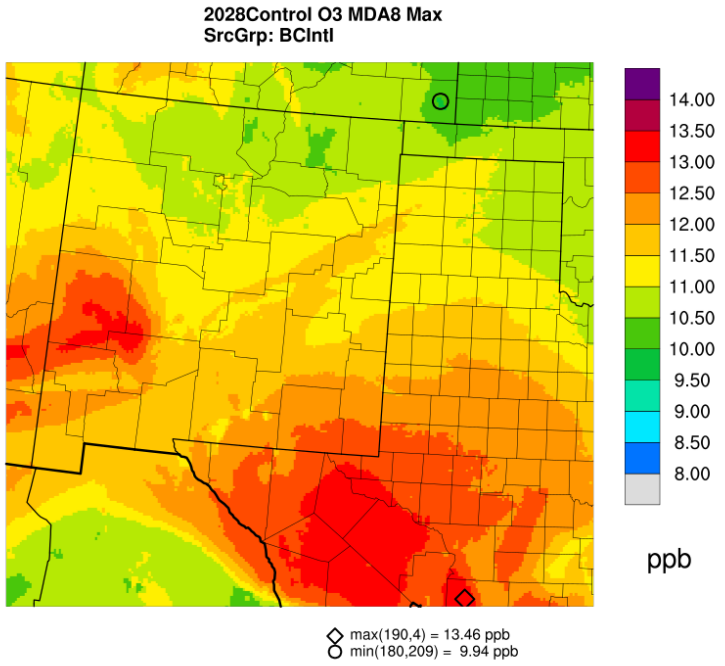
RAMBOLL

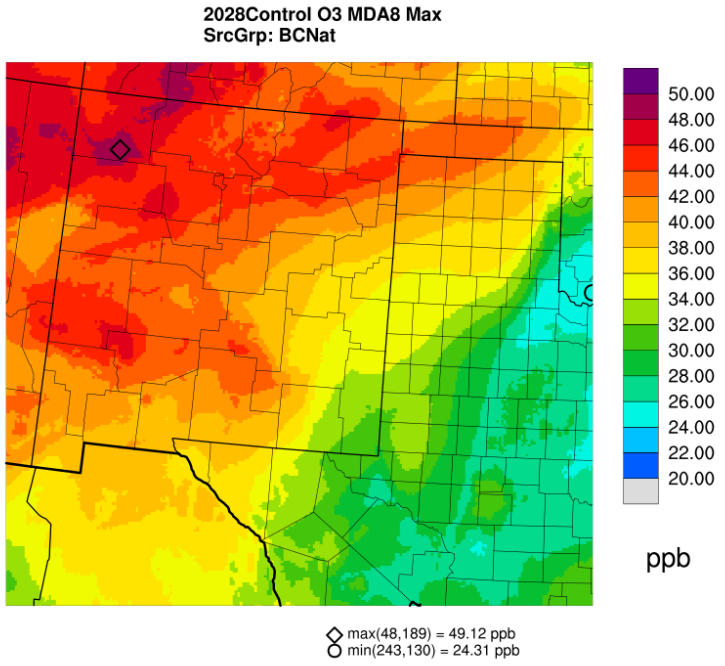
NMED Exhibit
25 - 0018

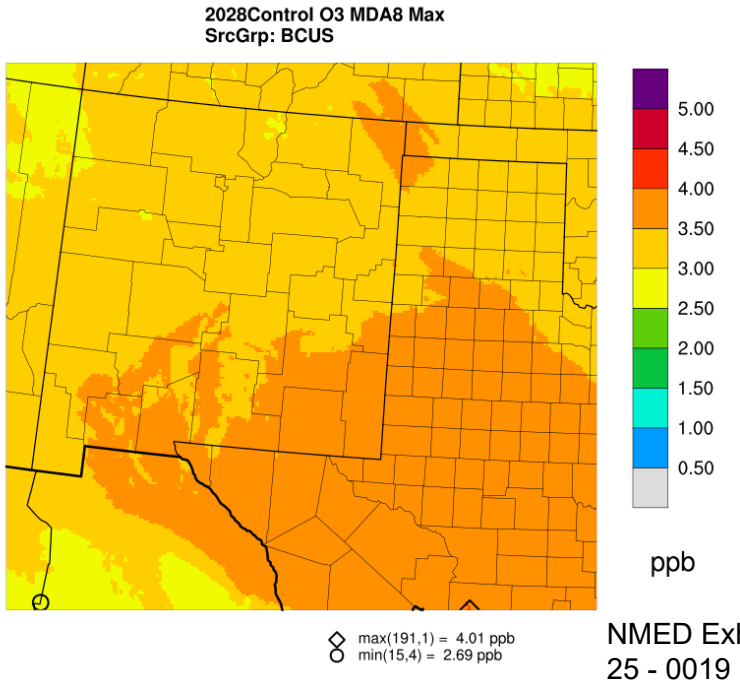
HIGHEST OZONE CONTRIBUTIONS TO MDA8 OZONE DURING EPISODE

- In-Domain International Anthropogenic Emissions (top left)
- Boundary Conditions from International Anthropogenic Emissions (top right)
- Boundary Conditions from Natural Sources (bottom left)
- Boundary Conditions from U.S. Anthropogenic Emissions (bottom right)





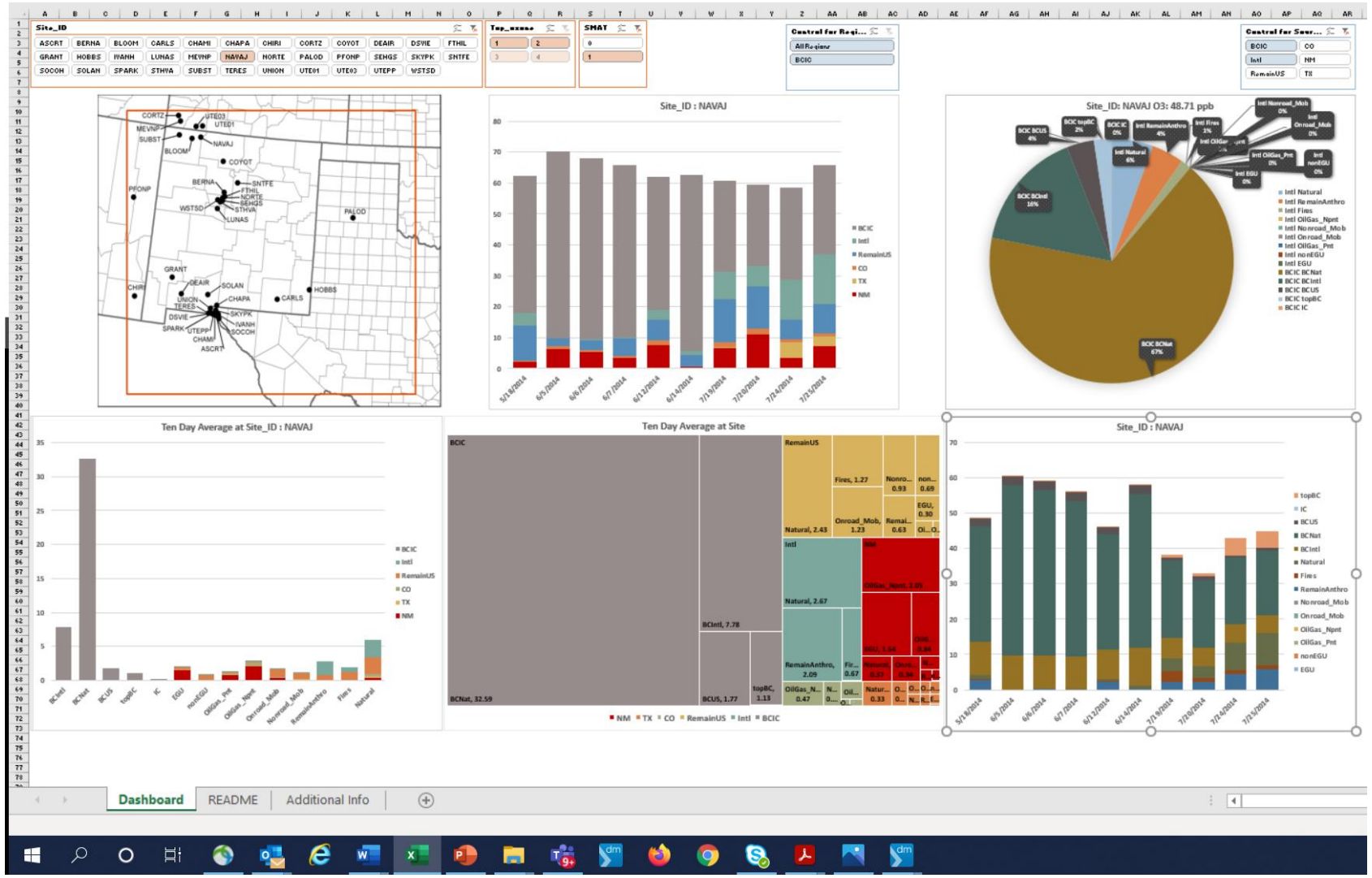




NMED Exhibit
25 - 0019

EXCEL DASHBOARD TO DISPLAY 2028 SOURCE SECTOR APCA OZONE SOURCE APPORTIONMENT MDA8 OZONE RESULTS

- User selects:
  - Monitoring Site
  - Which 10 days to display
    - SMAT days, 1-10, etc.
  - Dashboard Displays:
    - Stacked Bar Chart of MDA8 ozone contributions for 10 days
    - Stacked Bar Chart of Source Sector contributions averaged across 10 days
    - Tree Chart of contributions averaged across 10 days
- Also control source contributions by Source Region:
  - BC, Intl, NM, TX, CO and RemainUS
  - Dashboard generates stacked Bar Chart for 10 days and Pie Chart averaged across 10 days



RAMBOLL

NAVAJO LAKE: 10 SMAT DAYS

Contributions from All Sources

Average MDA8 O3

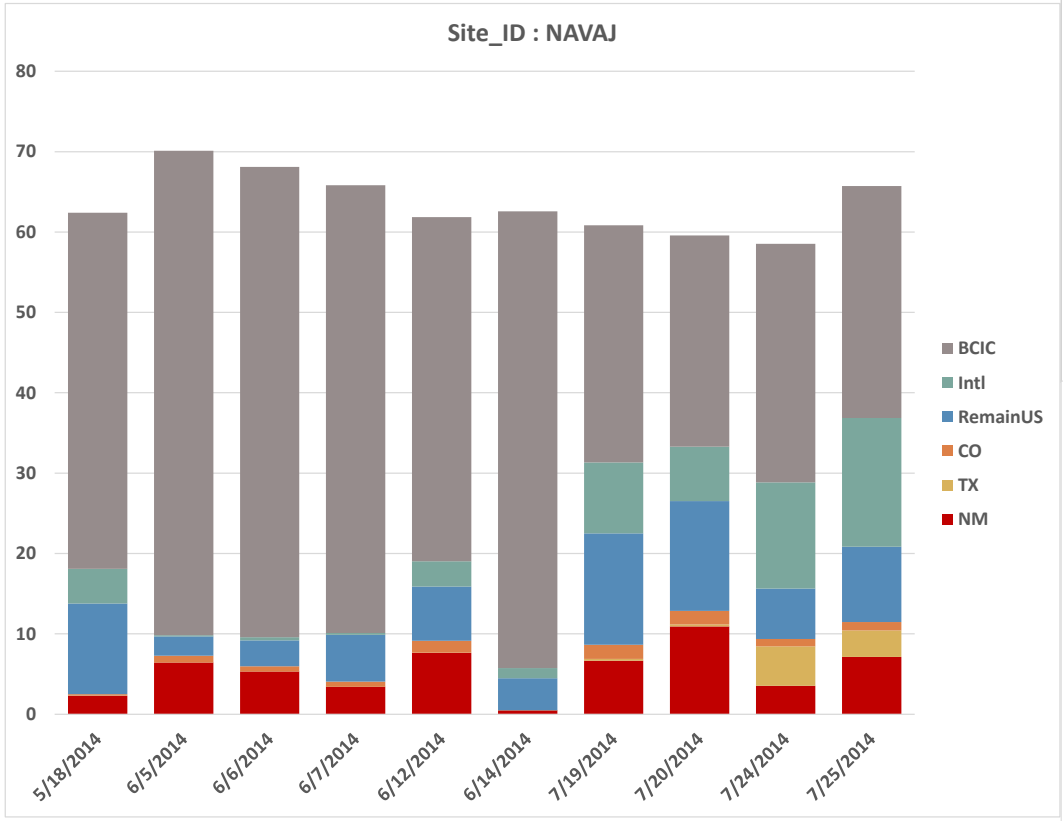
Ozone = 63.6 ppb

BC = 43.3 ppb (68%)

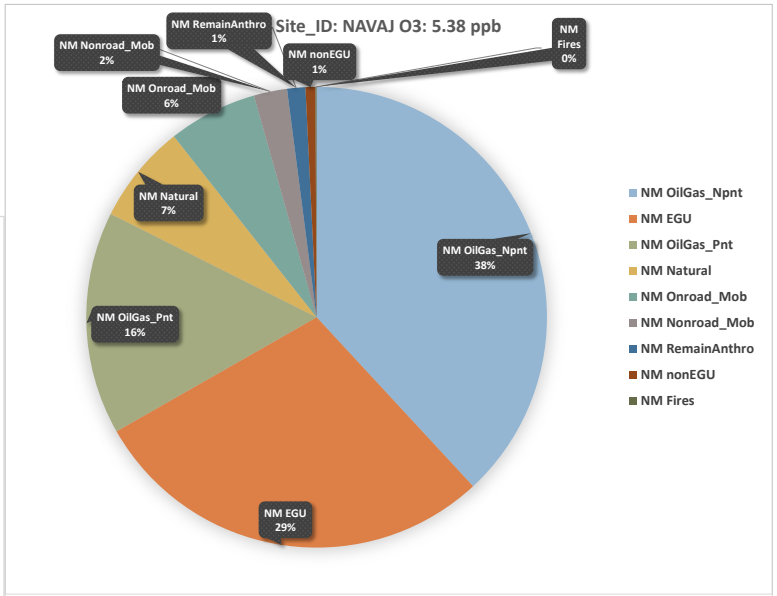
US = 14.8 ppb (23%)

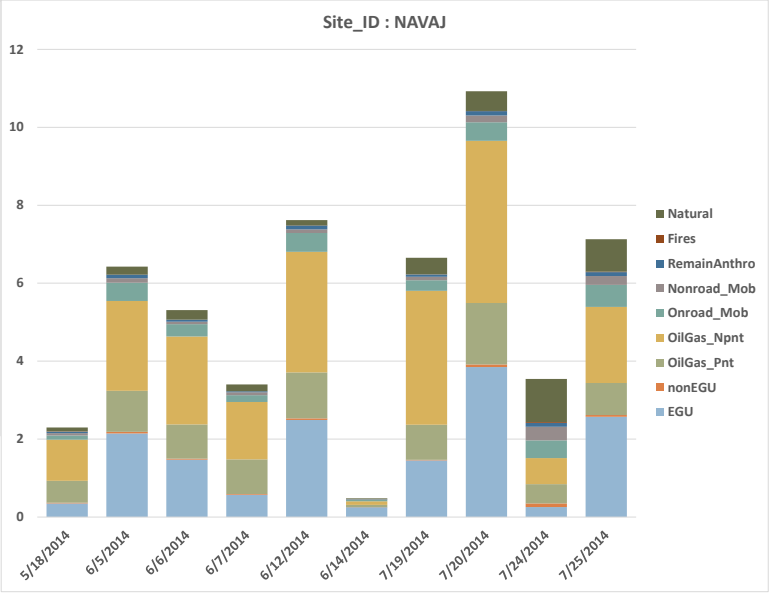
NM = 5.4 ppb (8%)

Intl Ant = 9.9 ppb (16%)



Contributions from New Mexico Sources





RAMBOLL

FOOTHILLS: 10 SMAT DAYS

Contributions from All Sources

Average MDA8 O3

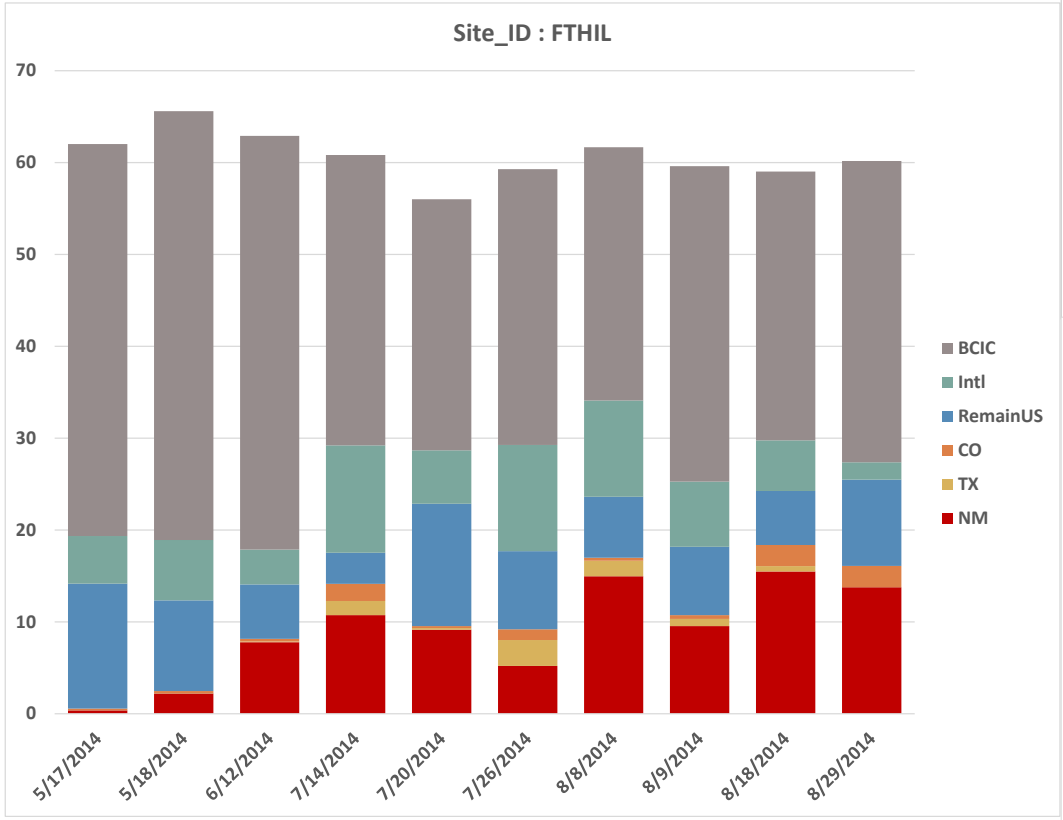
Ozone = 60.7 ppb

BC = 34.7 ppb (57%)

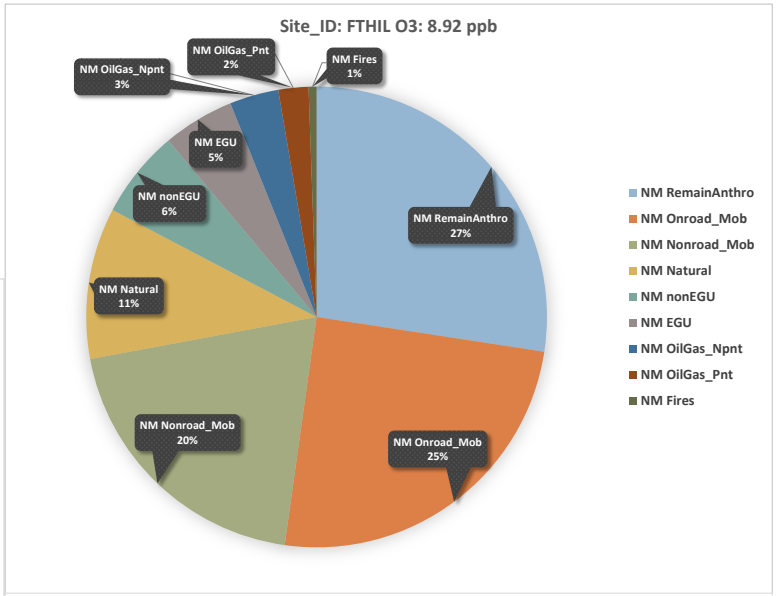
US = 19.0 ppb (31%)

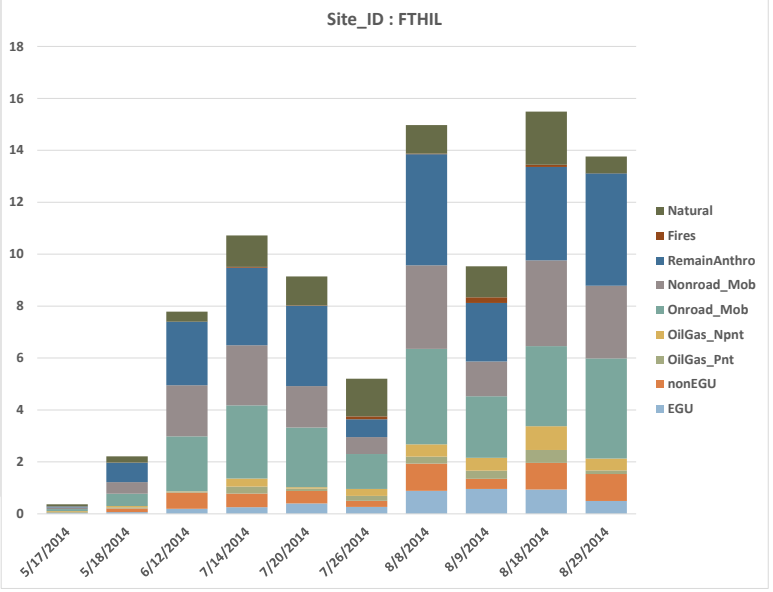
NM = 8.9 ppb (15%)

Intl Ant = 10.2 ppb (17%)



Contributions from New Mexico Sources





RAMBOLL

DESERT VIEW: 10 SMAT DAYS

Contributions from All Sources

Average MDA8 O3

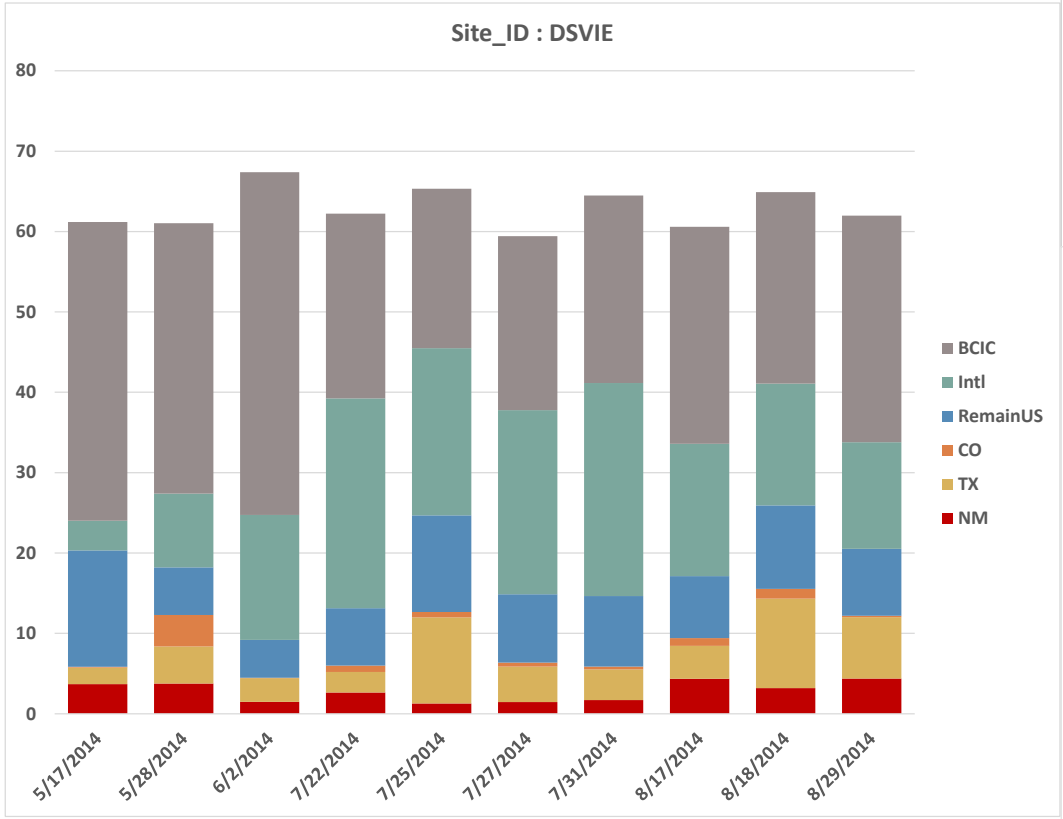
Ozone = 62.9 ppb

BC = 28.0 ppb (45%)

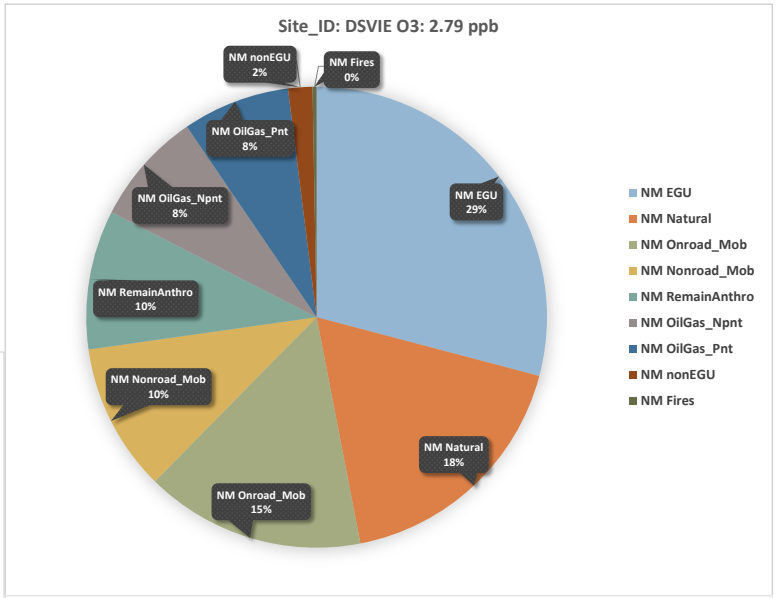
US = 17.9 ppb (28%)

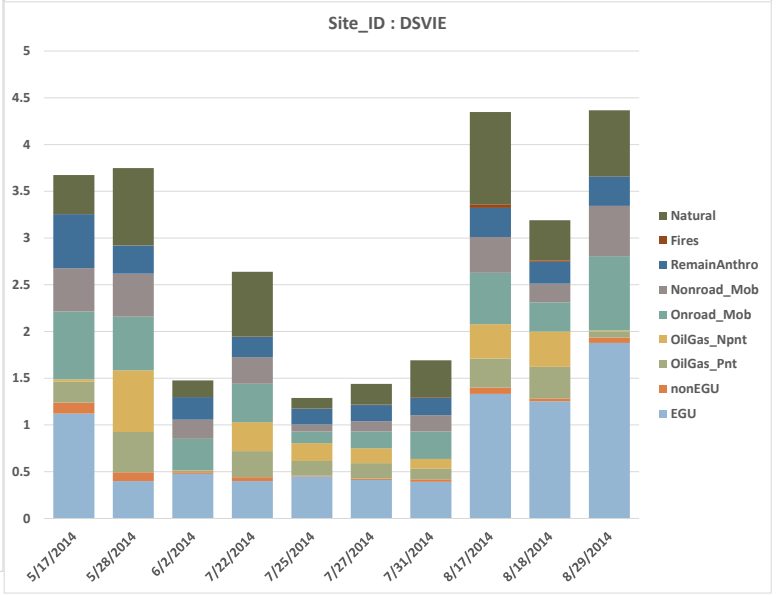
NM = 2.8 ppb (4%)

Intl Ant = 18.8 ppb (30%)



Contributions from New Mexico Sources





RAMBOLL

NMED Exhibit 25 - 0023

CARLSBAD: 10 SMAT DAYS

Average MDA8 O3

Ozone = 57.1 ppb

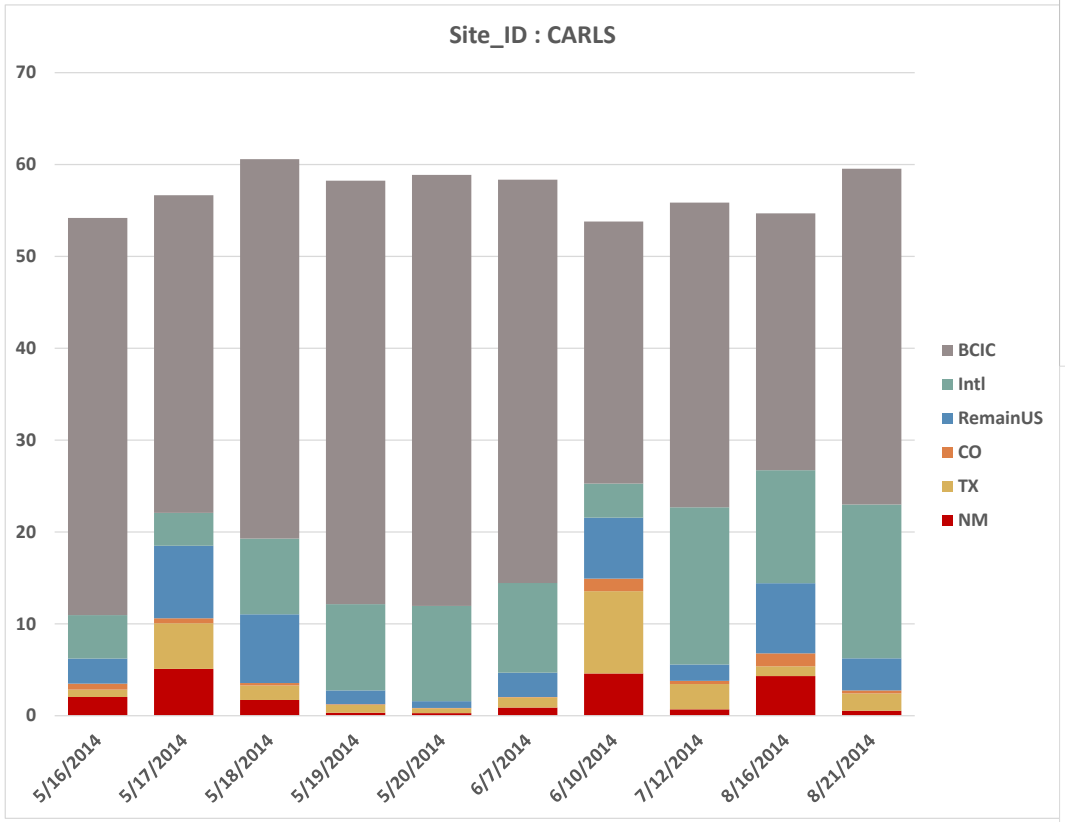
BC = 38.2 ppb (67%)

US = 9.3 ppb (16%)

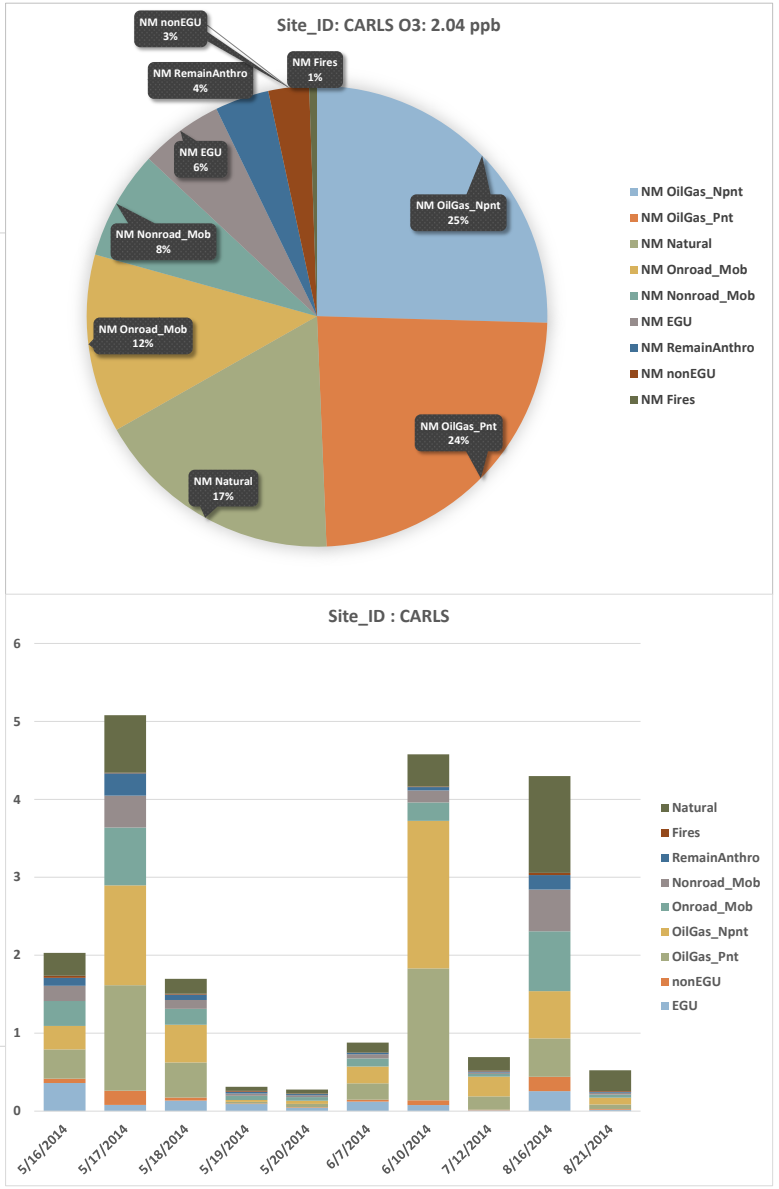
NM = 2.0 ppb (3%)

Intl Ant = 13.4 ppb (23%)

Contributions from All Sources



Contributions from New Mexico Sources



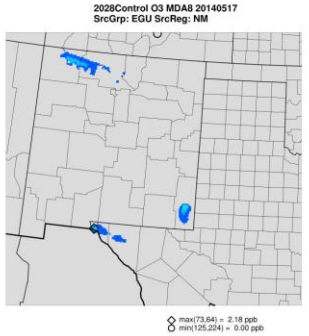
RAMBOLL

NMED Exhibit 25 - 0024

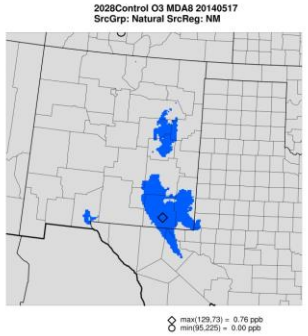
2028 SOURCE SECTOR -- MAY 17, 2014

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

New Mexico

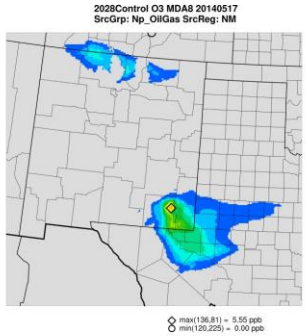


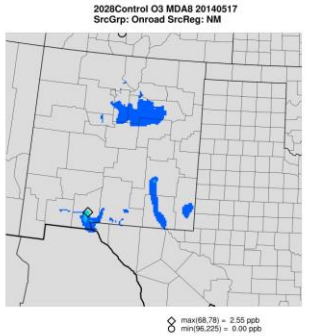




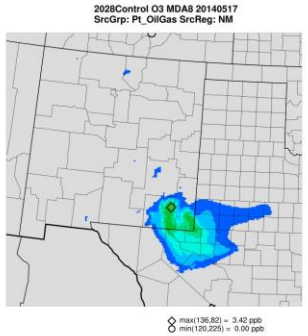




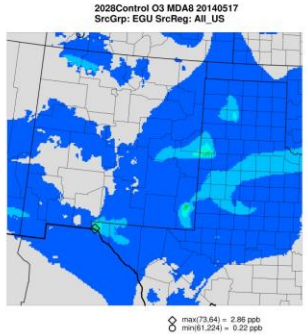


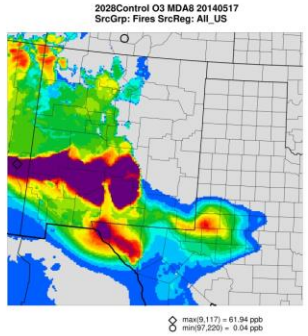


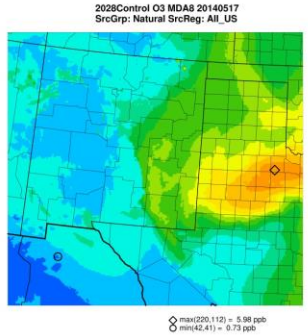


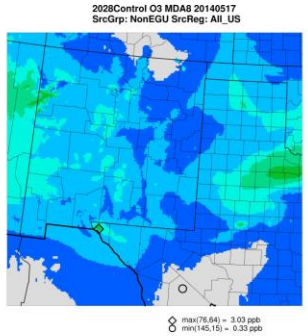


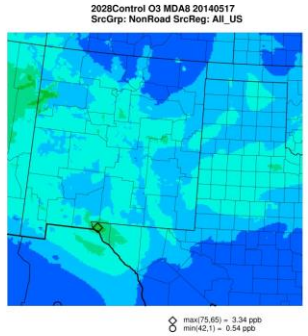
All United States

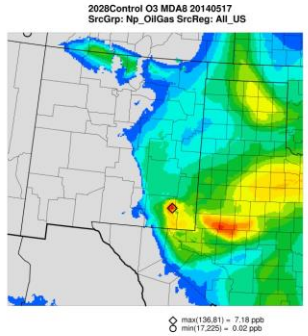


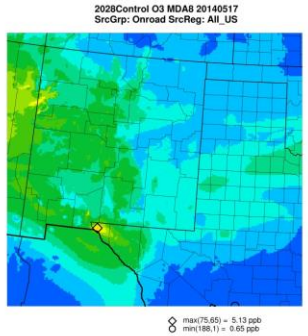


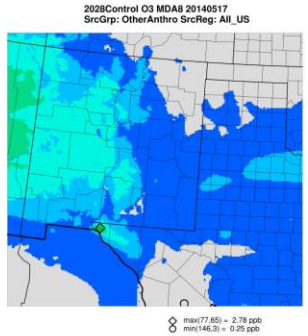


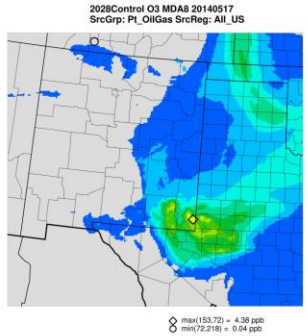








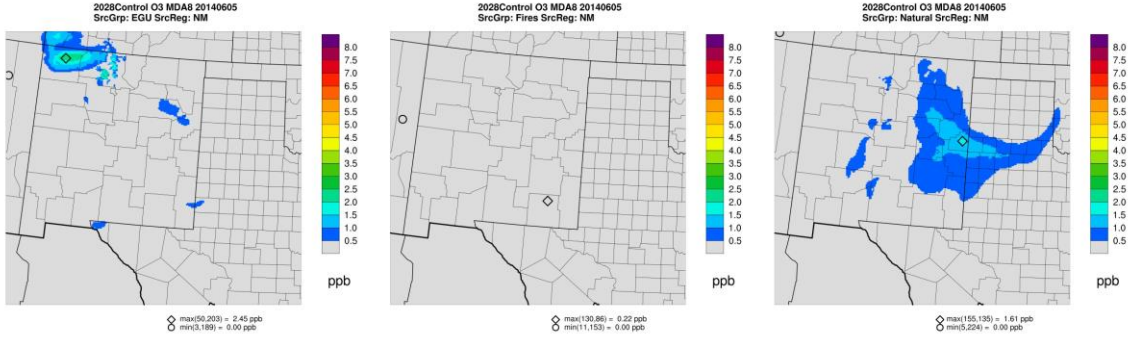




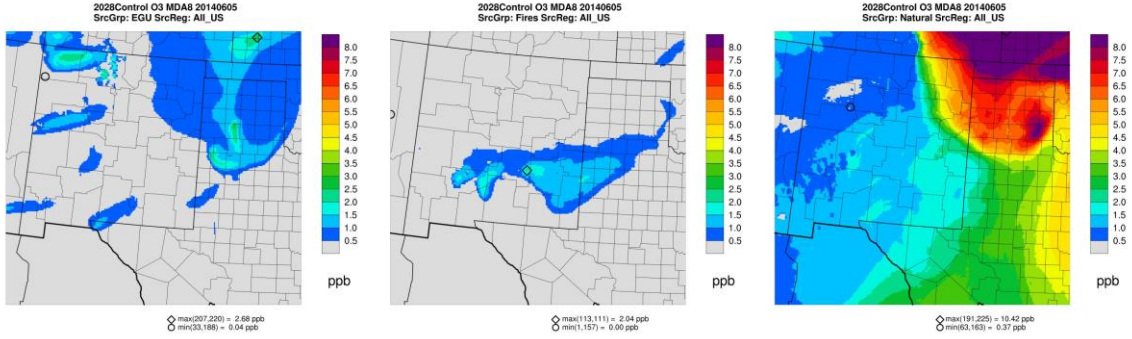
2028 SOURCE SECTOR – JUNE 5, 2014

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

New Mexico



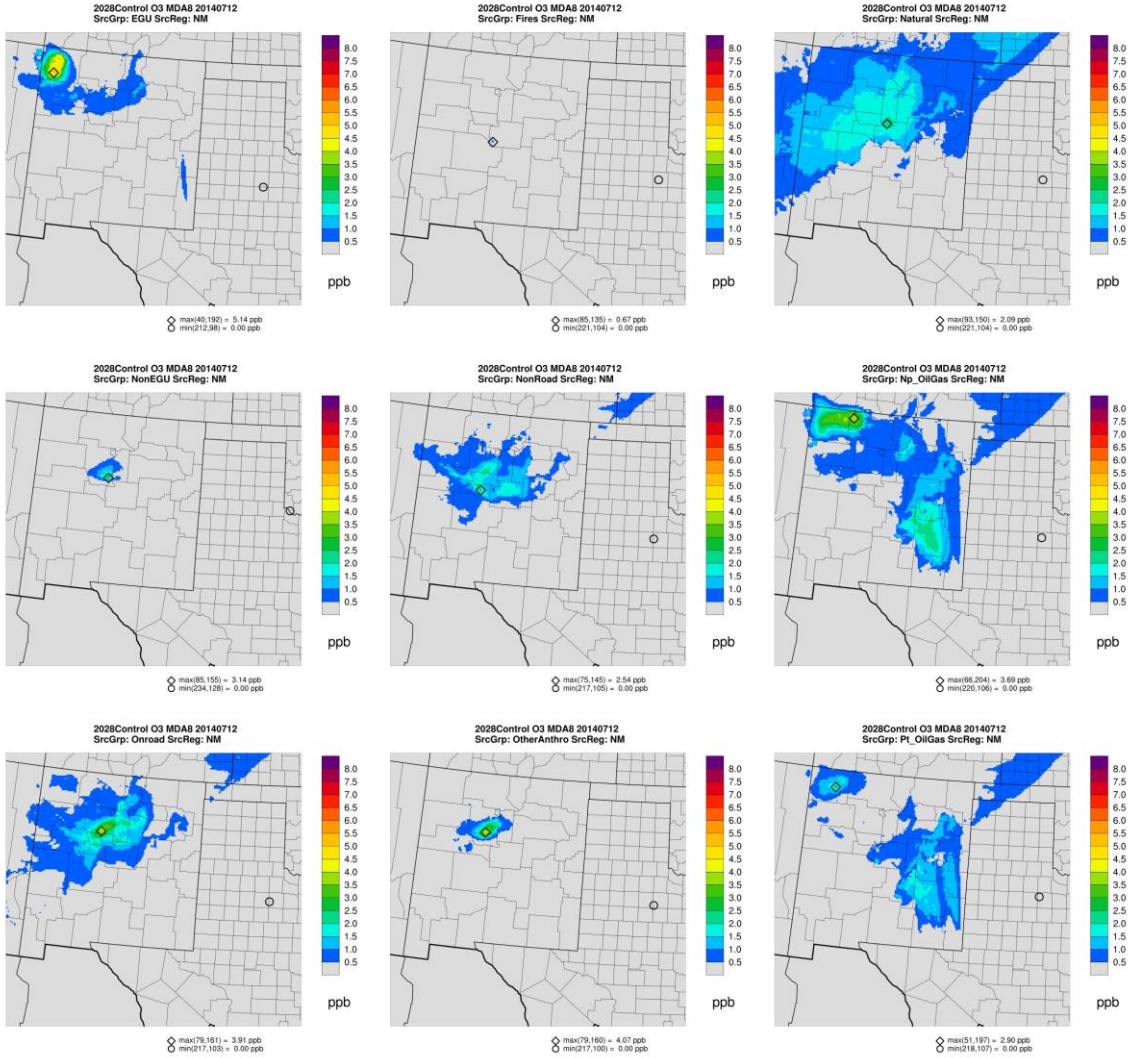
All United States



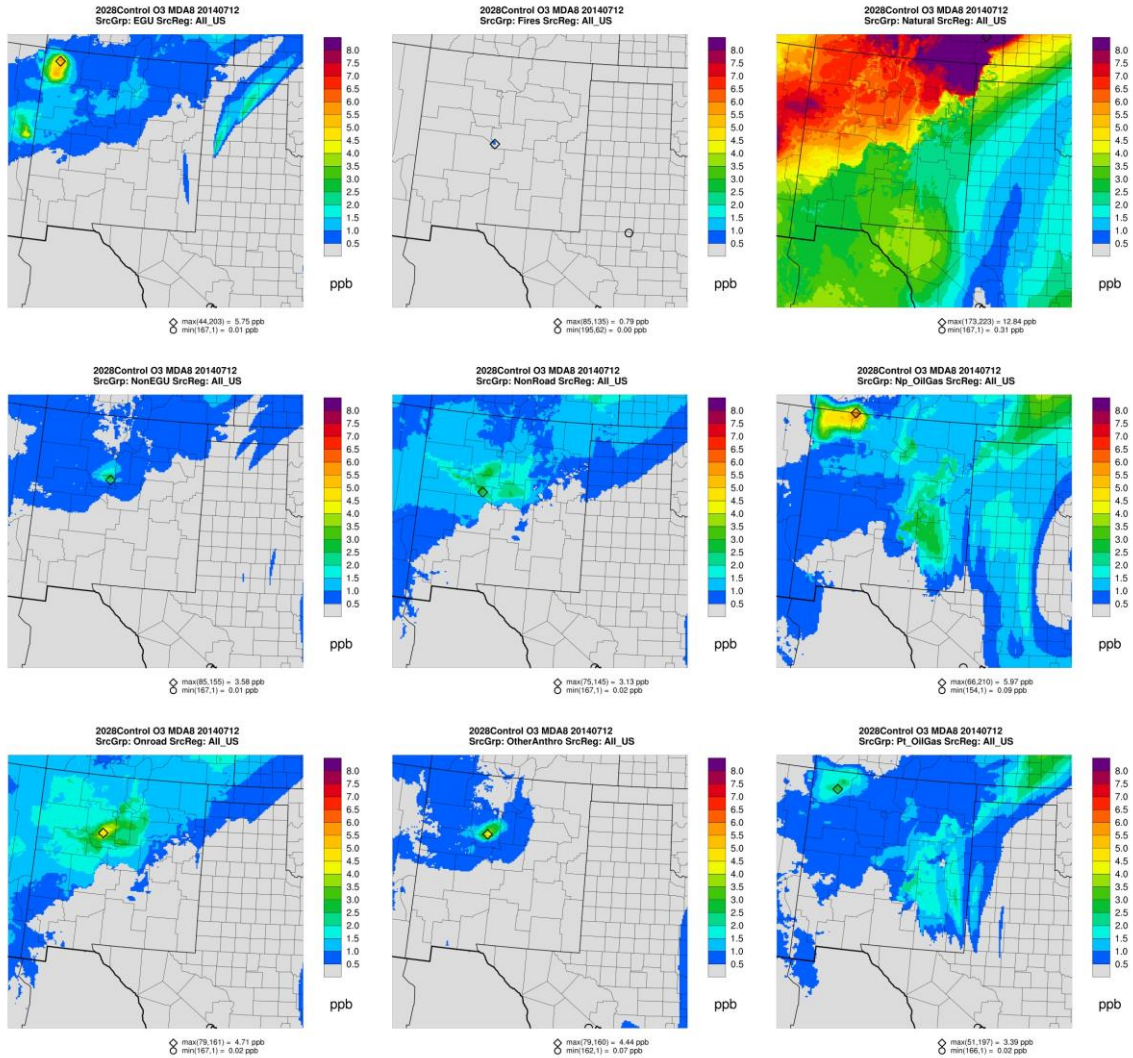
2028 SOURCE SECTOR – JULY 12, 2014

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

New Mexico



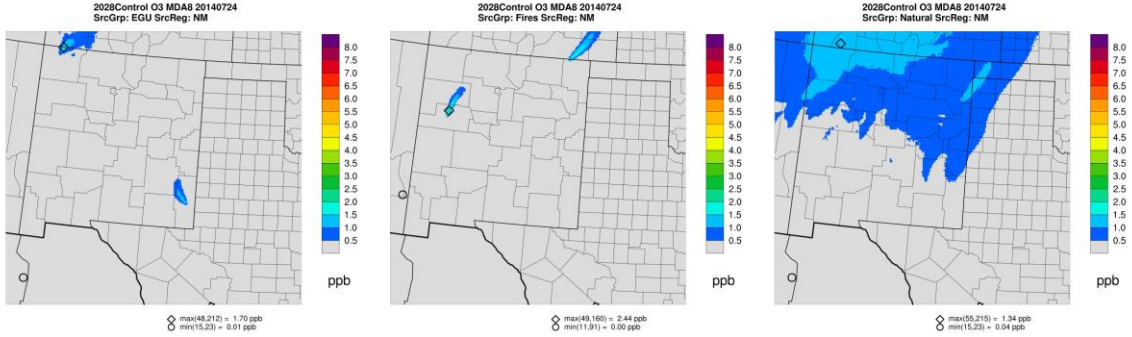
All United States



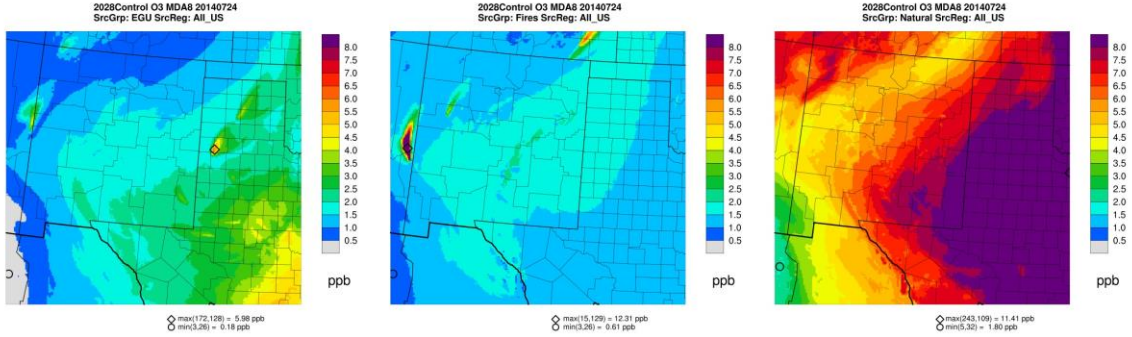
2028 SOURCE SECTOR – JULY 24, 2014

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

New Mexico



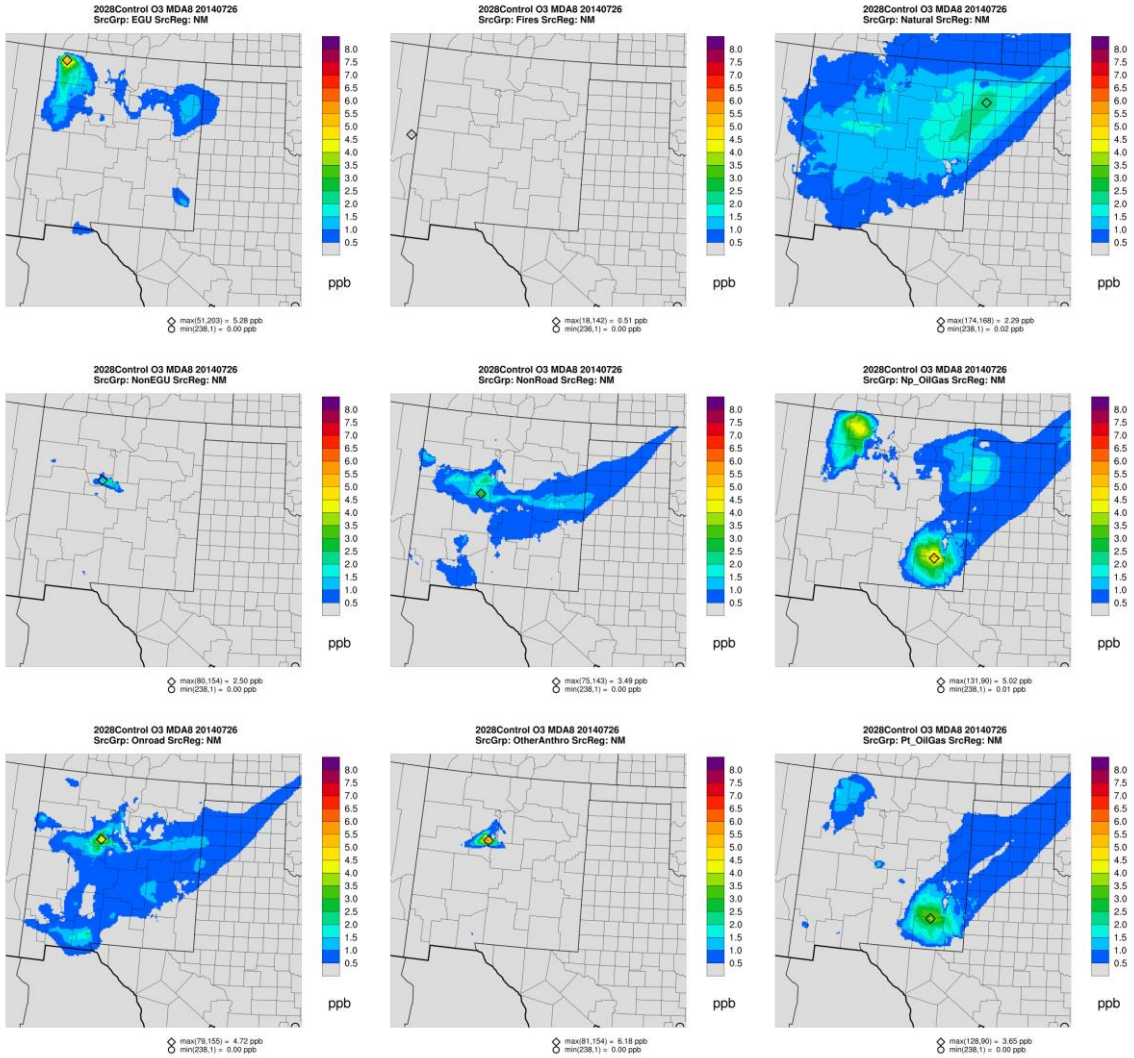
All United States



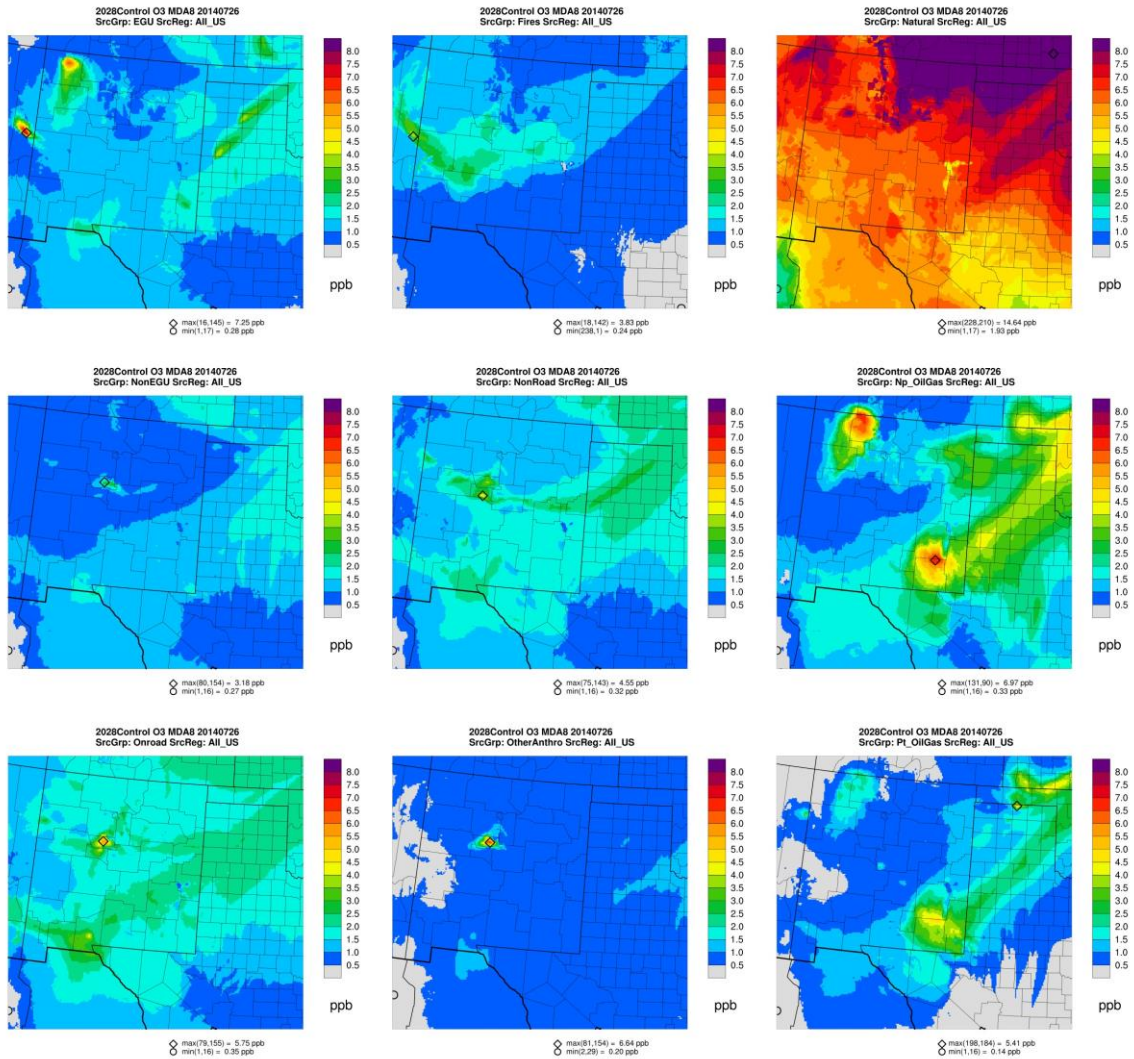
2028 SOURCE SECTOR – JULY 26, 2014

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

New Mexico



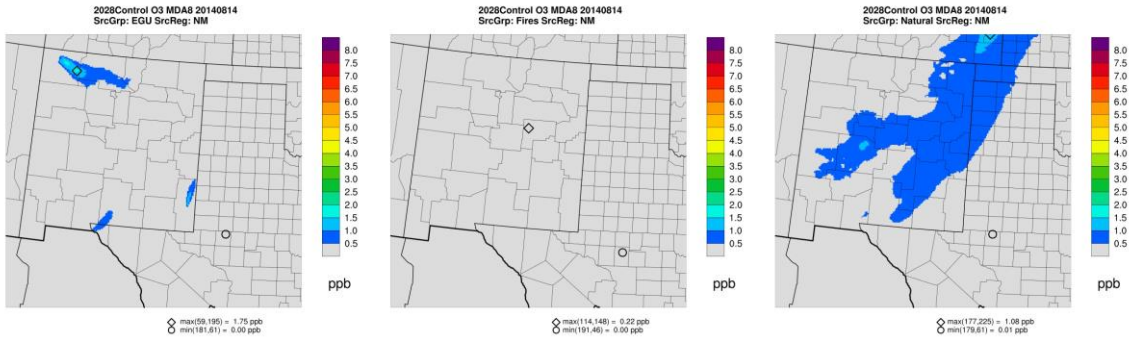
All United States



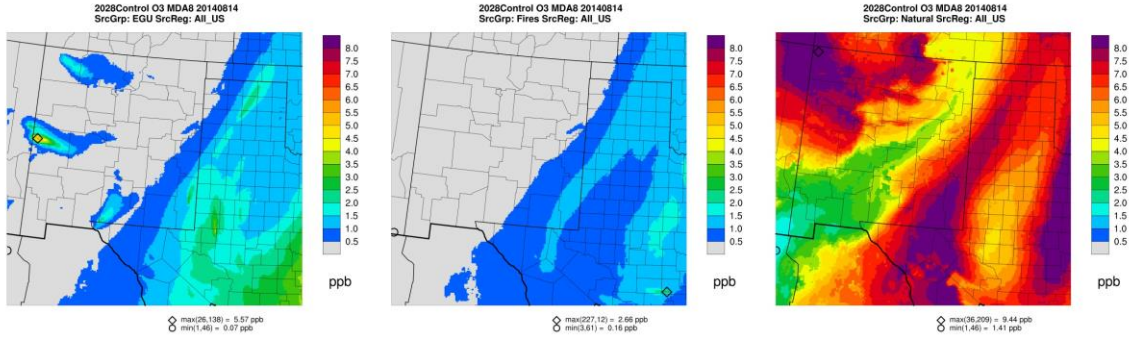
2028 SOURCE SECTOR – AUGUST 14, 2014

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

New Mexico



All United States



INTERNATIONAL ANTHROPOGENIC EMISSIONS CONTRIBUTIONS

1. CONTRIBUTIONS OF INTERNATIONAL ANTHROPOGENIC EMISSIONS TO PROJECTED 2028 OZONE DVFS AT MONITORING SITES USING THREE DEFINITIONS OF CURRENT YEAR DESIGN VALUES: $DVC_{2012\text{-}2016}$, $DVC_{2015\text{-}2019}$ AND $DVC_{2017\text{-}2019}$
2. CONTRIBUTIONS OF INTERNATIONAL ANTHROPOGENIC EMISSIONS TO SMAT UNMONITORED AREA ANALYSIS PROJECTED 2028 OZONE DVFS ACROSS 4-KM NEW MEXICO DOMAIN USING THREE DEFINITIONS OF CURRENT YEAR DESIGN VALUES: $DVC_{2012\text{-}2016}$, $DVC_{2015\text{-}2019}$ AND $DVC_{2017\text{-}2019}$

RAMBOLL

NMED Exhibit 25 - 0031

2028 OZONE DVF NO INTERNATIONAL ANTHRO EMISSIONS

- 2028 ozone DVF projections using $DVC_{2012\text{-}2016}$, $DVC_{2015\text{-}2019}$ and $DVC_{2017\text{-}2019}$
- Elimination of international anthropogenic emissions reduces 2028 ozone DVF by 13 to 25 ppb
- 2028 ozone DVF w/ no international anthropogenic emissions range from 38 to 53 ppb

2012-14 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name
66.3	60.7	47.2	-13.5	Del Norte HS
68.0	62.0	48.5	-13.5	South East Heights
66.0	60.5	47.1	-13.4	South Valley
67.0	62.1	48.5	-13.6	Westside
65.0	58.8	45.7	-13.1	Foothills
66.3	59.8	39.9	-19.9	La Union
67.0	61.8	38.4	-23.4	Sunland Park
67.0	62.2	39.6	-22.6	Chaparral
72.0	66.8	42.6	-24.2	Desert View
71.3	66.0	42.2	-23.8	Santa Teresa
65.0	60.2	41.5	-18.7	Solano
69.0	66.4	46.1	-20.3	Carlsbad
62.0	58.9	43.0	-15.9	Chino Copper Smelt
66.0	63.3	44.9	-18.4	Hobbs Jefferson
66.0	62.5	43.3	-19.2	Deming Airport
64.0	60.0	47.4	-12.6	Coyote Ranger Dist
64.0	58.1	44.4	-13.7	Bernalillo (E Avenida)
64.3	60.2	46.4	-13.8	Bloomfield
67.0	63.3	50.2	-13.1	Navajo Lake
63.7	59.6	48.5	-11.1	Substation
64.3	60.4	47.9	-12.5	Santa Fe Airport
66.3	62.0	47.5	-14.5	Los Lunas (Los Lentes)

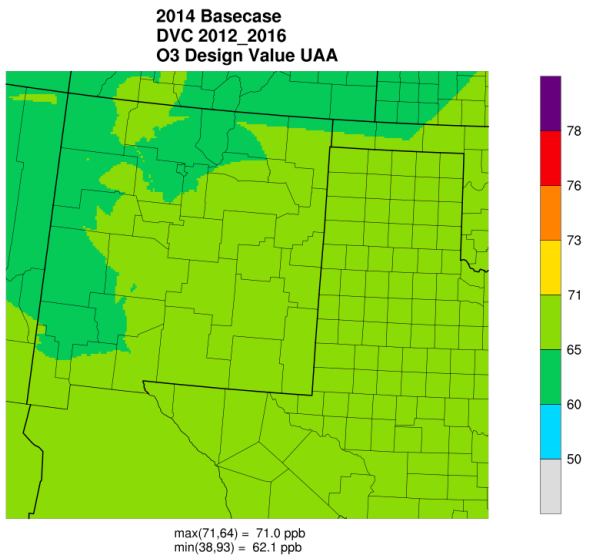
2015-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name
69.0	63.1	49.2	-13.9	Del Norte HS
66.0	60.5	47.1	-13.4	South Valley
69.0	62.4	48.5	-13.9	Foothills
68.7	62.0	41.3	-20.7	La Union
70.7	65.7	41.8	-23.9	Chaparral
74.3	68.9	43.9	-25.0	Desert View
74.0	68.5	43.8	-24.7	Santa Teresa
67.7	62.7	43.3	-19.4	Solano
73.7	70.9	49.2	-21.7	Carlsbad
71.0	69.3	44.1	-25.2	Carlsbad NP
69.3	66.5	47.1	-19.4	Hobbs Jefferson
66.3	62.2	49.1	-13.1	Coyote Ranger Dist
67.0	60.9	46.5	-14.4	Bernalillo (E Avenida)
67.0	62.8	48.3	-14.5	Bloomfield
69.0	65.2	51.7	-13.5	Navajo Lake
67.3	62.9	51.2	-11.7	Substation
65.0	61.0	48.4	-12.6	Santa Fe Airport
66.7	62.3	47.8	-14.5	Los Lunas (Los Lentes)

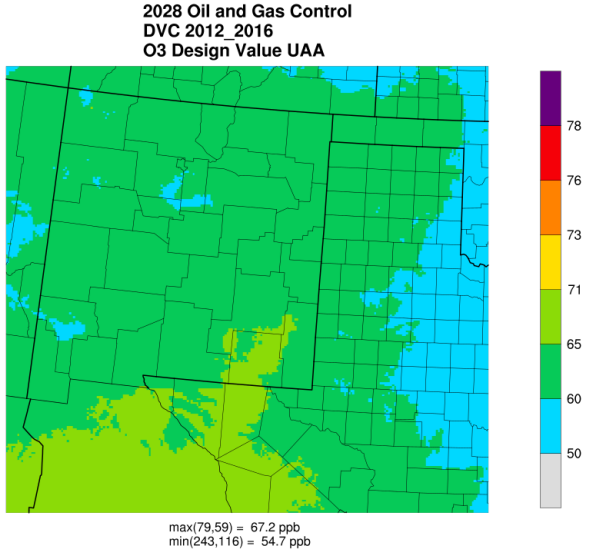
2017-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name
70.0	64.0	49.9	-14.1	Del Norte HS
67.0	61.4	47.8	-13.6	South Valley
71.0	64.2	49.9	-14.3	Foothills
70.0	63.2	42.1	-21.1	La Union
73.0	67.8	43.1	-24.7	Chaparral
77.0	71.4	45.5	-25.9	Desert View
76.0	70.3	45.0	-25.3	Santa Teresa
70.0	64.8	44.7	-20.1	Solano
79.0	76.0	52.8	-23.2	Carlsbad
71.0	68.1	48.3	-19.8	Hobbs Jefferson
67.0	62.8	49.6	-13.2	Coyote Ranger Dist
68.0	61.8	47.2	-14.6	Bernalillo (E Avenida)
68.0	63.7	49.1	-14.6	Bloomfield
69.0	65.2	51.7	-13.5	Navajo Lake
69.0	64.5	52.5	-12.0	Substation
66.0	62.0	49.1	-12.9	Santa Fe Airport
68.0	63.5	48.7	-14.8	Los Lunas (Los Lentes)

NMED Exhibit 25 - 0032

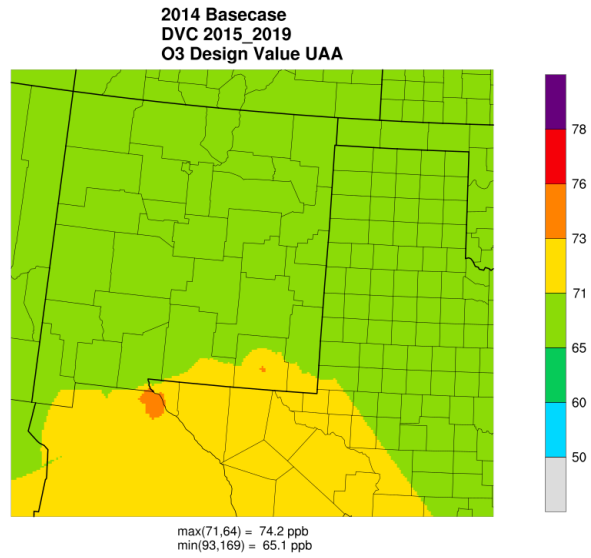
SMAT UAA -- DVC (TOP) AND 2028 O&G CONTROL DVF (BOTTOM)

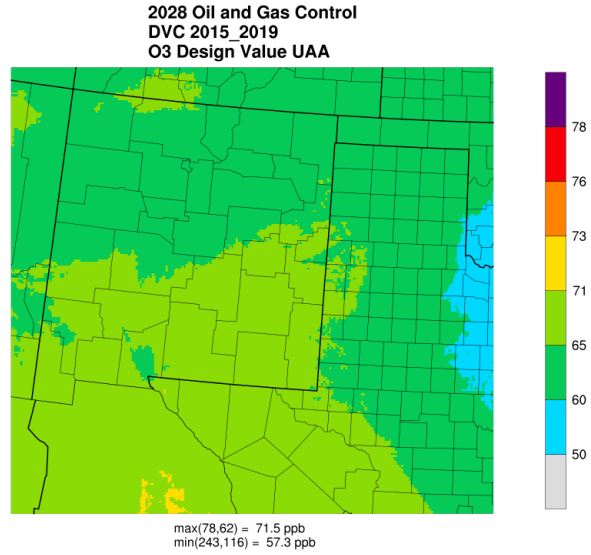
$DVC_{2012-2016}$



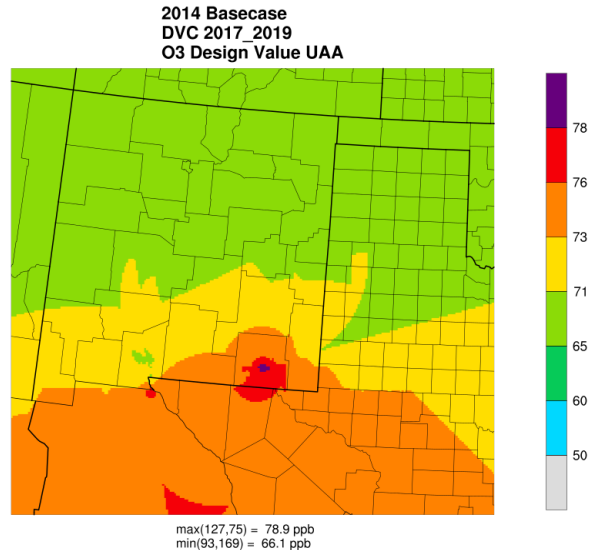


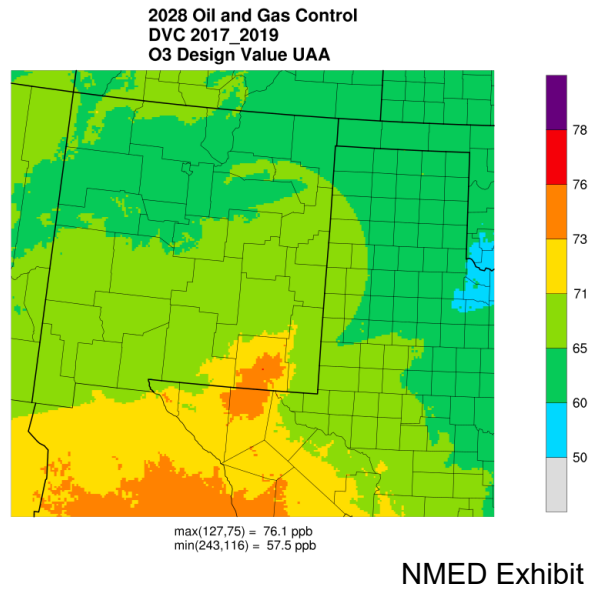
$DVC_{2015-2019}$





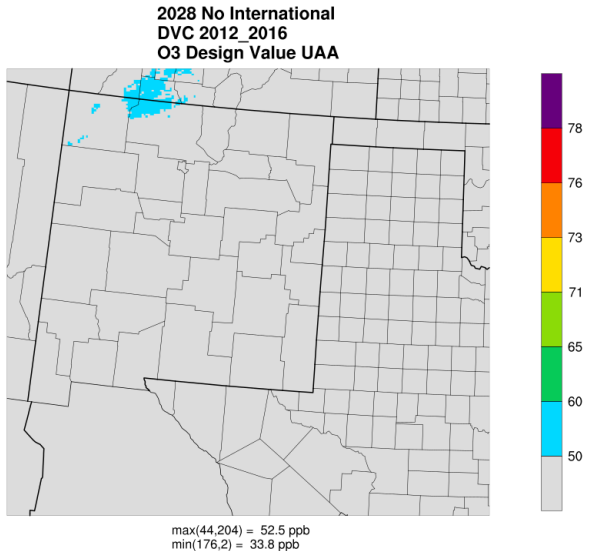
$DVC_{2017-2019}$

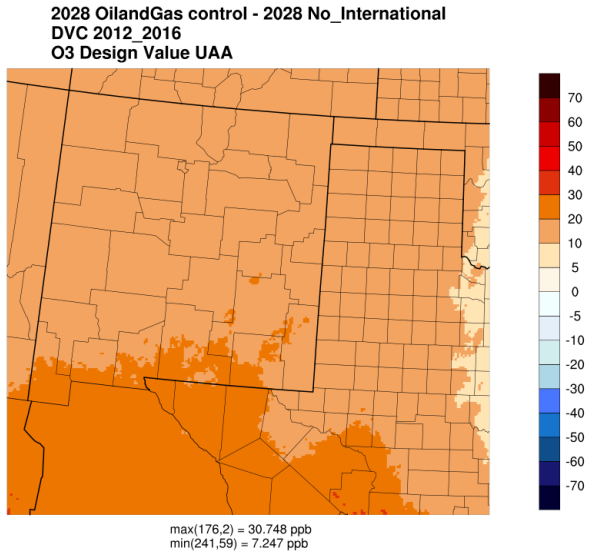




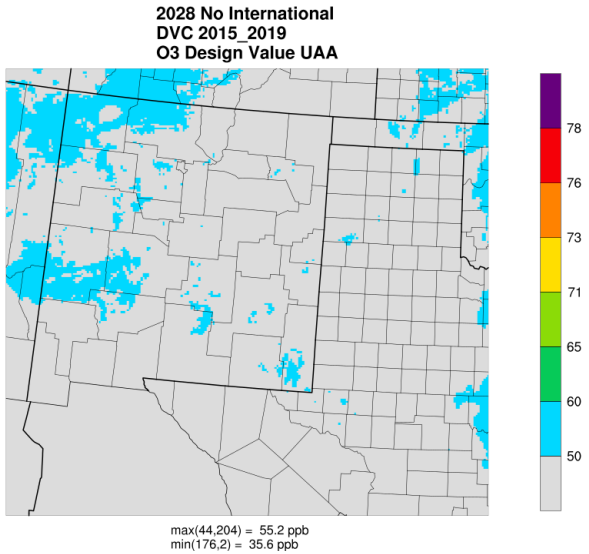
SMAT UAA – 2028 DVF NO INTL (TOP) AND DIFFERENCE (BOTTOM)

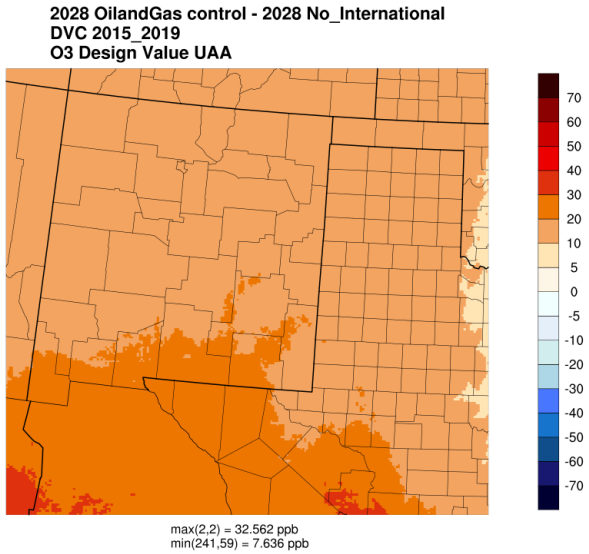
$DVC_{2012-2016}$



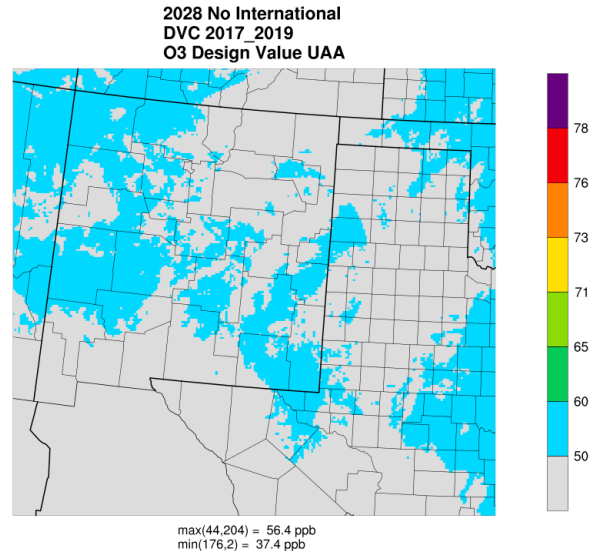


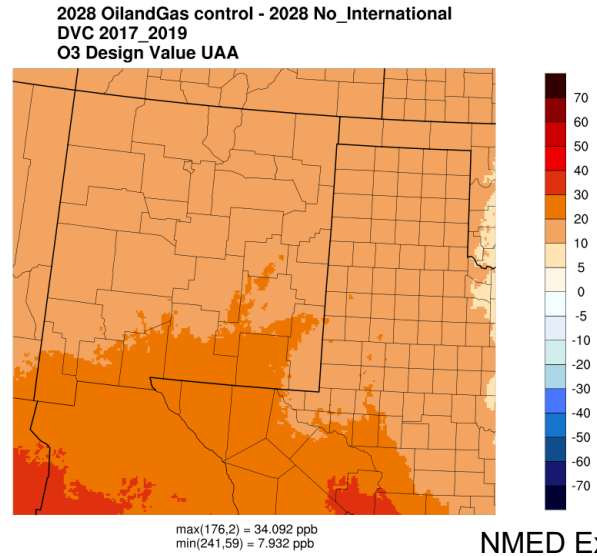
$DVC_{2015-2019}$





$DVC_{2017-2019}$





SECOND DRAFT AQTSD (DUE APRIL 4, 2021)

1. Introduction
2. 2014 WRF Meteorological Modeling
3. Boundary Condition Inputs
4. 2014 Emission Inputs
5. Diagnostic Sensitivity Tests
6. 2014 Base Case Modeling and Model Performance Evaluation
7. 2028 Base Case Modeling and Ozone Design Value Projections
8. 2028 Oil and Gas Control Strategy Modeling and Ozone Design Value Projections
9. Sensitivity of 2028 Ozone Design Value Projections to Current Year Design Values
10. APCA Source Sector Ozone Source Apportionment Modeling
11. Summary and Conclusions
12. References

To Come:

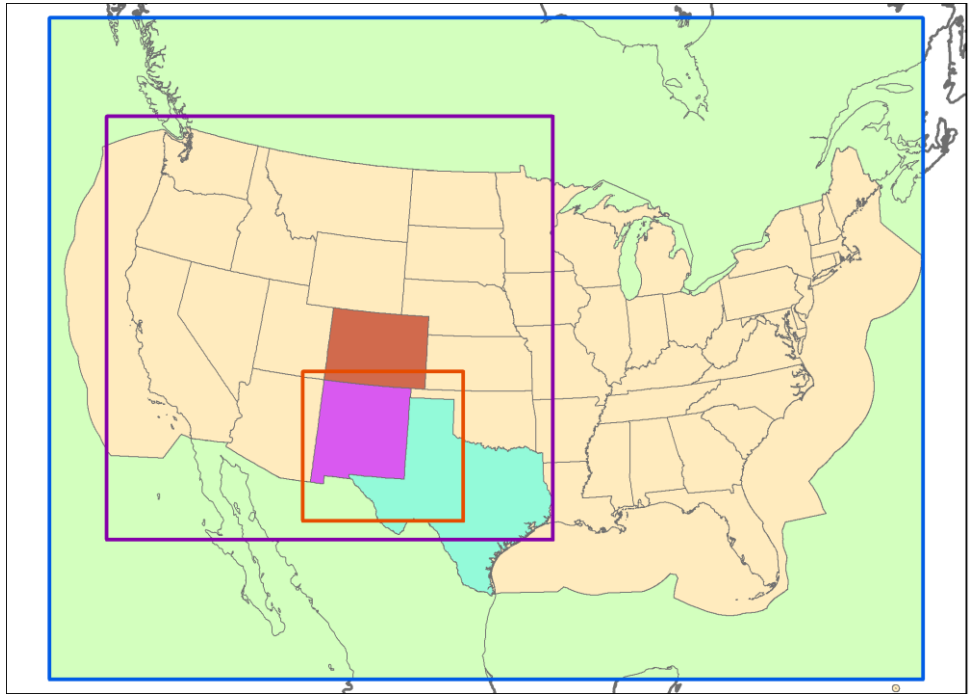
11. OSAT VOC/NOx Sensitivity Ozone Source Apportionment Modeling

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NMED Exhibit 25 - 0035

CAMX 2028 O&G CS OSAT OZONE SOURCE APPORTIONMENT

- Use the OSAT version of CAMx ozone source apportionment tool
  - OSAT O3V and O3N tracers give indication of amount of VOC-limited and NOx-limited ozone formation
- Definition of Source Groups
  - Source Regions (5):
    - Use same 5 Source Regions as APCA SA run
  - Source Categories (3):
    - Anthropogenic Emissions
    - Natural (Biogenic, lightning NOx, WBD, oceanic)
    - Fires (WF, Rx, Ag and other)
  - 17 Source Groups (5 x 3 + 2 [IC,BC])
    - Will run faster than CAMx APCA SA Run (50 Source Groups)



- Post-Processing
  - Amount of VOC-limited vs. NOx-limited ozone across 4-km domain from New Mexico sources alone, and all sources

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NEW MEXICO OZONE ATTAINMENT INITIATIVE

2028 VOC and NOx Sensitivity OSAT Ozone Source Apportionment Modeling and Draft Final Air Quality Technical Support Document

Marco Rodriguez, Pradeepa Vennam, Jung Chien, John Grant, Tejas Shah and Ralph Morris, Ramboll

Tom Moore and Mary Uhl, WESTAR

NM OAI Study Webinar

April 21, 2021

RAMBOLL Bright ideas. Sustainable change.

2028 VOC/NOX SENSITIVITY OSAT OZONE SOURCE APPORTIONMENT

01 CAMx Ozone Source Apportionment Tools and Differences Between OSAT and APCA

02 Highlights of 2028 Source Sector APCA Ozone Source Apportionment Modeling (presented at April 2, 2021 Webinar)

03 2028 VOC/NOx Sensitivity OSAT Ozone Source Apportionment Modeling Results

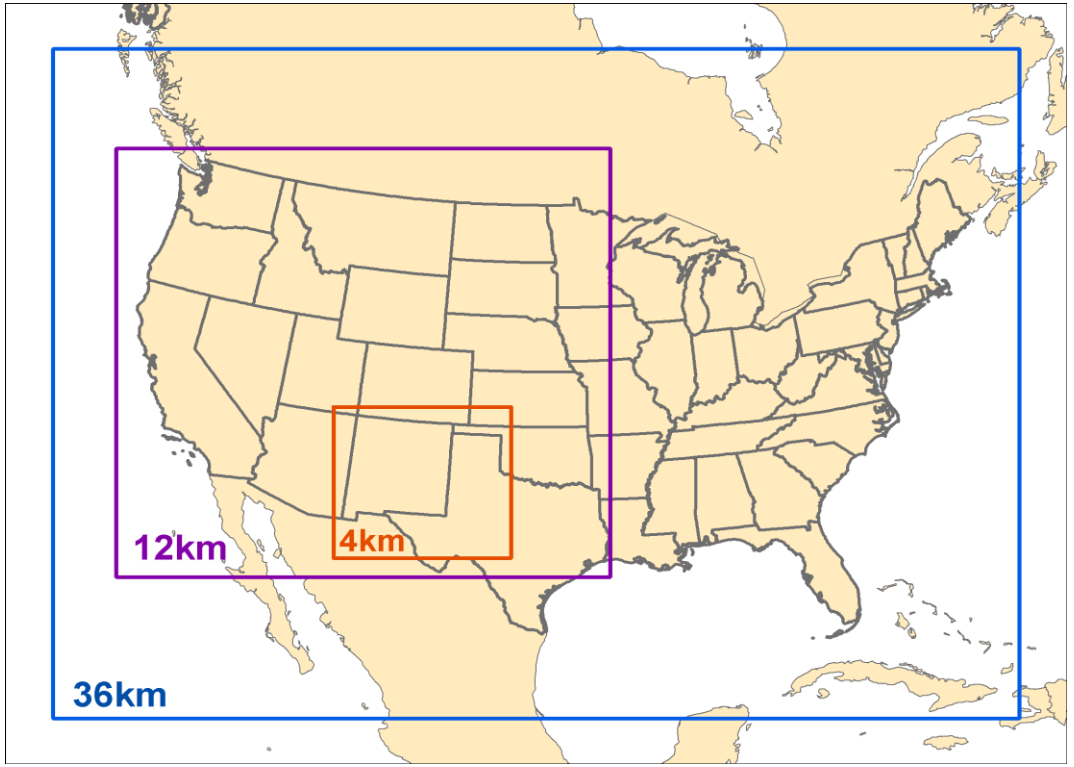
04 Draft Final Air Quality Technical Support Document (AQTSD)

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NMED Exhibit 26 - 0002

CAMX 2014 NM OAI STUDY MODEL CONFIGURATION

- Episode: May-August 2014
  - 16-day spin-up before first high ozone day in NM
    - 68 ppb on May 17
- 36/12/4-km Modeling Domains
  - 36/12-km domains same as WRAP Regional Haze
  - New 4-km New Mexico domain
- Boundary Conditions (BC) WRAP 2014 GEOS-Chem
- Four Meteorological Diagnostic Sensitivity tests
  - Selected WRF/NAM with Kv=CMAQ
- WRAP 2014v2 base year emissions
  - EPA NEI2014v2 w/ western state updates



- WRAP 2028OTBa2 for future year w/ 2014 actual fires and new 2028 NM O&G

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CAMX OZONE SOURCE APPORTIONMENT TOOLS

- **Ozone Source Apportionment Technology (OSAT)**
  - OSAT uses tagged species/reactive tracers to calculate contributions of VOC and NOx emissions from user-defined Source Groups to ozone concentrations that are VOC sensitive (O3V) and ozone concentrations that are NOx sensitive (O3N)
    - Accounting system that operates in parallel to host model extracting ozone source apportionment information
    - User-defined Source Groups can be Source Regions and/or Source Categories and includes all sources (including BCs) of ozone (e.g., on-road mobile sources from New Mexico)
  - When ozone is formed, OSAT determines whether ozone formation is more sensitive to VOC or NOx emissions and allocates it to Source Group's ozone tracers (O3V or O3N) based on the relative contribution of the more sensitive ozone precursor (VOC or NOx)
- 10 Reactive Tracers used for each Source Group
  - V_i = VOC emissions
  - NIT_i = Nitric oxide (NO) & nitrous acid (HONO) emissions
  - RGN_i = Nitrogen dioxide (NO2), nitrate radical (NO3) and dinitrogen pentoxide (N2O5)
  - TPN_i = Peroxyl acetyl nitrate (PAN), analogues of PAN and peroxy nitric acid (PNA)
  - NTR_i = Organic nitrates (RNO3)
  - $HN3_i$ = Gaseous nitric acid (HNO3)
  - $O3N_i$ = Ozone formed under NOx-limited conditions from Ni
  - $O3V_i$ = Ozone formed under VOC-limited conditions from Vi
  - OON_i = Odd-oxygen in NO2 formed from O3Ni
  - OOV_i = Odd-oxygen in NO2 formed from O3Vi

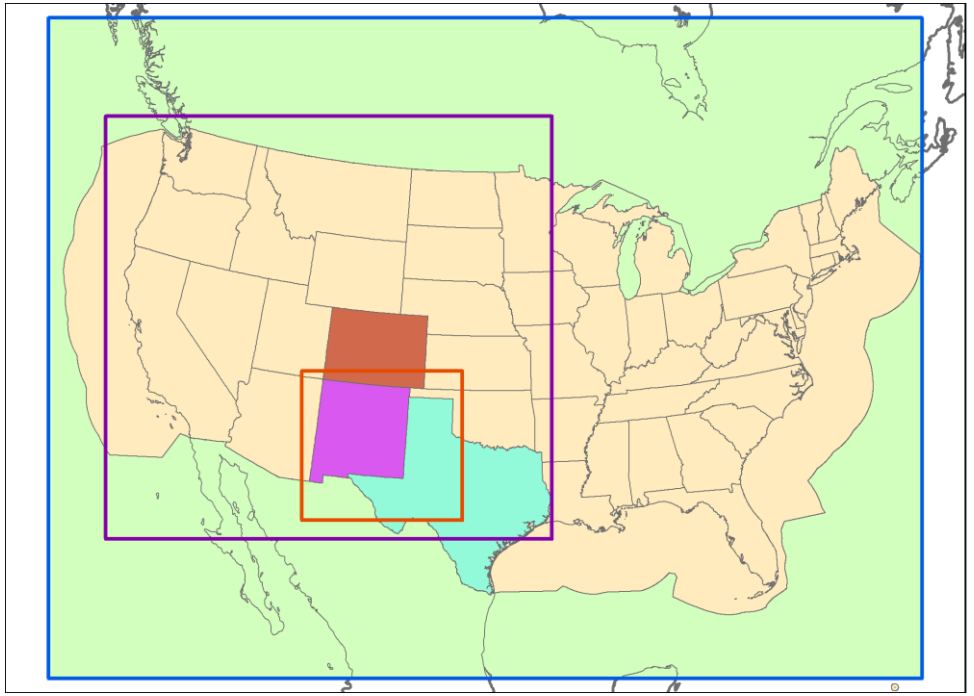
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CAMX OZONE SOURCE APPORTIONMENT TOOLS

- **Anthropogenic Precursor Culpability Assessment (APCA)**
  - APCA differs from OSAT in that it only allocates ozone formed to the Natural (e.g., biogenic) Source Groups when it is due to Natural VOC reacting with Natural NOx
    - For example, ozone formed due to biogenic VOC reacting with anthropogenic NOx under VOC emissions sensitive conditions, a case OSAT assigns to Natural Source Group O3V, APCA redirects ozone formed to anthropogenic Source Group O3N
  - APCA provides more control strategy relevant information and is used in ozone contribution assessments, while OSAT provides information on whether ozone formation is more sensitive to VOC or NOx emissions
    - APCA used in EPA's Cross State Air Pollution Rule (CSAPR) to identify when an upwind state's anthropogenic emissions contributes significantly to nonattainment in a downwind state
    - APCA also used in NMED OAI Study 2028 Local Source APCA ozone source apportionment modeling
  - If analyzing whether ozone formation is more sensitive to VOC or NOx emissions, then OSAT source apportionment or a sensitivity method (e.g., DDM/HDDM or Brute Force) must be used
    - NM OAI Study 2028 VOC/NOx sensitivity OSAT ozone source apportionment modeling

CAMX 2028 O&G CS SOURCE SECTOR APCA OZONE SA

- **Definition of Source Groups**
  - Boundary Conditions (BCs) from WRAP 2014 GEOS-Chem runs:
    - BC_{Intl} - International anthropogenic emissions
    - BC_{USA} – U.S. anthropogenic emissions
    - $BC_{Natural}$ – Natural sources
    - BC_{Top} – BC above the top of domain
  - Source Categories (9):
    1. Natural (biogenic, lightning NOx, etc.);
    2. Fires (WF, Rx, Ag, other);
    3. Oil and gas point sources (surrogate for midstream);
    4. Oil and gas non-point sources (surrogate for upstream;
    5. EGU point;
    6. Non-EGU point;
    7. On-road mobile;
    8. Non-road mobile; and
    9. Remainder anthropogenic.
  - Source Regions (5):
    - New Mexico
    - Texas
    - Colorado
    - Remainder U.S.
    - International (Mex, Can, CMV > 200 nmi)
  - 50 Source Groups (50 = 5 x 9 + 5)



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NMED Exhibit 26 - 0006

REDUCTIONS 2028 OZONE DVFS NEW MEXICO SOURCE SECTORS

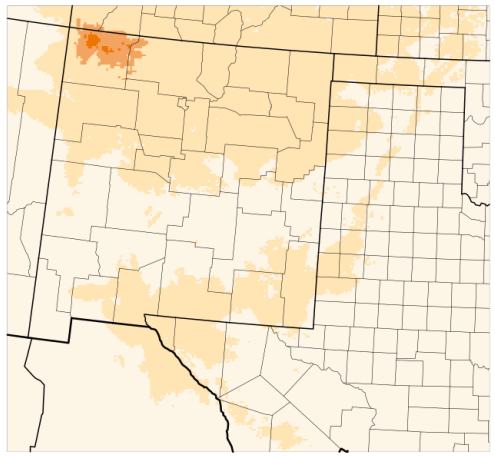
- 2028 ozone DVF Reductions from New Mexico Source Sectors
  - O&G Point: -0.1 to -0.9 ppb
  - O&G Non-Pt: -0.1 to -2.1 ppb
  - EGU Point: 0.0 to -3.1 ppb
  - Non-EGU Pt: 0.0 to -1.1 ppb
  - On-Road: -0.1 to -2.7 ppb
  - Non-Road: -0.1 to -1.9 ppb
  - Other Anthro: 0.0 to -3.6 ppb

AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	OnRoad	NonRoad	OAnth
350010023	NORTE	66.3	60.7	-0.2	-0.3	-0.5	-1.0	-2.7	-2.0	-3.6
350010024	SEHGS	68.0	62.0	-0.2	-0.3	-0.5	-1.1	-2.5	-1.9	-3.2
350010029	STHVA	66.0	60.5	-0.3	-0.5	-0.5	-1.0	-2.2	-1.7	-2.4
350010032	WSTSD	67.0	62.1	-0.2	-0.4	-0.4	-0.4	-1.6	-1.2	-1.8
350011012	FTHIL	65.0	58.8	-0.2	-0.3	-0.5	-0.7	-2.5	-2.0	-3.0
350130008	UNION	66.3	59.8	-0.2	-0.2	-0.7	0.0	-0.5	-0.3	-0.1
350130017	SPARK	67.0	61.8	-0.2	-0.2	-0.9	0.0	-0.4	-0.2	-0.2
350130020	CHAPA	67.0	62.2	-0.1	-0.1	-0.3	0.0	-0.2	-0.1	-0.1
350130021	DSVIE	72.0	66.8	-0.2	-0.3	-0.9	-0.1	-0.5	-0.3	-0.2
350130022	TERES	71.3	66.0	-0.3	-0.3	-0.7	-0.1	-0.5	-0.3	-0.2
350130023	SOLAN	65.0	60.2	-0.2	-0.2	-0.2	-0.2	-1.2	-0.7	-0.3
350151005	CARLS	69.0	66.4	-0.5	-0.5	-0.2	-0.1	-0.3	-0.2	-0.1
350171003	GRANT	62.0	58.9	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0
350250008	HOBBS	66.0	63.3	-0.9	-1.1	-0.2	0.0	-0.3	-0.2	-0.1
350290003	DEAIR	66.0	62.5	-0.2	-0.1	-0.2	0.0	-0.6	-0.4	0.0
350390026	COYOT	64.0	60.0	-0.2	-0.5	-0.5	0.0	-0.2	-0.1	0.0
350431001	BERNA	64.0	58.1	-0.1	-0.2	-0.4	-0.4	-2.1	-1.5	-1.9
350450009	BLOOM	64.3	60.2	-0.7	-1.4	-1.9	0.0	-0.4	-0.1	-0.1
350450018	NAVAJ	67.0	63.3	-0.9	-2.1	-1.7	-0.1	-0.4	-0.2	-0.1
350451005	SUBST	63.7	59.6	-0.6	-1.5	-3.1	-0.1	-0.5	-0.2	-0.2
350490021	SNTFE	64.3	60.4	-0.2	-0.3	-0.2	-0.3	-1.2	-0.7	-0.8
350610008	LUNAS	66.3	62.0	-0.2	-0.3	-0.3	-0.3	-1.1	-1.0	-0.4

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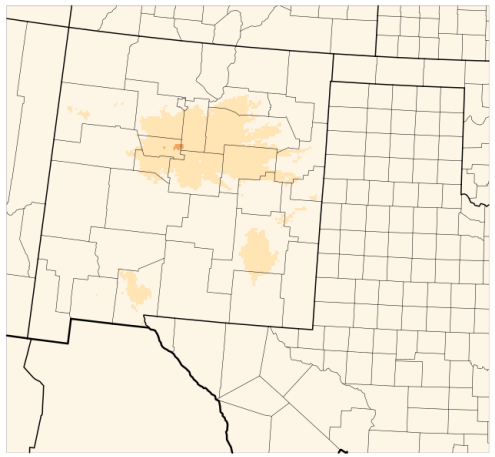
SMAT UAA ($DVC_{2012-2016}$) 2028 DVF NM SOURCE CONTRIBUTIONS

2028 Contributions
EGU point
O3 Design Value UAA



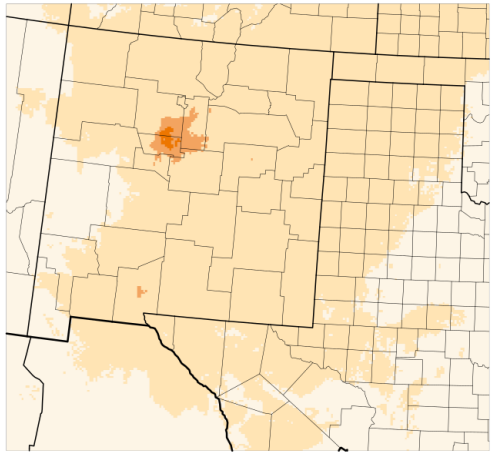
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2028 Contributions
NonEGU point
O3 Design Value UAA



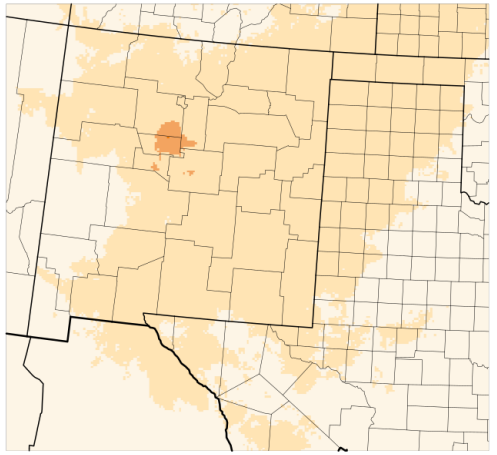
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2028 Contributions
On-road mobile
O3 Design Value UAA



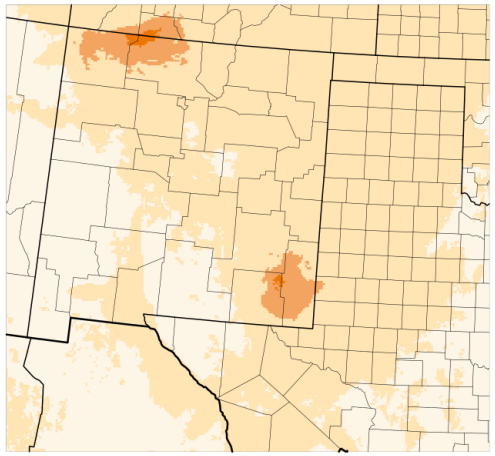
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2028 Contributions
Non-road mobile
O3 Design Value UAA



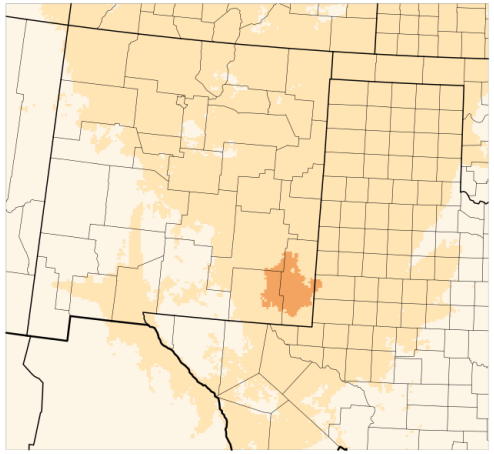
max(82,158) = 2.103 ppb
min(22,200) = 0.006 ppb

2028 Contributions
OilandGas non-point
O3 Design Value UAA



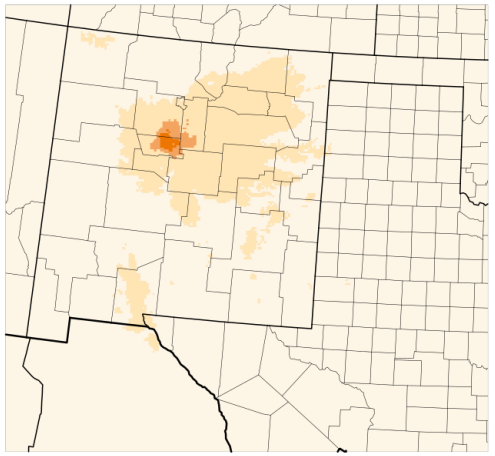
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min(18,192) = 0.006 ppb

2028 Contributions
OilandGas point
O3 Design Value UAA



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min(12,165) = 0.000 ppb

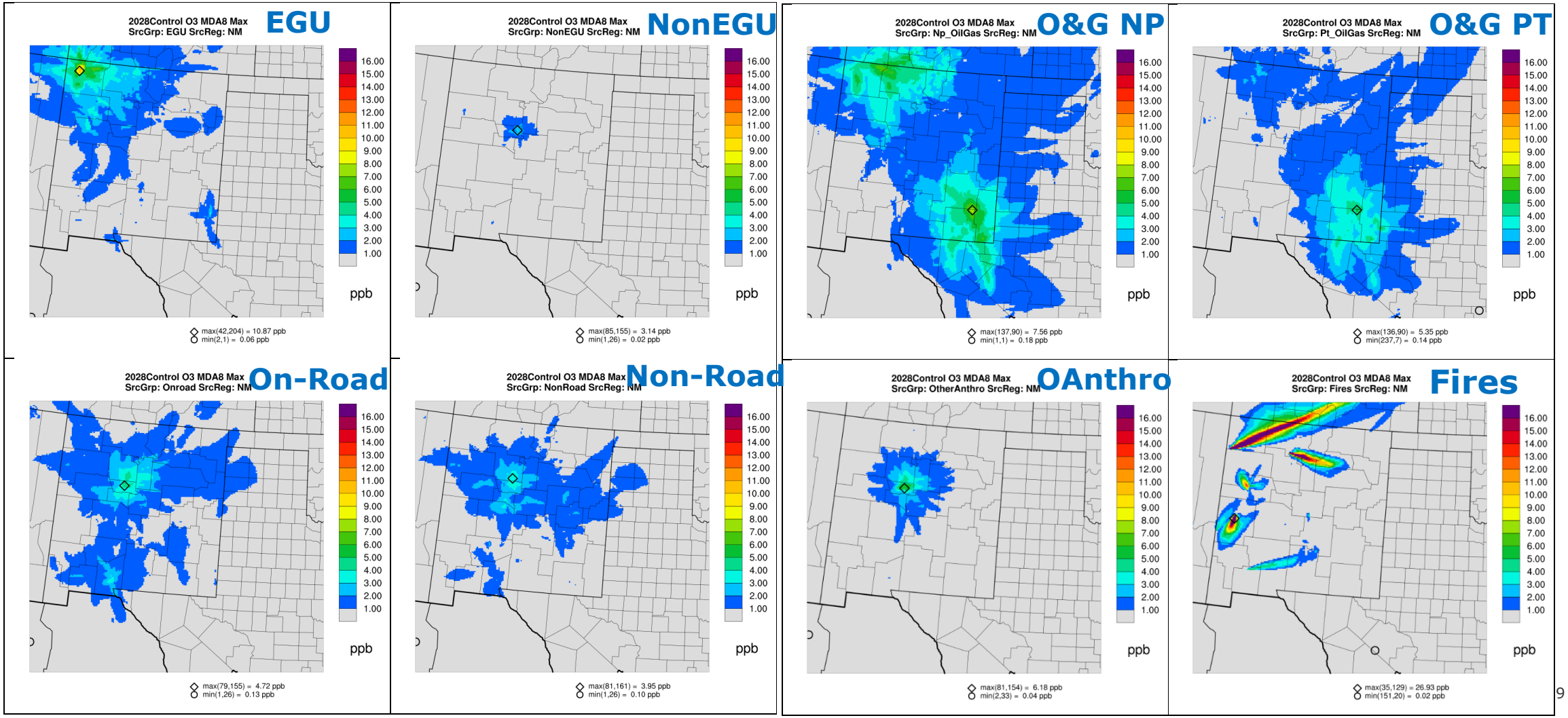
2028 Contributions
Remainder Anthro
O3 Design Value UAA



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NMED Exhibit 26 - 0008

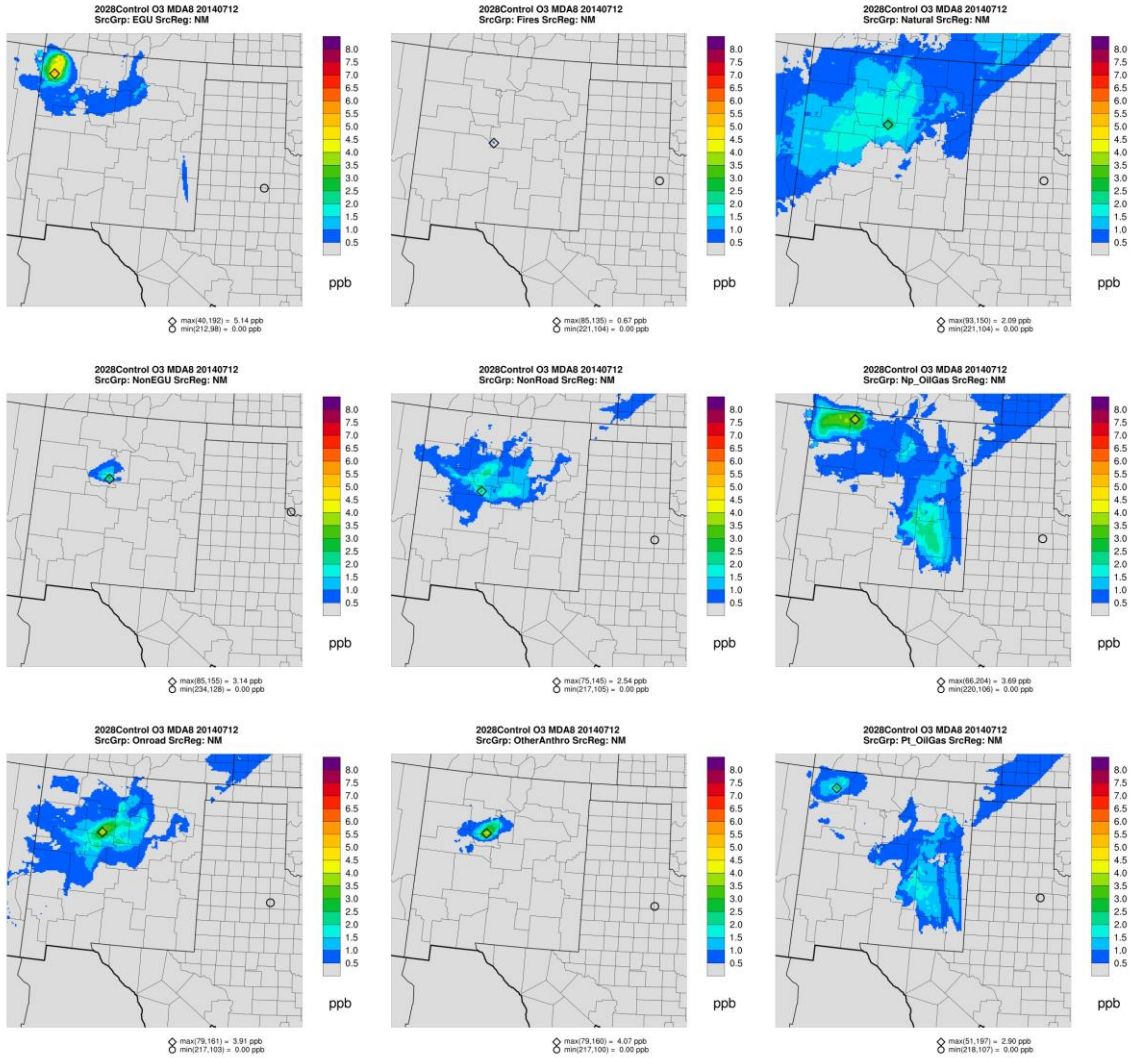
HIGHEST NEW MEXICO SOURCE SECTOR OZONE CONTRIBUTIONS TO MDA8 OZONE DURING EPISODE



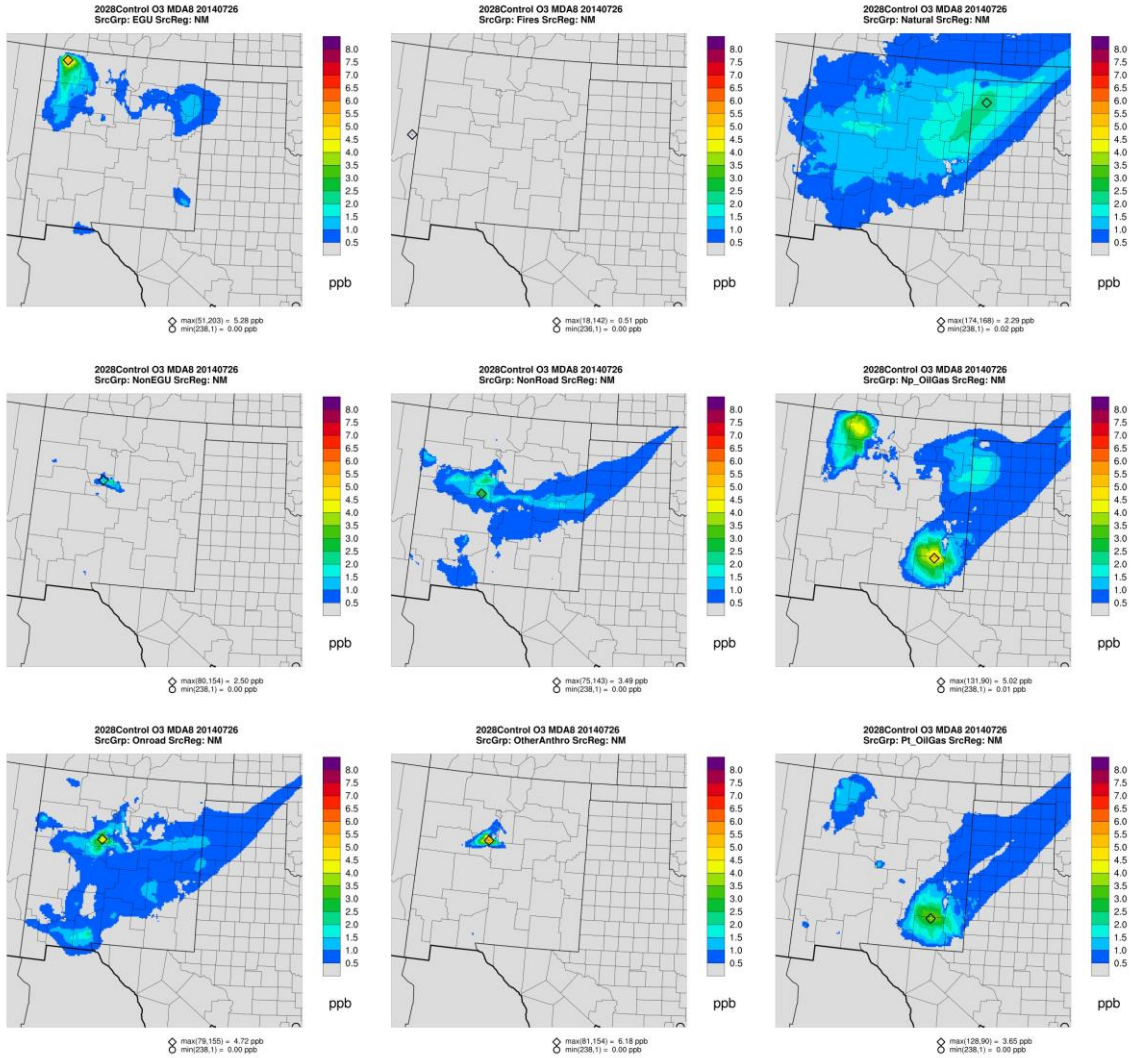
2028 NEW MEXICO SOURCE SECTOR

EGU	Fires	Natural
NonEGU	Non-Road	O&G_NP
On-Road	OAnthro	O&G_PT

July 12, 2014



July 26, 2014



2028 OZONE DVF NO INTERNATIONAL ANTHRO EMISSIONS

- 2028 ozone DVF projections using $DVC_{2012\text{-}2016}$, $DVC_{2015\text{-}2019}$ and $DVC_{2017\text{-}2019}$
- Elimination of international anthropogenic emissions reduces 2028 ozone DVF by 13 to 25 ppb
- 2028 ozone DVF w/ no international anthropogenic emissions range from 38 to 53 ppb

2012-14 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name
66.3	60.7	47.2	-13.5	Del Norte HS
68.0	62.0	48.5	-13.5	South East Heights
66.0	60.5	47.1	-13.4	South Valley
67.0	62.1	48.5	-13.6	Westside
65.0	58.8	45.7	-13.1	Foothills
66.3	59.8	39.9	-19.9	La Union
67.0	61.8	38.4	-23.4	Sunland Park
67.0	62.2	39.6	-22.6	Chaparral
72.0	66.8	42.6	-24.2	Desert View
71.3	66.0	42.2	-23.8	Santa Teresa
65.0	60.2	41.5	-18.7	Solano
69.0	66.4	46.1	-20.3	Carlsbad
62.0	58.9	43.0	-15.9	Chino Copper Smelt
66.0	63.3	44.9	-18.4	Hobbs Jefferson
66.0	62.5	43.3	-19.2	Deming Airport
64.0	60.0	47.4	-12.6	Coyote Ranger Dist
64.0	58.1	44.4	-13.7	Bernalillo (E Avenida)
64.3	60.2	46.4	-13.8	Bloomfield
67.0	63.3	50.2	-13.1	Navajo Lake
63.7	59.6	48.5	-11.1	Substation
64.3	60.4	47.9	-12.5	Santa Fe Airport
66.3	62.0	47.5	-14.5	Los Lunas (Los Lentes)

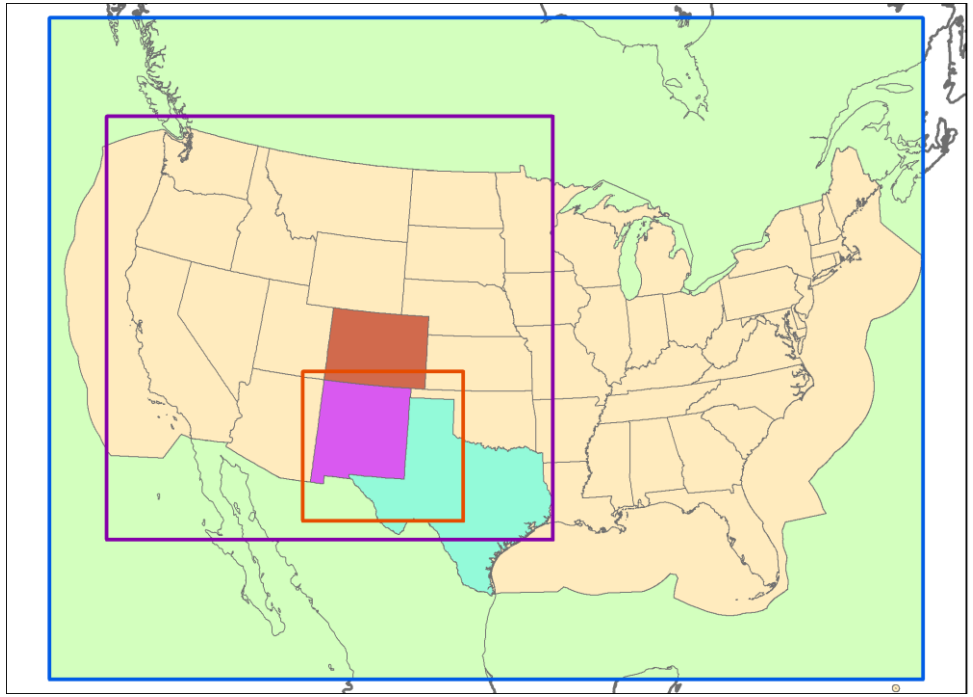
2015-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name
69.0	63.1	49.2	-13.9	Del Norte HS
66.0	60.5	47.1	-13.4	South Valley
69.0	62.4	48.5	-13.9	Foothills
68.7	62.0	41.3	-20.7	La Union
70.7	65.7	41.8	-23.9	Chaparral
74.3	68.9	43.9	-25.0	Desert View
74.0	68.5	43.8	-24.7	Santa Teresa
67.7	62.7	43.3	-19.4	Solano
73.7	70.9	49.2	-21.7	Carlsbad
71.0	69.3	44.1	-25.2	Carlsbad NP
69.3	66.5	47.1	-19.4	Hobbs Jefferson
66.3	62.2	49.1	-13.1	Coyote Ranger Dist
67.0	60.9	46.5	-14.4	Bernalillo (E Avenida)
67.0	62.8	48.3	-14.5	Bloomfield
69.0	65.2	51.7	-13.5	Navajo Lake
67.3	62.9	51.2	-11.7	Substation
65.0	61.0	48.4	-12.6	Santa Fe Airport
66.7	62.3	47.8	-14.5	Los Lunas (Los Lentes)

2017-19 DVC (ppb)	2028OGCS DVF (ppb)	2028INTL DVF (ppb)	2028 DVF Difference OGCS–INTL (ppb)	Site Name
70.0	64.0	49.9	-14.1	Del Norte HS
67.0	61.4	47.8	-13.6	South Valley
71.0	64.2	49.9	-14.3	Foothills
70.0	63.2	42.1	-21.1	La Union
73.0	67.8	43.1	-24.7	Chaparral
77.0	71.4	45.5	-25.9	Desert View
76.0	70.3	45.0	-25.3	Santa Teresa
70.0	64.8	44.7	-20.1	Solano
79.0	76.0	52.8	-23.2	Carlsbad
71.0	68.1	48.3	-19.8	Hobbs Jefferson
67.0	62.8	49.6	-13.2	Coyote Ranger Dist
68.0	61.8	47.2	-14.6	Bernalillo (E Avenida)
68.0	63.7	49.1	-14.6	Bloomfield
69.0	65.2	51.7	-13.5	Navajo Lake
69.0	64.5	52.5	-12.0	Substation
66.0	62.0	49.1	-12.9	Santa Fe Airport
68.0	63.5	48.7	-14.8	Los Lunas (Los Lentes)

NMED Exhibit 26 - 0011

CAMX 2028 O&G CS OSAT OZONE SOURCE APPORTIONMENT

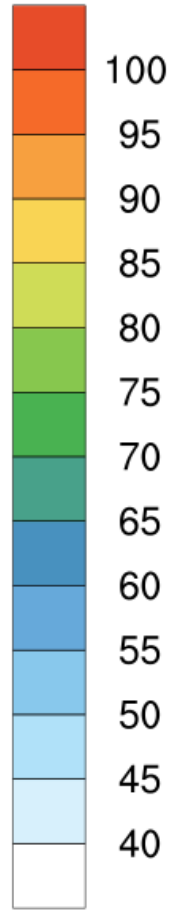
- Use the OSAT version of CAMx ozone source apportionment tool
  - OSAT O3V and O3N tracers give indication of whether ozone formation is more VOC or NOx sensitive
- Definition of Source Groups
  - Source Regions (5):
    - Use same 5 Source Regions as APCA SA run
  - Source Categories (3):
    - Anthropogenic Emissions
    - Natural (Biogenic, lightning NOx, WBD, oceanic)
    - Fires (U.S. WF, Rx and Ag and other)
  - 17 Source Groups (5 x 3 + 2 [IC,BC])
    - Runs faster than CAMx APCA SA Run (50 Source Groups)
- Post-Processing
  - Compare amount of ozone that is formed under more VOC sensitive vs. NOx sensitive conditions



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SPATIAL MAPS OF OSAT VOC/NOX OZONE SENSITIVITY

- Use O3N and O3V tracers from emissions-based Source Groups to determine amount of ozone formed under VOC sensitive versus NOx sensitive conditions:
  - Percent NOx Sensitive Ozone Formation = 100 x O3N / (O3V + O3N)
- Daily spatial maps of MDA8 ozone concentrations and percent ozone formed under NOx emissions sensitive conditions
  - Total MDA8 ozone from all Source Groups (O3V + O3N + $O3_{BC}$)
    - Boundary Condition (BC) ozone defined by 2014 GEOS-Chem run so no information on VOC/NOx sensitivity
  - MDA8 ozone and percent NOx sensitive ozone for all emissions-based Source Groups
    - (O3V + O3N) from anthropogenic, fire and natural emissions Source Categories and all 5 Source Regions
  - MDA8 ozone and percent NOx sensitive ozone for all anthropogenic emissions Source Groups
  - MDA8 ozone and percent NOx sensitive ozone for New Mexico anthropogenic emissions
    - Provide control strategy relevant information on relative importance of New Mexico VOC and NOx emissions



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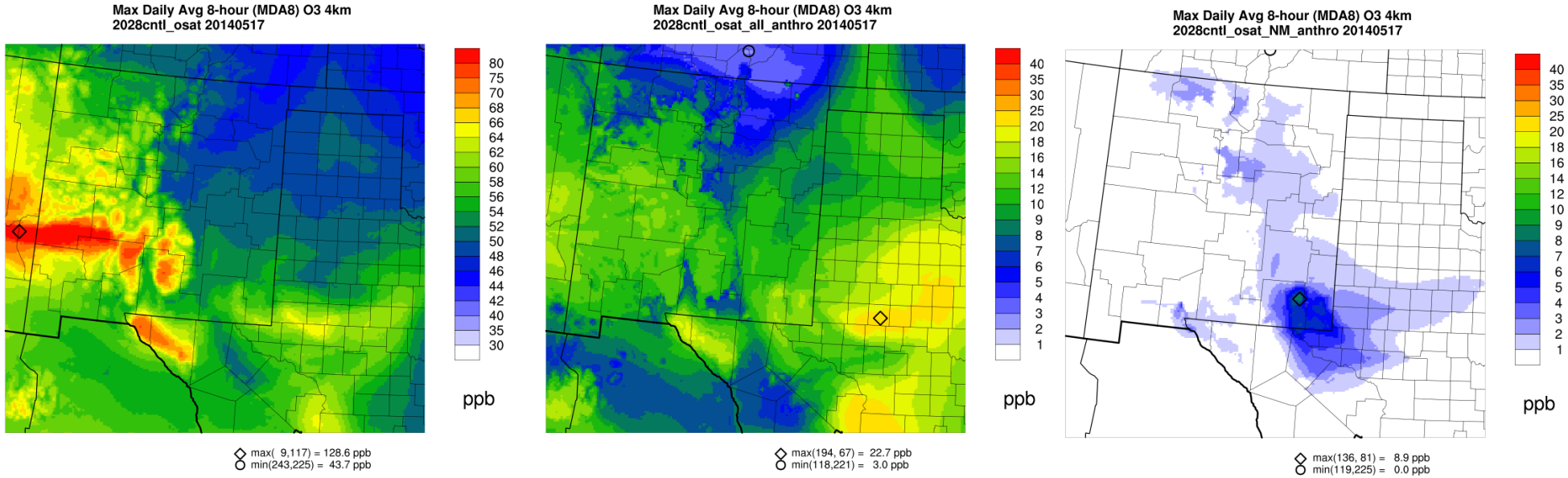
2028 OSAT SA RESULTS FOR MAY 17, 2014

All Source Regions/Categories

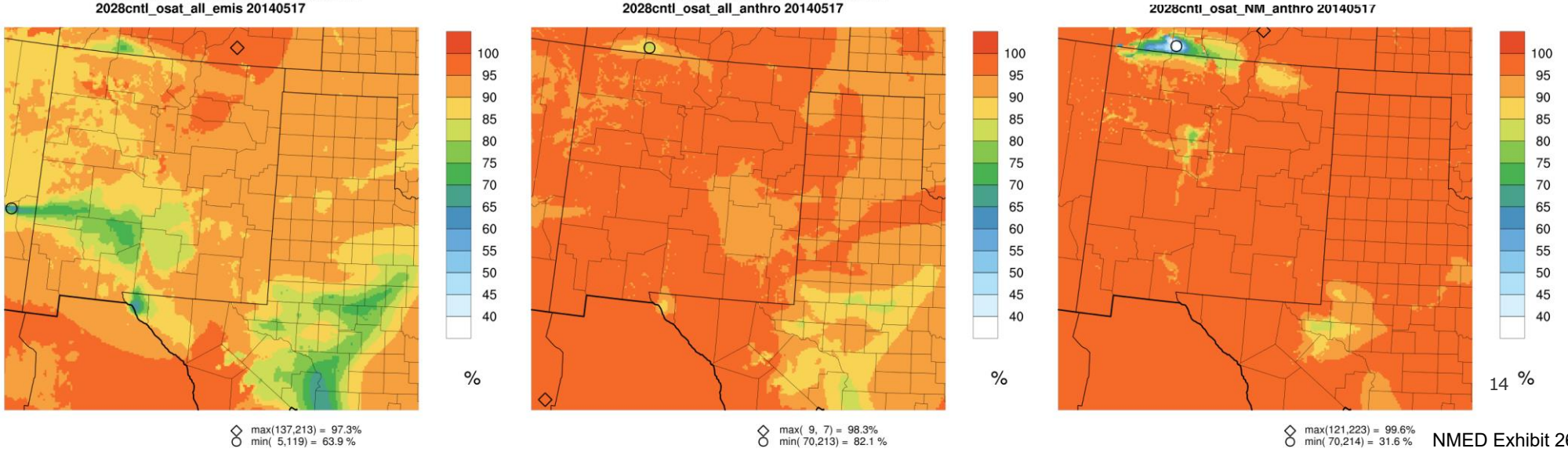
All Regions Anthro

New Mexico Anthro

Ozone Concentrations (ppb)



Percent NOx Sensitive Ozone



RAMBOLL

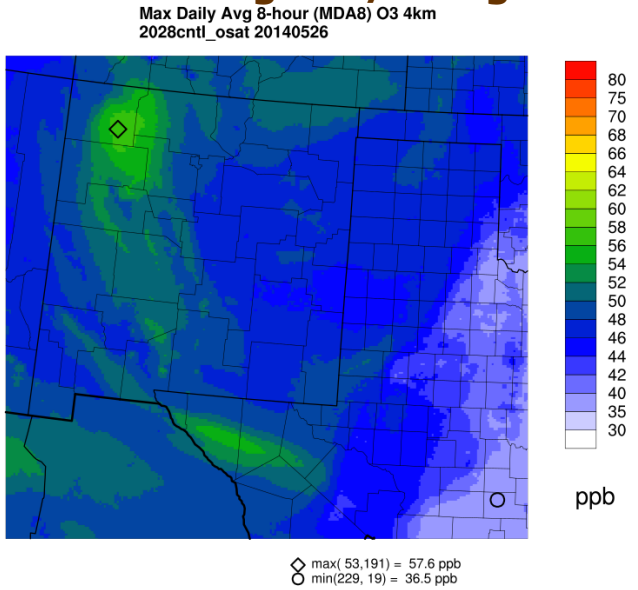
2028 OSAT SA RESULTS FOR MAY 26, 2014

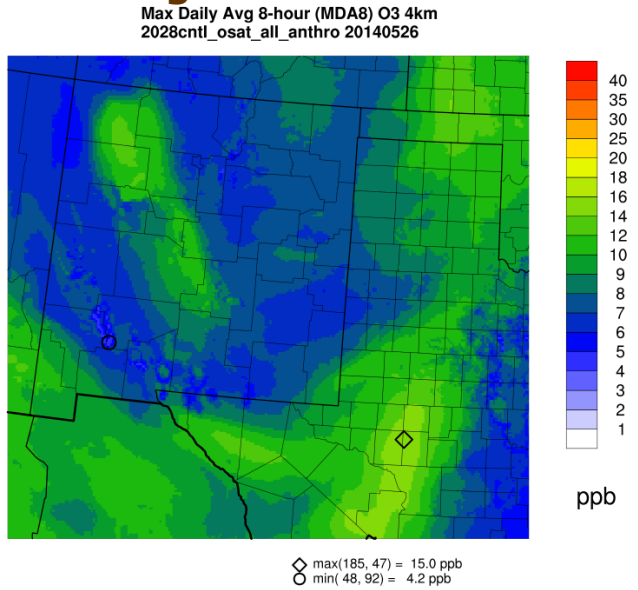
All Source Regions/Categories

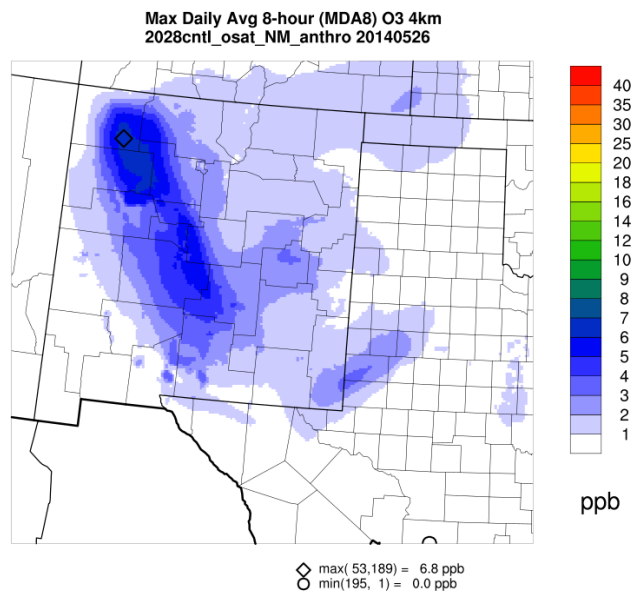
All Regions Anthro

New Mexico Anthro

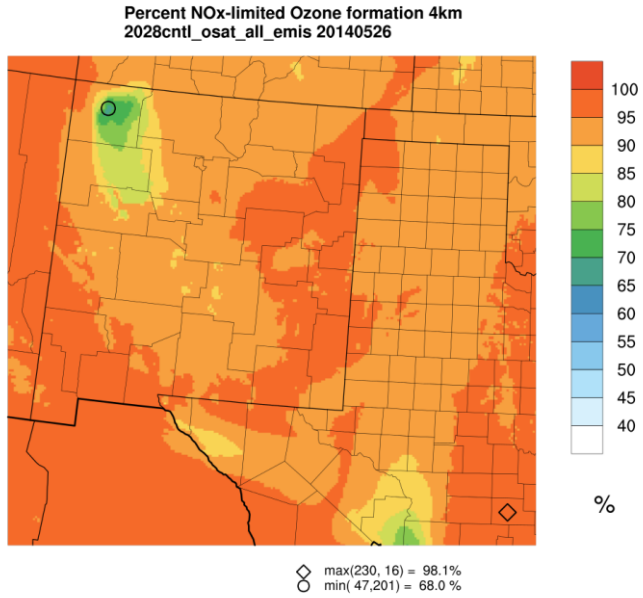
Ozone Concentrations (ppb)

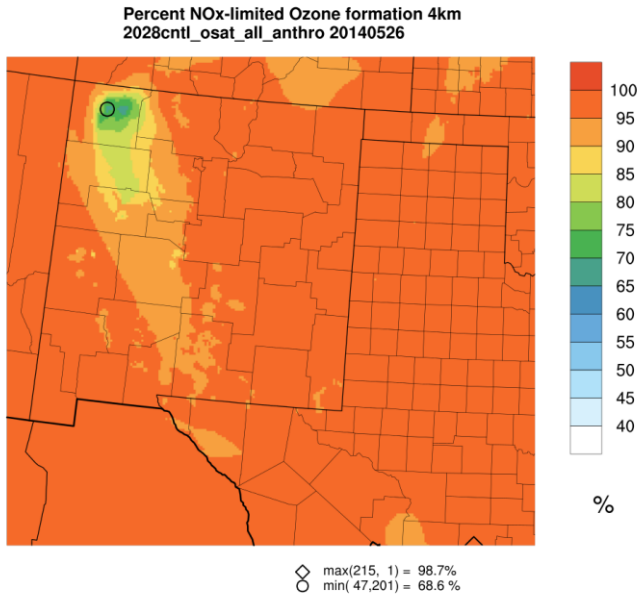


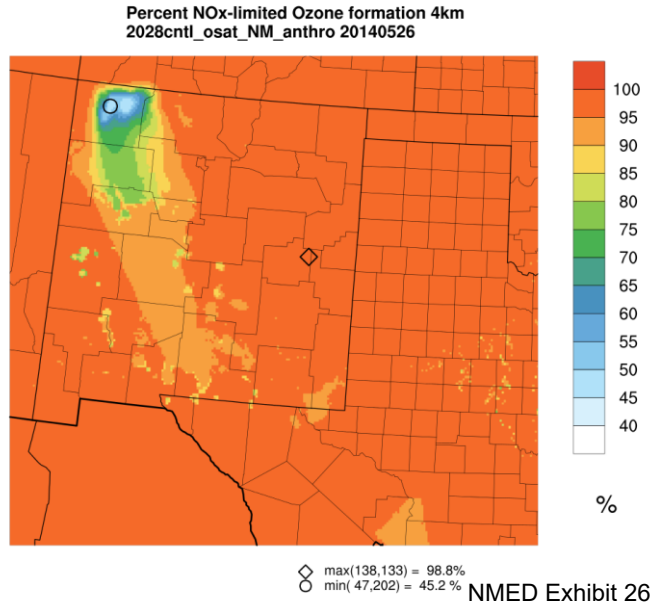




Percent NOx Sensitive Ozone







RAMBOLL

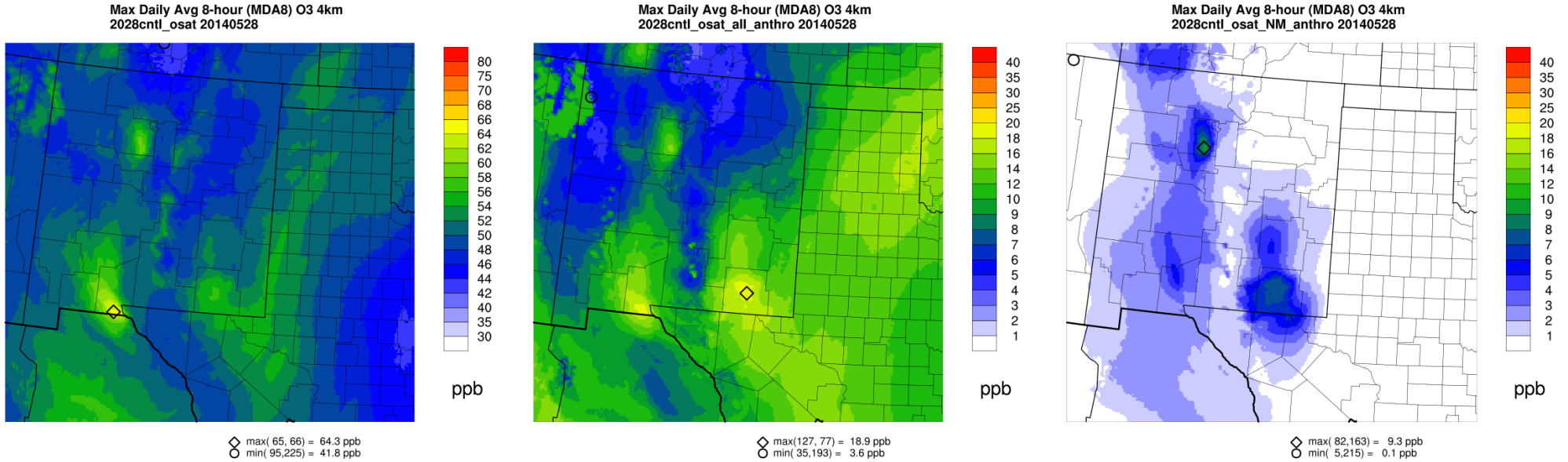
2028 OSAT SA RESULTS FOR MAY 28, 2014

All Source Regions/Categories

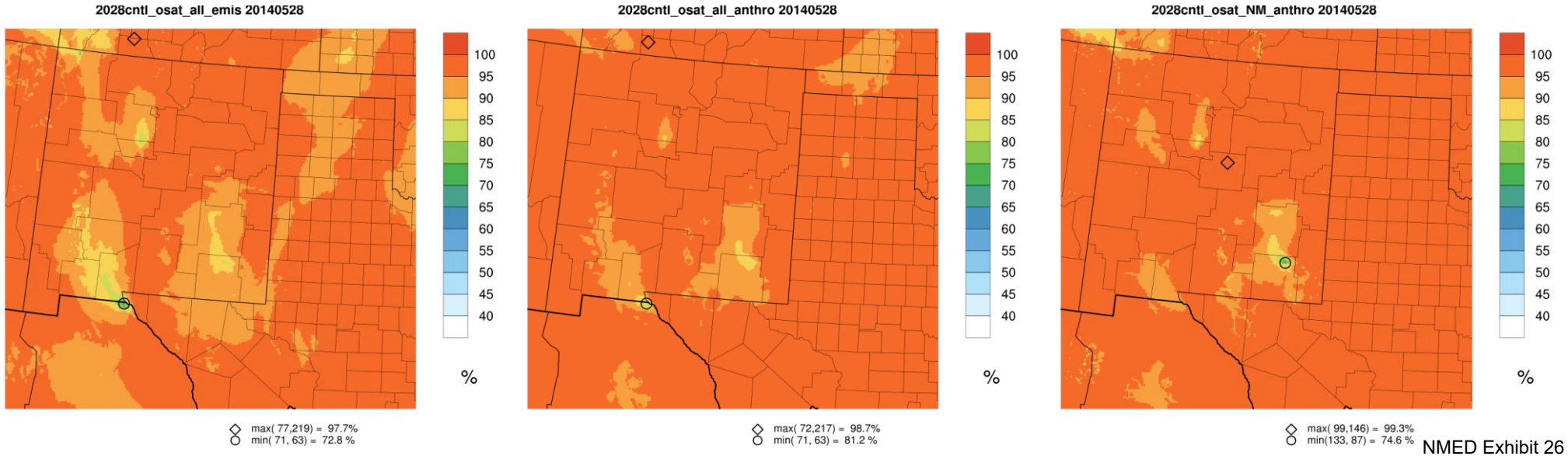
All Regions Anthro

New Mexico Anthro

Ozone Concentrations (ppb)



Percent NOx Sensitive Ozone



RAMBOLL

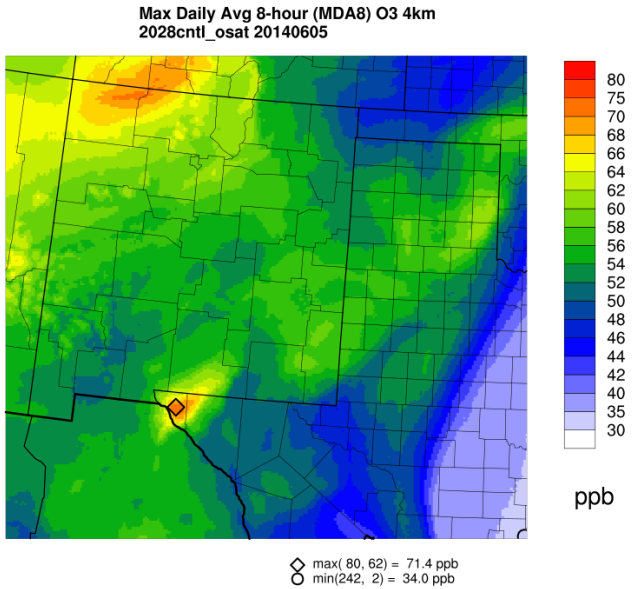
2028 OSAT SA RESULTS FOR JUNE 5, 2014

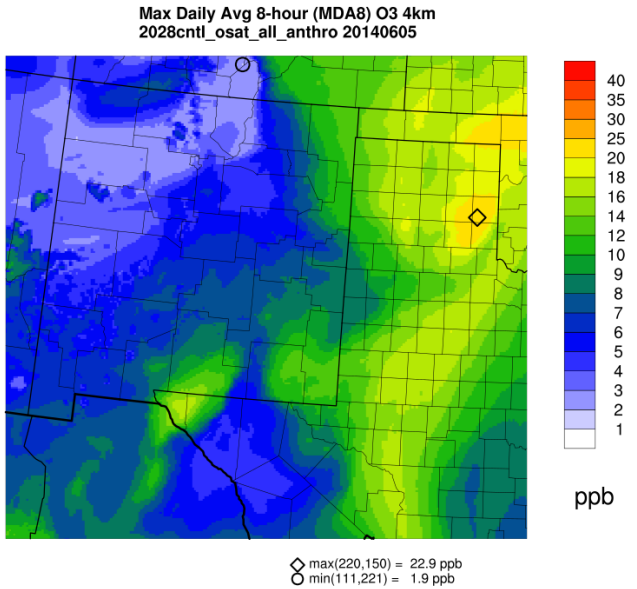
All Source Regions/Categories

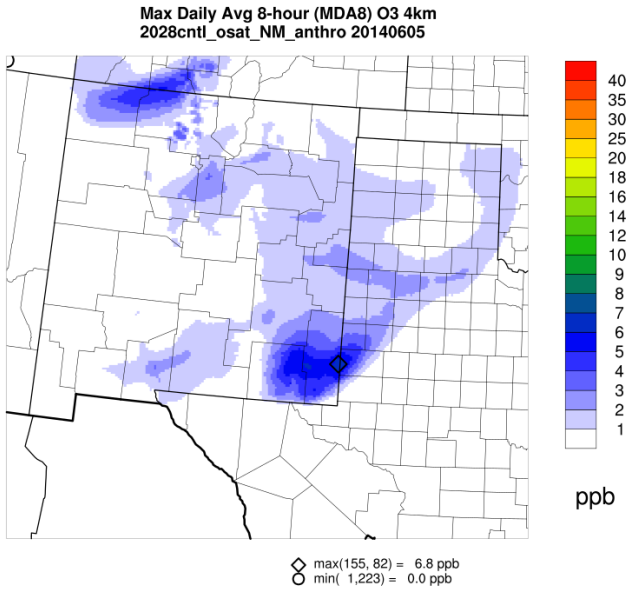
All Regions Anthro

New Mexico Anthro

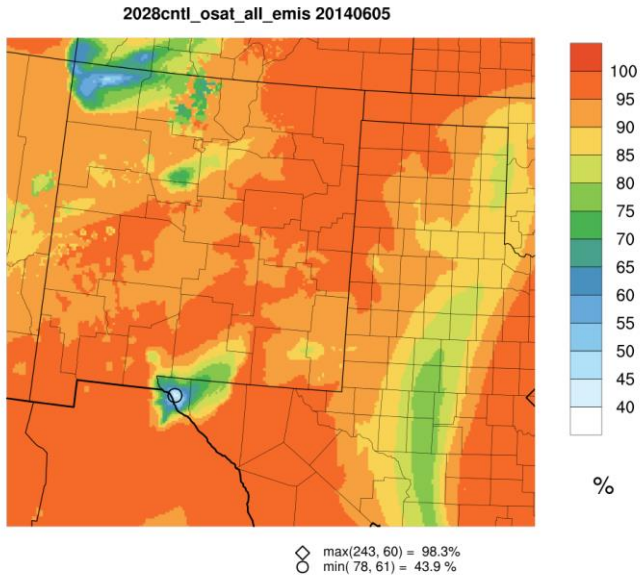
Ozone Concentrations (ppb)

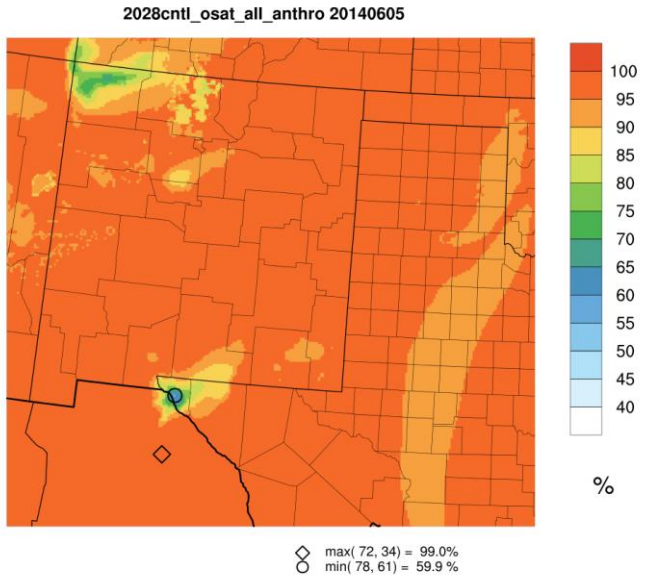


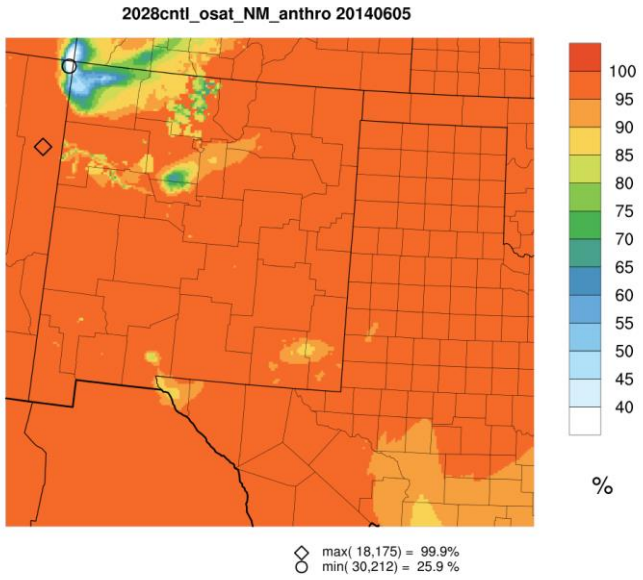




Percent NOx Sensitive Ozone







RAMBOLL

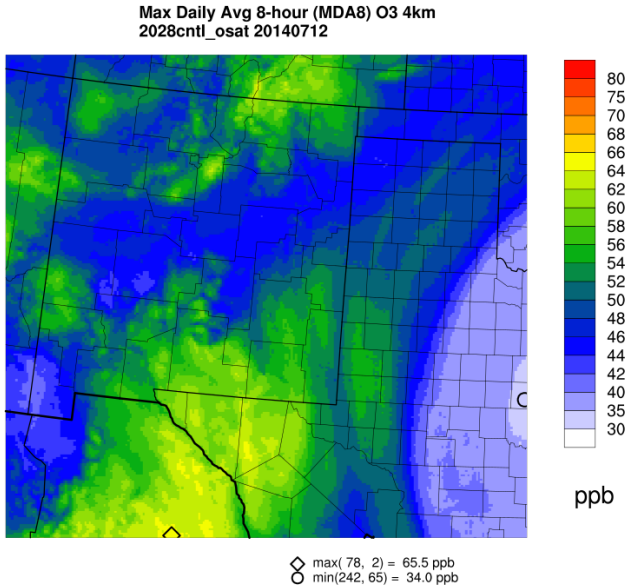
2028 OSAT SA RESULTS FOR JULY 12, 2014

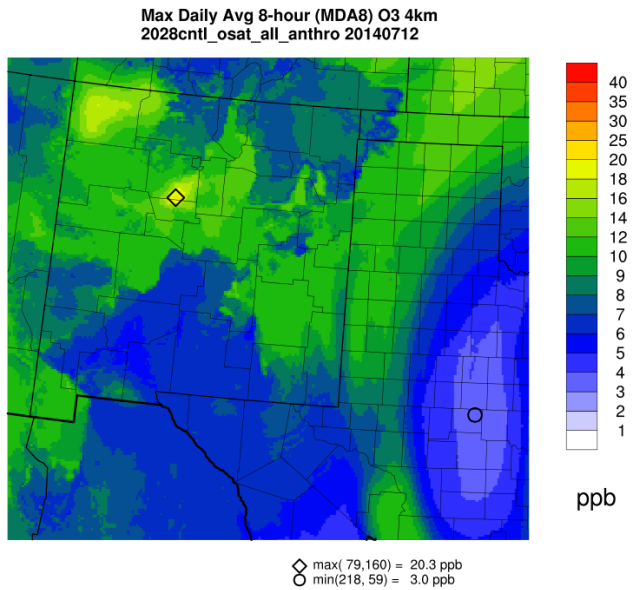
All Source Regions/Categories

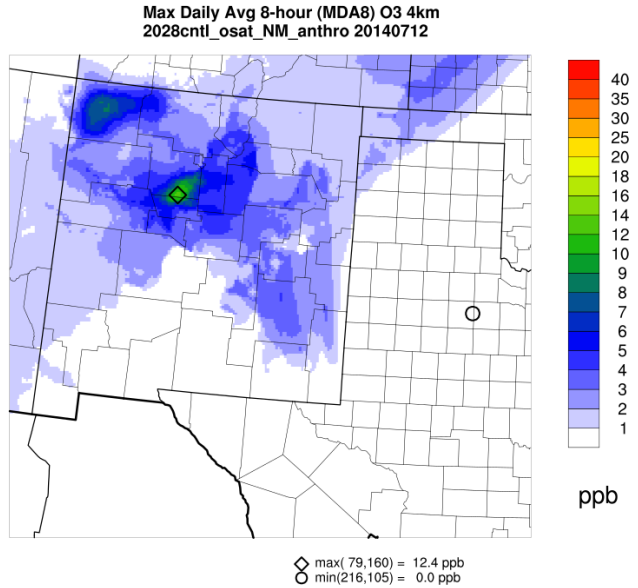
All Regions Anthro

New Mexico Anthro

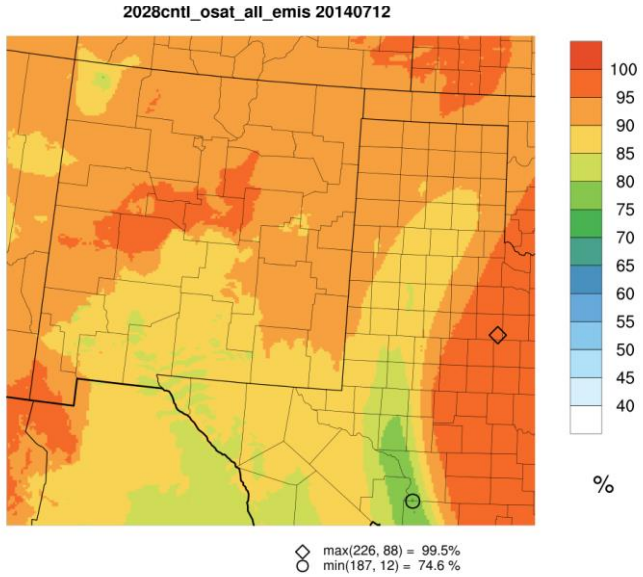
Ozone Concentrations (ppb)

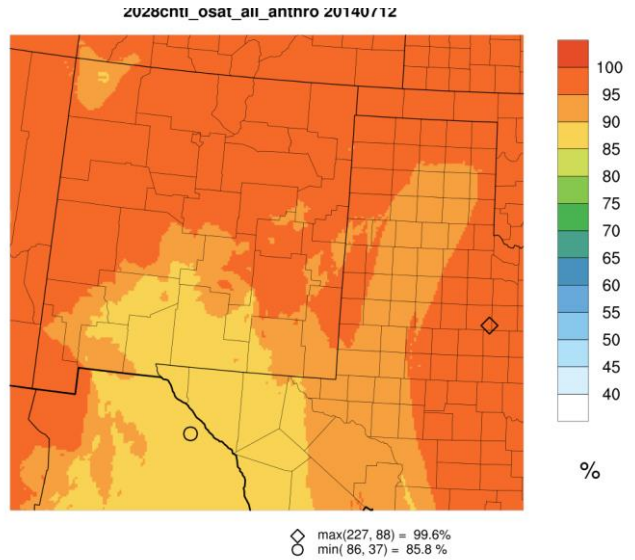


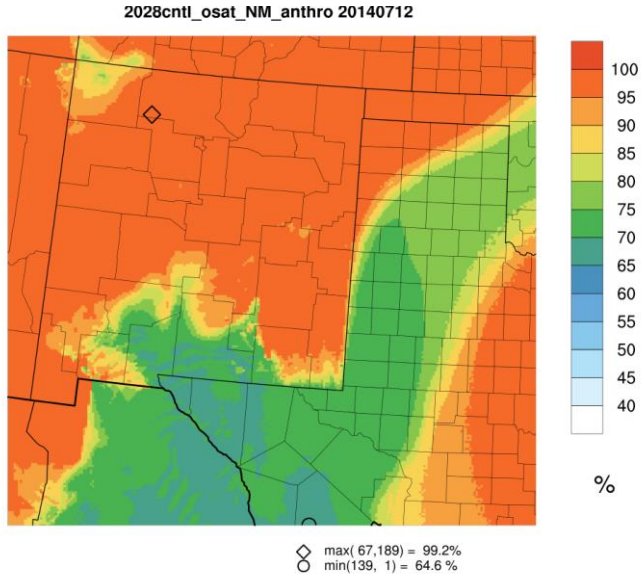




Percent NOx Sensitive Ozone







RAMBOLL

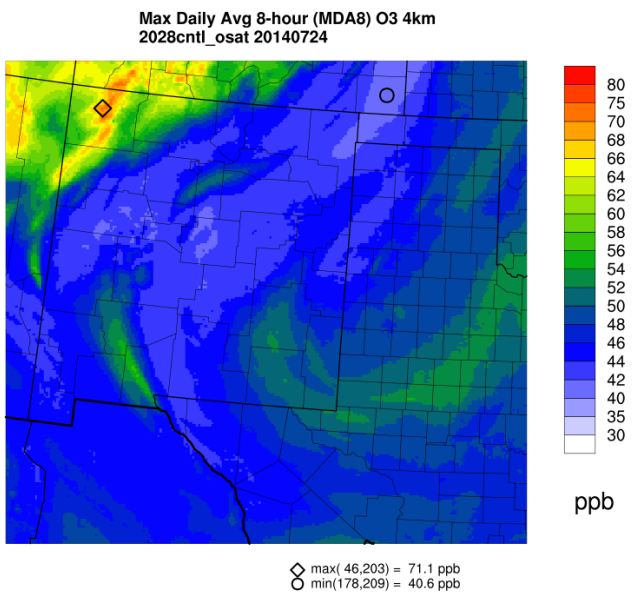
2028 OSAT SA RESULTS FOR JULY 24, 2014

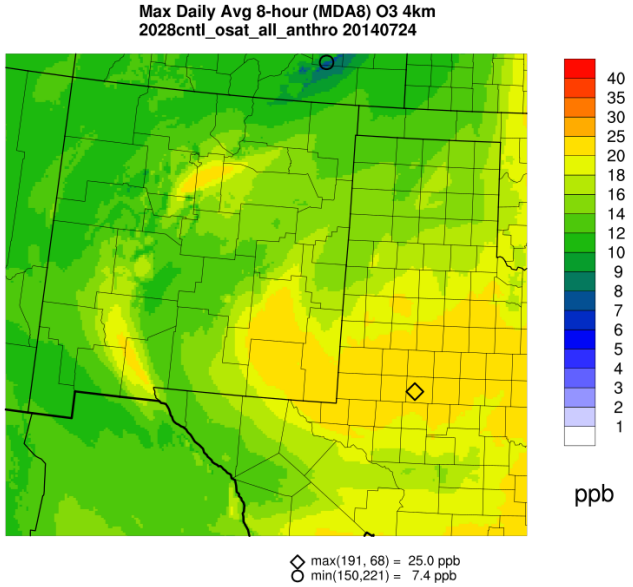
All Source Regions/Categories

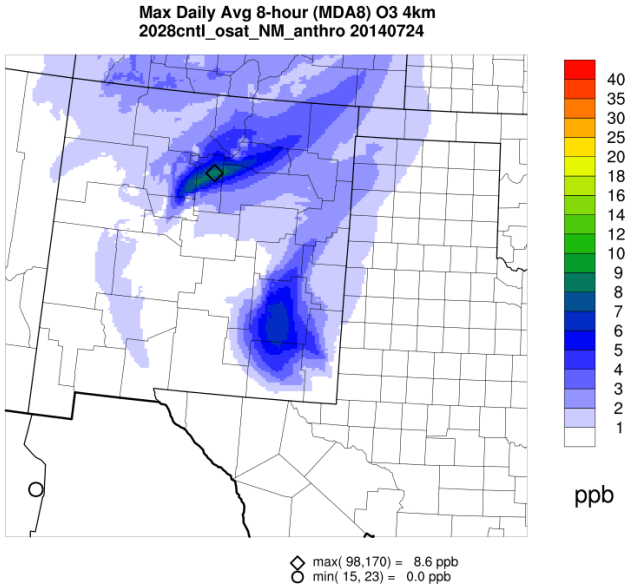
All Regions Anthro

New Mexico Anthro

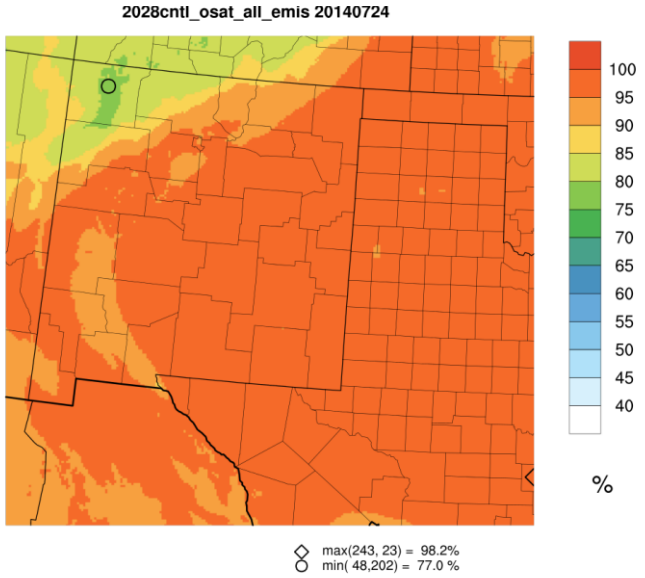
Ozone Concentrations (ppb)

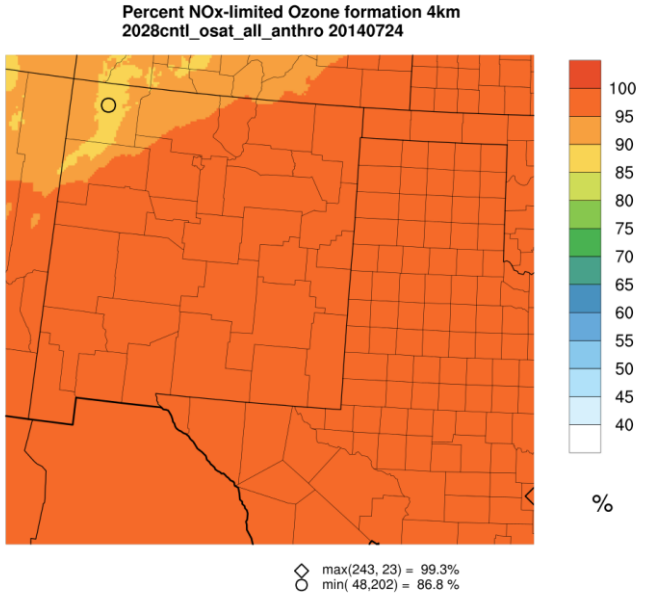


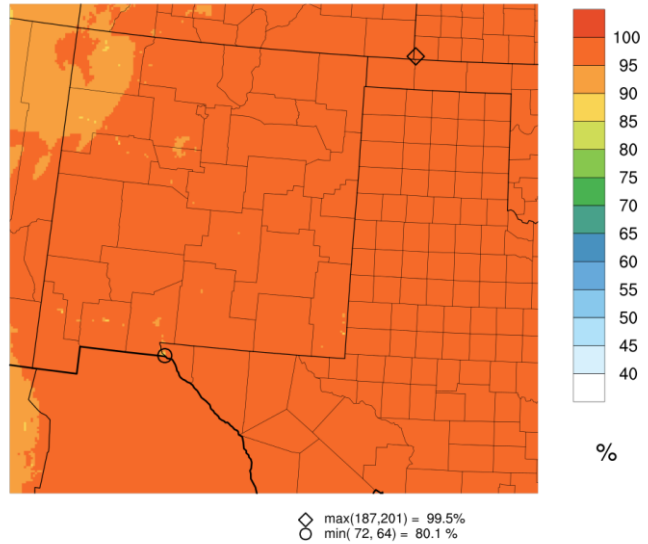




Percent NOx Sensitive Ozone







RAMBOLL

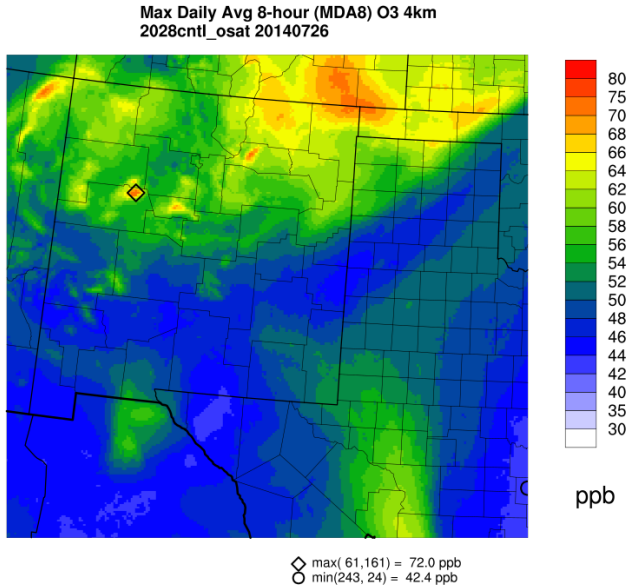
2028 OSAT SA RESULTS FOR JULY 26, 2014

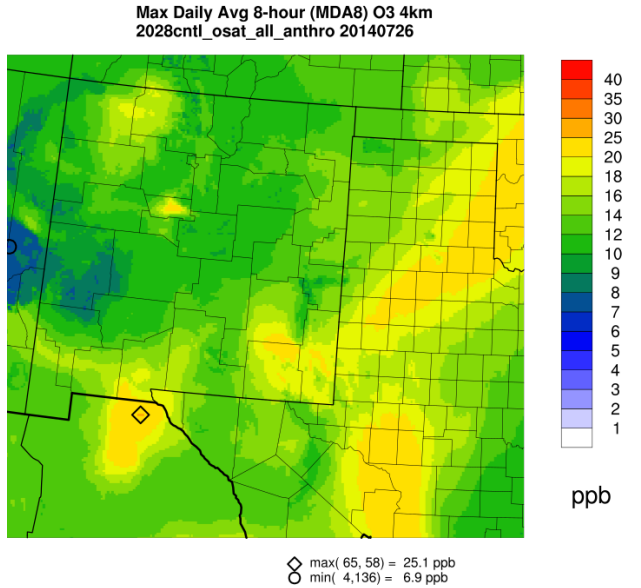
All Source Regions/Categories

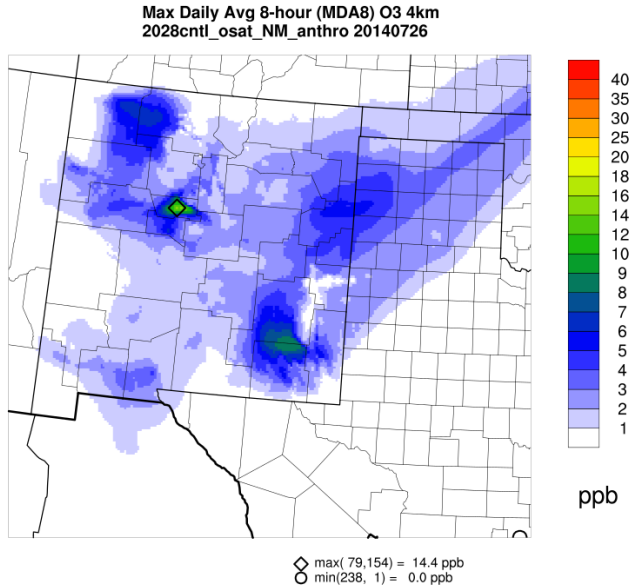
All Regions Anthro

New Mexico Anthro

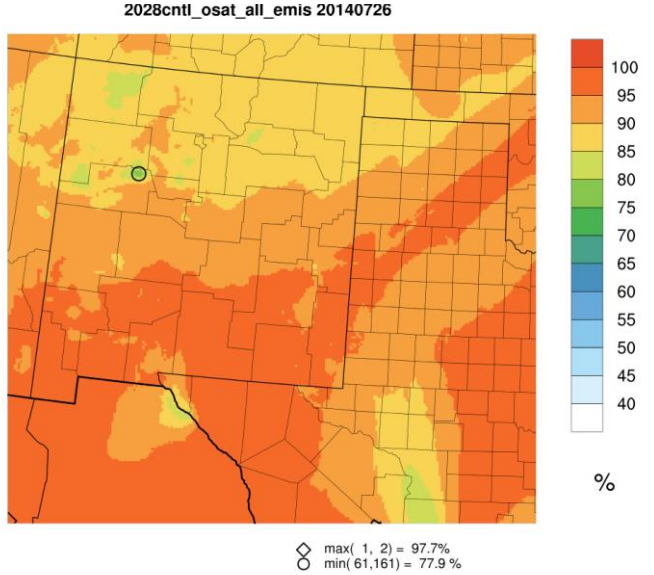
Ozone Concentrations (ppb)

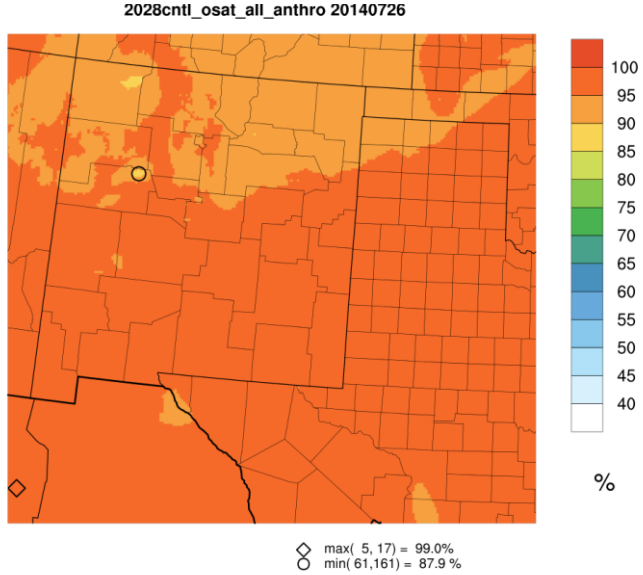


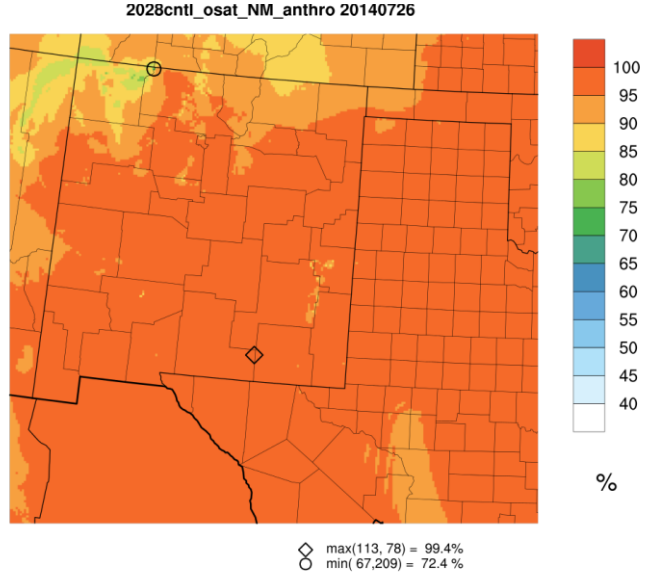




Percent NOx Sensitive Ozone







RAMBOLL

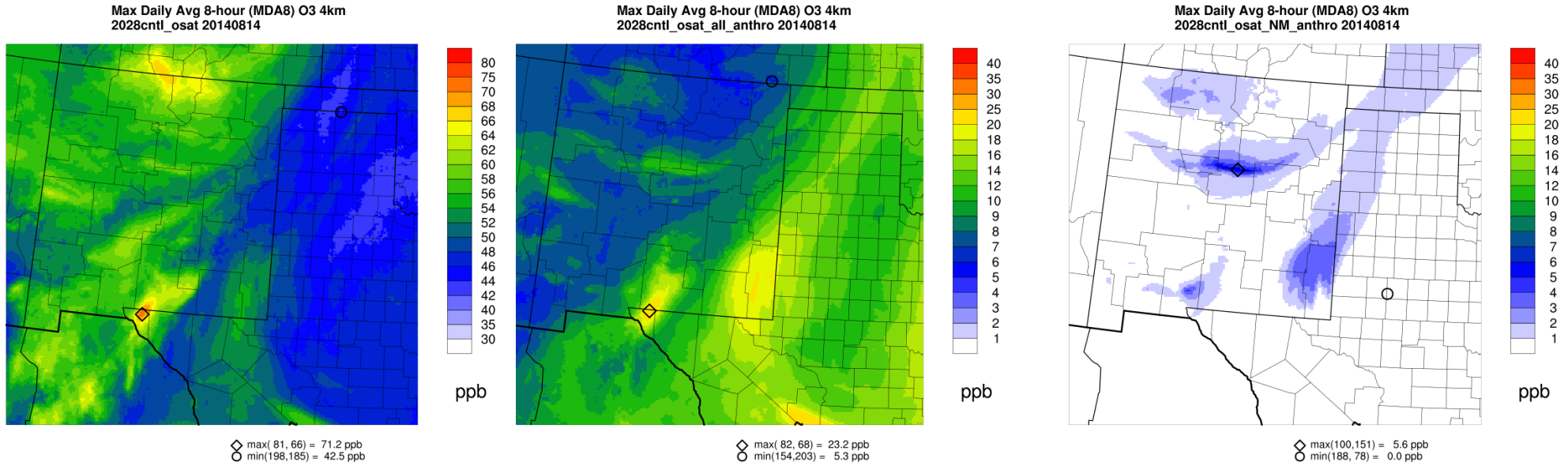
2028 OSAT SA RESULTS FOR AUGUST 14, 2014

All Source Regions/Categories

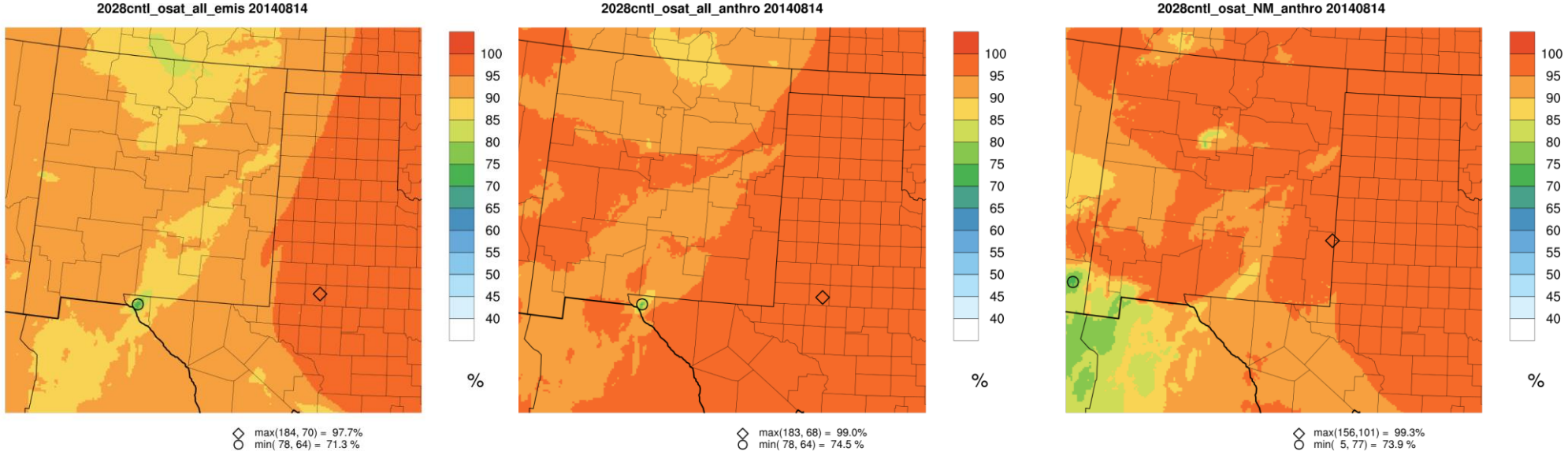
All Regions Anthro

New Mexico Anthro

Ozone Concentrations (ppb)

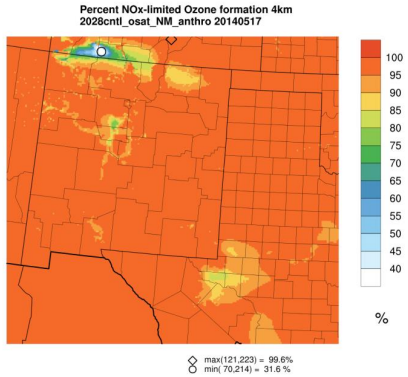


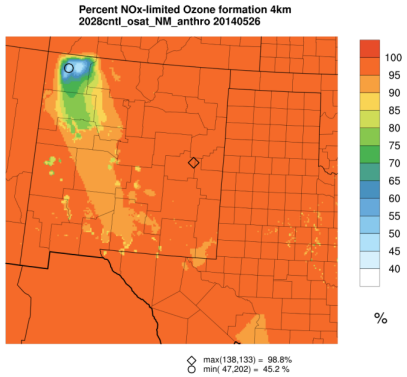
Percent NOx Sensitive Ozone

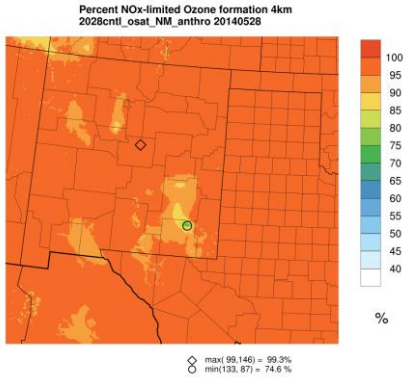


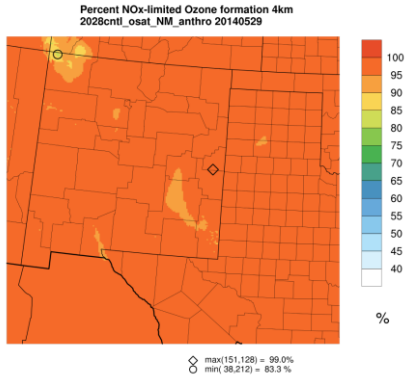
RAMBOLL

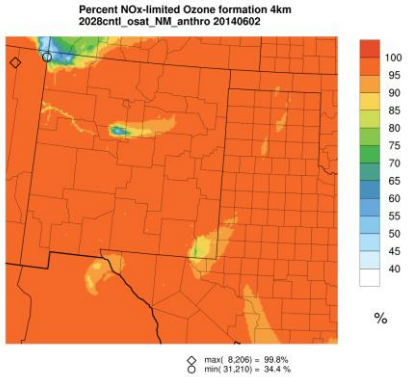
PERCENT NOX SENSITIVE OZONE FROM NEW MEXICO ANTHROPOGENIC EMISSIONS ON 15 HIGHER OZONE DAYS

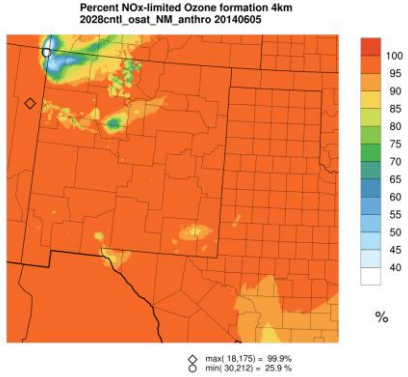


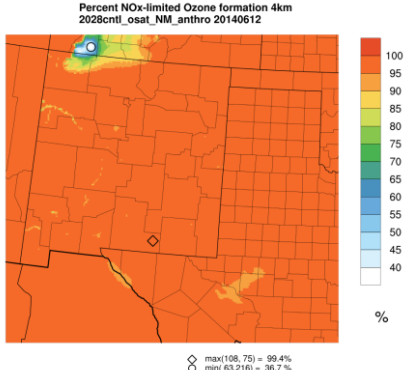


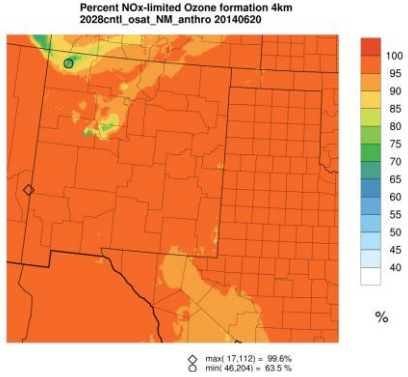


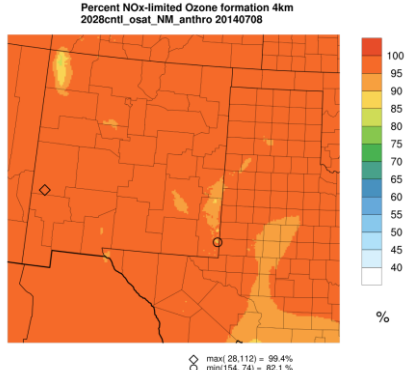


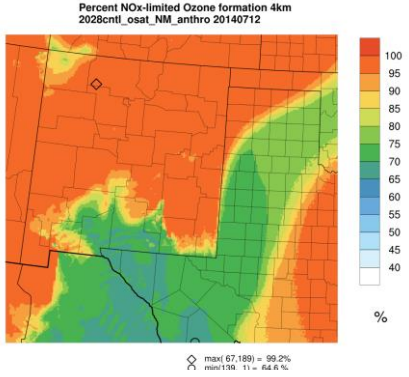


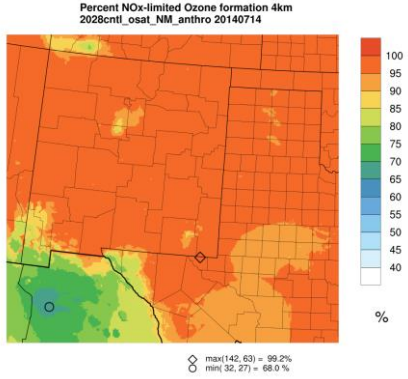


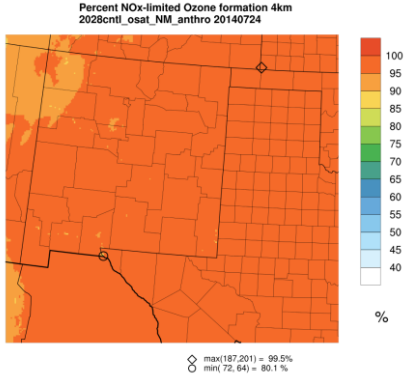


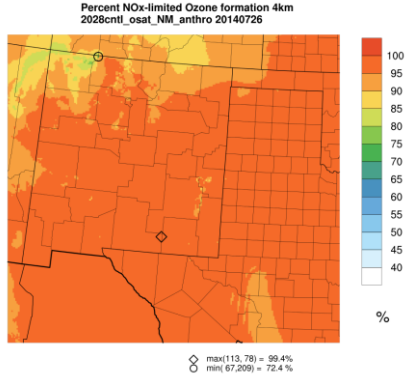


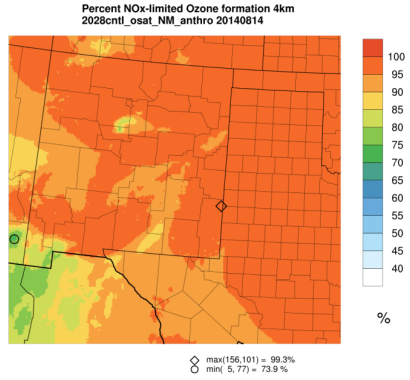


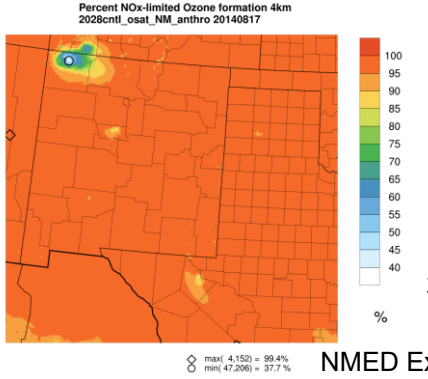


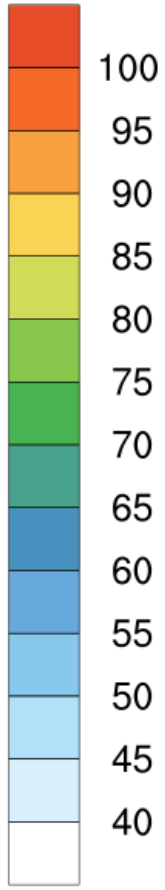






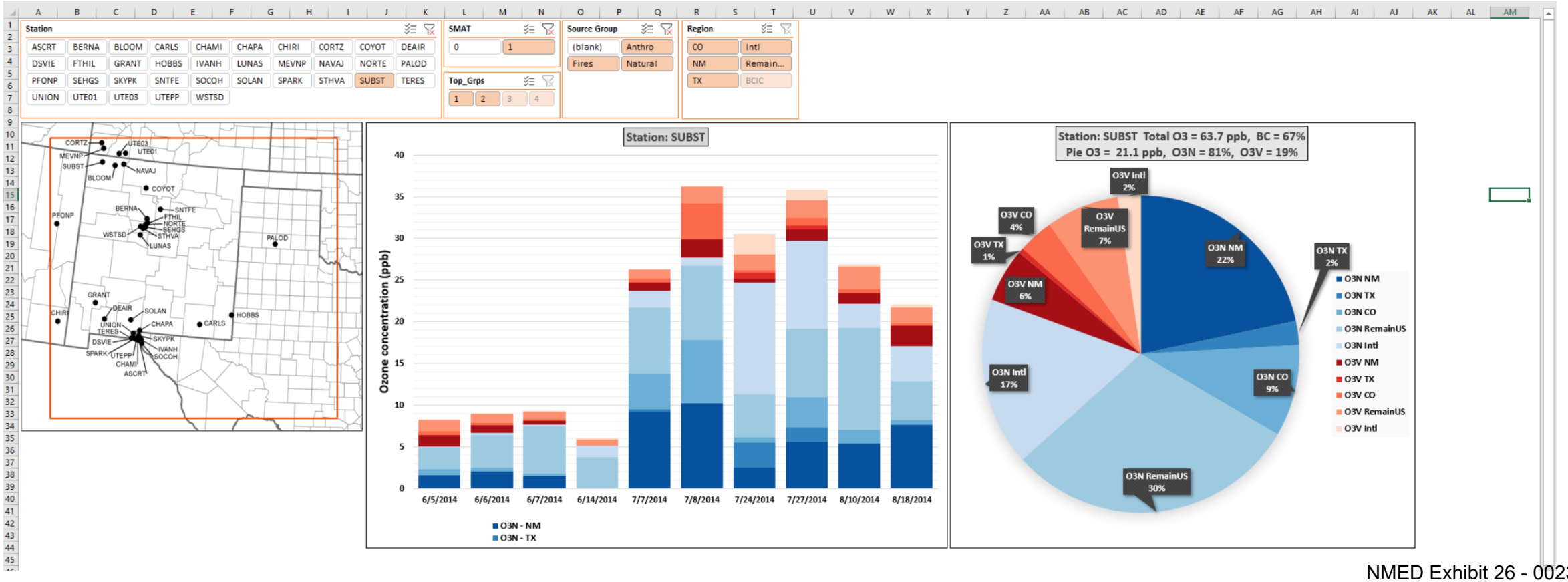






DASHBOARD OF OSAT RESULTS AT MONITORING SITES

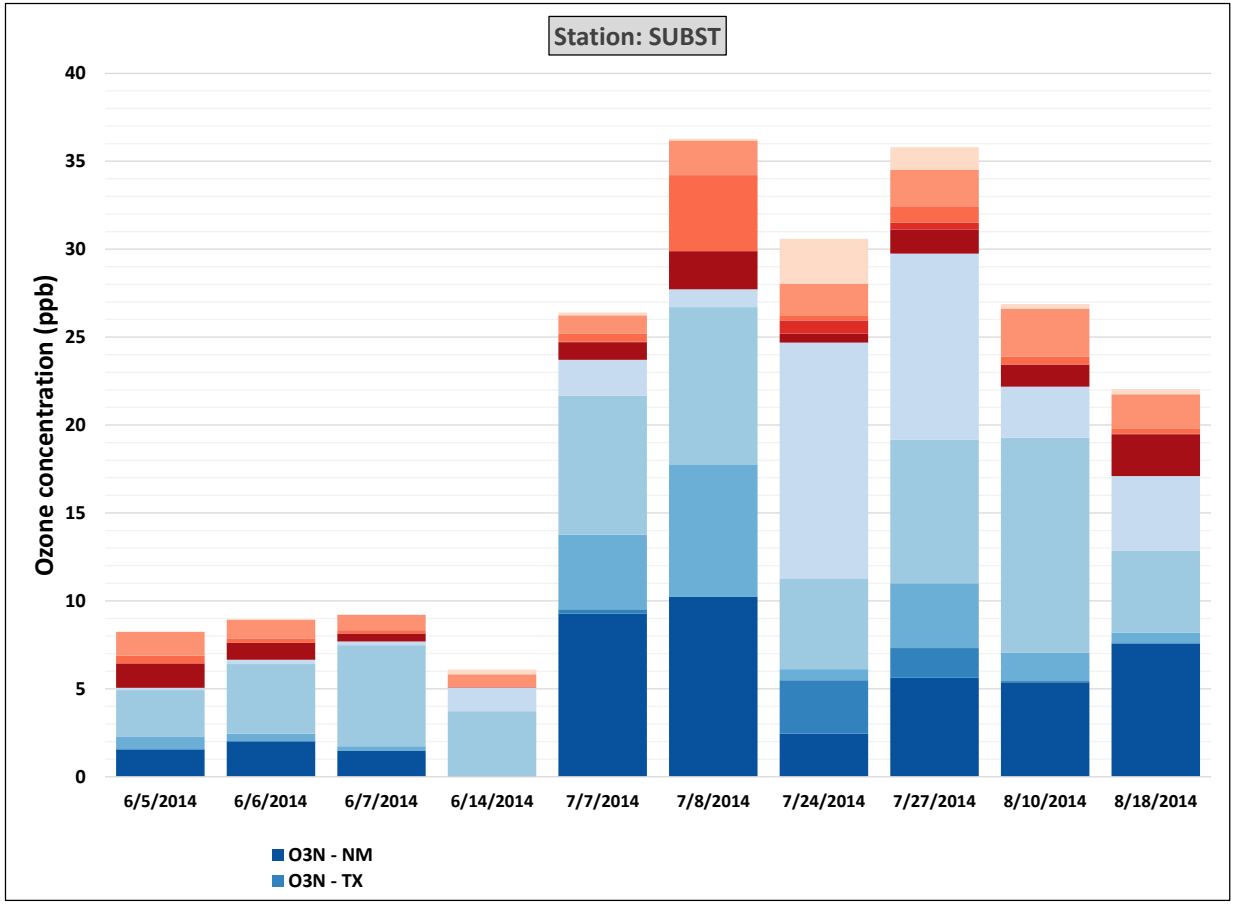
- Select display: monitoring site; 10 days to visualize (SMAT, 2028 1-10, 11-20, etc.); Source Categories (Anthro, Fires, Natural); Source Regions (NM, CO, TX, Remaining U.S. Intl.)
- Displays: Stacked Bar Charts of 10 days O3V and O3N; Pie Chart average across 10 days
  - Cooler colors for NOx sensitive ozone, warmer coolers for VOC sensitive ozone



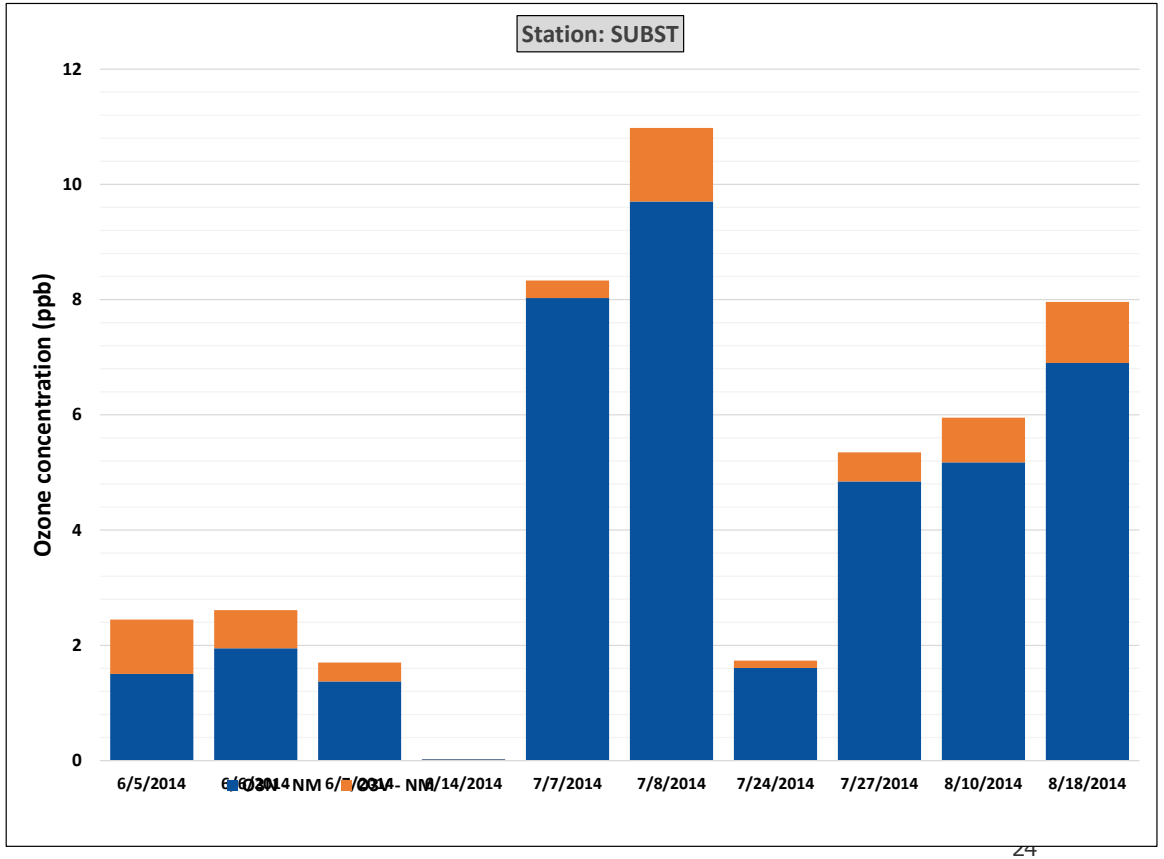
SUBSTATION, SAN JUAN COUNTY – 10 SMAT DAYS

- Lots of day-to-day variation in ozone contributions and percent VOC vs. NOx sensitive ozone
- 70% - 90% NOx sensitive MDA8 ozone

All Source Categories and Regions



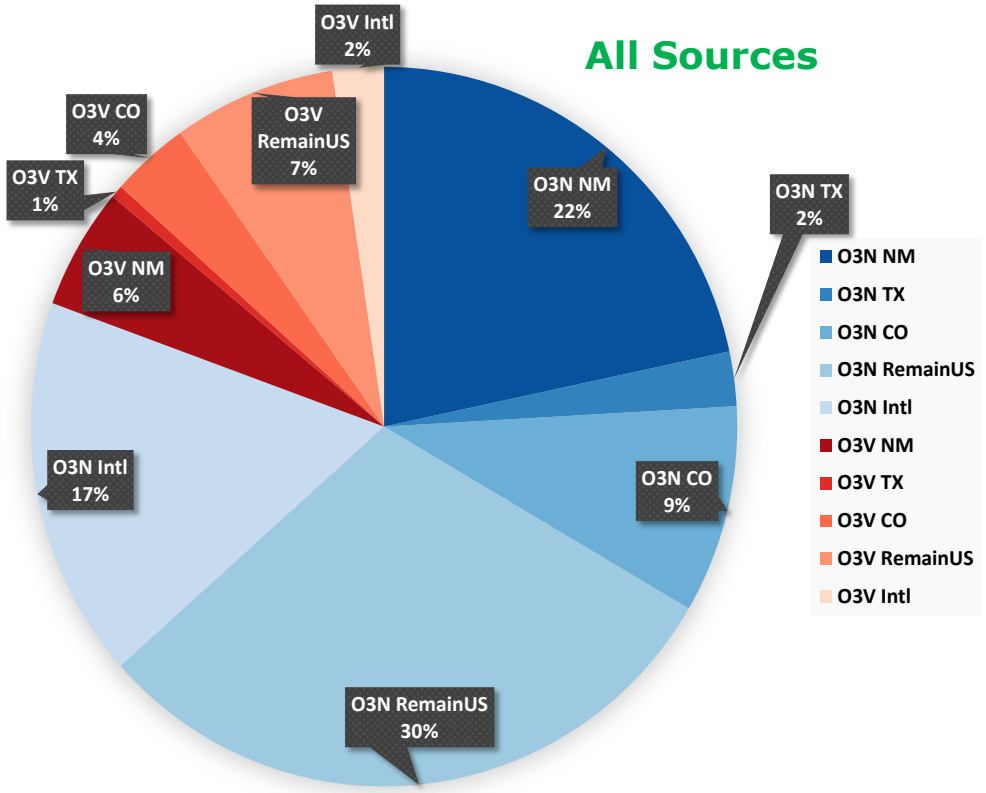
New Mexico Anthropogenic



Substation, San Juan County
Average 10 SMAT Days

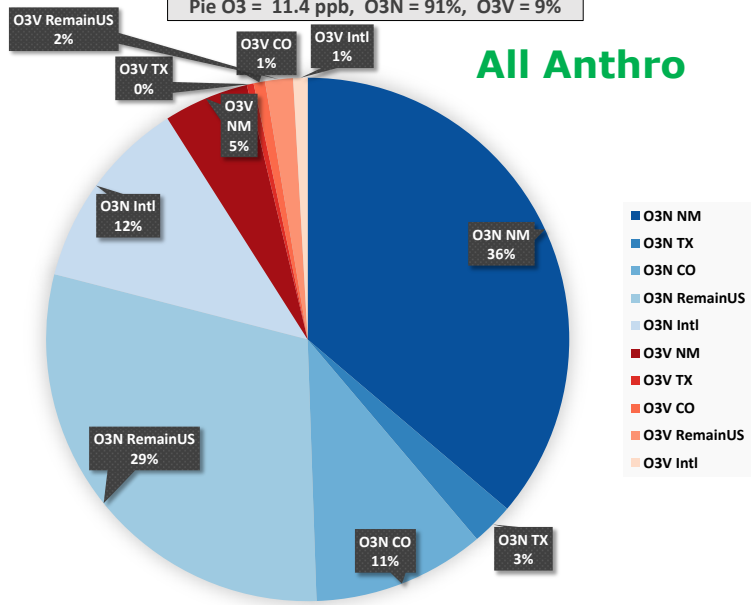
Station: SUBST Total O3 = 63.7 ppb, BC = 67%
Pie O3 = 21.1 ppb, O3N = 81%, O3V = 19%

All Sources



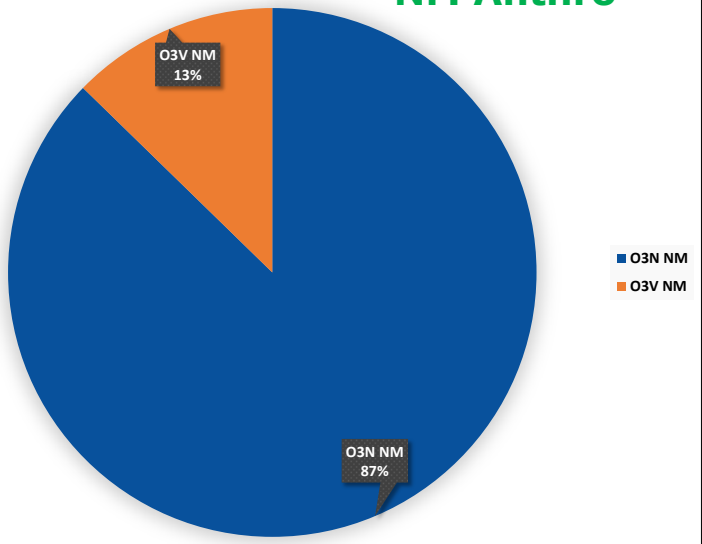
Station: SUBST Total O3 = 63.7 ppb, BC = 67%
Pie O3 = 11.4 ppb, O3N = 91%, O3V = 9%

All Anthro



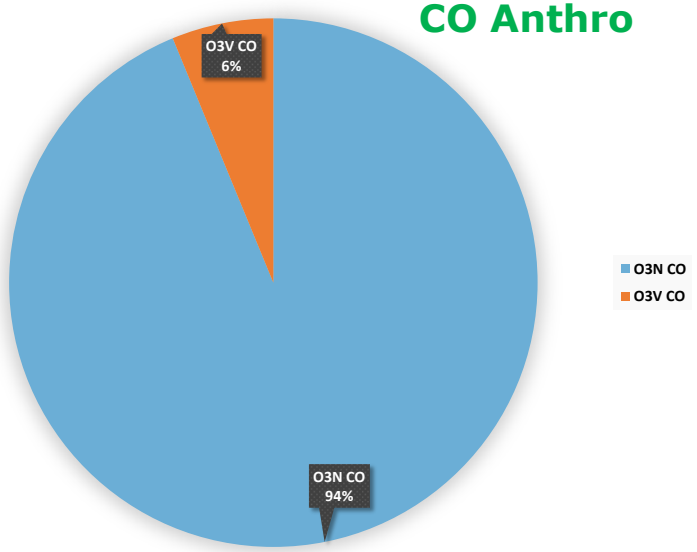
Station: SUBST Total O3 = 63.7 ppb, BC = 67%
Pie O3 = 4.7 ppb, O3N = 87%, O3V = 13%

NM Anthro



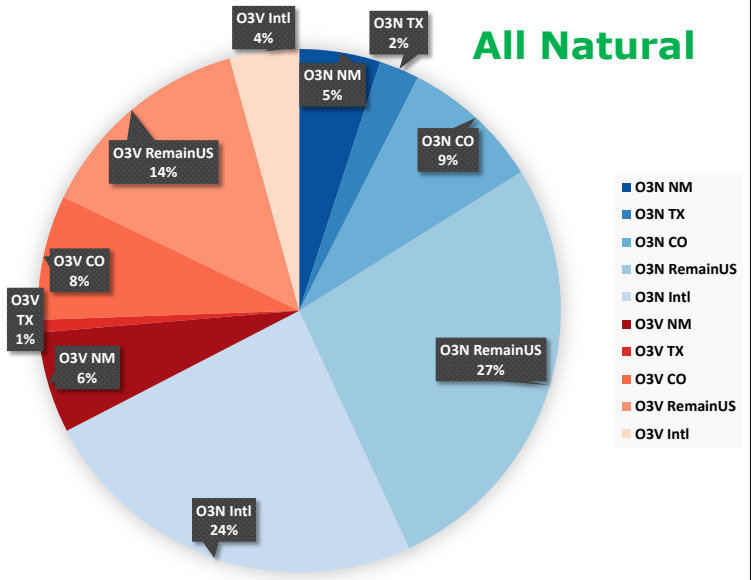
Station: SUBST Total O3 = 63.7 ppb, BC = 67%
Pie O3 = 1.3 ppb, O3N = 94%, O3V = 6%

CO Anthro



Station: SUBST Total O3 = 63.7 ppb, BC = 67%
Pie O3 = 8.8 ppb, O3N = 67%, O3V = 33%

All Natural

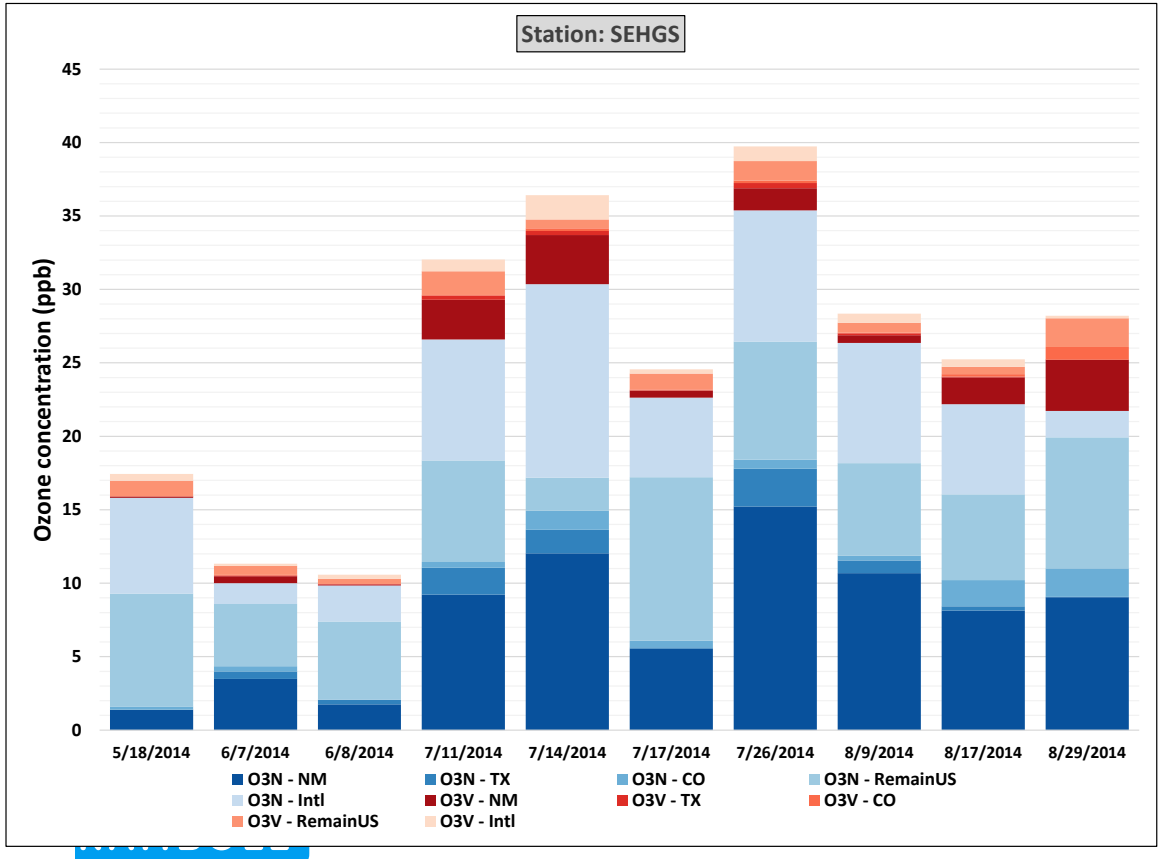


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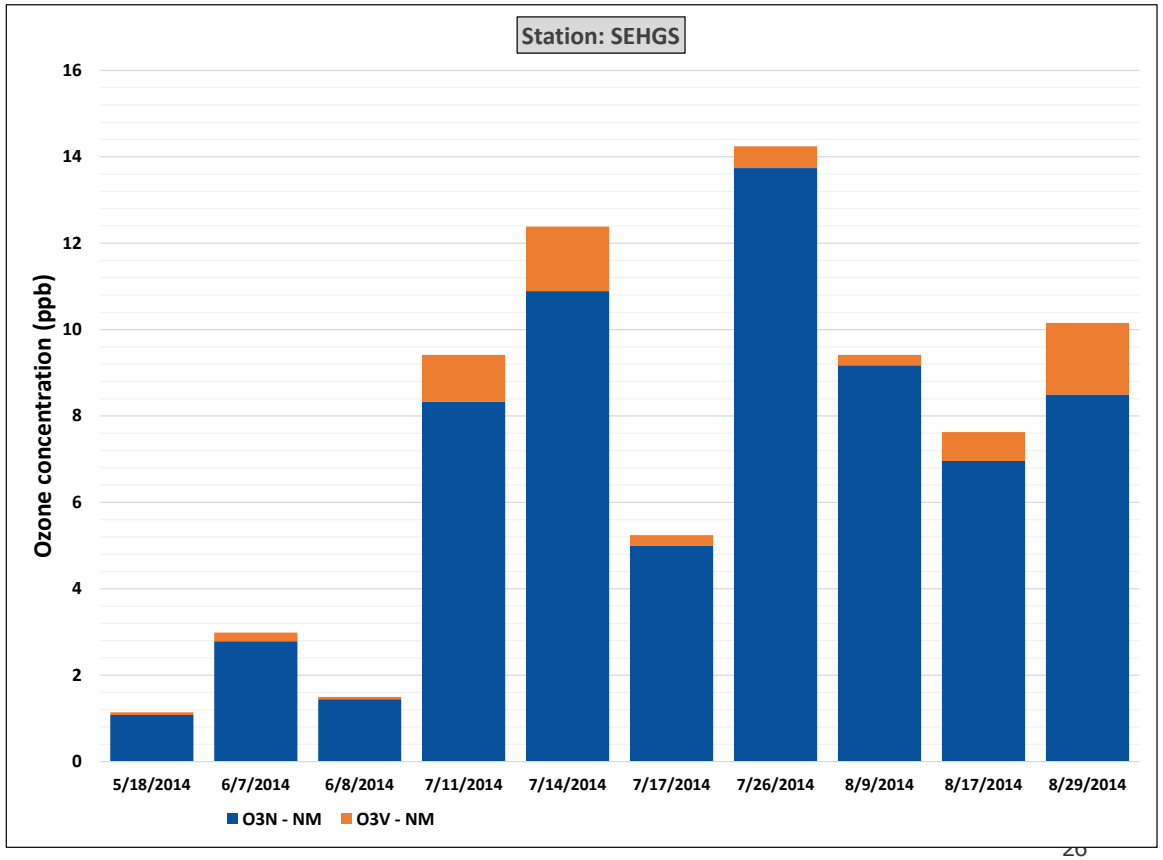
SOUTH EAST HEIGHTS, BERNALILLO COUNTY – 10 SMAT DAYS

- Lots of day-to-day variation in ozone contributions and percent VOC vs. NOx sensitive ozone
- Vast majority is NOx sensitive ozone, a little less VOC sensitive ozone than Substation

All Source Categories and Regions

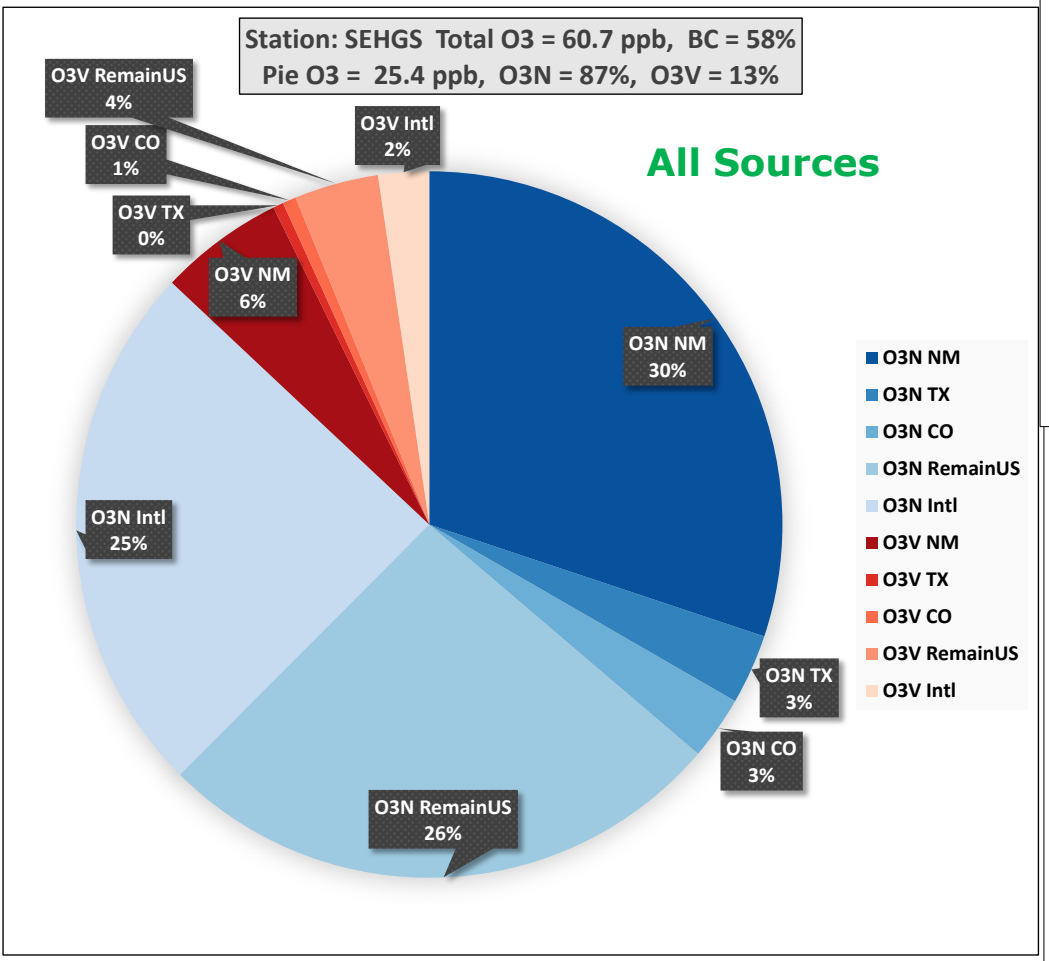


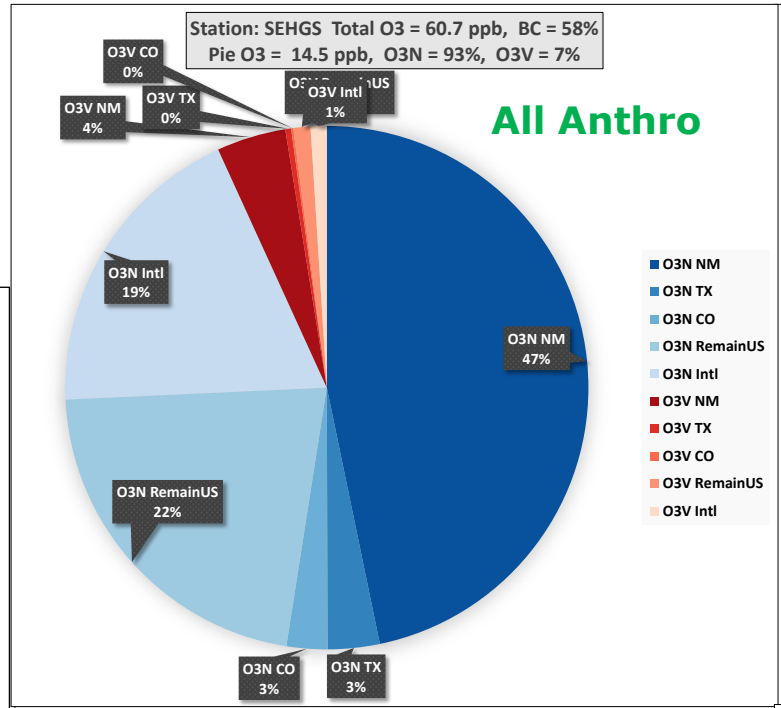
New Mexico Anthropogenic

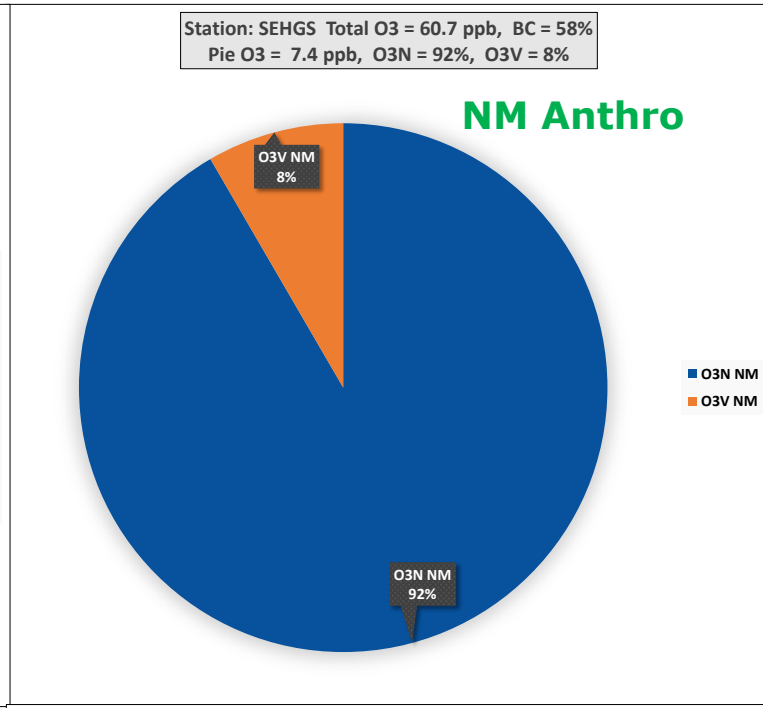


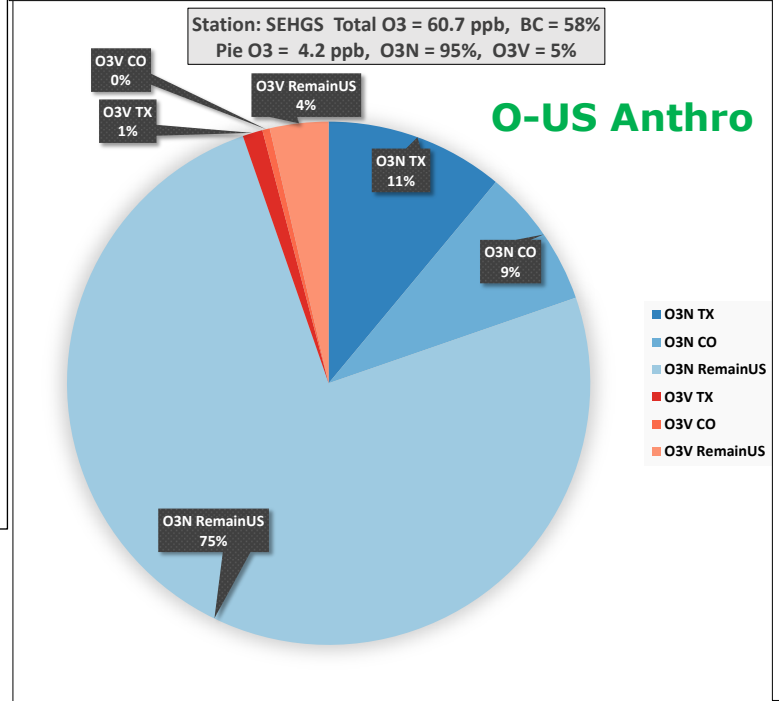
SE Heights, Bernalillo County

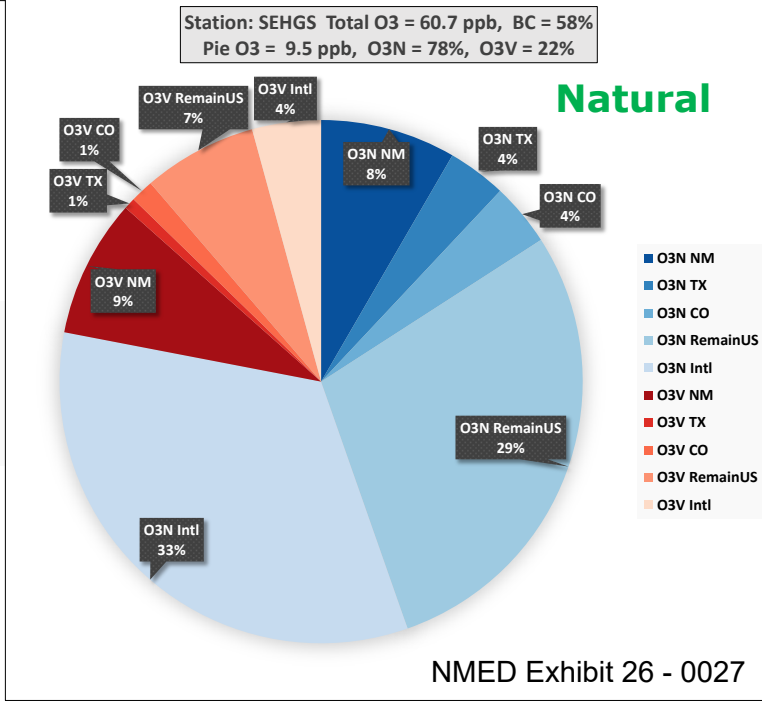
Average 10 SMAT Days









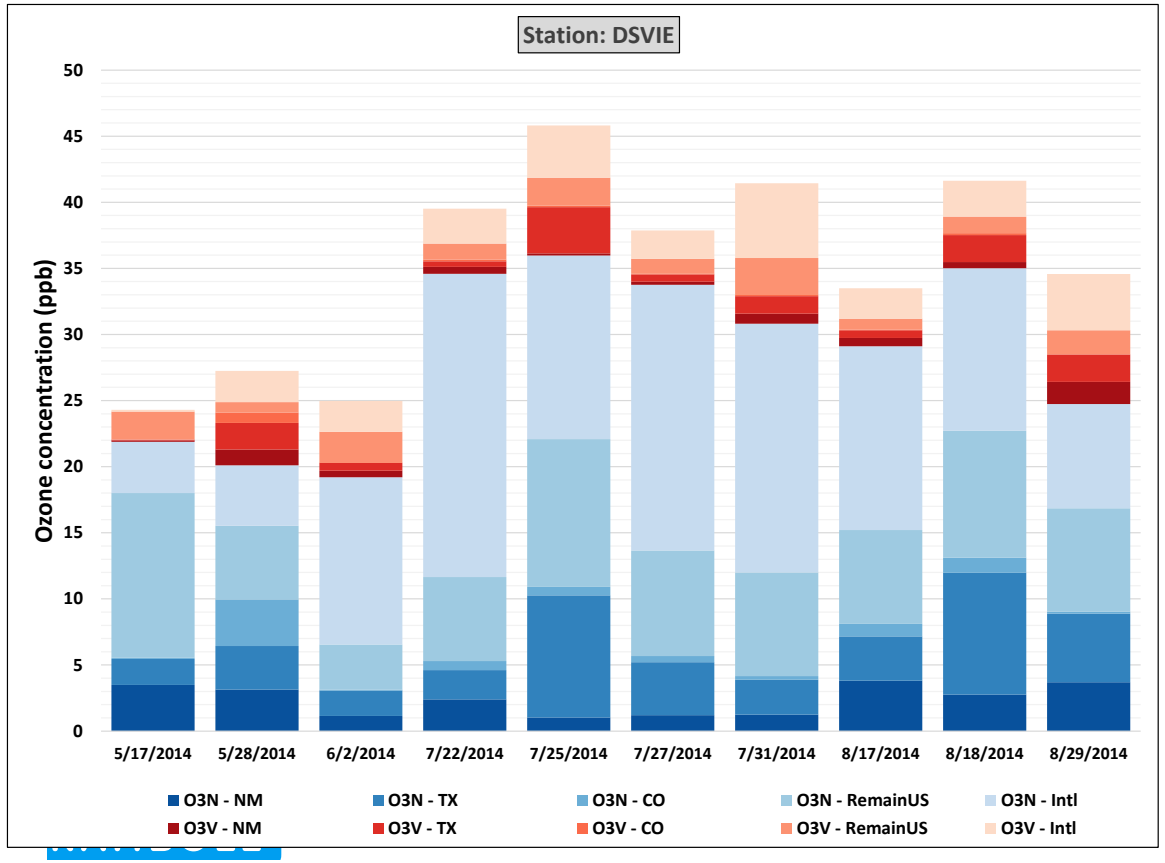


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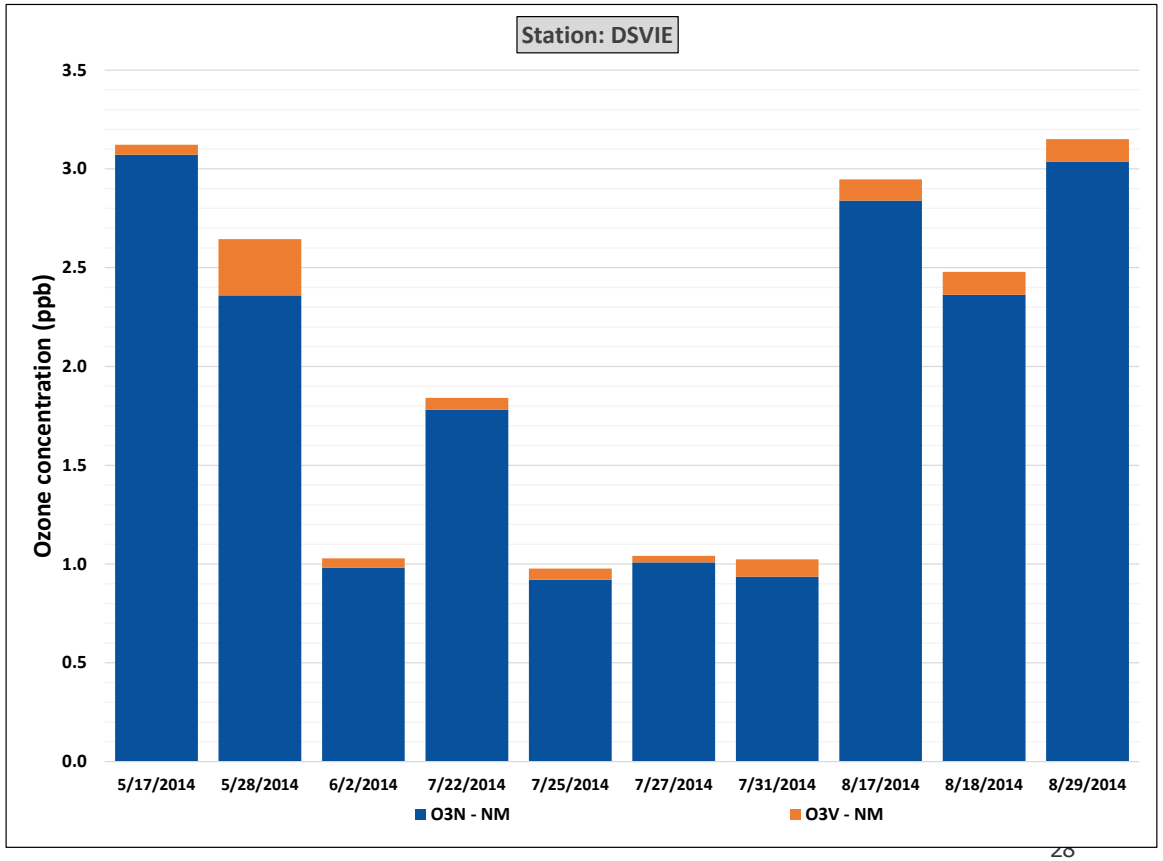
DESERT VIEW, DONA ANA COUNTY – 10 SMAT DAYS

- Mostly NOx sensitive ozone, but more VOC sensitive than other sites due to El Paso
- New Mexico contributions NOx sensitive

All Source Categories and Regions

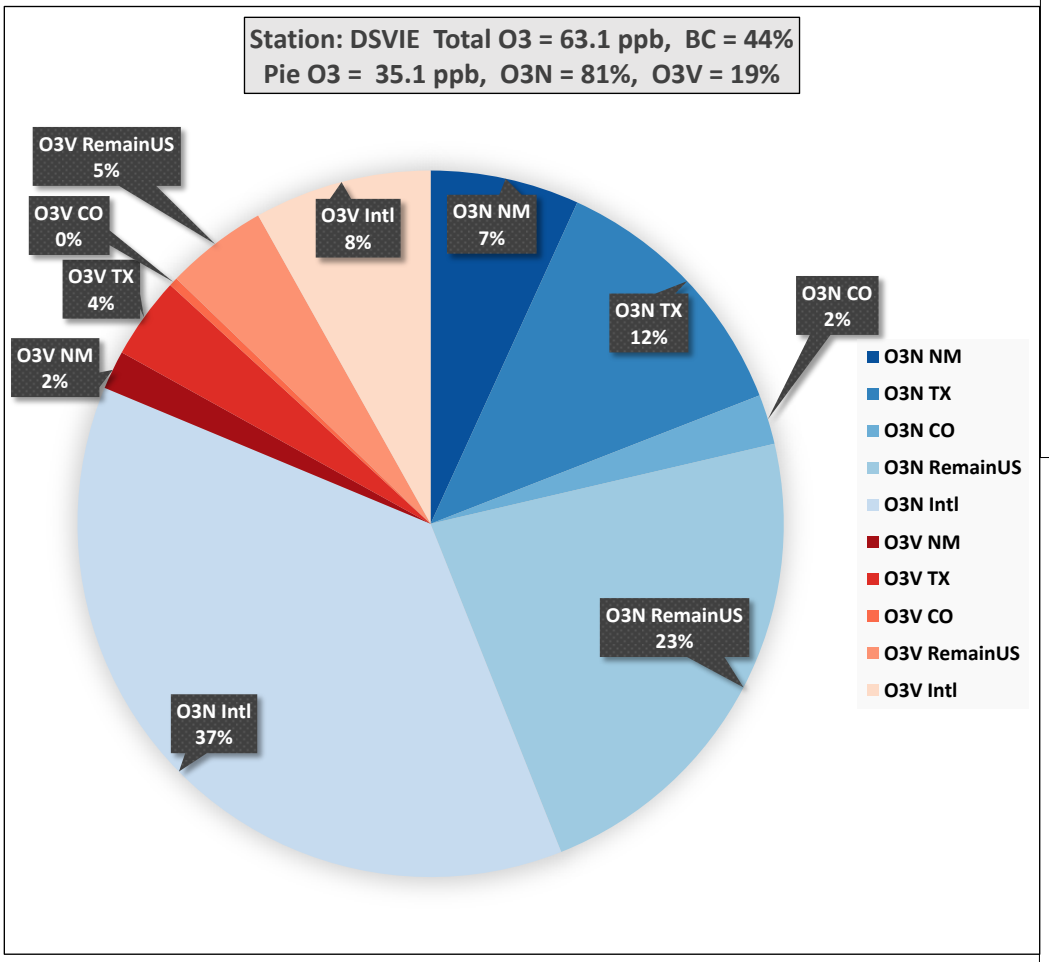


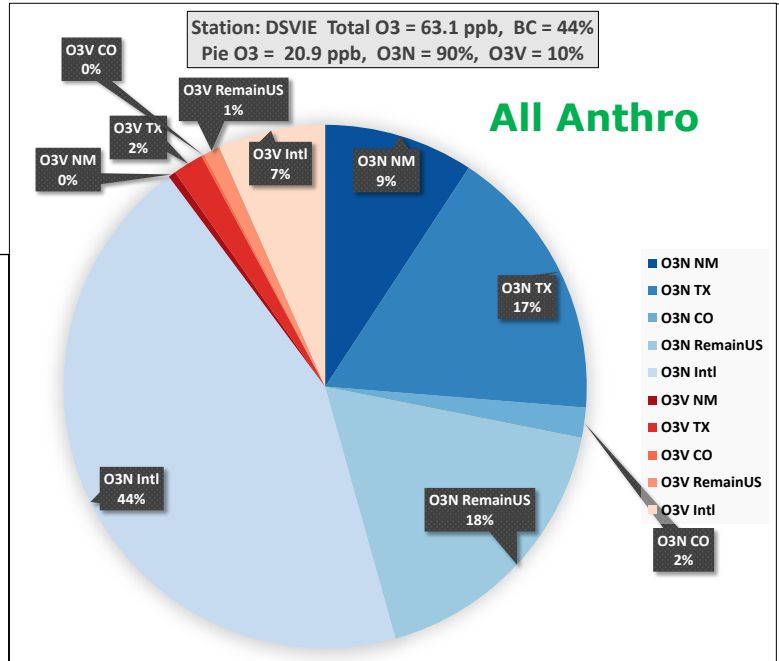
New Mexico Anthropogenic

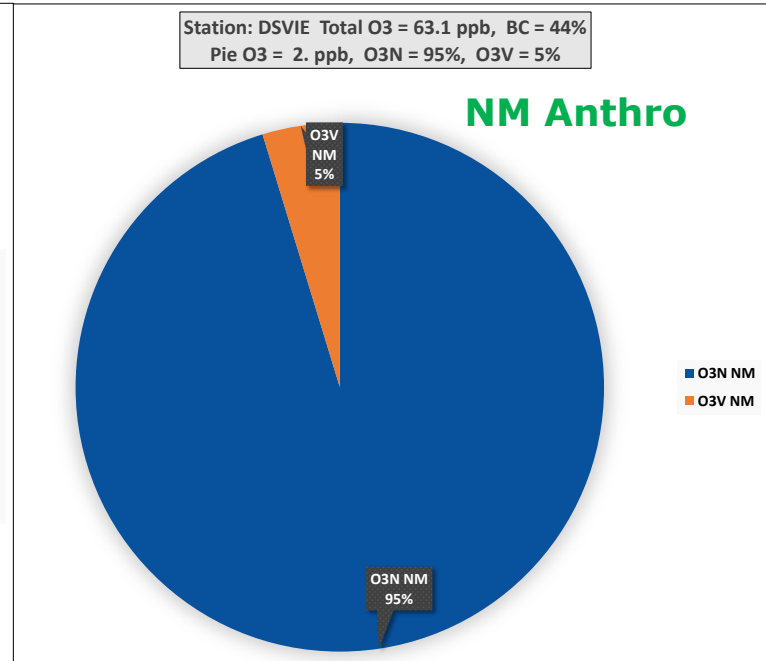


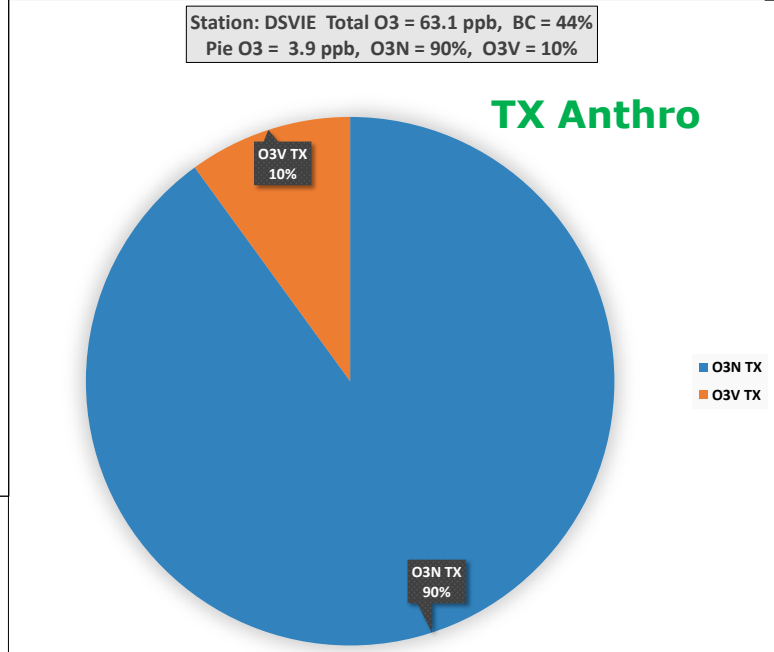
NMED Exhibit 26 - 0028

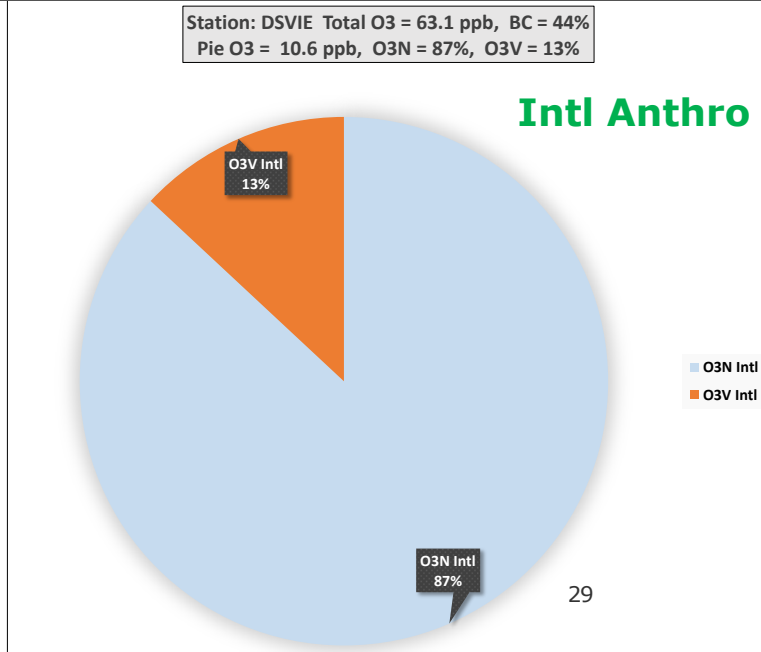
Desert View, Dona Ana County
Average 10 SMAT Days











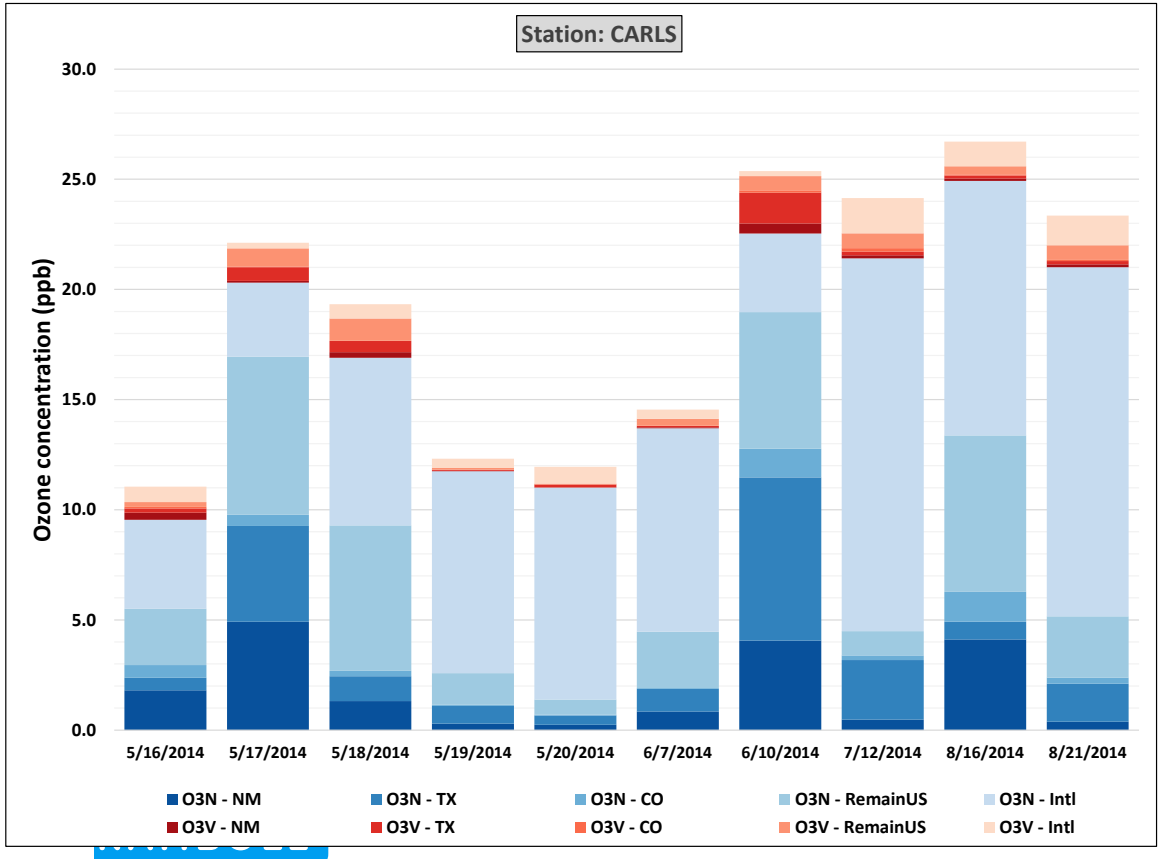
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NMED Exhibit 26 - 0029

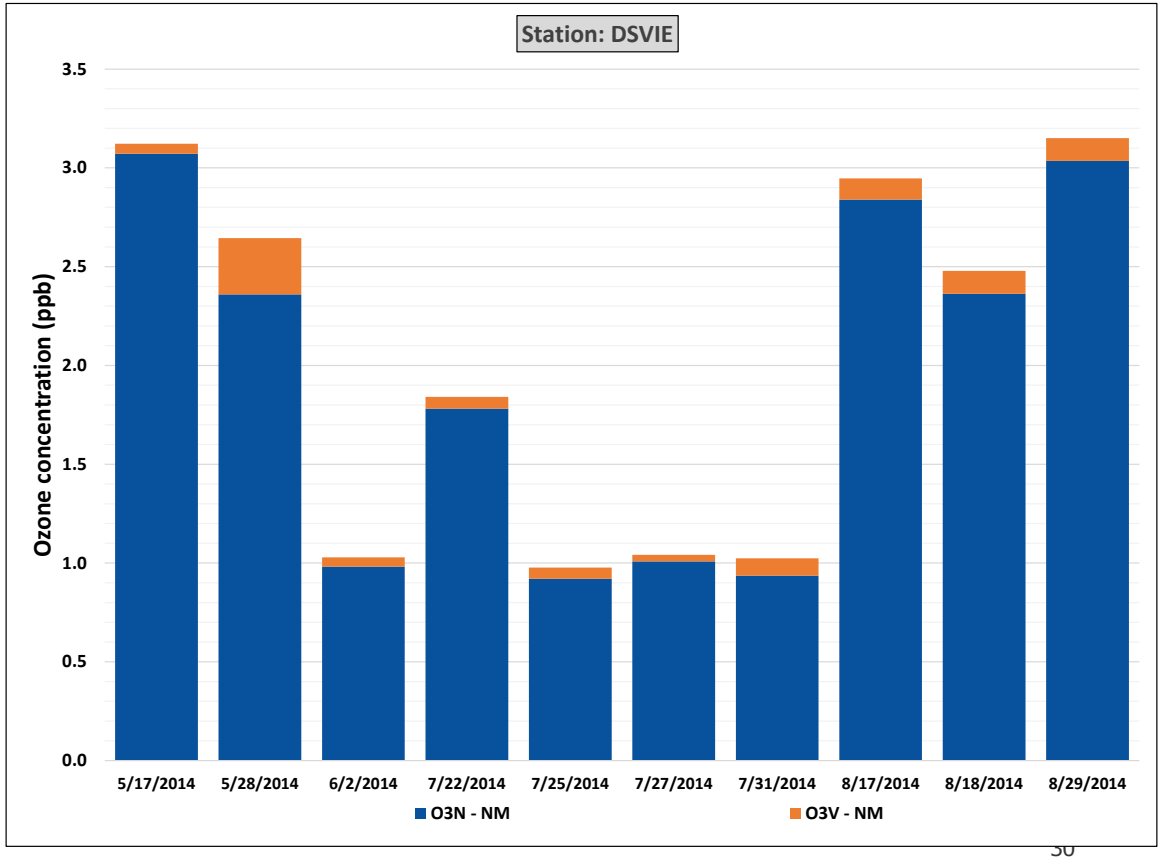
CARLSBAD, EDDY COUNTY – 10 SMAT DAYS

- Mostly NOx sensitive ozone with New Mexico contributions even more NOx sensitive

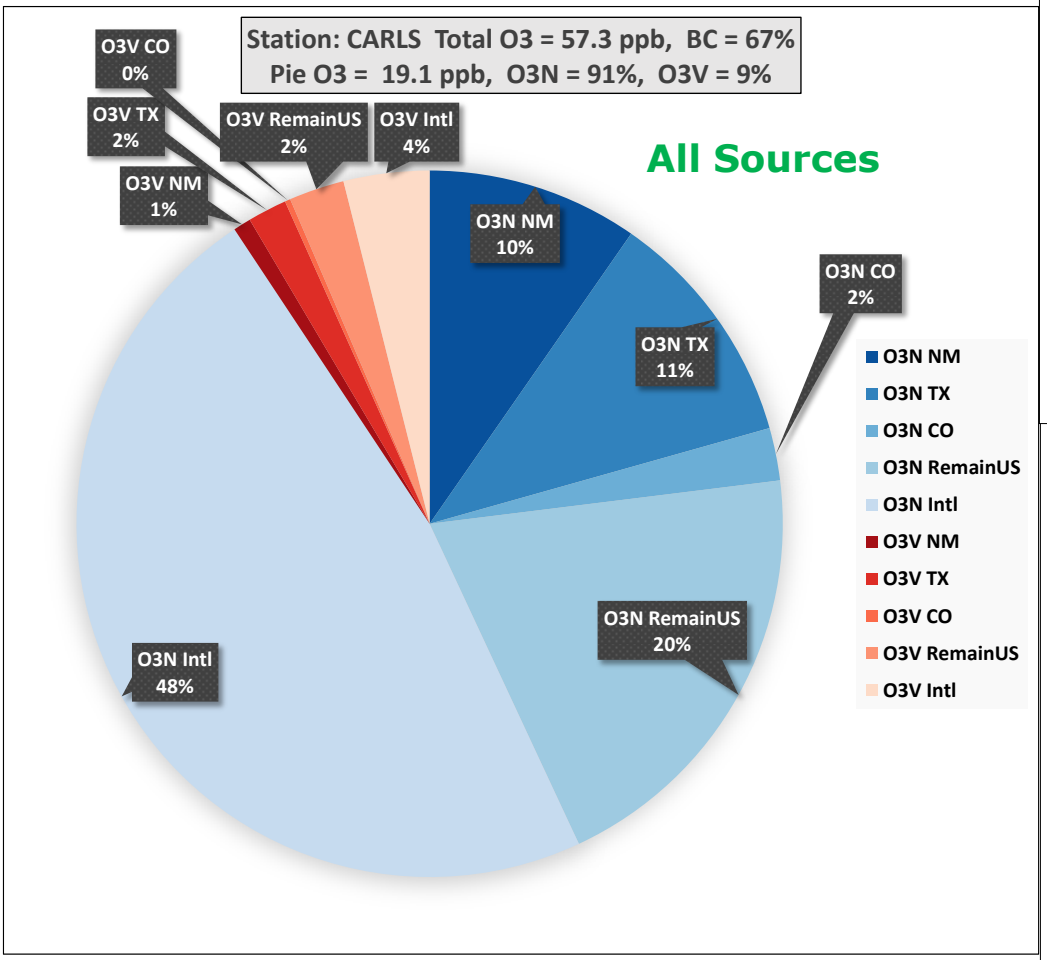
All Source Categories and Regions

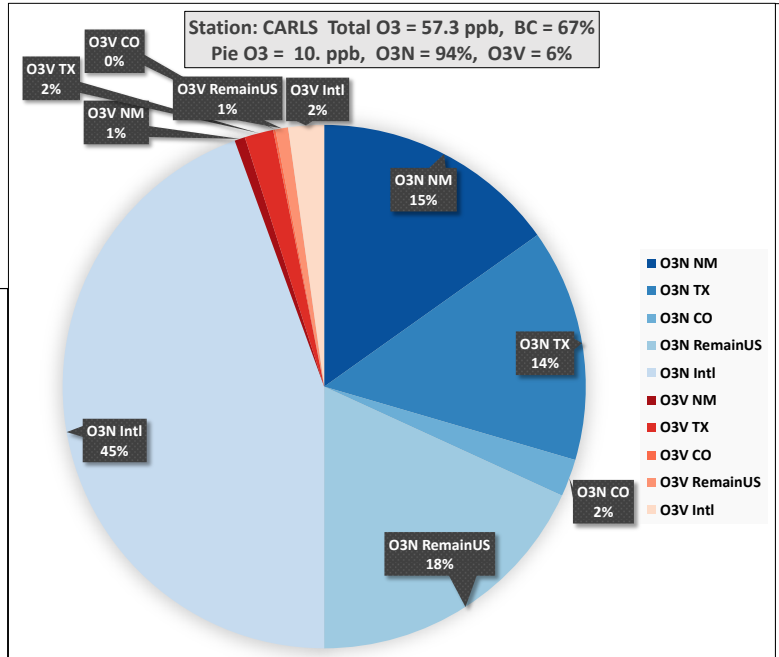


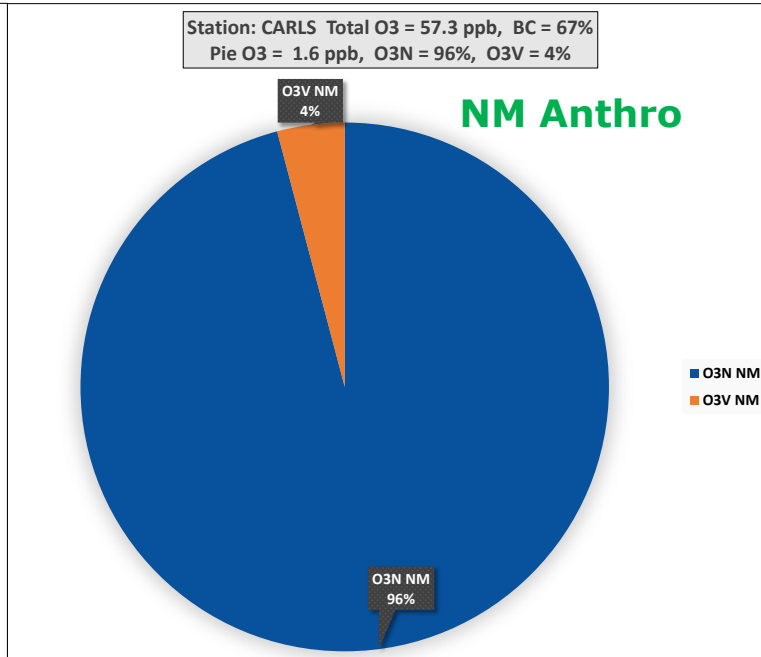
New Mexico Anthropogenic

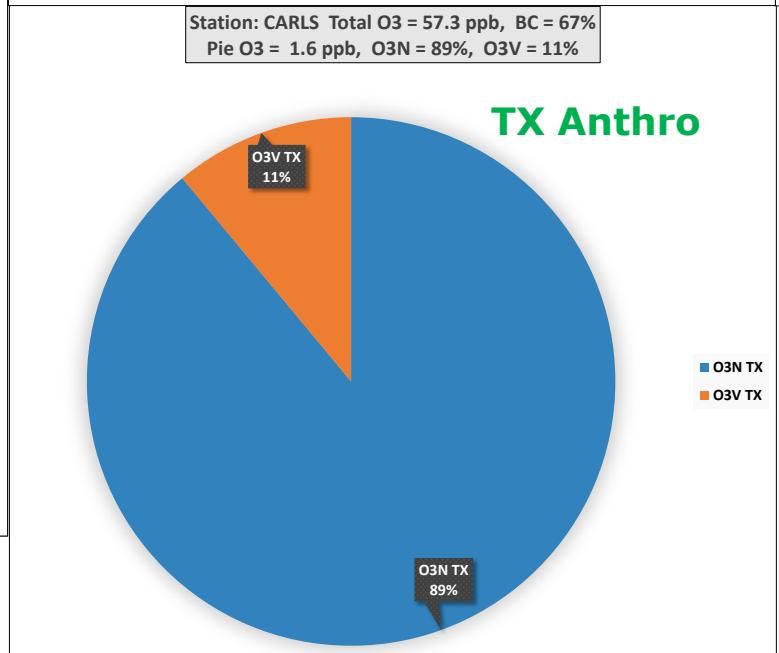


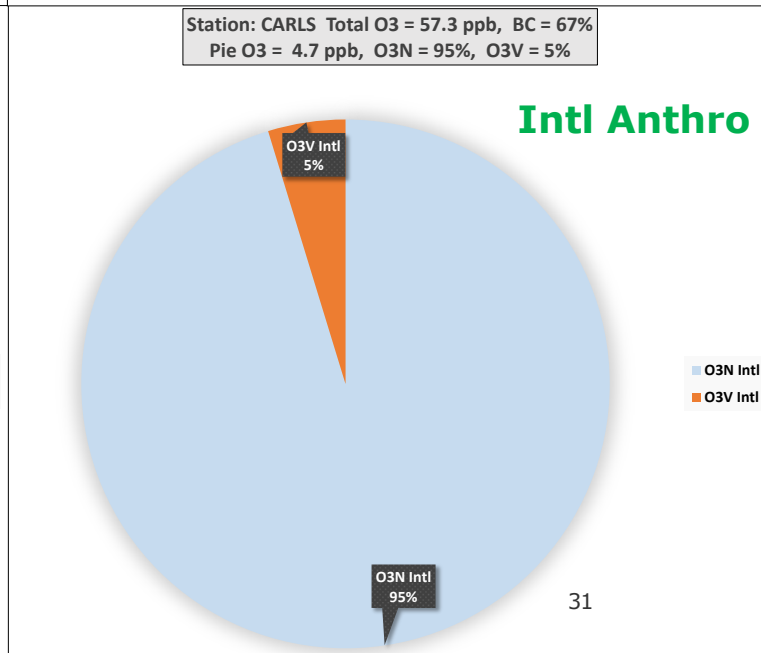
Carlsbad, Eddy County
Average 10 SMAT Days











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CONCLUSIONS VOC/NOX SENSITIVE OZONE OSAT SA

- The OSAT source apportionment suggests that ozone formation leading to elevated ozone concentrations in New Mexico is primarily NOx sensitive
  - Consistent with regional ozone modeling studies (e.g., OTAG) that found regional NOx emissions controls most effective at reducing regional ozone concentrations and ozone transport
    - VOC controls can also be effective in urban areas and other areas with concentrated emissions
- There are locations and days when there are higher amounts of VOC sensitive ozone formation:
  - San Juan Basin, El Paso-Juarez, Albuquerque and, to a lesser extent, Permian Basin
- The OSAT source apportionment provides a general indication of potential relative effectiveness of NOx vs. VOC controls for reducing ozone concentrations. It is not a substitute for actual control strategy modeling with explicit emission reductions of targeted sources.
  - Ozone formation is complex and reducing emissions changes the chemistry from the previous state that can cause non-linear responses in ozone concentrations

DRAFT FINAL AQTSD (DUE MAY 4; ACTUAL WEEK OF APR 26)

1. Introduction
2. 2014 WRF Meteorological Modeling
3. Boundary Condition Inputs
4. 2014 Emission Inputs
5. Diagnostic Sensitivity Tests
6. 2014 Base Case Modeling and Model Performance Evaluation
7. 2028 Base Case Modeling and Ozone Design Value Projections
8. 2028 Oil and Gas Control Strategy Modeling and Ozone Design Value Projections
9. Sensitivity of 2028 Ozone Design Value Projections to Current Year Design Values
10. APCA Source Sector Ozone Source Apportionment Modeling
11. OSAT VOC/NOx Sensitivity Ozone Source Apportionment Modeling
12. Summary and Conclusions
13. References

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NMED Exhibit 26 - 0033

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF BRENT ELLINGTON

My name is Brent Ellington, and I am an Environmental Scientist Specialist with the Ambient Air Monitoring Section of the New Mexico Environment Department's ("Department" or "NMED") Air Quality Bureau ("Bureau"). I am presenting this written testimony on behalf of the Department in this proceeding on proposed new air quality regulations at 20.2.50 NMAC ("Part 50"). My testimony will address the following topics: ozone monitoring, methods and procedures, and federal requirements for monitoring equipment.

I. QUALIFICATIONS

I have been employed by the Bureau for approximately 7 years as an ambient air quality monitoring section operator and supervisor. I have over 17 years of experience as an environmental scientist for the State of New Mexico, having worked for the New Mexico Office of the State Engineer and the New Mexico Interstate Stream Commission prior to joining the Department.

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 28.

II. AMBIENT AIR QUALITY MONITORING

The NMED Ambient Air Quality Monitoring Network

The Department is responsible for collecting ambient air data to document present air quality and significant trends in pollutant concentrations. This data must be of high quality because its use may have significant health, social, and economic impacts. The data collected is

used to determine the State's status with regard to compliance with federal National Ambient Air Quality Standards ("NAAQS"), which are designed to protect the public health and avoid secondary effects such as damage to vegetation or property, or the reduction of public values such as visibility. The Bureau's public awareness programs are designed to provide current air quality information to the public.

New Mexico consists of eight Air Quality Control Regions ("AQCRs") located in 33 counties covering a total area of 120,000 square miles. Three of these AQCRs encompass areas with surrounding states, and five lie entirely within New Mexico.

The NMED ambient air quality monitoring network ("NMED Air Monitoring Network") consists of State and Local Air Monitoring Stations ("SLAMS") and Special Purpose Monitors ("SPMs"). The purpose of the network is to support the NAAQS, and the Bureau is designated by EPA to operate the monitors. The network is designed to: (1) determine highest pollutant concentrations expected to occur in the area covered by the network; (2) determine representative pollutant concentrations in areas of high population density; (3) determine the impact on ambient pollution levels of significant sources or source categories; and (4) determine general background concentration levels. The monitoring locations are appropriately sited to determine highest concentrations expected to occur.

Overview of the NMED Air Monitoring Network

The existing NMED Air Monitoring Network includes monitors in the areas of highest population density: Dona Ana, Santa Fe, and Sandoval Counties. The monitors in the network are sited to determine the impact on ambient pollution levels of significant sources and source categories, in particular those in San Juan County, a region of concentrated energy development

and generation. The network includes sites that measure general background concentrations, including sites in San Juan County and in Carlsbad, La Union, and Santa Teresa.

The current network is capturing data that enables NMED to determine the extent of regional pollutant transport among populated areas. The Navajo Lake site serves this purpose for transport between San Juan County and Southwestern Colorado. The monitoring objective of the Coyote Ranger District site is to determine regional ozone transport. The monitoring objective of the Las Cruces site is to determine regional PM 2.5 transport.

Data gathered from the current network of monitoring sites can be used to determine welfare-related impacts in rural and remote areas. Data from the network is being used by citizen groups in both the Four Comers Region and the Border Region of New Mexico/US and Mexico. There are currently 14 ozone analyzers deployed at various monitoring stations throughout New Mexico. *See* NMED Air Quality Bureau Air Monitoring Quality Assurance Project Plan 2020, Section A.

Federal Regulations Governing the NMED Air Monitoring Network

The locations of the SLAMS and SPMs meet the general ambient monitoring site types specified in the U.S. Environmental Protection Agency's ("EPA") regulations at 40 CFR Part 53 and 58. The Bureau maintains air monitoring instruments in such a manner as to attain 95% probability goals for accuracy and precision within EPA's required limits. The Bureau adheres to the Measurement Quality Objectives and Validation Templates as published in Appendix D of the EPA QA Handbook for Air Pollution Measurement Systems, Vol. II (EPA-454/B-17-001) (January 2017).[1]

[1] Available at https://www.epa.gov/sites/production/files/2020-10/documents/app_d_validation_template_version_03_2017_for_amtic_rev_1.pdf

Air Pollutants Required to be Monitored

The Department monitors sulfur dioxide (SO^2), nitrogen dioxide (NO^2), ozone (O^3), and particulate matter (PM10 and PM 2.5) in areas of New Mexico where the respective pollutants are expected to occur at significant levels, such as in and near cities and near coal-fired power plants, mining operations, oil and gas operations, and petroleum refineries. The data collected are compared to the NAAQS and the New Mexico Ambient Air Quality Standards, both of which are health-based standards developed for protection of the general public. *See* NMED Exhibit 29, Ambient Air Monitoring Quality Assurance Project Plan 2020, Section A ("Monitoring QA Plan 2020").

Ambient air data collected by the Bureau is submitted to EPA for inclusion in the Air Quality System ("AQS") and is used to determine compliance with state and federal air quality regulations. Also submitted to AQS are quality assurance data showing precision and accuracy comparisons, which are used for compiling statistics on data quality.

The majority of data collected by the Bureau is obtained continuously by automated methods. This data describes the current air quality conditions in New Mexico and is disseminated to the public. The Bureau's ozone and fine particulate matter data is also submitted automatically every hour to the EPA's AirNow program, which publishes maps of pollutant concentrations for the country. The Bureau also makes air pollutant data available via its Air Quality Index and Monitoring Data Website.[2] Information on this site includes the pollutant concentration values and Air Quality Indices that provide a common scale for comparison and interpretation of air quality. Also included are maps and locations of the

[2] Available at: https://www.nmaqinow.net/

various monitoring sites.

Equipment Used to Monitor Ozone Pollution

The Bureau currently utilizes the Thermo Fisher Model 49i Ultra-Violet Photometric Ozone Analyzer ("Model 49*i*") to monitor ozone. Model 49*i* is designated by EPA as a Federal Equivalent Method ("FEM") for the measurement of ambient concentrations of ozone pursuant with the federal regulations at Title 40, Part 53. A FEM is an EPA approved method to determine the concentration of air pollutants and is required by EPA. EPA developed standard monitoring and calculation methods such as the FEM to ensure consistency at monitoring stations and how pollutant concentrations are determined across states. Equipment utilized to maintain the calibration of the 49i ozone analyzer are a Thermo 146i Dynamic Gas Calibrator and a Thermo 49iQPS Ozone Primary Standard. Calibrations are required by EPA to ensure that the ambient pollutant data is accurate by verifying the analyzer is operating within manufacturer specifications. The ozone analyzer and the calibrators are operated according to manufacturer specifications and Bureau Standard Operating Procedures ("SOPs").

Monitoring of Ambient Ozone Levels

The Thermo 49i ozone analyzer calculates the ambient air concentration of ozone at a monitoring station by counting the molecules of ozone that are present as they pass by an ultraviolet (UV) lamp inside the analyzer over a defined period of time. The calculated ozone concentration is then reported to the station datalogger computer and is available on the Bureau's Air Quality Index and Monitoring Data website for public review.

Auditing and Calibration Requirements of Ozone Monitors

Weekly calibration checks, referred to by the Bureau as "QC checks," are performed by the in-station data logger computer and calibration systems. The Bureau evaluates the results of

the QC checks as part of the data validation process. Results are reported to EPA through the AQS. Station operators perform unscheduled calibrations of the ozone analyzer whenever the results of a scheduled calibration check exceed the thresholds specified in 40 CFR part 58. SOPs have been adopted by the Bureau for the operation/calibration of the 49i, 49iQPS, and146i equipment. These SOP's are followed by all operations staff to maintain uniform practices and quality control at each of the AQB ambient air monitoring stations.

Brent A. Ellington

Cellular (505)690-0624 brent.ellington1@state.nm.us

EDUCATION

Eastern New Mexico University, Portales NM
Bachelor of Science - May 2002
Major: Biology Minor: Chemistry

Eastern New Mexico University-Roswell, Roswell, NM
Associate of Arts - December 1997

RESEARCH EXPERIENCE

Undergraduate Research, 1/01- 5/02
Eastern New Mexico University
Project: **Multiple Antibiotic Resistant (MAR) Enteric Bacteria from Dairy Farm Topsoil.** Bacteria collected from the dairy farms were identified genotypically as well as phenotypically. MICs were determined by antibiotic resistance assays. The presence of the MAR operon in the enteric bacteria was determined by PCR and gel electrophoresis.

EMPLOYMENT EXPERIENCE

Environmental Scientist/Specialist Supervisor-Laboratory Manager 09/18 – Present
New Mexico Environment Department-Air Quality Bureau
Responsibilities: Supervise Northern NM operations staff in order to provide the NMED AQB with accurate and complete air monitoring data in accordance with Title 40 Code of Federal Regulations Parts 50 and 58. Coordinate special projects in support of NMED and AQB State and Federal initiatives. Perform the duties of an AQB operator in order to maintain a high level of data capture within the statewide ambient air monitoring network. Train operations staff in State /Federal methodologies relative to National Ambient Air Quality Standards and evaluate operations staff performance. Maintain a working knowledge of the theory of operation for Thermo 42i, 43i, and 49i continuous pollutant gas monitors, calibration equipment, and BAM1020, TEOM, and Partisol samplers.

Water Resource Specialist Senior-Field Coordinator and Well Field Operations Manager 4/15 – 09/18
New Mexico Interstate Stream Commission-Pecos River Bureau
Responsibilities: Assist in oversight of operation of the ISC Pecos River augmentation well fields, including well field equipment installation, operation, maintenance, repair and replacement; gathering of water use data from totalizing meters, ensuring proper implementation of operations agreement and plans with private entities. Develop work plans and work budgets and present to the commission for approval. Maintain professional contracts within a fiscal year by processing and approving invoicing for payment. Assist in the development and protection of ISC water rights designated to meet the requirements of the Pecos River Decree, Carlsbad Irrigation District Settlement Agreement, and state law. Research and observe the configuration and use of water

rights to determine the potential impacts on ISC programs. Gather, compile and disseminate stream flow data through downloading of stream gage data loggers and perform field measurement of live stream flow and electrical conductivity for water quality analysis. Work with federal and state agencies related to biological opinions of endangered aquatic species in order to comply with Endangered Species Act requirements. Serve as point of contact in the Lower Pecos River are for local, state, and federal agencies providing field and technical assistance as needed. Conduct public meetings as required. Develop and implement Health and Safety Program for field operations. Coordinate training of staff and contractors to comply with OSHA 1910 and ANSI requirements. Maintain OSHA certificate as competent person for confined space entry programs as well as electrical hazard and lock out tag out certifications.

Adjunct Instructor of Biology/Geology, 06/04- Present
Eastern New Mexico University-Roswell
Responsibilities: Conduct lecture and laboratory courses in an online and on-campus setting in the subjects of Biology, Wildlife Biology, Geology, and Environmental Geology at ENMU-R. Instruction includes fall, spring and summer semesters.

Environmental Scientist/Specialist Supervisor 8/13 – 4/15
New Mexico Environment Department-Air Quality Bureau
Responsibilities: Supervise Southern NM operations staff in order to provide the NMED AQB with accurate and complete air monitoring data in accordance with Title 40 Code of Federal Regulations Parts 50 and 58. Coordinate special projects in support of NMED and AQB State and Federal initiatives. Perform the duties of an AQB operator in order to maintain a high level of data capture within the statewide ambient air monitoring network. Train operations staff in State /Federal methodologies relative to National Ambient Air Quality Standards and evaluate operations staff performance. Maintain a working knowledge of the theory of operation for Thermo 42i, 43i, and 49i continuous pollutant gas monitors, calibration equipment, and BAM1020, TEOM, and Partisol samplers.

Environmental Scientist/Specialist Operational 8/11 – 08/13
New Mexico Environment Department-Air Quality Bureau
Responsibilities: Operate, calibrate and maintain continuous pollutant gas and particulate monitors. Operate, collect filters, calibrate and maintain Partisol Plus PM 2.5 and Wedding PM 10 particulate samplers. Monitor and maintain operational status of automated data logger and calibration systems at multiple ambient air monitoring sites. Maintain multiple software and hardware systems as they relate to the continuous operation and function of ambient air quality gas and particulate monitors. Maintain an uninterrupted annual air quality sampling schedule at multiple sites in SE NM.

Probation/Parole Officer, 04/10- 8/11
New Mexico Department of Corrections
Responsibilities: Supervise caseload of 120 felony offenders. Ensure public safety by conducting arrests of said felons for violations of State Statutes and court orders, prepare court documents and testify in District and Magistrate Court.

Certified New Mexico State Police Officer, 08/09- 04/10
New Mexico State Police

Responsibilities: Conduct patrols for public safety in rural and municipal areas. General duties of a certified police officer to include enforcement of State Statutes, apprehension and arrest of criminal offenders and attend judicial/court proceedings as required.

Roswell Artesian Basin Supervisor, 3/07 – 8/09
Office of the State Engineer District II, Roswell, NM
Responsibilities: Perform duties of water resource specialist listed below. In addition to those duties, responsible for coordinating all applications for permit that pertain to the Roswell Artesian Basin consisting of 11,000 square miles in southeast NM.

Water Resource Specialist, 6/03- 8/09
Office of the State Engineer District II, Roswell, NM
Responsibilities: Administration of NMSA 1978 Chapter 72: Water Law. Assist public in research of water rights information; in addition to performing the same duties as technician. Conduct investigations into water right applications as submitted by individuals to the OSE District II for approval. Investigations include hydrogeologic analyses and review of effects on groundwater and surface sources within the jurisdiction of District II. Process all relevant documents with each water right investigation. Maintain proficiency in the use of GIS technology and associated hardware and software in hydrogeologic analyses of water right applications submitted to the OSE District II.

Water Resource Technician, 9/02- 06/03
Office of the State Engineer District II, Roswell, NM
Responsibilities: Compile and interpret water right permits and well logs; enter data into the Water Administration Technical Engineering Resource System. Research/abstract water right files, adjudication and associated maps. Work independently in an office environment with occasional fieldwork. Fieldwork includes identifying well locations using GIS and measuring well depths.

PUBLICATIONS

Burgos, J., Ellington, B.A., Varela, M.F. *Presence of Multidrug-Resistant Enteric Bacteria in Dairy Farm Topsoil.* Journal of Dairy Science. 2005 88: 1391-1398.

ABSTRACTS

Burgos, J., Ellington, B.A., Varela, M.F. (2002). *Multiple Antibiotic Resistant (MAR) Enteric Bacteria from Dairy Topsoil*. Rio Grande ASM Conference 2/02.

COMPUTER SKILLS

Flow Tracker stream gaging**,** EQuis Database, programming and operation of Sutron dataloggers, programming and operation of DanfossVariable Frequency Drives (480V, 3 phase) for groundwater well turbine pump operation. W.A.T.E.R.S., I.W.A.T.E.R.S, NMWRRS, Arc Map**,** Arc View, GPS Pathfinder, Trimble XM/XT unit, Microsoft Office Suite, Envista**,** Comet, RPCOMM, pcAnywhere,VNC-viewer,TUS BioPac; HP Infrared Spectroscopy software and associated hardware. HNMR/C^{14}NMR software and associated hardware. Foss120 infrared spectrophotometer and associated software.

Quality Assurance Project Plan

For

Ambient Air Monitoring

March 2020

State of New Mexico Environment Department

Air Quality Bureau

Quality Assurance and Ambient Air Monitoring Sections

525 Camino de los Marquez
Suite 1
Santa Fe, New Mexico 87505

(505) 476-4300

EPA Region 6 QTRAK # _____

Quality Assurance Project Plan

For Ambient Air Monitoring

Approval Signatures

New Mexico Environment Department Signatures:

Elizabeth Bisbey-Kuehn – Chief, Air Quality Bureau — Date: 2/7/20

Donna Intermont – Chief, Operations Section — Date: 02/05/2020
QA Training Certified

Andrew Ahr – Manager, Quality Assurance — Date: 2/5/2020

New Mexico Department of Health, Scientific Laboratory Division Signatures:

Phillip Adams – Chemistry Bureau Chief — Date: 1/27/2020

Allison Treloar
– Director, Office of Quality, Safety, Security
And Emergency Preparedness — Date: 28 Jan 2020

Frank See – Supervisor, Air and Heavy Metals Section — Date: 1.27.2020

Environmental Protection Agency - Region 6 Signatures

EPA Region 6 Program Officer — Date

EPA Region 6 Technical Reviewer — Date

EPA Region 6 QTRAK # _____

Quality Assurance Project Plan

For Ambient Air Monitoring

Approval Signatures

New Mexico Environment Department Signatures:

Elizabeth Bisbey-Kuehn – Chief, Air Quality Bureau — Date: 2/7/20

Donna Intermont – Chief, Operations Section — Date: 02/05/20
QA Training Certified

Andrew Ahr – Manager, Quality Assurance — Date: 2/5/2020

New Mexico Department of Health, Scientific Laboratory Division Signatures:

Phillip Adams – Chemistry Bureau Chief — Date: 1/27/2020

Allison Treloar — Date: 28 Jan 2020
– Director, Office of Quality, Safety, Security
And Emergency Preparedness

Frank See – Supervisor, Air and Heavy Metals Section — Date: 1/27/2020

Environmental Protection Agency - Region 6 Signatures

EPA Region 6 Program Officer — Date

EPA Region 6 Technical Reviewer — Date

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History of This Document

From October 2003 to October 2004, and continuing to the present with upgrades, the Air Quality Bureau (AQB) has worked on automating its ambient air and meteorological monitoring systems, and using data acquisition software ("DAS"). The automation was applied to both the operational processes at the monitoring stations and the management of ambient air and meteorological data collected at these stations.

The Ambient Air Monitoring Quality Assurance Project Plan submittal was revised in 2018 to conform with the standardized elements set forth in EPA Requirements for Quality Assurance Project Plans (EPA QA/R-5) (EPA/240/B-01-003 March 2001).

A3: Distribution List

The individuals listed below will receive copies of this approved Quality Assurance Project Plan. Supervisory staff of the Air Quality Bureau Ambient Air Monitoring Section will distribute or make available all appropriate sections of the plan to all staff responsible for implementation. The document is also available electronically to all staff within the Air Quality Bureau by its storage within the Bureau's shared file system.

Name	Position	Organization
Donna Intermont	Operations Section Chief	NMED AQB
Andrew Ahr	Staff Manager, Quality Assurance Unit	NMED AQB
Mary Hilbert	QA Data Handling Specialist	NMED AQB
Ryan Maxfield	QA Auditor	NMED AQB
Vacant	QA Auditor	NMED AQB
Roman Szkoda	Staff Manager, Ambient Air Monitoring Unit	NMED AQB
Brent Ellington	Supervisor, Ambient Air Monitoring Unit	NMED AQB
Michaela Lane-Sanchez	Supervisor, Ambient Air Monitoring Unit	NMED AQB
Phillip Adams	Chemistry Bureau Chief	NM DOH, Scientific Laboratory Division
Allison Treloar	Director, Office of Quality, Safety, Security and Emergency Preparedness	NM DOH, Scientific Laboratory Division
Frank See	Supervisor Air & Heavy Metals	NM DOH, Scientific Laboratory Division
Mariama Mitchell	Project Officer	EPA Region 6, Air, State and Tribal Operations Section

Table A3: Distribution List

A4: PROJECT/TASK ORGANIZATION

The structure of the Air Quality Bureau's Quality Assurance and Ambient Air Monitoring Units is shown in Figure A4.1 A current personnel roster for the two sections is given in Table A4.1.

A. Air Quality Bureau

The Air Quality Bureau is part of the New Mexico Environment Department's Environmental Protection Division, one of four divisions within the Department. The Bureau is composed of four major Sections: Planning, Compliance and Enforcement, Permitting and Operations. The Air Quality Bureau Chief is responsible for overseeing all activities and personnel within the Bureau. Directly reporting to the Bureau Chief are the Section Chiefs who are in charge of the four major Sections in the Bureau.

B. Operations Section

The Operations Section Chief is responsible for overseeing all activities and personnel within the Operations Section, which includes managing the operations of the administrative staff, the statewide air quality monitoring network, the quality assurance of monitoring data, the invoicing and collection of the Bureau's Permitting fees, and oversees Bureau's budgets and EPA grants.

C. Ambient Air Monitoring Unit

Upon hire and annually thereafter, all Ambient Air Monitoring staff are required to review the current Ambient Air Monitoring QAPP and Appendices, and the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance, and submit a signed statement to the Staff Manager that they have done so. This document is also available electronically to all staff within the Air Quality Bureau by its storage within the Bureau's shared file system.

Monitoring Manager: This is the program manager responsible for overseeing the work performed by the Ambient Air Monitoring Unit. In addition to working with Unit personnel to assign duties and evaluate their performance, specific duties include:

1. Manage monitoring operations so that 75% data capture and other EPA grant conditions are met.
2. Provide or delegate staff to give necessary information to QA staff to assist in evaluating monitor operations and data validation.
3. Prepare or delegate staff to assemble and update SOPs for ambient air monitoring.
4. Develop training schedules to ensure that Unit personnel are provided with up-to-date information concerning their job duties.
5. Create and maintain a monitor replacement schedule to ensure that monitoring equipment is kept technically current.
6. Work with Operations Chief and financial staff to identify resources to meet Unit priorities such as equipment purchase, supplies and contracts for sample analyses.
7. Conduct monitoring network reviews to identify trends, redundancy or special needs to recommend to Operations Section Chief.
8. Oversee special monitoring projects.

9. Prepare yearly Network Review and 5-year Network Assessments according to EPA requirements.

Environmental Scientist & Specialist - Supervisor: The Environmental Scientist & Specialist - Supervisor is responsible for the performance of automated analyzers operated by the Air Quality Bureau. Currently, there are two Supervisors for the respective north and south geographic areas of the state. Specific duties include:

1. Supervise, train, and evaluate the respective northern network site operators and southern network site operators.
2. Install and test new equipment at monitoring sites. Repair sampling equipment when necessary.
3. Set up and operate special purpose monitors as required by Department/Bureau priorities or public health emergencies.
4. Maintain an inventory of spare parts, tools, and supplies required to service continuous and non-continuous analyzers. Distribute these items to operators throughout the state as needed to maintain daily operations and achieve the greatest data capture.
5. Keep informed of data acquisition software upgrades to allow for full utilization of the product and expansion of its functionality. Share this information with site operators.
6. Provide technical information to QA staff as needed for validation of data.
7. Maintain contact with data acquisition system contractor and download data acquisition software upgrades to allow for full utilization of the product and expansion of its functionality. Share this information with site operators.

Site Operators Advanced and Operational: Site operators are based in field offices around the state to run the monitoring sites in their areas. Specific duties include:

1. Oversee operation of all analyzers and all supporting equipment at assigned monitoring sites. Each Monday morning review results of qc checks performed by calibrators on gas monitors by viewing the DAS calibration reports for one's assigned sites. Take action on invalid or out-of-range results.
2. Perform quarterly multipoint calibrations on automated analyzers and calibrators/transfer standards operated by the Air Quality Bureau.
3. Perform manual precision checks, zero/span checks on gas monitors as needed. Perform regularly scheduled flow checks and maintenance on particulate monitors. Make adjustments necessary to maintain instruments within prescribed operational limits.
4. Document in detail in the DAS site log all site visits and instrument repairs, calibrations, and adjustments performed on monitoring equipment and calibrators. This information is used for subsequent repairs and also by QA to document data gaps and monitor malfunctions.
5. Report equipment malfunctions immediately to the supervisor and Monitoring Manager for corrective action.
6. Provide assistance to the Quality Assurance staff as needed for validation of data.

7. Maintain cleanliness and order at assigned monitoring sites. Follow safety rules.
8. Perform monitor repairs as needed.
9. Assist QA Auditor in performing semi-annual audits and repairs as needed on meteorological equipment in the field.
10. Set up and operate special purpose monitors as required by Department/Bureau priorities or public health emergencies.

D. Quality Assurance Unit

Upon hire and annually thereafter, all Quality Assurance Unit staff are required to review the current Ambient Air Monitoring QAPP and Appendices, and the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance, and submit a signed statement to the QA Manager that they have done so.

QA Manager: The Quality Assurance Manager is responsible for coordinating all quality assurance activities. This position does not generate any data. In addition to working with Unit personnel to assign duties and evaluate their performance, specific duties include:

1. Write, update and obtain yearly approval for all Bureau quality assurance documents required by EPA. These documents include the Bureau's Quality Management Plan (QMP) and Quality Assurance Project Plans (QAPPs) for any projects within the Bureau that collect environmental data. For QAPPs dealing with projects outside the Ambient Monitoring Unit, the QA Manager will enlist assistance from staff members directly related to the projects, such as the Emissions Inventory Project and the Four Corners Modeling Project.
2. Write, update, and obtain yearly EPA approval for the Quality Assurance Plan for Ambient Air Monitoring. Maintain updated SOP appendices for monitoring and quality assurance activities and obtain SOPs from SLD (DOH State Laboratory Division) for filter-weighing to determine particulate deposition.
3. Ensure that quality control checks are performed on schedule and that quality control procedures are observed. Confirm that standards and reference materials required for the quality assurance program are certified on schedule.
4. Ensure that Monitor Siting Criteria Audits are conducted periodically throughout the year. Report site criteria deficiencies and provide recommendations to the Operations Section Chief and Monitoring Manager.
5. Investigate training opportunities for the Quality Assurance Unit.
6. Oversee any corrections to the ambient air data including the updating of the in-house DAS database and the EPA/AQS database.
7. Manage quality assurance to ensure that 75% data capture is met. Report instances of data loss to Operations Section Chief who reports instances of data loss to EPA Region 6 Air Quality Analysis Chief.
8. Ensure that hourly data is being submitted to EPA's AIRNOW.

9. Consult with the Operations Section Chief and the Data Handling Specialist to review and officially certify to EPA the Ambient Monitoring Data for previous year by May 1 of the following year. Official certification includes AQS AMP600 report, AMP450NC report, and an official letter sent to both Region 6 and OAQPS.

QA Auditor: The QA Auditor performs accuracy audits on ambient air monitoring instruments using independent and separate equipment and gases; performs semi-annual audits on meteorological equipment and annual audits on federal siting criteria. Specific duties include:

1. Conduct accuracy audits on ambient air pollution monitors in accordance with federal requirements and an auditing schedule that ensures that all gas monitors are audited annually and particulate monitors audited semi-annually according to EPA requirements. Monitors showing extreme problems or requiring in-depth repairs will be audited more frequently. It is NMED's intention to perform audits on instruments to be removed and on replacement instruments within a week of each action. If a problem with an instrument indicates that it needs to be replaced/repaired, then an audit shall be conducted within a week on the failing unit before it is removed and an audit within a week on the replacement instrument once it is installed.
2. Work with Monitoring Manager to evaluate and document air pollution monitoring sites to ensure that EPA guidelines are followed and federal siting criteria are met by conducting siting criteria audits annually and upon request.
3. Coordinate, schedule and perform semiannual field audits of meteorological monitoring equipment with the assistance of field operators.
4. Assist site operators in understanding and performing quality control procedures as necessary to ensure high quality data results.
5. At the time of meteorological audits, update the site Digi Modems (if applicable) modems with latest Preferred Roaming List (PRL). Also update site computer with latest version of DAS.
6. Develop, maintain, and/or update QA SOPs as needed.
7. Document in detail in the DAS site log all site visits and any operations performed on monitoring equipment or auxiliary equipment.
8. Assist Data Handling Specialist with review of questionable data.
9. Maintain all local primary standards used by the Bureau keeping them in excellent working condition.
10. Certify transfer standards on schedule.
11. Keep track of and order gas cylinders as needed.
12. Maintain records of all certifications and verifications.
13. Perform acceptance tests on new equipment.
14. Order needed replacement parts for the meteorological audits and various other items.

Data Handling Specialist: The Data Handling Specialist is responsible for processing and verifying all ambient air data generated by the Air Quality Bureau. Specific duties include:

1. Collect, review and edit continuous ambient air data through the entire process from raw data through submittal to AIRS/AQS.
2. Retrieve all non-continuous particulate data from SLD and perform calculations on blanks and particulate concentrations. Load non-continuous particulate data into the DAS database. Format and report these data to EPA/AQS.
3. Provide feedback to field operators and the Scientific Laboratory Division concerning problems or changes in data collection matters.
4. Report precision and accuracy results to EPA/AQS. Retrieve precision results from DAS calibration reports and format them through DR-DAS Reporter. Enter accuracy results on spreadsheet provided by AQS and report these results to AQS.
5. With assistance of QA Auditor, validate all meteorological data.
6. Assist the QA Manager in filling data requests and preparing reports.
7. Flag data appropriately to reflect Exceptional Events situations. See Appendix F: Exceptional Events Flow Chart.
8. Ensure that hourly data is being submitted and backfill data if a system has gone offline.

Figure A4.1: New Mexico Environment Department Air Quality Bureau (Simplified)

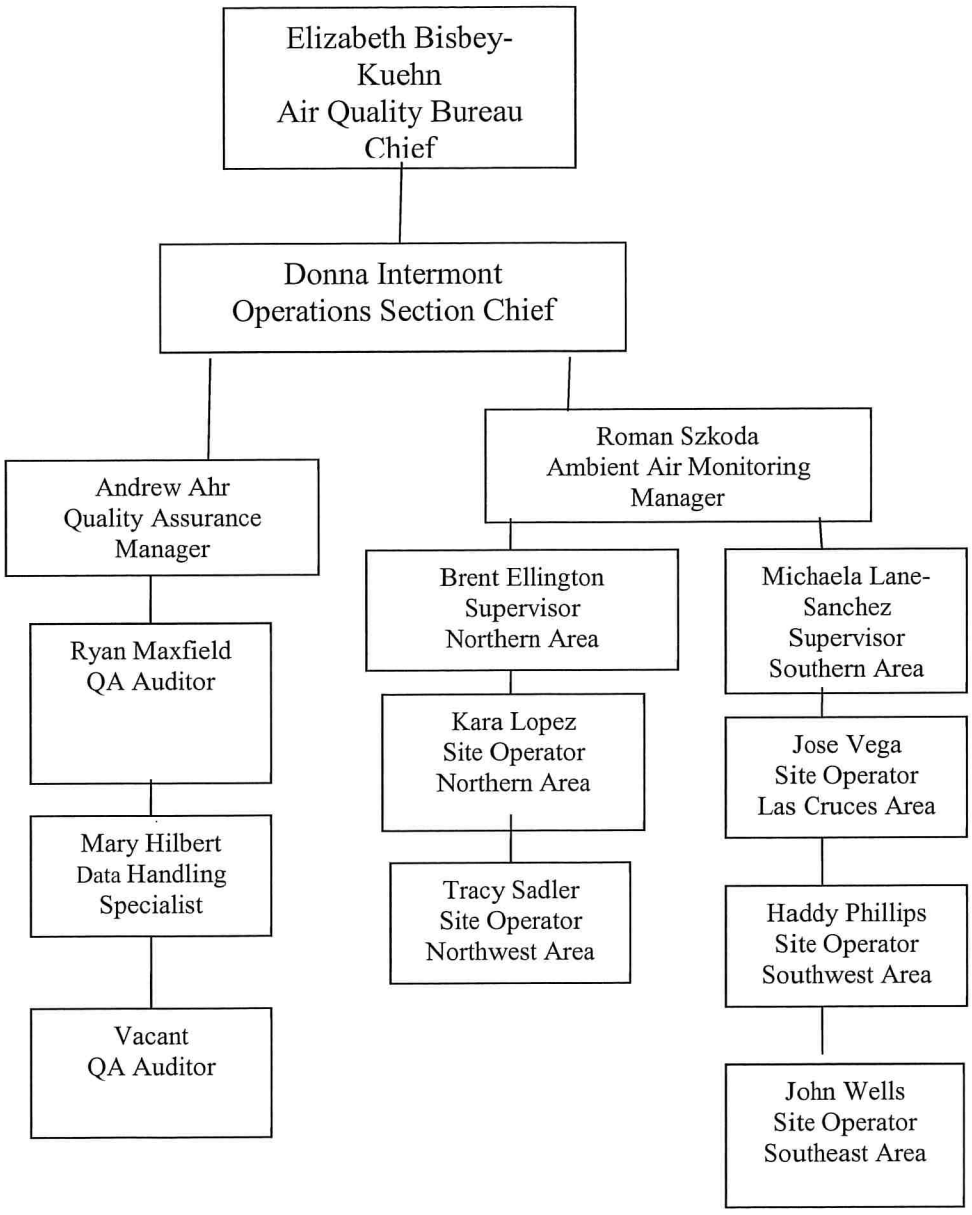


Table A4.1 - List of Persons Filling Monitoring & QA Positions

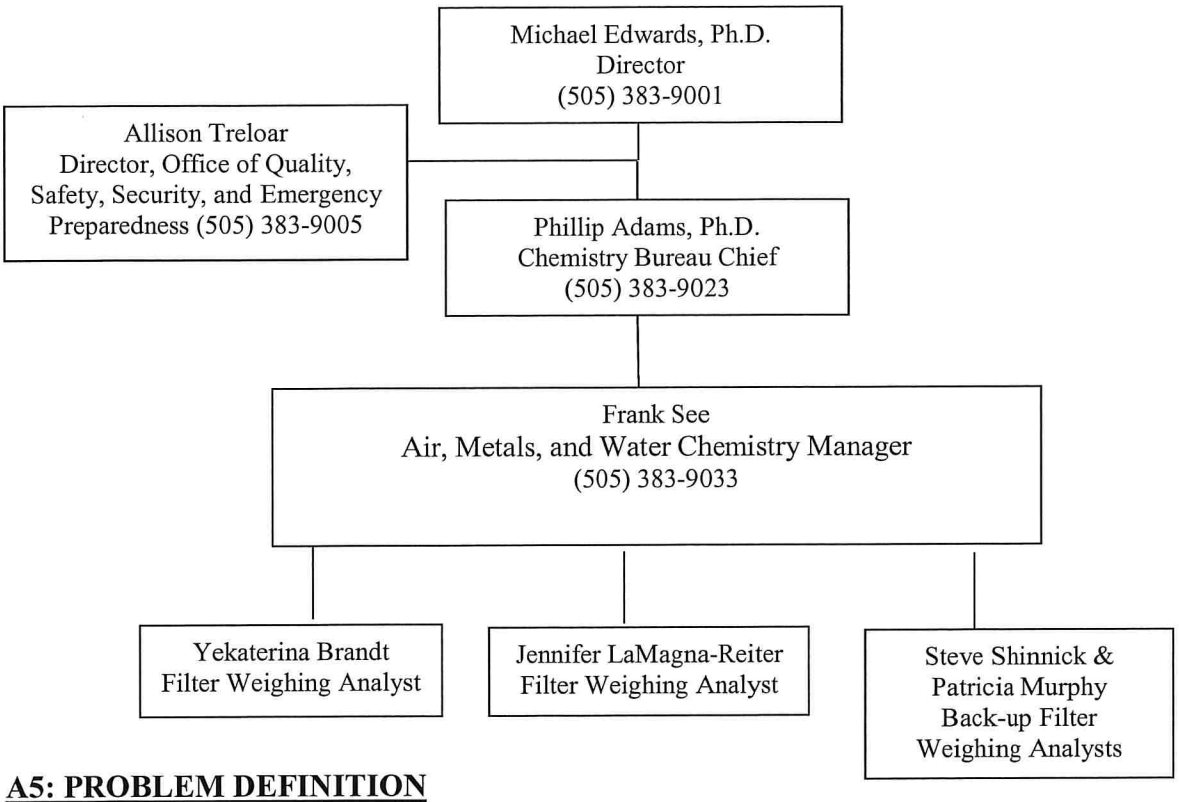
Name	Title	Section	Location	Phone Number
Donna Intermont	Section Chief	Operations	Santa Fe	505.476.4348
Roman Szkoda	Staff Manager	Monitoring	Santa Fe	505.476.4316
Brent Ellington	Supervisor	Monitoring	Santa Fe	505.827.9685
Kara Lopez	Site Operator	Monitoring	Santa Fe	505.827.0032
Tracy Sadler	Site Operator	Monitoring	Farmington	505.566.9747
Michaela Lane-Sanchez	Supervisor	Monitoring	Las Cruces	575.915.1106
Haddy Phillips	Site Operator	Monitoring	Silver City	575.388.1934
Joey Vega	Site Operator	Monitoring	Las Cruces	575.915.1085
John Wells	Site Operator	Monitoring	Roswell	575.624.6046
Andrew Ahr	Staff Manager	Quality Assurance	Santa Fe	505.476.4314
Mary Hilbert	Data Handling Specialist	Quality Assurance	Santa Fe	505.476.4320
Vacant	QA Auditor	Quality Assurance	Santa Fe	505.827.0133
Ryan Maxfield	QA Auditor	Quality Assurance	Las Cruces	575.915.1104

C. Scientific Laboratory Division Organization

The Air Quality Bureau uses the analytical services of the Chemistry Bureau of the Scientific Laboratory Division (SLD) of the New Mexico Department of Health located in Albuquerque, New Mexico. A basic organizational chart of the Scientific Laboratory Division is illustrated in Figure A4.2. The Chemistry Bureau is divided into six sections; the Air and Heavy Metals Section is the only section that provides services to the Air Quality Bureau. It prepares and weighs particulate PM_{10} and $PM_{2.5}$filters before and after sampling.

Appendix B to this QAPP contains detailed descriptions of the procedures used by SLD in weighing the particulate filters.

Figure A4.2: New Mexico Department of Health Scientific Laboratory Division (Simplified)



A5: PROBLEM DEFINITION

The Air Quality Bureau (AQB) of the New Mexico Environment Department (NMED) is responsible for collecting ambient air data to document present air quality and significant trends in pollutant concentrations. This data must be of high quality because its use may have significant health, social, and economic impacts. The data collected is used to determine the State's status with regard to compliance with National Ambient Air Quality Standards (NAAQS) designed to protect the public health and avoid secondary effects such as damage to vegetation or property, or the reduction of public values such as visibility. The AQB's public awareness programs are designed to provide current air quality information to the public.

New Mexico consists of eight Air Quality Control Regions (AQCRs) located in 33 counties covering a total area of 120,000 square miles (Figure A6.1). Three of these AQCRs are shared with surrounding states, and five are completely within New Mexico.

The NMED/AQB network consists of State and Local Air Monitoring Stations (SLAMS) and Special Purpose Monitors (SPMs). The purpose of the network is to support the National Ambient Air Quality Standards (NAAQS). It is designed to:

- determine highest concentrations expected to occur in the area covered by the network
- determine representative concentrations in areas of high population density
- determine the impact on ambient pollution levels of significant sources or source categories
- determine general background concentration levels.

Based on United States Census estimates for 2018, the population of New Mexico is about 2.09 million. Approximately 679,701, or 32.4%, of these people reside in Bernalillo County. The Albuquerque Environmental Health Department is a separate reporting agency responsible for air programs within Bernalillo County. The Air Quality Bureau is responsible for monitoring ambient air quality in all other counties of New Mexico. The three next population-dense counties within the State are Doña Ana County with 10.4% of the State's total population, Santa Fe County with 7.2% of the State's total population, and Sandoval County with 6.9% of the State's total population.

The Air Quality Bureau monitors sulfur dioxide (SO_2), nitrogen dioxide (NO_2), ozone (O_3), and particulate matter (PM_{10} and $PM_{2.5}$) in areas of New Mexico where the respective pollutants are expected to occur at significant levels, e.g. in and near cities, near coal-fired power plants, mining operations, and petroleum refineries. As designated by the US Environmental Protection Agency (EPA), the Bureau operates SLAMS. The data collected are compared to the NAAQS and the New Mexico Ambient Air Quality Standards (NMAAQS). These health-based standards were developed for protection of the general public.

Ambient air data collected by the State is submitted to the EPA for inclusion in the Air Quality System (AQS) and is used to determine compliance with state and federal air quality regulations. Also submitted to AQS are quality assurance data showing precision and accuracy comparisons, which are used for compiling statistics on data quality.

The majority of data collected by AQB is obtained continuously by automated methods. This data describes the current air quality conditions in New Mexico and is disseminated to the public. AQB's ozone and fine particulate data is also submitted automatically every hour to the EPA's AirNow program that publishes pollution maps for these pollutants. The AQB also makes pollution data available via AQB's Air Quality Index and Monitoring Data Website (http://nmaqinow.net/). Information on this site includes the concentration values and Air Quality Indices that provide a common scale for comparison and interpretation of air quality. Also included are maps and locations of the various monitoring sites.

To evaluate sites for continuation, relocation or termination, the Bureau performs an annual review of the network. The document is submitted to the EPA and the results of the review are conveyed to NMED. The Bureau considers federal requirements, federal recommendations, changes in nearby sources, changes in demographics, and expressed public interest or concern.

The five-year assessment of the ambient air monitoring network submitted to the EPA by NMED provides an opportunity to evaluate the network and the monitoring data at each location, consider emerging monitoring needs and consider changes to the network, as well as recommend special projects that would provide useful information to NMED.

A6: PROJECT/TASK DESCRIPTION

The overall purpose of the Bureau's Quality Assurance Unit is to ensure both the scientific and legal integrity of all ambient air data collected by the State. The purpose of this Quality Assurance Project Plan (QAPP) is to document the procedures of the AQB's Ambient Air Monitoring and Quality Assurance Units in obtaining quality data for this air quality monitoring project. This QAPP documents the specific responsibilities, activities and procedures employed by the Bureau. This plan complies with EPA's QA requirements (EPA QA/R-5 EPA/240/B-01/003).

All measurements reported to the EPA are considered critical and so all procedures used are approved EPA reference or equivalent methods. The specific equipment and methods are listed in Section B of this QAPP. Because of the importance of these measurements, the entire project, technical methods for monitoring, sample collection and analysis and data management are reviewed and audited on a regular basis as described in Section B5: Quality Control and Section D1: Data Review Validation, and Verification Requirements and Methods.

The monitoring described in this project plan is designed to directly support regulatory and policy decisions. As such it is considered to be a Use Category I project. The EPA, the State of New Mexico and the public are the customers for this project.

The NMED/AQB air monitoring network is comprised of eight air quality control regions (AQCRs). These regions are noted in Table A6.1 below.

New Mexico AQCR	EPA Region	Counties in AQCR	Monitors in AQCR
1	014	San Juan	1H; 1NL; 1ZB
2	152	Sandoval; Valencia	2LL; 2ZJ
3	157	Santa Fe; Taos; Rio Arriba	3SFA; 3ZD; 3CRD
4	154	San Miguel, Mora, Colfax, Union, Harding; Torrance	None
5	155	Eddy; Lea	5ZR; 5ZS
6	153	Doña Ana	6CM; 6O; 6Q; 6WM; 6ZK; 6ZL; 6ZM; 6ZN; 6ZQ
7	012	Luna	7E
8	156	Socorro, Catron, Cibola	None

Table A6.1: Air Quality Control Regions

Depending on the site, parameters monitored are ozone, sulfur dioxide, nitrogen dioxide, PM_{10}, and $PM_{2.5}$. The continuous monitoring sites also monitor meteorological data. Pertinent site information can be found in Appendix C: Network Elements Spreadsheet. Maps of these areas and their respective sites are found in Figures A6.1, A6.2 and A6.3. The public can retrieve hourly data from the continuous sites at the following site: http://nmaqinow.net/

The five-year assessment of the NMED ambient air quality network was submitted to the EPA on October 8, 2015. Appendix C: Network Element Spreadsheet contains detailed descriptions of each site, and an evaluation of the data collected at each site.

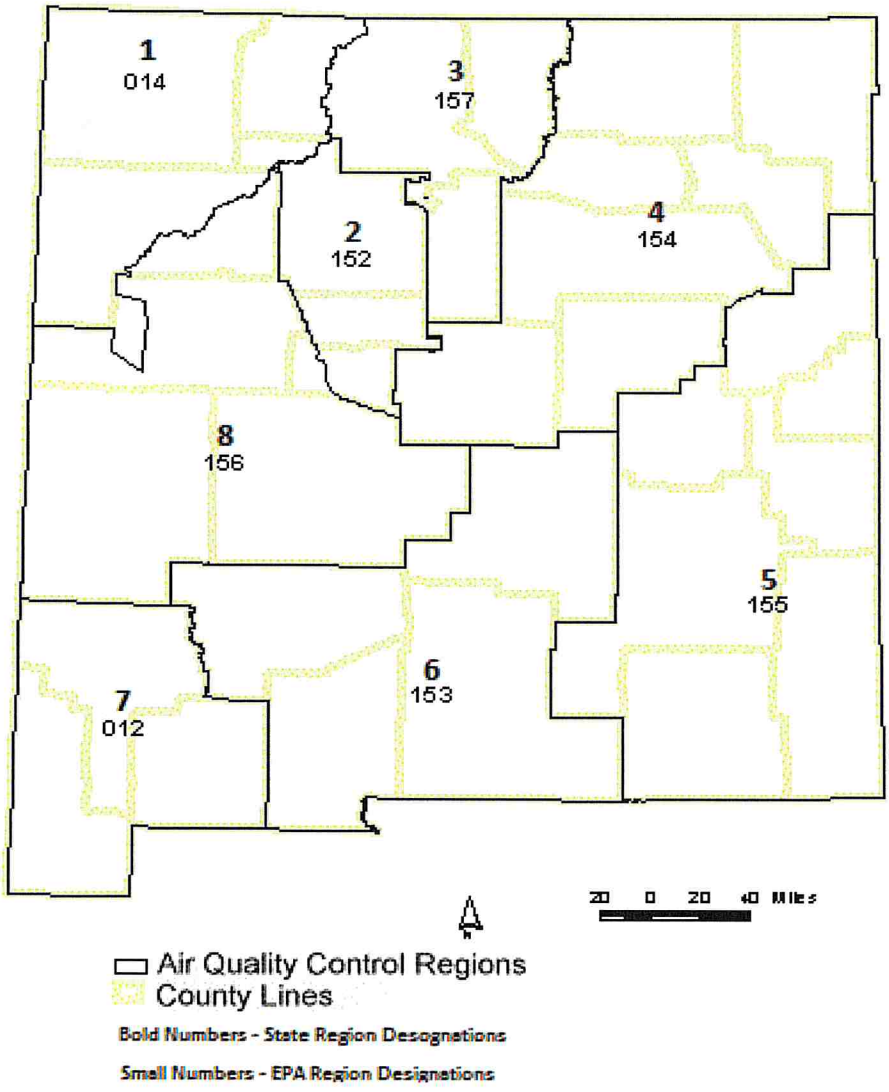


Figure A6.1: Air Quality Control Regions in New Mexico

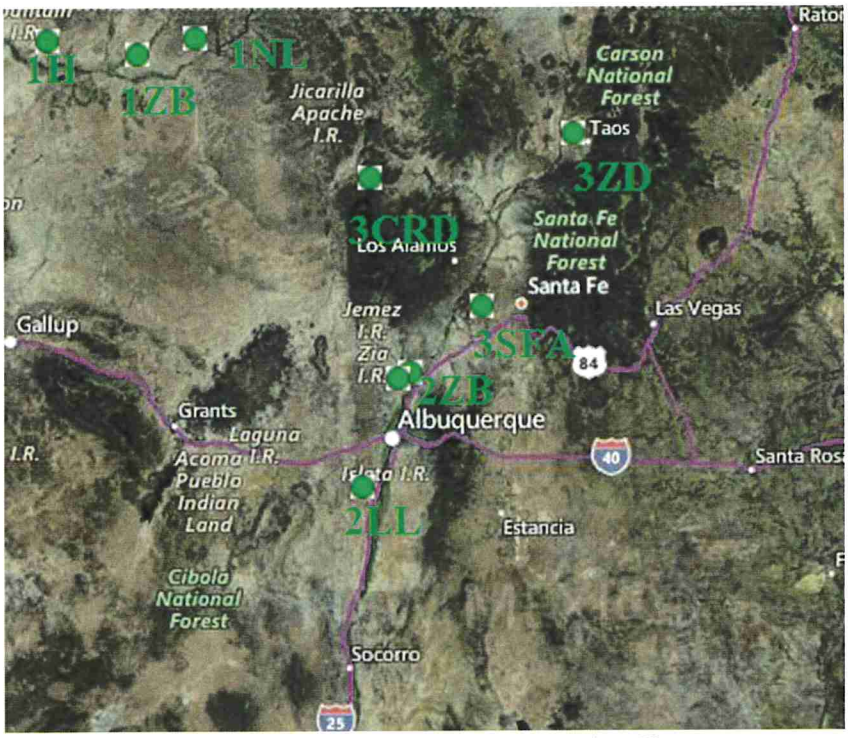


Figure A6.2: NMED Northern Sampling Sites



Figure A6.3: NMED Southern Sampling Sites

Code	Site Name	Code	Site Name	Code	Site Name
1H	San Juan Substation	3ZD	Taos Fire Station	6ZK	Chaparral
1NL	Navajo Lake	5ZR	Carlsbad	6ZL	Holman Road
1ZB	Bloomfield	5ZS	Hobbs Jefferson	6ZM	Desert View
2LL	Los Lunas	6CM	Anthony	6ZN	Santa Teresa
2ZJ	Bernalillo	6O	La Union	6ZQ	Solano Road
3CRD	Coyote Ranger District	6Q	Las Cruces ED	7E	Deming Airport
3SFA	Santa Fe Airport	6WM	West Mesa		

Table A6.2: Monitoring Site Codes

The NMED network of SLAMS and SPMs meets the six general site types put forth in 40 CFR Part 58, Appendix D 1.1.1:

a. The monitoring locations are appropriately sited to determine highest concentrations expected to occur. See Appendix C: Network Elements Spreadsheet.
b. The existing network includes monitors in the areas of high population density: Doña Ana, Santa Fe, and Sandoval Counties.
c. The monitors in the network are sited to determine the impact on ambient pollution levels of significant sources and source categories, in particular, those in San Juan County, a region of concentrated energy development and generation.
d. The network includes sites that adequately measure general background concentrations, including sites in San Juan County and the sites of Carlsbad, La Union, and Santa Teresa.
e. The current network is capturing data that enables NMED to determine the extent of regional pollutant transport among populated areas. The Navajo Lake site serves this purpose for transport between San Juan County and Southwestern Colorado. The monitoring objective of the Coyote Ranger District site is to determine regional ozone transport. The monitoring objective of the Las Cruces site is to determine regional $PM_{2.5}$ transport.
f. Data gathered from the current network of monitoring sites can be used to determine welfare-related impacts in rural and remote areas. Data from the network is being used by citizen groups in both the Four Corners Region and the Border Region of New Mexico/US and Mexico.

A7: Quality Objectives and Criteria

It is the intention of the Air Quality Bureau to provide accurate, complete, representative, and comparable air pollution monitoring data to accomplish the following specific objectives:

1. Ensure that New Mexico and Federal Air Quality Standards are met.

2. Detect sources that may cause violations of National Ambient Air Quality Standards.

3. Establish background concentrations for criteria pollutants.

4. Evaluate air pollution trends in order to project impacts and make judgments on land use planning, industrial growth, transportation planning, population growth, and to develop future Air Quality Control Regulations.

The Air Quality Bureau expects to maintain air monitoring instruments in such a manner as to attain 95% probability goals for accuracy and precision within the EPA required limits. The Air Quality Bureau adheres to the Measurement Quality Objectives and Validation Templates as published in Appendix D of the EPA QA Handbook for Air Pollution Measurement Systems, Vol. II (EPA-454/B-17-001) January 2017.

A data capture rate of over 75% is expected. Typically, AQB data capture rates are in the 90% range. For representativeness, only EPA approved methods and procedures are used to collect and evaluate ambient air monitoring data. For comparability, all parameters will be reported in standard units (e.g. $\mu g/m^3$, ppm, etc.) and EPA recommended formats.

When the Bureau detects sources that may cause exceedances of NAAQS, the QA staff review logs, meteorological data and data on the performance of the specific monitors to ensure that the data is reliable. The QA staff confers with staff in Policy and Planning. Sometimes special studies are performed to gather more information, for example, the Paso del Norte particulate monitoring study in Dona Ana County conducted in 2009.

To ensure that Federal Air Quality standards are met, the Bureau works with local and regional groups, for example, the U.S.-Mexico Border Joint Advisory Committee in Dona Ana County and the Four Corners Air Quality Task Force in San Juan County.

New Mexico has standards for ambient air quality (20.2.3. NMAC, see below, hereinafter referred to as "NMAAQS"). NMAAQS are used for air quality permitting purposes, and differ from NAAQS as follows:

- The size of total suspended particulates is not differentiated in NMAAQS as it is in NAAQS (PM_{10} and $PM_{2.5}$).
- NMAAQS has 24-hour and annual averages for sulfur dioxide, while NAAQS has 1- and 3-hour.
- NMAAQS has standards for hydrogen sulfide and total reduced sulfur, while NQAAS has none.
- NMAAQS has 8-hour and 1-hour averages for carbon monoxide as 8.7 ppm and 13.1 ppm respectively, while NAAQS are 9ppm and 35 ppm.
- NMAAQS has 24-hour and annual arithmetic averages for nitrogen dioxide as 0.10 ppm and 0.05 ppm respectively. NAAQS are 100 ppb and 53 ppb for 1-hour and 1-year averaging times.

Below is an excerpt from Title 20, "Environmental Protection", of the New Mexico Administrative Code regarding the NMAAQS.

20.2.3.108 PREAMBLE: Ambient Air Quality Standards are not intended to provide a sharp dividing line between air of satisfactory quality and air of unsatisfactory quality. They are, however, numbers which represent objectives that will preserve our air resources. It is understood that at certain times, due to unusual meteorological conditions, these standards may be exceeded for short periods of time without the addition of specific pollutants into the atmosphere. The adoption of these statewide ambient air quality standards does not prohibit the promulgation of standards for specific areas, functions, and conditions within the state such as air sheds, municipalities, and certain counties, as authorized under the Act. As scientific data accumulates on the effects of a contaminant, these standards may be revised or additional standards added.
[11/30/95; 20.2.3.108 NMAC - Rn, 20 NMAC 2.3.108 10/31/02]

20.2.3.109 TOTAL SUSPENDED PARTICULATES: The maximum allowable concentrations of total suspended particulate in the ambient air are as follows:

A. 24-hour average: 150 ug/m3;
B. 7-day average: 110 ug/m3;
C. 30-day average: 90 ug/m3;
D. Annual geometric mean: 60 ug/m3.

[11/30/95; 20.2.3.109 NMAC - Rn, 20 NMAC 2.3.109 10/31/02]

20.2.3.110 SULFUR COMPOUNDS: The maximum allowable concentrations of the following sulfur-containing air contaminants in the ambient air are as follows:

A. Sulfur Dioxide:

(1) For the state except on the area within 3.5 miles of the Chino Mines Company smelter furnace stack at Hurley:

(a) 24-hour average: 0.10 ppm;
(b) Annual arithmetic average: 0.02 ppm;

(2) For the area within 3.5 miles of the Chino Mines Company smelter furnace stack at Hurley:

(a) 24-hour average, not be exceeded more than once per year: 0.14 ppm;
(b) 3-hour average, not to be exceeded more than once per year: 0.50 ppm;
(c) Annual arithmetic average: 0.03 ppm.

B. Hydrogen Sulfide:

(1) For the state, except the Pecos-Permian Basin Intrastate Air Quality Control Region (1-hour average, not to be exceeded more than once per year): 0.010 ppm;

(2) For the Pecos-Permian Basin Intrastate Air Quality Control Region (1/2 hour average): 0.100 ppm;

(3) For within corporate limits of municipalities within the Pecos-Permian Basin Intrastate Air Quality Control Region (1/2 hour average): 0.030 ppm;

(4) For within five miles of the corporate limits of municipalities having a population of greater than twenty thousand and within the Pecos-Permian Basin Intrastate Air Quality Control Region (1/2 hour average): 0.030 ppm.

C. Total Reduced Sulfur:

(1) For the state, except the Pecos-Permian Basin Intrastate Air Quality Control Region except for hydrogen sulfide (1/2 hour average): 0.003 ppm;

(2) For the Pecos-Permian Basin Intrastate Air Quality Control Region, except for hydrogen sulfide (1/2 hour average): 0.010 ppm;

(3) For within corporate limits of municipalities within the Pecos-Permian Basin Intrastate Air Quality Control Region, except for hydrogen sulfide (1/2 hour average): 0.003 ppm;

(4) For within five miles of the corporate limits of municipalities having a population of greater than twenty thousand and within the Pecos-Permian Basin Intrastate Air Quality Control Region, except for hydrogen sulfide (1/2 hour average): 0.003 ppm.
[11/30/95; 20.2.3.110 NMAC - Rn, 20 NMAC 2.3.110 10/31/02]

20.2.3.111 OTHER AIR CONTAMINANTS: The maximum allowable concentrations of the following air contaminants in the ambient air are as follows:

A.	Carbon Monoxide:	
(1)	8-hour average:	8.7 ppm;
(2)	1-hour average:	13.1 ppm;
B.	Nitrogen Dioxide:	
(1)	24-hour average:	0.10 ppm;
(2)	Annual arithmetic average:	0.05 ppm.

A8: Special Training/Certification

All staff working with monitoring and data collection are hired through the New Mexico State Personnel Office (SPO). The SPO positions of staff involved with this project are Natural Science Manager and Environmental Scientist & Specialist (Operational, Advanced, and Supervisor). The distinguishing characteristics of the Technical Occupation Group are found in Appendix A: New Mexico Personnel Board Technical Occupation Group Descriptors for Environmental Scientists and Specialists, Including Health, which list minimum education and experience qualifications for all employees who can be considered for these positions. It is the responsibility of the State Personnel Office to screen applicants for the minimum qualifications.

In addition to the formal schooling required to obtain air quality positions, all staff are required to review and adhere to the Air Quality Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. The manual is updated as equipment is added to or removed from the network, and as procedures are refined. A list of the Standard Operating Procedures currently in the Manual is attached hereto as Appendix G.

New staff receive on-the-job training from co-workers. They are supervised in sampling, monitor audits and data collection and review until they can perform these tasks independently.

All staff may attend any applicable courses presented by EPA's Air Pollution Training Institute. They also attend conferences and workshops sponsored by the EPA, NMED, Air and Waste Management Association, WESTAR, and other groups. Vendors of equipment used by the QA and Monitors staff provide specialized training. With supervisor approval, any staff member is encouraged to take pertinent courses that are presented by local academic institutions. Computer systems training is encouraged due to the many automated procedures in use to collect, review, and report the data.

There is no special certification required for these positions; however, the Operations Section Chief and Quality Assurance Manager, who will certify the data, review and revise the QMP and QAPP, must have the proper training. The QMP and QAPP training certificates can be

found in Appendix E. New QA Manager, Andrew Ahr, will receive QMP and QAPP training in 2020.

A9: Documents and Records

All data is submitted to EPA's national database, the Air Quality System (AQS), after validation. The validation path and procedures are described more fully in Section D2. The procedures for documents and records are listed in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. The formatting for these submittals is prescribed by AQS and accomplished through the DAS Reporter software.

Details of operation of the continuous monitors and manual samplers at all of the sites are documented by the operators in the electronic logbook within the DAS application. The operator or auditor may access the electronic logbook through the site computer or remotely using a laptop. The electronic logbook is accessed through the DAS "Operational" menu option. In the "Log Book" tab, "Add" is selected to enter information, or "Report" is selected to review entries at a site for a designated time period.



Figure A9.1: DAS Menu for Entering and Reviewing Log Book Notes

The site operator can choose "Log Book - Add" and enter information in the "Generic List" box. The operator selects the appropriate instrument selection (e.g., NO2 or O3) from the drop down list, and enters his or her name, the type of visit (i.e. scheduled weekly, monthly), and details of the visit in the space provided. Log notes include dates and times of all calibrations, precision and accuracy audits as well as details of unusual operation or repair. The log notes are saved before exiting or starting a second set of log notes.

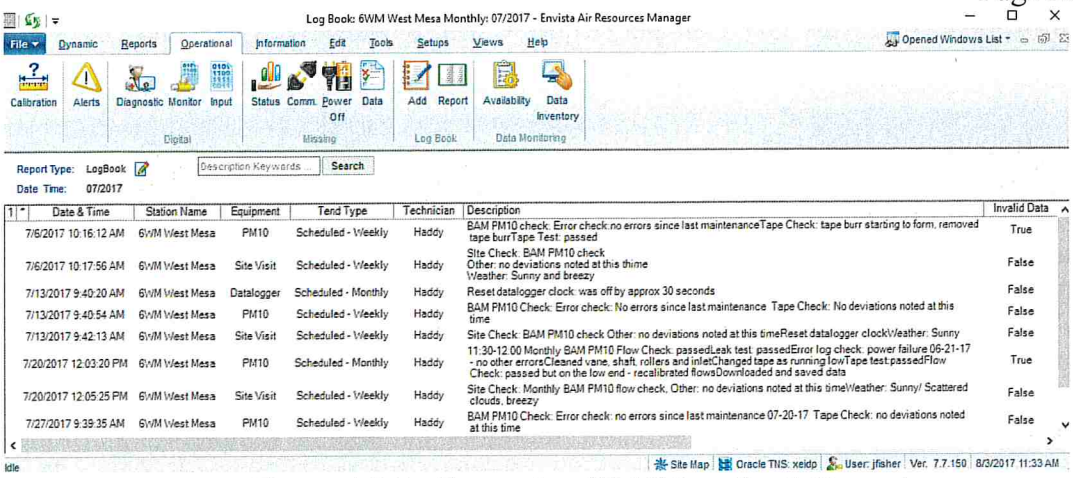


Figure A9.2: Example of DAS Log Book Report

Staff can access log book events by selecting "Report" and entering site information. Figure A9.2 shows a Report of entries made concerning a monitoring site.

The DAS maintains a record of all automatic precision and zero/span checks, referred to as qc checks, which are performed on the continuous gas monitors every Sunday. Qc check reports are used to review validity of data produced by each gas monitor. Operators may perform additional qc checks to check on a monitor at other times. These results are also maintained in the DAS.

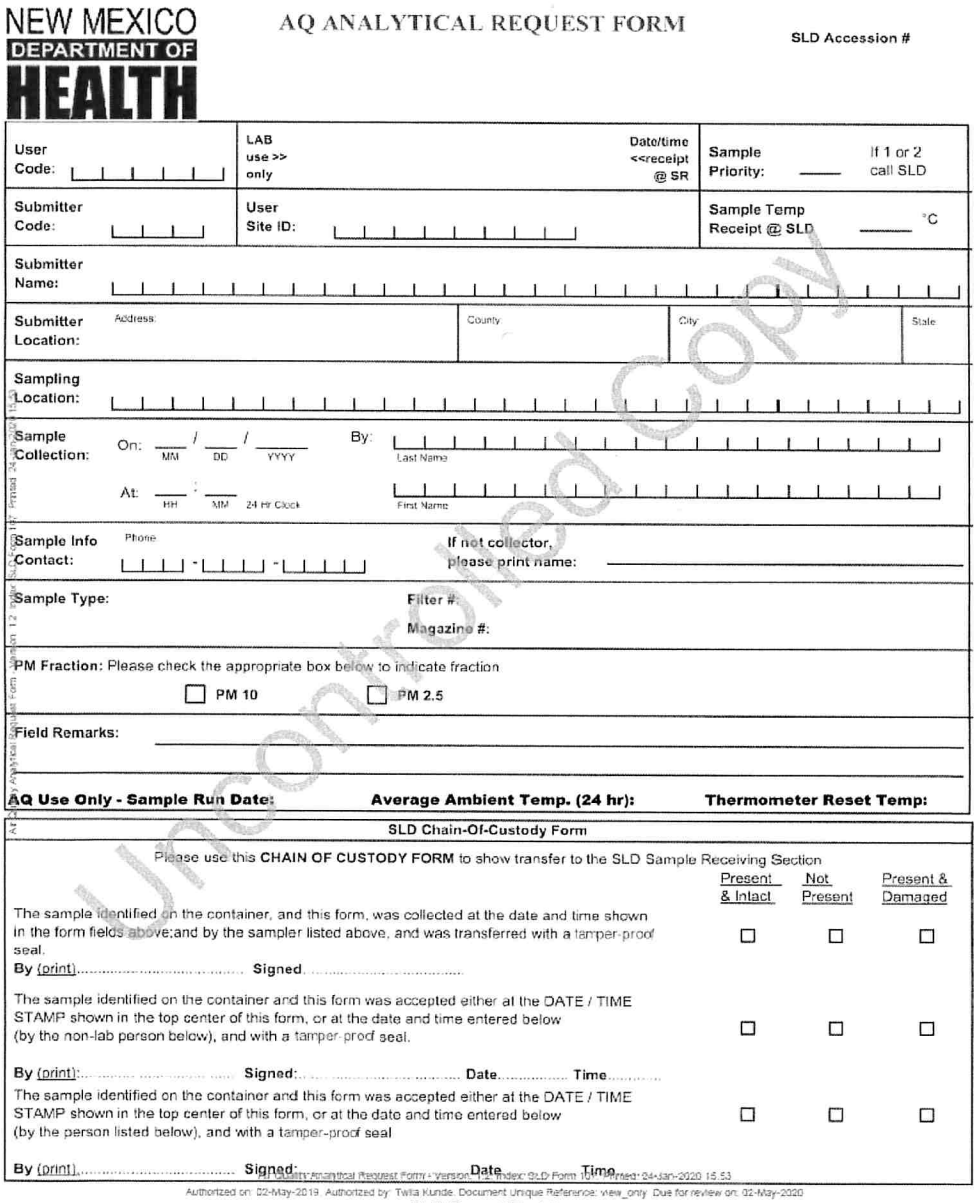
Monitor calibrations on both gaseous and particulate matter continuous monitors are performed quarterly by the site operators. The dates and times of these calibrations are noted in the electronic log. The actual concentrations are entered on an Excel spreadsheet for calculating results. QA auditors record dates, times and general results of accuracy audits in the electronic log, and use a separate Excel spreadsheet to calculate the audit results. Both the monitor calibrations and the accuracy audits made available to the Data Handling Specialist, who verifies associated data. The Data Handling Specialist enters the audit results into AQS.

Filter tapes used by the BAM-1020 particulate matter monitors are discarded after use, as there is no federal requirement to archive or retain the filter tapes from continuous FEM monitors.

For manual samplers, SLD provides an AQ Analytical Request and Chain of Custody Form (see Figure A9.3) for each filter sent to the site operator for the specific manual sampling equipment. User Code 55600 indicates a PM_{10} sample filter, and Use Code 55625 indicates a PM2.5 sample filter. Submitter Code 304 identifies NMED-AQB. The User Site ID, the Alpha-Numeric code assigned to the monitoring location, is also entered by SLD.

After the filters have collected the particulate samples, original field records are annotated by the site operators with the sample collection time and priority. In the Sample Priority section, operators enter "3" to indicate a normal priority. The Field Remarks section is used by the site

operator to note any voided filters due to equipment issues or power failures, conditions at the site, or problems such as flows or temperatures. This is important information that after analysis may deem a sample filter as void per determination by the SLD, Data Handling Specialist or QA Manager. The field records are sent to the SLD as hard-copy forms along with the exposed filters. Copies of the completed Chain of Custody forms are sent to the QA Manager by SLD monthly. The QA Manager reviews the forms for notations regarding the filters that may warrant further review by the Data Handling Specialist or QA Manager. This Standard Operating Procedure for Chain of Custody Forms is in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.



NEW MEXICO DEPARTMENT OF HEALTH

AQ ANALYTICAL REQUEST FORM

SLD Accession #

User Code:	LAB use >> only — Date/time <<receipt @ SR	Sample Priority: ____ If 1 or 2 call SLD
Submitter Code:	User Site ID:	Sample Temp Receipt @ SLD ____ °C
Submitter Name:		
Submitter Location:	Address: / County / City / State	
Sampling Location:		
Sample Collection:	On: ___ / ___ / ___ (MM / DD / YYYY) By: (Last Name / First Name)	
	At: ___ : ___ (HH / MM 24 Hr Clock)	
Sample Info Contact:	Phone: ___ - ___ - ____	If not collector, please print name: ____
Sample Type:	Filter #: / Magazine #:	

PM Fraction: Please check the appropriate box below to indicate fraction

☐ PM 10 ☐ PM 2.5

Field Remarks: ____

AQ Use Only - Sample Run Date: Average Ambient Temp. (24 hr): Thermometer Reset Temp:

SLD Chain-Of-Custody Form

Please use this CHAIN OF CUSTODY FORM to show transfer to the SLD Sample Receiving Section

	Present & Intact	Not Present	Present & Damaged
The sample identified on the container, and this form, was collected at the date and time shown in the form fields above;and by the sampler listed above, and was transferred with a tamper-proof seal. By (print)..... Signed.....	☐	☐	☐
The sample identified on the container and this form was accepted either at the DATE / TIME STAMP shown in the top center of this form, or at the date and time entered below (by the non-lab person below), and with a tamper-proof seal. By (print):..... Signed:..... Date..... Time.....	☐	☐	☐
The sample identified on the container and this form was accepted either at the DATE / TIME STAMP shown in the top center of this form, or at the date and time entered below (by the person listed below), and with a tamper-proof seal. By (print)..... Signed:..... Date..... Time.....	☐	☐	☐

Air Quality Analytical Request Form - Version 1.2, Index: SLD Form 107, Printed: 24-Jan-2020 16:53

Authorized on: 02-May-2019. Authorized by: Twila Kunde. Document Unique Reference: view_only. Due for review on: 02-May-2020

SLD Form 107 v1.2

Uncontrolled Copy

Figure A9.3: AQ Analytical Request and Chain of Custody Form

The SLD maintains data in a secure LabWare LIMS data base, and extracts data in crystal reports from the LIMS and exports them to a spreadsheet for AQB's use. AQB's Data Handling Specialist employs a macro that brings the SLD's initial and final weights into AQB's Excel spreadsheet for the calculation of particulate concentrations. The results are uploaded from Excel to the main DAS database.

After weighing, the 47-mm filters are archived at SLD. In accordance with 40 CFR 58.16(f), SLD archives all sample filters in the laboratory for a minimum of five years. The archiving period includes cold storage of the filters after post-sampling laboratory analyses for at least twelve months.

AQB's main DAS database contains monitoring data as well as electronic logbook and qc check data for access, review and retention. Ten years of data are retained in the DAS database.

B Data Generation and Acquisition

B1: Sampling Process Design

The monitoring performed in this project is to determine ambient concentrations of criteria air pollutants. These air pollutants have been determined to be injurious to the health and welfare of the public, and ambient standards have been established on the state and federal levels. The National and New Mexico Ambient Air Quality Standards have been developed to protect the public from excessive exposure. The design of the project follows strict federal guidance as found in 40 CFR Part 58 and the *Quality Assurance Handbook for Air Pollution Measurement Systems Volume II: Ambient Air Quality Monitoring Program* (EPA-454/B-17-001) ("QA Handbook").

Data from the monitors in the AQB network are used to determine attainment status defined in the Federal Clean Air Act. Because of the importance of the results of the monitoring, only EPA Reference and Equivalent Methods are reported to AQS. Sampling time intervals, 1-hour for continuous monitors and 24-hour for non-continuous monitors, are used to generate data that relate to the time period of the applicable standards.

Note: Values for ambient air quality standards are collected to the decimal precision in which the standard is promulgated plus one decimal place. Measurement values are truncated to the level of precision of the standard for reporting purposes.

The network has been designed to monitor suspected pollutants in areas where they may be reasonably expected to occur at relatively high levels. Financial and logistical constraints may limit the number of actual locations. The Air Quality Bureau prefers to locate monitors on public properties in order to assure continued permission to operate. New monitoring sites are established in several stages: identifying a possible air quality problem or responding to public concern, finding and evaluating potential sampling sites, and selecting the best site. Among the criteria used to select sites are monitoring objectives, location of the highest expected concentration, and the availability of power, space, and security specified in 40 CFR Part 58, Appendix D, the siting regulations set forth in 40 CFR Part 58, Appendix E, and relevant EPA guidance. The Ambient Air Monitoring Program Manager collaborates with other Operations Section staff, the Operations Section Chief and the Air Quality Bureau Chief to determine locations of new monitoring sites when needed.

All procedures are described in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance and are based on guidelines obtained from EPA, including the QA Handbook.

All automated instruments are housed in clean, insulated, and air-conditioned shelters. All manual analyzers are inherently weatherproof.

B2: Sampling Methods

To ensure that air quality measurements are made with methods proven to be accurate and reliable, only EPA reference or equivalent methods for collection and analysis are used. Criteria used to select monitoring instruments are price, noise, drift, linearity, accuracy and long-term reliability. All equipment is prepared in accordance with manufacturer's instructions. The continuous monitors analyze samples immediately so there is no relevant sample preservation or custody issues. For non-continuous monitors, the sampling methods are discussed in the in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. Table B2 below lists the current monitoring instrumentation employed in this network and the respective sampling methods utilized.

Pollutant	Manufacturer	Model	Principle	EPA Method Code	Method Type
SO2	Thermo Fisher	43i	Pulsed Fluorescence	060	FEM
SO2	Thermo Fisher	43i	Pulsed Fluorescence	009	FEM
NO2	Thermo Fisher	42i	Chemiluminescence	074	FRM
O3	Thermo Fisher	49i	UV Photometry	047	FEM
PM_{10}	Thermo Fisher Partisol	2025i	Low Volume, Size Selective Inlet	127	FRM
PM_{10}	MET One BAM	1020	Beta Attenuation	122	FEM
$PM_{2.5}$	Thermo Fisher Partisol	2025i	Low Volume, Size Selective Inlet	145	FRM
$PM_{2.5}$	MET One BAM	1020	Beta Attenuation	170	FEM

Table B2: Current Monitoring Instrumentation and EPA Methods

B3: Sample Handling and Custody

Continuous Monitors (Electronic Data)

The software for data acquisition and control ("DAS") is installed on a PC set up at each station except stations with only meteorological sensors. The DAS communicates over serial communications lines to obtain data. A Moxa 4 or 8 serial port PCI expansion card is added to each PC to expand the total serial port count on the PC to 6 or 10 as needed. DAS units communicate serially with the existing Campbell Scientific data loggers at the station.

Meteorological sensor signals and analog outputs from analyzers are connected to the Campbell units. For newer analyzers with their own serial ports the DAS will interface serially to obtain data and diagnostics. Elimination of digital-to-analog and analog-to digital circuits with serial communications improves the quality of the measurements by reducing signal conversion errors.

Campbell Scientific CR1000 data loggers are installed at each site where continuous monitors are employed and maintain their own local data storage buffers.

Each DAS data logger in the system is programmed to record sensor inputs from the Campbell data loggers every second and process each signal to form 5, 15, and 60-minute averages. Serial interfaces to analyzers are programmed to sample the analyzer every 15 seconds.

The DAS offers comprehensive in-station support and communications options. All configuration and remote access functions are password-protected. Analyzer status conditions are monitored and the data flagged if the analyzer is reporting a fault. In-station and central location reports allow review of all analyzer status changes. Manual flagging of data can also be performed. Operators can toggle data channels to OFF, and OFF SCAN modes. OFF SCAN continues to report the data values but flags the data. OFF channels do not report values. If a monitor is removed from the station the channel is set to OFF. For maintenance and other quality checks not otherwise tracked by the system the channel is set to OFF SCAN. If the operator were to accidentally fail to return the channel to ON the data can always be recovered by just editing the status flag. Remote access via modem to the station PC allows an oversight such as this to be quickly corrected.

The DAS interfaces serially to the on-site calibrator. The calibrators may be controlled serially or via digital control lines. Calibration control sequences can flag data with zero, span and 5 other span level flags corresponding to the desired dilution levels.

The station data is collected hourly from all stations. Polling PCs running the CommServ communications program are located in Santa Fe. The DAS data loggers hold 10 years of historical data with automatic data recovery in the event communications with a site is interrupted for a period. An operator can also copy data sets to files for upload to the central database by QA staff.

The data collection process writes the data for all the stations to the Department's Oracle Server. Data values and status as initially collected and as edited are stored in separate data tables for each station. These are referred to as the Raw and Standard data tables. The DAS data logger collects and stores the results of automated Zero, Span, and Precision Checks as well as station faults.

Manual Monitors (Filter Based)

Site operators collect filters from non-continuous particulate samplers in the field on a 3-day schedule for $PM_{2.5}$ and a 6-day schedule for PM_{10}. The actual days in the schedules are prescribed by EPA and uniform across the country, so that measurements may be comparable across regions. Special schedules such as every-day sampling may be put into place for problematic areas.

The New Mexico State Scientific Laboratory Division (SLD) provides an AQ Analytical Request and Chain of Custody Form (see Figure A9.3) for each filter sent to the site operator for

the specific manual sampling equipment. User Code 55600 indicates a PM_{10} sample filter, and User Code 55625 indicates a $PM_{2.5}$ sample filter. Submitter Code 304 identifies NMED-AQB. The User Site ID, the Alpha-Numeric code assigned to the monitoring location, is also entered by SLD. In the Sample Priority section, operators enter "3" to indicate a normal priority.

After the filters have collected the particulate samples, original field records are annotated by the site operators with the sample collection time and priority. The Field Remarks section is used by the site operator to note any voided filters due to equipment issues or power failures, conditions at the site, or problems such as flows or temperatures. This is important information that after analysis may deem a sample filter as void per determination by the SLD, Data Handling Specialist or QA Manager.

The field records are sent to the SLD as hard-copy forms along with the exposed filters. in suitable shipping containers via United Parcel Service. The filters are weighed at the SLD to determine particulate concentrations.

Copies of the completed Chain of Custody forms are sent to the QA Manager by SLD monthly. The QA Manager reviews the forms for notations regarding the filters that may warrant further review by the Data Handling Specialist or QA Manager. The Standard Operating Procedure for Chain of Custody Forms is in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

B4: Analytical Methods

The analytical methods employed by the ambient air monitors used in this project may be found in Table B.2: Current Monitoring Instrumentation and EPA Methods.

B5: Quality Control

A. Automated Gas Analyzers

Weekly zero/span/precision checks, referred to by the Air Quality Bureau as qc checks, are performed by the in-station data logger and calibration systems. At stations with other gas analyzer combinations, a gas dilution calibrator and zero air supply are used in conjunction with the station data logger to conduct the qc checks. Except for Ozone, the equipment used for these checks is the same equipment as used for calibrations. Qc check results are available in tabular form as a report from the DAS. The Air Quality Bureau evaluates the results of the qc checks as part of the data validation process. Results for precision points are reported to EPA through AQS, where they are used to calculate precision statistics.

The operators perform unscheduled, confirmatory zero/span/precision checks whenever the results of a scheduled zero/span/precision check exceed the thresholds as set forth in Table B5.

QC Check Measurement	Adjust Monitor if Value is greater than:
Zero Drift	± 2 ppb
Span Drift	± 5% of actual span concentration
Precision Point	± 5% of actual precision concentration

Table B5: AQB QC Check Thresholds Requiring Adjustment

Appendix D of the EPA QA Handbook includes precision and zero and span drift criteria for analyzer adjustments, recalibrations and data invalidation. The Air Quality Bureau follows this guidance.

Monitors are adjusted and a subsequent zero/span check is run after any minor maintenance that might affect the calibration. These zero/span checks are initiated on demand from the automated station data logger, and may also be initiated remotely.

B. Continuous Particulate Monitors (BAM 1020s)

Site operators perform monthly precision flow checks on these monitors using Alicat mass flow meters. Per the manufacturer's recommendation as well as seasonal changes, the site operator performs a BAM 1020 quarterly check to ensure proper flow and operating parameters, such as temperature and pressure. The check performed in the second quarter is recorded as the annual check to conform with the QA Handbook requirements. The results of these precision checks are to determine the quality of monitor operation, and are uploaded to the AQS database.

The QA auditor performs semi-annual accuracy audits on these monitors, auditing the flow, temperature and pressure using instruments dedicated to QA.

C. Manual Particulate Analyzers (Partisols)

Operators perform monthly checks on these instruments. A monthly check consists of a flow audit against a mass flow meter, leak checks, verification of the ambient temperature, filter temperature, filter compartment temperature, and pressure. Annual multi-point flow, temperature and pressure calibrations are also performed, in accordance with the QA Handbook. The results of these precision checks are to determine the quality of monitor operation, and are uploaded to the AQS database.

The QA auditor performs semi-annual accuracy audits on these monitors, auditing the flow, temperature and pressure with instruments dedicated to QA.

D. Corrective Action

When a problem is identified, either during a precision check, accuracy audit, or daily observation of data, the Site Operator is usually the first in line to attempt analysis of the problem. Upon initial failure of any one-point flow or temperature verification failure, Site Operators are directed to trouble shoot and recheck the equipment before calibrating in order to minimize the number of calibrations.

When further information is needed, the Instrumentation Specialist, QA Auditor, or manufacturer might be consulted, and the site operator can review previously completed Corrective Action Reports (CARs) on same or similar instruments as a learning devise. The completed CARs can be accessed by the Site Operators and/or QA Auditors in a common folder. The QA Auditors always inform the Site Operator, Instrumentation Specialist, and Monitoring Manager of any problems found. The QA Manager and Data Handling Specialist review problems resulting in data falling outside of acceptance criteria as set forth in the QA Handbook Volume II, Appendix D to decide whether it is appropriate to invalidate or qualify accompanying data. If deletion of data is necessary due to a problem that falls outside of our routine procedures and preventative maintenance schedules, a CAR will be completed. CARs are generally not used unless the problem resulted in data invalidation or qualification greater than 120 hours. The procedure for Corrective Action Reports is fully outlined in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

Quality assurance statistics are calculated both in-house and in the AQS database and are relied upon for performance determinations.

B6: Instrument/Equipment Testing, Inspection and Maintenance

All analyzers in the field are inspected on the routine site visits by site operators and before their quarterly calibrations. Additionally, the Data Handling Specialist will notify the Site Operator or Environmental Specialist Supervisor in the event of suspicious monitor output. The Site Operators test, adjust and clean monitors as a part of the calibration procedure.

The purpose of preventive maintenance is to increase system reliability, increase data completeness, and minimize analyzer down time. Spare parts inventory of the items most likely to fail are maintained for all analyzers and support equipment. Preventive maintenance procedures and frequencies correspond to those recommended by each instrument manufacturer. All routine preventive maintenance is performed at each individual monitoring site and takes place quarterly unless a prior problem is detected. Maintenance for manual analyzers takes place as needed. All Scientific Laboratory Division instruments used for analysis are on a maintenance contract, which includes both corrective and preventive maintenance.

Details of maintenance requirements and procedures for each type of equipment may be found in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

It is Bureau policy to have one backup monitor of each type available at all times in case of monitor failure. This obviates the necessity of maintaining a large inventory of spare parts.

AQB site operators use the DAS software program's electronic log book to record air monitoring operations. The electronic log book is used to document maintenance, calibrations, and repair of equipment. The electronic log book entries are available for viewing by all Monitoring or QA staff members on the DAS reports.

B7: Instrument/Equipment Calibration and Frequency

All calibrations are performed following the procedures and acceptance criteria of the EPA *QA Handbook for Air Pollution Measurement Systems, Vol. II (EPA-454/B-17-001)* ("QA Handbook").

A. Monitoring Equipment

Continuous Gas Monitors

Calibrations are performed on continuous gas monitors quarterly and following major repairs. A calibration is defined as the introduction of reference concentrations to a monitor and comparison with the response of the monitor to determine if the monitor response is linear. Calibration may involve adjustment as necessary to achieve linearity. A calibration sequence includes a zero, span and four additional reference concentrations.

During calibration, the analyzer is operated in the normal sampling mode. Test gases pass through all filters, scrubbers, conditioners, and other components of the normal sampling system.

A gas monitor is considered linear if the concentration response of all points is < + 2.1 % or < +1.5 ppb difference of best-fit straight line whichever is greater and Slope 1 + .05, per QA Handbook Volume II, Appendix D.

In accordance with the QA Handbook Appendix D, acceptance criteria for the certification/verification of a transfer standard is the relative standard deviation (RSD) of six slopes ≤ 3.7%; and standard deviation of 6 intercepts ≤ 1.5. In accordance with the QA Handbook Volume II, Appendix D, acceptance criteria for the recertification/reverification of a transfer standard is that the new slope is within ± 0.05 of the previous; and the relative standard deviation of six slopes ≤ 3.7%; and standard deviation of 6 intercepts ≤ 1.5.

Calibration equipment used for continuous monitors consists of API and Thermo Fisher brand gas dilution calibrators and ozone transfer standards permanently installed at each site. The performance of the calibration is coordinated through the station DAS data logger. The following methods are used for station calibrations:

Pollutant	Method
SO_2	Dynamic dilution of a gas standard (NIST traceable SO2 or SO2/NO blended gas)
NO_2	Gas-phase titration of NO and O3(NIST traceable NO or SO2/NO blended gas)
O_3	Ultraviolet photometry using either the station calibrator or a separate O_3 transfer standard

Table B7.1: List of Field Calibration Methods

Particulate Monitors

Calibrations are performed on continuous particulate monitors at least twice a year and following major repairs.

Calibrations of non-continuous particulate monitors are performed at least yearly or after any maintenance that could affect flow rate, or after the results of a flow rate check indicate a difference greater than ±4.1% between sampler calibrations as specified in the QA Handbook Volume II and the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. Quality Assurance Auditors conduct independent audits on a semiannual basis.

Details on calibrations of each type of particulate sampler are in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

B. Verification of Audit Equipment and Station Calibration Equipment

Equipment used to conduct accuracy audits and calibrations is subject to verification requirements. Accuracy audit equipment is generically referred to as transfer standards. These are verified on a fixed schedule against local primary standards. The transfer standards used by the Bureau are given in Table B7.2 along with verification intervals and superior standards against which they are verified. Acceptance ranges for all transfer standards conform with the QA Handbook or, if not specified in the QA Handbook, the recommendation of the transfer standard's manufacturer.

Standard	Parameter	Interval	Verified Against
Thermo Fisher 49iPS (Level 2)	O_3	1 year	EPA's Transfer Standard
Thermo Fisher 49iPS (Level 3)	O_3	6 months	Thermo Fisher 49iPS (Level 2)

Thermo Fisher 49iQPS (Level 3)	O_3	6 months	Thermo Fisher 49iPS (Level 2)
API T703/703E	O_3	6 months	Thermo Fisher 49iPS
API T700 Photometer	O_3	Quarterly	Thermo Fisher 49iPS and 49iQPS
API T700 Gas Calibrator	Gas flows	Quarterly	Alicat Flow Meter
Thermo Fisher 146i Calibrator	Gas flows	Quarterly	Alicat Flow Meter
Thermo Fisher 146iQ Calibrator	Gas flows	Quarterly	Alicat Flow Meter
Alicat Flow Meter	Gas and air flows	1 year	Fluke Calibration molbloc-L and molbox+1
Fluke Calibration molbloc and molbox (NIST traceable)	Gas and air flows	1 year	Fluke Calibration
Druck DPI 800	Pressure	1 year	Fluke Calibration molbloc-L and molbox+1
Digi-Sense ThermistorThermometer, NIST-Traceable Calibration	Temperature	1 year	Fluke Temperature Calibration Bath
Fluke Temperature Calibration Bath (NIST-Traceable(	Thermistor Thermometer	1 year	Fluke Calibration

Table B7.2: Transfer Standards

When necessary, gas cylinders are verified according to procedures outlined in EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (EPA-600/R93/224, Revised September 1993). However, this is not done as standard practice. Cylinders that are out of certification are returned to vendor for re-certification or replacement.

Verification audit procedures are detailed in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

C. Scientific Laboratory Division

Particulate filter weighing is done at the Scientific Laboratory Division (SLD) in Albuquerque. The procedures followed by the SLD are detailed in Appendix B.

B8: Inspection/Acceptance of Supplies and Consumables

Filters, analyzers, calibration gases and monitoring equipment are ordered in accordance with State purchasing rules with exact specifications relating to minimum performance, quality, and acceptable tolerances. The QA Auditor assigned to the QA Lab and the Monitoring Unit Staff Manager order and receive the supplies. Included in the monitoring supplies ordered by AQB are filters for Met One BAM particulate monitors. Filter tapes for the BAM-1020 samplers are of the glass fiber type and used for both PM_{10} and $PM_{2.5}$ monitoring. The BAM-1020 does not contain filters that require pre-weighing by a laboratory since the particulate is indirectly weighed within the monitor. The procedures for inspection and acceptance of supplies and consumables are detailed in are in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

Filters for non-continuous particulate measurements are provided by EPA. EPA provides 47mm Teflon filters for Partisols, which are used for both PM_{10} and $PM_{2.5}$ monitoring. The Teflon filters undergo acceptance inspections regarding consistent thickness and weight at EPA's RTP laboratories, and are sent to the New Mexico Health Department Scientific Laboratory Division (SLD). There, a laboratory staff member checks in the filters, visually inspects them, and weighs each filter using procedures set forth in Appendix B: Gravimetric Analysis of 47mm Air Filters – AHM Method 41710.

Calibration gases purchased by the Bureau are certified by the vendor and are NIST-traceable. The QA Auditor assigned to the QA Lab distributes cylinder gases to monitoring sites in the most efficient manner in order not to have gases existing in the cylinder longer than the period of valid certification. In cases where the period of certification has expired and a substantial amount of gas is still in the cylinder, the cylinders may be returned to the manufacturer for a re-certification of the gas.

When new analyzers are received, they are unpacked and checked for loose fittings, loose electrical connections, and damage during shipment. The instruments are then assembled and acceptance-tested by the QA Auditor assigned to the QA Lab and Monitoring Staff Manager before use at a monitoring site.

C Assessment and Oversight

C1: Assessments and Response Actions

A. Internal Audits

1. Continuous Monitors

Quality Assurance Auditors perform accuracy audits using a calibrator and transfer standard reserved for exclusive QA use. 40 CFR Part 58, Appendix A 3.1.2.1(a), identifies ten audit levels for each gaseous pollutant:

"3.1.2.1 The evaluation is made by challenging the monitor with audit gas standards of known concentration from at least three audit levels. One point must be within two to three times the method detection limit of the instruments within the PQAOs network, the second point will be less than or equal to the 99th percentile of the data at the site or the network of sites in the PQAO or the next highest audit concentration level. The third point can be around the primary NAAQS or the highest 3-year concentration at the site or the network of sites in the PQAO. An additional 4th level is encouraged for those agencies that would like to confirm the monitors' linearity at the higher end of the operational range. ..."

Accuracy audits on gas monitors are performed by challenging each analyzer with known concentration from the selected ranges as listed in Table C1. The analyzer's response is observed using either the station's DAS data logger or directly reading from the monitor.

Audit level	O3 Range, ppm	Range Selected	SO2 Range, ppm	Range Selected	NO2 Range, ppm	Range Selected
Zero						
1	0.004-0.0059		0.00030-0.0029	X	0.0003-0.0029	
2	0.006-0.019	X	0.0030-0.0049		0.0030-0.0049	X
3	0.020-0.039	X	0.0050-0.0079	X	0.0050-0.0079	X
4	0.040-0.069	X	0.0080-0.0199	X	0.0080-0.0199	X
5	0.070-0.089	X	0.0200-0.0499	X	0.0200-0.0499	X
6	0.090-0.119	X	0.0500-0.0999	X	0.0500-0.0999	X
7	0.120-0.139	X	0.1000-0.1499		0.1000-0.2999	X
8	0.140-.0169		0.1500-0.2599		0.3000-0.4999	
9	0.170-0.189		0.2600-0.7999		0.5000-0.7999	
10	0.190-0.259		0.8000-1.000		0.8000-1.000	

Table C1 - Concentration Ranges for Accuracy Audits in PPM

Audits are performed on one-fourth of the gaseous analyzers for each gaseous criteria pollutant each quarter, or at a minimum at least once per year.

The results of these audits are used to identify problems or inconsistencies within the monitoring network. If a certain monitor has significantly different responses to the auditing equipment of the Quality Assurance Auditor and the Site Operator, it points to either monitor malfunction or a possible problem with the calibration of auditing equipment or standards. The auditor or operator notifies the Environment Scientist & Specialist - Supervisor and or Monitoring Operator responsible for the site to discuss additional investigation, re-calibrations or other appropriate actions.

The QA Auditors perform semiannual audits concerning flow, temperature, and pressure on the BAM analyzers. Only the flow audit, which is performed with an Alicat mass flow meter, is reported to EPA.

For Met One BAM 1020 accuracy audits, the QA Auditor begins with an external leak check. If a leak is discovered, the audit is aborted and the site operator is notified immediately. If the leak check passes, the audit continues with a comparison of the flow of the Met One BAM 1020 monitors to the reading on the Alicat flow meter. The Met One BAM 1020's design flow rate is 16.67 liters/minute. Comparisons of the flow rates are submitted to EPA as the accuracy audit for these monitors. Criteria for the comparison of actual flow rates with transfer standard flow rates are ± 4.1%, consistent with the QA Handbook Appendix D. When these criteria are not met, the auditor or operator notifies the Site Operator and Monitoring Supervisor responsible for the site to discuss appropriate actions.

2. Manual Analyzers

Partisol ($PM_{2.5}$ and PM_{10})

The QA Auditors perform semiannual audits on flow, temperature, and pressure on the Partisol analyzers. Only the flow audit, which is performed with an Alicat mass flow meter, is reported to EPA.

The QA Auditor does accuracy audits of flow rates on a semiannual basis for each $PM_{2.5}$ and PM_{10} sampler in the system. These comparisons are reported to EPA as the accuracy audit.

Site operators do similar flow checks once a month on each sampler. The results are used for validation of data and as a check on the calibration. The results of these flow checks are submitted to EPA through AQS.

Precision for particulate samplers is estimated from duplicate samples collected by co-located pairs of samplers. Each sampler in a co-located pair is calibrated, operated and audited identically. During calibrations, flow checks, and audits of each of these samplers, the other sampler is left running to mimic actual operating conditions. The pair of samplers is sited such that they are at least 1 meter but no more than 4 meters apart, in accordance with the requirements set forth at 40 CFR 58, Appendix A, 3.2.3.4(c). At each co-location site, one sampler is designated

as the primary sampler, and the other is designated as the duplicate sampler. The exposed filters from each member of the pair are processed identically and the relative differences incorporated into the quarterly precision and accuracy report.

B. Systems Audit

Once every three years or as EPA budget allows, the Air Quality Bureau undergoes a systems audit performed by staff from the EPA Region 6 Office in Dallas, Texas EPA evaluates the entire ambient air monitoring program against the systems audit criteria listed in the EPA QA Handbook Volume II.

C. National Performance Audit Program and Performance Evaluation Program

The Air Quality Bureau participates to the maximum extent possible in the National Performance Audit Program (NPAP) and Performance Evaluation Program (PEP), both sponsored by the EPA. Currently, NPAP TTP (through the probe) audits are performed on gaseous monitors by a contractor with the EPA. The same contractor performs audits on the particulate monitors. The PEP is a quality assurance activity which will be used to evaluate measurement system bias of the PM2.5 monitoring network. The goal is to audit 20% of the network each year. Scheduling of the audits is managed by EPA Region 6.

D. Other Assessments

1. A Corrective Action Report (CAR) will be filled out any time a problem has been discovered at any monitoring site and that falls outside of our routine procedures and preventative maintenance schedules and results in data loss or qualification of 120 hours or greater, or 2 or more filters. The reports are intended to be used as a tracking, documenting, and learning device for internal review. The internal procedures for Corrective Action Reports are in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. Each CAR is identified and tracked with a unique identifying number. It contains a standard set of questions and will capture specific details about each situation. The person most directly tied to the situation will fill out the CAR within five business days of discovering the problem and it will be filled out as completely as possible. The CAR will be reviewed and approved by the direct supervisor, Monitoring Manager, QA Data Handling Specialist, QA Manager, with final approval given by the Operations Section Chief. Once a CAR has been completed, it will be filed in a central location retrievable by the QA and Monitoring staff. In addition, it may be presented at internal section meetings to serve as a learning tool for coworkers. These reports are retained for a minimum of three years.

2. Many of the assessments are informal. For example, the result of each accuracy audit is distributed with the QA and Monitoring Units. Informal peer reviews take place regularly among the QA staff.

E. Reconciliation with Data Quality Objectives

Detailed procedures of the statistical equations and procedures as they relate to the collection of valid ambient air data are found in 40 CFR Part 58, Appendix A. These procedures are followed in order to assess precision, accuracy and completeness of the collected data. Often the solution to poor precision and accuracy results is repair and replacement of aging and failing monitoring and calibration equipment. Resources available are allocated to remedy the problems identified in the QA process.

C2: Reports to Management

The primary method of informing management of current monitoring performance and results is through data reports retrievable from both DAS and AQS. After quarterly data is uploaded to AQS, a variety of reports may be obtained. Standard reports of interest are the Quicklook Report, Maximum Values Report, Data Completeness Report, Precision/Accuracy Reporting Organization Summary, and the Air Quality Index (AQI) Report. The AQI Report is currently being used as a Bureau performance measure within the NM Environment Department.

Since October 2004 with the inception of the Data Acquisition System, a variety of reports are available as part of the software. The reports most utilized are:

- Station Reports, which retrieve pollutant data from any of the monitoring sites, obtainable in 5 minute, 1 hour, 8 hour, or 24 hour averages
- Calibration Reports, which show actual and indicated results of weekly quality control tests on the gas monitors performed by an automatic calibrator, referred to internally as "QC Reports"
- Wind Reports, which correlate pollutant concentrations with wind speed and direction, to gain an understanding of origin of pollutants or wind speeds that cause high particulate concentrations
- Edit History Reports, which indicate reasons for any data that has been invalidated such as for monitor malfunctions or change of status flags
- Logbook Reports, which retrieve electronic logbook entries for any of the monitoring sites where operators have made electronic entries on the site computers explaining their work to maintain monitors or perform checks on monitor performance when at the monitoring site

D Data Validation and Usability

D1: Data Review, Verification, and Validation

A. Continuous Monitors

DAS software for data acquisition and control is installed on a PC set up at each station. The DAS communicates over serial communications lines to obtain data from the equipment at the station.

The DAS software offers comprehensive in-station support and communications options. All configuration and remote access functions are password-protected. Analyzer status conditions are monitored and the data is flagged if the analyzer is reporting a fault. In-station and central location reports allow review of all analyzer status changes. Manual flagging of data can also be performed. Site operators can toggle data channels to OFF, and OFF SCAN modes. OFF SCAN continues to report the data values but flags the data. OFF channels do not report values. If a monitor is removed from the station, the channel is set to OFF. For maintenance and other quality checks not otherwise tracked by the system, the channel is set to OFF SCAN. If the operator were to accidentally fail to return the channel to ON the data can always be recovered by just editing the status flag. Remote access via modem to the station PC allows an oversight such as this to be quickly corrected.

DAS interfaces serially to the on-site calibrator. The calibrators may be controlled serially or by digital control lines. Calibration control sequences can flag data with zero, span and 5 other span level flags corresponding to the desired dilution levels.

The station data is collected hourly from all stations. Polling PC running the CommServ communications program from the DAS is located in Santa Fe. Cellular modem connections are utilized. The DAS data loggers hold 10 years of historical data with automatic data recovery in the event communications with a site is interrupted for a period. An operator can also copy data sets to files for update to the central database by QA staff.

The data collection process writes the data for all the stations to the Department's Oracle Server. Data values and status as initially collected and as edited are stored in separate data tables for each station. These are referred to as the Raw and Standard data tables. The DAS data logger collects and stores the results of automated Zero, Span, and Precision Checks as well as station faults.

The data collected is subject to quality review at four levels.

(1) Station data loggers flag values recorded in the field to indicate that the values are considered invalid. Samples used from 5 minute and hourly values are invalidated when instrument maintenance is being performed. Maintenance includes calibrations. All stations are equipped with DAS data logger software, enabling the service or audit staff to flag any data channel in the logger as Off Scan when maintenance or audits are being performed. A defective instrument is flagged as Off to indicate no data are available. In addition the DAS checks for data samples as being above or below the range of the meteorological sensor are excluded from the averages.
(2) All data averages collected from the monitoring locations are examined contemporaneously by the data collection software to check for outlier values and values that either change too radically or exhibit too little change. The criteria used are based on manufacturer's recommendation, AQB experience and EPA guidelines.
(3) The QA staff performs a daily visual review of data. This review is supported by the creation of statistical and graphical data presentations that facilitate and highlight data of interest. Data are invalidated whenever there is verifiable evidence of instrument malfunction or departure from the operating specifications.
(4) Staff members from any of the sections involved in air quality monitoring may access the standard database records and provide information to the QA Section that may facilitate and/or inform the data validation process.

Validity criteria are implemented within the station logger, QA criteria, daily data review procedures and statistical tests. Whenever data needs to be edited (including validity changes) only the QA Data Handling Specialist or QA Manager may do so. Validity criteria and editing procedures are described in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

Note: If suspicious data are observed by QA Staff, it is reported to the Air Monitoring Manager. The manager shall assign staff to investigate the apparent problem and make repairs as needed. The staff's finding shall be reported to the QA Manager for determination of whether data needs to be adjusted, invalidated, or re-validated.

Data within the database is further reviewed whenever the Data Handling Specialist receives information regarding new maintenance actions that have been performed. These records are examined and compared to data collected and checked from the field to determine if data for the documented maintenance periods were in fact flagged correctly. Any apparent differences are submitted to the QA Manager for review and a decision on what if any edits of the database are warranted.

After editing and all validation procedures have been completed, the data is converted into AQS format using the DAS and uploaded to the EPA AQS database. This is accomplished quarterly.

B. Manual Analyzers

Site operators collect filters from particulate samplers in the field on a 3-day schedule for $PM_{2.5}$ and a 6-day schedule for PM_{10}. The actual days in the schedules are prescribed by EPA and uniform across the country so that measurements may be comparable across regions. Special schedules such as every-day sampling may be put into place for problematic areas.

The filters are enclosed in suitable shipping containers and sent along with the Chain of Custody (COC) forms to the Scientific Laboratory Division (SLD) in Albuquerque via UPS. In accordance with 40 CFR 50, Appendix L at 10.13, to protect the integrity of the sample during transport and storage, the filters are maintained as cool as practical and continuously protected from exposure to temperatures over 25 °C. At the SLD, the filters are weighed for determining particulate concentrations. After the filters have been weighed, the SLD sends copies of the completed COC forms to AQB, where they are reviewed in accordance with the Chain of Custody Forms SOP for completeness and adherence to handling criteria set forth in the QA Handbook Volume II, Appendix D.

SLD tabulates exposed PM_{10} and $PM_{2.5}$ filter weights in a spreadsheet, which is then sent to the Data Handling Specialist. (See Appendice B for SLD's procedures.) The Data Handling Specialist uses an Excel macro to obtain the particulate weights and insert them into an Excel spreadsheet combined with flow data downloaded from Partisol samplers so that particulate concentrations may be calculated. A second macro is used to format the concentration results so that they may be uploaded to the main database.

Operators maintain Excel spreadsheets for each analyzer with flow data, slopes, and intercepts and make these spreadsheets available to the Data Handling Specialist.

Data uploaded to the database are subjected to the quality review procedures, which are detailed in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. Data passing all quality review checks are uploaded to AQS.

Data review, validation and verification take place at four levels in the data collection and data processing activities. These were discussed previously in Section D1.A. Detailed procedures, requirements and methods for data review, validation and verification are given in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. These sections provide the criteria used within the data collection and management system to conduct automated review and validation.

D2: Verification and Validation Methods

Verification is not automated. Verification consists of confirming that the validity assigned to data is correct. This necessitates independent review of the data, validity criteria and other information to verify that the validity criteria have been properly applied.

A. Continuous Monitors

At the DAS data logger, the values received are subject to quality examinations. As the data is collected, the RAW data values are subjected to random checks. These are detailed in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

The Quality Assurance staff review data daily. Details of this review are presented in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance. QA staff also review the results of the weekly Zero/Span and Precision checks of the continuous gas monitors. General invalidation criteria for each pollutant for these checks are provided in the Quality Assurance Handbook Volume II, Appendix D. These criteria are applied routinely, although decisions on all questions of data editing and invalidation are ultimately the responsibility of the QA Manager.

B. Manual Monitors

The manual monitors in the AQB network measure particulate matter. As described in Section A.9, data from the exposed filters from the manual monitors and Chain of Custody forms are sent to the AQB for analysis. The Chain of Custody forms are reviewed in accordance with the procedure detailed in the Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance.

General validation criteria for particulate matter are provided in the Quality Assurance Handbook Volume II, Appendix D. These criteria are applied routinely, although decisions on all questions of data editing and invalidation are ultimately the responsibility of the QA Manager.

D3: Reconciliation with User Requirements

In the case of ambient air monitoring which is required by the EPA, the data quality objectives are to collect data that is accurate, complete, representative and comparable for inclusion in the national database, AQS and also for verification that the state has met all state and federal air quality standards. The ambient air monitoring project is unlike uniquely designed projects, which are devised for making specific decisions. Thus, we consider that data quality objectives have been met when we successfully complete all EPA-approved quality assurance requirements for monitor calibrations, audits, precision checks and data validation.

References

New Mexico Environment Department, Air Quality Bureau: Manual of Standard Operating Procedures Ambient Air Monitoring and Quality Assurance

Environmental Protection Agency: *Regulations on National Primary and Secondary Ambient Air Quality Standards* 40 CFR Ch. 1, Part 50 http://www.ecfr.gov/cgi-bin/text-idx?SID=41ae02c0a776d964a08f2ca9b57498b0&mc=true&node=pt40.2.50&rgn=div5

Environmental Protection Agency: *Ambient Air Quality Surveillance* 40 CFR Ch. 1, Part 58 http://www.ecfr.gov/cgi-bin/text-idx?SID=41ae02c0a776d964a08f2ca9b57498b0&mc=true&node=pt40.6.58&rgn=div5

Environmental Protection Agency, *Guideline on the Meaning and the Use of Precision and Bias Data Required by 40 CFR Part 58 Appendix A*, EPA-454/B-07-001, January 2007 https://www3.epa.gov/ttn/amtic/files/ambient/monitorstrat/precursor/07workshopmeaning.pdf

Environmental Protection Agency, EPA QA/G-5 *Guidance for Quality Assurance Project Plans,* EPA/240/R-02/009 https://www.epa.gov/quality/guidance-quality-assurance-project-plans-epa-qag-5

Environmental Protection Agency, *Technical Assistance Document for the Calibration of Ambient Ozone Monitors*, EPA-600/4-79-057 https://www3.epa.gov/ttn/amtic/files/ambient/criteria/4-79-057.pdf

Environmental Protection Agency, *Quality Assurance Handbook for Air Pollution Measurement Systems, Volume I, A Field Guide to Environmental Quality Assurance* (EPA/600/r-94/038a) April 1994 https://www3.epa.gov/ttnamti1/qalist.html

EPA QA Handbook for Air Pollution Measurement Systems, Vol. II (EPA-454/B-17-001) January 2017 https://www3.epa.gov/ttnamti1/files/ambient/pm25/qa/Final%20Handbook%20Document%201_17.pdf

QTRAK # _____

APPENDIX A

To

QUALITY ASSURANCE PROJECT PLAN FOR AMBIENT AIR MONITORING

2020

NEW MEXICO ENVIRONMENT DEPARTMENT

AIR QUALITY BUREAU

New Mexico State Personnel Office

2600 Cerrillos Road
Santa Fe, New Mexico 87505-0127

Classification Description

ENVIROMENTAL SCIENSTISTS AND SPECIALISTS, INCLUDING HEALTH

Class Title	Class Code	Pay Band	Alt Pay Band*
Environmental Scientists & Spec-B	F2041B	55	65
Environmental Scientists & Spec-O	F2041O	60	70
Environmental Scientists & Spec-A	F2041A	65	75

**In accordance with SPB Rule 1.7.4.10 NMAC, the assignment to alternative pay bands shall be reviewed annually to determine their appropriateness.*

Occupation Description

Conduct research or perform investigation for the purpose of identifying, abating or eliminating sources of pollutants or hazards that affect either the environment or the health of the population. Utilizing knowledge of various scientific disciplines may collect, synthesize, study, report and take action based on data derived from measurements or observations of air, food, soil, water and other sources.

Nature of Work

Environmental scientists and specialists use their knowledge of the natural sciences to protect the environment by identifying problems and finding solutions that minimize hazards to the health of the environment and the population. They analyze measurements or observations of air, food, water, and soil to determine the way to clean and preserve the environment. Understanding the issues involved in protecting the environment degradation, conservation, recycling, and replenishment is central to the work of environmental scientists. They often use this understanding to design and monitor waste disposal sites, preserve water supplies, and reclaim contaminated land and water. They also write risk assessments, describing the likely affect of construction and other environmental changes; write technical proposals; and give presentations to managers and regulators.

Distinguishing Characteristics of Levels

Note: Examples of Work are intended to be cumulative for each progressively higher level of work. The omission of specific statements does not preclude management from assigning other duties which are reasonably within the scope of the duties.

Basic

- Employees in this Role perform routine investigations into environmental problems.
- Employees collect and submit samples for laboratory or field analysis; assist in making inspections; conduct routine field and office project reviews; may compile project-oriented engineering, social, economic and other technical data necessary for public hearings.

ENVIRONMENTAL SCIENSTISTS AND SPECIALISTS, INCLUDING HEALTH

New Mexico State Personnel Office

2600 Cerrillos Road
Santa Fe, New Mexico 87505-0127

Classification Description

Recommended Education and Experience for Full Performance
Bachelor's Degree in Physical, Natural, or Environmental Science, Soil Science, or Engineering.

Minimum Qualifications
Bachelor's Degree in Physical, Natural, or Environmental Science, Soil Science, or Engineering. Any combination of education from an accredited college or university in a related field and/or direct experience in this occupation totaling four (4) years may substitute for the required education and experience.

Operational

- Employees in this Role review applications, preliminary and final plans, and specifications for proposed plants, facilities, and/or equipment to determine completeness, technical feasibility, engineering accuracy, and compliance.
- Employees conduct supplementary investigations, research and surveys as needed; announce and conduct public hearings; issue permits and approvals and notify concerned public of the action; participate in inspections, cost estimates, progress reports, and design change orders; perform tests and audits test results to determine conformity; and compile findings and technical data for reports and projections.

Recommended Education and Experience for Full Performance
Bachelor's Degree in Physical, Natural, or Environmental Science, Soil Science, or Engineering and four (4) years of work experience in public/environmental health, environmental science, Air Quality Management, Biology, Engineering, Chemistry, Geology, Hazardous Waste Management, Wildlife Management, and/or Water Resources.

Minimum Qualifications
Bachelor's Degree in Physical, Natural, or Environmental Science, Soil Science, or Engineering and two (2) years of work experience in public/environmental health, environmental science, Air Quality Management, Biology, Engineering, Chemistry, Geology, Hazardous Waste Management, Wildlife Management, and/or Water Resources. Any combination of education from an accredited college or university in a related field and/or direct experience in this occupation totaling six (6) years may substitute for the required education and experience.

Advanced

- Employees in this Role determine adverse and beneficial environmental, social, and economic effects of highway proposals, archaeological sites and excavations.
- Employees coordinate environmental and archaeological activities with project development and design; analyze and generate procedural changes; determine manpower needs; review and authorize mitigation contracts for ongoing and completed projects; assemble data for planning; engage in or monitor research; develop public information programs; assist management in planning objectives, budget, records, and reports; prepare complex scientific reports and advanced analysis of data.

Recommended Education and Experience for Full Performance
Bachelor's Degree in Physical, Natural, or Environmental Science, Soil Science, or Engineering and six (6) years of work experience in public/environmental health, environmental science, Air Quality Management, Biology, Engineering, Chemistry, Geology, Hazardous Waste Management, Wildlife Management, and/or Water Resources.

ENVIRONMENTAL SCIENSTISTS AND SPECIALISTS, INCLUDING HEALTH

New Mexico State Personnel Office

2600 Cerrillos Road

Santa Fe, New Mexico 87505-0127

Classification Description

Minimum Qualifications

Bachelor's Degree in Physical, Natural, or Environmental Science, Soil Science, or Engineering and five (5) years of work experience in public/environmental health, environmental science, Air Quality Management, Biology, Engineering, Chemistry, Geology, Hazardous Waste Management, Wildlife Management, and/or Water Resources. Any combination of education from an accredited college or university in a related field and/or direct experience in this occupation totaling nine (9) years may substitute for the required education and experience.

Knowledge and Skills

*Note: This information has been produced by compiling information and documentation provided by O*NET. O*NET™ is a trademark of the U.S. Department of Labor, Employment and Training Administration.*

Knowledge

English Language — Knowledge of the structure and content of the English language including the meaning and spelling of words, rules of composition, and grammar.

Chemistry — Knowledge of the chemical composition, structure, and properties of substances and of the chemical processes and transformations that they undergo. This includes uses of chemicals and their interactions, danger signs, production techniques, and disposal methods.

Mathematics — Knowledge of arithmetic, algebra, geometry, calculus, statistics, and their applications.

Biology — Knowledge of plant and animal organisms, their tissues, cells, functions, interdependencies, and interactions with each other and the environment.

Law and Government — Knowledge of laws, legal codes, court procedures, precedents, government regulations, executive orders, agency rules, and the democratic political process.

Engineering and Technology — Knowledge of the practical application of engineering science and technology. This includes applying principles, techniques, procedures, and equipment to the design and production of various goods and services.

Geography — Knowledge of principles and methods for describing the features of land, sea, and air masses, including their physical characteristics, locations, interrelationships, and distribution of plant, animal, and human life.

Customer and Personal Service — Knowledge of principles and processes for providing customer and personal services. This includes customer needs assessment, meeting quality standards for services, and evaluation of customer satisfaction.

Persuasion — Persuading others to change their minds or behavior.

Negotiation — Bringing others together and trying to reconcile differences.

Social Perceptiveness — Being aware of others' reactions and understanding why they react as they do.

Instructing — Teaching others how to do something.

Physics — Knowledge and prediction of physical principles, laws, their interrelationships, and applications to understanding fluid, material, and atmospheric dynamics, and mechanical, electrical, atomic and sub- atomic structures and processes.

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Time Management — Managing one's own time and the time of others.

Skills

Classification Description

Science — Using scientific rules and methods to solve problems.

Critical Thinking — Using logic and reasoning to identify the strengths and weaknesses of alternative solutions, conclusions or approaches to problems.

Reading Comprehension — Understanding written sentences and paragraphs in work related documents.

Speaking — Talking to others to convey information effectively.

Active Listening — Giving full attention to what other people are saying, taking time to understand the points being made, asking questions as appropriate, and not interrupting at inappropriate times.

Writing — Communicating effectively in writing as appropriate for the needs of the audience.

Complex Problem Solving — Identifying complex problems and reviewing related information to develop and evaluate options and implement solutions.

Coordination — Adjusting actions in relation to others' actions.

Judgment and Decision Making — Considering the relative costs and benefits of potential actions to choose the most appropriate one.

Active Learning — Understanding the implications of new information for both current and future problem-solving and decision-making.

Statutory Requirements: N/A

Conditions of Employment: Working Conditions for individual positions in this classification will vary based on each *agency's utilization*, *essential functions*, and the *recruitment needs* at the time a vacancy is posted. All requirements are subject to possible modification to reasonably accommodate individuals with disabilities.

Default FLSA Status: Exempt. FLSA status may be determined to be different at the agency level based on the agency's utilization of the position.

Bargaining Unit: This position may be covered by a collective bargaining agreement and all terms/conditions of that agreement apply and must be adhered to.

Established: 07/07/2001 **Revised:** 9/4/2014

**Adapted from the United States Bureau of Labor Statistics and are intended to illustrate the typical education and experience required for this occupation.*

Note: Classification description subject to change. Please refer to the SPO website www.spo.state.nm.us to ensure this represents the most current copy of the description.

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APPENDIX B

To

QUALITY ASSURANCE PROJECT PLAN FOR AMBIENT AIR MONITORING

2020

NEW MEXICO ENVIRONMENT DEPARTMENT

AIR QUALITY BUREAU

NEW MEXICO
DEPARTMENT OF
HEALTH

SCIENTIFIC LABORATORY DIVISION

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Title: Gravimetric Analysis of 47mm Air Filters - AHM Method 41710

Version: 3.0

Index Number: CB AHM 104

Release Date: 24-Apr-2018

Authors: Frank See and Patricia Murphy

Ou Name: Air and Heavy Metals

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Air and Heavy Metals Methods Manuals

GRAVIMETRIC ANALYSIS of 47mm Air Filters

Effective date: February 28th, 2018

Prepared by Patricia Murphy and Frank See

1. SCOPE AND APPLICATION

NMED Exhibit 29 - 0059

1.1 This method is a gravimetric analysis for the mass determination of particulates suspended in air. Particle size can vary by the type of particle-size discriminator used on the sampling equipment. The most common have an aerodynamic diameter of less than or equal to either 2.5 or 10 microns; this method is applicable to either size. These fine particulates are collected on 47-mm Teflon filters. The method covers the conditioning and weighing of the filters, data handling and reporting.

2. SUMMARY OF METHOD

2.1 Clean filters are conditioned under precisely controlled conditions of temperature and relative humidity until stable for weighing on a microbalance. Filters are weighed to the nearest microgram (10^{-6} gram) at the lab, and then sent to clients for exposure. Exposed filters are returned to SLD, where they are again conditioned and weighed to the nearest microgram. The difference of exposed weight minus clean weight yields the net mass loading on the filter

3. DEFINITIONS

3.1 National Institute of Standards and Tests: (NIST) US Dept of Commerce Laboratory measurement standards laboratory.
3.2 Accuracy -The degree to which a measurement relates to its actual (true) value. For digital scales, expressed as a percent deviation of actual reading (%AR)
3.3 American Society for Testing and Materials: (ASTM) international standards program.
3.4 $PM_{2.5}$: Particulate Matter (PM) ≤ 2.5 microns in diameter.
3.5 PM_{10}: Particulate Matter (PM) ≤ 10.0 microns in diameter.
3.6 Gravimetric analysis: Analysis determined by the measurement of mass (weight).
3.7 Filter: 47-mm diameter Teflon. Each filter as supplied has a unique identifier (alphanumeric).
3.8 Primary mass reference standards: Certified ASTM class 1 or better mass standards (weights), 200, 300 & 500 mg. Verified annually by a certified technician.
3.9 Working mass reference standards: 200, 300 & 500 mg. mass standards (ASTM Class 2 or better) used for routine filter weighings. The working standards are calibrated against the primary mass standards every 6 months.
3.10 Laboratory Information Management System (LIMS): This is the database of record for SLD. All samples are logged into the facility and tracked through each step needed to properly analyze and report out on samples submitted.
3.10.1 Pre-accessioning: This process is used to create samples in the LIMS system for the purpose of pre-sampling prior to sending filters out into the field.
3.11 Pre-sampling: Weighing of filter media before exposure (tare weight).
3.12 Post-sampling: Weighing of filter media after exposure (exposed).
3.13 Filter loading: the amount of particulates, in micrograms, entrained on the filter medium.
3.14 Filter lot: A single shipment of filters received from EPA or manufacturer. Identified by lot number.

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3.15 Filter exposure lot blanks: 3 filters randomly selected from each filter exposure lot, used to assess the conditioning time necessary for the given lot.
3.16 Lab blank (LB): A conditioned, unsampled filter, used to assess contamination in the lab and microbalance environment. Filters should be weighed in the pre-sampling session and again in a post-sampling session. Enough filters should be weighed to represent 10% of filters in a batch per weighing session.
3.17 Field blank (FB): A conditioned, unsampled filter sent to the field, used to assess possible contamination during sampling. The field blank is placed in the sampler but not exposed. Field blanks are conditioned, stored, and weighed the same as sampled filters
3.18 Duplicate: The duplicate measurement (weighing) of a filter, used to assess the precision of the weighing and conditioning procedures.
3.19 Precision (also Repeatability): A measure of random variation among individual measurements of the same property under prescribed identical conditions. For microbalance measurements, precision is the measure of the ability to display the same result in repetitive weighings of the same mass under the same measurement conditions. ASTM: American Society of Testing and Materials.
3.20 Bias: The systematic or persistent distortion of a measurement process that causes errors in one direction. The lack of accuracy associated with a specific measurement.
3.21 Filter Integrity Check: Examination of each pre-sampled (unexposed) filter against a defined set of criteria before conditioning. Filters that do not pass the filter integrity check must not be used.
3.22 Qualifier: A 3-letter description giving further explanation of a particular filter. See table 15.2 for a list of qualifiers and their meanings.
3.23 Readability: (also Resolution, Scale Division, Scale Interval, Increment, Digit) – On electronic and digital scales, this is the smallest change in mass that corresponds to a change in displayed value. In other words, this is the amount that the scale will increment by as weight is added or removed.
3.24 Reproducibility: This is the scale's ability to show consistent results under changed conditions.

4. SAMPLE COLLECTION, PRESERVATION AND STORAGE

4.1 Pre-sampled (clean) filters

4.1.1 Filters are "pre-accessioned" in LIMS. Each filter is given a unique SLD number and request form that is tracked with the barcode label that is affixed to filter storage container and each request form is printed with the same information. At this point, each filter and its unique identifier is associated with a unique SLD number in LIMS and tracked with a barcode reading system.
4.1.2 All Supplied filters are conditioned, weighed, and checked for integrity before being sent to clients for exposure.
4.1.3 To ensure that contamination and/or static charge is not a problem, the analyst must wear static-free, non-powdered gloves and clean lab coats when handling filters. Long sleeve garments are discouraged (dust build up).
4.1.4 Filters shall ONLY be weighed in the designated, conditioned environment.

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4.1.5 Clean filters are removed from the shipping material and retained in their original boxes (usually 50 filters per box). Boxes of clean filters are stored in the Air Quality Weight Room 2348A until filters are set out for conditioning. Refer to section 9.2 for clean filter conditioning procedure.

4.1.6 Upon completion of weighing, the filters are packaged and prepared as described in Section 9 of this SOP and are then available for pickup or being shipped to the client.

4.1.7 **Note:** Pre-sampled filters must be exposed (sampled) within 30 days from the date of weighing.

4.2 **Exposed filters**

4.2.1 Exposed filters upon being returned to SLD are brought into the Specimen and Receiving (SR) area of the Laboratory and accessioned through LIMS. Refer to section 9.5 for exposed filter check-in and handling.

4.2.2 The SR area of the Laboratory is responsible for checking and maintaining proper Chain of Custody. Each exposed filter's unique identifier is matched with paperwork and prepared for conditioning and weighing.

5. INTERFERENCES

5.1 Static charge will cause delays and inaccuracies in balance measurements. The analyst must take proper precautions to minimize static charge.

5.2 Insufficient conditioning of unexposed filters may result in erroneous filter loading calculations. Unexposed filters need sufficient time for the support ring to de-gas before pre-sample weighing and equilibrate with the laboratory environment.

5.3 Filter exposure in the presence of NO_x and SO_2 vapors (primarily from nitric and sulfuric acids, respectively) may cause the agglomeration of nitrate and/or sulfate containing particles on high-alkalinity filter media, resulting in a falsely high result.

6. APPARATUS AND EQUIPMENT

6.1 Microbalance: Capable of 1 µg (0.001 mg) readability and 0.0008 mg repeatability.(See Appendix A for currently used equipment.)

6.2 Conditioning & Weighing Room: Room 2348A and 2348B. The conditioning and weighing rooms must be maintained at a mean temperature of 20.0-23.0 ^{0}C, with <± 2.0 ^{0}C variation in the 24-hour period preceding filter weighing. The mean relative humidity in the same rooms must be maintained between 30.0%-40.0 % with <± 5.0% variation in the 24-hour period preceding filter weighing. The climate control equipment should be able to read both the room temperature and relative humidity in the room frequently and adjust such that these conditions are maintained. The room is equipped with Johnson Controls data logging that tracks the environmental parameters.

6.3 Hygrometer/temperature sensor: A separate hygrometer & temperature sensor [Dickenson THDX with chart recorder, and battery backup should be located near the

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microbalance. Relative humidity must be measured to the nearest 1 percent, while temperature must be measured to the nearest 1 °C.

6.4 Computer with microbalance interfaced to LIMS.

6.5 Bar code label maker and scanner: interfaced to LIMS to make and read bar code labels for filter storage container.

6.6 Balance table: Stone or other heavy (stable) surface for microbalance.

6.7 Damping pads/slab: Isolate balance table from floor.

6.8 Primary and Working Mass standards: 200 mg, 300mg and 500 mg standards certified to ASTM or NIST class 1 or better.

6.9 ^{210}Polonium strips: Strips used to neutralize static electricity. Strips should contain no more than 500 Picocuries of radiation.

6.10 Anti-static brush: Small brush, used to clean the microbalance-weighing pan.

6.11 Filter: 47-mm diameter Teflon. With unique alphanumeric identifier. Available from US EPA through the national $PM_{2.5}$ contract.

6.12 Filter cassette: Handling device attached to each filter ring, which holds the filter in place in the sampler. Two pieces (top and bottom half) to each cassette. Filter cassettes: Various, depending on filter manufacturer. Reusable.

6.13 Filter storage containers: Storage containers used to store the filter during conditioning. Each container must be labeled with the enclosed filter number on the lid. The dish should be large enough to accommodate the filter easily but with minimal extra room, to prevent filter movement inside the dish.

6.14 Cassette protective containers: This may be a Petri dish plus foam blocks (manual sampler) or sampling magazine holding several filter cassettes and solid spacers (automated sequential sampler).

6.15 Magazine Protective Container: Padded metal box used for additional protection, used to ship the filter plus cassette

6.16 Forceps: Smooth, non-serrated. A different pair is used to handle the filters (**filter**) and mass standards (**standard**).

6.17 ^{210}Po: Polonium 210, an alpha emitter used to neutralize static charge build-up.

6.18 Magazine Pump: Pneumatic tool to push filter cassettes through the magazine.

6.19 Filter cassette separator tool: Used to separate the top & bottom cassette halves for filter retrieval.

6.20 Shipping Coolers: Picnic coolers with leak proof ice substitute, for shipping filters.

6.21 Min-Max Thermometers: Thermometers for recording the minimum and maximum temperatures inside the shipping coolers.

6.22 Earth-ground flooring: used to drain away static charge.

6.23 Tacky mats: Adhesive mats, used to trap dust and other particulate contamination from analysts' shoes; placed outside of the balance room.

6.24 Kim Wipes: Lint free wipes used to remove debris and solution from apparatus.

6.25 Alcohol Wipes: Used to clean the inside of the filter magazines.

6.26 Anti-Static Solution: Spray-on type, applied to weighing areas to minimize static charge accumulation.

6.27 Alconox or similar detergent to clean filter cassettes.

6.28 Methanol: Used to clean forceps.

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7. REAGENTS -NA

8. CALIBRATION

8.1 The microbalance calibration must be verified annually by a certified technician.
8.2 The microbalance calibration must be checked before each weighing session, using both the 300 and 500 mg. working mass standards.
8.3 Utilize any calibration programs that may be installed in the analytical balance as needed.

9. PROCEDURE

9.1 General

9.1.1 Wash hands thoroughly before entering the outer room (Rm. 2348).
9.1.2 Before entering the balance room, the analyst must walk across a tacky mat with both feet, to remove as must dust as possible from their feet.
9.1.3 Before entering the balance room, the analyst must discharge any static charge on their person to an earth ground by touching the ground with both hands for 2 seconds.
9.1.4 If contamination and/or static charge has been proven to be a concern, the analyst must wear non-static, powder-free gloves and a clean lab coat. Gloves and lab coats are put on in the outer room.
9.1.5 The analyst must verify via the balance room data recorders that the required conditions for temperature and relative humidity have been achieved over the previous 24 hours. See section 12.7 for requirements. If the conditions are outside the allowable range, weighing should not be done until the requirements are met. If the temperature and humidity cannot be controlled to requirements, then a notation must be entered into the batch under LIMS Batch Manager and be made available to the client
9.1.6 The weighing rooms (2348A and 2348B) are controlled environments. Access should be limited to people that have a need to work in the weight rooms.

9.2 Clean Filter Conditioning

9.2.1 All new filters must be checked for integrity, conditioned, and weighed before being sent to clients for exposure.
9.2.2 Filters meeting the integrity criteria are to be pre-logged into LabWare© LIMS.
9.2.2.1 Click on **Sample Interface Icon**. A **Sample Login Window** will appear.
9.2.2.2 Select **File>Open Template**. A **LIMS Browser Window** will appear
9.2.2.3 Click on **Template ID:** Select **Air Quality Sample Pre-Log**. Click **OK**.
9.2.2.4 In the **AQ Sample Pre-log Window** on the **Summary Tab** Select **Specimen Source** and from the Drop Down Menu **Air Filter (47mm)**
9.2.2.5 Enter the Filter Lot # from the EPA supplied filter box.

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9.2.2.6 In the upper-right hand corner of the **AQ Sample Pre-log Window** type in the appropriate amount of filters to be clean conditioned and Click the **Log Button**. Please confirm by hitting **Yes** when asked "Logging XX samples OK to continue"?

9.2.2.7 Select **File>Exit**.

9.2.2.8 Select **File>Folder Manager**

9.2.2.9 In the **Folder Manager Window** select **File>Open**.

9.2.2.10 When the **Folder Prompt Dialogue Window** appears, select the browse icon and then highlight the **AQ_Clean_Condition_XX Folder**

9.2.2.11 When the **SAMPLE Folder: Air Quality – Clean Condition Window** appears select **File>Rebuild .** The samples created in Login Interface previous step should be present in the left column.

9.2.2.12 Select **NMDOH>Clean Condition**. In the **AQ Clean Condition Window** type in the first filter number and then highlight the remaining cells in the column.

9.2.2.13 Using **NMDOH>Increment Filter Down**.

9.2.2.14 When done **File>Save; and Exit.** This will enter the filter numbers into the batch.

9.2.2.15 Select **File>Save.**

9.2.2.16 Select **Folder>Print Sample Labels.**

9.2.2.17 Select **NMDOH>Clean Condition**.

9.2.2.18 In the **AQ Clean Condition Window** enter the date in the Clean Condition Date Column.

9.2.2.19 Select **Edit>Propagate** down to fill all filter samples **.**

9.2.2.20 **Select File >Save** and then **Exit.**

9.2.2.21 Select rebuild folder.

9.2.2.22 Select **File> Save** and then **Exit.**

9.2.2.23 The created labels are then affixed to the bottom of the petri dishes.

9.2.3 Remove all filters from their original boxes. Perform the filter integrity check (see section 12.1 and table 15.1). If all criteria in table 15.1 are not satisfied, the filter is rejected. Rejected filters are voided in LIMS. If a large number of filters from a given lot do not meet the defined criteria, the entire lot is returned to the vendor for replacement.

9.2.4 Each filter that successfully passes the filter integrity check is placed in a clean petri dish. Handle the filter only by the support ring using the **filter** forceps; do NOT handle the filter directly. Filters have a unique identifier (alphanumeric filter number) that is printed above the LIMS sample number on the printed labels (see 9.2.2.16) and affixed to the bottom half of the petri dish (filter container). Place all filters in the bottom half of the petri dish, and partially cover with the top. Record the current date in LIMS (9.2.2.18).

9.2.5 Three (3) filters are randomly selected from the initial filter exposure lot (3.12) of each filter lot (3.11) and designated as Exposure Lot Blanks. The 3 filters are conditioned for a minimum of 24 hours, and then weighed on consecutive days until such time that the 24-hour weight change is less than 15 µg. While conditioning, the petri dishes must be open. Remaining filters in this exposure lot

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must not be weighed until this criterion is met. Record the Exposure Lot Blank filter numbers, dates of weighing, and weights in an Excel file.

9.2.6 The next group of clean filters set out to condition (filter exposure lot) following the initial exposure lot (9.2.5) must repeat the Exposure Lot Blank study. After clean filters have conditioned for at least the same period of time as determined by 9.2.5, subsequent weighings must agree within 15 µg.

9.2.6.1 If the Exposure Lot Blanks satisfy the criterion in 9.2.5, the amount of conditioning time has been established for the entire filter lot, and no new Exposure Lot Blanks need be weighed. All remaining clean filters in the given lot must condition for at least this amount of time.

9.2.6.2 If the Exposure Lot Blanks do not satisfy the criterion in 9.2.5, the blanks are conditioned for a longer period of time. Once the consecutive daily weighings agree within 15 µg, the clean filters in that specific Exposure Lot may be weighed. The Exposure Lot Blank study must again be conducted on the next group of clean filters set out to condition (filter exposure lot). The procedure is repeated until successive Exposure Lot Blank studies yield consistent results.

9.3 Pre-sampled (clean) filters

9.3.1 See section 9.2 for required filter conditioning.

9.3.2 Verify the required room conditions have been achieved (section 12.7); if the requirements cannot be achieved, the filters are flagged with the appropriate qualifiers.

9.3.3 Click on the Results Tab of the Batch window that you've just created. Enter the values for Humidity and Temperature Data in the lower left prompt in the window.

9.3.4 Select the appropriate clean filters for weighing, placing within easy reach of the balance. The following criteria must be satisfied:

a) Filters have been conditioning for the appropriate time; the Exposure Lot Blanks (9.2.5) determine this.
b) Filters have successfully passed the filter integrity check. See table 15.1.
c) Filters have been pre-logged as described in section 9.2.2

9.3.5 Designate three filters as Lab Blanks (LB) every time pre-sampled (unexposed) filters are weighed, and label the appropriate petri dishes. Label as filter number followed by LB or FB (as appropriate). **Ex:** T8197000(LB).

9.3.6 For weighing more than 30 clean filters in any one session, designate one lab blank for each block of ten filters. **Ex:** 35 clean filters are to be weighed; designate 4 lab blanks.

9.3.7 Clean the microbalance weighing-chamber with a fine-bristled, anti-static brush.

9.3.8 Clean the surfaces near the microbalance with methanol-moistened Kim Wipes or anti-static cleaner and Kim-Wipes.

9.3.9 Clean both pairs of forceps (mass standards and filters) with methanol-moistened Kim Wipes. It is very important that the forceps be dry before handling standards.

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Tare (zero) the balance by pushing the "re-zero" key before each weighing session.

Note: The microbalance will autozero between weighings, however, the balance should be re-zeroed when drift causes the zero reading (between filter weighings) to read other than 0.000 mg.

9.3.10 Open the balance software and check for connection.

9.3.11 Log into the LabWare LIMS. The analyst should have an account with the _TECH_AQ role and should log in under that role.

9.3.12 Click on **File >Batch Manager** (or use Batch Manager Icon): -A new window will appear. Click on **File >New** (or use New Batch Icon): Click on the **Template Browser** search icon and select the **AQ_47_Clean option**. Click OK and Save. This will create a new Batch

9.3.13 Select the Scan Icon and scan the barcode on the label printed out in section 9.2.2.16.

9.3.14 After scanning in the filter numbers select save.

9.3.15 Note: After every ten filters, you must add a duplicate and 300mg QC weighing into the batch.

9.3.16 Select **Options.Enter Results by Test**

9.3.17 You will see RS/232 Result Entry window.

9.3.18 Weigh lab blanks before other filters in any given session.

9.3.19 Pick up each filter, using the designated forceps for filters, by the support ring only. Pass every filter over the ^{210}Po strips for 15-30 seconds before placing in the weighing pan for measurement. Center each filter in the middle of the balance pan when weighing. Close the weighing chamber.

9.3.20 Press print on the scale. The weight will then be recorded and appear in the clean Weight cell when a stable reading is achieved.

9.3.21 After the measurement is transferred, open the weighing chamber and return each filter to its designated petri dish after weighing.

> **NB:** For each filter, ensure that the filter number matches against the label on the petri dish.

9.3.22 One filter in each group of ten filters is weighed in duplicate. Weigh the filter, remove the filter from the weighing pan, and again weigh the filter. See section 12.12 for acceptance criterion.

9.3.23 Repeat until all filters have been weighed. Then Select **Save,** then **Exit**.

9.3.24 Select **NMDOH>Modify Samples**. This is where qualifiers are added. This is the first step of Shipping Out.

9.3.25 You will see an AQ Batch Sample Edit Window. This is where you will enter the Cassette # and Magazine; Sample type (SAM, LB, FB)

9.3.26 Entering Site ID: The Site ID is demographic data provided by the client and is linked to, tables in LIMS that populate other information fields associated with it.

9.3.26.1 Site ID is entered by using a drop-down menu.

9.3.26.1.1 Select the appropriate Site ID based upon the client's request.

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9.3.26.1.2 Once the appropriate Site ID is selected, the analyst should confirm that the correct location information populates.

NB: IF you notice that you have selected the wrong Site ID from the drop down menu. STOP.
Exit the batch and DO NOT SAVE.
Go back in and enter the correct Site ID.

NB: If the Site ID does not match up with the location provided by the client, Immediately STOP and notify your supervisor.

Then Ship Date

9.3.27 NOTE Never hit the **Save** option until all data is entered and verified by the analyst.
9.3.28
9.3.29 When complete hit **Save. Then Exit**.
9.3.30 Enter the Serial Numbers of the Working Standards and any qualifiers. Save Data before exiting
9.3.31 When the batch sheet requires, weigh the 300 and 500 mg working standards using the **standard** forceps.
9.3.31.1 Place the appropriate mass standard in the center of the pan. Close the weighing chamber door. Press print on the scale. The software will transfer the measurement to the LIMS automatically when the measurement is stable.
9.3.32 Each standard must agree with the verified mass ± 3 µg. If not, reweigh the standard(s). If the mass still does not fall within the acceptable range, take appropriate corrective actions (see section 12.6).
9.3.33 Select NMDOH > Print paperwork to print out request forms for each filter.
9.3.34 The batch is now ready to be reviewed in LIMS by the AQ_Sup

9.4 Packaging Clean Filters for Shipment

9.4.1 Filters are shipped to NMED via UPS Ground; the City of Albuquerque (COA) picks up filters at SLD. Package filters such that clients receive them no later than the day previous to the day needed (check the appropriate client sample schedule). UPS usually takes one day.

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9.4.2 The deadline for packages sent via UPS is 1:30 p.m. each day. Packaged filters must be taken to Specimen Receiving by this time. Check with Specimen Receiving personnel should you not be able to meet this deadline, as they may be able to delay UPS pickup. Also check with Specimen Receiving for UPS holiday schedules.

9.4.3 Retrieve the appropriate client shipping labels; these are in the balance room.

9.4.4 Secure the necessary number of Pre-sampled (clean) filters (see section 9.3) to load one magazine at a time.

9.4.5 Complete the shipping label. **Note:** Magazines are loaded bottom to top; complete the shipping label in the exact order that filters and spacers are packed.

9.4.6 For NMED, the bottom cassette (first into the magazine) is a solid spacer. For COA, the first is a sample (filter).

9.4.7 Check the fit of the top and bottom halves for each cassette before loading a filter. The fit MUST be tight. If not, try another cassette half. Note that the screen will decrease the tightness; if there is any doubt regarding the fit, load a screen and check the fit again.

9.4.8 Spacers have no designated top or bottom.

9.4.9 Filter screens must be loaded with the number facing down.

9.4.10 The top half of each cassette has a beveled edge. The beveled edge faces up when loaded into the magazine.

9.4.11 Load the magazine. Push each successive cassette into the magazine such that the top of the cassette is even with the top of the magazine.

9.4.12 Place an orange-colored cap over the top of the magazine when loading is completed.

9.4.13 Repeat steps 9.4.3-9.4.12 as needed.

9.4.14 Load the magazine into a metal shipping container as each one is completed, and tape both ends of the shipping label to the top (lid) of the metal shipping container. Repeat for the remaining magazines.

9.4.15 For NMED samples, proceed to step 9.4.16. For COA samples, go to step 9.4.21.

9.4.16 Package no more than four metal shipping containers per Styrofoam cooler. Group by submitter. Place the metal shipping container(s) on the cooler bottom, and pack liberally with ice-substitute blocks.

9.4.17 Include one thermometer into the cooler, The paperwork to accompany the filters should be placed into the cooler and then covered with the Styrofoam lid. **Note:** Most coolers have an outer cardboard protective carton.

9.4.18 Place a sticky note on the outer cardboard protective carton, indicating the submitter code, submitter city, and client name. This info is found on the list posted on the wall.

9.4.19 Repeat steps 9.4.16-9.4.18 for the remaining metal shipping containers.

9.4.20 Take the packages to Shipping and Receiving for shipping by 1:30 p.m. for NMED samples.

9.4.21 Take the COA shipping containers to Specimen Receiving. COA pickup is before close of business on Wednesday afternoon, unless otherwise requested by COA.

9.5 Exposed filter check-in

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9.5.1 Filter receipt and check in by Specimen Receiving.

9.5.1.1 NMSLD Specimen Receiving personnel receive shipping/transport container(s); typically, this will be an insulated picnic cooler for NMED filters. The cooler is opened and the filter magazine protective container(s) (metal shipping box) and accompanying request form(s) are retrieved.

9.5.1.2 NMSLD Specimen Receiving personnel note the maximum temperature indicated on the min/max thermometer contained in the cooler and record on the request form to the nearest °C. For filter samples received not in a cooler, record the ambient temperature on the appropriate data sheet(s).

9.5.1.3 One form is required for each filter.

9.5.1.4 Upon receipt, collect the *Filter Chain of Custody Record(s)*. **Note:** The *Filter Chain of Custody Record(s)* must not be packaged inside the filter magazine.

9.5.1.5 **Note:** Filter magazines must only be opened by authorized AHM personnel.

9.5.1.6 NMSLD Specimen Receiving personnel return the metal shipping boxes back into their respective coolers and deliver to the AHM section facility. **Note:** NMSLD is a designated secure area; therefore, no internal custody transfers need be documented.

9.5.2 Filter receipt and check in by Air & Heavy Metals.

9.5.2.1 The filters are brought to AHM room 2366A still in the coolers and their protective containers (metal shipping boxes).

9.5.2.2 Retrieve the magazine from the metal shipping container. The magazines should not be wet from melting ice. If they are wet, flag as "questionable".

9.5.2.3 Remove the shipping label from the top of the metal shipping container and tape the shipping label to the orange cap. Leave the magazine in room 2348 for 24 hours before opening for thermal equilibration.

9.5.2.4 After thermal equilibration, take the magazines into Room 2348A, remove all solid spacers and filter cassettes from the filter magazine, and inspect the inside of the magazine for particulate matter and/or debris. If particulate matter and/or debris is found, all filters contained in the magazine are flagged as questionable.

9.5.2.5 Carefully separate the 2 halves of the cassette container to remove the filter sample. Inspect for and note any debris or filter compromise in LIMS. Flag all filters that have obvious signs of damage to either the filter or filter cassette as questionable in the LIMS Lab field remarks.

9.5.2.5.1 Damaged filters are voided and not weighed. Explain all voided filters in the LIMS field remarks.

9.5.2.6 Set the cassette halves and screens to wash.

9.5.2.6.1 Cassettes are reusable and shall be cleaned between uses. Wash with Alconox in warm water; rinse thoroughly with tap water, followed by deionized water after washing. Let dry at room temperature completely.

9.5.2.7 Retrieve the appropriate petri dishes previously used for clean filter conditioning, and place the exposed filter in the dish, exposed side up.

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Double check that the filter and LIMS numbers match up. Partially cover with the petri dish top half.

9.5.2.8 The filter in the open dish should be conditioned for a minimum of 24 hours before weighing.

9.5.2.9 Verify the user code, submitter code, priority, and sample location, site ID and analytical request fields are completed by the submitter. If not, the analyst completes these fields. Initial all changes to the request form. Do not add filter number unless there is only one filter per magazine (determine from shipping label).

9.5.2.10 Verify that each request form corresponds to the appropriate cassette and filter. Investigate and document all discrepancies.

9.5.2.11 Upon receiving the exposed filters back into SLD, Shipping and Receiving personnel record the filter temperatures and any field remarks into LIMS. Filters are delivered to the section as described above are and forms are returned to the AHM section.

9.5.2.12 With respect to the 47mm $PM_{2.5}$ filters If any are received at 4 ^{0}C they must be weighed within 30 calendar days from receipt. Filters received at > 4 ^{0}C, but < 25 ^{0}C must be weighed within 10 calendar days from receipt. Filters received at > 25 ^{0}C are weighed within 10 calendar days from receipt but are flagged as questionable. This rule does not pertain to 47mm PM_{10} filters.

9.6 Exposed Filter Weighing

9.6.1 The analyst must wear static-free, non-powdered gloves when handling filters.

9.6.2 Use the same balance for exposed weighing as was used for the unexposed weighing.

9.6.3 Clean the microbalance weighing-chamber with a fine-bristled, anti-static brush.

9.6.4 Clean the surfaces near the microbalance with methanol-moistened Kim Wipes or anti-static cleaner and Kim-Wipes.

9.6.5 Clean both pairs of forceps (mass standards and filters) with methanol-moistened Kim Wipes. It is very important that the forceps be dry before handling standards or filters.

9.6.6 Tare (zero) the balance by pushing the "re-zero" key before each weighing session.

Note: The microbalance will autozero between weighings, however, the balance should be re-zeroed when drift causes the zero reading (between filter weighings) to read other than 0.000 mg.

9.6.7 Start the balance software and confirm connection.

9.6.8 Start LIMS software. Go to Batch Manager and create a new Exposed Batch.

9.6.9 Record the room temperature and relative humidity in LIMS Results Tab as described in section 9.3.3.

9.6.10 Weigh the 500 and 300 mg. working standards using the **standard** forceps.

9.6.10.1 Open the weighing chamber and place the 500-mg mass standard in the center of the pan. Close the weighing chamber door. Press the print button on

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the scale. LIMS software will transfer the measurement automatically when the measurement is stable.

9.6.10.2 Repeat using the 300-mg mass standard.

9.6.11 Each standard must agree with the verified mass ± 3 µg. If not, reweigh the standard(s). If the mass still does not fall within the acceptable range, take appropriate corrective actions (see section 12.6).

9.6.12 Select an appropriate number of conditioned filters to weigh, placing within easy reach of the balance.

9.6.13 Exposed filters and cassettes must be inspected for signs of damage before weighing. Flag all filters that have obvious signs of damage to either the filter or filter cassette as questionable.

9.6.14 Weigh a Lab Blank (LB) filter first, then all exposed filters defined by the blank, including appropriate Field Blanks (FB). Pick up each filter, using the **exposed filter forceps** by the support ring only. Pick up each filter, using the designated forceps for filters, by the support ring only. Pass each filter over the ^{210}Po strips for 30-60 seconds before placing in the weighing pan for measurement. Center each filter in the middle of the balance pan when weighing.

9.6.15 Close the weighing chamber. Press the print button on the scale. The software will transfer the measurement when a stable reading is achieved (after the symbol ° disappears from the upper left corner of the balance display).

9.6.16 After the measurement is transferred, open the weighing chamber and return each filter to its designated petri dish after weighing, double checking filter numbers on the filters and petri dishes.

9.6.17 One filter in each group of ten filters is weighed in duplicate. Weigh the filter, remove the filter from the weighing pan, and again weigh the filter. See section 12.12 for acceptance criterion.

9.6.18 Reweigh the 300 mg. working standard after every duplicate filter, using the **standard** forceps. Each standard must agree with the verified mass ± 3 µg.

9.6.19 Repeat steps 9.6.12 through 9.6.19 until all necessary filters are weighed.

9.6.20 After all filters are weighed, reweigh the 300 mg working standard twice and then the 500 mg. working standard. Handle the mass standards using the **standard** forceps. Resume the macro.

9.6.21 The batch is now ready to be reviewed in LIMS by the "AQ_Sup."

10. CALCULATIONS AND REPORTING

10.1 The net filter loading is calculated by the following equation:

$$M_{2.5} = (M_f - M_I) \times 10^3$$

Where $M_{2.5}$ = total mass of particulates collected during the sampling period, in µg.
M_f = final mass of the equilibrated filter after sample collection, in mg
M_i = initial mass of the equilibrated filter before sample collection, in mg
10^3 = units conversion (10^3 µg/mg)

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10.2 Record filter weights in **milligrams** (mg).
10.3 Report the net difference (final weight – initial weight) in **micrograms** (µg).
10.4 Additional information for filters are noted as 3-digit qualifiers; see table 15.2.
10.5 Completed filter data is archived for a period of three (3) years following completion.

11. METHOD PERFORMANCE

11.1 The accuracy of the microbalance is assessed every 6 months, more often if indicated, using the certified Class 1 mass standards (200, 300 & 500 mg). The balance measurement must agree within ± 25 µg of the certified value.
11.2 The precision of the microbalance is assessed every 6 months, more often if indicated, using the certified Class 1 mass standards (200, 300 & 500 mg). The standard deviation of replicate measurements of each standard is compared to a pre-defined
11.3 Each working standard is verified against the appropriate certified class 1 primary mass standard every 6 months. The working standard must agree with the certified value within 25 µg.
  11.3.1 The acceptable range for the 200-mg working standard is 199.975 – 200.025 mg.
  11.3.2 The acceptable range for the 300-mg working standard is 299.975 – 300.025 mg.
  11.3.3 The acceptable range for the 500-mg working standard is 499.975 – 500.025
11.4 The precision of filter measurements is evaluated by replicate weighings of one filter out of every 10 filters weighed. Replicate weighings must agree within 15 µg.

12. QUALITY CONTROL

12.1 Filter Integrity Check: Before any filter can be weighed, either as a pre-sampled (unexposed) or post-sampled (exposed), the integrity of the filter and support ring must be examined. Refer to table 15.1 for parameters and criteria.
12.2 The calibration of the microbalance is checked yearly by a certified technician.
12.3 Class 1 primary mass standards are **certified** annually by a certified metrologist. These standards are used to verify the working standards.
12.4 Class 1 primary mass standards are **weighed** every 6 months, to assess balance accuracy and precision. Weigh each standard in duplicate and record in the appropriate file.
12.5 Working standards (200, 300 & 500 mg.) are verified against the Class 1 primary mass standards every 6 months. The measured value must be within 25 µg of the certified value. Record these values.
12.6 Working standards (300 & 500 mg.) are used to verify the balance calibration before every weighing session. The acceptable range is verified ± 3 µg. If the working standards are outside these limits, re-weigh the working standards. If the standards are still outside these limits, take corrective actions, including taring (zeroing) the balance, weighing the primary standards, passing the standards over the ^{210}Po strips, or other measures.

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12.7 Weighing should only be done when the balance room conditions meet the following criteria:

The mean relative humidity should be between 30.0-40.0%, with control of not more than ± 5.0% change in the 24 hours immediately prior to weighing.
The mean temperature should be between 20.0-23.0^{0}C, with control of not more than ± 2.0^{0}C change in the 24 hours immediately prior to weighing.

Control of both temperature and humidity may be demonstrated by calculating the arithmetic mean (AM) and standard deviation (SD) of the values taken from the data logger for the twenty-four hours prior to weighing.

$$AM = \frac{1}{n}\sum_{i=1}^{n} a_i = \frac{1}{n}(a, \mid a_2 \mid \cdots a_n)$$

$$SD = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(x-\mu)^2}$$

12.7.1 If these conditions cannot be achieved, the data must be flagged appropriately. Investigate and document possible causes and solutions.

12.8 Filter Exposure Lot Blank (Section 3.15): Three (3) filters are randomly selected from each filter lot and designated as Exposure Lot Blanks. The 3 filters are conditioned for a minimum of 24 hours, then weighed on consecutive days until such time that the 24-hour weight change is less than 15 µg. While conditioning, the petri dishes must be open. If the exposure lot blanks do not agree within ± 15 µg, return the blanks for further conditioning. When three (3) consecutive daily weighings agree within ± 15 µg, all filters of the same lot as the exposure lot blanks may be pre-sampled once they have conditioned for the same length of time as did the blanks.

12.9 Lab Blank (Section 3.16): Weigh a minimum of three (3) Lab Blank (LB) filters at each pre-sampling weighing session. One lab blank filter must be weighed at each post-sampling weighing session. Do NOT use a lab blank for more than one post-sampling weighing session. The acceptable weight difference (post-sampling minus pre-sampling) must be within ± 15 µg.

12.9.1 If the difference is > 15 µg, contamination in the conditioning and/or weighing areas should be suspected. The analyst must take appropriate corrective actions,

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including: Reweigh the working mass standards and verify they are within acceptable range; weigh a second lab blank. If a second lab blank also shows > 15 µg difference, do not proceed with filter weighing, but advise the section supervisor. If a second lab blank also shows < 15 µg difference, proceed with filter weighing, but investigate possible sources of contamination and take corrective actions to eliminate them.

12.10 Field Blank (Section 3.14): Weigh all Field Blanks (FB) submitted with the group(s) of filters to be weighed at each post-sampling (exposed filter) weighing session. The acceptable weight difference (post-sampling minus pre-sampling) must be within ± 30 µg.

12.10.1 If the difference is > 30 µg, but the lab blanks are within acceptable range, the analyst should return the filters to the conditioning area, as the filters may have not had adequate time to condition.

12.10.2 After further conditioning, if the difference is > 30 µg, but the lab blanks are within acceptable range, contamination in the field/sampling process should be suspected. The sample filters defined by the specific field blank that is out of acceptable range should be flagged.

12.10.3 If the difference is > 30 µg, and the lab blanks are out of the acceptable range, contamination in the conditioning and/or weighing areas should be suspected. The analyst must take appropriate corrective actions.

12.11 Post-sampled (exposed) $PM_{2.5}$ filters should weigh approximately 110-160 mg. Exposed filters outside this range should be investigated by the client or an independent party.

12.12 Replicate measurements of the filter selected for duplicate weighing (section 9.3.15 and 9.6.18) should agree within 2 µg. If the difference is greater than 2 µg, reweigh the filter. If the difference is still greater than ± 2 µg, reweigh both working standards. If the standards are within the acceptable range (section 12.5), reweigh the last group of filters (since the last measurement of the 300-mg. working standard).

12.13 DI water is obtained from the SLD house DI water system and is filtered to 18 megaohms resistance prior to use.

12.14 The tacky mat outside the balance room shall be changed at least once each week, more often if indicated.

12.15 The Dickson Hygrometer/Thermometer is the environmental monitor of record for the filters processed. The circular data charts record continuous data for 1-week periods and the charts are kept on file for a period of 3 years.

13. SAFETY

13.1 ^{210}Po strips are alpha emitters and should not be touched directly.

13.2 Analysts must not be in the 2348A balance room when they have compromises to their skin (cuts, abrasions, etc.) that are exposed to the ^{210}Po strips. In all such cases, the analyst must cover the compromised skin with bandages, clothing, or gloves as appropriate.

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13.3 Appropriate PPE should be worn in the balance rooms to minimize and protect against exposure from α-particle emissions from Po^{210}. Minimum PPE includes safety glasses, lab coat, and gloves.

14. REFERENCES

14.1 Code of Federal Regulations, Part 40 parts 53 and 58.

14.2 Quality Assurance Document 2.12. *Monitoring $PM_{2.5}$ in Ambient Air Using Designated Reference or Class I Equivalent Methods*. U.S. EPA Aril 1998.

14.3 Quality Assurance Guidance Document. *Model Quality Assurance Project Plan for the $PM_{2.5}$ Ambient Air Monitoring Program at State and Local Air Monitoring Stations (SLAMS)*. EPA-454/R-98-005. April 1998.

14.4 CAHN Technical Note. *Static Control for Balances by Jerry Weil*. Cahn Instruments, Inc.

14.5 *Quality Assurance Guidance Document 2.12 Monitoring PM2.5 in Ambient Air Using Designated Reference or Class I Equivalent Methods* EPA 454/B-16-001 January 2016).

14.6 *NAAMC Contract Lab Training*: 2016 National Ambient Air Monitoring Conference; Greg Noah; US EPA QAQPS; Stephanie McCarthy, US EPA Region 4

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15. TABLES

15.1 Filter Integrity Check

Each pre-sampled (unexposed) filter must be inspected for, and pass the criteria described in the table below.

Filter Integrity Checklist	
Filter Defect.	Defect description
Pinhole	A small hole appearing as: a distinct and obvious bright point of light when examined over a light table or a dark spot when viewed over a dark surface.
Separation of ring	Any separation or lack of seal between the filter and filter border reinforcing the ring.
Chaff or flashing	Any extra material on the reinforcing ring or on the heat seal area that would prevent an airtight seal during sampling.
Loose Material	Any extra loose material or dirt particles on the filter.
Discoloration	Any obvious discoloration that might be evidence of contamination.
Filter nonuniformity	Any obvious nonuniformity in the appearance of the filter when viewed over a light or dark surface that might indicate gradations in porosity or density across the face of the filter.
Other	A filter with any imperfection not described above, such as irregular surfaces or other indications of poor manufacture.

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15.2 Qualifiers

The following qualifiers are used to provide additional information regarding the conditioning and/or weighing processes.

Code	Definition	Description
ALT	Alternate Measurement	The subject parameter was determined using an alternate measurement method. Value is believed be accurate but could be suspect.
AVG	Average Value	Average value-used to report a range of values.
CAN	Canceled	The analysis of this parameter was canceled and r performed.
FFB	Failed Field Blank	Field blank samples exceeded acceptance criteria limits.
FLB	Failed Laboratory Blank	Laboratory blank samples exceeded acceptance criteria limits.
FLD	Failed Laboratory Duplicate	Laboratory duplicate samples exceeded acceptanc criteria limits.
FLH	Failed Laboratory Humidity	Laboratory humidity exceeded acceptance criteria limits.
FLT	Failed Laboratory Temperatu	Laboratory temperature exceeded acceptance crit limits.
FQC	Failed Quality Control	The analysis result is not reliable because quality control criteria were exceeded when the analysis was conducted. Numeric field, if present, is estimated value.
GSI	Good Shipping Integrity	Integrity of filter upon receipt by shipping/receivi looked good.
HTE	Holding Time Exceeded	Filter holding time exceeded acceptance criteria limits.
ISP	Improper Sample Preservatic	Due it improper preservation of the sample, it wa rendered not suitable for analysis.
INV	Invalid Sample	Due to a single or multiple flags or events, the sample was determined to be invalid.
LAC	Laboratory Accident	There was an accident in the laboratory that eithe destroyed the sample or rendered it not suitable fo analysis.
OTH	Other	Miscellaneous event(s) occurred requiring further explanation.
REJ	Rejected	The analysis results have been rejected for an unspecified reason by the laboratory. For any resu where a mean is being determined, this data was r utilized in the calculation of the mean.

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APPENDIX A

List of equipment used in SLD Gravimetric Laboratory

Analytical Microbalance

Mettler XP6 microbalance (Serial Number B607093202).
Capacity 6.1 grams
Readability 1µg.
Repeatability 0.0008 mg
Linearity 0.004 mg

Hygrometer and temperature logger
Dickson THDX (Serial Number 8002212) #

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Appendix B: Archiving of 47mm air filters.

This appendix describes the procedure for archiving filters used in the EPA ambient air program. Filters require storage under controlled conditions and should be available for reanalysis if needed. Filters that have been exposed, returned to SLD and conditioned for weighing to determine the net gravimetric difference need to be properly stored as described below.

1. **Equipment**:
   - 1.1. SR walk in refrigerator (SLD room G392B) maintained at 0-4˚C with Reese™ computer monitored temperature control. One storage shelf is reserved for AHM.
   - 1.2. AHM Prep-lab storage area for ambient storage of 47 filters (SLD Room2366A)
   - 1.3. Analyslide™ Petri-Dishes with storage boxes
   - 1.4. 47mm Teflon Filters
   - 1.5. Aluminum foil rolls, 12" in width
   - 1.6. Plastic wrap rolls, 12" in width.
   - 1.7. Electronic Filter Logbook
2. **Procedure for Preparing Filters for Archival Storage**
   - 2.1. In preparation for storage, the filters should be placed in Analyslide™ Petri Dishes used to house the filters during conditioning, weighing, and handling in the laboratory. Each Petri Dish is labeled with the manufacturer's filter number as well as the SLD accession number, (with barcode) and allows for ease of tracking and retrieval during storage. Each filter is also recorded onto an electronic logbook (Excel spreadsheet) (See Figure 2). The logbook documents the storage time and dates and location so that filters can be stored, retrieved and disposed of according to EPA requirements.
   - 2.2. When filter placement in the Petri Dishes is complete, the filters are then placed in storage boxes as described below.
   - 2.3. The Analyslide™ Petri Dishes come in boxes of 25 and these boxes will be used for storage. Each box will have a label affixed that contains the following information:

CY	20*XX*
Box *X*	
Zm	Cold Disp Date Jan-Year
Ambient Storage Disp. Date Jan-Year	

Where:

CY 20*XX* is the Calendar Year that the filter was exposed.
Box *X* is a unique serial number assigned to each box. For each calendar year the Box x is reset to Box 1.
*Z*m is the particle fraction determined at the time of exposure. (2.5m or 10m.)

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Cold Disp Date: Jan-Year. For 2.5m particulate fractions, this is the date after which filters may be removed from cold storage.
Ambient Storage Disp. Date Jan-Year. For 2.5m and 10m particulate fractions, this is the date after which filters may be discarded.

2.4. Logbook for tracking filters

2.4.1. The Filter Logbook will contain the following fields for each filter.

2.4.1.1. Year the sample was exposed. (Year)
2.4.1.2. SLD accession number assigned to each filter. (SLD#)
2.4.1.3. The manufacturer's filter number (Filter #)
2.4.1.4. Sampling Site (Site)
2.4.1.5. User Code used for billing purposes (User Code)
2.4.1.6. Box 1 (Box #)
2.4.1.7. Information on void status (Void)
2.4.1.8. Analyst (Analyst)
2.4.1.9. Position of the filter in the Analyslide™ Petri Dish box (Box Position)
2.4.1.10. Particle Size (Particle Size)

2.5 Filters from the 2.5m and 10m size particle fractions will be stored in separate boxes and not intermingled. Filters will be stored sequentially in their respective boxes based upon the SLD number assigned to them. An example of a logbook page is represented by Figure 2 below. The Filter Logbook will be kept electronically on the AHM drive @ F:\Air Filter Storage Archive

Year	SLD #	Filter #	Site	User code	Box #	Void	Analyst	Box position	Particle size
2013	2013022083	T2658588	6Q	55625	1	X	RSF	1	2.5
2013	2013022084	T2658589	6Q	55625	1		RSF	2	2.5
2013	2013022085	T2658590	6ZG	55625	1		RSF	3	2.5
2013	2013022086	T2658591	6ZG	55625	1		RSF	4	2.5
2013	2013022087	T2658592	6ZG	55625	1		RSF	5	2.5
2013	2013022088	T2658593	6ZG	55625	1		RSF	6	2.5
2013	2013022089	T2658594	6ZG	55625	1		RSF	7	2.5
2013	2013022090	T2658595	6ZG	55625	1		RSF	8	2.5

Figure 2. A sample of the Filter Logbook page that contains all the required fields.

2.6 PM2.5 and PM10 Filter Storage: All PM filters will require storage in a refrigerated environment. The storage temperature should be maintained 0-4˚C. They are to be placed in the Analyslide™ Petri Dish box and then wrapped with a single layer of plastic wrap followed by a single layer of aluminum foil wrap. Each box will have a label affixed on the end and a label on the outer aluminum foil wrap. They will be stored

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under refrigerated conditions in Shipping and Receiving Section Refrigerated Storage room G392B

3. Filter Storage Time Limits

3..1. PM2.5 and PM10 filters will be stored in cold storage during the calendar year in which they were exposed plus one additional calendar year. After that they may be stored at ambient temperature for an additional four years.

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Gravimetric Analysis of 47mm Air Filters - AHM Method 41710 - Version: 3.0. Index: CB AHM 104. Printed: 05-Dec-2018 15:10

Revision 2.1 February 20, 2011

- Eliminated milligram, microgram, and millimeter definitions from definitions sections.
- Defined LIMS as the database system of record for AQ gravimetric analysis
- Defined the business procedures that are appropriate for carrying out LIMS operations.
- Moved description of filters and related equipment from definitions to equipment section.
- Moved references to specific equipment to Appendix A.
- Referenced rooms now currently in use in the new SLD building for AQ gravimetric analysis.
- Consolidated 47mm PM_{10} into this document.

Revision 2.2 August 27th, 2013

- Added Appendix B which describes archiving procedure for 47mm filters.

Revision 3.0 March 26, 2018

- Added changes requested by EPA through NMED AQB.
    - Revise acceptance ranges for temperature, relative humidity weighing checks, field blank checks to reflect precision to decimal criteria recommended in EPA QAH App D. and change definition of Lab Control to be determined by mean and standard deviation of values in the previous 24-hour period per 40 CFR 58. Method 2.12 Section 10.4.1.3.
- Revised Appendix B to reflect EPA recommendation to follow 40 CFR 58.16(f) requirement to store all 47mm filters in cold storage for 1 year and ambient storage for an additional 4 years.
- Update EPA reference material to reflect most current EPA documentation and guidance.

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APPENDIX C

To

QUALITY ASSURANCE PROJECT PLAN FOR AMBIENT AIR MONITORING

2020

NEW MEXICO ENVIRONMENT DEPARTMENT

AIR QUALITY BUREAU

Appendix C to 2020 Ambient Air Monitoring QAPP: Network Elements Spreadsheet

New Mexico Monitoring Network in 2019

Continuous Monitors & Non-Continuous Monitors

Site AQS #	Site Name	Station Type	Site Address	Latitude	Longitude	Pollutants Measured	Analysis Method	Operating Schedule	Is site proposed to be removed/moved within next 18 months?	Monitoring Objective	NAAQS Comparable ?	msa/cbsa/csa represented	Spatial Scale
35-045-1005	1H Substation	SLAMS	Shiprock Electrical Substation, Waterflow, NM 87421	36.7976	-108.4801	Ozone	U.V. Photometric	Continuous	No	General Background	Yes	Farmington MSA	Regional
		SLAMS				Nitrogen Dioxide	Chemiluminescence	Continuous		General Background	Yes	Farmington MSA	Regional
		SLAMS				Sulfur Dioxide	Pulsed Fluorescence	Continuous		Source Oriented	Yes	Farmington MSA	Regional
		SPM				PM_{10}	Continuous; BAM-1020	Continuous		General Background	Yes	Farmington MSA	Regional
35-045-0009	1ZB Bloomfield	SLAMS	2200 N 1st Street, Bloomfield, NM 87413	36.7421	-107.9774	Ozone	U.V. Photometric	Continuous	No	General Background	Yes	Farmington MSA	Neighborhood
		SLAMS				Nitrogen Dioxide	Chemiluminescence	Continuous		General Background	Yes	Farmington MSA	Neighborhood
		SLAMS				Sulfur Dioxide	Pulsed Fluorescence	Continuous		Source Oriented	Yes	Farmington MSA	Neighborhood
35-045-0018	1NL Navajo Lake	SLAMS	423A Highway 539, Navajo Dam, NM 87419	36.8097	-107.6514	Ozone	U.V. Photometric	Continuous	No	Regional Transport	Yes	Farmington MSA	Middle
		SLAMS				Nitrogen Dioxide	Chemiluminescence	Continuous		Regional Transport	Yes	Farmington MSA	Middle
35-061-0008	2LL Los Lunas	SLAMS	1000 W. Main St, Los Lunas, NM 87031	34.8147	-106.7410	Ozone	U.V. Photometric	Continuous	No	Population Exposure	Yes	Albuquerque MSA	Neighborhood
35-043-1001	2ZJ Bernalillo	SLAMS	600 Oak Street, Bernalillo NM 87004	35.2998	-106.5470	Ozone	U.V. Photometric	Continuous	No	Population Exposure	Yes	Albuquerque MSA	Neighborhood
35-039-0026	3CRD Coyote Ranger District	SLAMS	21 New Mexico 96, Coyote, NM, 87012	36.1877	-106.6984	Ozone	U.V. Photometric	Continuous	No	Regional Transport	Yes	Albuquerque-Santa Fe-Las Vegas CSA	Regional
35-049-0021	3SFA Santa Fe Airport	SLAMS	2001 Aviation Dr, Santa Fe, NM 87507	35.6198	-106.0797	Ozone	U.V. Photometric	Continuous	No	Population Exposure	Yes	Santa Fe MSA	Neighborhood
		SLAMS				$PM_{2.5}$	Continuous; BAM-1020	Continuous		Population Exposure	Yes	Santa Fe MSA	Neighborhood
35-055-0005	3ZD Taos	SLAMS	123 Camino de Santiago Fire Station, Taos, NM 87571	36.3833	-105.5849	$PM_{2.5}$	Continuous; BAM-1020	Continuous	No	Population Exposure	Yes	Taos µSA	Neighborhood
35-015-1005	5ZR Carlsbad	SLAMS	2811 Holland St., Carlsbad, NM 88220	32.3840	-104.2640	Ozone	U.V. Photometric	Continuous	No	General Background	Yes	Carlsbad-Artesia, CBSA/µSA	Urban
		SLAMS				Nitrogen Dioxide	Chemiluminescence	Continuous		General Background	Yes	Carlsbad-Artesia, CBSA/µSA	Urban
35-025-0008	5ZS Hobbs Jefferson	SLAMS	2320 N. Jefferson St., Hobbs, NM 88240	32.7268	-103.1230	Ozone	U.V. Photometric	Continuous	No	Population Exposure	Yes	Hobbs CBSA/µSA	Neighborhood
		SLAMS				Nitrogen Dioxide	Chemiluminescence	Continuous		Population Exposure	Yes	Hobbs CBSA/µSA	Neighborhood
		SLAMS				$PM_{2.5}$	Continuous; BAM-1020	Continuous		General Background	Yes	Hobbs CBSA/µSA	Neighborhood
35-013-0016	6CM Anthony	SLAMS	705 Church St., Anthony, NM 88021	32.0033	-106.5992	PM_{10}	Sequential FRM	Every 6th Day	No	Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
		SLAMS				PM_{10}	Co-Located Continuous; BAM-1020	Continuous		Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
		SLAMS				$PM_{2.5}$	Continuous; BAM-1020	Continuous		Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
		SLAMS				$PM_{2.5}$	Co-located Sequential FRM	Every 3rd Day		Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
35-013-0008	6O La Union	SLAMS	7048 McNutt, La Union, NM 88021	31.9187	-106.6330	Ozone	U.V. Photometric	Continuous	No	General Background	Yes	El Paso-Las Cruces CSA	Urban
35-013-0024	6WM West Mesa	SLAMS	West Mesa Well #46, Las Cruces, NM 88005	32.2781	-106.8649	PM_{10}	Continuous; BAM-1020	Continuous	No	Up Wind Background	Yes	El Paso-Las Cruces CSA	Urban
35-013-0019	6ZL Holman Road	SLAMS	Las Cruces Well #41, Las Cruces, NM 88012	32.4246	-106.6739	PM_{10}	Continuous; BAM-1020	Continuous	No	Population Exposure	Yes	El Paso-Las Cruces CSA	Urban
35-013-0020	6ZK Chaparral	SLAMS	680 McCombs, Chaparral, NM 88081	32.0409	-106.4095	Ozone	U.V. Photometric	Continuous	No	General Background	Yes	Not in an MSA	Urban
		SLAMS				PM_{10}	Continuous; BAM-1020	Continuous		Population Exposure	Yes	Not in an MSA	Neighborhood
35-013-0021	6ZM Desert View	SLAMS	5935A Valle Vista, Sunland Park, NM 88063	31.7961	-106.5839	Ozone	U.V. Photometric	Continuous	No	General Background	Yes	El Paso-Las Cruces CSA	Neighborhood
		SLAMS				Nitrogen Dioxide	Chemiluminescence	Continuous		Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
		SLAMS				PM_{10}	Continuous; BAM-1020	Continuous		Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
		SLAMS				$PM_{2.5}$	Sequential FRM	Every 3rd Day		Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
		SLAMS				$PM_{2.5}$	Co-located Sequential FRM	Every 3rd Day		Population Exposure	Yes	El Paso-Las Cruces CSA	Neighborhood
35-013-0022	6ZN Santa Teresa	SLAMS	104-2 Santa Teresa Int'l. Blvd., Santa Teresa, NM 88063	31.7881	-106.6826	Ozone	U.V. Photometric	Continuous	No	General Background	Yes	El Paso-Las Cruces CSA	Urban
		SLAMS				Nitrogen Dioxide	Chemiluminescence	Continuous		General Background	Yes	El Paso-Las Cruces CSA	Urban
		SLAMS				$PM_{2.5}$	Continuous; BAM-1020	Continuous		General Background	Yes	El Paso-Las Cruces CSA	Urban
35-013-0023	6ZQ Solano	SLAMS	750 N. Solano Drive, Las Cruces, NM 88001	32.3187	-106.7675	Ozone	U.V. Photometric	Continuous	No	Population Exposure	Yes	El Paso-Las Cruces CSA	Urban
35-013-0025	6Q Las Cruces	SLAMS	2301 Entrada del Sol, Las Cruces, NM 88001	32.3103	-106.7512	$PM_{2.5}$	Continuous; BAM-1020	Continuous	No	Regional Transport	Yes	El Paso-Las Cruces CSA	Neighborhood
35-029-0003	7E Deming Airport	SLAMS	3412 Raymond Reed Blvd., Deming, NM 88030	32.2558	-107.7227	PM_{10}	Continuous; BAM-1020	Continuous	No	Population Exposure	Yes	Deming CBSA/µSA	Neighborhood

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APPENDIX D

To

QUALITY ASSURANCE PROJECT PLAN FOR AMBIENT AIR MONITORING

2020

NEW MEXICO ENVIRONMENT DEPARTMENT

AIR QUALITY BUREAU

Ozone Validation Template

1) Requirement (O_3)	2) Frequency	3) Acceptance Criteria	Information /Action
CRITICAL CRITERIA-OZONE			
Monitor	NA	***Meets requirements listed in FRM/FEM designation***	1) 40 CFR Part 58 App C Sec. 2.1 2) NA 3) 40 CFR Part 53 & FRM/FEM method list
One Point QC Check Single analyzer	***Every 14 days***	< ±7.1% (percent difference) or < ±1.5 ppb difference whichever is greater	1 and 2) 40 CFR Part 58 App A Sec. 3.1 3) Recommendation based on DQO in 40 CFR Part 58 App A Sec. 2.3.1.2. QC Check Conc range 0.005 - 0.08 ppm and 05/05/2016 Technical Note on AMTIC
Zero/span check	Every 14 days	Zero drift < ± 3.1 ppb (24 hr) < ± 5.1 ppb (>24hr-14 day) Span drift < ± 7.1 %	1 and 2) QA Handbook Volume 2 Sec. 12.3 3) Recommendation and related to DQO
OPERATIONAL CRITERIA -OZONE			
Shelter Temperature Range	Daily (hourly values)	20.0 to 30.0° C. (Hourly avg) or per manufacturers specifications if designated to a wider temperature range	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2 Generally, the 20-30.0° C range will apply but the most restrictive operable range of the instruments in the shelter may also be used as guidance. FRM/FEM list found on AMTIC provides temp. range for given instrument. FRM/FEM monitor testing is required at 20-30° C range per 40 CFR Part 53.32
Shelter Temperature Control	Daily (hourly values)	< 2.1° C SD over 24 hours	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Shelter Temperature Device Check	Every 182 days and 2/ calendar year	<± 2.1° C of standard	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Annual Performance Evaluation Single analyzer	***Every site every 365 days and 1/ calendar year within period of monitor operation,***	Percent difference of audit levels 3-10 < ±15.1% Audit levels 1&2 < ± 1.5 ppb difference or <± 15.1%	1 and 2) 40 CFR Part 58 App A Sec. 3.1.2 3) Recommendation- 3-audit concentrations not including zero. AMTIC guidance 2/17/2011 AMTIC Technical Memo
Federal Audits (NPAP)	***20% of sites audited in calendar year***	Audit levels 1&2 < ± 1.5 ppb difference all other levels percent difference < ± 10.1%	1 and 2) 40 CFR Part 58 App A Sec. 3.1.3 3) NPAP QAPP/SOP
Verification/Calibration	Upon receipt/adjustment/repair/ installation/moving and repair and recalibration of standard of higher level Every 182 day and 2/ calendar year if manual zero/span performed biweekly Every 365 day and 1/ calendar year if continuous zero/span performed daily	All points < ± 2.1 % or ≤ ±1.5 ppb difference of best-fit straight line whichever is greater and Slope 1 ± .05	1) 40 CFR Part 50 App D 2) Recommendation 3) 40 CFR Part 50 App D Sec 4.5.5.6 Multi-point calibration (0 and 4 upscale points) Slope criteria is a recommendation
Zero Air/Zero Air Check	Every 365 days and 1/calendar year	Concentrations below LDL	1) 40 CFR Part 50 App D Sec. 4.1 2 and 3) Recommendation
Ozone Level 2 Standard			

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NMED Exhibit 29 - 0092

1) Requirement (O_3)	2) Frequency	3) Acceptance Criteria	Information /Action
Certification/recertification to Standard Reference Photometer (Level 1)	Every 365 days and 1/calendar year	single point difference < ± 3.1%	1) 40 CFR Part 50 App D Sec. 5.4 2 and 3) Transfer Standard Guidance EPA-454/B-10-001 Level 2 standard (formerly called primary standard) usually transported to EPA Regions SRP for comparison
Level 2 and Greater Transfer Standard Precision	Every 365 days and 1/calendar year	***Standard Deviation less than 0.005 ppm or 3.0% whichever is greater***	1) 40 CFR Part 50 Appendix D Sec. 3.1 2) Recommendation, part of reverification 3) 40 CFR Part 50 Appendix D Sec. 3.1
(if recertified via a transfer standard)	Every 365 days and 1/calendar year	Regression slopes = 1.00 ± 0.03 and two intercepts are 0 ± 3 ppb	1, 2 and 3) Transfer Standard Guidance EPA-545/B-10-001
Ozone Transfer standard (Level 3 and greater)			
Qualification	Upon receipt of transfer standard	< ±4.1% or < ±4 ppb (whichever greater)	1, 2 and 3) Transfer Standard Guidance EPA-545/B-10-001
Certification	After qualification and upon receipt/adjustment/repair	RSD of six slopes ≤ 3.7% Std. Dev. of 6 intercepts ≤ 1.5	1, 2 and 3) Transfer Standard Guidance EPA-545/B-10-001 1
Recertification to higher level standard	Beginning and end of O3 season or every 182 days and 2/calendar year whichever less	New slope = ± 0.05 of previous and RSD of six slopes ≤3.7% Std. Dev. of 6 intercepts ≤ 1.5	1, 2 and 3) Transfer Standard Guidance EPA-545/B-10-001 recertification test that then gets added to most recent 5 tests. If does not meet acceptability certification fails
Detection (FEM/FRMs) Noise and Lower Detectable Limits (LDL) are part of the FEM/FRM requirements. It is recommended that monitoring organizations perform the LDL test to minimally confirm and establish the LDL of their monitor. Performing the LDL test will provide the noise information.			
Noise	Every 365 days and 1/ calendar year	***≤ 0.0025 ppm (standard range)*** ***≤ 0.001 ppm (lower range)***	1) 40 CFR Part 53.23 (b) (definition & procedure) 2) Recommendation- info can be obtained from LDL 3) 40 CFR Part 53.20 Table B-1
Lower detectable limit	Every 365 days and 1/calendar year	***≤ 0.005 ppm (standard range)*** ***≤ 0.002 ppm (lower range)***	1) 40 CFR Part 53.23 (b) (definition & procedure) 2) Recommendation 3) 40 CFR Part 53.20 Table B-1
SYSTEMATIC CRITERIA-OZONE			
Standard Reporting Units	***All data***	***ppm (final units in AQS)***	1, 2 and 3) 40 CFR Part 50 App U Sec. 3(a)
Rounding convention for design value calculation	***All routine concentration data***	***3 places after decimal with digits to right truncated***	1, 2 and 3) 40 CFR Part 50 App U Sec. 3(a) The rounding convention is for averaging values for comparison to NAAQS not for reporting individual hourly values.
Completeness (seasonal)	***3-Year Comparison***	***≥ 90% (avg) daily max available in ozone season with min of 75% in any one year.***	1,2,3) 40 CFR Part 50 App U Sec 4(b)
	8- hour average	***≥ if at least 6 of the hourly concentrations for the 8-hour period are available***	1) 40 CFR Part 50 App U 2 and 3) 40 CFR Part 50 App U Sec. 3(b)
	Valid Daily Max	***≥ if valid 8-hour averages are available for at least 13 of the 17 consecutive 8-hour periods starting from 7:00 a.m. to 11:00 p.m***	1) 40 CFR Part 50 App U 2,3) 40 CFR Part 50 App U Sec. 3(d)
Sample Residence Time Verification	Every 365 days and 1/calendar year	***≤ 20 Seconds***	1) 40 CFR Part 58 App E, Sec. 9 (c) 2) Recommendation

1) Requirement (O_3)	2) Frequency	3) Acceptance Criteria	Information /Action
			3) 40 CFR Part 58 App E, Sec. 9 (c)
Sample Probe, Inlet, Sampling train	***All sites***	***Borosilicate glass (e.g., Pyrex®) or Teflon®***	1) 40 CFR Part 58 App E, Sec. Sec. 9 (a) 2) Recommendation 3) 40 CFR Part 58 App E, Sec. Sec. 9 (a) FEP and PFA have been accepted as an equivalent material to Teflon. Replacement or cleaning is suggested as 1/year and more frequent if pollutant load or contamination dictate
Siting	Every 365 days and 1/calendar year	***Meets siting criteria or waiver documented***	1) 40 CFR Part 58 App E, Sec. 2-6 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 2-6
EPA Standard Ozone Reference Photometer (SRP) Recertification (Level 1)	Every 365 days and 1/calendar year	Regression slope = 1.00 ± 0.01 and intercept < 3 ppb	1, 2 and 3) Transfer Standard Guidance EPA-454/B-10-001 This is usually at a Regional Office and is compared against the traveling SRP
Precision (using 1-point QC checks)	***Calculated annually and as appropriate for design value estimates***	**90% CL CV < 7.1%**	1) 40 CFR Part 58 App A 2.3.1.2 & 3.1.1 2) 40 CFR Part 58 App A Sec. 4 (b) 3) 40 CFR Part 58 App A Sec. 4.1.2
Bias (using 1-point QC checks)	***Calculated annually and as appropriate for design value estimates***	**95% CL < ± 7.1%**	1) 40 CFR Part 58 App A 2.3.1.2 & 3.1.1 2) 40 CFR Part 58 App A Sec. 4 (b) 3) 40 CFR Part 58 App A Sec. 4.1.3

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NMED Exhibit 29 - 0094

NO_2, NOx, NO Validation Template

1) Requirement (NO_2)	2) Frequency	3) Acceptance Criteria	Information /Action
CRITICAL CRITERIA- NO_2			
Sampler/Monitor	***NA***	***Meets requirements listed in FRM/FEM designation***	1) 40 CFR Part 58 App C Sec. 2.1 2) NA 3) 40 CFR Part 53 & FRM/FEM method list
One Point QC Check Single analyzer	***Every 14 days***	< ±15.1% (percent difference) or < ± 1.5 ppb difference whichever is greater	1 and 2) 40 CFR Part 58 App A Sec. 3.1.1 3) Recommendation based on DQO in 40 CFR Part 58 App A Sec. 2.3.1.5 QC Check Conc range 0.005 - 0.08 ppm and 05/05/2016 Technical Note on AMTIC
Zero/span check	Every 14 days	Zero drift < ± 3.1 ppb (24 hr) < ± 5.1 ppb (>24hr-14 day) Span drift < ± 10.1 %	1 and 2) QA Handbook Volume 2 Sec. 12.3 3) Recommendation and related to DQO
Converter Efficiency	During multi-point calibrations, span and audit Every 14 days	***(≥96%)*** 96% – 104.1%	1) 40 CFR Part 50 App F Sec. 1.5.10 and 2.4.10 2) Recommendation 3) 40 CFR Part 50 App F Sec. 1.5.10 and 2.4.10 Regulation states ≥96%, 96 – 104.1% is a recommendation.
OPERATIONAL CRITERIA- NO_2			
Shelter Temperature Range	Daily (hourly values)	20.0 to 30.0° C. (Hourly avg) or per manufacturers specifications if designated to a wider temperature range	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2 Generally, the 20-30.0 ° C range will apply but the most restrictive operable range of the instruments in the shelter may also be used as guidance. FRM/FEM list found on AMTIC provides temp. range for given instrument. FRM/FEM monitor testing is required at 20-30 ° C range per 40 CFR Part 53.32
Shelter Temperature Control	Daily (hourly values)	< 2.1° C SD over 24 hours	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Shelter Temperature Device Check	every 182 days and 2/calendar year	< ± 2.1° C of standard	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Annual Performance Evaluation Single Analyzer	***Every site every 365 days and 1/ calendar year***	Percent difference of audit levels 3-10 < ±15.1% Audit levels 1&2 < ± 1.5 ppb difference or < ±15.1%	1) 40 CFR Part 58 App A Sec. 3.1.2 2) 40 CFR Part 58 App A Sec. 3.1.2 3) Recommendation - 3-audit concentrations not including zero. AMTIC Technical Memo
Federal Audits (NPAP)	20% of sites audited in calendar year	Audit levels 1&2 < ± 1.5 ppb difference all other levels percent difference < ± 15.1%	1 & 2) 40 CFR Part 58 App A Sec. 3.1.3 3) NPAP QAPP/SOP

1) Requirement (NO_2)	2) Frequency	3) Acceptance Criteria	Information /Action
Verification/Calibration	Upon receipt/adjustment/repair/ installation/moving Every 182 day and 2/ calendar year if manual zero/span performed biweekly Every 365 day and 1/ calendar year if continuous zero/span performed daily	Instrument residence time ≤ 2 min Dynamic parameter ≥ 2.75 ppm-min All points <± 2.1 % or ≤ ± 1.5 ppb difference of best-fit straight line whichever is greater and Slope 1 ± .05	1) 40 CFR Part 50 App F 2 and 3) Recommendation Multi-point calibration (0 and 4 upscale points) Slope criteria is a recommendation
Gaseous Standards	All gas cylinders	**NIST Traceable** (e.g., EPA Protocol Gas) 50-100 ppm of NO in Nitrogen with < 1 ppm NO_2	1) 40 CFR Part 50 App F Sec. 1.3.1 2) NA Green Book 3) 40 CFR Part 50 App F Sec. 1.3.1. A technical memo may change the concentration requirment. Gas producer used must participate in EPAAmbient Air Protocol Gas Verification Program 40 CFR Part 58 App A Sec. 2.6.1
Zero Air/ Zero Air Check	Every 365 days and 1/ calendar year	Concentrations below LDL	1) 40 CFR Part 50 App F Sec. 1.3.2 2 and 3) Recommendation
Gas Dilution Systems	Every 365 days and 1/ calendar year or after failure of 1 point QC check or performance evaluation	Accuracy < ± 2.1 %	1, 2 and 3) Recommendation based on SO2 requirement in 40 CFR Part 50 App A-1 Sec. 4.1.2
Detection (FEM/FRMs) Noise and Lower Detectable Limits (LDL) are part of the FEM/FRM requirements. It is recommended that monitoring organizations perform the LDL test to minimally confirm and establish the LDL of their monitor. Performing the LDL test will provide the noise information.			
Noise	Every 365 days and 1/ calendar year	***≤ 0.005 ppm***	1) 40 CFR Part 53.23 (b) (definition & procedure) 2) Recommendation- info can be obtained from LDL 3) 40 CFR Part 53.20 Table B-1
Lower detectable level	Every 365 days and 1/ calendar year	***≤ 0.01 ppm***	1) 40 CFR Part 53.23 (c) (definition & procedure) 2) Recommendation 3) 40 CFR Part 53.20 Table B-1
SYSTEMATIC CRITERIA- NO_2			
Standard Reporting Units	***All data***	***ppb (final units in AQS)***	1, 2 and 3) 40 CFR Part 50 App S Sec. 2 (c)
Rounding convention for data reported to AQ S	***All routine concentration data***	***1 place after decimal with digits to right truncated***	1, 2 and 3) 40 CFR Part 50 App S Sec. 4.2 (a) The rounding convention is for averaging values for comparison to NAAQS not for reporting individual hourly values.
Completeness	***Annual Standard***	***≥ 75% hours in year***	1) 40 CFR Part 50 App S Sec. 3.1(b) 2) 40 CFR Part 50 App S Sec. 3.1(a) 3) 40 CFR Part 50 App S Sec. 3.1(b)
	1-hour standard	***1) 3consecutive calendars years of complete data 2) 4 quarters complete in each year 3) ≥75% sampling days in quarter 4) ≥ 75% of hours in a day***	1) 40 CFR Part 50 App S Sec. 3.2(b) 2) 40 CFR Part 50 App S Sec. 3.2(a) 3) 40 CFR Part 50 App S Sec. 3.2(b) More details in 40 CFR Part 50 App S

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NMED Exhibit 29 - 0096

1) Requirement (NO_2)	2) Frequency	3) Acceptance Criteria	Information /Action
Sample Residence Time Verification	Every 365 days and 1/ calendar year	***≤ 20 Seconds***	1) 40 CFR Part 58 App E, Sec. 9 (c) 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 9 (c)
Sample Probe, Inlet, Sampling train	***All sites***	***Borosilicate glass (e.g., Pyrex®) or Teflon®***	1, 2 and 3) 40 CFR Part 58 App E Sec. 9 (a) FEP and PFA have been accepted as equivalent material to Teflon. Replacement or cleaning is suggested as 1/year and more frequent if pollutant load or contamination dictate
Siting	Every 365 days and 1/ calendar year	***Meets siting criteria or waiver documented***	1) 40 CFR Part 58 App E, Secs 2-6 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 2-6
Precision (using 1-point QC checks)	***Calculated annually and as appropriate for design value estimates***	***90% CL CV < 15.1%***	1) 40 CFR Part 58 App A Sec. 2.3.1.5 & 3.1.1 2) 40 CFR Part 58 App A Sec. 4 (b) 3) 40 CFR Part 58 App A Sec. 4.1.2
Bias (using 1-point QC checks)	***Calculated annually and as appropriate for design value estimates***	***95% CL < ± 15.1%***	1) 40 CFR Part 58 App A Sec. 2.3.1.5 & 3.1.1 2) 40 CFR Part 58 App A Sec. 4 (b) 3) 40 CFR Part 58 App A Sec. 4.1.3

SO_2 Validation Template

1) Requirement (SO_2)	2) Frequency	3) Acceptance Criteria	Information /Action
CRITICAL CRITERIA- SO_2			
Sampler/Monitor	NA	***Meets requirements listed in FRM/FEM designation***	1) 40 CFR Part 58 App C Sec. 2.1 2) NA 3) 40 CFR Part 53 & FRM/FEM method list
One Point QC Check Single analyzer	***Every 14 days***	< ±10.1% (percent difference) or < ± 1.5 ppb difference whichever is greater	1 and 2) 40 CFR Part 58 App A Sec. 3.1.1 3) Recommendation based on DQO in 40 CFR Part 58 App A Sec. 2.3.1.2 QC Check Conc range 0.005 - 0.08 ppm and 05/05/2016 Technical Note on AMTIC
Zero/span check	Every 14 days	Zero drift < ± 3.1 ppb (24 hr) < ± 5.1 ppb (>24hr-14 day) Span drift < ± 10.1 %	1 and 2) QA Handbook Volume 2 Sec. 12.3 3) Recommendation and related to DQO
OPERATIONAL CRITERIA- SO_2			
Shelter Temperature Range	Daily (hourly values)	20.0 to 30.0° C. (Hourly avg) or per manufacturers specifications if designated to a wider temperature range	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2 Generally, the 20-30.0 ° C range will apply but the most restrictive operable range of the instruments in the shelter may also be used as guidance. FRM/FEM list found on AMTIC provides temp. range for given instrument. FRM/FEM monitor testing is required at 20-30 ° C range per 40 CFR Part 53.32
Shelter Temperature Control	Daily (hourly values)	< 2.1° C SD over 24 hours	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Shelter Temperature Device Check	every 180 days and 2/calendar year	< ± 2.1° C of standard	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Annual Performance Evaluation Single Analyzer	***Every site every 365 days and 1/ calendar year***	Percent difference of audit levels 3-10 < ±15.1% Audit levels 1&2 < ± 1.5 ppb difference or < ±15.1%	1 and 2) 40 CFR Part 58 App A Sec. 3.1.2 3) Recommendation - 3-audit concentrations not including zero. AMTIC Technical Memo
Federal Audits (NPAP)	20% of sites audited in calendar year	Audit levels 1&2 < ± 1.5 ppb difference all other levels percent difference < ± 15.1%	1&2) 40 CFR Part 58 App A Sec. 3.1.3 3) NPAP QAPP/SOP
Verification/Calibration	Upon receipt/adjustment/repair/ installation/moving Every 182 day and 2/ calendar year if manual zero/span performed biweekly Every 365 day and 1/ calendar year if continuous zero/span performed daily	All points < ± 2.1 % or < ± 1.5 ppb difference of best-fit straight line whichever is greater and Slope 1 ± .05	1) 40 CFR Part 50 App A-1 Sec. 4 2 and 3) Recommendation Multi-point calibration (0 and 4 upscale points) Slope criteria is a recommendation
Gaseous Standards	***All gas cylinders***	***NIST Traceable (e.g., EPA Protocol Gas)***	1) 40 CFR Part 50 App A-1 Sec. 4.1.6.1 2) NA Green Book 3) 40 CFR Part 50 App F Sec. 1.3.1 Producers must participate in Ambient Air Protocol Gas

NMED Exhibit 29 - 0097

NMED Exhibit 29 - 0098

1) Requirement (SO_2)	2) Frequency	3) Acceptance Criteria	Information /Action
			Verification Program 40 CFR Part 58 App A Sec. 2.6.1
Zero Air/ Zero Air Check	Every 365 days and 1/ calendar year	Concentrations below LDL < 0.1 ppm aromatic hydrocarbons	1) 40 CFR Part 50 App A-1 Sec. 4.1.6.2 2) Recommendation 3) Recommendation and 40 CFR Part 50 App A-1 Sec. 4.1.6.2
Gas Dilution Systems	Every 365 days and 1/ calendar year or after failure of 1point QC check or performance evaluation	***Accuracy < ± 2.1 %***	1) 40 CFR Part 50 App A-1Sec. 4.1.2 2) Recommendation 3) 40 CFR Part 50 App A-1 Sec. 4.1.2
Detection (FEM/FRMs) Noise and Lower Detectable Limits (LDL) are part of the FEM/FRM requirements. It is recommended that monitoring organizations perform the LDL test to minimally confirm and establish the LDL of their monitor. Performing the LDL test will provide the noise information.			
Noise	Every 365 days and 1/ calendar year	***≤ 0.001 ppm (standard range)*** ***≤ 0.0005 ppm (lower range)***	1) 40 CFR Part 53.23 (b) (definition & procedure) 2) Recommendation- info can be obtained from LDL 3) 40 CFR Part 53.20 Table B-1
Lower detectable level	Every 365 days and 1/ calendar year	***≤ 0.002 ppm (standard range)*** ***≤ 0.001 ppm (lower range)***	1) 40 CFR Part 53.23 (c) (definition & procedure) 2) Recommendation 3) 40 CFR Part 53.20 Table B-1
SYSTEMATIC CRITERIA- SO_2			
Standard Reporting Units	***All data***	***ppb (final units in AQS)***	1, 2 and 3) 40 CFR Part 50 App T Sec. 2 (c)
Rounding convention for design value calculation	***All routine concentration data***	***1 place after decimal with digits to right truncated***	1, 2 and 3) 40 CFR Part 50 App T Sec. 2 (c) The rounding convention is for averaging values for comparison to NAAQS not for reporting individual hourly values.
Completeness	***1 hour standard***	Hour – 75% of hour ***Day- 75% hourly Conc*** ***Quarter- 75% complete days*** ***Years- 4 complete quarters*** ***5-min value reported only for valid hours***	1, 2 and 3) 40 CFR Part 50 App T Sec. 3 (b), (c) More details in CFR on acceptable completeness. 5-min values or 5-min max value (40 CFR part 58.16(g)) only reported for the valid portion of the hour reported. If the hour is incomplete no 5-min or 5-min max reported.
Sample Residence Time Verification	Every 365 days and 1/ calendar year	***≤ 20 Seconds***	1) 40 CFR Part 58 App E, Sec. 9 (c) 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 9 (c)
Sample Probe, Inlet, Sampling train	***All sites***	***Borosilicate glass (e.g., Pyrex®) or Teflon®***	1, 2 and 3) 40 CFR Part 58 App E Sec. 9 (a) FEP and PFA have been accepted as equivalent material to Teflon. Replacement or cleaning is suggested as 1/year and more frequent if pollutant load or contamination dictate
Siting	Every 365 days and 1/ calendar year	***Meets siting criteria or waiver documented***	1) 40 CFR Part 58 App E, Sec. 2-6 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 2-6
Precision (using 1-point QC checks)	***Calculated annually and as appropriate for design value estimates***	***90% CL CV < 10.1%***	1) 40 CFR Part 58 App A Sec. 2.3.1.6 & 3.1.1 2) 40 CFR Part 58 App A Sec. 4 (b) 3) 40 CFR Part 58 App A Sec. 4.1.2

1) Requirement (SO_2)	2) Frequency	3) Acceptance Criteria	Information /Action
Bias (using 1-point QC checks)	***Calculated annually and as appropriate for design value estimates***	***95% CL < ± 10.1%***	1) 40 CFR Part 58 App A Sec. 2.3.1.6 & 3.1.1 2) 40 CFR Part 58 App A Sec. 4 (b) 3) 40 CFR Part 58 App A Sec. 4.1.3

NMED Exhibit 29 - 0099

NMED Exhibit 29 - 0100

$PM_{2.5}$ Filter Based Local Conditions Validation Template

1) Criteria (PM2.5 LC)	2) Frequency	3) Acceptable Range	Information /Action
CRITICAL CRITERIA- $PM_{2.5}$ Filter Based Local Conditions			
Field Activities			
Sampler/Monitor	NA	*Meets requirements listed in FRM/FEM/ARM designation*	1) 40 CFR Part 58 App C Sec. 2.1 2) NA 3) 40 CFR Part 53 & FRM/FEM method list
Filter Holding Times			
Pre-sampling	*all filters*	*≤ 30 days before sampling*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.3.5
Sample Recovery	*all filters*	*≤ 7 days 9 hours from sample end date*	1, 2 and 3) 40 CFR Part 50, App. L 10.10
Sampling Period (including multiple power failures)	*all filters*	*1380-1500 minutes, or if value < 1380 and exceedance of NAAQS* 1/ *midnight to midnight local standard time*	1, 2 and 3) 40 CFR Part 50 App L Sec. 3.3 and 40 CFR Part 50 App N Sec. 1 for the midnight to midnight local standard time requirement See details if less than 1380 min sampled
Sampling Instrument			
Average Flow Rate	*every 24 hours of op*	*average within 5% of 16.67 liters/minute*	1, 2 and 3) Part 50 App L Sec. 7.4.3.1
Variability in Flow Rate	*every 24 hours of op*	*CV ≤ 2%*	1, 2 and 3) 40 CFR Part 50, App L Sec. 7.4.3.2
One-point Flow Rate Verification	*every 30 days each seperated by 14 days*	*< ± 4.1% of transfer standard* < ± 5.1% of flow rate design value	1, 2 and 3) 40 CFR Part 50, App L, Sec. 9.2.5 and 7.4.3.1 and 40 CFR Part 58, Appendix A Sec. 3.2.1
Design Flow Rate Adjustment	*After multi-point calibration or verification*	*< ± 2.1% of design flow rate*	1, 2 and 3) 40 CFR Part 50, App. L, Sec. 9.2.6
Individual Flow Rates	*every 24 hours of op*	*no flow rate excursions > ±5% for > 5 min.* 1/	1, 2 and 3) 40 CFR Part 50, App. L Sec. 7.4.3.1
Filter Temp Sensor	*every 24 hours of op*	*no excursions of > 5° C lasting longer than 30 min* 1/	1, 2 and 3) 40 CFR Part 50, App. L Sec. 7.4.11.4
External Leak Check	***Before each flow rate verification/calibration*** and before and after $PM_{2.5}$ separator maintenance	*< 80.1 mL/min* (see comment #1)	1) 40 CFR Part 50 App L, Sec. 7.4.6.1 2) 40 CFR Part 50 App L Sec. 9.2.3 and Method 2-12 Sec. 7.4.3 3) 40 CFR Part 50, App. L, Sec. 7.4.6.1
Internal Leak Check	If failure of external leak check	*< 80.1 mL/min*	1) 40 CFR Part 50, App. L, Sec. 7.4.6.2 2) Method 2-12, Sec. 7.4.4 3) 40 CFR Part 50, App. L, Sec. 7.4.6.2
Laboratory Activities			

1) Criteria (PM2.5 LC)	2) Frequency	3) Acceptable Range	Information /Action
Post-sampling Weighing	*all filters*	*Protected from exposure to temperatures above 25C from sample retrieval to conditioning* *≤10 days from sample end date if shipped at ambient temp, or* *≤ 30 days if shipped below avg ambient (or 4° C or below for avg sampling temps < 4° C) from sample end date*	1, 2 and 3) 40 CFR Part 50 App L Sec. 8.3.6 and L Sec. 10.13. See technical note on holding time requirements at : https://www3.epa.gov/ttn/amtic/pmpolgud.html
Filter Visual Defect Check (unexposed)	*all filters*	*Correct type & size and for pinholes, particles or imperfections*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 10.2
Filter Conditioning Environment			
Equilibration	*all filters*	*24 hours minimum*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.5
Temp. Range	*all filters*	*24-hr mean 20.0-23.0° C*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.1
Temp. Control	*all filters*	*< 2.1° C SD* over 24 hr.*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.2 SD use is a recommendation
Humidity Range	*all filters*	*24-hr mean 30.0% - 40.0% RH or Within ±5.0 % sampling RH but ≥ 20.0%RH*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.3
Humidity Control	*all filters*	*< 5.1 % SD* over 24 hr.*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.4 SD use is recommendation
Pre/post Sampling RH	*all filters*	*difference in 24-hr means < ± 5.1% RH*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.3.3
Balance	*all filters*	*located in filter conditioning environment*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.3.2
Microbalance Auto-Calibration	*Prior to each weighing session*	Manufacturer's specification	1) 40 CFR Part 50, App. L, Sec. 8.1 2) 40 CFR Part 50, App. L, Sec. 8.1 and Method 2.12 Sec. 10.6 3) NA
OPERATIONAL EVALUATIONS TABLE $PM_{2.5}$ Filter Based Local Conditions			
Field Activities			
One-point Temp Verification	every 30 days	< ± 2.1°C	1) 40 CFR Part 50, App. L, Sec. 9.3 2) Method 2.12 Sec. 7.4.5 and Table 6-1 3) Recommendation
Pressure Verification	every 30 days	< ± 10.1 mm Hg	1) 40 CFR Part 50, App. L, Sec. 9.3 2) Method 2.12 Sec. 7.4.6 and Table 6-1 3) Recommendation
Annual Multi-point Verifications/Calibrations			
Temperature multi-point Verification/Calibration	on installation, then every 365 days and once a calendar year	< ± 2.1°C	1) 40 CFR Part 50, App. L, Sec. 9.3 2 and 3) Method 2.12 Sec. 6.4.4 Table 6-1

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NMED Exhibit 29 - 0102

1) Criteria (PM2.5 LC)	2) Frequency	3) Acceptable Range	Information /Action
Pressure Verification/Calibration	on installation, and on one-point verification failure	< ± 10.1 mm Hg	1) 40 CFR Part 50, App. L, Sec. 9.3 2 and 3) Method 2.12 Sec. 6.5 Sampler BP verified against independent standard verified against a lab primary standard that is certified as NIST traceable 1/year
Flow Rate Multi-point Verification/ Calibration	***Electromechanical maintenance or transport*** or every 365 days and once a calendar year	< ± 2.1% of transfer standard	1) 40 CFR Part 50, App. L, Sec. 9.2. 2) 40 CFR Part 50, App. L, Sec. 9.1.3, Method 2.12 Sec. 6.3 & Table 6-1 3) Recommendation
Other Monitor Calibrations	per manufacturers' op manual	per manufacturers' operating manual	1, 2 and 3) Recommendation
Precision			
Collocated Samples	***every 12 days for 15% of sites by method designation***	CV < 10.1% of samples ≥ 3.0 µg/m^3	1) and 2) Part 58 App A Sec. 3.2.3 3 Recommendation based on DQO in 40 CFR Part 58 App A Sec. 2.3.1.1
Accuracy			
Temperature Audit	every 180 days and at time of flow rate audit	< ± 2.1°C	1, 2 and 3) Method 2.12 Sec. 11.2.2
Pressure Audit	every 180 days and at time of flow rate audit	< ±10.1 mm Hg	1, 2 and 3) Method 2.12 Sec. 11.2.3
Semi Annual Flow Rate Audit	***Twice a calendar year and between 5-7 months apart***	< ± 4.1% of audit standard < ± 5.1% of design flow rate	1 and 2) Part 58, App A, Sec. 3.2.2 3) Method 2.12 Sec. 11.2.1
Monitor Maintenance			
$PM_{2.5}$ Separator (WINs)	every 5 sampling events	cleaned/changed	1, 2, and 3) Method 2.12 Sec. 8.2.2
$PM_{2.5}$ Separator (VSCC)	every 30 days	cleaned/changed	1, 2 and 3) Method 2.12 Sec. 8.3.3
Inlet Cleaning	every 30 days	cleaned	1, 2 and 3) Method 2.12 Sec. 8.3
Downtube Cleaning	every 90 days	cleaned	1, 2 and 3) Method 2.12 Sec. 8.4
Filter Housing Assembly Cleaning	every 30 days	cleaned	1, 2 and 3) Method 2.12 Sec. 8.3
Circulating Fan Filter Cleaning	every 30 days	cleaned/changed	1, 2 and 3) Method 2.12 Sec. 8.3
Manufacturer-Recommended Maintenance	per manufacturers' SOP	per manufacturers' SOP	
Laboratory Activities			
Filter Checks			
Lot Blanks	9 filters per lot	< ±15.1 µg change between weighings	1, 2, 3) Recommendation and used to determine filter stability of the lot of filters received from EPA or vendor. Method 2.12 Sec. 10.5
Exposure Lot Blanks	3 filters per lot	< ±15.1 µg change between weighings	1, 2 and 3) Method 2.12 Sec. 10.5 Used for preparing a subset of filters for equilibration
Filter Integrity (exposed)	each filter	no visual defects	1, 2 and 3) Method 2.12 Sec. 10.7 and 10.3
Lab QC Checks			

1) Criteria (PM2.5 LC)	2) Frequency	3) Acceptable Range	Information /Action
Field Filter Blank	10% or 1 per weighing session	<± 30.1 µg change between weighings	1) 40 CFR Part 50, App. L Sec. 8.3.7.1 2 and 3) Method 2.12 Table 7-1 & Sec.10.5
Lab Filter Blank	10% or 1 per weighing session	<± 15.1 µg change between weighings	1) 40 CFR Part 50, App. L Sec. 8.3.7.2 2 and 3) Method 2.12 Sec. 10.5
Balance Check (working standards)	beginning, 10th sample, end	< ±3.1 µg from certified value	1, 2 and 3) Method 2.12 Sec. 10.6 Standards used should meet specifications in Method 2.12, Sec. 4.3.7
Routine Filter re-weighing	1 per weighing session	<± 15.1 µg change between weighings	1, 2 and 3) Method 2.12 Sec. 10.8
Microbalance Audit	every 365 days and once a calendar year	<± 0.003 mg or manufacturers specs, whichever is tighter	1, 2 and 3) Method 2.12 Sec. 11.2.7
Lab Temp Check	Every 90 days	< ± 2.1°C	1, 2 and 3) Method 2.12 Sec. 10.10
Lab Humidity Check	Every 90 days	< ± 2.1%	1, 2 and 3) Method 2.12 Sec. 10.10
Verification/Calibration			
Microbalance Calibration	***At installation*** every 365 days and once a calendar year	Manufacturer's specification	1) 40 CFR Part 50, App. L, Sec. 8.1 2) 40 CFR Part 50, App. L, Sec. 8.1 and Method 2.12 Sec. 10.11 3) NA
Lab Temperature Certification	every 365 days and once a year	< ± 2.1°C	1, 2 and 3) Method 2.12 Sec. 4.3.8 and 9.4
Lab Humidity Certification	every 365 days and once a year	< ± 2.1%	1, 2 and 3) Method 2.12 Sec. 4.3.8 and 9.4
Calibration & Check Standards -			
Working Mass Stds. Verification Compared to primary standards	Every 90 days	< ± 2.1 ug	1, 2 and 3) Method 2.12 Sec. 9.7
Primary standards certification	every 365 days and once a calendar year	0.025 mg tolerance (Class 2)	1, 2 and 3) Method 2.12 Sec. 4.3.7
SYSTEMATIC CRITERIA -$PM_{2.5}$ Filter Based Local Conditions			
Siting	every 365 days and once a calendar year	***Meets siting criteria or waiver documented***	1) 40 CFR Part 58 App E, Sec. 2-5 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 2-5
Data Completeness	***Annual Standard***	***≥ 75% scheduled sampling days in each quarter***	1, 2 and 3) 40 CFR Part 50, App. N, Sec. 4.1 (b) 4.2 (a)
	24- Hour Standard	***≥ 75% scheduled sampling days in each quarter***	1, 2 and 3) 40 CFR Part 50, App. N, Sec. 4.1 (b) 4.2 (a)
Reporting Units	***all filters***	***µg/m³ at ambient temp/pressure ($PM_{2.5}$)***	1, 2 and 3) 40 CFR Part 50 App N Sec. 3.0 (b)
Rounding convention for design value calculation	***all filters***	***to one decimal place, with additional digits to the right being truncated***	1, 2 and 3) 40 CFR Part 50 App N Sec. 3.0 (b) The rounding convention is for averaging values for comparison to NAAQS not for reporting individual values.

NMED Exhibit 29 - 0103

NMED Exhibit 29 - 0104

1) Criteria (PM2.5 LC)	2) Frequency	3) Acceptable Range	Information /Action
Annual 3-yr average	***all concentrations***	***nearest 0.1 µg/m³*** (≥ 0.05 round up)	1, 2 and 3) 40 CFR Part 50, App. N Sec. 3 and 4 Rounding convention for data reported to AQS is a recommendation
24-hour, 3-year average	***all concentrations***	***nearest 1 µg/m³*** (≥ 0.5 round up)	1, 2 and 3) 40 CFR Part 50, App. N Sec. 3 and 4 Rounding convention for data reported to AQS is a recommendation
Detection Limit			
Lower DL	***all filters***	***≤ 2 µg/m³***	1, 2 and 3) 40 CFR Part 50, App. L Sec. 3.1
Upper Conc. Limit	***all filters***	***≥ 200 µg/m³***	1, 2 and 3) 40 CFR Part 50, App. L Sec. 3.2
Precision			
Single analyzer (collocated monitors)	every 90 days	Coefficient of variation (CV) < 10.1% for values ≥ 3.0 µg/m³	1, 2 and 3) Recommendation in order to provide early (quarterly) evaluation of achievement of DQOs.
Primary Quality Assurance Org.	***Annual and 3 year estimates***	***90% CL of CV < 10.1 % for values ≥ 3.0 µg/m³***	1, 2 and 3) 40 CFR Part 58, App A, Sec. 4.2.1 and 2.3.1.1
Bias			
Performance Evaluation Program (PEP)	***5 audits for PQAOs with ≤ 5 sites 8 audits for PQAOs with > 5 sites***	***< ± 10.1% for values ≥ 3.0 µg/m³***	1, 2 and 3) 40 CFR Part 58, App A, Sec. 3.2.4, 4.2.5 and 2.3.1.1
Field Activities			
Verification/Calibration Standards Recertifications – All standards should have multi-point certifications against NIST Traceable standards			
Flow Rate Transfer Std.	every 365 days and once a calendar year	***< ± 2.1% of NIST Traceable Std.***	1) 40 CFR Part 50, App. L Sec. 9.1 & 9.2 2) Method 2-12 Sec. 4.2.2 & 6.4.3 3) 40 CFR Part 50, App. L Sec. 9.1 & 9.2
Field Thermometer	every 365 days and once a calendar year	± 0.1° C resolution, ± 0.5° C accuracy	1, 2 and 3) Method 2.12 Sec. 4.2.2
Field Barometer	every 365 days and once a calendar year	± 1 mm Hg resolution, ± 5 mm Hg accuracy	1, 2 and 3) Method 2.12 Sec. 4.2.2
Clock/timer Verification	Every 30 days	***1 min/mo***	1 and 2) Method 2.12 Sec. 4.2.1 3) 40 CFR Part 50, App. L Sec. 7.4.12
Laboratory Activities			
Microbalance Readability	***At purchase***	***1 µg***	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.1
Microbalance Repeatability	At purchase	1 µg	1) Method 2.12 Sec. 4.3.6 2) Recommendation 3) Method 2.12 Sec. 4.3.6
Primary Mass/Working mass Verification/Calibration Standards	At purchase	0.025 mg tolerance (Class 2)	1, 2 and 3) Method 2.12 Sec. 4.3.7

1) Criteria (PM2.5 LC)	2) Frequency	3) Acceptable Range	Information /Action
Comment #1 The associated leak test procedure shall require that for successful passage of this test, the difference between the two pressure measurements shall not be greater than the number of mm of Hg specified for the sampler by the manufacturer, based on the actual internal volume of the sampler, that indicates a leak of less than 80 mL/min.			

1/ value must be flagged SD * = standard deviation CV= coefficient of variation

NMED Exhibit 29 - 0105

NMED Exhibit 29 - 0106

Continuous PM2.5 Local Conditions Validation Template

NOTE: This validation template attempts to provide the critical criteria, annual multipoint verifications/calibrations, and verification/calibration standards recertification frequencies and acceptable ranges for PM2.5 continuous FEMs and ARMs. At the time this validation template was most recently updated (January 2016) there were eleven continuous monitors designated as a Federal Equivalent Method (FEM) and none designated as an Approved Regional Method (ARM). For the most widely used continuous FEMs we have added select method specific operational criteria. However, due to limited available information, we do not have operational criteria for all approved FEMs, especially those methods with just a handful or less of monitors that have been implemented. Where we do list operational criteria for a specific method, we only list the criteria believed to be the most important. More detailed information on operational criteria is available for the most widely used PM2.5 continuous FEMs in Technical System Audit Supplementary Checklists for PM Continuous Monitors. These files are available on the web at: https://www3.epa.gov/ttn/amtic/contmont.html.

Technical Systems Audit Checklists

- PM continuous TSA checklist – Met One BAM – Draft (PDF)
- PM continuous TSA checklist – Thermo TEOM-FDMS – Draft (PDF)

Where appropriate, 40 CFR Part 58 App A and 40 CFR Part 50 App L requirements apply to Continuous PM2.5 FEMs; however, not all criteria may apply to each continuous FEM and ARM due to the nature of the measurement principle and design of the instrument. Also, while this validation template is designed to apply to PM2.5 continuous FEMs and ARMs, it may also apply to PM2.5 continuous methods that are not specifically approved as FEMs or ARMs and used to meet SLAMS monitoring requirements in support of the AQI, but not the NAAQS.

1) Criteria (PM2.5 Cont)	2) Frequency	3) Acceptable Range	Information /Action
CRITICAL CRITERIA- $PM_{2.5}$ Continuous, Local Conditions			
Sampler/Monitor Designation	NA	***Meets requirements listed in FRM/FEM/ARM designation*** Confirm method designation on front panel or just inside instrument.	1) 40 CFR Part 58 App C Sec. 2.1 2) NA 3) 40 CFR Part 53 & FRM/FEM method list
Firmware of monitor	At setup	1. Must be the firmware (or later version) as identified in the published method designation summary. ***2. Firmware settings must be set for flowrate to operate and report at "local conditions" (i.e., not STP).***	40 CFR Part 50 App N. sec. 1 (c)
Data Reporting Period	Report every hour	1. The calculation of an hour of data is dependent on the design of the method. ***2. A 24-hour period is calculated in AQS if 18 or more valid hours are reported for a day*** [1/].	See operator's manual. Hourly data are always reported as the start of the hour on local standard time 40 CFR Part 50 App N. Sec 3 (c)

1) Criteria (PM2.5 Cont)	2) Frequency	3) Acceptable Range	Information /Action
Sampling Instrument			
PM10 Inlet (if applicable to method designated)	At Setup	Must be a Louvered PM10 size selective inlet as specified in 40 CFR 50 appendix L, Figures L-2 through L-19	
PM2.5 second stage separator (if applicable to method designated)	At Setup	Must be a BGI Inc. Very Sharp Cut Cyclone (VSCC™) or equivalent second stage separator approved for the method.	The other approved second stage separator option for select FEMs is the Dichot. Only the GRIMM 180 and Teledyne T640 and T640X are known to not have a second stage seperator as part of the method.
Average Flow Rate	***every 24 hours of operation; alternatively, each hour can be checked***	***average within 5% of 16.67 liters/minute at local conditions***	1, 2 and 3) Part 50 App L Sec. 7.4.3.1
Variability in Flow Rate	***every 24 hours of op***	***CV ≤ 2%***	1, 2 and 3) 40 CFR Part 50, App L Sec. 7.4.3.2
One-point Flow Rate Verification	***every 30 days each seperated by 14 days***	***< ± 4.1% of transfer standard*** < ± 5.1% of flow rate design value	1, 2 and 3) 40 CFR Part 50, App.L, Sec. 9.2.5, 40 CFR Part 58, Appendix A Sec. 3.2.3 & 3.3.2
Design Flow Rate Adjustment	***After multi-point calibration or verification***	***< ± 2.1% of design flow rate***	1,2 and 3) 40 CFR Part 50, App. L, Sec. 9.2.6
External Leak Check	***Before each flow rate verification/calibration*** and before and after $PM_{2.5}$ separator maintenance	Method specific. See operator's manual.	1) 40 CFR Part 50 App L, Sec. 7.4.6.1 2) 40 CFR Part 50 App L Sec.t 9.2.3 and Method 2-12 Sec. 7.4.3 3) 40 CFR Part 50, App. L, Sec. 7.4.6.1
Internal Leak Check	If failure of external leak check	Method specific. See operators manual.	1) 40 CFR Part 50, App. L, Sec. 7.4.6.2 2) Method 2-12 7.4.4 3) 40 CFR Part 50, App. L, Sec. 7.4.6.2
Annual Multi-point Verifications/Calibrations			
Leak Check	every 30 days	< 1.0 lpm BAM (Not Thermo BAMS) ± 0.15 lpm TEOM	1) 40 CFR Part 50 App L, Sec. 7.4.6.1 2) Recommendation 3) BAM SOP Sec. 10.1.2 TEOM SOP Sec. 10.1.6 Thermo BAM leak check should not be attempted. Foils could be ruptured.
Temperature multi-point Verification/Calibration	on installation, then Every 365 days and 1/ calendar year	< ± 2.1°C	1) 40 CFR Part 50, App.L, Sec. 9.3 2 and 3) Method 2.12 Sec. 6.4.4
One-point Temp Verification	every 30 days	< ± 2.1°C	1) 40 CFR Part 50, App.L, Sec. 9.3 2) Method 2.12 Sec. 7.4.5 and Table 6-1 3) Recommendation
Pressure Verification/Calibration	on installation, then Every 365 days and 1/ calendar year	< ± 10.1 mm Hg	1) 40 CFR Part 50, App.L, Sec. 9.3 2 and 3) Method 2.12 Sec. 6.5 BP verified against independent standard verified against a lab primary standard that is certified NIST traceable 1/year

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1) Criteria (PM2.5 Cont)	2) Frequency	3) Acceptable Range	Information /Action
Flow Rate Multi-point Verification/ Calibration	***Electromechanical maintenance or transport or*** Every 365 days and 1/ calendar year	< ± 2.1% of transfer standard	1) 40 CFR Part 50, App.L, Sec. 9.2. 2) 40 CFR Part 50, App.L, Sec. 9.1.3, Method 2.12 Sec. 6.3 & Table 6-1 3) Recommendation
Other Monitor Calibrations/checks	per manufacturers' op manual	Annual zero test on Met One BAM 1020 and BAM 1022	per manufacturers' operating manual. Note: more frequent zero tests may be appropriate in areas with seasonal changes in dew-points.
Precision			
Collocated Samples	***every 12 days for 15% of sites by method designation***	CV < 10.1% of samples ≥ 3 $\mu g/m^3$	1) and 2) Part 58 App A Sec. 3.2.3 3 Recommendation based on DQO in 40 CFR Part 58 App A Sec. 2.3.1.1
Accuracy			
Temperature Audit	every 180 days and at time of flow rate audit	< ± 2.1°C	1, 2 and 3) Method 2.12 Sec. 11.2.2
Pressure Audit	every 180 days and at time of flow rate audit	< ±10.1 mm Hg	1, 2 and 3) Method 2.12 Sec. 11.2.3
Semi Annual Flow Rate Audit	***Twice a calendar year and 5-7 months apart***	< ± 4.1% of audit standard < ± 5.1% of design flow rate	1 and 2) Part 58, App A, Sec. 3.3.3 3) Method 2.12 Sec. 11.2.1
Shelter Temperature			
Temperature range	At setup	per operator manual	
Temperature Control	Daily (hourly values)	< 2.1° C SD over 24 hours	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Temperature Device Check	every 180 days and twice a calendar year	< ± 2.1° C	1, 2 and 3) QA Handbook Volume 2 Sec. 7.2.2
Monitor Maintenance			
$PM_{2.5}$ Separator (WINS)	every 5 sampling events	cleaned/changed	1, 2,and 3) Method 2.12 Sec. 8.2.2
$PM_{2.5}$ Separator (VSCC)	every 30 days	cleaned/changed	1,2 and 3) Method 2.12 Sec. 8.3.3
Inlet Cleaning	every 30 days	cleaned	1,2 and 3) Method 2.12 Sec. 8.3
Downtube Cleaning	every 90 days	cleaned	1,2 and 3) Method 2.12 Sec. 8.4
Filter Housing Assembly Cleaning	every 30 days	cleaned	1, 2 and 3) Method 2.12 Sec. 8.3
Circulating Fan Filter Cleaning	every 30 days	cleaned/changed	1, 2 and 3) Method 2.12 Sec. 8.3
Manufacturer-Recommended Maintenance	per manufacturers' SOP	per manufacturers' SOP	
TEOM-FDMS Specific Operational Criteria			
Total Flow Verification	every 30 days	Sum of flow rates from 3 paths equal design flow rate < ± 5.1%	1,2 and 3) TEOM SOP Sec. 10.1.2
Bypass leak check (TEOM)	every 30 days	± 0.60 lpm	1,2 and 3) TEOM SOP Sec. 10.1.6 or TEOM Operating Manual Sec. 5-4
Replace TEOM filters	as needed	Change TEOM filter as filter loading approaches 90%, but must be changed before reaching 100%.	1,2 and 3) TEOM SOP Sec. 10.1.8
Replace the 47-mm FDMS (Purge) filters	every 30 days or any time TEOM filters are replaced	replaced	1,2 and 3) TEOM SOP Sec. 10.1.10

1) Criteria (PM2.5 Cont)	2) Frequency	3) Acceptable Range	Information /Action
Internal/External Data Logger Data	Every 30 days 10 randomly selected values	agree exactly (digital) and $\pm$ 1 $\mu g/m^3$ (analog). Note: digital is expected and should be used unless there is no capacity to utilize digital in the monitoring agencies' data system.	1, 2 and 3) TEOM SOP Sec. 10.1.24
Replace In-line filters	every 180 days and twice a calendar year	replaced	1, 2 and 3) TEOM SOP Sec. 10.2
Clean cooler assembly	every 365 days and once a calendar year	cleaned	1, 2 and 3) TEOM SOP Sec. 10.3.1
Clean/Maintain switching valve	every 365 days and once a calendar year	cleaned	1, 2 and 3) TEOM SOP Sec. 10.3.2
Clean air inlet system of mass transducer enclosure	every 365 days and once a calendar year	cleaned	1, 2 and 3) TEOM SOP Sec. 10.3.3
Replace the dryers	1/yr or due to poor performance	Review dryer dew point data to determine acceptable performance of dryer	1, 2 and 3) TEOM SOP Sec. 10.3.4
Calibration (KO) constant verification	every 365 days and once a calendar year	Pass or Fail ($\leq$ 2.5%)	1, 2 TEOM SOP Sec. 10.3.6 3) 1405-DF operating guide. Verification software either passes or fails the verification. Acceptance criteria is $\leq$ 2.5 %
Rebuild sampling pump	18 months	< 66% of local pressure	1, 2 and 3) TEOM SOP Sec. 10.4
GRIMM Specific Operational Criteria			
Internal rinsing air filter	After a few years	Changed	1, 2 and 3) GRIMM SOP Sec. 12.4 May require a trained service staff to change. May only require changing if a message reads "check nozzle and air inlet"
Change Dust Filter	Every 365 days and 1/ calendar year	Changed	1, 2 and 3) GRIMM SOP Sec. 12.3
Relative Humidity Setting	At Setup	Per Operators manual (55%) unless otherwise directed and approved to use at a different value	
Calibration of spectrometer	Yearly	+/- 5% for mass	Operators' Manual section 5.2
Cleaning or changing of the Nafion in inlet	As needed	We are seeking clarification from GRIMM on this	Operators' Manual section 11.4.2
Thermo BAM Specific Operational Criteria			
Cleaning Nozzle and Vane (BAM)	Minimally every 30 days	cleaned	1, 2 and 3) BAM SOP Sec. 10.1.3
Leak Check	every 30 days	$\leq$ 0.42 L/min	1) BAM 5014i Instruction Manual 2) 3) BAM 5014i Instruction Manual
Replace or clean pump muffler	every 180 days and twice a calendar year	Cleaned or changed	

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1) Criteria (PM2.5 Cont)	2) Frequency	3) Acceptable Range	Information /Action
Internal/External Data Logger Data (BAM)	Every 30 days 10 randomly selected values	agree exactly (digital) and $\pm$ 1 $\mu g/m^3$ (analog). Note: digital is expected and should be used unless there is no capacity to utilize digital in the monitoring agencies' data system.	1, 2 and 3) BAM SOP Sec. 10.1.9
Clean/replace internal debris filter	Every 365 days and 1/ calendar year		
MetOne BAM Specific Operational Criteria			
BAM check of membrane span foil	Daily	Avg. $< \pm$ 5.1% of ABS	1, 2 and 3) BAM SOP Sec. 10.4.3. Applies on the BAM 1020
BAM electrical grounding	At setup	1. Is the chassis of the BAM grounded? Is the downtube grounded to the chassis at the collar (i.e., with setscrews)	Per operator manual
Nozzle cleaning	Every 30 days, or more often as needed	cleaned	Per operator manual
Zero test	Yearly	Standard deviation of the data from a 72-hour zero test < 2.4 $\mu g/m^3$	Per operator manual
SYSTEMATIC CRITERIA- $PM_{2.5}$ Continuous, Local Conditions			
Siting	every 365 days and once a calendar year	***Meets siting criteria or waiver documented***	1) 40 CFR Part 58 App E, Sec. 2-5 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 2-5
Data Completeness	***Annual Standard***	***$\geq$ 75% scheduled sampling days in each quarter***	1, 2 and 3) 40 CFR Part 50, App. N, Sec. 4.1 (b) 4.2 (a)
	24- Hour Standard	***$\geq$ 75% scheduled sampling days in each quarter***	1, 2 and 3) 40 CFR Part 50, App. N, Sec. 4.1 (b) 4.2 (a)
Reporting Units	***all filters***	***$\mu g/m^3$ at ambient temp/pressure ($PM_{2.5}$)***	1. 2 and 3) 40 CFR Part 50 App N Sec. 3.0 (b)
Rounding convention for data reported to AQS	***all filters***	***to one decimal place or as reported by instrument***	1. 2 and 3) 40 CFR Part 50 App N Sec. 3.0 (b)
Annual 3-yr average	***all concentrations***	***nearest 0.1 $\mu g/m^3$*** ($\geq$ 0.05 round up)	1,2 and 3) 40 CFR Part 50, App. N Sec. 3 and 4 Rounding convention for data reported to AQS is a recommendation
24-hour, 3-year average	***all concentrations***	***nearest 1 $\mu g/m^3$*** ($\geq$ 0.5 round up)	1,2 and 3) 40 CFR Part 50, App. N Sec. 3 and 4 Rounding convention for data reported to AQS is a recommendation
Verification/Calibration Standards Recertifications - All standards should have multi-point certifications against NIST Traceable standards			
Flow Rate Transfer Std.	every 365 days and once a calendar year	***$< \pm$ 2.1% of NIST Traceable Std.***	1) 40 CFR Part 50, App.L Sec. 9.1 & 9.2 2) Method 2-12 Sec. 4.2.2 & 6.4.3 3) 40 CFR Part 50, App.L Sec. 9.1 & 9.2
Field Thermometer	every 365 days and once a calendar year	$\pm$ 0.1° C resolution, $\pm$ 0.5° C accuracy	1, 2 and 3) Method 2.12 Sec. 4.2.2

1) Criteria (PM2.5 Cont)	2) Frequency	3) Acceptable Range	Information /Action
Field Barometer	every 365 days and once a calendar year	± 1 mm Hg resolution, ± 5 mm Hg accuracy	1, 2 and 3) Method 2.12 Sec. 4.2.2
Clock/timer Verification	Every 30 days	***1 min/mo****	1 and 2) Method 2.12 Sec. 4.2.1 3) 40 CFR Part 50, App.L Sec. 7.4.12
Precision			
Single analyzer (collocated monitors)	every 90 days	Coefficient of variation (CV) < 10.1% for values ≥ 3.0 $\mu g/m^3$	1,2 and 3) Recommendation in order to provide early (quarterly) evaluation of achievement of DQOs.
Primary Quality Assurance Org.	***Annual and 3 year estimates***	***90% CL of CV < 10.1 % for values ≥ 3.0 $\mu g/m^3$***	1,2 and 3) 40 CFR Part 58, App A, Sec. 4.2.1 and 2.3.1.1
Bias			
Performance Evaluation Program (PEP)	***5 audits for PQAOs with ≤ 5 sites 8 audits for PQAOs with > 5 sites***	***< ±10.1% for value > 3 $\mu g/m^3$***	1,2 and 3) 40 CFR Part 58, App A, Sec. 3.2.7, 4.3.2 and 2.3.1.1

1/ 24 hour average value must be flagged if not meeting criteria
SD= standard deviation , CV= coefficient of variation
**** = need to ensure data system stamps appropriate time period with reported sample value**

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Continuos PM10 STP Conditions Validation Template

NOTE: There are a number of continuous PM10 monitors that are designated as FEM. These monitors may have different measurement or sampling attributes that cannot be identified in this validation template. Monitoring organizations should review specific instrument operating manuals and augment the validation template with QC information specific to their EPA reference or equivalent method designation and instrument (https://www3.epa.gov/ttn/amtic/criteria.html). In general, 40 CFR Part 58 App A and 40 CFR Part 50 App J requirements apply to Continuous PM10. Since a guidance document was never developed for continuous PM10, many of the requirements reflect a combination of manual and continuous PM2.5 requirements and are therefore considered recommendations.

1) Criteria (PM_{10} Cont)	2) Frequency	3) Acceptable Range	Information /Action
CRITICAL CRITERIA- PM_{10} Continuous			
Sampler/Monitor	NA	***Meets requirements listed in FRM/FEM/ARM designation***	1) 40 CFR Part 58 App C Sec. 2.1 2) NA 3) 40 CFR Part 53 & FRM/FEM method list
Sampling Period	**all filters**	**1440 minutes ± 60 minutes midnight to midnight local standard time**	1, 2 and 3) 40 CFR Part 50 App J Sec. 7.1.5
Average Flow Rate	every 24 hours of op	Average within < ± 5.1% of design	recommendation
Verification/Calibration			
One-point Flow Rate Verification	***every 30 days each seperated by 14 days***	< ± 7.1% of transfer standard	1 and 2) 40 CFR Part 58, App A, Sec. 3.3 3) Method 2.10 Table 3-1
OPERATIONAL EVALUATIONS TABLE PM_{10} Continuous			
Verification/Calibration			
System Leak Check	During precalibration check	Auditory inspection with faceplate blocked	1, 2 and 3) Method 2.11 Sec. 2.3.2
FR Multi-point Verification/Calibration	every 365 days and once a calendar year	3 of 4 cal points within < ± 10.1% of design	1) 40 CFR Part 50 App J Sec. 8.0 2 and 3) Method 2.10 Sec. 2.2.4
Audits			
Semi Annual Flow Rate Audit	***Twice a calendar year and 5-7 months apart***	< ± 10.1% of audit standard	1, 2) Part 58, App A, Sec. 3.3.3 3) Method 2.10 Sec. 7.1.5
Monitor Maintenance			
Inlet/downtube Cleaning	every 90 days and 4 times a calendar year	cleaned	1, 2 and 3) Method 2.10 Sec. 6.1.2
Manufacturer-Recommended Maintenance	per manufacturers' SOP	per manufacturers' SOP	
SYSTEMATIC CRITERIA - PM_{10} Continuous			
Siting	Every 365 days and 1/ calendar year	***Meets siting criteria or waiver documented***	1) 40 CFR Part 58 App E, Sections 2-5 2) Recommendation 3) 40 CFR Part 58 App E, Sections 2-5
Data Completeness	24-hour quarterly	≥ 75%	1, 2 and 3) 40 CFR Part 50 App. K, Sec. 2.3b & c

1) Criteria (PM_{10} Cont)	2) Frequency	3) Acceptable Range	Information /Action
Reporting Units	all filters	$\mu g/m^3$ at standard temperature and pressure (STP)	40 CFR Part 50 App K
Rounding convention for design value calculation			
24-hour, 3-year average	***quarterly***	***nearest 10 $\mu g/m^3$ ($\geq$ 5 round up)***	1, 2 and 3) 40 CFR Part 50 App K Sec. 1 The rounding convention is for averaging values for comparison to NAAQS not for reporting individual values.
Verification/Calibration Standards and Recertifications - All standards should have multi-point certifications against NIST Traceable standards			
Flow Rate Transfer Std.	every 365 days and once a calendar year	***< $\pm$ 2.1% of NIST-traceable Std.***	1) 40 CFR Part 50, App.J Sec. 7.3 2) Method 2.11 Sec. 1.1.3 3) 40 CFR Part 50, App.J Sec. 7.3
Field Thermometer	every 365 days and once a calendar year	$\pm$ 0.1° C resolution, $\pm$ 0.1° C accuracy	1, 2 and 3) Method 2.10 Sec. 1.1.2
Field Barometer	every 365 days and once a calendar year	$\pm$ 1 mm Hg resolution, $\pm$ 5 mm Hg accuracy	1, 2 and 3) Method 2.10 Sec. 1.1.2
Clock/timer Verification	every 180 days and twice a calendar year	***15 min/day***	1) 40 CFR Part 50, App.J Sec. 7.1.5 2) Recommendation 3) 40 CFR Part 50, App.J Sec. 7.1.5

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PM_{10} Low Volume STP Filter-Based Local Conditions Validation Template

Monitoring organizations can use low-volume PM instruments for PM_{10} monitoring. However, PM_{10} data collection for NAAQS purposes must be reported in standard temperature and pressure (STP). 40 CFR Part 50 App J describes the reference method for PM_{10} but this method was promulgated for dichot and high volume methods that have improved over the years. Since monitoring organization may be able to use the low volume methods for multiple uses (PM_{10c}, PM_{10}-Pb) it is suggested that the validation criteria for this method follow the method requirements associated with the $PM_{2.5}$ which is Appendix L. Where there are particular requirement directly related to the NAAQS evaluation App J will be used.

1) Criteria (PM10 Lo-Vol STP)	2) Frequency	3) Acceptable Range	Information /Action
CRITICAL CRITERIA- PM_{10} Lo-Vol Filter Based STP			
Field Activities			
Sampler/Monitor	NA	*Meets requirements listed in FRM/FEM/ARM designation*	1) 40 CFR Part 58 App C Sec. 2.1 2) NA 3) 40 CFR Part 53 & FRM/FEM method list
Sample Recovery	*all filters*	*≤7 days 9 hours from sample end date*	1, 2 and 3) 40 CFR Part 50 App L Sec. 10.10
Pre-sampling	*all filters*	*≤ 30 days before sampling*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.3.5
Sampling Instrument			
Average Flow Rate	*every 24 hours of op*	*average within < 5.1% of 16.67 liters/minute*	1, 2 and 3) Part 50 App L Sec. 7.4.3.1
Variability in Flow Rate	*every 24 hours of op*	*CV < 2.1%*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 7.4.3.2
One-point Flow Rate Verification	*every 30 days each seperated by 14 days*	*< ± 4.1% of transfer standard* < ± 5.1% of flow rate design value	1) 40 CFR Part 50, App. L, Sec. 9.2.5, 40 CFR Part 58, App A Sec. 3.3.1 2) Part 58, App A, Sec. 3.3.1 3) 40 CFR Part 50, App. L, Sec. 9.2.5 & 7.4.3.1
Design Flow Rate Adjustment	*at one-point or multi-point verification/calibration*	*< ± 2.1% of design flow rate*	1, 2 and 3) 40 CFR Part 50, App. L, Sec. 9.2.6
Individual Flow Rates	*every 24 hours of op*	*no flow rate excursions > ±5.1% for > 5 min.* 1/	1, 2 and 3) 40 CFR Part 50, App. L Sec. 7.4.3.1
Filter Temp Sensor	*every 24 hours of op*	*no excursions of > 5° C lasting longer than 30 min* 1/	1, 2 and 3) 40 CFR Part 50, App. L Sec. 7.4.11.4
External Leak Check	*Before each flow rate verification/calibration* and before and after maintenance	*< 80.1 mL/min* (see comment #1)	1) 40 CFR Part 50 App L, Sec. 7.4.6.1 2) 40 CFR Part 50, App. L Sec. 9.2.3 Method 2-12 Sec. Table 8-1 3) 40 CFR Part 50, App. L, Sec. 7.4.6.1
Internal Leak Check	every 5 sampling events	*< 80.1 mL/min*	1) 40 CFR Part 50, App. L, Sec. 7.4.6.2 2) Method 2-12 Table 8-1 3) 40 CFR Part 50, App. L, Sec. 7.4.6.2
Laboratory Activities			

1) Criteria (PM10 Lo-Vol STP)	2) Frequency	3) Acceptable Range	Information /Action
Post-sampling Weighing	*all filters*	*Protected from exposure to temperature ≤10 days from sample end date if shipped at ambient temp, or ≤30 days if shipped below avg ambient (or 4° C or below for avg sampling temps < 4° C) from sample end date*	1, 2 and 3) 40 CFR Part 50 App L Sec. 8..3.6
Filter Visual Defect Check (unexposed)	*all filters*	*Correct type & size and for pinholes, particles or imperfections*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 10.2
Filter Conditioning Environment			
Equilibration	*all filters*	*24 hours minimum*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.5
Temp. Range	*all filters*	*24-hr mean 20.0-23.0° C*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.1
Temp.Control	*all filters*	*< 2.1° C SD* over 24 hr*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.2 SD use is recommendation
Humidity Range	*all filters*	*24-hr mean 30.0% - 40.0% RH or <5.1% sampling RH but ≥ 20.0%RH*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.3
Humidity Control	*all filters*	*< 5.1% SD* over 24 hr.*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.2.4 SD use is recommendation
Pre/post Sampling RH	*all filters*	*difference in 24-hr means < ± 5.1% RH*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.3.3
Balance	*all filters*	*located in filter conditioning environment*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.3.2
OPERATIONAL EVALUATIONS TABLE PM_{10} Lo-Vol Filter Based STP			
Field Activities			
Sampling Instrument			
Routine Verifications			
One-point Temp Verification	every 30 days	< ± 2.1°C	1) 40 CFR Part 50, App. L, Sec. 9.3 2) Method 2.12 Sec. 7.4.5 and Table 6-1 3) Recommendation
Pressure Verification	every 30 days	< ± 10.1 mm Hg	1) 40 CFR Part 50, App. L, Sec. 9.3 2) Method 2.12 Sec 7.4.6 and Table 6-1 3) Recommendation
Annual Multi-point Verifications/Calibrations			
Temperature multi-point Verification/Calibration	on installation, then every 365 days and once a calendar year	< ± 2.1°C	1) 40 CFR Part 50, App. L, Sec. 9.3 2 and 3) Method 2.12 Sec. 6.4.4 and Table 6-1
Pressure Verification/Calibration	on installation, then every 365 days and once a calendar year	< ± 10.1 mm Hg	1) 40 CFR Part 50, App. L, Sec. 9.3 2 and 3) Method 2.12 Sec. 6.5 Sampler BP verified against independent standard verified against a lab primary standard that is certified as NIST traceable 1/year

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1) Criteria (PM10 Lo-Vol STP)	2) Frequency	3) Acceptable Range	Information /Action
Flow Rate Multi-point Verification/ Calibration	***Electromechanical maintenance or transport or*** every 365 days and once a calendar year	< ± 2.1% of transfer standard	1) 40 CFR Part 50, App. L, Sec. 9.2. 2) 40 CFR Part 50, App. L, Sec. 9.1.3, Method 2.12 Sec. 6.3 Table 6-1 3) Recommendation
Other Monitor Calibrations	per manufacturers' op manual	per manufacturers' operating manual	1, 2 and 3) Recommendation
Precision			
Collocated Samples	***every 12 days for 15% of sites***	CV < 10.1% of samples ≥ 3.0 µg/m^3	1) and 2) 40 CFR Part 58 App A Sec. 3.3.4 3) Recommendation
Accuracy			
Temperature Audit	every 180 days and at time of flow rate audit	< ± 2.1°C	1, 2 and 3) Method 2.12 Sec. 11.2.2
Pressure Audit	every 180 days and at time of flow rate audit	< ±10.1 mm Hg	1, 2 and 3) Method 2.12 Sec. 11.2.3
Semi Annual Flow Rate Audit	***Twice a calendar year and 5-7 months apart***	< ± 4.1% of audit standard < ± 5.1% of design flow rate	1 and 2) Part 58, App A, Sec. 3.3.3 3) Method 2.12 Sec. 11.2.1
Monitor Maintenance			
Inlet Cleaning	every 30 days	cleaned	1, 2 and 3) Method 2.12 Sec. 8.3
Downtube Cleaning	every 90 days	cleaned	1, 2 and 3) Method 2.12 Sec. 8.4
Filter Chamber Cleaning	every 30 days	cleaned	1, 2 and 3) Method 2.12 Sec. 8.3
Circulating Fan Filter Cleaning	every 30 days	cleaned/changed	1, 2 and 3) Method 2.12 Sec. 8.3
Manufacturer-Recommended Maintenance	per manufacturers' SOP	per manufacturers' SOP	
Laboratory Activities			
Filter Checks			
Lot Blanks	9 filters per lot	< ±15.1 µg change between weighings	1, 2, 3) Recommendation and used to determine filter stability of the lot of filters received from EPA or vendor. Method 2.12 Sec. 10.5
Exposure Lot Blanks	3 filters per lot	< ± 15.1 µg change between weighings	1, 2 and 3) Method 2.12 Sec. 10.5 Used for preparing a subset of filters for equilibration
Filter Integrity (exposed)	each filter	no visual defects	1, 2 and 3) Method 2.12 Sec. 10.3 and 10.7
Lab QC Checks			
Field Filter Blank	10% or 1 per weighing session	< ± 30.1 µg change between weighings	1) 40 CFR Part 50, App. L Sec. 8.3.7.1 2 and 3) Method 2.12 Table 7-1 & Sec. 10.5
Lab Filter Blank	10% or 1 per weighing session	< ± 15.1 µg change between weighings	1) 40 CFR Part 50, App. L Sec. 8.3.7.2 2 and 3) Method 2.12 Sec. 10.5
Balance Check (working standards)	beginning, 10th sample, end	< ± 3.1 µg from certified value	1, 2 and 3) Method 2.12 Sec. 10.6 Standards used should meet specifications in Method 2.12, Sec. 4.3.7
Routine Filter re-weighing	1 per weighing session	< ± 15.1 µg change between weighings	1, 2 and 3) Method 2.12 Sec. 10.8

1) Criteria (PM10 Lo-Vol STP)	2) Frequency	3) Acceptable Range	Information /Action
Microbalance Audit	every 365 days and once a calendar year	< ± 0.003 mg or manufacturers specs, whichever is tighter	1, 2 and 3) Method 2.12 Sec. 11.2.7
Lab Temp Check	Every 90 days	< ± 2.1°C	1, 2 and 3) Method 2.12 Sec. 10.10
Lab Humidity Check	Every 90 days	< ± 2.1%	1, 2 and 3) Method 2.12 Sec. 10.10
Verification/Calibration			
Microbalance Calibration	***At installation*** every 365 days and once a calendar year	Manufacturer's specification	1) 40 CFR Part 50, App. L, Sec. 8.1 2) 40 CFR Part 50, App. L, Sec. 8.1 and Method 2.12 Sec. 10.11 3) NA
Lab Temperature Certification	every 365 days and once a year	< ± 2.1°C	1, 2 and 3) Method 2.12 Sec. 4.3.8 and 9.4
Lab Humidity Certification	every 365 days and once a year	< ± 2.1%	1, 2 and 3) Method 2.12 Sec.4.3.8 and 9.4
Calibration & Check Standards -			
Working Mass Stds. Verification Compared to primary standards	Every 90 days	< ± 2.1 ug	1, 2 and 3) Method 2.12 Sec. 9.7
Primary standards certification	every 365 days and once a calendar year	0.025 mg tolerance (Class 2)	1, 2 and 3) Method 2.12 Sec. 4.3.7
SYSTEMATIC CRITERIA - PM_{10} Lo-Vol Filter Based STP			
Siting	Every 365 days and 1/ calendar year	***Meets siting criteria or waiver documented***	1) 40 CFR Part 58 App E, Sec. 2-5 2) Recommendation 3) 40 CFR Part 58 App E, Sec. 2-5
Data Completeness	***24- Hour Standard***	***≥ 75% scheduled sampling days in each quarter***	1, 2 and 3) 40 CFR Part 50 App. K, Sec. 2.3b
Reporting Units	all filters	$\mu g/m^3$ at standard temperature and pressure	1, 2 and 3) 40 CFR Part 50 App K Sec. 1
Rounding convention for design value calculation	***Each routine concentration***	***nearest 10 $\mu g/m^3$ (≥ 5 round up)***	1, 2 and 3) 40 CFR Part 50 App K Sec. 1 The rounding convention is for averaging values for comparison to NAAQS not for reporting individual values.
Detection Limit			
Lower DL	***all filters***	***≤ 2 $\mu g/m^3$***	1, 2 and 3) 40 CFR Part 50, App. L Sec. 3.1
Upper Conc. Limit	***all filters***	***≥200 $\mu g/m^3$***	1, 2 and 3) 40 CFR Part 50, App. L Sec. 3.2
Precision			
Single analyzer	every 90 days and 4 times a calendar year.	Coefficient of variation (CV) < 10.1% ≥ 3.0 $\mu g/m^3$	1, 2 and 3) Recommendation
Single analyzer	1/ yr	CV < 10.1% ≥ 3.0 $\mu g/m^3$	1, 2 and 3) Recommendation
Primary Quality Assurance Org.	Annual and 3 year estimates	90% CL of CV < 10.1% ≥ 3 $\mu g/m^3$	1, 2 and 3) Recommendation
Field Activities			
Verification/Calibration Standards Recertifications – All standards should have multi-point certifications against NIST Traceable standards			

NMED Exhibit 29 - 0117

NMED Exhibit 29 - 0118

1) Criteria (PM10 Lo-Vol STP)	2) Frequency	3) Acceptable Range	Information /Action
Flow Rate Transfer Std.	every 365 days and once a calendar year	*< ± 2.1% of NIST Traceable Std.*	1) 40 CFR Part 50, App. L Sec. 9.1 & 9.2 2) Method 2.12 Sec.4.2.2 & 6.4.3 3) 40 CFR Part 50, App. L Sec. 9.1 & 9.2
Field Thermometer	every 365 days and once a calendar year	± 0.1° C resolution, ± 0.5° C accuracy	1, 2 and 3) Method 2.12 Sec. 4.2.2
Field Barometer	every 365 days and once a calendar year	± 1 mm Hg resolution, ± 5 mm Hg accuracy	1, 2 and 3) Method 2.12 Sec. 4.2.2
Clock/timer Verification	every 30 days	*1 min/mo*	1and 2) Method 2.12 Sec. 4.2.1 3) 40 CFR Part 50, App. L Sec. 7.4.12
Laboratory Activities			
Microbalance Readability	*at purchase*	*1 µg*	1, 2 and 3) 40 CFR Part 50, App. L Sec. 8.1
Microbalance Repeatability	at purchase	1 µg	1) Method 2.12 Sec. 4.3.6 2) Recommendation 3) Method 2.12 Sec. 4.3.6
Primary Mass. Verification/Calibration Standards Recertifications	at purchase	0.025 mg tolerance (Class 2)	1, 2 and 3) Method 2.12 Sec. 4.3.7
Comment #1 The associated leak test procedure shall require that for successful passage of this test, the difference between the two pressure measurements shall not be greater than the number of mm of Hg specified for the sampler by the manufacturer, based on the actual internal volume of the sampler, that indicates a leak of less than 80 mL/min.			

QTRAK # _____

APPENDIX E

To

QUALITY ASSURANCE PROJECT PLAN FOR AMBIENT AIR MONITORING

2020

NEW MEXICO ENVIRONMENT DEPARTMENT

AIR QUALITY BUREAU

United States Environmental Protection Agency

This Certifies that

Donna Intermont

has satisfactorily completed a training program in
Quality Project & Program Management
at Sandia Pueblo, New Mexico on May 14-16, 2013

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Donald L. Johnson, Instructor

Walter R. Helmick, Instructor

Donald L. Johnson
Regional Quality Assurance Manager

NMED Exhibit 29 - 0121

United States Environmental Protection Agency

This Certifies that

Mary Hilbert

has satisfactorily completed a training program in

Orientation to Quality Assurance Management

at San Felipe Pueblo, New Mexico on September 27, 2010

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Donald L. Johnson, Instructor

Donald L. Johnson
Regional Quality Assurance Manager

NMED Exhibit 29 - 0122

United States Environmental Protection Agency

This Certifies that

Mary Hilbert

has satisfactorily completed a training program in

Data Quality Objectives

at San Felipe Pueblo, New Mexico on September 28, 2010

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Walter R. Helmick, Instructor

Donald L. Johnson
Regional Quality Assurance Manager

United States Environmental Protection Agency

This Certifies that

Mary Hilbert

has satisfactorily completed a training program in

Quality Management Plan and Quality Assurance Project Plan Seminar

at San Felipe Pueblo, New Mexico on September 29-30, 2010

UNITED STATES • ENVIRONMENTAL PROTECTION AGENCY •

Donald L. Johnson, Instructor

Donald L. Johnson
Regional Quality Assurance Manager

NMED Exhibit 29 - 0124

QTRAK # _____

APPENDIX F

To

QUALITY ASSURANCE PROJECT PLAN FOR AMBIENT AIR MONITORING

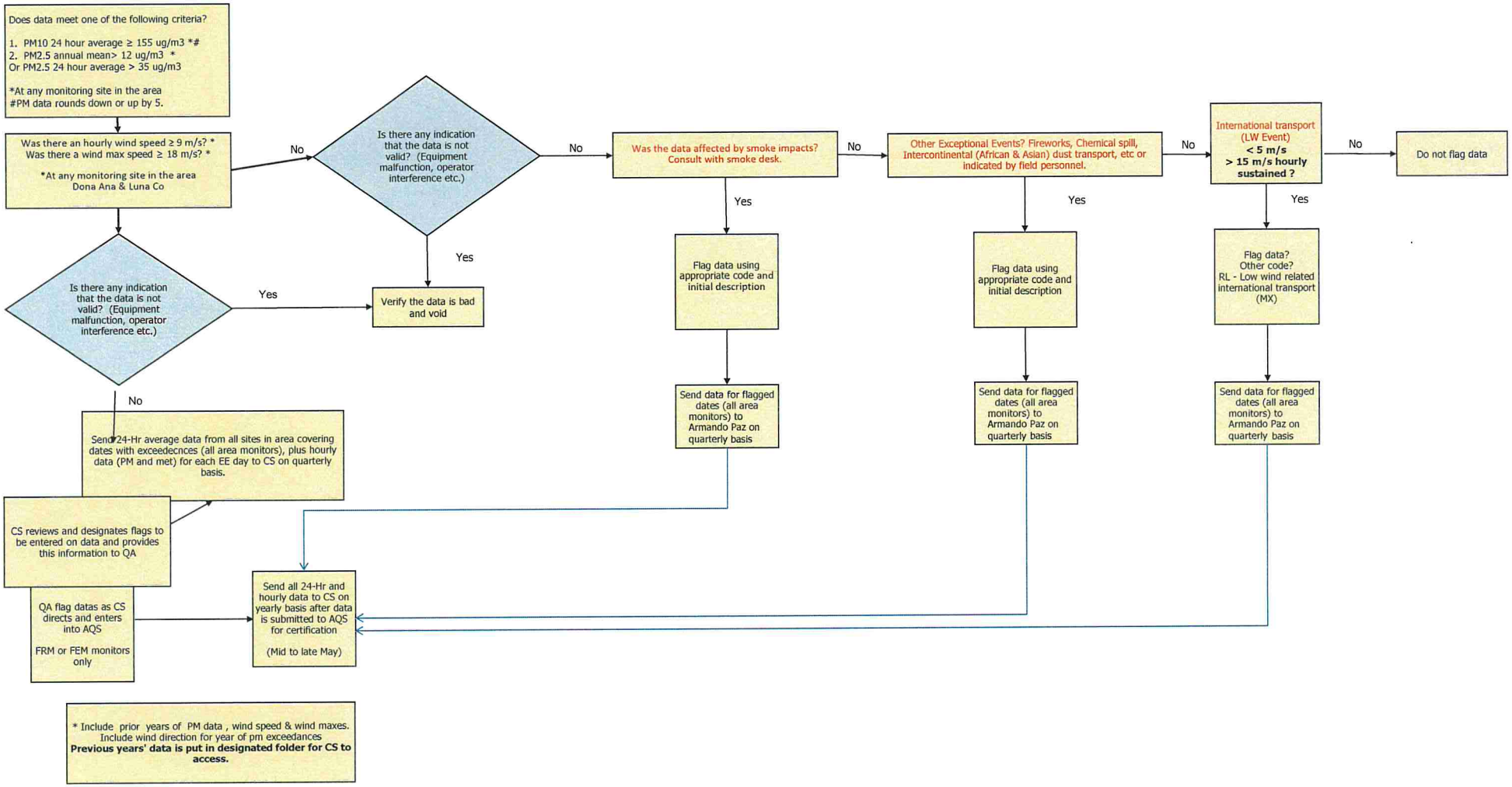
2020

NEW MEXICO ENVIRONMENT DEPARTMENT

AIR QUALITY BUREAU

Appendix F to 2020 New Mexico Ambient Air Monitoring QAPP

Exceptional Events Flagging Process



NMED Exhibit 29 - 0127

QTRAK # _____

APPENDIX G

To

QUALITY ASSURANCE PROJECT PLAN FOR AMBIENT AIR MONITORING

2020

NEW MEXICO ENVIRONMENT DEPARTMENT

AIR QUALITY BUREAU

Appendix G to 2020 New Mexico Ambient Air Monitoring QAPP

Table of Standard Operating Procedures included in the Air Quality Bureau's Standard Operating Procedure Manual for Ambient Air Monitoring and Quality Assurance

Control ID	Standard Operating Procedure	Revision Number	Effective Date	Section
AQB1-01	146i Calibration SOP	5	April 2019	Monitoring
AQB1-02	2025A/i Calibration - Maintenance SOP	1.7	February 2019	Monitoring
AQB1-03	42i Calibration using 146i	0	May 2019	Monitoring
AQB1-04	43i Calibration using 146i	0	May 2019	Monitoring
AQB1-05	49i Calibration SOP (using49i-QPS)	0	May 2019	Monitoring
AQB1-06	BAM 1020 SOP	0	April 2019	Monitoring
AQB1-07	Campbell CR21X Met Data Download SOP	0	July 2018	Monitoring
AQB1-08	e-BAM SOP	0	October 2019	Monitoring
AQB1-09	Opeartors Daily Site Check SOP	1.1	November 2018	Monitoring
AQB2-01	Calibration of Dynamic Dilution Calibrator, Model T700	1	July 2019	Quality Assurance
AQB2-02	Reviewing Chain of Custody Forms	1	February 2019	Quality Assurance
AQB2-03	Corrective Action Report	4	February 2019	Quality Assurance
AQB2-04	Data Certification	2	May 2019	Quality Assurance
AQB2-05	Data Entry to AQS	0	January 2020	Quality Assurance
AQB2-06	Review & Validation of Data	0	April 2019	Quality Assurance
AQB2-07	Instrument and Equipment Labeling	0	November 2016	Quality Assurance
AQB2-08	Backfilling Data into Envista ARM	0	May 2019	Quality Assurance
AQB2-09	Meteorological Monitoring Parts Replacement - Adjustment	0	August 2017	Quality Assurance
AQB2-10	Monitoring Siting Criteria Audit	5	October 2019	Quality Assurance
AQB2-11	Operation of Alicat Flow Meters	0	May 2016	Quality Assurance
AQB2-12	Meteorological Audits	0	August 2016	Quality Assurance
AQB2-13	QA Field Accuracy Audit of Chemiluminescent 42i NO-NO_2-NO_x Analyzer	1	May 2019	Quality Assurance
AQB2-14	QA Field Accuracy Audit of Pulsed Fluorescence 43i SO_2 Analyzer	0	January 2019	Quality Assurance
AQB2-15	QA Field Accuracy Audit of UV Photometric 49i Ozone Analyzers	1	May 2019	Quality Assurance
AQB2-16	QA Field Accuracy Auditing of Non-Continuous 2025i Partisol PM_{10} and $PM_{2.5}$ Sequential Air Samplers	0	March 2018	Quality Assurance
AQB2-17	Qualification, Verification and Reverification of the QA 49iPS Ozone Transfer Standard	0	January 2019	Quality Assurance
AQB2-18	Standards for Conducting Ambient Air Monitoring Network Audits	0	January 2018	Quality Assurance
AQB2-19	Roles of Monitoring and Quality Assurance Sections in Documenting Exceptional Events	0	November 2018	Quality Assurance
AQB2-20	Calibrating Field Temperature Meters Using the Fluke 7109A Calibration Bath	0	May 2019	Quality Assurance
AQB2-21	Calibration of Alicat Flow Meters using Fluke Molbox1+	0	October 2019	Quality Assurance
AQB2-22	Calibration of Multi-Gas Calibrator, Model 146iQ	0	June 2019	Quality Assurance
AQB2-23	Quarterly Analysis of Daily Zero Data	0	October 2019	Quality Assurance
AQB2-24	Performing a QA Audit on the BAM 1020 Particulate Monitor	1	November 2019	Quality Assurance
AQB2-25	Qualification, Verification and Reverification of the QA 49iQPS Ozone Transfer Standard	0	Draft	Quality Assurance

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF ANDREW AHR

My name is Andrew Ahr, and I am the Quality Assurance Staff Manager for the Air Quality Bureau ("Bureau") of the New Mexico Environment Department ("Department"). I have been asked to provide testimony in support of the Department's proposed new air quality regulations at 20.2.50 NMAC ("Part 50"). My testimony will address the following topics: how design values for ozone are calculated, quality assurance ("QA") of the data, and how the data is submitted to the U.S. Environmental Protection Agency ("EPA").

I. QUALIFICATIONS

I have been employed with the Bureau for over four years and have held the positions of Permit Writer and Compliance Inspector prior to becoming the QA Staff Manager. Before coming to the Department, I worked in the chemical industry for approximately 18 years at EKC Technology, Inc., DuPont, and SBA Materials. I also have 15 years of experience working in various engineering positions within the semiconductor manufacturing industry.

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 31.

II. DESIGN VALUES

Overview

A design value is a statistic that describes the air quality status of a given location relative to the level of the National Ambient Air Quality Standards ("NAAQS"). Design values are

typically used to designate and classify nonattainment areas, as well as to assess progress towards meeting the NAAQS. Design values are computed and published annually by EPA's Office of Air Quality Planning and Standards, and reviewed in conjunction with the EPA Regional Offices. Some of these design values can change after the date of publication for a variety of reasons, including but not limited to:

- EPA agreement that certain data were influenced by exceptional events and therefore not subject for comparison with the NAAQS;
- States retroactively entering or changing erroneous data based on later findings; and/or
- Notification of a monitoring issue (e.g. network design, site combination, change in the regulatory status of a monitor) that would prompt a revision.

Ozone Design Values

The primary and secondary NAAQS for ozone are met at an ambient air monitoring site when the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration (i.e., the design value) is less than or equal to 0.070 ppm. This ozone design value has been in effect since October 26, 2015. *See* 40 CFR Part 50, Appendix U.

The form of the ozone NAAQS requires the use of a 3-year period (as opposed to a 2-year period for other criteria pollutants) to determine the average number of exceedances per year. In its simplest form, the ozone standard requires that the average number of exceedances during a 3-year period cannot be greater than 1.0. An area with four exceedances during a 3-year period, therefore, does not meet the ozone standard because four exceedances in 3 years averages out to more than once per year. If the fourth highest value was equal to the level of the ozone standard, i.e. 0.070 ppm, then the area would have no more than three exceedances during the 3-year period and the average number of exceedances per year would be less than one. This

assumes no missing data, and is how the fourth highest value in 3-years came to be used as the design value. An example is given at the end of the section titled Minimum Data Capture Requirements (Data Completeness).

Calculation of Ozone Design Values

Ozone season for most states is generally considered to be from May through September (the warmest months of the year). However, New Mexico's ozone season is designated as all 12 months, unlike many parts of the country. *See* 40 CFR Part 50, Table D-3 to Appendix D - Ozone Monitoring Season by state. Hourly average ozone concentrations are reported at each ozone monitor in parts per million (ppm) to the third decimal place, with digits to the right of the third decimal place truncated. Each hour is identified using local standard time.

The daily maximum 8-hour average ozone concentration for a given day is the highest of the 17 consecutive 8-hour averages beginning with the 8-hour period from 7:00 a.m. to 3:00 p.m., followed by 8:00 a.m. to 4:00 p.m. and ending with the 8-hour period from 11:00 p.m. to 7:00 a.m. the following day (i.e., the 8-hour averages for 7:00 a.m. to 11:00 p.m.). Daily maximum 8-hour average ozone concentrations are determined each day with ambient ozone monitoring data, including days outside the ozone monitoring season if those data are available. *See* 40 CFR Part 50, Appendix U.

The primary and secondary ozone design value statistic is the annual fourth-highest daily maximum 8-hour ozone concentration, averaged over three years, expressed in ppm. The 3-year average is computed using the three most recent, consecutive years of ambient ozone monitoring data. Design values are also reported in ppm to three decimal places, with digits to the right of the third decimal place truncated.

III. DATA GATHERING AND QUALITY ASSURANCE

Minimum Data Capture Requirements (Data Completeness)

Both the daily maximum 8-hour average ozone concentration data and the design value data, must meet specific requirements to be considered valid:

(1) A daily maximum 8-hour average ozone concentration shall be considered valid if valid 8-hour averages are available for at least 13 of the 17 consecutive 8-hour periods starting from 7:00 a.m. to 11:00 p.m. In the event that fewer than 13 valid 8-hour averages are available, a daily maximum 8-hour average ozone concentration shall also be considered valid if it is greater than the NAAQS. Hourly ozone concentrations that have been approved under 40 CFR § 50.14 as having been affected by exceptional events shall be included when determining whether these criteria have been met. *See* 40 CFR Part 50, Appendix U.

(2) A design value less than or equal to the level of the NAAQS must meet minimum data completeness requirements in order to be considered valid. However, a design value greater than the level of the NAAQS is always considered to be valid.

(3) These requirements are met for a 3-year period at a site if valid daily maximum 8-hour average ozone concentrations are available for at 90% of the days within the ozone monitoring season, on average, for the 3-year period, with a minimum of at least 75% of the of the days within the ozone monitoring season in any one year. *See* 40 CFR Part 50, Appendix U.

See the examples below:

EXAMPLE 1—SITE MEETING THE PRIMARY AND SECONDARY O_3 NAAQS

Year	Percent valid days within O_3 monitoring season (Data completeness)	1st highest daily max 8-hour O_3 (ppm)	2nd highest daily max 8-hour O_3 (ppm)	3rd highest daily max 8-hour O_3 (ppm)	4th highest daily max 8-hour O_3 (ppm)	5th highest daily max 8-hour O_3 (ppm)
2014	100	0.082	0.080	0.075	0.069	0.068
2015	96	0.074	0.073	0.065	0.062	0.060
2016	98	0.070	0.069	0.067	0.066	0.060
Average	98				0.065	

As shown in Example 1, this site meets the primary and secondary O_3 NAAQS because the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentrations (*i.e.,* 0.065666 ppm, truncated to 0.065 ppm) is less than or equal to 0.070 ppm. The minimum data completeness requirements are also met (*i.e.,* design value is considered valid) because the average percent of days within the O_3 monitoring season with valid ambient monitoring data is greater than 90%, and no single year has less than 75% data completeness.

EXAMPLE 2—SITE FAILING TO MEET THE PRIMARY AND SECONDARY O_3 NAAQS

Year	Percent valid days within O_3 monitoring season (Data completeness)	1st highest daily max 8-hour O_3 (ppm)	2nd highest daily max 8-hour O_3 (ppm)	3rd highest daily max 8-hour O_3 (ppm)	4th highest daily max 8-hour O_3 (ppm)	5th highest daily max 8-hour O_3 (ppm)
2014	96	0.085	0.080	0.079	0.074	0.072
2015	74	0.084	0.083	0.072	0.071	0.068
2016	98	0.083	0.081	0.081	0.075	0.074
Average	89				0.073	

As shown in Example 2, this site fails to meet the primary and secondary O_3 NAAQS because the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentrations (*i.e.,* 0.073333 ppm, truncated to 0.073 ppm) is greater than 0.070 ppm, even

though the annual data completeness is less than 75% in one year and the 3-year average data completeness is less than 90% (*i.e.,* design value would not otherwise be considered valid). *See* 40 CFR Part 50, Appendix U.

QA Requirements for Design Value Data

Before daily 8-hour average ozone concentration data is submitted to the EPA, the data is reviewed by QA personnel at the Bureau to meet validity requirements as described below:

(1) Ozone monitoring equipment must pass an annual accuracy audit performed by a QA Auditor to ensure that all flows, pressures, lamp intensities, temperatures and instrument response to ozone concentrations are within instrument specifications.

(2) Quarterly calibrations (four times per year) are performed on all ozone monitoring instruments by personnel from the Bureau's Monitoring Section.

(3) Ozone monitoring instruments must pass weekly 1-point quality control ("QC") checks. These checks are performed automatically on Sunday mornings. If any ozone monitors do not pass this weekly check, Monitoring personnel make required adjustments/fixes to the failing instrument to bring it back within specification in order to pass the weekly check. QA personnel verify that all ozone monitoring instruments pass this check within a 14-day span and then submit the weekly 1-point QC check data to EPA through the Air Quality System ("AQS") website as per precision and accuracy requirements.

(4) Daily checks are performed everyday by Monitoring Section personnel to ensure ozone monitoring equipment is reporting and operating within specifications. They also look for any equipment alarms and note any unusual or high value concentrations above 0.070 ppm. The QA Data Steward also performs a daily check of ozone data each morning to ensure that instruments are reporting and takes note of any data abnormalities.

(5) Lastly, an Annual Data Certification is performed on all monitoring data by QA personnel. A certification letter and related AQS reports are submitted to EPA by May 1st of each year by the Bureau's QA Staff Manager. EPA then sends an acknowledgement letter to the Bureau.

III. SUBMISSION OF DATA TO EPA

Following review by the Bureau's QA personnel to ensure that the data meets all validity requirements, the data is submitted to and processed by EPA as follows:

(1) On a quarterly basis, hourly ozone data is submitted using XLM Reporter software to EPA through the AQS website. The submittal of data is performed by the Bureau's QA Data Steward.

(2) Once the hourly ozone data is submitted, EPA uses it to calculate the 8-hour average ozone concentrations for each day.

(3) From the 8-hour average ozone concentration data, the EPA determines the 1st, 2nd, 3rd and 4th highest daily maximum 8-hour ozone concentrations for the entire year.

(4) Design values are produced by the EPA (not the Bureau) based on the annual fourth-highest daily maximum 8-hour ozone concentration, averaged over three years, expressed in ppm. The 3-year average is computed using the three most recent, consecutive years of ambient ozone monitoring data.

Theodore Andrew Ahr
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Career Summary: Technically oriented professional who brings a skill set consisting of applications/process engineering, technical sales, customer service and management from the areas of semiconductor manufacturing, chemical materials applications and environmental science. A positive attitude, attention to detail, imaginative problem solving, along with high level of integrity and self-confidence have made for a successful career.

Work Experience

State of New Mexico, Environment Department, Air Quality Bureau (AQB) – **Quality Assurance Staff Manager** – Sep. 2019 to present. Manage Quality Assurance Auditors to perform field audits of all air monitoring site equipment to insure it is reporting data as accurately as possible. Manage a Data Handling Specialist to produce periodic air monitoring reports and certification of data to the EPA. Write the AQB's annual Quality Assurance Project Plan, Quality Management Plan, ICIS – Air Quality Assurance Project Plan, and quality assurance standard operating procedures. Perform annual data certification of the AQB's air monitoring data that is submitted to the EPA.

State of New Mexico, Environment Department, Air Quality Bureau – **Compliance Inspections Specialist** - Sep. 2018 – Sep. 2019; Santa Fe, NM
Perform onsite inspections of oil/gas facilities, construction product facilities, landfills and other types of industrial facilities throughout the state of New Mexico. Review permits, regulations and reports associated with the facility. Write detailed reports along with Areas of Concern documents if irregularities are discovered during inspection of facility or regulatory documents.

State of New Mexico, Environment Department, Air Quality Bureau – **Major Source Permit Writer** - Jul. 2017 to Sep. 2018; Santa Fe, NM
Performed technical and regulatory review of complex air quality permit applications. This includes verifying emissions calculations, determining applicable state and federal regulations and drafting legally enforceable air permits and technical support documents.

SBA Materials, Inc. - **Process Engineer and Facility Manager** – Dec. 2010 to Jul. 2016
Albuquerque, NM and San Jose, CA
Assured and maintained the operation of all laboratory/facility equipment and material stocks used in the product formulation and development of spin-on ultra-low-κ dielectric materials. Performed engineering studies on low-k films using a wide variety of laboratory equipment. Researched and applied state and federal environmental regulations for storage, use, shipment and disposal of dangerous chemicals. Other duties include evaluation of test data, purchasing, writing of specifications (SOPs), training new personnel, facility maintenance and the international shipping of dangerous goods.

DuPont **/** EKC Technology, Inc. - **Senior Field Applications Engineer** – Dec. 1997 to Jul. 2009
Albuquerque, NM / Hayward, CA
Performed engineering and sales support for chemical cleaning and surface preparation products to semiconductor and electronics manufacturers throughout North America. Developed wafer cleaning processes at the in-house lab to plug and play at the customer's facility with minimal adjustments. Frequently used process problem solving skills to unravel issues at customer sites associated with plasma etch tools and chemical cleaning systems. These included automated spray / rinse /dry tools and wet benches. Acted as the main point of contact for customer technical questions about products and services. Worked with internal

sales/marketing teams, R&D engineers, quality control engineers and customer development teams to design, evaluate and characterize new products. Designed manufacturing processes that were both more environmentally friendly and lower in cost of ownership. My efforts helped acquire new accounts and expand business at existing customer sites. Prepared reports and presented technical information directly to customers. Used my superior interpersonal communication skills to resolve difficult issues at customer meetings. Primarily used Microsoft Office Suite software for the generation of technical reports. Compiled and prepared application data for use in technical marketing materials. Traveled up to 80% of the time when required for business purposes.

Philips Semiconductors - **Senior Process Engineer** (metal etch) – Mar. 1996 to Dec. 1997 and from Aug. 1991 to Mar. 1994 – Albuquerque, NM
Developed and maintained plasma etch and wet etch processes on aluminum, tungsten and titanium metals using Lam 9600 TCP and Applied Materials 8330 plasma metal etch systems. Used manual and automated wet benches for wet etch processes. SPC disciplines were used to maintain process control and to consistently drive for improved results. Inspected metal profiles with a scanning electron microscope.

High Yield Technology - **Senior Field Applications Engineer** – Mar. 1994 to Mar. 1996
Albuquerque, NM
Installed and developed in-situ particle monitors using laser light scattering /detection technology on a wide variety of high vacuum semiconductor process equipment at customer sites in the U.S., Ireland and Israel. Wrote application notes and lead training sessions for technicians and engineers. Performed field service engineering of the sensors.

Signetics Fab 22 & Fab 23 - **Defect Density Engineer** - Mar. 1986 to Aug. 1991
Albuquerque, NM
Helped establish and supervise this new engineering group which collected defect data from key fab process areas. The statistical data was graphed and reported weekly. Defect data was analyzed so correlations to particular tool events could be understood. Defect data was collected through the use of a KLA-2028 wafer inspection system and optical microscopes.

Signetics Fab 22 - **Quality Assurance Coordinator** – Feb. 1983 to Mar. 1986
Albuquerque, NM
Supervised a group of up to six operators to perform incoming acceptance inspections on all masks and reticles. Other duties included specification distribution and checking all measurement equipment for proper calibration and functionality.

U.S. Navy (Reserve) – **Lieutenant (junior grade)** – Oct. 1980 to Nov. 1986
Pensacola, FL and Corpus Christi, TX
Student Naval Aviator and later became an assistant air operations officer for the Chief of Naval Air Training. Scheduled aircraft for cargo missions and air show appearances.

Education

Bachelor of Science degree from the University of New Mexico in Albuquerque, NM
Majored in Biology with a minor in Chemistry

Graduated from the U.S. Navy's Aviation Officer Candidate School in Pensacola, FL
Earned a commission as an officer in the U.S. Navy (Reserve)

Master of Business Administration degree from New Mexico Highlands University branch in Albuquerque, NM

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STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF ELIZABETH BISBEY-KUEHN AND BRIAN PALMER

Elizabeth Bisbey Kuehn

My name is Elizabeth Bisbey-Kuehn. I am the Bureau Chief of the Air Quality Bureau ("Bureau") of the New Mexico Environment Department ("NMED" or "Department"). I am presenting this written testimony on behalf of the Department in this proceeding before the Environmental Improvement Board ("Board") on the Department's proposed new air quality regulation at 20.2.50 NMAC ("Part 50"). This part of my direct testimony will address the following topics:

- Facility and equipment data compiled for this rulemaking from the Bureau's TEMPO database (Part II. of this testimony);
- Key exhibits referred to throughout my and Mr. Palmer's testimony on the proposed rule requirements (Part III of this testimony);
- The proposed provisions in Sections 20.2.50.1 through 20.2.50.112, and 20.2.50.127 of Part 50; and
- The proposed provisions in Sections 20.2.50.113 through 20.2.50.124 of Part 50 with respect to applicability, description of equipment or process, control options, and proposed rule requirements. Mr. Palmer's testimony will cover Sections 20.2.50.113 through 20.2.50.124 with respect to the basis for the proposed requirements, estimated reductions, and estimated costs.

I will also be presenting direct testimony on other topics in this rulemaking in separate pieces of pre-filed testimony.

Brian Palmer

My name is Brian Palmer and I am a Senior Environmental Scientist with Eastern Research Group, Inc. ("ERG"). I have been asked to provide testimony on behalf of NMED in this proceeding regarding Part 50. I am part of a team from ERG that was contracted to assist the Department in developing the requirements in Part 50 and to provide testimony before the Board at the hearing on the proposed rule. My testimony covers Sections 20.2.50.113 through 20.2.50.124 with respect to the basis for the proposed requirements in those Sections, the estimated emissions reductions from compliance with those requirements, and estimated costs of compliance.

I. QUALIFICATIONS

A. Elizabeth Bisbey-Kuehn

A summary of my background and qualifications is provided in my other pre-filed testimony at NMED Exhibit 5. My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 6.

B. Brian Palmer

I have been a Senior Environmental Scientist with ERG since 1996. Prior to that, I was an Environmental Scientist with Radian International LLC for five years. My experience at ERG has included development of proposed amendments to EPA's regulations at 40 CFR Part 98, Subpart W – Mandatory Greenhouse Gas Reporting for Petroleum and Natural Gas systems; leading regulatory development projects for fifteen source categories, including baseline emission

inventories and estimating emission reductions; and supporting numerous projects related to the mandatory greenhouse gas reporting regulations at 48 CFR Part 98.

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 33.

II. FACILITY AND EQUIPMENT DATA FOR PROPOSED PART 50

The Bureau utilizes a database called "TEMPO" to record, monitor, and track information about equipment and facilities regulated by the Department under the New Mexico Air Quality Control Act ("AQCA") and the Board's air quality regulations at Title 20, Chapter 2 of the New Mexico Administrative Code ("NMAC"). This information is collected from different types of submittals, including notice of intent registrations, air quality permit applications, compliance reports, report submittals required by state and federal air quality regulations, settlement requirements, and emissions inventories.

In TEMPO, a facility-level entry is referred to as the "Agency Interest" or the acronym "AI." Each facility entered in TEMPO includes: the company that owns, operates, and is the billing party for the facility; the person designated as the main contact or consultant for air permitting submittals; the estimated, potential, and actual quantities of facility-wide emissions; location information; applicable air quality regulations; the reported NAICS and SIC codes; and general information related to the facility. The general information includes identifying numbers assigned by the Bureau, the general category of industry type (such as compressor station, tank battery, or refinery), and the source classification status for facilities with air quality permits or registrations.

Additionally, TEMPO maintains information about individual equipment, which is referred to as the "Subject Item" or the acronym "SI." The information maintained for individual equipment will depend on the particular state and federal regulations that apply. Facilities with an

issued air quality permit have extensive information about emitting equipment entered in TEMPO. At the equipment-level, at a minimum, TEMPO captures the following: equipment stack parameters (including diameter, height, velocity, flow rate, and temperature); operating hours; permitted hourly and annual air emission limits for all regulated air contaminants; air increment consumption; control device if used and control efficiency; fuel type, heating value, and fuel use rates; general information such as serial numbers, manufacturer and construction dates, operating or capacity rates; applicable federal regulations and subparts; and source classification codes ("SCCs").

The Bureau maintains the SI level of information for equipment at facilities with air quality permits but does not enter the SI level of information for facilities operating with a notice of intent, which is not an air quality permit.

The Bureau uses TEMPO and the equipment and emissions data in the database in multiple ways. Electronic copies of public records and documents related to permit applications, compliance reports, emissions inventory, and a variety of submittal requirements are maintained in TEMPO. The emissions data in TEMPO is used to assess annual emission fees and annual permitting fees. The Bureau reports federally mandated regulatory information to EPA via TEMPO. Companies, regulated facilities, consultants, and the Bureau use the information in TEMPO to determine surrounding sources for air dispersion modeling analyses required for air permit applications. AQB uses TEMPO data to track prevention of significant deterioration increment consumption and/or expansion. TEMPO is also used as a project management tool to track action dates and deadlines for multiple sections within the Bureau.

Since TEMPO is a database, the Bureau has many options for compiling information according to business need. The data extracted from TEMPO is normally returned as spreadsheets.

The Bureau commonly uses reports to analyze emission trends, analyze application submittal trends, respond to Inspection of Public Records Act requests, generate lists of historical permit actions, generate lists of active or closed facilities, and track open actions. The Bureau can create custom reports based on any information in TEMPO.

To provide underlying data and information for this rulemaking on proposed Part 50, the Department downloaded the following information from TEMPO and provided it to ERG: owner, facility name, AI ID, source type, county, latitude, longitude, source classification, equipment type, category, designation, description, manufacturer, model number, serial number, manufactured date, construction date, operating rating capacity, maximum rating capacity, type of pollutant, quantity of hourly emissions, quantity of annual emissions, primary and secondary control devices, type of fuel, hours of operation, applicable federal air quality regulations, and SCC information. ERG used this data to develop the equipment spreadsheets used to evaluate the emissions reductions and costs of Part 50. The NMED data pulled from TEMPO and provided to ERG is included in a tab in each equipment spreadsheet, and is referred to throughout this testimony as the "NMED Equipment Data." The ERG spreadsheets generated from the TEMPO data are provided as exhibits in electronic format as Microsoft Xcel files.

III. KEY EXHIBITS

The Department and its consultants at ERG developed and/or relied upon a number of key documents in developing the proposed rule and the supporting technical information, and these documents are referred to throughout this testimony. The following list contains the exhibit number, name as referred to in the testimony, and description or citation information for each key document:

- **NMED Exhibit 34** – "**EPA CTG"**: EPA Office of Air and Radiation, *Control Techniques Guidelines for the Oil and Natural Gas Industry*, EPA-453/B-16-001 (October 2016)
- **NMED Exhibit 35 – "NSPS Subpart OOOO"**: EPA New Source Performance Standards at 40 C.F.R. Part 60, Subpart OOOO - Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011 and on or before September 18, 2015.
- **NMED Exhibit 36 – "NSPS Subpart OOOOa"**: EPA New Source Performance Standards at 40 C.F.R. Part 60, Subpart OOOOa - Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015.
- **NMED Exhibit 37 – "Pennsylvania GP-5"**: Pennsylvania GP-5, GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT BAQ-GPA/GP-5 for Natural Gas Compression Stations, Processing Plants, and Transmission Stations.
- **NMED Exhibit 38 – "Pennsylvania GP-5A"**: Pennsylvania GP-5A, GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT BAQ-GPA/GP-5A for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations.
- **NMED Exhibit 39 – "Colorado Reg. 7"**: Colorado Regulation Number 7 - CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS (EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES). All citations to Colorado Reg. 7 in this testimony are to Part D of that regulation unless expressly identified otherwise.

- **NMED Exhibit 40 ("Wyoming Permitting Guidance") –** Wyoming Department of Environmental Quality, Air Quality Division – *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance* (Revised through May 2016).

IV. REVISIONS TO MAY 6, 2021 VERSION OF PART 50

The Department has made a number of editorial and clarifying revisions to the May 6, 2021 version of proposed Part 50. The new proposed version of Part 50 with these changes to the May 6, 2021 version shown in redline strikeout format is attached as NMED Exhibit 41. The revisions address inconsistencies in verbiage, clarify terms and definitions in the definition and applicability sections of each section and throughout the rule, correct punctuation errors, and edit text to clarify the Department's intent. The revisions to the proposed rule are explained as follows:

1) The term "wellhead site" is replaced with "well site" in the definition of "commencement of operation" (20.2.50.7.G); the definition "gathering and boosting station" (20.2.50.7.Q); the definition of "wellhead site" (20.2.50.7.TT); and in the other sections of Part 50 where that term appears. The new term "well site" is more consistent with the federal definition of well site. The term "wellhead" is narrowly defined in NSPS Subpart OOOOa, Section 60.5430a, and excludes equipment that the Department intended to include within the requirements of Part 50. The new terminology more accurately reflects the Department's intent and better aligns Part 50 with other federal air quality regulations.
2) The term "air fuel ratio controller" ("AFRC") is removed from the definition of "control device" at 20.2.50.7.L. The Department did not analyze AFRCs as potential control devices under Part 50, and did not intend for them to be an option for compliance with the emission standards under the rule. AFRCs are typically required when other control devices are in use, such as catalytic converters. The removal of AFRCs clarifies that the Department did

not analyze these types of equipment for potential application under Part 50, and did not intend to include them in the definition of control device.

3) The definition of "gathering and booster station" in 20.2.50.7.Q is revised to clarify the segment of the oil and gas industry intended to be included in this term. The new definition is "a facility, including all equipment and compressors, located downstream of well sites, designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant."

4) The definition of "natural gas compressor station" in 20.2.50.7.W is revised to add the following language: "Natural gas compressor stations include transmission compressor stations." This additional language clarifies the Department's intent to include transmission compressor stations within the meaning of a natural gas compressor station.

5) A definition of "transmission compressor station" is added at 20.2.50.7.SS to clarify the segment of the oil and gas industry included in this term, as used in the revised definition of "natural gas compressor station" at 20.2.50.7.W. Under the new definition, the term "transmission compressor station" means "a facility, including all equipment and compressors, that moves natural gas at elevated pressure from well sites or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids." The definition of "Well Workover" is renumbered to 20.2.50.7.TT, and the definition of "Well Site" is renumbered to 20.2.50.7.UU to accommodate the addition of the definition for "transmission compressor station".

6) The term "gathering and boosting sites" is replaced with "gathering and boosting stations" in Section 20.2.50.111 and throughout the other sections of the rule where the term "gathering and boosting sites" was used. The replacement provides consistency in the terminology throughout Part 50, and aligns the language in the definitions section with the remaining sections of the rule.

7) The term "transmission compressor stations" is replaced with "natural gas compressor stations" in Section 20.2.50.111 and throughout the other sections of the rule where the term "transmission compressor station" was used. The replacement provides consistency in the terminology throughout Part 50, and aligns the language in the definitions section with the remaining sections of the rule.

8) A sentence was added in Subsection B of Section 20.2.50.111 to clarify that an owner or operator may not account for the effects of compliance with the requirements of Part 50 in calculating the potential to emit ("PTE") of a source for purposes of determining if the source is subject to Part 50. The following sentence was added: "Owners and operators may not include emissions reductions from compliance with this Part in calculating the PTE of a source for purposes of this Section, or in determining whether a source is subject to the requirements of this Part."

9) A sentence was added in 20.2.50.116(A) to clarify that an owner or operator may account for compliance with the requirements of Part 50 in the PTE calculations under Section 20.2.50.116, and in determining the monitoring frequency for a facility required in that Section. The following sentence was added: "Compliance with the requirements of this Part may be accounted for in determining a facility's PTE under this Section for purposes of determining applicable monitoring frequencies."

10) The phrase "an artificial lift engine" in 20.2.50.117.B(3)(b) was changed to "artificial lift." This revision clarifies the Department's intent that artificial lift is an option to comply with Section 20.2.50.117.

11) The words "during normal operation" were added to the end of the requirement in 20.2.50.118.B(3)(c) to read: "still vent and flash tank emissions shall not be vented to the atmosphere *during normal operation*." (Emphasis added). The additional language addresses a conflict with language in 20.2.50.118.B(3)(b) which requires owners and operators using a VRU to comply with the emission standards to meet a minimum capture and control efficiency of 95%. The revision addresses the conflict by clarifying under what conditions venting to the atmosphere may occur, while maintaining the minimum 95% emission reduction requirement.

12) The language in 20.2.50.120(B)(1) was revised to require owners and operators using vapor balancing or vapor recovery to control emissions by 100% when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel. The language further clarifies that the 98% control requirement applies to owners and operators using a control device to comply with this emission standard when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

13) The language in 20.2.50.120(B)(6) was revised to replace the word "prevents" with the word "minimizes." This revision clarifies the Department's intent to have owners and operators minimize emissions after a liquid leak has occurred. The revision resolves a conflict in the original proposed language that was problematic because a liquid leak by definition involves emissions to the atmosphere, so emissions from a liquid leak cannot be

entirely prevented, but they can be minimized in the cleaning and disposal of the leaked liquid.

14) The requirement in 20.2.50.120(C)(3) to conduct vapor testing on trucks used for hydrocarbon liquid transfers was removed. This revision clarifies the equipment and operations intended to be covered under Part 50. Tanker trucks and tanker rail cars transporting hydrocarbon liquids are not subject to Part 50 and were not analyzed by the Department during the development of the requirements in Part 50. The Department did not intend to impose testing and inspection requirements on equipment not subject to Part 50. The removal of 20.2.50.120(C)(3) also requires the deletion of the phrase "and testing" from 20.2.50.120(D)(2) and D(2)(a) through (d). This deletion is necessary in order to align the recordkeeping requirements with the revisions made to 20.2.50.120(C).

15) The colon at the end of the requirement in 20.2.50.120(D)(1) was replaced with a period to correct a drafting error.

16) The requirement in 20.2.50.122(B)(4)(c)(v) was revised to clarify that if an owner or operator meets at least a 75% total of non-emission controllers by January 1, 2025, the owner or operator is not subject to the requirements of Tables 1 and 2 of 20.2.50.122(B)(3). The phrase "has satisfied" was replaced by "is not subject to."

17) The word "in" was deleted from the requirement in 20.2.50.123.D(2) to correct a drafting error.

V. PROPOSED RULE PROVISIONS

Section 20.2.50.1 – Issuing Agency

The Board is the issuing agency pursuant to the AQCA.

Section 20.2.50.2 - Scope

This section explains the areas of the State that are subject to, or may become subject to, Part 50. As explained in the testimony of NMED witness Michael Baca, the Department developed the proposed rule as part of its Ozone Attainment Initiative, according to the directives of the AQCA at NMSA 1978, Section 74-2-5. *See* NMED Exhibit 1 at p. 4-5.

In accordance with the AQCA, Part 50 establishes emissions standards for oil and gas production and processing sources located in areas of the State within the Board's jurisdiction that, as of the effective date of the rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard ("NAAQS") for ozone, as measured by a design value calculated and based on data from one or more Department monitors.[1] Those areas currently include Chaves, Eddy, Lea, Rio Arriba, San Juan, Sandoval, and Valencia Counties (hereinafter referred to as the "Subject Counties"). Once a source becomes subject to Part 50, the requirements of Part 50 are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in Part 50.

Section 20.2.50.3 – Statutory Authority

The Environmental Improvement Board ("Board") is authorized to adopt Part 50 pursuant to the New Mexico Environmental Improvement Act ("EIA"), NMSA 1978, §§ 74-1-1 to -17, and the AQCA. Section 74-1-8(A) of the EIA provides that the Board, as part of its responsibility for environmental management, shall promulgate rules and standards governing air quality management as provided in the AQCA (74-1-8(A)(4)), and nuisance abatement (74-1-8(A)(7)).

[1] Discussion regarding ozone monitoring in New Mexico is presented in the direct testimony of NMED witness Brent Ellington. *See* NMED Exhibit 28.

The Board's statutory authority under the AQCA is addressed in the direct testimony of NMED witness Michael Baca. *See* NMED Exhibit 1, at p. 4-5.

Section 20.2.50.4 – Duration

The Department proposes to for Part 50 to be permanently in effect from the effective date established in Section 20.2.50.5.

Section 20.2.50.5 – Effective Date

This section establishes the date on which the regulation becomes effective and is required by the New Mexico State Records Center and Archives. The effective date depends on when the final regulation is published in the New Mexico Register.

Section 20.2.50.6 - Objective

This section identifies the purpose of Part 50 and is required by the New Mexico State Records Center and Archives. The stated objective of Part 50 is "to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NOx) for oil and gas production, processing, and transmission sources."

Section 20.2.50.7 - Definitions

Section 20.2.50.7 contains definitions of terms used throughout Part 50. The proposed definitions are derived from state and federal regulations, and other technical glossaries used as part of standard practice by the regulated community and environmental regulatory agencies.

Subsection A. – "Approved instrument monitoring method" means an optical gas imaging ("OGI"); EPA reference method 21, 40 CFR § 60, Appendix B (NMED Exhibit 42); or other instrument-based monitoring method or program approved by the Department in advance and in accordance with Part 50. This definition establishes the types of monitoring methods that may be

used to monitor fugitive emissions and that are approved or may be approved by the Department. This definition was derived from Colorado Reg. 7, Section I.L.8.

Subsection B. – "Auto-igniter" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream. This definition was derived in part from Colorado Reg. 7, Section I.B.5.

Subsection C. – "Bleed rate" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection D. – "Calendar year" means a year beginning January 1 and ending December 31. This definition implements the commonly accepted interpretation of a calendar year.

Subsection E. – "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection F. – "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere. This definition was derived in part from language in Colorado Reg. 7, Section I.J, and NSPS Subpart OOOOa, 40 CFR § 60.5411a(a).

Subsection G. – "Commencement of operation" means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage vessels from the first producing well at the stationary source, but

no later than the end of well completion operation. This definition describes when operation of a production well may be presumed to have begun and was derived in part from Colorado Reg. 7, Section I.B.7.

Subsection H. – "Component" means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol. This definition was derived in part from Colorado Reg. 7, Section I.B.10.

Subsection I – "Connector" means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube, or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part. This definition was derived in part from Colorado Reg. 7, Section I.B.11.

Subsection J. – "Construction" means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources. This definition describes the types of activities that constitute construction and was taken from the Board's regulations at 20.2.72 NMAC – *Construction Permits*.

Subsection K. – "Custody transfer" means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation. This definition describes the concept of custody transfer and was derived in part from Colorado Reg. 7, Part B, Section IV.A.2.c.

Subsection L. – "Control device" means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices ("ECDs"), thermal oxidizers ("TOs"), vapor recovery units ("VRUs"), fuel cells, condensers, air fuel ratio controllers ("AFRs"), catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part. This definition was derived in part from Colorado Reg. 7, Part A, Section II.A.7.

Subsection M. – "Department" means the New Mexico Environment Department.

Subsection N. – "Downtime" means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation. This definition was derived in part from Merriam-Webster dictionary.

Subsection O. – "Enclosed combustion device" or "ECD" means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater. This definition describes the types of equipment that are considered ECDs and the theory of ECD operation. Enclosed combustion device is a common term used in oil and gas regulatory provisions. *See, e.g.*, NSPS Subpart OOOOa, 40 CFR § 60.5412(d)(1). The definition in Part 50 was developed during rule drafting based on the knowledge and experience of NMED technical staff.

Subsection P. – "Existing" means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed. This definition is required because the

applicability of numerous requirements and timeframes in Part 50 is based on whether a source is "existing" or "new".

Subsection Q. – "Gathering and boosting station" means a facility, including all equipment and compressors, located downstream of well sites, designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection R. – "Glycol dehydrator" means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water. This definition was derived in part from Colorado Reg. 7, Section I.B.15.

Subsection S. – "Hydrocarbon liquid" means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. This definition was derived in part from Colorado Reg. 7, Section I.B.16.

Subsection T. – "Liquid unloading" means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production. This definition derived from general information on EPA's Natural Gas STAR website and the EPA publication "Options for Removing Accumulated Fluid and Improving Flow in Gas Wells" (NMED Exhibit 44).

Subsection U. – "Liquid transfer" means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport. This definition was derived from general information from EPA's website and EPA's AP-42 Chapter 5.2 Transportation and Marketing of Petroleum Liquids, Section 5.2.2 (NMED Exhibit 43).

Subsection V. – "Local distribution company custody transfer station" means a metering station where the local distribution ("LDC") company receives a natural gas supply from an

upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines. This definition was derived from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection W. – "Natural gas compressor station" means a facility, including all equipment and compressors, designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline. Natural gas compressor stations include transmission compressor stations. This definition was derived in part from Colorado Reg. 7, Section I.B.19, and the EPA CTG, Section C.7.

Subsection X. – "Natural gas-fired heater" means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process. This definition was derived in part from Colorado Reg. 7., Part E, section II.A.3.p.

Subsection Y. – "Natural gas processing plant" means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant. This definition was derived from the NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection Z. – "New" means constructed or reconstructed on or after the effective date of this Part. This definition is required because the applicability of numerous requirements and timeframes in Part 50 is based on whether a source is "existing" or "new".

Subsection AA. – "Operator" means the person or persons responsible for the overall operation of a stationary source. The definition was derived in part from the CAA at 42 U.S.C Section 7411.

Subsection BB. – "Optical gas imaging" or ("OGI") means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons. This definition was derived in part from Colorado Reg. 7, Section I.B.17, and NSPS Subpart OOOOa, 40 CFR § 60.5397a.

Subsection CC. – "Owner" means the person or persons who own a stationary source or part of a stationary source. This definition was derived in part from the CAA at 42 U.S.C Section 7411.

Subsection DD. – "Permanent pit" means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year. This definition was derived in part from the New Mexico Oil Conservation Commission's ("OCC") regulations at 19.15.17 NMAC.

Subsection EE. – "Pneumatic controller" means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature. The definition was derived in part from Colorado Reg. 7, Section III.B.10.

Subsection FF. – "Pneumatic diaphragm pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that

relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection GG. – "Potential to emit" or ("PTE") means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen. This definition was derived from the Board's air quality operating permit regulations at 20.2.70 NMAC.

Subsection HH. – "Produced water" means a fluid that is an incidental byproduct from drilling for or the production of oil and gas. This definition describes what is meant by the term produced water and was derived from the OCC's regulations at 19.15.2 NMAC.

Subsection II. – "Produced water management unit" means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels. This definition describes what is meant by the term produced water management unit and was derived in part from the OCC's regulations at 19.15.2, 19.15.17, and 19.15.34 NMAC.

Subsection JJ. – "Qualified Professional Engineer" means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical

certifications required under this Part. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection KK. – "Reciprocating compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod. This definition was derived from Colorado Reg. 7, Section I.B.24.

Subsection LL. – "Reconstruction" means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility. This definition was derived from the Board's regulations at 20.2.72 NMAC.

Subsection MM. – "Recycling facility" means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used. This definition was derived from the OCC's regulations at 19.15.34 NMAC.

Subsection NN. – "Responsible official" means one of the following: (1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source, or (2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively. This definition was derived from the Board's operating permit regulations at 20.2.70 NMAC.

Subsection OO. – "Small business facility" means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of

another business, that employs no more than employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers. This definition was developed during rule drafting by NMED technical staff and contractors. An in-depth discussion of the basis for this definition is provided in the testimony of NMED witnesses Elizabeth Bisbey-Kuehn and Susan Day.

Subsection PP. – "Startup" means the setting into operation of air pollution control equipment or process equipment. This definition was derived from the Board's regulations at 20.2.7 NMAC – *Excess Emissions*.

Subsection QQ. – "Stationary Source" or "source" means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly. This definition was derived from the Board's air quality construction permit regulations at 20.2.72 NMAC.

Subsection RR. – "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 1 kilopascals without emissions to the atmosphere. This definition

describes was derived in part from Colorado Reg. 7, Section I.B.27, and NSPS Subpart OOOOa, 40 CFR § 60.5365a.

Subsection SS. – "Transmission Compressor Station" means a facility, including all equipment and compressors, that moves natural gas at elevated pressure from well sites or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

Subsection TT. – "Well workover" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons. This definition was derived from the MAP report.

Subsection UU. – "Wellhead site" means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping. This definition was derived from Colorado Reg. 7, Section I.B.30, and NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Section 20.2.50.111 - Applicability

Subsection A of Section 20.2.50.111 outlines the specific sources of air pollutants that are covered under Part 50. The rule applies to crude oil and natural gas production and processing equipment, including equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, handle hydrocarbon liquids or produced water in areas of the state specified in Section 20.2.50.2 and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations located up to the point

of the local distribution company custody transfer station. Part 50 applies to state, federal, and privately owned land, but does not apply to tribal lands or Bernalillo County.

Subsection B of Section 20.2.50.111 specifies how to determine whether a source is subject to Part 50; specifically, owners and operators must calculate the PTE of each potentially affected source to determine if it is subject to requirements under the rule. The PTE calculation must be certified by a qualified profession engineer. This certification is critical to ensuring the potential air emissions from equipment and processes are properly calculated and representative of the source, and present a true and accurate representation of the source's potential emissions. Without this certification, emission calculations may be performed based on process, emission, or operational inputs that are not accurate or representative, which then underestimate the true potential emissions and result in a determination that equipment is not subject to this part. The PTE calculation is the foundation of determining applicability of this part and the certification of the PTE calculation ensures the integrity of how that fundamental calculation is performed.

Subsection C of Section 20.2.50.111 provides that owners and operators of small business facilities as defined in 20.2.50.7.OO are subject to the requirements of Section 20.2.50.125. A full discussion of Section 20.2.50.125

Subsection D of Section 20.2.50.111 provides that petroleum refiners and transmission pipelines are not subject to Part 50.

Section 20.2.50.112 – General Provisions

<u>General Requirements</u>

Subsection A of Section 20.2.50.112 outlines general provisions that establish a universal set of requirements applicable to all owners and operators of sources of emissions subject to emissions standards and other requirements of Part 50. Owners and operators of all affected

sources must meet the general operational, monitoring, recordkeeping, and reporting requirements set forth in Subsection A.

Paragraph (1) of Subsection (A) establishes work practice standards requiring equipment to be operated consistent with manufacturer specifications, for those specifications to be kept on file. For older equipment, it is often the case that equipment specifications provided by the equipment manufacturer is outdated, cannot be located, or in some cases does not exist. Thus, for equipment constructed prior to 1980 for which there is no manufacturer specification, NMED requires owners and operators to develop and follow a maintenance schedule sufficient to operate and maintain the sources in good working order.

Paragraph (2) of Subsection A establishes a requirement that equipment be operated a manner that minimizes emissions of air contaminants, including NOx and VOC. This is a standard operational requirement intended to ensure that equipment is used for its intended purpose only; that equipment is maintained in good working order such that it operates within its normal operating parameters, loads, and process and throughput rates; and that owners and operators proactively address any operational issues to avoid excess emissions due to equipment failures, malfunctions, or lack of proper maintenance and operation.

Paragraphs (3) through (9) of Subsection A establishes requirements for owners and operators to install an Equipment Monitoring Tag ("EMT") on certain equipment. The EMT is a tag that interacts with a company's equipment database and is used to track equipment information and compliance monitoring events and data. This section outlines what equipment data and compliance monitoring information are required to be maintained for each source subject to Part 50. The EMT is required to be scanned by owners and operators prior to compliance monitoring events, which certifies that owners and operators have initiated a compliance event. After the

compliance monitoring event concludes, owners and operators must complete a final scan of the EMT, which concludes event. The data required to be maintained includes a unique identification number, location, source type, the potential to emit; make, model, serial number; and a link to the manufacturer's maintenance and repair schedule. This section also outlines the general requirements for maintaining and operating the EMT; requirements for the owner and operator to manage the sources' record of data in a database that can generate a compliance database report in a format determined by the department; requirements to contemporaneously track compliance events for each subject source and requirements for timely uploads of monitoring or testing event data; and requirements for maintaining those records for a period of at least five years.

The EMT requirements will significantly improve the Department's ability to receive, review, and analyze compliance monitoring data for subject sources. In addition, these requirements will help improve and increase the public's confidence that required compliance monitoring is in fact occurring as required, because the contemporaneous scanning and recordkeeping during the monitoring and testing events ensures that owners and operators are fulfilling the monitoring requirements of the rule.

Paragraph (10) of Subsection A establishes a requirement for owners and operators to retain a third party at their own expense to verify any information collected, reported, or recorded pursuant to Part 50, if requested by the Department. The third party must conduct an assessment and make recommendations to correct or improve the data collected. The owner or operator is required to share the third party assessment and recommendations with the Department and implement them in a manner approved by the Department. The third-party compliance verification requirement provides a critical new auditing option if the Department suspects or finds that an owner or operator is failing to meet requirements under Part 50. Such verification will benefit the

Department's compliance program in significant ways. Having a compliance assessment conducted and a report prepared by an outside third party results in a considerable time and resource savings for the Department, which already operates under limited staffing and financial resources. The Department can review the compliance assessment report highlighting any issues and recommendations, and approve is the manner in which the recommendations are implemented. This approach will improve and increase the public's confidence in the company's compliance with Part 50. In sum, the ability of the Department to require a third-party compliance audit strengthens the overall rule; saves limited staffing resources; improves the public's confidence in compliance with the rule; will result in overall better compliance; and provides owners and operators with targeted recommendations on how to improve any compliance issues identified in the report.

General Monitoring Requirements

Subsection B of 20.2.50.112 specifies general monitoring requirements for sources subject to Part 50. Monitoring of equipment, processes, and emissions provides owners and operators with information they can use to evaluate the equipment operation and performance relative to the requirements of the rule, and assist them in determining proper corrective actions when necessary. Equipment monitoring provides the basis for most on-going compliance demonstrations and provides documentation to support the required compliance certification. The provisions in Subsection B establish a monthly inspection requirement for sources subject to emissions standards and monitoring under Part 50; a process for submitting an alternative monitoring strategy for the Department's consideration; and requirements for EMT scanning and reporting of certain required data and information obtained during the monitoring event.

Paragraph (1) of Subsection (B) requires owners and operators to inspect affected sources at least monthly to ensure proper operation and maintenance of such sources, unless a different schedule is specified under another Section of Part 50. This monthly inspection is the minimum periodic monitoring requirement for sources subject to Part 50 and requires owners and operators to evaluate the overall operation of the source. There are different types of source monitoring required under the other sections of the rule, and this requirement establishes the baseline monthly inspection. In the source-specific subparts, additional types of monitoring, including parametric monitoring, emissions stack testing, and other types of inspections are required.

Paragraph (2) of Subsection (b) provides a process by which owners and operators can propose an equally effective, enforceable, and equivalent alternative monitoring strategy to the Department for consideration. This is a critical option for both the Department and affected owners and operators, as it provides a process by which new and innovative monitoring approaches and technologies can be used to comply with the monitoring requirements of Part 50. As new monitoring technology becomes available and technically feasible, it is important for operators to have flexibility in the performance of compliance monitoring required under the rule. For instance, fence line air monitoring and aerial surveillance technologies are quickly evolving and both approaches can improve real time emissions data collection and enable faster compliance assessments covering multiple sources.

An alternative monitoring strategy must first be reviewed and approved in writing by the Department prior to implementation. The Department will provide an alternative monitoring strategy request form, which will outline the criteria for demonstrating that the proposed alternative meets the requirements of the rule that it be equally effective, enforceable, and equivalent. At a minimum, the proposal must effectively monitor the source for the pollutants of

concern and establish sufficient monitoring, recordkeeping, and reporting requirements such that the requirements are legally and practically enforceable.

Paragraph (3) of Subsection B provides that monitoring events for equipment required to have an EMT must be initiated and completed by scanning the unit's EMT. As previously discussed, requiring an affirmative scanning of the EMT prior to and after the conclusion of any monitoring event provides assurance that the monitoring event actually occurred and will reduce the incidences of missed compliance monitoring requirements and inaccurate monitoring records. The minimum set of data required to be uploaded to the company database includes: the date and time of the monitoring event, name of the personnel conducting the event, ID and type of unit, description of any maintenance or repair conducted, and the results of the event as required under Part 50.

General Recordkeeping Requirements

Subsection C of Section 20.2.50.112 establishes minimum universal recordkeeping requirements that owners and operators of sources subject to Part 50 must comply with. These include a requirement to upload monitoring data within three business days of any monitoring event; to maintain all records required under this part for at least five years; and to complete a full compliance evaluation of sources subject to this part prior to any transfer of ownership.

The requirement for a full compliance evaluation prior to any transfer of ownership will have significant and positive benefits for public health and the environment, as well as for the Department and its air compliance program. This requirement obligates owners and operators to conduct and document a full evaluation of all affected sources' compliance with the full requirements of Part 50. The documentation must include a certification by a responsible official as to the compliance status of all affected sources with respect to the emission standards,

monitoring, recordkeeping, and reporting requirements of Part 50. The compliance evaluation must be conducted at least three months prior to any transfer of ownership, and the documentation must be kept by the new owner or operator for at least five years. This provision is important as it requires owners and operators to perform a preemptive compliance determination, which can highlight potential compliance issues for the current owner, future owner, and the Department. The report will also provide important compliance status information to the Department, which may be used in the development of enforcement cases and can provide a compliance baseline from which to reference and compare the new owner's compliance progress and improvement, or decline.

General Reporting Requirements

Subsection D of Section 20.2.50.111 establishes general reporting requirements for sources subject to Part 50. Owners and operators are required to make any reports required to be generated under Part 50 available to the Department within 24 hours of the Department's request. Those reports must be made available in an electronic format and submitted to the Department's secure extranet portal or by other means or formats as specified by the Department.

Section 20.2.50.113 – Engines and Turbines

Section 20.2.50.113 applies to portable and stationary natural gas-fired spark ignition engines; compression ignition engines; and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations with a rated horsepower greater than those shown in Tables 1, 2, and 3 of Section 113.

Description of Equipment and Process

Engines and turbines are used in the oil and gas industry to power compressors that maintain natural gas pressures at levels sufficient to move gas through gathering and transmission pipelines. Compressors at gathering compressor stations move the gas from the wellhead to gas processing plants. Compressors at gas processing plants move the gas from the processing plants to transmission pipelines, and compressors at transmission compressor stations maintain pressure and move the gas along the transmission pipelines to the ultimate user of the processed gas.

In addition to driving compressors, engines may also be used as the driver for power generators that provide electrical power to sites that are not connected to the commercial electrical grid or may be used as backup power supply in case of a power outage. Engines are also used to drive pumpjacks in the oil production sector. Pumpjacks are used to mechanically lift liquid out of the well if bottom hole pressure is not high enough to allow liquid to flow to the surface.

Two kinds of reciprocating internal combustion engines are used in the oil and gas industry: spark ignition and compression ignition. In a spark ignition engine, fuel mixes with air and is introduced during the intake process. After compression of the fuel-air mixture, it is ignited by a spark from a spark plug to cause combustion. The combustion gases expand and push the piston during the power stroke. In compression ignition engines, typically diesel, only air is inducted into the engine then highly compressed. Fuel is injected or sprayed into the hot, compressed air, causing it to ignite without the need for an external spark.

The work cycle of both types of engines may either be two-stroke or four-stroke. A four-stroke spark ignition engine consists of the following: the suction or intake stroke, compression

stroke, combustion and power stroke, and exhaust stroke, each consisting of 180 degrees of crankshaft rotation. A two-stroke cycle completes its power cycle with only two strokes of the piston. In a two-stroke engine, the end of the combustion stroke and the beginning of the compression stroke occur simultaneously, with the intake and exhaust occurring at the same time. Reciprocating internal combustion engines are generally used to power reciprocating compressors, and often the engine and compressor share the same crankshaft in what is known as an integral compressor.

A combustion turbine consists of an upstream rotating combustion gas compressor, a combustor, and a downstream turbine on the same shaft as the combustion gas compressor. During operation, the combustion turbine compresses atmospheric air and mixes it with fuel that is burned at extremely high temperatures, creating a hot gas. This hot mixture moves through blades in the turbine, causing them to spin quickly. These blades rotate the turbine drive shaft, which powers the combustion gas compressor.

Control Options

Control Options for NOx – Engines

Readily available options for controlling NOx on two-stroke and four stroke lean burn[2] engines include low emissions controls, selective catalytic reduction, and non-selective catalytic reduction.

Low Emissions Controls ("LEC")[3] is a NOx emissions reduction method that can be retrofitted on most fuel injected two-stroke lean burn engines. NOx emissions increase with

[2] The difference between a rich-burn or lean-burn engine lies in the air-to-fuel ratio. A rich-burn engine has excess fuel in the combustion chamber, while a lean-burn engine has excess air in the combustion chamber.

[3] LEC consist of a combination of combustion controls in which various engine modifications, upgrades, and tuning methods result in lower combustion emissions. One upgrade includes increasing the air-to-fuel (AFR) ratio to reduce thermal NO_X formation by diluting combustion gases and lowering peak flame temperature, that would require upgrades to the AFR controller and turbocharger (a device that increases an engine's power output by forcing extra compressed air - and proportionally more fuel - into the combustion chamber). Another modification associated with

higher combustion temperature. LEC engine retrofit modifications reduce NOx by adding excess air in the combustion zone to reduce combustion temperature, thereby reducing NOx emissions. This change in the air-to-fuel ratio may require other changes to an engine's combustion process. Variation in the amount of NOx emission reduction, required modifications, and cost will depend on the make, model, and vintage of the engine.

Selective catalytic reduction ("SCR") is a post-combustion NOx control for lean-burn engines that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gas. The reagent, typically ammonia or urea is injected into the exhaust stream of the engine where the ammonia (or urea, that decomposes to produce ammonia in the exhaust stream) passes over a catalyst and combines with oxygen to enhance the conversion of NO_X and ammonia into nitrogen and water. An oxidation catalyst must be added to the SCR design if hydrocarbons and carbon monoxide need to be controlled in addition to NOx on a lean-burn engine. Oxidation catalysts consist of precious metals, such as platinum, palladium or rhodium, or metal oxides containing chlorinated compounds, impregnated on high surface area carriers (e.g., a honeycomb structure referred to as a catalyst bed) placed in the exhaust stream. An oxidation catalyst promotes the oxidation of CO and hydrocarbons (HCs) to carbon dioxide and water as the gas stream passes through the catalyst bed. The CO_2, water, and NOx then enter the SCR catalyst where the NOx reacts with the ammonia.

Catalyst selection is partly based on the expected range of the engine exhaust, and is sized to achieve the desired amount of NO_X reduction. The reagent injection system is comprised

LEC is adjusting ignition timing to delay ignition in the power stroke when the chamber is below its maximum pressure. This results in ignition at a lower temperature and lower thermal NO_X formation during combustion. Other LEC options include installing cylinder heads fitted with pre-combustion chambers (a space in which combustion gases are ignited a combustion commenced ahead of the main combustion chamber, resulting in complete combustion of the fuel), larger intercooling applications, and enhanced mixing of air and fuel.

of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature, and NOx emissions. The Ozone Transport Commission's[4] final technical document, *Technical Information - Oil and Gas Sector – Significant Stationary Sources of NOx Emissions* (October 17, 2012) (NMED Exhibit 45),[5] indicates that NOx reductions of up to 95% may be achieved using SCR. The energy and non-air environmental impacts should be evaluated on a case-by-case basis to determine the suitability of SCR. SCR requires ammonia and catalyst replacements, generating waste that must be disposed of, and there is some increase in electric input to operate the system. SCR systems also emit unreacted ammonia in the process, referred to as ammonia slip. This ammonia can combine with sulfur dioxide and nitrogen oxides in the atmosphere to form ammonium sulfate and ammonium nitrate as fine particulate matter.

Non-selective catalytic reduction ("NSCR"), or three-way catalyst, is a potential control option for reducing NOx, CO, and VOC emissions from rich burn engines. Exhaust from the engine is passed through a metallic or ceramic honeycomb covered with a platinum group metal catalyst. The catalyst promotes the low temperature (approximately 850^0F) reduction of NO_X into N_2, the oxidation of CO into CO_2, and the oxidation of VOCs into water and CO_2. The catalyst efficiency is directly related to the air/fuel mixture and temperature of the exhaust. To maintain the proper exhaust gas oxygen concentration across the operating range of the engine, an air/fuel ratio controller[6] must be installed for varying engine load, engine speed conditions, and varying ambient conditions. *See* NMED Exhibit 45 at p. 32.

[4] The Ozone Transport Commission is a multi-state organization created under the CAA that develops regional solutions for ozone in the Northeast and mid-Atlantic states.
[5] Available at: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf
[6] Air fuel ratio controllers-To obtain the proper exhaust gas O_2 across the operating range, an air/fuel ratio controller is installed that measures the oxygen concentration in the exhaust and adjusts the inlet air/fuel ratio to meet the

Control Options for NOx – Turbines

Readily available NO_X control options for turbines include water or steam injection, dry low-NO_X burners, and SCR.

Water or steam injection involves injecting water into the combustion zone of a turbine to lower peak flame temperatures, which subsequently lowers the amount of thermal NO_X formation during combustion. Water may be injected directly into the turbine combustor or may be converted to steam using waste heat recovered from turbine exhaust with a heat recovery steam generator, and then injected into the combustor as steam. More steam than water is required to achieve a comparable reduction of NO_X. *See* NMED Exhibit 45 at p. 62.

Dry Low NO_X Burners ("DLNB"), also referred to as improved combustion technology, reduce the peak flame temperature and residence time of fuel in the combustor, thereby reducing thermal NO_X formation by increasing the air-to-fuel ratio in the combustion chamber. Not all turbine designs can accommodate a DLNB, and this technology may not be available for all makes and models of combustion turbines. In addition to the replacement of the turbine's combustors, the installation of this technology may require modifications or replacement of associated piping and turbine control modification or replacement.

SCR technology, described above, is also a potential control option for turbines.

Control Options for VOC – Engines

Readily available VOC control options for engines include NSCR and catalytic oxidation. The control of VOCs using NSCR for rich burn engines to control CO and VOC, as well as NOx, is explained above in the discussion of using NSCR for NOx control. The use of catalytic

proper 0.5% O_2 exhaust requirement for varying engine load conditions, engine speed conditions, and ambient conditions.

oxidation for VOC and CO emissions control for lean burn engines is explained above in the discussion of SCR systems for lean burn engines.

Control Options for VOC – Turbines

A readily available VOC control option for turbines is catalytic oxidation. The control of VOCs using catalytic oxidation is explained above under the control options for VOC from engines.

Proposed Rule Requirements

Section 20.2.50.113 requires owners and operators of new and existing portable and stationary engines and turbines equal to or exceeding specified horsepower ratings to meet NOx, CO, and VOC emission limits.

For existing spark ignited engines, owners and operators are required to develop an inventory of those engines and meet the emission limits over a specified timeline. This timeline requires a certain percentage of the inventoried fleet to meet the requirements by specified deadlines. The timeline allows owners and operators sufficient time to come into compliance with the requirements of this subpart. In lieu of meeting the emissions limits, owners and operators may reduce the number of hours of operation in order to reduce emissions to rates similar to the emissions reduction requirements achieved by utilizing emission control devices. This option provides an alternative method of compliance for engines that are difficult to retrofit, while ensuring equivalent emission reductions.

New spark ignited engines must meet the emission limits upon startup. New and existing compression ignited engines must meet specified emission limitations depending upon the construction date of the units. New and existing turbines must meet specified emission limitations depending upon the construction date of the units. Owners and operators are required

to meet the minimum recommended maintenance schedule; document when those units are taken out of service for more than two hours; operate emission control devices per the manufacturer specifications; perform initial and annual emissions testing; monitor the hours of operation for certain units; and install an EMT on all units subject to this subpart. Owners and operators are required to maintain records of certain information on units subject to this Section, including the make, model, and serial number; a copy of the engine, turbine, and control device manufacturer specifications; information on the initial and annual emissions testing; hours of operation; and information documenting that emissions reductions realized through the reduction in hours of operation is equivalent to a 95% reduction in NOx and VOC emissions. Owners and operators are required to report in accordance with the requirements of Section 20.2.50.112.

Basis for Proposed Regulatory Requirements

Natural Gas-Fired Spark-Ignition Engines

The proposed NOx limit of 0.50 grams per brake horsepower per hour (g/bhp-hr) for existing lean burn engines greater than 1,000 bhp is based on the use of low emission combustion retrofit on existing engines, or the addition of a SCR control system.

This is the same limit as that used in Section C of Pennsylvania GP-5 for natural gas-fired spark ignition engines greater than 500 hp authorized to operate on or after February 2, 2013. A less stringent standard (2.0 g/bhp-hr) applies to all spark ignition engines authorized to operate between March 10, 1997, and February 2, 2013. A more stringent standard (0.30 g/bhp-hr) applies to engines greater than or equal to 2,370 hp authorized to operate on or after August 8, 2018. *See* NMED Exhibit 37.

Cooper Machinery Services advertises that they offer engine upgrades that will allow engines to meet a NOx limit of 0.5 g/bhp-hr NOx for all Clark, Cooper-Bessemer, and Ingersoll

Rand slow speed engine models. *See* NMED Exhibit 46 – Cooper Machinery Services webpage visited 07/26/2021.[7] The modifications include a combination of adding a forced air delivery system using either a turbocharger or a blower, and completing electronic system upgrades for fuel, ignition, air/fuel ratio control, diagnostics, and combustion cylinder balancing. Cooper Machinery lists examples of 41 units in nine states that have already been retrofitted to meet 0.5 g/bhp-hr NOx, and are either operating at 0.5 g/bhp-hr or are capable of operating at 0.5 g/bhp-hr.

The California South Coast Air Quality Management District Rule 1110.2, attached as NMED Exhibit 47,[8] specifies a NOx emission limit, effective July 1, 2011, applicable to all existing stationary spark and compression ignition engines (i.e., making no distinction by engine type) with a nameplate rating of 50 hp or greater of 11 parts per million by volume, dry basis (ppmvd) NOx at 15% O_2. This is equal to approximately 0.15 g/bhp-hr, assuming a conversion factor of 1 g/bhp-hr for a lean burn engine controlled by low emission combustion technology.

EPA's *Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques*, Publication No. EPA-457/R-00-001 (September 2000), summarized the results of 476 individual tests conducted from 1991 to 1998 of lean-burn engines fitted or retrofitted with low emission combustion technology either by the original equipment manufacturer ("OEM") or a third-party vendor. In these tests, NOx emissions ranged from 0.1 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent (97%) of these tests (460) measured emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests measured emissions less

[7] Available at: https://www.cooperservices.com/engines-and-compressors/upgrades/0-5-gbhp-hr-nox-solution%E2%80%8B/
[8] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf

than or equal to 1 g/bhp-hr, and 25 percent (120) measured emissions of less than or equal to 0.5 g/bhp-hr. *See* NMED Exhibit 48 at p. 2-2.

The same EPA report summarized test results for lean burn engines controlled by SCR. Summary data obtained for 1997 emission tests were of three 3,130-bhp, 4-stroke, lean-burn SI engines equipped with SCR control systems and subject to a permit emission limit for NOx of 15 ppmv (on a dry basis corrected to 15 percent oxygen), corresponding to about 0.2 g/bhp-hr. During 20 individual test runs in 1997 on these three engines, NOx emissions ranged between 0.11 g/bhp-hr and 0.21 g/bhp-hr. *See id.* at p. 4-15.

The proposed limits for CO (47 ppmvd at 15 percent O_2 or 93% reduction) and non-methane non-ethane hydrocarbon ("NMNEHC") (0.70 g/bhp-hr, as propane) for existing lean burn engines greater than 1,000 bhp are based on the addition of an oxidation catalyst control. This CO limit is also the same as the operating limit specified in the federal regulations at 40 CFR 63, Subpart ZZZZ, for non-emergency and non-remote existing 4SLB engines greater than 500 hp using an oxidation catalyst.[9]

The proposed CO limit (47 ppmvd at 15 percent O_2 or 93% reduction) is the same limit as that set forth in Pennsylvania GP-5 for natural gas-fired spark ignition engines greater than 500 hp authorized to operate on or after February 2, 2013. This is also the same limit specified in 40 CFR Part 63, Subpart ZZZZ, for existing natural gas fired spark ignition non-emergency lean burn engines rated greater than 500 bhp, located at an area source of hazardous air pollutants ("HAP"). *See* NMED Exhibit 49. A less stringent CO standard (2.0 g/bhp-hr) in Pennsylvania GP-5 applies to all spark ignition engines authorized to operate between March 10, 1997 and February 2, 2013. A more stringent standard (0.30 g/bhp-hr) in GP-5 applies to engines greater

[9] See 40 CFR part 63, subpart ZZZZ, See Table 2c, row #10; Table 2d, row #9; Table 5, #13; Table 6, Row #14.

than or equal to 2,370 hp authorized to operate on or after August 8, 2018. The proposed CO limit of 47 ppmvd at 15 percent O_2 is approximately equal to 0.50 g/bhp-hr, assuming a conversion factor of 95 ppmvd per 1.0 g/bhp-hr. *See* NMED Exhibit 37, at p. 12-13.

The proposed limit for NMNEHC is the same as the VOC limit in Table 1 to 40 CFR 60, Subpart JJJJ, for engines greater than 500 hp and manufactured after July 1, 2010. *See* NMED Exhibit 50.

Existing Rich Burn Engines greater than 1,000 bhp

The proposed limits for NOx (0.50 g/bhp-hr), CO (0.70 g/bhp-hr), and NMNEHC (0.70 g/bhp-hr as propane) for existing rich burn engines greater than 1,000 bhp are all based on the addition of NSCR controls.

The proposed NOx limit is less stringent than the limits in the PA GP-5 and GP-5A (0.20 g/bhp-hr) for rich burn engines authorized to operate on or after February 2, 2013. The proposed NOx limit is more stringent than the New Source Performance Standard (NSPS) limit in 40 CFR 60, Subpart JJJJ, for engines with a manufacture date after July 1, 2007 (2.0 g/bhp-hr) and after July 1, 2010 (1.0 g/bhp-hr), although the NSPS applies the same NOx limit to both lean burn and rich burn engines.

The proposed NOx limit is more stringent than the numerical NOx limits specified in Colorado Reg. 7, Part E:

- Section I.D.3.b: "State only" requirements for new, modified or relocated engines ≥ 500 Hp:
    - Constructed or relocated on or after January 1, 2007: 2.0 g/hp-hr; and
    - Constructed or relocated on or after January 1, 2010: 1.0 g/hp-hr).

- Section I.D.5.b: "State only" requirements for new, modified or relocated engines ≥ 1,000 Hp:
    - In service on or before November 14, 2020: 0.8 g/hp-hr.
    - Placed in service, modified, or relocated after November 14, 2020: 0.5 g/hp-hr.

All new and existing rich burn engines located in the Colorado 8-hour ozone control area are required to use NSCR. *See* Colorado Reg. 7, Part E, Sections I.A and I.B (NMED Exhibit 39).

The proposed CO limit is less stringent than the limits in Pennsylvania GP-5 and GP-5A (0.30 g/bhp-hr) for rich burn engines authorized to operate on or after February 2, 2013. The proposed CO limit is more stringent than the NSPS limit in 40 CFR 60, Subpart JJJJ, for engines with a manufacture date after July 1, 2007 (4.0 g/bhp-hr) and after July 1, 2010 (2.0 g/bhp-hr), although the NSPS applies the same NOx limit to both lean burn and rich burn engines. The proposed CO limit is also more stringent than the limits specified in Colorado Reg. 7 for engines constructed or relocated after July 1, 2007 (4.0 g/bhp-hr) and after July 1, 2020 (2.0 g/bhp-hr) (Part E, Section I.D.3.b) and before and after November 14, 2020 (2.0 g/bhp-hr) (Part E, Section I.D.5.b).

The proposed NMNEHC limit is less stringent than the limits in Pennsylvania GP-5 and GP-5A (0.20 g/bhp-hr, excluding formaldehyde) for rich burn engines authorized to operate on or after February 2, 2013. The proposed NMNEHC limit is more stringent than the limit in NSPS Subpart JJJJ for engines with a manufacture date after July 1, 2007 (1.0 g/bhp-hr), and is the same as the limit for engines with a manufacture data after July 1, 2010 (0.7 g/bhp-hr). The proposed NMNEHC limit is more stringent than the VOC limits specified in Colorado Reg. 7

for engines constructed or relocated after July 1, 2007 (1.0 g/bhp-hr), and is the same (0.7 g/bhp-hr) for engines constructed or relocated after July 1, 2010 (Part E, Section I.D.3.b) and for engines constructed or relocated after November 14, 2020 (Part E, Section I.D.5.b).

The Ohio EPA provides on-line emission test summaries for many emission tests for the years 2003 to 2016.[10] These include many emission tests of reciprocating internal combustion engines and turbines. These Ohio EPA test data show that the proposed emission limits for existing lean burn and rich burn engines are readily achievable. The Ohio data for NOx, CO, and VOC (as surrogate for NMNEHC) emissions from engines and turbines are presented in the Engines and Turbines OH Stack Tests Spreadsheet at NMED Exhibit 51.

New Spark Ignition Engines

The proposed NOx emission limits for new lean burn and rich burn engines are the same as those in Pennsylvania GP-5 and GP-5A for engines authorized to operate on or after August 8, 2018. These limits are based on vendor guarantees and other information collected by the Pennsylvania Department of Environmental Protection ("PA DEP") and summarized in the June 2018 Technical Support Document for Pennsylvania GP-5 and GP-5A ("PA TSD 2018"), attached as NMED Exhibit 52. The NOx limits for lean burn engines are based on low emission combustion designs for engines greater than 500 bhp but less than 1,000 bhp, and based on low emission combustion designs or the use of add-on SCR for engines equal to or greater than 1,000 bhp.

The CO and NMNEHC limits for lean burn engines greater than 500 bhp are the same limits as for existing lean and rich burn engines greater than 1,000 bhp and are based on the use of add-on oxidation catalysts.

[10] *See* https://www.epa.ohio.gov/dapc/engineer/stackg#123883452-test-summaries.

The NOx, CO, and NMEHC limits for rich burn engines greater than 500 bhp are based on the use of add-on NSCR.

The Ohio EPA's on-line emission test summaries include many emission tests of reciprocating internal combustion engines and turbines. The Ohio test data show that the proposed emission limits for new lean burn and rich burn engines are readily achievable. The data for NOx, CO and VOC (as surrogate for NMNEHC) are presented in the Engines and Turbines OH Stack Tests Spreadsheet at NMED Exhibit 51.

New Compression Ignition Engines

The proposed NOx emission limit for new compression ignition engines equal to or greater than 500 hp of 9 g/bhp-hr is the same limit as Colorado Reg. 7 Part E, Section II.A.4.e. The emission limit is based on the use of add-on SCR controls.

The proposed rule does not include proposed emission limits for existing compression ignition engines.

Stationary Combustion Turbines

The proposed requirements for both existing and new turbines apply to turbines with rated bhp greater than or equal to 1,000 bhp.

The proposed emission limits and applicability thresholds for turbines are based on the PA TSD 2018 (NMED Exhibit 52), except that the proposed NOx limits for existing turbines are based on EPA Office of Air and Radiation's *Alternative Control Techniques Document – Nox Emissions from Stationary Gas Turbines*, EPA-453/R-93-007 (January 1993) ("EPA 1993 ACT"), included as NMED Exhibit 53.

The proposed NOx emission limits of 50 ppmvd at 15% O_2 for existing turbines, as set forth in Table 3 of Section 20.2.50.113, are based on the use of water or steam injection control

technology. The EPA 1993 ACT for NOx emissions from stationary combustion turbines reported that water or steam injection can commonly achieve 70 to 90 percent NOx emission reductions and vendor guaranteed controlled emission rates of 25 to 75 ppmvd, with many vendors offering a guarantee of 42 ppmvd. *See id.*, at Table 5-5. The Ozone Transport Commission recommended the following NOx limits for existing natural gas pipeline compressor prime mover turbines:

- Turbines less than 2,000 hp – 150 ppmvd at 15% O_2
- Turbines equal to or greater 2,000 hp and less than 5,000 hp – 50 ppmvd at 15% O_2
- Turbines equal to or greater than 5,000 hp – 25 ppmvd at 15% O_2

See NMED Exhibit 54 – OTC Stationary and Area Sources Committee, *OTC Regulatory and Technical Guideline for Control of Nitrogen Oxides (NOx) Emissions from Natural Gas Pipeline Compressor Fuel-Fired Prime Movers* (May 14, 2019), at p. 8-9.

The proposed CO and NMNEHC emission limits in Table 3 of Section 20.2.50.113 for existing turbines are based on the same limits in Pennsylvania GP-5 for turbines authorized to operate on or after February 1, 2013, but prior to August 8, 2018. For turbines between 1,000 and 15,000 HP, Pennsylvania GP-5 establishes a CO limit of 50 ppmvd at 15% O_2 and a NMNEHC limit of 9 ppm NMNEHC at 15% O_2. These limits were identified as achievable for turbines using good combustion practices and without the use of oxidation catalysts. These limits are based on vendor data for uncontrolled turbines, and the vendor data showed that oxidation catalysts were not cost effective for turbines in this size range to achieve a lower emission level, according to the 2018 TSD for GP-5/GP-5A. *See* NMED Exhibit 52, at p. 75.

For turbines greater than or equal to 15,000 HP and authorized to operate under GP-5 on or after February 1, 2013, but prior to August 8, 2018, PA DEP determined that oxidation

catalysts were cost effective to achieve a CO limit of 50 ppmvd at 15% O_2 (or a 93% reduction) and a NMNEHC emission limit of 5 ppm NMNEHC at 15% O_2 (or a 50% reduction). *See id*.

The proposed NOx, CO, and NMNEHC limits for new turbines in Table 3 of Section 20.2.50.113 are almost identical those in the Pennsylvania GP-5 for turbines authorized to operate on or after August 8, 2018. According to the PA DEP's 2018 TSD for GP-5/GP-5A, vendor data for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp indicated uncontrolled emission rates of 25 ppm NOx, 25 ppm CO, and 25 ppm THC as methane, with the THC emission rate converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. The standards in GP-5 for these new turbines are based on good combustion engineering and turbine design, and not on the use of add-on controls for turbines greater than 1,000 hp and less than 5,000 hp. *See id*.

According to the PA DEP's 2018 TSD for GP-5/GP-5A, vendor data for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp indicated uncontrolled emission rates of 25 ppm NOX, 25 ppm CO, and 25 ppm THC as methane, with the THC emission rate converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. However, based on stack test results, the limit for NOx was established at 15 ppm, for CO at 10 ppm, and for NMNEHC at 5 ppm as achievable without control. The PA DEP determined that oxidation catalyst was not cost effective for turbines in the 5,000 to 15,900 bhp range. *See id*. The Department has proposed a NMNEHC limit for new turbines greater than 1,000 bhp and less than 15,900 bhp of 9 ppmvd, instead of 5 ppmvd, as indicated in Table 3 of Section 20.2.50.113 NMAC.

According to the PA 2018 TSD, vendor data for new turbines greater than or equal to 15,900 bhp indicated uncontrolled emission rates of 25 ppm NOx, 25 ppm CO, and 25 ppm THC

as methane (9 ppm NMNEHC as propane). The PA DEP determined limits of 15 ppm for NOx, 10 ppm for CO, and 5 ppm for NMNEHC were achievable without controls based on stack test data, and also determined that that oxidation catalysts were cost effective for turbines greater than or equal to 15,900 bhp for CO and NMNEHC. Pennsylvania GP-5 includes CO limits of 10.0 ppmvd for turbines without controls and 1.75 (rounded to 1.8) ppmvd for turbines with controls, and a single limit for NMNEHC of 5.0 ppmvd (whether controlled or uncontrolled). *See id.*, at p. 77.

According to the PA 2018 TSD, recent permits and plan approvals showed that turbines greater than or equal to 15,900 bhp could achieve 9.0 ppmvd NOx without controls. The PA 2018 TSD also noted that SCR vendors typically guaranteed 90% reductions, and that stack tests for turbines in Pennsylvania controlled by SCR have achieved NOx emissions ranging from 1.6 to 1.8 ppmvd. As a result, PA DEP included NOx limits for turbines greater than or equal to 15,900 bhp of 9.0 ppmvd if uncontrolled and 2.0 ppmvd if controlled. *See id.*, at p. 72. The proposed NOx limits for new turbines equal to greater than 15,900 bhp in Table 3 of Section 20.2.50.113 are the same as those in the Pennsylvania GP-5; i.e., 9.0 ppmvd if uncontrolled and 2.0 ppmvd if controlled.

Emission Reductions

NOx Reductions – Engines

Data from the NMED Equipment Report indicates there are 4,718 active internal combustion engines with records for NO_2 located in Chaves, Eddy, Lea, Rio Arriba, San Juan, Sandoval, and Valencia Counties (collectively, the "Subject Counties"), or designated as 'Portable.' These 4,718 engines are situated at 1,463 unique locations.[11] Of these, 1,950 engines

[11] Engines located at refineries were removed from the analysis.

have a horsepower rating greater than 1,000 bhp. 1,866 engines lacked add-on NOx controls and may require additional NOx control (either add-on controls or low emission combustion retrofits) to meet the proposed standards. ERG estimated reductions in NOx for the various engine types as shown in the following Table.

Percent Reduction By Engine Type			
NG	Controlled by SCR / NSCR		0%
NG	Uncontrolled	Lean Burn 4-stroke >1000	49%
NG	Uncontrolled	Lean Burn 2-stroke >1000	78%
NG	Uncontrolled	Rich Burn >1000	81%
NG	NSPS JJJJ Before 2011	Lean Burn 4-stroke >1000	49%
NG	NSPS JJJJ Before 2011	Lean Burn 2-stroke >1000	75%
NG	NSPS JJJJ Before 2011	Rich Burn >1000	75%
NG	NSPS JJJJ 2011 +	Lean Burn 4-stroke >1000	49%
NG	NSPS JJJJ 2011 +	Lean Burn 2-stroke >1000	50%
NG	NSPS JJJJ 2011 +	Rich Burn >1000	50%
Diesel	Controlled	>1000 hp	55%

In cases where the engine type was unknown, ERG assumed the engine was lean burn 4-stroke because that is the most common engine type for those over 1,000 hp.

The percent reductions by engine type were estimated as either (1) the difference between uncontrolled emission factors from the U.S. EPA's AP-42 Compilation of Air Emissions Factors for gas and diesel industrial engines (NMED Exhibit 55) and the proposed limits in 20.2.50.113 NMAC for engines not subject to NSPS; or (2) the difference between the NSPS emission limits in 40 CFR 60, Subpart JJJJ ("NSPS Subpart JJJJ"), and the proposed emission limits in 20.2.50.113 NMAC for engines currently subject to NSPS Subpart JJJJ because some of the proposed emission limits in 20.2.50.113 NMAC are more stringent than those in NSPS Subpart JJJJ.

ERG estimated total baseline allowable NOx emissions from all 4,718 operating internal combustion engines located in the Subject Counties, or designated as "Portable." Allowable NOx

emissions from those units were 62,005 tpy. ERG then estimated the NOx emission reductions from implementing the proposed regulations on existing engines. For the 1,866 uncontrolled engines and partially controlled engines that are subject to NSPS Subpart JJJJ, ERG estimated reductions of NOx based on the NOX control technologies discussed above by applying the 'Percent Reduction By Engine Type' shown in the table above.

Adding controls to uncontrolled engines would reduce NOx emissions by 17,905 tpy, leading to a 28.9% overall reduction in NOx emissions from operating engines from the baseline emissions. See NMED Exhibit 56 - ICE Reductions and Costs NO_2 Spreadsheet.

VOC Reductions - Engines

Data from the NMED Equipment Report indicates there are 4,276 active internal combustion engines with records for allowable VOC emissions located in the Subject Counties, or designated as "Portable". These 4,276 engines are situated at 1,339 unique locations.[12] Of these, 2,041 engines have a horsepower rating great than 1,000 bhp. Engines with VOC controls (catalytic oxidation, catalytic converter, flare, NSCR); engines subject to NSPS (40 CFR 60, Subpart IIII or Subpart JJJJ); and engines subject to National Emission Standards for Hazardous Air Pollutants ("NESHAP") (40 CFR 63, Subpart ZZZZ) were considered to have adequate VOC controls to meet the proposed standards. For the remaining 186 uncontrolled engines, ERG calculated VOC emission reductions using the following considerations: (1) if the engine was uncontrolled and not subject to an NSPS or NESHAP for engines, a 90% VOC emission reduction for lean-burn spark ignition engines was calculated based on adding catalytic oxidation; and (2) if the engine was uncontrolled and not subject to an NSPS or NESHAP for engines, a 90% VOC emission reduction for rich-burn spark ignition engines and compression

[12] Engines located at refineries were removed from the analysis.

ignition engines was calculated based on adding SNCR. In cases where the engine type was unknown, ERG assumed the engine was lean burn 4-stroke because that is the most common engine type for those over 1,000 hp.

ERG estimated emissions from the entire inventory of 4,276 operating internal combustion engines located in the Subject Counties or designated as "Portable" at 24,224 tpy of VOC. ERG then estimated the VOC emission reductions that would be achieved by implementing the proposed requirements for existing engines. For the 186 uncontrolled engines, ERG estimated reductions of 1,663 tpy of VOC based on the use of an add-on control to achieve the required emission reduction to meet the proposed standard, leading to a 6.8% overall reduction in VOC emissions from existing engines. See NMED Exhibit 57 – ICE Reductions and Costs VOC Spreadsheet.

Emission reductions were estimated for VOC instead of NMNEHC because the allowable emissions data are for VOC, the limits for NMNEHC are a surrogate for VOC, and the two are nearly equal.

Emission reductions were not estimated for CO. The limits for CO are intended to ensure good combustion practices that will lead to further VOC reductions.

NOx Reductions - Turbines

Data from the NMED Equipment Report indicates there are 160 active combustion turbines in the O&G industry with records for NOx located in the Subject Counties. These 160 turbines are situated at 44 unique locations. Of these, 136 turbines have a horsepower rating equal to or greater than 1,000 bhp. ERG filtered out turbines that are regulated by NSPS (40 CFR 60, Subpart GG Subpart KKKK) from the analysis, as these federal rules already limit NOx

emissions. The remaining 51 combustion turbines were then evaluated for appropriate NOx reduction measures.

For turbines with a horsepower rating less than 15,900, ERG applied water or steam injection as NOx control. This is based on Tables 6-1 and 6-6 of the EPA 1993 ACT. *See* NMED Exhibit 53 at pp. 6-3 and 6-15. Using water or steam injection on an uncontrolled combustion turbine results in 71% control of NOx. For turbines with a horsepower rating greater than 15,900, ERG applied SCR as NOx control. This is based on the PA TSD 2018. Using SCR on an uncontrolled combustion turbine results in 90% control of NOx.

ERG calculated the allowable NOx emissions from the entire inventory of 160 active combustion turbines located in the Subject Counties. Emissions from these units total 10,313 tpy of allowable NOx. ERG then examined the effect of implementing the proposed regulations on the 51 unregulated and uncontrolled combustion turbines with a horsepower rating greater than 1,000. Applying controls to these units results in a reduction of 3,377 tpy of allowable NOx. The reductions are based on the percent reductions by engine horsepower rating as indicated above. Adding controls to uncontrolled combustion turbines with horsepower ratings greater than 1,000 would result in a 32.7% overall reduction in NOx emissions. See NMED Exhibit 58 – Turbines Reductions and Costs NO_2 Spreadsheet.

VOC Reductions - Turbines

Data from the NMED Equipment Report indicates there are 144 active combustion turbines in the O&G industry with records for allowable VOC emissions located in the Subject Counties. These 144 turbines are situated at 39 unique locations. The estimated baseline allowable VOC emissions from the current inventory of 144 active combustion turbines located in the Subject Counties is 707 tpy of VOC.

Of these, 122 turbines have a horsepower rating equal to or greater than 1,000 bhp. ERG filtered out turbines that: (1) have VOC controls (catalytic oxidation); or (2) are regulated by NESHAP 40 CFR 63, Subpart YYYY ("NESHAP Subpart YYYY"). ERG filtered out turbines that are subject to NESHAP Subpart YYYY because turbines complying with this NESHAP would likely be using oxidation catalysts, so no additional reductions would be achieved.

Of the remaining 115 uncontrolled and unregulated combustion turbines, ERG determined that, for 76 combustion turbines, the allowable VOC emissions in the permit data provided by NMED was lower than the NMNEHC tpy emissions allowed under the proposed NMHEHC limits. The PA DEP 2018 TSD included emission factors (lb NMNEHC/MMBtu heat input) and equations to calculate MMBtu/hr from horsepower. *See* NMED Exhibit 52 at p. 75. These were used to calculate the allowed NMNEHC in tpy under the NMED proposed NMNEHC emission limits (9 ppm and 5 ppm). For these 76 turbines, it was assumed that no additional controls or reductions would be needed to meet the proposed standard, so no costs or reductions were assigned.

ERG estimated the emission reductions from 39 turbines without controls as the difference between the allowable VOC emissions in the permit data and the estimated NMNEHC emissions under the proposed emission limits. The emission reductions are based on the use of an add-on control (oxidation catalyst) to achieve the VOC (NMNEHC) emission limits in the proposed NM standards.

Adding controls to these 39 combustion turbines would reduce VOC emissions by 353 tpy, leading to a 49.9% overall reduction in VOC emissions from combustion turbines. *See* NMED Exhibit 59 – Turbines Reductions and Costs VOC Spreadsheet.

Emission reductions were estimated for VOC instead of NMNEHC because the allowable emissions data are for VOC, the limits for NMNEHC are a surrogate for VOC, and the two are nearly equal.

Emission reductions were not estimated for CO. The limits for CO are intended to ensure good combustion practices that will lead to further VOC reductions.

Costs of Reductions

Costs of NOx Reductions - Engines

The annualized costs of NOx emission reductions for the 1,866 uncontrolled and partially controlled natural gas-fired spark-ignition engines were estimated by applying cost equations for the different types and sizes of engines. In cases where the engine type was unknown, ERG assumed the engine was a lean burn 4-stroke because that is the most common engine type for those over 1,000 hp.

For 2-stroke and 4-stroke lean-burn engines, costs were calculated for adding Low Emission Combustion ("LEC") Technology as a retrofit. As described previous, LEC consists of retrofits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) Precombustion chamber (on larger engines), (3) Turbocharger, (4) High energy ignition system, (5) Aftercooler, and (6) Air-to-fuel ratio controller. Cost information for LEC retrofits for lean burn engines rated less than 3,000 bhp comes from a NOx emission control assessment prepared for the EPA Cross State Air Pollution Rule for the 2008 Ozone NAAQS. *See* NMED Exhibit 60 – EPA Office of Air and Radiation, *Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS – Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance*

Final TSD, Docket ID No. EPA-HQ-OAR-2015-0500 (August 2016), at Appendix A, p. 5-5. Cost information for LEC retrofits for lean burn engines rated equal to or greater than 3,000 bhp comes from a document prepared for the Interstate Natural Gas Association of America ("INGAA") titled "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry." *See* NMED Exhibit 61 – INGAA Foundation Final Report No. 2014.03, at p. 25-29.

Cost information for adding NSCR to control NOx from rich-burn engines comes from a 2006 memo prepared for the U.S. EPA to support development of the NSPS and NESHAP for stationary spark ignition engines. NMED Exhibit 62 – Alpha-Gamma Technologies, Inc., *Control Costs for Reciprocating Internal Combustion Engines at Major and Area Sources*, EPA Docket Item No. EPA-HQ-OAR-2005-0030-0005 (April 28, 2006). Cost information for adding NSCR to control NOx from rich-burn engines also comes from a 2010 memo prepared for EPA to support amendments to the NSPS and NESHAP for stationary spark ignition engines. NMED Exhibit 63 – EC/R, Inc., *Control Costs for Existing Stationary RICE*, EPA Docket Item No. EPA-HQ-OAR-2008-0708-0554 (June 29, 2010) ("2010 RICE Memo"). Because the two memos presented different cost equations for controlling NOx from rich burn engines using NSCR, ERG compared the NSCR costs using the two equations for different size engines. The equation in the 2010 RICE Memo estimated higher capital costs but lower annual costs for NSCR for rich burn engines greater than 1,000 bhp, so the more recent 2010 annual cost equation was used for the cost analysis for rich-burn engines.

Costs were scaled from 2005 dollars (2005$) to 2019 dollars (2019$) for SCR, and from 2001$ (for engines less than 3,000 hp) or 2013$ (for engines equal to or greater than 3,000 hp)

for LEC using the Chemical Engineering Plant Cost Index ("CEPCI"), which is an index used to adjust cost estimates from one year to a different year.[13]

Full details on how these cost equations were applied is set forth in NMED Exhibit 56 – ICE Reductions and Costs NO_2 Spreadsheet.

Because the proposed NOx emission limit for compression ignition engines applies only to new engines, no costs were estimated for existing compression ignition engines.

The total annualized costs of adding LEC to lean-burn spark ignition engines and NSCR to rich-burn spark ignition engines was estimated to be $120,267,152 per year, at an average annual cost per engine of $64,452 and a cost per ton of NOx reduced of $6,717.

Costs of VOC Reductions - Engines

ERG estimated the cost of adding VOC controls to those engines that are not already controlled with either SNCR for rich burn engines or oxidation catalyst for lean burn engines. ERG assumed that engines subject to NSPS Subpart ZZZZ would already have VOC controls in order to comply with the limits required under those regulations.

The costs of adding NSCR for VOC control for rich burn engines were already accounted for in the NOx cost estimates (NSCR controls NOX, CO, and VOC emissions), and no further control costs were added for rich burn engines. Therefore, these cost control estimates only include the cost of adding catalytic oxidizers to control VOC emissions from uncontrolled lean burn engines that lack oxidation catalysts and that are not subject to NSPS Subpart ZZZZ.

[13] The CEPCI is published monthly and annually by *Chemical Engineering* and is described on the magazine's website (https://www.chemengonline.com/pci-home) as follows: "The CEPCI consists of a composite index assembled from a set of four sub-indexes: Equipment; Construction Labor; Buildings; and Engineering & Supervision. Each index and subindex is the weighted sum of several components. Most of these components correspond to Producer Price Indexes (PPIs), updated and published monthly by the U.S. Department of Labor's Bureau of Labor Statistics."

In cases where the engine type was unknown, ERG assumed the engine was lean burn 4-stroke because that is the most common engine type for those over 1,000 hp.

Costs information for adding oxidation catalysts to control VOC emissions from 2-stroke lean-burn engines and 4-stroke lean-burn engines comes from equations from the 2010 RICE Memo. *See* NMED Exhibit 63 at Section 4.0.

Costs were scaled from 2009$ to 2019$ using the CEPCI.

Full details on how ERG applied these cost equations is set forth in the ICE Reductions and Costs VOC Spreadsheet at NMED Exhibit 57.

The annualized costs of VOC emission reductions for natural gas-fired spark-ignition engines were calculated by applying the control costs for adding oxidation catalysts to 172 uncontrolled lean burn engines. Total annualized costs for these 172 engines would be approximately $1,626,842 per year at an average annual cost per engine of $9,458 and a cost per ton of VOC reduced of $990.

Costs of NOx Reductions - Turbines

The annualized costs of NOx emission reductions were estimated for the 51 uncontrolled natural gas-fired combustion turbines. The cost for NOx emission reductions for the 48 uncontrolled turbines with horsepower rating less than 15,900 were estimated by applying cost estimates for steam injection from Tables 6-1 and 6-6 of the EPA 1993 ACT. *See* NMED Exhibit 53, at pp. 6-3 and 6-15. The cost for NOx emission reductions for the 3 uncontrolled turbines with horsepower rating greater than 15,900 were estimated by applying cost equations for adding SCR from Table 19 of the PA TSD 2018. Costs were scaled from 2016$ to 2019$ using the CEPCI.

Full details on how ERG applied these cost equations is available in the Turbine Reductions and Costs NO_2 Spreadsheet at NMED Exhibit 58.

The total annualized costs of NOx emission reductions for these 51 natural gas-fired turbines is approximately $13,764,391 per year at an average annual cost per turbine of $269,890 and a cost per ton of NOx reduced of $4,076.

Costs of VOC Reductions - Turbines

To estimate costs of VOC reductions for turbines, ERG assumed that an oxidation catalyst is added as a control device to 39 uncontrolled turbines that are unregulated by an NSPS or NESHAP, and that have allowable VOC emissions that exceed the proposed limits.

Cost information for adding oxidation catalysts to control VOC emissions from 39 turbines are from the PA TSD 2018. Costs were scaled from 2016$ to 2019$ using the Chemical Engineering Plant Cost Index.

Full details on how these ERG applied theses cost equations is available in the Turbine Reductions and Costs VOC Spreadsheet at NMED Exhibit 59.

The total annualized costs of VOC emission reductions for 39 natural gas-fired turbines are estimated at $3,392,186 per year, with an average annual cost per turbine of $86,979 and a cost per ton of VOC reduced of $9,608.

Section 20.2.50.114 – Compressor Seals

Applicability

Section 20.2.50.114 applies to centrifugal compressors using wet seals and reciprocating compressors located at tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations. Centrifugal compressors and reciprocating compressors located at well sites are not subject to the requirements of Section 20.2.50.114.

Description of Equipment and Process

Compressors are used throughout the oil and natural gas industry to compress gas for processing, movement through pipelines, and other needs. Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported in pipelines from the production site, through the processing and supply chain, and to the consumer. Vented emissions from compressors occur from seals (wet seal compressors) or packing surrounding the mechanical compression components (reciprocating compressors) of the compressor. These emissions typically increase over time as the compressor components begin to wear and degrade.

Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by a reciprocating internal combustion engine. Emissions occur when natural gas leaks around the compressor piston rod when pressurized natural gas is in the cylinder. The compressor piston rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. Over time, the rings become worn and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder. See Figure 1 for a depiction of a typical rod compressor packing system configuration.

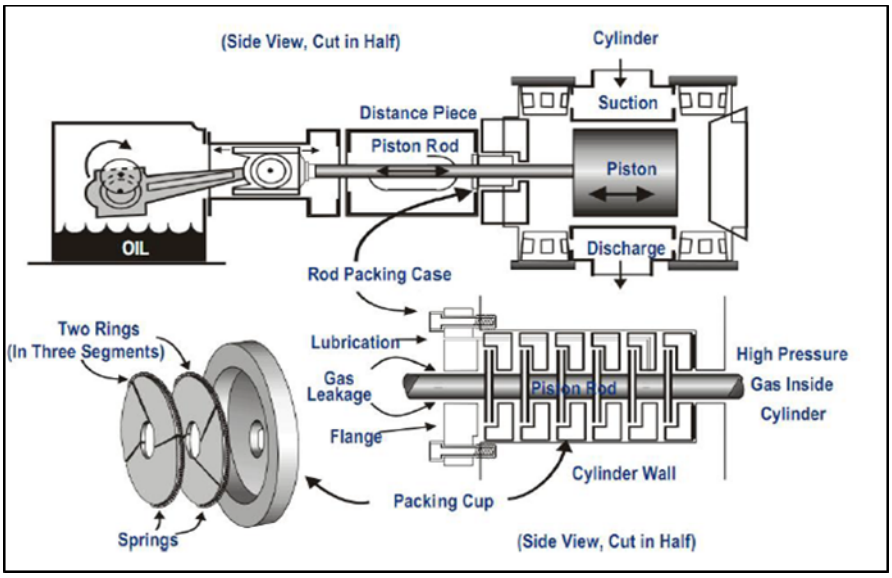


Figure 1. Typical Reciprocating Compressor Rod Packing System Diagram

Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for pipeline transport of natural gas in the natural gas processing and transmission segments of the industry. These compressors require seals around the rotating shaft to prevent high pressure gases from escaping where the shaft exits the compressor casing. Many centrifugal compressors use wet (i.e., oil-filled) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. Other compressors, including most newer compressors, use a dry seal with a mechanical barrier around the rotating shaft to prevent natural gas from escaping.

Wet seals use a specialty oil that is circulated between rings around the compressor shaft under higher pressure than the gas in the adjacent compressor case, forming a barrier against compressed gas leakage. In the wet seal design shown in Figure 2, the center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing and pressed

against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. "O-ring" rubber seals prevent leakage around the stationary rings. Very little gas escapes through the oil barrier; however, gas is entrained in the oil that comes in direct contact with the high-pressure gas at the "inboard" (compressor side) interface, thus contaminating the seal oil. Prior to recirculation, the seal oil must be purged of natural gas in a process called "seal oil degassing." The gas is primarily methane, but also contains some VOC; the fraction of VOC depends on the point in the production chain the compressor is located. Methane and VOC released during seal oil degassing are commonly vented to the atmosphere with vent outlets usually located in elevated areas that are not easily accessible to operators for inspection or maintenance (e.g., roof vent stacks). As a result, the majority of methane and VOC emissions from a centrifugal compressor often go undetected by operators.

Figure 2 displays a typical centrifugal compressor wet seal. The seal oil enters through the inlet (top) and provides a barrier to gas attempting to escape by forming two thin films under higher pressure between the center rotating ring and the two stationary rings (seen with surrounding O-rings).

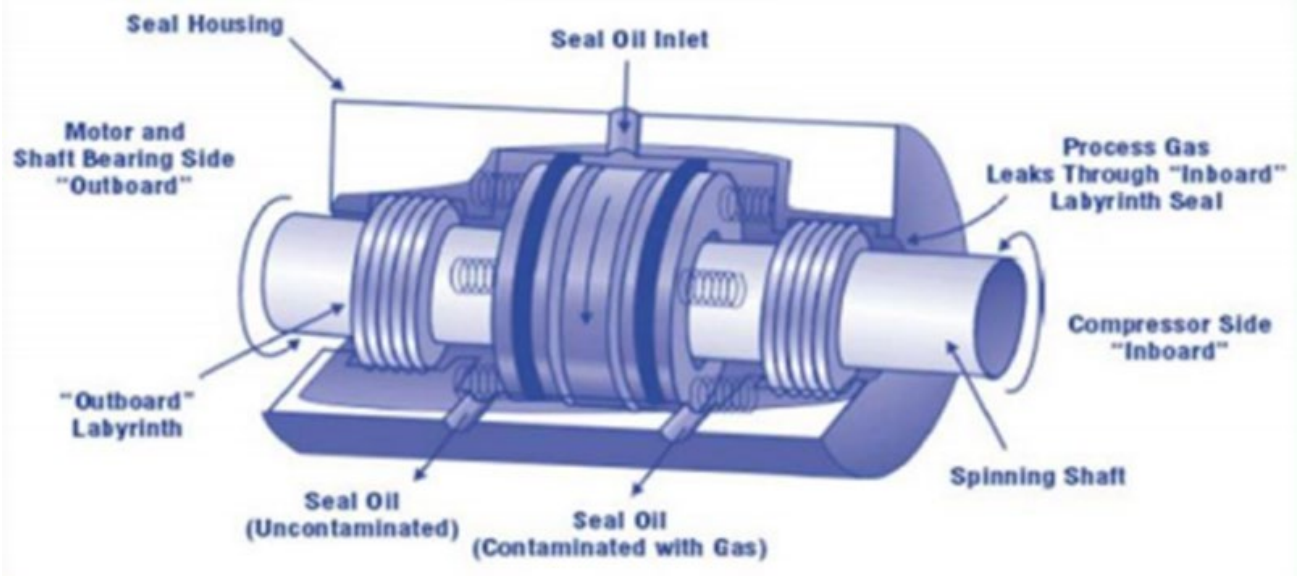


Figure 2. Typical Centrifugal Compressor Wet Seal

Control Options for Compressor Seals

Reciprocating Compressors

VOC emissions from reciprocating compressor rod packing can be minimized by replacing the rod packing on a regular basis before it becomes excessively worn. A typical regulatory schedule is to replace the rod packing seals after every 26,000 hours of operation or every 36 months, whichever is later. A second control option is to collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, a fuel cell, a process stream, or to be used as fuel. Figure 3 shows a general diagram of a closed vent collection and control or recovery system.

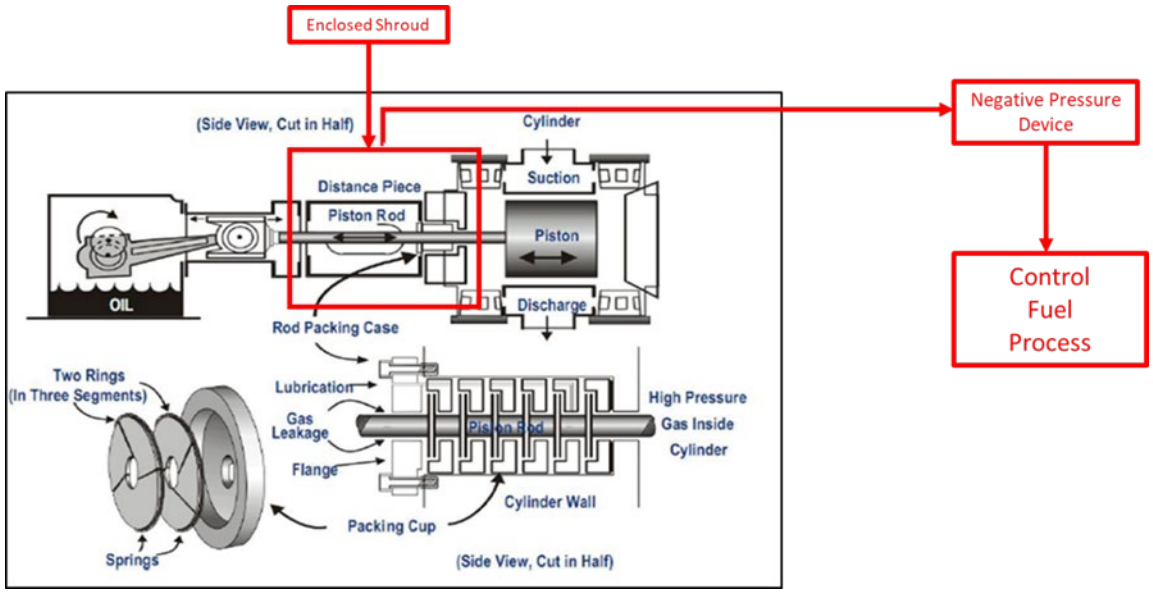


Figure 3. General Flow Process for a Closed Vent System. (Existing equipment shown in black and new equipment for closed vent system and control or recovery shown in red)

Centrifugal Compressors

Centrifugal compressor seal oil that is contaminated with entrained gas is typically routed directly to an atmospheric pressure degassing tank in which the entrained gas (methane and VOC) will evaporate from the seal oil and is then vented to the atmosphere. A wet seal fluid degassing system that is designed to capture the released methane and VOC is shown in Figure 4. In the capture system, the contaminated seal oil separated from entrained gas in a separator operating at seal oil pressure with gas flow controlled by a critical orifice. The entrained gas captured from the seal oil is routed to a seal oil demister to remove entrained seal oil before routing the gas to a control device, a process, for use as a fuel, or to the suction side of a compressor to be pressurized and put back into the pipeline or another use. The seal oil from the bottom of the high-pressure seal oil degassing separator flows to the atmospheric degassing separator where the remaining, but now reduced, volume of entrained/dissolved gas is removed and vented to the atmosphere. The regenerated seal oil is then recirculated back to the compressor seal oil system.

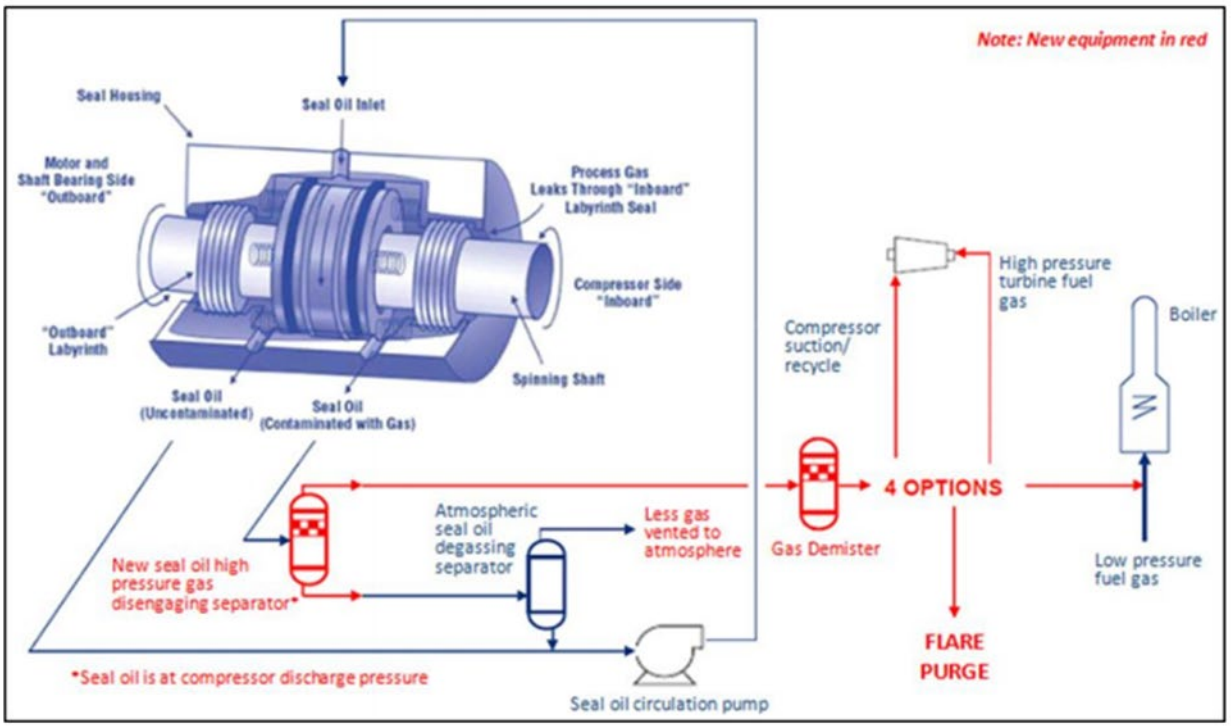


Figure 4. General process flow of wet seal degassing recovery system. (Existing equipment shown in blue and new equipment for seal oil degassing recovery shown in red)

Proposed Rule Requirements for Compressor Seals

Section 20.2.50.114 requires owners and operators of existing centrifugal compressors to control VOC emissions from centrifugal compressor wet seal fluid degassing systems by at least 95 percent within two years of the effective date of Part 50. Emissions must be captured and routed through a closed vent system to a control device, recovery system, fuel cell, or a process stream. Owners and operators of new centrifugal compressors are required to control VOC emissions from wet seal fluid degassing systems by at least 98 percent upon startup, capturing and routing emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

Owners and operators of existing reciprocating compressors must either replace the rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is

later, or collect VOC emissions from the rod packing under negative pressure and route them through a closed vent system to a control device, recovery system, fuel cell, or a process stream. Rod packing for new reciprocating compressors must be replaced after every 26,000 hours of operation or every 36 months, whichever is later, or emissions must be collected from the rod packing using a closed vent system to a control device, a recovery system, fuel cell or a process stream.

All centrifugal and reciprocating compressors must be equipped with an EMT in accordance with Section 20.2.50.112, and the owner or operator must comply with the general monitoring, recordkeeping, and reporting requirements in that Section. An owner or operator complying with the emission standards in Section 20.2.50.114 through the use of a closed vent system and control device, including a wet seal fluid degassing system, must also comply with the closed vent system and control device monitoring, recordkeeping, and reporting requirements in Section 20.2.50.115.

Owners and operators complying with the emission standards for new or existing reciprocating compressors are required to continuously monitor the hours of operation with a non-resettable hour meter, and track the number of hours from initial startup or from the previous reciprocating compressor rod packing replacement. Owners and operators of reciprocating compressors who are collecting emissions under negative pressure and routing those emissions through a closed vent system to a control device, a recovery system, fuel cell or a process stream are required to monitor the collection system semi-annually to ensure that it continues to operate under negative pressure.

Owners and operators of centrifugal compressors using wet seal fluid degassing systems are required to maintain records of the following: location of the compressor; date of

construction, reconstruction, or modification of the compressor; required monitoring data; and the type, make, model and identification number of the control device used to comply with the emission standards.

Owners and operators of reciprocating compressors are required to maintain a record of the following: location of the compressor; date of construction, reconstruction, or modification of the compressor; and the required monitoring data.

Basis for Proposed Requirements

Compressor Seals on Centrifugal Compressors

The proposed requirement in Section 20.2.50.114.B(1) to control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least 95 percent is based on NSPS Subpart OOOOa at 40 CFR § 60.5380a(a)(1)-(2), which requires that owners and operators reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent. The federal rule requires the wet seal degassing system to be equipped with a cover and closed vent system that routes the gas to a control system or a process.

Compressor Seals on Reciprocating Compressors

The proposed requirement in Section 20.2.50.114.B(2)(a) to control VOC emissions from a reciprocating compressor by replacing the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months is based on NSPS Subpart OOOOa at 40 CFR § 60.5385a(a)(1)-(2), which requires that owners and operators replace the rod packing on or before the compressor has operated for 26,000 hours or prior to 36 months from the date of the most recent rod packing replacement.

The proposed requirement in Section 20.2.50.114.B(2)(b) to collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device,

recovery system, fuel cell, or a process stream is based on NSPS Subpart OOOOa at 40 CFR § 60.5385a(a)(3), which requires that owners and operators collect emissions from the rod packing with a system under negative pressure and route to a process through a closed vent system.

Estimated Emissions Reductions

Reciprocating Compressors

The NMED Equipment Data indicates that there are 3,740 active oil and gas industry reciprocating engines located in the Subject Counties, or designated as "Portable." Engines located at refineries, mining, onsite remediation, reinjection sites, and wellheads were removed from the analysis. Engines identified as "generators" or "pump jack" engines in the emission unit description were also removed from the analysis. Engines whose capacity was stated in units of "kW" (kilowatts) were removed from the analysis under the assumption that they were used to power generators. ERG assumed that each of the remaining reciprocating engines is powering a reciprocating compressor. These 3,740 active reciprocating compressors are located at 1,193 unique locations. Of these, 2,612 reciprocating compressors are not already regulated by NSPS Subpart OOOO or OOOOa, based on their manufacture date, construction date, or the "Sub-Program Information" in the NMED Equipment Data.

ERG estimated emissions from the compressor seals of these 2,612 reciprocating compressors using the emission factor from Tables 5-2 and 5-3 of the EPA CTG. *See* NMED Exhibit 34. For reciprocating compressors located at gathering and boosting stations, the emission factor is 3.42 tpy of VOC. For reciprocating compressors located at gas processing sites, the emission factor is 6.12 tpy of VOC. ERG used the emission factor for gathering and boosting stations for all facility types (including production facilities and compression stations) other than natural gas processing plants. The CTG does not contain a separate emission factor for

reciprocating compressors at natural gas compression stations. However, because larger compression stations are generally located downstream from a gas processing plant, and the gas therefore has a lower VOC content, ERG assumed for this analysis that the emission factor for gathering and boosting would also be representative for compression stations. Total baseline VOC emissions before controls for these 2,612 reciprocating compressors are estimated at 9,260 tpy of VOC.

ERG estimated annual emission reductions from the reciprocating compressor seals by increasing the frequency of replacing the rod packing using the estimated emission reductions (tpy VOC per compressor) from Table 5-4 of the CTG. The CTG estimated the reductions achieved by increasing the replacement frequency from every 4 years to every 3 years. For reciprocating compressors located at gathering and boosting stations, this estimated emission reduction is 1.9 tpy VOC, and for reciprocating compressors located at processing sites the estimated emission reduction is 4.89 tpy VOC. For the 2,612 reciprocating compressors in the NMED data, total annual emission reductions with increased rod packing replacement were estimated to be 5,325 tpy VOC, a 57.5 percent reduction, and emissions after replacement of rod packing were estimated to be 3,935 tpy VOC. *See* NMED Exhibit 64 – Compressor Seals - Reciprocating Engines Spreadsheet.

Centrifugal Compressors

The NMED Equipment Data indicates there are 160 active oil and gas industry combustion turbines located in the Subject Counties. ERG removed from the analysis 25 turbines located at refineries and wellheads or designated as generators. ERG assumed that each of the remaining 135 turbines is powering a centrifugal compressor. These 135 centrifugal compressors are situated at 36 unique locations. Of these, 116 centrifugal compressors are not already

regulated by NSPS Subparts OOOO or OOOOa, based on their manufacture date, construction date, or "Sub-Program Information" in the NMED Equipment Data.

ERG assumed that each of these 116 compressors is equipped with wet seals, based on an applicable EPA 2014 Natural Gas Star Program document which states that "most new compressors [are] equipped with [a] dry seal." *See* NMED Exhibit 65 – Partner Reported Opportunities (PROs) for Reducing Methane Emissions, *Wet Seal Degassing Recovery System for Centrifugal Compressors* (2014) ("Centrifugal Compressors Technical Document").[14] ERG assumed that the remaining 19 compressors had dry seals.

ERG estimated baseline emissions from the compressor seals of the 116 wet seal and 19 dry seal centrifugal compressors using the emission factors from Tables 5-2 and 5-3 of the EPA CTG. *See* NMED Exhibit 34. The EPA CTG includes VOC emission factors for centrifugal compressors located only at natural gas processing sites, and these emission factors are 19.1 tpy VOC for centrifugal compressors with wet seals and 2.4 tpy VOC for compressors with dry seals. The EPA CTG did not include separate VOC emission factors for centrifugal compressors located at other types of facilities (e.g., gathering and boosting stations or natural gas compression stations). As a result, ERG used the same emission factors (19.1 tpy of VOC per compressor with wet seals and 2.4 tpy VOC for dry seals) for estimating baseline VOC emissions for all centrifugal compressors, depending on whether or not they were subject to the NSPS. Total VOC emissions before controls for the 116 centrifugal compressors that predate the NSPS are estimated at 2,197 tpy of VOC, and the VOC for the other 19 centrifugal compressors that are likely subject to the NSPS are estimated at 46 tpy. Total baseline VOC emissions from all centrifugal compressors are 2,243 tpy VOC.

[14] Available at: https://www.epa.gov/natural-gas-star-program/wet-seal-degassing-recovery-system-centrifugal-compressors

ERG estimated emission reductions from the compressor seals on centrifugal compressors after installation of a wet seal degassing recovery and re-use system. The estimated emission reductions after installation of a wet seal degassing recovery and re-use system is from the CTG, which assumed "that routing VOC emissions from a wet seal fluid degassing system to a process reduces VOC emissions greater than or equal to a combustion device (i.e., greater than or equal to 95 percent)." A 95% reduction in VOC emissions is equivalent to 1.0 tpy VOC after control. Total emissions after installation of a wet seal degassing recovery and re-use system for these 116 centrifugal compressors are therefore estimated at 110 tpy VOC.

Requiring centrifugal compressors to install a wet seal degassing recovery and re-use system would result in a 95 percent reduction in VOC emissions for these previously unregulated sources. Overall VOC reductions would be 2,087 tpy VOC, and the overall percent VOC emission reduction would be 93%. *See* NMED Exhibit 66 – Compressor Seals - Turbines Spreadsheet.

Estimated Costs

Reciprocating Compressors

ERG estimated the annualized costs of VOC emission reductions for the 2,612 uncontrolled reciprocating compressors by applying cost estimates from Table 5-5 of the CTG. Costs were scaled from 2012$ to 2019$ using the CEPCI. Since rod packing replacement is done every three years, the capital costs of replacement were annualized over three years, assuming an interest rate of 7%. The resulting annual cost per compressor for rod packing replacement is $2,237 per year for a compressor in the gathering and boosting sector, and $1,695 per year for a compressor in the processing sector. These annual costs are incremental costs compared to the

annual costs of replacing the rod packing every four years. The total cost for replacing rod packing every three years for all 2,612 reciprocating compressors is $5,778,289.

Full details on how these cost equations were applied can be found in the Compressor Seals – Reciprocating Engines Spreadsheet. *See* NMED Exhibit 64.

Centrifugal Compressors

ERG estimated the annualized costs of VOC emission reductions for the 116 uncontrolled centrifugal compressors located at 36 unique locations by applying the cost estimates from Exhibit 3 of the Centrifugal Compressors Technical Document. *See* NMED Exhibit 65. Costs were scaled from 2011$ to 2019$ using the CEPCI. Because some of the equipment for a degassing system can be shared across all compressors at a site, the capital cost of installing these systems per compressor decreases with an increasing number of compressors at a site. EPA estimated the cost for sites with one compressor and four compressors in the Centrifugal Compressors Technical Document. ERG adopted the same procedure to calculate the capital and annual costs for different numbers of compressors, as presented in the following table. The capital costs of installing the degassing system were annualized over a period of five years, assuming an interest rate of 7%.

# of Compressors at a Site	Total Capital Cost ($2019)	Annualized Cost ($2019)
1 Compressor	$34,228	$8,348
2 Compressors	$53,935	$13,154
3 Compressors	$73,643	$17,961
4 Compressors	$93,350	$22,767
5 Compressors	$113,057	$27,574
6 Compressors	$132,764	$32,380
7 Compressors	$152,471	$37,186
8 Compressors	$172,179	$41,993
9 Compressors	$191,886	$46,799
10 Compressors	$211,593	$51,606

ERG calculated the annualized cost for installing a degassing system at each of the 36 locations with centrifugal compressors that would be affected by Part 50 based on the number of compressors at that site, not for each individual compressor. The total initial capital cost for installing a degassing system at the 36 compressor sites is $2,735,150 and the annualized cost of installing a degassing system at the 36 compressor sites is $667,078.

Full details on how these cost equations were applied can be found in the Compressor Seals – Turbines Spreadsheet. *See* NMED Exhibit 66.

Section 20.2.50.115 – Control Devices

The requirements of Section 20.2.50.115 apply to control devices used to comply with the emission standards and emission reduction requirements found in Part 50.

Description of Process

A control device is any mechanical, thermo, or chemical means to capture, convert, destroy, or recover air contaminants. The purpose of control devices as defined in Part 50 is the reduction of VOCs and NOx. Some control devices are specific to a particular process or type of equipment, while others can be used for multiple processes or types of equipment. The discussion below focuses on those controls outlined in Part 50 and commonly used in oil and gas operations. A brief overview of control devices is provided in this section; for additional discussions of controls for specific processes or types of equipment covered by Part 50, see the testimony for the section of Part 50 that covers the specific process or type of equipment.

Examples of control devices include, but are not limited to, open flares, enclosed combustion devices ("ECDs"), thermal oxidizers ("TOs"), vapor recovery units ("VRUs"), fuel cells, condensers, and catalytic converters (oxidative, selective, and non-selective). A control

device may also include any other air pollution control equipment or emission reduction technologies approved by the Department to comply with emission standards in Part 50.

Open Flares

Open flares or "flaring" refers to the routing of natural gas from anywhere in the process to a device where the gas is combusted as it leaves the tip of the flare. Flaring is a high-temperature oxidation process used to burn or incinerate waste gases containing combustible components such as VOCs, natural gas (methane), carbon monoxide (CO), and hydrogen (H2). Flares convert, or destroy, waste gases into less harmful components (ideally, water vapor and carbon dioxide).

The flare system consists of a header, stack, tip, and ignition system. Gas is sent to the flare through a header system and is combusted as it exits the flare stack at the tip. The flare tip is designed to ensure the proper mixing of gas and air to achieve the proper burn efficiency. Ignition of the gas stream is through the use of a continuously burning pilot or auto-ignition system. Flaring is a necessary part of drilling and completion activities, oil and natural gas field production, pipeline gas gathering, and facility processing of oil and natural gas because of safety considerations (personnel and equipment) and its effectiveness in combusting harmful emissions (environmental).

Enclosed Combustion Devices

Enclosed combustion devices use a high-temperature oxidation process to control VOCs in many industrial settings because the enclosed combustor can normally handle fluctuations in concentration, flow rate, heating value, and unreactive (i.e., non-combustible) compounds found in the gas stream. For this analysis, it is assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuous

basis. Combustion devices can be designed to meet a 98 percent control efficiency, and can control emissions by 98 percent on average, or more in practice when properly operated. Combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions. A typical combustor used to control emissions from storage vessels in the oil and natural gas sector is an enclosed combustion system. The basic components of an enclosed combustion system include (1) piping for collecting emission source gases; (2) a single- or multiple-burner unit; (3) a stack enclosure; (4) a pilot flame to ignite the mixture of emission source gas and air; and (5) combustor fuel/piping (as necessary). Figure 1 presents a schematic of a typical dual-burner enclosed combustion system.

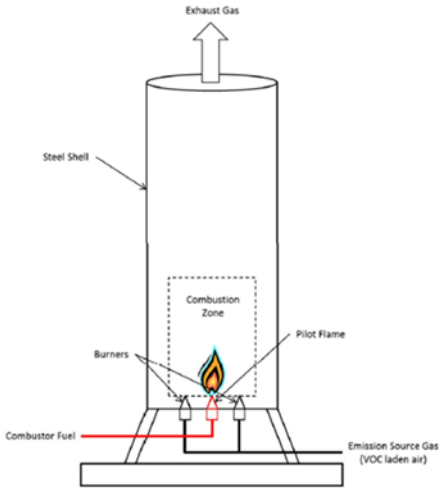


Figure 1 Schematic of a Typical Enclosed Combustion System

Thermal oxidizers – also referred to as direct flame incinerators, thermal incinerators, or afterburners – can also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC-laden emission source gas is injected into

the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted (i.e. vented) to the atmosphere. *See* NMED Exhibit 34 (EPA CTG).

Vapor Recovery Units

Vapor recovery units ("VRUs") route vapors from an emission source back to the inlet line of a separator, to a sales gas line, or to another process line for beneficial use, such as use as a fuel. A VRU is often referred to as a compressor that is used to boost recovered vapors back into the line. In a typical VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator or suction scrubber to collect any condensed liquids, which are recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite.

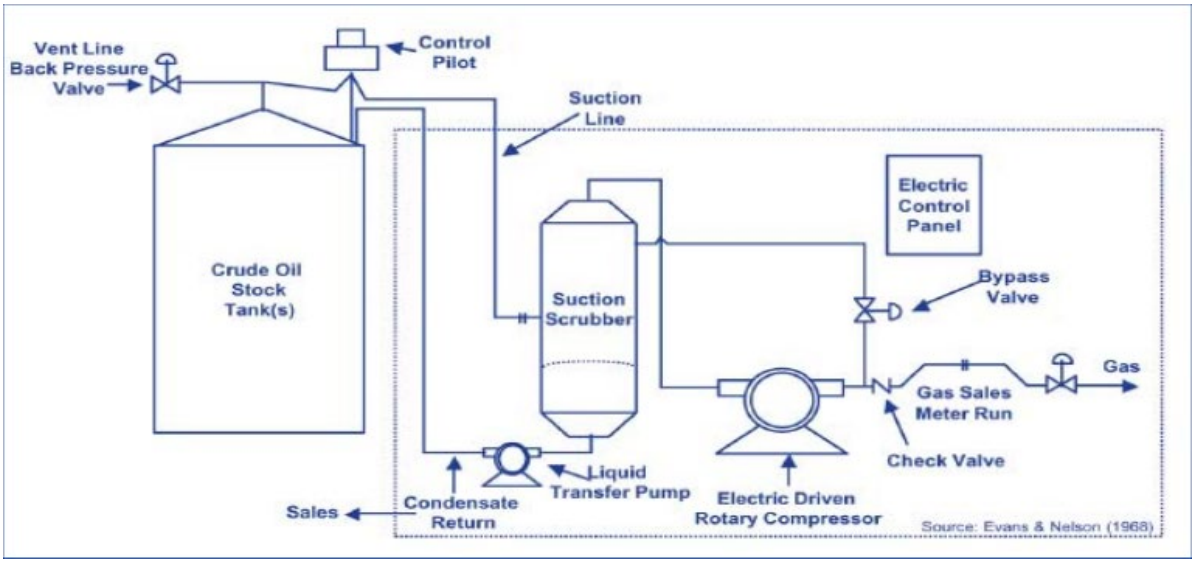


Figure 2 Conventional Vapor Recovery System

Condensers

A condenser is a heat exchanger used to condense a gaseous substance into a liquid state through cooling. Condensers are often used to control VOC emissions from glycol dehydration units by condensing the organic vapors from the regenerator still vent.

Fuel Cells

A fuel cell is an electrochemical cell that converts the chemical energy of a fuel (typically hydrogen but may also be methane or organic vapors) and an oxidizing agent (commonly oxygen) into electricity through oxidation and reduction reactions that convert the fuel into water vapor (in the case of hydrogen fuel) or into carbon dioxide and water vapor (in the case of methane or organic vapors). The use of fuel cells has been investigated as a potential VOC emission control option for the surface coating industry, but has not yet been demonstrated for controlling VOC emissions from oil and natural gas production operations.

Gaseous Emission Control of Stationary Internal Combustion Engines

Gas compressor operations are an essential element of oil and gas production. To produce oil and natural gas and keep natural gas pressures at the level required to move gas from the wellhead to the consumer, compressors and the associated driver are found at multiple locations in the natural gas value chain. In addition to driving compressors, engines may also be used as the driver for power generators that provide electrical power to sites that are not connected to the commercial electrical grid.

Catalytic Converters (oxidative, selective, and non-selective)

Stationary engines, typically fueled by natural gas or propane, are widely used for prime power and for gas compression. In gas compression, the types of engines are either rich-burn or lean-burn. The difference between rich-burn and lean-burn engine operation lies in the air-to-fuel

ratio: a rich-burn engine is characterized by excess fuel in the combustion chamber during combustion, while a lean-burn engine is characterized by excess air in the combustion chamber during combustion. For gas transmission, engines are typically lean-burning. Gas engines are also used for prime power applications, especially where it is convenient to connect a natural gas line to the engine. Depending on the application, engines in oil and natural gas operations range in size from relatively small (approximately 50 hp) for certain types of pumps and generators to thousands of horsepower for natural gas compressors at transmission compression stations.

Different emission control technologies have to be applied to engines depending on their air-to-fuel ("A/F") ratio. This is because the exhaust gas composition differs depending on whether the engine is operated in a rich, lean, or stoichiometric burn[15] condition. See the previous testimony regarding control options for engines (Section 20.2.50.113) for a discussion of selective catalytic reduction and non-selective catalytic reduction as effective NOx control technologies for engines.

Proposed Rule Requirements for Control Devices

General Requirements (Subsection B)

Section 20.2.50.115 requires control devices to be designed, sized, installed, operated, and maintained in order to minimize emissions and achieve the emission standards required by Part 50. Each device must operate as a closed vent system, have an EMT installed, and a monthly inspection is required to ensure proper operation. Closed vent systems must be designed and

[15] In an internal combustion engine or industrial furnace, the air-fuel ratio is an important measure for anti-pollution and performance-tuning reasons. If exactly enough air is provided to completely burn all of the fuel, the ratio is known as the stoichiometric mixture, often abbreviated to stoich. Ratios lower than stoichiometric are considered "rich." Rich mixtures are less efficient, but may produce more power and burn cooler. Ratios higher than stoichiometric are considered "lean." Lean mixtures are more efficient but may cause higher temperatures, which can lead to the formation of nitrogen oxides. Some engines are designed with features to allow lean-burn. For precise air-fuel ratio calculations, the oxygen content of combustion air should be specified because of different air density due to different altitude or intake air temperature, possible dilution by ambient water vapor, or enrichment by oxygen additions.

certified by a professional engineer or an in-house engineer. Manufacturer specifications for control devices must be kept on file by the owner or operator and include identifying information, specific operational parameters (e.g., maximum rated capacity) and control efficiency.

Open Flares (Subsection C)

Owners and operators using open flares are required to install a continuous pilot, auto-igniter, or require manual ignition upon start up for new flares, and one year after the effective date of Part 50 for existing flares. All gas sent to the flare must be combusted. For existing flares at facilities with an average daily production of 10 bbls/day of oil or 60,000 scf/day of natural gas, owners and operators are required to install an auto-igniter, continuous pilot, or flare malfunction alarm technology upon replacement or reconstruction. Flares must be operated with no visible emissions, as determined by visual observations or continuous monitoring technology, and all repairs must be completed within three days of an alarm activation.

Flares with a continuous pilot must be monitored continuously for the presence of a pilot flame. When an auto igniter is used, the presence of a flame must be continuously monitored during flaring using a thermocouple or alternative equivalent technology approved by the Department. Manually ignited flares must be continuously visually monitored during a flaring event to ensure the flare is lit. Owners and operators are required to perform quarterly EPA Method 22 (40 CFR Part 60, Appendix A) observations to ensure compliance with visible emissions and opacity limits. *See* NMED Exhibit 67 – EPA Reference Method 22 – *Visual determination of Fugitive Emissions from Material Sources and Smoke from Flares* (January 14, 2019).

Owners and operators of open flares are required to keep records of alarm activation, cause of the alarm, corrective actions, name of personnel conducting the action, and any maintenance activities performed.

Owners and operators of open flares must comply with the general reporting requirements in Section 20.2.50.112.

Enclosed Combustion Devices and Thermal Oxidizers (Subsection D)

Enclosed combustion devices and thermal oxidizers ("ECD/TOs") must be operated within the maximum rated capacity and must combust all gas sent to the equipment. Continuous pilot flames or auto-igniters must be installed upon startup for new ECD/TOs, or within one year for existing ECD/TOs. All ECD/TOs must operate with a continuous flame present and with no visible emissions during flaring events.

ECD/TOs with a continuous pilot must be monitored continuously for the presence of a pilot flame. When an auto igniter is used, the presence of a flame must be continuously monitored during flaring using a thermocouple or alternative equivalent technology approved by the Department. Owners and operators are required to perform quarterly EPA Method 22 observations to ensure compliance with visible emissions and opacity limits.

Owners and operators of ECD/TOs are required to keep records of alarm activation, cause of the alarm, corrective action taken, name of personnel conducting the inspection, and any maintenance activities performed. Additionally, owners and operators must record the results of the quarterly EPA Method 22 observations. Gas analysis results must be recorded for the combustion gas to include the VOC content and heating value.

Owners and operators of ECD/TOs must comply with the general reporting requirements in Section 20.2.50.112.

Vapor Recovery Units

All VRUs must be operated as a closed vent system that captures and routes VOC emissions back to the process or to a sales pipeline. Venting to the atmosphere is prohibited and a backup control device (e.g. ECD/TO) or a redundant VRU is required during periods of startup, shutdown, maintenance, or other downtime such as malfunctions.

Owners and operators of VRUs must comply with the monitoring requirements for equipment leaks as specified in Section 20.2.50.116, or implement a program that meets the requirements of NSPS Subpart OOOOa.

For each VRU inspection or monitoring event, the owner or operator must record the result of the event, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator must also record the type of redundant control device used during VRU downtime.

The owner or operator of a VRU must comply with the general reporting requirements in Section 20.2.50.112.

Basis for Proposed Requirements for Control Devices

The proposed general requirements for control devices in 20.2.50.115.B(1) through (5) are based on similar rules for closed vent systems and control devices in Pennsylvania GP-5 and GP-5A (NMED Exhibits 37 and 38), Colorado Reg. 7, Section II.C.5 (NMED Exhibit 39), NSPS Subpart OOOOa (NMED Exhibit 36), and EPA's NSPS regulations at 40 CFR 60, Subpart A – General Provisions ("NSPS Subpart A").

The proposed requirements for closed vent systems for centrifugal compressor wet seal fluid degassing systems in 20.2.50.115.B(6) are based on Colorado Reg. 7, Section I.J.1; and NSPS Subpart OOOOa, Section 60.5380a.

The proposed requirements for open flares in 20.2.50.115.C are based on NSPS Subpart OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b).

The proposed requirements for enclosed combustion devices and thermal oxidizers in 20.2.50.115.D are based on Pennsylvania GP-5, Section J; Colorado Reg. 7, Sections I.C.1 and II.B.2; NSPS Subpart OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b).

The proposed requirements for VRUs in Section 20.2.50.115.E are based on Pennsylvania GP-5, Section J; and NSPS Subpart OOOOa, Section 60.5412a.

Estimated Emissions Reductions

The estimated reductions in VOC and NOx emissions from oil and gas operations are discussed in the testimony regarding the proposed requirements for the specific equipment and processes addressed in Part 50. Details on the emissions and emissions reductions are found in the 'Reductions and Costs' spreadsheets for each of the various equipment and process categories regulated under the proposed rule.

Estimated Costs

The estimated annualized costs of the VOC and NOx emissions reductions resulting from implementation of Part 50 are discussed in the testimony regarding the proposed requirements for the specific equipment and processes addressed in Part 50. Details on the emissions, costs, and reductions are found in the 'Reductions and Costs' spreadsheets for each of the various equipment and process categories regulated under the proposed rule. These costs are specific to the particular equipment/process and the pollutant being controlled.

Section 20.2.50.116 – Equipment Leaks and Fugitive Emissions

Section 20.2.50.116 applies to well sites; tank batteries; gathering and boosting stations; gas processing plants; natural gas compressor stations; and associated piping and components.

Description of Equipment and Process

The processing of natural gas includes the removal of natural gas liquids from field gas and/or the fractionation of mixed liquids to natural gas products. There are a number of potential sources of equipment leaks during production and processing, such as pumps, pressure relief devices, valves, flanges, and other connectors that have a leak potential due to seal failure. In addition, leaks can occur from open-ended lines and valves as well as from corrosion of welded connections, flanges, and valves. The large number of valves, pumps, and other equipment associated with natural gas production and processing can be a significant sources of VOC emissions.

There are also a number of potential sources of fugitive emissions throughout the oil and gas sector. These can occur from poorly fitted connection points or deterioration of seals and gaskets. Fugitive emissions can also be caused by changes in pressure, temperature, or mechanical stresses. A "fugitive emissions component" may be defined as any component that has the potential to emit fugitive emissions at any of the sources previously identified, including valves; connectors; pressure relief devices; open-ended lines; access doors; flanges; closed vent systems; thief hatches or other openings on storage vessels; agitator seals; distance pieces; crankcase vents; blowdown vents; pump seals or diaphragms; compressors; separators; pressure vessels; dehydrators; heaters; instruments; and meters. Devices that would naturally vent as part of normal operations, such as natural gas-driven pneumatic controllers or pumps, are not included as fugitive emissions components. *See* NMED Exhibit 34 (EPA CTG)

Control Options for Equipment Leaks and Fugitive Emissions

Emissions from fugitive emission sources such as leaking valves, connectors, and flanges can be controlled through implementation of an emission leak detection and repair ("LDAR")

program. In simple terms, LDAR programs reduce emissions by requiring owners and operators to inspect their facilities to find and repair leaks. Leak detection methods include:

- Audio, visual, and olfactory ("AVO") inspections;
- Instrument monitoring according to EPA Reference Method 21, 40 CFR Part 60, Appendix A-7 ("EPA Method 21"); and
- Monitoring using optical gas imaging ("OGI").

AVO inspections rely on the use of sight, sound, and smell to identify leaking components by listening for hissing or unusual sounds coming from equipment (audio); looking for cracks, holes, visible liquids leaks, or staining (visual); and smelling for unusual or strong odors (olfactory).

EPA Method 21 is an established reference method that identifies leaks using a portable instrument that can detect the presence of organic gases and measure their volumetric concentration in parts per million (ppm). The method also allows for the use of a soap solution applied to components that will form bubbles if there is a leak present.

OGI is a newer method for leak detection that utilizes forward-looking infrared ("FLIR") cameras to conduct inspections of equipment components to identify leaks. OGI infrared cameras are highly specialized thermal cameras that can identify methane using its infrared absorption characteristics. OGI cameras can be used to survey large numbers of components in a short amount of time, whereas EPA Method 21 inspections require inspecting one component at a time with the instrument probe.

When using EPA Method 21, a leak is detected whenever the measured concentration exceeds the defined concentration threshold standard. In Section 20.2.50.116.C.(4)(c), this is specified as 500 ppm. When using OGI, a leak is detected if the emission images recorded by the

OGI instrument are not associated with normal equipment operation. An owner or operator also has the option of proposing an alternative equipment leak monitoring plan for approval by the department.

The control effectiveness of an LDAR program is based on the frequency of monitoring and the leak definition. More frequent monitoring means that leaks are detected and repaired sooner, so that they emit for a shorter time period, and possibly while they are still small and before they grow larger. A lower ppm leak definition will mean that a larger number of leaks must be repaired than with a higher ppm definition.

Proposed Rule Requirements for Equipment Leaks and Fugitive Emissions

Section 20.2.50.116 sets forth default monitoring requirements that apply to the inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components. Owners and operators of facilities with an annual average daily production greater than 10 barrels of oil (bbls) per day, or an average daily production greater than 60,000 standard cubic feet per day of natural gas, are required to conduct AVO inspections at least weekly. Facilities with an annual average daily production equal to or less than 10 bbls per day, or an average daily production equal to or less than 60,000 standard cubic feet per day of natural gas, are required to conduct an AVO inspection at least monthly.

Owners or operators of the following facilities must perform inspections using EPA Method 21 (explained above) OGI according to the following schedules:

- **Well sites and tank battery facilities:** annually at facilities with a PTE less than two tpy VOC; semi-annually at facilities with a PTE equal to or greater than two tpy and

less than five tpy VOC; and quarterly at facilities with a PTE equal to or greater than five tpy VOC.

- **Gathering and boosting stations, gas processing plants, and natural gas compressor stations:** quarterly at facilities with a PTE less than 25 tpy VOC; and monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

Inspections using EPA Method 21 require daily calibration of instruments before use. Regulated leaks are those with a measurement of 500 ppm or greater of hydrocarbons and that not associated with normal operations.

Inspections using OGI must comply with the requirements in EPA's regulations at 40 CFR Section 60.18. A leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation. Components that are difficult, unsafe, or inaccessible to monitor are not required to be inspected until it becomes feasible to do so.

As an equivalent means of compliance with Subsection C of 20.2.50.116, an owner or operator can submit an alternative monitoring plan. The plan must be approved by the Department and can be terminated by the Department if the owner/operator fails to comply with elements of the plan, or fails to correct or disclose a violation within 15 days of discovery.

For leaks detected under Section 20.2.50.116, the component must be visibly tagged until repaired and the leak must be repaired within 15 days of discovery, except those detected leaks using OGI, which must be repaired within 7 days of discovery. Equipment must be re-monitored no later than 15 days after discovery of a leak to demonstrate that the leak has been repaired. For leaks that cannot be repaired in the required timeframes above without a process shutdown, the leak may be designated as "Repair Delayed" and repaired before the end of the next process unit shutdown.

Owners or operators are required to keep records of the following for all AVO, EPA Method 21, OGI, or alternative equipment leak monitoring inspections conducted pursuant to Section 20.2.50.116: facility location; date of inspection; monitoring method; name of the personnel performing the inspection; description of any leak requiring repair or a note that no leak was found; and whether a visible flag was placed on the leak or not. The owner or operator is required to record any leak detected, the date of detection, and the date of attempted repair. For leaks designated "repair delayed," the owner or operator must record the reason for delay for leaks not repaired within the allowed time frame, and an authorized representative's signature who determined the leak could not be implemented without process unit shutdown. The owner or operator must also record information regarding repair and follow-up monitoring. For a leak detected using OGI, the owner or operator must keep records as specified in EPA regulations at 40 CFR Section 60.18(i)(1)-(3).

Subsection G of 20.2.50.116 requires owners and operators to certify the use of an alternative equipment leak monitoring plan under Subsection D, if used, to the Department annually, and comply with the general reporting requirements in Section 20.2.50.112.

Basis for Proposed Rule

The requirements in Section 20.2.50.116 are based on similar rules for LDAR programs for oil and gas sources adopted by Colorado and Pennsylvania, and in NSPS Subparts OOOO and OOOOa.

Colorado Reg. 7 (NMED Exhibit 39) specifies the following LDAR frequencies for different types of facilities:

- Natural gas processing plants must comply with the LDAR provisions in NSPS Subpart OOOO, regardless of the age of the facility, unless the facility is subject to NSPS Subpart OOOOa. (Section .I.G).
- Natural gas compressor stations must perform quarterly instrument monitoring. (Section I.L.1).
- Well production facilities must perform annual instrument monitoring if uncontrolled actual VOC emissions are equal to or greater than 1 tpy of VOC, but less than or equal to 6 tpy VOC, and must perform semiannual instrument monitoring if uncontrolled actual VOC emissions are greater than 6 tpy VOC. (Section I.L.2).

Under Pennsylvania GP-5 and GP-5A for oil and gas operations, all owners and operators of unconventional natural gas well sites, remote pigging stations, natural gas compressor stations, processing plants, and transmission stations must conduct monthly AVO inspections and quarterly inspections using EPA Method 21 or OGI. When using EPA Method 21, a leak is defined as 500 ppm. *See* NMED Exhibits 37 and 38, at pp. 3, 18-19.

The equipment leak provisions in NSPS Subpart OOOO apply only to onshore natural gas processing plants and incorporate the provisions of 40 CFR 60, Subpart KKK (Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011), which in turn incorporate the provisions of 40 CFR 60, Subpart VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006).

The fugitive emission (i.e., equipment leak) provisions in NSPS Subpart OOOOa, 40 CFR § 60.5397a and 60.5400a, require semi-annual inspections using EPA Method 21 or OGI at well-sites, and quarterly inspections at compressor stations and gas processing plants. Well sites that contain only wellheads are exempt from the fugitive emission requirements.

Estimated Emissions Reductions

Based on the NMED Equipment Data and oil and gas well data from OCD,[16] ERG estimated that there are 23,969 wellhead facilities (based a total well count of 47,937 in the Subject Counties, and assuming an average of 2 wells per wellhead facility), and another 1,950 non-wellhead facilities involved in collecting, processing, and transmitting oil and gas. ERG estimated that the non-wellhead facilities have fugitive equipment leak emissions of 7,131 tons per year of VOC, and the wellhead facilities have fugitive equipment leak emissions of 18,894 tons per year of VOC. The baseline VOC emissions from equipment leaks at the wellhead facilities and non-wellhead facilities are based on the *Baseline 2014-2016 Oil and Gas Emission Inventory for the WESTAR-WRAP Region* (June 2019) ("2014 Oil and Gas Emission Inventory") attached as NMED Exhibit 68. *See* NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet.

ERG then evaluated the effect of the proposed requirements on VOC emissions. For non-wellhead facilities, ERG examined the list of 1,950 facilities to determine which facilities were currently implementing an LDAR program under existing federal regulations, which facilities would be required to implement a new LDAR program under Part 50, and what the required frequency of inspection would be for those facilities required to implement a new LDAR

[16] Petroleum Recovery Research Center, GO-TECH website. Oil and gas production data on the PRRC website has been provided primarily by the New Mexico Oil Conservation Division, and is updated on a monthly basis. http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx

program under Part 50, based on the facility type and the facility's total allowable VOC emissions. The total allowable VOC emissions were used as a surrogate for the facility's PTE of VOC. Under NSPS Subparts OOOO and OOOOa, many oil and gas facilities are already required to conduct LDAR. ERG assumed no additional emission reductions would occur at these sources as a result of the proposed rule. The emission reductions expected for each facility implementing a new LDAR program was then estimated based on the following frequency of Method 21 or OGI inspections:

Frequency	**Average Percent Reduction (assuming facilities will use a mix of OGI and Method 21)**	**Inspection Technology**
Monthly	92%	Method 21
Quarterly	82%	Method 21/OGI
Semiannually	68%	Method 21/OGI
Annually	54%	Method 21/OGI

These reduction percentages are based on data compiled by EPA in developing updated standards for reducing emissions from equipment leaks for oil and natural gas production sources. *See* NMED Exhibit 70 – EPA, *Background Technical Support Document for the Final New Source Performance Standards (40 CFR Part 60, Subpart OOOOa)*, EPA-HQ-OAR-2010-0505-7631 (May 2016), at page 41 for EPA Method 21 and page 42 for OGI). As a result of this analysis, ERG estimated total emission reductions of 4,654 tons per year of VOC for non-wellhead facilities. *See* NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet.

For well sites facilities, emission reductions were estimated assuming semi-annual inspections would be required at well sites not currently conducting inspections under existing federal requirements in NSPS Subpart OOOOa. Estimated VOC reductions for well sites that

would be required to implement a new LDAR program under the proposed rule are based on EPA estimates of reductions associated with an LDAR program to be:

Facility Type	**Annual VOC Emission Reduction (tpy)**
NG Well Site (GOR > 100,000)	0.917
Oil Well Site (GOR < 300)	0.199
Oil Well Site (GOR > 300, < 100,000)	0.451

See NMED Exhibit 34 – EPA CTG, at Table 9-12. As a result of this analysis, ERG estimates total emission reductions of 14,896 tons per year of VOC for well site facilities. *See* NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet. This approach would result in total VOC reductions of 14,896 tpy of VOC, which is 79% of the baseline VOC emissions from the New Mexico oil and gas inventory.

Costs of Proposed Requirements

The costs of implementing an LDAR program to reduce fugitive equipment leak emissions are those associated with labor required to conduct inspections and repair leaking components. ERG estimated the costs required to implement a new LDAR program under the proposed rule for well sites based on estimates for well sites from the EPA CTG (NMED Exhibit 34) and from the cost analysis for the 2014 amendments to Colorado Reg. 7. *See* NMED Exhibit 71 – Colorado Dept. of Public Health and Environment, *Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6 and 7 (5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9)*, (February 11, 2014) ("2014 Colorado Regulatory Analysis"). The LDAR costs for each type of facility were estimated as follows:

Well sites: ERG assumed that all well sites would have two wells, and that all would use semiannual OGI LDAR monitoring. The cost per well site, based on a model plant analysis, was

taken from Table 9-12 of the EPA CTG (NMED Exhibit 34). The cost per LDAR inspection was scaled from 2012$ to 2019$ using the CEPCI for an annual cost of $2,375 per site.

Gathering and Boosting Stations: The cost per gathering and boosting station for quarterly LDAR inspections using OGI, based on a model plant analysis, was taken from Table 9-13 of the EPA CTG. The cost per LDAR inspection was scaled from 2012$ to 2019$ using the CEPCI for an annual cost of $26,030 per site.

The cost per gathering and boosting station for monthly LDAR inspections was based on the weighted average cost per inspection for LDAR inspections (Table 23) and repairs (Table 24) of the 2014 Colorado Regulatory Analysis. For 359 inspections, the total LDAR costs were $1,007,064 and the total repair costs were $523,071. Costs do not include any credit for recovered gas volume. The cost per inspection was multiplied by 12 to obtain the annual LDAR cost. The costs were scaled to 2019$ using the CEPCI.

Natural Gas Compressor Stations: The costs for quarterly and monthly LDAR inspections for compressor stations were estimated using the same methodology as that used to estimate the costs of monthly LDAR inspections for gathering and boosting stations as described in the previous paragraph. The annual costs per station were estimated to be $18,256 for quarterly inspections and $54,768 for monthly inspections.

Tank batteries: The cost per LDAR inspection per tank battery includes costs for three elements: (1) a cost per inspection of the closed vent system inspection; (2) a cost per inspection of the tank battery; and (3) the average cost of repairs per inspection. Costs were estimated based on the 2014 Colorado Regulatory Analysis. Costs for storage tank closed vent system inspections are based on 2 hours of a contractor at $134 per hour per tank battery using EPA Reference Method 21 or an OGI camera. Costs for the tank battery inspection were based on a weighted

average cost per inspection in Table 27 of the 2014 Colorado Regulatory Analysis. Costs were scaled from 2013$ to 2019$. Costs for repairs were based on the weighted average repair cost per inspection using the total repair cost from Table 28, and the total number of inspections from Table 27, in the 2014 Colorado Regulatory Analysis. *See* NMED Exhibit 71. Costs were in 2013$ and they were scaled to 2019$ using the CEPCI. The cost per inspection was multiplied by the estimated number of inspections per year required for each tank battery to obtain the total annual cost for each facility of $1,160 for annual inspections, $2,319 for semiannual inspections, and $4,638 for quarterly inspections.

Natural Gas Plants: The average total number of components (5,947) at a gas plant was taken from Table 8-2 in the EPA CTG (NMED Exhibit 34). The cost per LDAR inspection was estimated assuming a check of 120 components per hour at a cost of $110/hour for company labor, assuming a "loaded" rate that includes benefits, overhead, vehicle costs, and estimated hourly cost for a purchased EPA Method 21 detector. The hourly labor rate of $110/hour is from Table 20 on page 41 of the 2014 Colorado Regulatory Analysis (NMED Exhibit 71). The rate of $103/hr in Table 20 was scaled from 2013$ to 2019$ using the CEPCI. The cost per LDAR inspection was multiplied by the estimated number of inspections per year to obtain the total annual cost for each facility of $21,806 for quarterly inspections and $65,417 for monthly inspections.

The total annualized costs of implementing the LDAR requirements in Part 50 are estimated to be $2,847,945 for non-wellhead facilities, and $52,220,185 for well site facilities. Given the emissions reductions expected as a result of the proposed rule, ERG estimated the cost effectiveness of reducing emissions from non-wellhead facilities at $5,100 per ton of VOC, and $3,506 per ton of VOC for well site facilities.

Section 20.2.50.117 – Natural Gas Well Liquid Unloading

Applicability

The requirements of Section 20.2.50.117 apply to liquid unloading operations including down-hole well maintenance events at natural gas wells.

Process Description and Control Options for Natural Gas Well Liquid Unloading

Liquids unloading is used to remove accumulated fluids in the wellbore of a natural gas production well. Managing wellbore liquid build-up in gas wells is fundamental to maintaining production, avoiding early abandonment of wells, and maximizing resource recovery. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production declines, wellbore (tubing) velocity goes down, and liquid loading begins to occur in the wellbore. Liquid loading begins when the gas velocity up the production string is not sufficient to lift liquids up to the surface at a pressure that will allow gas production to overcome the surface equipment and flow out of the wellbore. While pressure is a factor, it is generally a lack of velocity that causes liquids to accumulate in the wellbore (i.e., to "load" or "load up").

New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and velocity declines and eventually a point is reached where liquids loading begins to be an issue. The time at which liquids loading occurs is dependent on the reservoir characteristics, and varies from well to well.

At the onset of liquids unloading, techniques that rely on the reservoir energy are typically used to remove liquids. The following techniques can be used individually or in combination to manage wellbore liquids and maintain production:

- **Intermitting:** Shutting in a well (i.e., stopping or reducing production) for a period of time to allow the reservoir near the wellbore to "refill" the pressure and volume "void" so that when the well is restarted the production rate and velocity are higher and the well can "unload" liquids through the normal production route to sales;
- **Velocity strings:** Installing a smaller diameter tubing string in the well that increases the flow velocity at a given production rate sufficiently to drag liquids up the wellbore and prevent liquid loading; and
- **Surfactants and foaming agents**: Introducing surfactants and foaming agents to the bottom of a well (various techniques are used) creating foam with lower specific gravity which enables liquids to be carried up the wellbore at lower velocities.

Eventually a well will reach a point where the reservoir energy is not sufficient to remove the liquids from the well and adding energy to the well is necessary to continue production. Three common methods are:

- Installing a plunger lift system, which uses differential pressure between the bottom-hole and the surface/gas collection line instead of velocity to remove liquids. A plunger lift consists of a plunger that is dropped down the well bore when the gas pressure declines to a predetermined set point. A valve on the plunger allows gas and liquid to pass through the plunger as if falls. When the plunger reaches the bottom, the valve is automatically closed, and gas pressure in the well below the plunger accumulates until the plunger and fluid column above it are lifted to the top of the well bore. The plunger is caught at the top of the well bore and held until the gas pressure decreases to the point the plunger is released down into the well, and the cycle is repeated. The plunger lift can be operated automatically, and it eliminates the need to vent the well unload fluids.

- Installing wellhead compression that lowers the surface back-pressure on a well to increase the differential pressure between the reservoir and the collection/sales line, and therefore increase production rate and flow velocity.
- Installing a downhole positive displacement reciprocating rod pump with a surface pumping unit to pump liquids from the well bore, or installing a submersible electric liquids pump. These options (sometimes referred to as "artificial lift") are generally used when there is insufficient pressure to operate a plunger lift. These pumping units can eliminate the need to vent the well to unload fluids.

There are a number of different pump types and gas lift systems, each more effective in some respects than others. Installation of a system to add energy to a well is an economic decision based on whether the continuing production will be sufficient to support the costs of installing and operating a pump or gas lift system.

VOC emissions from liquids unloading operations occur when the well is vented to the atmosphere to unload fluids or when the liquids are unloaded through atmospheric tanks and the gas mixed with the liquid is vented to the atmosphere. To reduce emissions and waste of gas during manual (i.e., non-automated) liquids unloading activities, operators can monitor manual liquids unloading events onsite within close proximity to the well or via remote telemetry to ensure that the well returns to normal production operation as soon as possible.

<u>Proposed Rule Requirements for Liquids Unloading</u>

Section 20.2.50.117 requires the owner or operator of a natural gas well to use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

- Reduce wellhead pressure before blowdown;

- Monitor manual liquid unloading in close proximity to the well or via remote telemetry; and
- Close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

The owner or operator of a natural gas well is required to use one of the following methods to reduce emissions during an unloading event:

- Installation and use of a plunger lift;
- Installation and use of artificial lift (e.g., a positive displacement rod pump or a submersible pump); or
- Installation and use of a control device.

Monitoring, recordkeeping, and reporting requirements are proposed to ensure the owner or operator is properly performing liquid unloading operations and down-hole well maintenance in a manner that meets the emissions reduction requirements in Part 50. The monitoring requirements include monitoring well-head parameters and performing VOC volume and mass calculations during an unloading event. Owners and operators are required to maintain records of well location and ID number, liquid unloading dates, wellhead pressure, vented gas flow rate (to the extend feasible), duration of venting event, VOC management practice used before and during liquid unloading, device used to control VOC emissions during unloading, and calculation of VOC emissions vented during unloading. The VOC calculation is based on the duration, volume, and mass of the VOC.

Owners and operators must also comply with the general monitoring, recordkeeping, and reporting requirements in Section 20.2.50.112.

Basis for Proposed Requirements

The proposed operational requirements and best management practices for limiting VOC emissions during natural gas well liquids unloading events are based on requirements in Colorado Reg. 7, Pennsylvania GP-5 and GP-5A, and the Wyoming Permitting Guidance.

Colorado Reg. 7, Sec. II.G.1, requires owners and operators to "use best management practices to minimize hydrocarbon emissions and the need for emissions from the well associated with …, well liquids unloading, … unless emitting is necessary for safety." The owner/operator must first use any means of creating differential pressure to attempt to unload the liquids from the well without emitting; if these methods are not successful, the well is permitted to emit to the atmosphere in order to create the necessary differential pressure to bring the liquids to the surface. The owner/operator is required to "be present on-site during any planned well liquids unloading and must ensure that any emissions from the well associated with the event are limited to the maximum extent practicable." Finally, the owner/operator is required to keep records of the unloading event, as well as an estimate of the amount of emissions. *See* NMED Exhibit 39.

Pennsylvania GP-5 and GP-5A, Condition 2.L.1, requires the owner/operator conducting wellbore liquids unloading operations to:

> [U]se best management practices including, but not limited to, plunger lift systems, soaping, swabbing, unless venting is necessary for safety to mitigate emissions during liquids unloading activities. In all cases, where technically feasible and safe, the owner or operator shall direct the gas generated during liquids unloading to a control device, a gas production line or existing separator or storage vessel which is controlled.

The owner or operator is also required to keep records of each liquids unloading operation, including the technique used, the disposition of the associated gas, the duration of the event, and an estimate of the emissions. *See* NMED Exhibits 37 and 38.

The Wyoming Permitting Guidance requires that owners/operators minimize VOC emissions to the extent practicable during manual and automated blowdown/venting episodes associated with liquids unloading. Personnel are required to remain on site to ensure minimal gas venting occurs during manual blowdown or venting. The Guidance states that permits will include requirements to keep records of the unloading event, as well as an estimate of the emissions. *See* NMED Exhibit 40, at p. 13.

Estimated Emissions Reductions

Emission estimates for liquid unloading operations were included in the emissions inventory used in the ozone modeling conducted as part of this rulemaking. The inventory estimated 13,020 tpy of VOC emitted from gas well liquids unloading events. No data on liquid unloading operations are found in the NMED Equipment Data.

A review of EPA's 2019 Greenhouse Gas Reporting Program Data (40 CFR part 98, Subpart W) indicated that 97% of gas wells in the Permian and San Juan basins that require liquids unloading currently employ plunger lifts.[17] These data are summarized in the following table.

[17] GHGRP data available at: https://enviro.epa.gov/index.html

Subpart W-2019 Liquids Unloading Data for San Juan and Permian Basins in New Mexico

Parameter	San Juan - NM	Permian – NM	Totals
Total # Gas Wells	17,536	2,929	
% of gas wells requiring liquids unloading	26.4%	2.2%	
% of gas wells requiring liquids unloading - Vent Using Plunger Lifts	25.9%	0.3%	
% of gas wells requiring liquids unloading - Vent Without Using Plunger Lifts	0.5%	1.9%	
Wells that require liquids unloading that have a plunger lift			
# Wells With Plunger Lift	4,544	10	4554
% With Plunger Lift	98%	15%	97.1%
Wells that require liquids unloading that do not have a plunger lift			
# Wells - Non-Plunger Lift	82	55	137
% Non-Plunger Lift	2%	85%	2.9%

A 2016 analysis estimated that installation of plunger lifts would reduce emissions by 95%. *See* NMED Exhibit 72 - ICF International, *Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems*, (May 2016) ("ICF Economic Analysis"). Using this estimated percentage reduction, ERG estimated that installation of plunger lifts on the remaining 2.9% of wells requiring liquids unloading that currently do not employ this technology would result in reductions of 4,272 tpy of VOC, or 36% of the baseline VOC emissions.

No estimates are available to quantify the reductions expected from implementation of the proposed best management practices requirements under Part 50.

Estimated Costs

Section 20.2.50.117 requires the use of best management practices to minimize the frequency of and emissions from natural gas well liquids unloading events. The rule also requires an owner or operator to use plunger lifts, artificial lift (i.e., positive displacement pumps or submersible pumps), or a control device during liquids unloading events to minimize emissions. The ICF Economic Analysis estimated that costs associated with installation of a plunger lift include capital costs of $20,000 and operating costs of $2,400. *See* NMED Exhibit 72, at p. 2-8.

In a 2011 report, EPA estimated that the payback period for installing a plunger lift could be from 1 to 8 years, depending on the value of natural gas and well-specific parameters. *See* NMED Exhibit 73 – EPA report, *Lessons Learned from Natural Gas STAR Partners – Options for Removing Accumulated Fluid and Improving Flow in Gas Wells* (2011). EPA has further found that the advantages of a plunger lift, in addition to reduced VOC and methane emissions, include increased productivity and reduced well maintenance, such as treatments to remove scale and paraffin. *See* NMED Exhibit 74 – EPA report, *Lessons Learned from Natural Gas STAR Partners – Installing Plunger Lift Systems in Gas Wells* (2006).

Section 20.2.50.118 – Glycol Dehydrators

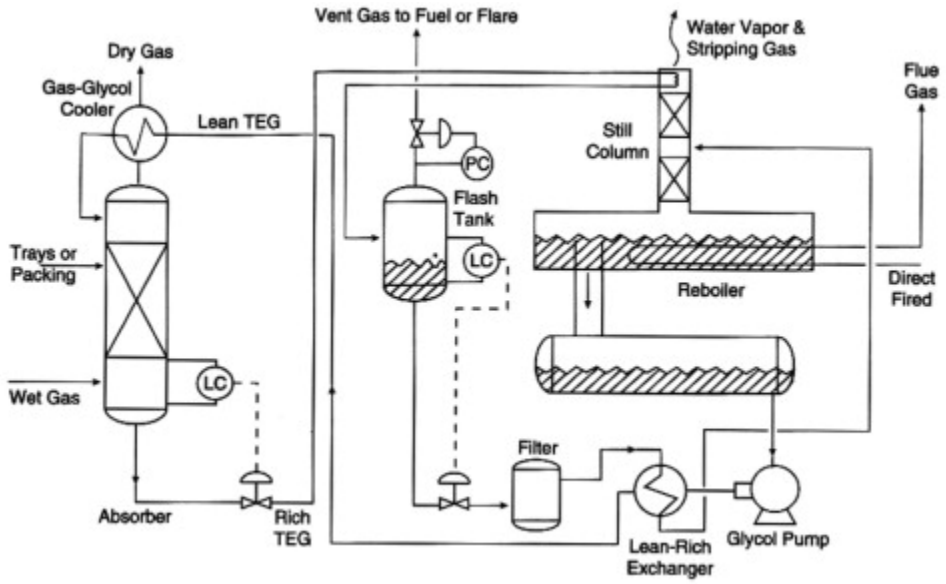
Applicability

Section 20.2.50.118 applies to glycol dehydrators with a PTE equal to or greater than two tons per year of VOC and are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

Description of Glycol Dehydrator

A glycol dehydrator is a liquid desiccant system for the removal of water from natural gas and natural gas liquids. Triethylene glycol is the most commonly used desiccant in these systems. Failure to remove water results in formation of crystalline hydrates at the high pressures used to transport the gas. Hydrates can block pipelines, jam valves, and can generally wreak havoc on pipeline equipment and instrumentation. In the glycol dehydrator, the triethylene glycol absorbs water and VOCs from the gas. The triethylene glycol is then regenerated by heating it to release the absorbed compounds. The reboiler from a large glycol dehydrator can discharge more than one hundred tons per year of VOCs, including benzene, toluene, ethylbenzene and xylene (collectively known as "BTEX").

The actual setup of a glycol dehydrator system can vary amongst manufacturers, but the following description outlines the basics. Wet gas typically passes first through an inlet separator to remove natural gas liquids, which are then stored prior to further processing to separate the components of the gas. The wet gas is introduced into the bottom of a contact tower, and dry, lean glycol flows down the tower from the top. Contact of the two streams is enhanced through the use of tower trays or packing material. The inlet gas is stripped of water and VOCs as it travels up the tower, and becomes drier as it rises. The glycol absorbs more water as it travels down the tower, becoming "rich" or wet glycol. The dehydrated gas, may at this point, pass through a heat exchanger with lean glycol to reduce the temperature of the dry, lean glycol from the surge tank before it is introduced to the contact tower. The dry gas is returned to the pipeline as pipeline-quality natural gas, or goes to other processing units for the recovery of natural gas liquids. The rich glycol exits the tower at the bottom and passes through a filter prior to entering the glycol pump to help reduce wear on the glycol pump.



(Image from ScienceDirect.com)

After leaving the glycol pump, the rich glycol may enter a phase separator, also referred to as a flash tank. As the rich glycol enters the flash tank, its pressure is reduced to atmospheric pressure, and the glycol is separated from contaminants, lubricating oil, free water and condensate. The flashed gas, comprised of VOCs, exits through a vent to atmosphere, or is used as fuel, flared, or used as a stripping gas to aid in the regeneration process.

The glycol regenerator, or reboiler, is comprised of two pieces – the reboiler and surge tank. The reboiler is gas-fired, and is equipped with a baffle to ensure that the glycol contained inside covers the fire tube. Burner exhaust is vented to the atmosphere, and consists of products of combustion.

The rich glycol enters the regenerator through a packed still column. The rich glycol hits the preheated glycol in the reboiler, and water flashes off as steam and goes back through the still column, while the glycol drops back into the reboiler. The regenerated glycol then flows over the baffle and into the surge tank. From the surge tank, the lean glycol is pumped back to contact tower for reuse.

The regenerator off-gas is either vented to the atmosphere, or sent to a condenser or thermal oxidizer. Because of their high solubility, most of the BTEX compounds are not flashed from the glycol at the flash tank, but instead are separated from the glycol in the regenerator.

Control Options for Glycol Dehydrators

There are a number of options available to owners and operators of glycol dehydrators for controlling emissions. Still vent and flash tank emissions can be routed at all times to the reboiler firebox (for use as fuel), a condenser, combustion control device, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a vapor recovery unit (VRU) that reinjects the VOC emissions back into the process stream or a natural gas gathering

pipeline. See testimony regarding control devices (Section 20.2.50.115) for a discussion of VRUs. A combustion control device is either a flare or an enclosed combustor. A condenser uses water, air, or another coolant to lower the temperature of the vent gases and cause the vapors to condense from gas to liquid phase where they can be collected. Costs were estimated for condensers and combustion control devices because existing cost estimates are readily available and are more universally applicable. Costs for other control options are more site-specific and standardized cost estimating methods are not readily available.

Proposed Rule Requirements for Glycol Dehydrators

Section 20.2.50.118 requires owners and operators of existing dehydrators with a PTE greater than 2 tpy VOC are required to reduce VOC emissions from the still vent and flash tank by at least 95% no later than two years after the effective date of the rule. Owners and operators of new glycol dehydrators with a PTE greater than 2 tpy VOC are required to reduce VOC emissions from the still vent and flash tank by at least 95% upon startup. For both new and existing dehydrators, the combustion device (if used) must meet a minimum 98% destruction efficiency.

Still vent and flash tank emissions must be routed to a control device, a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline. If a VRU is used, the VRU must be operational at least 95% of the time, resulting in a minimum combined capture and control efficiency of 95%. The requirements of Section 20.2.50.118 cease to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol dehydrator are less than 2 tpy VOC.

Section 20.2.50.118 contains monitoring, recordkeeping, and reporting requirements that ensure affected sources are being properly operated and maintained in a manner that meets the emissions reduction requirements in Part 50. The monitoring requirements include conducting an annual extended gas analysis to determine the composition of the gas being processed by the dehydrator. Owners and operators are required to use this gas analysis to calculate the uncontrolled and controlled emissions from the dehydrator. This calculation will demonstrate whether the 95% emission reduction requirement is met.

Owners and operators are required to inspect dehydrators and control devices or processes semi-annually to ensure integrity of the equipment and that the equipment is being operated as initially designed and in accordance with manufacturers specifications.

Owners and operators must also meet the monitoring requirements of Sections 20.2.50.112 (general requirements) and 20.2.50.115 (control devices).

Records of equipment throughput data, emissions calculations and supporting documentation, inspection results, and manufacturer information are required to be maintained onsite and submitted to the Department upon request.

Basis for Proposed Requirements

The proposed requirements in Section 20.2.50.118 are based on similar requirements for dehydrators adopted by Colorado and Pennsylvania, as well as federal regulations. The applicability threshold of 2 tpy of VOC is based on the applicability threshold for individual dehydrators in Colorado Reg. 7, Sec. II.D). However, Section 20.2.50.118 does not incorporate the Colorado applicability specification that the total VOC from all dehydrators at a site (counting only those with VOC emissions greater than or equal to 1 tpy) must also be greater than or equal to 15 tpy. If the site-wide applicability threshold of 15 tpy used in Colorado were

adopted in Part 50, the number of sites with glycol dehydrators subject to regulation would be reduced by about 60 percent, but the total VOC from glycol dehydrators subject to regulation would be reduced by 25 percent. Therefore, the Department is proposing an applicability threshold of 2 tpy VOC emissions per dehydrator in order to maximize potential VOC reductions. *See* NMED Exhibit 75 – Dehydrator 15 tpy Cutoff Analysis Spreadsheet.

Pennsylvania GP-5 and GP-5A, both at Section B, have a threshold of greater than or equal to 2.7 tpy for dehydrators. *See* NMED Exhibit 37, at p. 11; NMED Exhibit 38. at p. 10. The proposed capture and control efficiency of 95% for emissions from an uncontrolled dehydrator's still vent and flash tank is taken from the federal National Emissions Standards for Hazardous Air Pollutants ("NESHAP") regulations for emissions from glycol dehydrators, 40 CFR Part 63, Subpart HH ("NESHAP Subpart HH"), Section 63.765, requiring controls for VOCs.

Emissions from dehydrators are typically controlled with either a condenser or a combustor (enclosed flare).

Estimated Emissions Reductions

The NMED Equipment Data indicates that there are 571 active glycol dehydrators located in the Subject Counties, or that are considered "Portable" units. Of these dehydrators, 341 glycol dehydrators at 230 unique sites have allowable emissions equal to or greater than 2 tpy of VOC. The NMED Equipment Data indicates that 199 of these dehydrators currently do not have VOC emissions controls, and of these 199 dehydrators, 93 are not subject to NESHAP Subpart HH; thus, those 93 dehydrators would be required to control emissions under Part 50. For uncontrolled dehydrators that are subject to NESHAP Subpart HH, ERG assumed that these facilities are complying with those regulations by optimizing the glycol recirculation rate, which

the background document for NESHAP Subpart HH assumed would reduce emissions by 48%. ERG assumed that facilities without add-on controls and not subject to NESHAP Subpart HH would achieve a 95% emission reduction, and the uncontrolled facilities subject to NESHAP Subpart HH would achieve an incremental emission reduction of 47% (i.e., 95% - 48%) by installing add-on controls. An emission reduction of 0% was assumed for dehydrators that already have add-on controls for VOC. *See* NMED Exhibit 76 – Memo from Heather Brown, P.E., to Greg Nizich, *Impacts of Applying Management Practices to a Single Oil and Natural Gas Production Area Source Facility*, EPA Docket No. EPA-HQ-OAR-0238-0061 (December 21, 2006) at Table 1.

Adding controls to dehydrator units would reduce emissions by 1,865 tpy, leading to a 46.2% overall reduction in VOC emissions from dehydrators. These reductions are calculated starting from a baseline calculated as the total allowable emissions for all 577 dehydrators. *See* NMED Exhibit 77 – Dehydrators Reductions and Costs Spreadsheet.

Estimated Costs

The annualized costs of emission reductions for glycol dehydrators were calculated by applying the control costs for either condensers or combustors to each of the 199 uncontrolled dehydrators. Condenser costs are taken from two memos in the EPA rulemaking docket for the 2007 amendments that added regulations for dehydrators at lower emitting "area" source facilities to the existing regulations for higher emitting "major" source facilities, codified at 40 CFR 63, Subpart HH. *See* NMED Exhibit 78 – Memo from Heather Brown, P.E., to Greg Nizich, *Revised Impacts from Area Sources in the Oil and Natural Gas Production Source Category*, EPA Docket No. EPA-HQ-OAR-2004-0238-0002 (June 25, 2005); NMED Exhibit 79 – Memo from Heather Brown, P.E., to Greg Nizich, *Impacts of the Final Standards for Oil and Natural Gas Production*

Area Sources, EPA Docket No. EPA-HQ-OAR-2004-0238-0055 (December 21, 2006). Those costs were updated to 2019 costs using the CEPCI. Combustor costs are taken from the 2018 Technical Support Document for the rulemaking proceedings on Pennsylvania GP-5 and GP-5A. *See* NMED Exhibit 52. These costs were updated to 2019 costs using the CEPCI.

Based on ERG's research and analysis, the annualized cost for installing and operating a condenser is estimated to be $21,560. The annualized cost for installing and operating a combustor is estimated to be $10,583. The total annualized costs of adding condensers to the 199 dehydrator units would be approximately $4,300,000 per year, while the total annualized costs of adding combustors to the 199 dehydrator units would be approximately $2,100,000 per year. Costs for both condensers and combustion controls are presented for information purposes, although for each dehydrator the owner of operator would install either a condenser or a combustor, not both.

Section 20.2.50.119 – Heaters

Applicability

Section 20.2.50.119 applies to natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

Description of Equipment and Process

Natural gas-fired heaters are used throughout the oil and gas production and processing sectors to prevent equipment from freezing and being blocked by the formation of ice or hydrates; to improve the separation of well products into oil, water, and natural gas; and in certain types of process equipment, such as glycol dehydrators.

A 'heater treater' is a heated vessel that separates the natural gas and liquids coming from a well into a natural gas stream, an oil/condensate stream, and a produced water stream. The heater treater uses heat to break the oil/condensate-water emulsion coming from the well so the oil/condensate can be accepted by the pipeline or for tanker transport.

Heaters may also be used to prevent the formation of ice and natural gas hydrates that can form under the high pressures associated with the gas well production process. These solids can plug the wellhead and other equipment where there is a drop in pressure and/or temperature as the liquids and gas are removed from the well and processed downstream. Since the wellhead is fitted with a device (a "choke") to restrict the flow of the oil and gas from the well, temperatures within the wellhead may drop due to the pressure changes caused by the choke – i.e., as the gas pressure drops, the temperature of the equipment also drops and can reach temperatures well below freezing. This may cause the water or hydrates to freeze and plug the wellhead, resulting in slowing or stopping the condensate and gas production.

Heaters are also used to regenerate certain process materials used in oil and gas production so they can be used again. For example, a heater is used in ethylene glycol dehydrators to remove water from the glycol by heating the glycol and causing the water to evaporate from the glycol. Heaters are also used to regenerate dry desiccants (water absorbing materials) that are used in some types of natural gas dehydrators in place of ethylene glycol.

Natural gas-fired hot oil (or thermal) heaters may be used in combination with heat exchangers to warm a secondary fluid that may be gas or liquid, for example amine that is used in gas processing plants for the removal of H_2S and CO_2 from field gas. Hot oil heaters may also be used to provide heat for regenerative gas heaters which are used to drive water from molecular sieves within the gas dehydration process.

Control Options for Heaters

NO_X emissions from heaters may be controlled through combustion modifications that reduce the formation of NO_X; through the use of add-on controls to control NOx in the exhaust stack; or through a combination of combustion modifications and add-on controls. Combustion modifications include low-NO_X burners ("LNBs"), ultra-low NO_X burners ("ULNBs"), and flue gas recirculation ("FGR"). Add-on controls include selective noncatalytic reduction ("SNCR") and selective catalytic reduction ("SCR"). In addition to combustion modifications and add-on controls, many regulatory programs require periodic equipment tune-ups and good combustion practices to keep heaters operating at maximum efficiency in order to reduce emissions. Good combustion practices are also important in controlling CO and VOC emissions.

Proposed Rule Requirements for Heaters

Section 20.2.50.119 limits existing and new natural gas-fired heaters to 30 ppmvd NO_X at 3% oxygen, and 300 ppmvd CO at 3% oxygen. Existing heaters must comply with these standards no later than one year after the effective date of Part 50, while new heaters must comply upon startup. Owners and operators of heaters subject to this Section are required to install an EMT on the heaters in accordance with Section 20.2.50.112.

Owners and operators are required to conduct emission testing for NO_X and CO within 180 days of the applicable compliance date, and at least every two years thereafter. The equipment must be inspected, maintained, and repaired in accordance with the manufacturer's specifications at least once every two years after the applicable compliance date. An owner or operator may deviate from the specified periodic testing procedures by submitting a written request to use an alternative procedure to the Department at least 60 days prior to performing the periodic testing, but must receive written approval from the Department prior to conducting periodic testing using an alternative procedure.

Owners and operators are required to maintain records of the following information: location of the heater; summary of the complete test report and results of periodic testing; and inspections, testing, maintenance, and repairs. The owner or operator must comply with the general reporting requirements in Section 20.2.50.112.

Basis for Proposed Requirements

The proposed NO_X and CO limits are based on limits adopted by the State of Pennsylvania and EPA for natural gas fired combustion units. The NO_X limits are the same as those in the Pennsylvania GP-5 requirements for natural gas-fired combustion units. *See* NMED Exhibit 37 at Section L, p. 24. The CO limits are the same as those in the federal regulations at 40 CFR 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* ("NESHAP Subpart DDDDD"). *See* NMED Exhibit 80. CO is commonly regulated as a surrogate for VOC or organic hazardous air pollutants ("HAP") because CO is a good indicator of incomplete combustion and VOC and HAP are products of incomplete combustion. EPA used CO limits instead of hazardous air pollutant limits in NESHAP Subpart DDDDD because it "concluded that CO, which is less expensive to test for and monitor, is appropriate for use as a surrogate for non-dioxin organic HAP." *See id.*, at p. 52210.

Estimated Emissions Reductions

Based on the NMED Equipment Data, ERG identified 337 facilities with heaters in the Subject Counties, and heaters that are listed as portable heaters. These heaters include separator heaters, heater treaters, glycol dehydrator reboilers, and fractionation column heaters. The data include 698 heaters with annual allowable NO_X emission limits that were used to estimate emissions reductions. The total allowable NO_X emissions from these 698 heaters are 1,355 tpy NO_X, and this was considered the baseline. Of the 698 heaters, 82 have a heat input equal to or

greater than 10 MMBtu/hour and would be subject to Part 50. These 82 heaters have total allowable NO_X emissions of 799 tpy.

ERG then examined the effect of implementing the proposed regulations on reducing NOx emissions. For purposes of this analysis, ERG assumed that there would be no additional reductions for units already subject to a federal New Source Performance Standard ("NSPS"). For any non-NSPS units, ERG estimated NO_X reductions of 50%, based on the use of low-NOx burners ("LNB"). *See* NMED Exhibit 81 – EPA, *Technical Bulletin: Nitrogen Oxides (NOx), Why and How They Are Controlled* (November 1999), at Table 16.

As a result of this analysis, ERG estimated total reductions of 216 tons per year of NO_X for an overall reduction of 16% from the baseline of 1,355 tpy NOx. *See* NMED Exhibit 82 – Heaters Reductions and Costs NO2 Spreadsheet.

Estimated Costs

ERG calculated estimated annualized costs to meet the proposed emission limits by assuming that all non-NSPS units would need to install LNB technology at an estimated average total annual cost of $9,250 ($1991) per heater, according to the EPA's Alternative Control Techniques Document – NOx Emissions from Process Heaters, Table 6-2 – NOx Emissions from Process Heaters *See* NMED Exhibit 109, EPA Office of Air Quality and Standards, *Alternative Control Techniques Document – NOx Emissions from Process Heaters*, EPA 453/R-93-034 (September 1993) (excerpt), p. 6-13. These costs were updated to reflect 2019 costs of $15,553 per heater using the CPECI of 361.3 for 1991 and 607.5 for 2019. The 2019 annualized cost per heater is therefore estimated as:

$9,250 per heater * (607.5/361.3) = $15,533 per heater.

Based on the NMED Equipment Data, a total of 44 units would require this technology, for a total annualized cost of approximately $684,341. Based on the emissions reductions of 216.4 tons per year of NO_X, the cost effectiveness of reducing emissions through the use of LNB to meet the required emission limits would be $3,162 per ton of NO_X reduced.

Section 20.2.50.120 – Hydrocarbon Liquid Transfers

Applicability

Section 20.2.50.120 is applicable to hydrocarbon liquid transfer operations (or hydrocarbon liquid loading) at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

Description of Process

Hydrocarbon liquid transfers involve moving hydrocarbon liquid from a transfer vessel to a storage tank, or from a storage tank to a transfer vessel. There are three primary methods of vessel loading: splash loading, submerged fill pipe,[18] and bottom loading. For splash loading, the fill pipe is lowered only part way into the vessel, and the resultant splashing generates VOC emissions. In submerged fill pipe loading, the fill pipe will extend close to the bottom of the vessel. In bottom loading, a permanent fill pipe is connected at the bottom of the vessel. Both submerged fill pipe loading and bottom loading reduce the generation of VOC emissions. During the transfer of hydrocarbon liquids from one vessel to another, the remaining VOC-containing vapor from the previous contents of the vessel will also be vented as the vessel is filled.

Control Options for Hydrocarbon Liquid Transfers

The options typically used to reduce VOC emissions from hydrocarbon liquid transfers are similar those for storage tanks, and include:

[18] A pipe inserted into a tank to facilitate loading.

(1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – "route to a process" (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite; and/or

(2) route emissions from the storage vessel to a combustion device.

In practice, many operators use a single, common VRU system or combustion device to control emissions from both hydrocarbon liquid transfers and storage tanks.

In addition to these control options, emissions from hydrocarbon liquid transfers are also commonly controlled using vapor balancing service, whereby the vapors in the tanker truck or railcar are routed back into the storage vessel as the liquids in the storage vessel are emptied into the receiving vessel (the truck or railcar). Vapor balancing requires a pipe or hose connected between the storage vessel and the receiving vessel prior to transfer. Bottom loading and submerged filling are additional best management practices used to reduce emissions from hydrocarbon liquid transfers.

Proposed Rule Requirements for Hydrocarbon Liquid Transfers

Section 20.2.50.120 requires owners or operators to control VOC emissions by at least 98% via vapor balance, vapor recovery, or a control device.

If using vapor balance, the rule at 20.2.50.120.B(2)(a) through (e) imposes the following requirements: owners and operators must load displaced vapor back to the vessel being emptied via pipe or hose connected before the start of the transfer operation; transfer cannot begin until the vapor collection and return systems are properly connected; connector pipes, hoses, couplers, valves and pressure relief devices must be free of leaks; liquid and vapor line connections must

be checked for proper connection prior to commencing the transfer operation; and the transfer equipment must be operated at a pressure that is less than the pressure relief valve setting of the receiving vehicle or vessel.

Bottom loading or submerged filling are required; splash loading is not an acceptable method of transfer under the rule.

For all transfer operations, hose and pipe connections must be supported on drip trays to collect any leaks, and the materials collected must be returned to the process or properly disposed of. Leaks must be cleaned and disposed of in a manner that minimizes emissions to the atmosphere, and the material collected must be returned to the process or properly disposed of.

Owners and operators employing a control device to comply with the emission standards of Section 20.2.50.120 are required to comply with the control device requirements in Section 20.2.50.115.

Owners or operators are required to visually inspect the transfer equipment during a transfer operation to ensure that components are not leaking. If leaks are discovered, they must be repaired prior to the next transfer operation. Operations employing a control device must follow the manufacturer's recommend operation and maintenance procedures. An owner or operator using vapor balance, vapor recovery, or a control device to minimize VOC emissions must comply with the monitoring requirements contained in Section 20.2.50.115. All owners and operators shall comply with the general monitoring requirements in Section 20.2.50.112.

Owners or operators of a storage vessel subject to Section 20.2.50.120 must maintain a record of the storage vessel and, if using a control device, records of the type, make and model. The owner or operator must also maintain a record of all required inspections. Records must also be maintained of the annual total hydrocarbon liquid transferred and annual VOC emissions from

each site. On an annual basis, the owner or operator is required to create a company-wide record summarizing the total annual hydrocarbon liquid transferred and the total annual calculated VOC emissions.

Owners and operators must also comply with the general recordkeeping and reporting requirements in Section 20.2.50.112.

Basis for Proposed Rule Requirements

The proposed control and operational requirements are based on requirements in Colorado's Reg. 7, Section II.C.5 (NMED Exhibit 39); Pennsylvania GP-5 and GP-5A (NMED Exhibits 37 and 38); Utah's Rule R307-504 – Oil and Gas Industry: Tank Truck Loading, (NMED Exhibit 83); and Wyoming's presumptive BACT for oil and gas truck loading operations, found in the Wyoming Permitting Guidance (NMED Exhibit 40). As described below, these other states require various best management practices and/or the use of control devices such as enclosed combustors to control emissions from hydrocarbon liquid transfers.

The proposed emission standard in 20.2.50.120.B(1) requiring all hydrocarbon liquid transfer operations to use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-eight percent is based on the following:

1) Colorado Reg. 7, Section II.C.5.a, which requires control of loadout emissions from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment;
2) Pennsylvania GP-5A, Section F, which requires use of a vapor balancing system when removing liquids from the storage vessel;
3) Utah's Rule R307-504-4, which requires using a vapor capture line connected to a control of process with 95% destruction efficiency; and

4) Wyoming's Permitting Guidance, Chapter 6, Sec. 2, which requires a vapor capture line with a collection efficiency of 70% connected to a control device with a destruction efficiency of 98%.

The proposed standard in 20.2.50.120.B(2)(a) through (e) for owners and operators using the vapor balance option (see proposed requirements section above) is based on Colorado Reg. 7, part D, Section II.C.5.a.(iii)(A)-(E). The proposed emission standard in 20.2.50.120.B(3) requiring liquid transfers to use bottom loading or submerged filling is similar to Utah's Rule R307-504-4(1). The proposed emission standards in 20.2.50.120.B(4) and (5) requiring connector pipes and couplers be maintained in a leak-free condition and connections be supported on drip trays during transfer operations is similar to Colorado Reg. 7, part D, Section II.C.5.a.(iii)(E). The emission standards in 20.2.50.120.B(6) requiring liquid leaks be cleaned and disposed in a manner that minimizes emissions to the atmosphere is based on good engineering practices.

Because vapor balancing during transfers from storage vessels to transport vessels returns all vapors displaced from the tanker truck or railcar back into the storage vessel, and because all emissions from storage vessels with a PTE equal to or greater than 2 tpy of VOC are required to be controlled, the emissions attributed to vapor balancing are controlled at the storage tank by the requirements for storage vessels in Section 20.2.50.123. During liquid transfers from trucks and railcars to storage vessels, the vapor balancing requirements would require transfer of displaced vapors back to the trucks/railcars up to the pressure relief limits of these vessels, at which point excess emissions would be controlled by the storage tank control devices. Thus, any excess emissions generated during liquid transfers are controlled.

Estimated Emissions Reductions

Based on the NMED Equipment Data, ERG identified 684 active hydrocarbon liquid transfer operations in the Subject Counties with annual allowable VOC emission limits that allow for emissions reductions estimates. These 684 operations are located at 637 unique facilities. The total allowable VOC emissions from these 684 operations are 4,911 tpy. Of these 684 operations, there are 537 without controls. To estimate reductions, a 98% control efficiency was applied to these operations, resulting in total emissions reductions of 4,263 tpy of VOC for an overall reduction of 86.8%. *See* NMED Exhibit 84 – Transfers Reductions and Costs Spreadsheet.

Estimated Costs

Based on the NMED Equipment Data, ERG identified 537 affected hydrocarbon liquid transfer operations in the Subject Counties that require additional controls. For purposes of estimating costs, ERG assumed that each unique facility with operations requiring control would only require one control device that would be used to control emissions from all affected operations at that facility. There are 493 such facilities. As mentioned previously, many facilities use a common control device to control emissions from both storage tanks and liquid transfer operations. Therefore, ERG assumed that the only facilities that would require controls for purposes of complying with the hydrocarbon liquid transfer operations requirements are those facilities without a current control device and that would not already be required to install a new control device under the storage tank provisions in 20.2.50.123 NMAC. There are 130 such facilities, and the total estimated annualized costs of installing controls at these facilities is $2,283,886. These costs result in an overall cost effectiveness of $536/ton of VOC controlled. The annualized cost includes capital and installation costs, as well as operation and maintenance

costs for installing combustors at the 130 affected facilities. The capital and annual costs per combustor are based on cost figures in the EPA CTG. *See* NMED Exhibit 34 at Table 4-5 – *Total Capital Investment and Total Annual Costs of a Combustor*. Costs were updated to reflect 2019 costs using the CEPCI of 584.6 for 2012$ and 607.5 for 2019$. The 2019 to 2012 cost ratio is therefore estimated as:

607.5/584.6 = 1.04

A detailed breakdown of costs for hydrocarbon liquids transfers is provided in the Transfers Reductions and Costs Spreadsheet (NMED Exhibit 84).

Section 20.2.50.121 – Pig Launching and Receiving

Applicability

Section 20.2.50.121 applies to owners and operators of pipeline pig launching and receiving operations located within or outside of the property boundary of well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

Description of Process

Natural gas passing through gathering pipelines contains VOCs, as well as other impurities such as water and carbon dioxide. As this gas passes through the pipeline system, any change in temperature or pressure may result in development of natural gas condensates in a liquid phase in the pipeline. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of these pipelines, operators insert a device called a "pig" into the pipeline which is swept along the pipeline by the pressure of the existing gas flow. Condensate and any other solid or liquid materials that have formed in the pipeline are pushed along in front of the

pig until it reaches a "receiver," at which point the pig is isolated in an offshoot pipeline segment and any condensates and liquids are drained out of the pipeline. The pig is then reinserted and swept along the next segment of pipeline. Pigs may also be used to create physical separation between different fluids flowing through the pipeline, for cleaning the internal surfaces of the pipelines, inspection of the condition of pipeline walls, and recording information relating to pipelines (e.g., size, location).

Emissions to the atmosphere may occur at both the pig launcher and receiver when the pipeline is opened to insert or extract the pig. Emissions from pigging operations depend on factors such as the launcher or receiver volume, pipeline pressure, the amount of liquid trapped in the pig receiver barrel prior to depressurization, frequency of pigging, and gas composition.

A conventional pig receiver is shown in Figure 1.[19] Pig launchers are very similar in design.

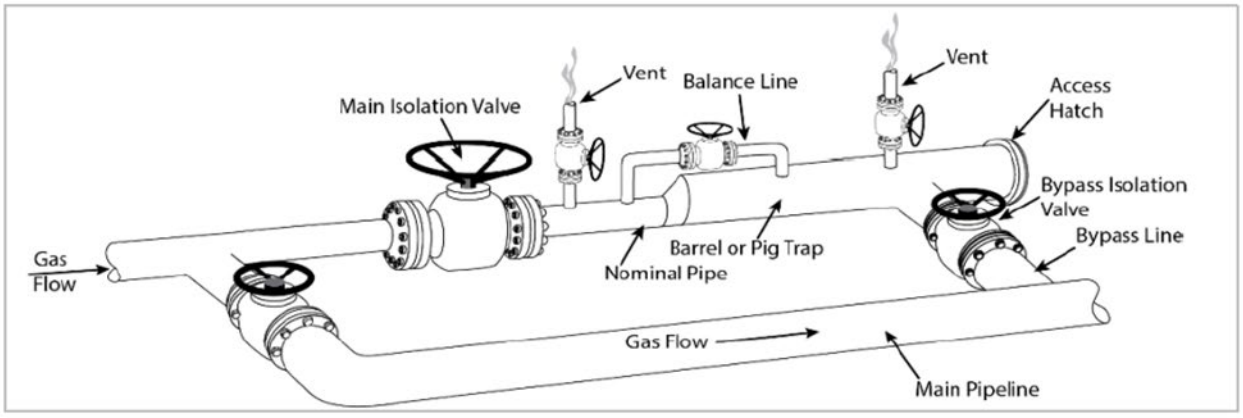


Figure 1 Conventional Pig Receiver

[19] "EPA Observes Air Emissions from Natural Gas Gathering Operations in Violation of the Clean Air Act". Publication no. EPA 325-F-19-001. September 2019.

Control Options for Pig Launching and Receiving

Emissions from pigging operations may be controlled through process modifications, through the use of add-on controls such as a flare, enclosed combustor or thermal oxidizer, or by using a vapor recovery unit (VRU). Process modifications identified by EPA to minimize emissions include:

- *Installing pig ball valves* - Pig ball valves are designed with a smaller sized barrel (or chamber) that launches and receives the pig which reduces the volume of gas that may be vented when the pig launcher or receiver is opened.
- *Receiver Barrel Design: Pig Ramps* - A pig ramp is a device that minimizes the accumulation of condensate in the receiver by directing the movement of the pig and liquid in the barrel to direct the flow of liquid into a bypass line. As part of a recent EPA settlement with midstream operator MarkWest, pig ramps were installed at hundreds of barrels in its wet gas midstream pipeline systems. *See* NMED Exhibit 85 – Consent Decree – *U.S. v. MarkWest Liberty Midstream & Resources, LLC*, No. 2:18-cv-00520-LPL (W.D. Penn., April 24, 2018) ("MarkWest Consent Decree").
- *Route High Pressure Systems to Lower Pressure Lines (Install Jumper Lines)* – Emissions from the opening of pig launchers and receivers can be reduced by routing high pressure gases in the unopened barrel to a lower pressure system before venting the remaining gases to the atmosphere or to control equipment.
- *Barrel Pump-down Systems* - Small fixed or portable compressors are used to pump gases in the receiver or a launcher barrel back into the main pipeline prior to opening the barrel. Barrel pump-down systems can recover greater than 99% of the depressurization vapors from pig launchers and receivers.

- *Enhanced Liquid Containment* - Liquids remaining in a receiver barrel after depressurization can be emptied into a container fitted with an impermeable material to reduce evaporative emissions from the liquids emptied from the barrel.

Additional technical details on pig launching and receiving emissions and mitigation strategies may be found in the MarkWest Consent Decree.

Proposed Rule Requirements for Pig Launching and Receiving

Section 20.2.50.121 requires affected facilities to comply with best management practices and emission limits. Owners and operators of pigging operations with a PTE equal to or greater than 1.0 tons VOC per year are required to capture and reduce VOC emissions by 98%. In addition, owners and operators must employ a suite of best management practices and equipment modifications during pigging operations to prevent or reduce emissions.

Basis for Proposed Requirements

The proposed requirements for pigging operations are based on Pennsylvania GP-5 and GP-5A, and Ohio's General Permit 21.1 for Title V and non-Title V pigging operations ("Ohio General Permits").[20] *See* NMED Exhibits 37, 38, and 86, respectively.

Pennsylvania GP-5A is applicable to sources located at unconventional natural gas well site operations and remote pigging stations, and Pennsylvania GP-5 is applicable to sources located at natural gas compression stations, processing plants, and transmission stations. The best management practices required in the Pennsylvania General Permits are required for all pigging operations. The same best management practices are also recommended in EPA's PRO Fact Sheet No. 505, *Recover Gas from Pipeline Pigging Operations* ("EPA Fact Sheet No. 505") (NMED Exhibit 87),[21] and a September 2019 EPA Enforcement Alert, EPA Publication No.

[20] Available at: https://www.epa.ohio.gov/dapc/genpermit/ngcs/GP_211
[21] Available at: https://www.epa.gov/sites/production/files/2016-06/documents/pigging.pdf

325-F-19-001 (NMED Exhibit 88).[22] The VOC emissions limit in Pennsylvania GP-5 and GP-5A apply to pigging operations that still have emissions equal to or greater than 2.7 tpy after employing best management practices. The Pennsylvania emission limit requires the owner or operator to control VOC emissions from all pigging operations by at least 95% with a control device. *See* NMED Exhibit 37 and 38 at p. 24.

Ohio has similar emission limits for pigging operations in its General Permits. Both general permits limit VOC emissions from one discrete pig launcher or receiver to less than 0.27 tons per month, averaged over a rolling 12-month period (equivalent to less than 3.24 tpy). The Ohio General Permits require use of an add-on control device to control emissions if needed to comply with the VOC emission limitations. *See* NMED Exhibit 86 at p. 4.

Estimated Emissions Reductions

Based on the NMED Equipment Data, ERG identified 10 facilities with pigging operations. However, this is not a complete inventory of pigging operations because they are most often located within other facilities and are not identified separately in NMED's permitting and facility databases. Further, pigging operations are also not quantified separately in the data from EPA's Greenhouse Gas Reporting Program for Petroleum and Natural Gas Systems, 40 CFR § 98, Subpart W.

Of the 10 facilities determined from NMED data, four facilities have five pigging operations with allowable VOC emissions equal to or greater than 1 tpy VOC each. Based on the applicability threshold of 1 tpy VOC, these operations would be required to implement reductions of 98% pursuant to 20.2.50.121.B(1). Total allowable VOC emissions from these five operations are 24.1 tpy, so the total reductions would be 23.6 tpy VOC based on the 98% control

[22] Available at: https://www.epa.gov/sites/default/files/2019-09/documents/naturalgasgatheringoperationinviolationcaa-enforcementalert0919.pdf

requirement. Total emissions from the pigging operations with emissions below the 1 tpy VOC 98% control applicability threshold are 1.6 tpy VOC, resulting in an overall control efficiency of 92%.

Estimated Costs

EPA Fact Sheet No. 505 provides an estimate of the costs and benefits of capturing liquids and gas from pigging operations. *See* NMED Exhibit 87. According to that document, best management practices for recovery of liquids and gas would require separating pigged liquids from the gas, storing the liquids temporarily at gathering system pressure, and then sending them to a low-pressure storage tank. These liquids (recovered at pipeline pressure) would flash and vent light hydrocarbon gases from the storage tanks. The flash emissions would be recovered by installing a dedicated vapor recovery system on the vessel where the liquids are depressurized. The recovered gas would then be sent to the sales line. This process would reduce emissions and add more gas to the sales line. The EPA 505 Fact Sheet states:

> The required equipment to be installed includes an electric or a gas engine driven vapor recovery compressor. A liquid/vapor flash vessel and low-pressure liquid pump may also be required depending on system design and/or ambient temperature and pressure. It is assumed that a pig launcher and receiver on gathering lines, vapor/liquid separation and pressurized liquid storage vessels, and low-pressure liquid storage tanks would already be present on site.

Id. at p. 1-2.

The cost estimates presented in EPA Fact Sheet No. 505 would be appropriate for launching and receiving stations located adjacent to processing plants or pipeline compressor stations that may already have the equipment needed for recovery on-site. In a presentation titled "Vapor Recovery and Gathering Pipeline Pigging" at the July 2008 Producers and Processors Technology Transfer Workshop in Midland, Texas, EPA provided an example from one Natural Gas STAR Program partner that purchased equipment and implemented this process. *See* NMED

Exhibit 89, Slide 35. This company installed a dedicated vapor recovery unit with an electric compressor at an installed cost of $24,000 and an annual operating cost of $40,000 (mostly for electricity). However, based on the value of the condensate recovered, the payback period for the same installation was estimated to be approximately 4 months.

Alternatively, companies may choose to use a temporary skid-mounted flare to meet the control standard for remote pigging operations or pigging operations where the existing infrastructure does not support product recovery. EPA Natural Gas STAR Program's PRO Fact Sheet No. 904, *Install Flares* (2011), provided costs to install and operate a flare at a remote site. *See* NMED Exhibit 90. The estimated implementation cost of a skid-mounted flare is $21,000 and the operating costs per year are $3,000, plus any fuel needed for a pilot light. If the flare were portable, it could be moved to sites on an as-needed basis, with additional cost for transport and set-up added for each pigging operation.

Section 20.2.50.122 – Pneumatic Controllers and Pumps

Applicability

The requirements of Section 20.2.50.122 apply to natural gas-driven pneumatic controllers and pumps, as defined in Section 20.2.50.7, that are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

Description of Equipment and Process

Pneumatic controllers are process control devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves. Natural gas-powered pneumatic controllers use natural gas as motive force to operate valves that regulate safety shut-down, position, fluid level, pressure, temperature and flow rate in oil and natural gas production

and processing. *See* NMED Exhibit 34 (EPA CTG). Pneumatic controllers may also be powered by compressed air instead of natural gas.

Pneumatic controllers are used to control multiple processes based on a sensed process parameter, such as liquid level in a tank or oil-water separator. Pneumatic controllers can be used as emergency shutoff devices, to regulate flow or liquid levels, or as temperature and pressure regulators. An example of the function of a pneumatic controller would be to control the liquid level in a separator. When the liquid level reaches a high set-point in the separator based on the setting of a level gauge, the associated pneumatic controller sends a signal to open the control valve between the separator and the tank. For an emitting pneumatic controller, this signal would consist of pressurized pneumatic gas turning the valve from the "closed" to the "open" position. When the level in the separator reaches a low level, the pneumatic controller sends a signal to the control valves to close and to stop flow from the separator to the tank. *See* NMED Exhibit 10 (MAP Technical Report).

VOC and methane emissions occur from natural gas-powered pneumatic controllers when the pressurized gas is directed to atmosphere after the control action is performed. *See* NMED Exhibit 34 (EPA CTG).

Pneumatic pumps are used to inject chemicals into the wellbore, to circulate glycol in cold climates, and to move liquids from one place to another (sump pumps). Pneumatic pumps range from chemical injection pumps which may inject a few tablespoons of corrosion inhibitor to a well bore, to large diaphragm pumps which move thousands of gallons of product per hour from one tank to another, to pump water out of containment areas after wet weather, or for heat trace to protect pipes from freezing in cold weather. *See* NMED Exhibit 34 (EPA CTG); NMED Exhibit 10 (MAP Technical Report).

VOC and methane emissions occur from pneumatic pumps when the pressurized natural gas used to drive the pumping action is released to atmosphere after being used for the pumping action. The quantity of VOCs emitted is dependent on the type of pump employed and the concentration of VOCs in the gas stream. *See* NMED Exhibit 10 (MAP Technical Report). Depending on their intended use, natural gas-driven pneumatic controllers and pumps are available in a variety of designs, but may be characterized by their bleed rate, which is a measure of how much natural gas is used to operate the pneumatic controller or pump, and therefore the emissions from the pneumatic controller or pump.

Continuous bleed pneumatic controllers have a continuous supply of natural gas to the process controller (e.g., liquid level control, temperature control, or pressure control) and emit or "bleed" natural gas continuously while the natural gas pressure in the controller is balanced against the process condition (e.g., liquid level, temperature, and pressure), and compared with the associated process set-point. When the process condition rises or falls above or below that set point, the pneumatic controller responds to return the process to that predetermined set point. Continuous bleed controllers may either be low bleed (with a bleed or emissions rate less than or equal to 6 standard cubic feet per hour (scfh), or high bleed (with a bleed or emissions rate greater than 6 scfh).

Intermittent pneumatic controllers do not vent continuously, but instead release gas only when they open or close a valve, or as they throttle (i.e, adjust) gas flow. The bleed rate from these controllers depends on the amount of gas vented per actuation (i.e., each opening or closing of a valve or adjustment of gas flow) and the frequency of actuation.

Zero bleed pneumatic controllers do not bleed natural gas at all. They are self-contained units that release gas to a downstream pipeline. *See* NMED Exhibit 91 – EPA Office of Air

Quality Planning and Standards, *Oil and Natural Gas Sector Pneumatic Devices: Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel as part of the President's Climate Action Plan: a Strategy to Reduce Methane Emissions* (April 2014) ("EPA 2014 O&G Pneumatic Devices Report").

Control Options for Pneumatic Controllers and Pumps

There are several ways to reduce emissions from pneumatic controllers, including replacing high bleed controllers with low bleed or zero bleed models, using instrument air rather than natural gas to drive controllers, and using non-gas-driven controllers such as mechanical or electric controllers, including solar-powered controllers. Regular maintenance and proper adjustment of pneumatic controllers can also be used to minimize emissions by repairing leaks and optimizing the amount of gas needed to operate the device. Options for reducing emissions from pneumatic pumps include using instrument air rather than natural gas to drive pumps, using non-gas-driven pumps, such as electric pumps, or routing emissions to a control device or process. *See* NMED Exhibit 92 – EPA Office of Air and Radiation, *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry* (October 2006).

Proposed Rule Requirements for Pneumatic Controllers and Pumps

All new natural gas-driven pumps are required to comply with the emission standards of 20.2.50.122 upon startup. Owners or operators of existing natural gas-driven pneumatic pumps must comply with the emission standards in Section 20.2.50.122 within three years of the effective date of Part 50.

The schedules and targets for replacing existing natural gas-driven pneumatic controllers with non-emitting controllers are contained in Table 1: Well Sites, Tank Batteries, Gathering and Boosting Stations, and Table 2: Natural Gas Compressor Stations and Gas Processing Plants.

The target is based on the number of pneumatic controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of Part 50. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except pneumatic controllers that are necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas.

New pneumatic controllers are required to have an emission rate of zero, as are existing pneumatic controllers with access to commercial line electrical power. Pneumatic controllers with a bleed rate exceeding six standard cubic feet per hour are allowed if the owner or operator has demonstrated to the satisfaction of the Department that a higher bleed rate is required based on functional needs. Natural gas-driven pumps located at natural gas processing plants must have an emission rate of zero. Natural gas-driven pumps located at well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations with access to commercial power must have an emission rate of zero.

Owners and operators of pneumatic pumps at well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations without access to commercial line electrical power are required to reduce VOC emissions from this equipment by 95 percent if it is technically feasible to route those emissions to a control device, fuel cell, or process. If an existing on-site control device is not capable of achieving a 95 percent reduction of VOC emissions, and it is not technically feasible to route pneumatic pump emissions to a fuel cell or process, the owner or operator must route the emissions to the existing control device.

Owners and operators of pneumatic controllers or pumps must install an EMT on each device in accordance with Section 20.2.50.112.

Section 20.2.50.122 contains monitoring, recordkeeping, and reporting requirements that ensure the owner or operator is properly operating and maintaining the affected pumps and controllers in a manner that meets the emissions reduction requirements in the rule. Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring or recordkeeping requirements of Section 20.2.50.122. The owner or operator of any controller subject to the deadlines in this section must monitor the compliance status of each controller at each facility and must develop and record the schedule and compliance status for each controller so that it meets the compliance deadlines.

The monitoring requirements for controllers or pumps with a gas bleed rate greater than zero include monthly AVO, mechanical inspections, and maintenance to ensure VOC emissions are minimized. The owner or operator must maintain an electronic record for each affected controller or pump that contains the ID number, controller type, design continuous bleed rate for continuous controllers, bleed volume per bleed for intermittent controllers, each controller's design annual bleed rate, inspection dates, name of personnel conducting the inspection, AVO inspection result, AVO level discrepancy in continuous or intermittent bleed rate, maintenance date and activity, and a record of the justification for use of a controller with a bleed rate greater than six scfh.

Owners and operators are required to maintain a total count of all emitting and non-emitting pneumatic controllers at affected facilities that commenced operation prior to the effective date of Part 50 and maintain a total count of units necessary for safety or process purposes that cannot be met without emitting VOC.

Electronic records must be maintained for natural gas-driven pneumatic pumps and the associated pump numbers that have emission rates greater than zero. The record must include the

dates of operation for any pump operating less than 90 days per calendar year; any control device designed to achieve at least 95% emission reduction, including an evaluation or the manufacturer specifications indicating percent reduction the control device is designed to achieve; and documents of engineering assessments and certifications from a qualified professional engineer stating that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

The owner or operator must also meet the monitoring, recordkeeping, and reporting requirements in Section 20.2.50.112.

Basis for Proposed Rule Requirements

The proposed rule is based on similar rules for new and existing pneumatic controllers and pneumatic pumps in Colorado Reg. 7, Sections I.K, III.C, and III.D. *See* NMED Exhibit 39.

The emission standard in 20.2.50.122.B(4)(a) requiring all new pneumatic controllers to have an emission rate of zero is based on Colorado Reg 7, Section III.C.1-3. The proposed standard is stricter than the Colorado standard in that it requires all new pneumatic controllers to have a bleed rate of zero. Both rules allow for exceptions where a pneumatic controller with a non-zero bleed rate is required for safety and/or process considerations.

The emission standard in 20.2.50.122.B(4)(b) requiring all existing pneumatic controllers with access to electrical power to have an emission rate of zero is based on Colorado Reg. 7, Section III.C.3.a.(i). Both rules allow for exceptions where this is not technically feasible.

The emission standard in 20.2.50.122.B(4)(c) requiring that a percentage of a company's total number of existing pneumatic controllers be replaced with non-emitting controllers by a certain date is based on a similar provision in Colorado Reg. 7, Section III.C.4. The requirement in 20.2.50.122.B(3) and (4)(c) that a company's "fleet" of pneumatic controllers must be

replaced over time with non-emitting or low-emitting controllers is based on the fact that many high bleed, low bleed, and intermittent bleed devices can be replaced with either non-emitting devices or lower-emitting devices, while allowing for continued use of those non-zero emitting controllers that cannot be replaced for safety and/or process considerations. This approach provides owners and operators flexibility to assess their total operations and reduce emissions from pneumatic controllers in ways they deem most cost-effective.

In 2017, the Colorado Air Quality Control Commission ("COAQCC") established the Statewide Hydrocarbon Emission Reduction ("SHER") team and the Pneumatic Controller Task Force ("PCTF"). The SHER team and the PCTF worked for two years and produced a report on pneumatic controllers in June 2020. *See* NMED Exhibit 93, *PCTF Report to the Air Quality Control Commission: Pneumatic Controller Field Study and Recommendations* (June 1, 2020) ("2020 PCTF Report"). In 2019, the Colorado Legislature passed Senate Bill 19-181 directing the COAQCC to consider requirements to reduce emissions from pneumatic devices. On February 18, 2021, COAQCC amended Colorado Reg. 7, Section III ("2021 Reg. 7 Amendments") to require more stringent standards to reduce VOC emissions from pneumatic controllers. *See* NMED Exhibit 39 (Colorado Reg. 7, Section III). The February 2021 rulemaking was informed by the 2020 PCTF Report.

Among other things, the 2021 Reg. 7 Amendments require the use of non-emitting controllers at new well production facilities and new natural gas compressor stations. *See* Colorado Reg. 7, Section III.C.4.a. The 2021 Reg. 7 Amendments also require companies to develop and submit company-wide plans to convert most of their pneumatic controllers at existing facilities to non-emitting controllers over a two-year period. Colorado Reg. 7, Section III.C.4.b. The percentage of controllers that must be converted is based on the historic percentage

of non-emitting controllers in that company, determined by the company as part of developing their plan. Companies with a lower percentage of non-emitting controllers will have to meet a lower final percentage of non-emitting controllers, but will need to achieve a higher percentage of additional controllers converted to non-emitting. Conversely, companies with a higher percentage of non-emitting controllers will have to meet a higher final percentage of non-emitting controllers but will need to achieve a lower percentage of additional controllers converted to non-emitting. Section 20.2.50.122 proposes similar requirements for controllers at new and existing facilities.

The emission standard proposed in 20.2.50.122.B(4)(d), which allows use of pneumatic controllers with a bleed rate greater than 6 scfm in operations where the controller's use is "required based on functional needs, including response time, safety, and positive actuation," is similar to the exceptions allowed in NSPS Subpart OOOOa, 40 CFR §6 0.5390a(a), and Colorado Reg. 7, Section III.C.3.a.(ii).

The emission standard proposed in 20.2.50.122.B(5)(a), which requires all new and existing pneumatic pumps located at natural gas processing plants to have an emission rate of zero, is similar to the requirement in Colorado Reg. 7, Section I.K.1.

The emission standard proposed in 20.2.50.122.B(5)(b), which requires all new and existing pneumatic pumps located at a well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations with access to commercial line electrical power to have an emission rate of zero, is similar to the requirement in Colorado Reg. 7, Section I.K.1. This requirement is also based on an assumption that, at sites with access to electrical power, it is feasible to replace emitting pumps with non-emitting pumps. This assumption is supported by the fact that data from EPA's Greenhouse Gas Reporting Program ("GHGRP") for Petroleum

and Natural Gas Systems (40 CFR 98, subpart W) indicate that natural gas processing plants, which all have access to electrical power, already have 100-percent non-emitting controllers and pumps.

The emission standard proposed in 20.2.50.122.B(5)(c), which requires all new and existing pneumatic pumps located at a well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations without access to commercial line electrical power to route emissions to a control device, fuel cell, or process if it is technically feasible, is similar to the requirement in CO Reg 7, Sec.I.K.2. Both rules allow exceptions if the requirement is not technically feasible.

The proposed requirement in 20.2.50.122.B(6) that all pneumatic controllers and pumps be tagged with an EMT is similar to the requirement in Colorado Reg 7, Section III.D.2.a, which requires pneumatic controllers located at a natural gas processing plant with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

Estimated VOC Emissions Reductions

Data for the number of pneumatic devices at oil and gas operations in New Mexico was derived from well data providing the number and age of wells, permit data providing the number of other types of (non-well) facilities, and technical papers estimating the number of pneumatic controllers and pumps found at each type of facility and their average VOC emission rates. Although NMED does not have an equipment inventory listing pneumatic controllers or pumps, estimates for the number of pneumatic devices at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and compression/transmission sites were derived

by combining data on the number of each type of site in New Mexico with EPA data on the number of controllers and pumps found at each type of site in the Permian and San Juan Basins.

Well count data came from the Petroleum Recovery Research Center ("PRRC"), which is an organization that provides up to date information on oil and gas production data for New Mexico.[23] Oil and gas production data on the PRRC website has been provided primarily by the New Mexico Oil Conservation Division and is updated on a monthly basis. The data downloaded from the PRRC site represents all producing oil and gas wells in the Subject Counties for the year 2020. See NMED Exhibit 94 – 2020 Producing Wells Spreadsheet. Although NMED has permit data for some wells and storage tanks, these data were not used in the analysis of pneumatic controllers and pumps as it was deemed incomplete because many wells and tanks do not require a permit from NMED. Tank batteries were combined with well sites and both were treated as one site for pneumatic device emission purposes, as these facilities are typically found together at the upstream end of the oil and gas production operations. Facility count data for gathering and boosting stations, natural gas processing plants, and transmission/compression stations came from the NMED Equipment Data. NMED permit data categorizes both gathering/boosting stations and transmission/compression sites as "Compressor Stations," so these two categories were disaggregated by assuming that a "Compressor Station" with a Title V permit is a transmission/compression station and all other "Compressor Stations" are gathering and boosting stations. This assumption was based on the fact that pipeline transmission/compression stations typically have several operating compressor engines or turbines onsite, and therefore are typically major sources of NOx which would require a Title V permit.

[23] Available at: http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx

Based on the NM well count and NMED permit data, there are 27,489 wellheads in the Permian Basin and 20,448 wellheads in the San Juan Basin; 570 gathering/boosting stations in the Permian Basin and 345 gathering/boosting stations in the San Juan Basin; 40 natural gas processing plants in the Permian Basin and 8 natural gas processing plants in the San Juan Basin; and 29 transmission/compression stations in the Permian Basin and 39 transmission/compression stations in the San Juan Basin. See NMED Exhibit 95 – Pneumatics Reductions and Costs Spreadsheet, "Facility Data" tab.

The number of devices per site for low-bleed, intermittent-bleed, and high bleed pneumatic controllers, as well as pneumatic pumps at each of these types of sites, was determined using EPA's GHGRP, Subpart W data for 2019. These counts are based on producer-reported data for the Permian and San Juan Basins. *See* NMED Exhibit 96 – NM Pneumatics Data Subpart W Spreadsheet, "Facility Data" tab. Based on data in Table 2-2 of the EPA 2014 O&G Pneumatic Devices Report, ERG assumed that all controllers and pumps at natural gas processing plants are non-emitting. *See* NMED Exhibit 91.

ERG also assumed that for well sites/tank batteries, gathering/boosting stations, and transmission/compression stations, 20% of all pneumatic devices are already non-emitting. This assumption was made to account for the fact that some non-emitting devices have already been put into service, and to avoid overestimating emission reductions. However, the actual frequency at which non-emitting controllers are used in New Mexico is not known. EPA indicated in the EPA 2014 Pneumatic Devices Report that it has not obtained any information on the prevalence of "zero-bleed" controllers in the field. *See* NMED Exhibit 91 at p. 41. The 2020 PCTF Report indicated that non-emitting controllers were not included in the scope of the 2018 PCTF field study of controllers in the Denver-Julesburg (DJ) Basin because the intent of the study was only

to examine emissions associated with natural gas-driven controllers. *See* NMED Exhibit 93 at p. 6.

The uncontrolled emission rates (also referred to as "emission factors") for low-bleed, intermittent-bleed, and high-bleed controllers, as well as pneumatic pumps, were based on four EPA sources. The emission rate of intermittent bleed devices and the data for VOC emissions from pneumatic devices at gathering and boosting stations comes from Subpart W of 40 CFR Part 98, Table W-1A – *Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities*. *See* NMED Exhibit 97 – 80 Fed. Reg. 64262, *Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems* (October 22, 2015). The data for VOC emission rates from low-bleed and high-bleed controllers in the production segment comes from Table 6-2 of the EPA CTG (NMED Exhibit 34). The data for the VOC emission rate from low-bleed and high-bleed controllers in the transmission segment is from Table 5-2 of U.S. EPA's Technical Support Document for Subpart OOOOa (NMED Exhibit 70). The data for the VOC emission rate from intermittent bleed controllers in the transmission segment comes from Table W–3B to Subpart W of 40 CFR Part 98. *See* NMED Exhibit 98 – 81 Fed. Reg. 86517, *Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems* (November 30, 2016).

The fraction of wells subject to either NSPS Subpart OOOO or OOOOa were determined based on well production dates found in the PRRC well data in the 2020 Producing Wells Spreadsheet. *See* NMED Exhibit 94. NSPS Subparts OOOO and OOOOa require certain pneumatic devices at oil and gas sites constructed after a certain date to be low-emitting or non-

emitting. The NM OCD well data were used to adjust the estimates of current emissions to reflect the fact that certain percentages of sites in the Subject Counties are subject to federal regulations, and thus have lower emissions as a result.

The fraction of pneumatic controllers that cannot be replaced for safety and/or process reasons (12.5%) is based on two technical documents. First, the regulatory analysis for the 2014 amendments to Colorado Reg. 7 assumed that 95% of high-bleed pneumatic controllers could eventually be replaced and 5% are needed for safety or process reasons. *See* NMED Exhibit 71. Second, the Technical Support Document for NSPS Subpart OOOOa assumed an 80% replacement rate for high-bleed pneumatic controllers and 20% are needed for safety or process reasons. *See* NMED Exhibit 70. The estimate of 12.5% of high-bleed controllers that cannot be replaced is the midpoint between the Colorado and the EPA estimates.

The formulas for the emissions calculations for baseline VOC emissions and the VOC emission reductions using the factors described above that would result from the requirements in Section 20.2.50.122 are detailed in the Pneumatics Reductions and Costs VOC Spreadsheet. *See* NMED Exhibit 95.

ERG researched the technical literature and determined the types of replacement pneumatic devices needed to reduce VOC emissions. A primary determinant of the suitability of a replacement device is whether a site already has electric power. ERG estimated the percentage of well sites, gathering/boosting stations, and transmission/compression stations sites in the Subject Counties that have existing electrical power using the NMED Equipment Data. That data indicates that 10.9% of wellhead/tank battery sites, 3.9% of gathering/boosting stations, and 100% of transmission/compression stations have electrical generator engines onsite. Because not all 47,937 well sites are reflected in the NMED Equipment Data, ERG's assumption regarding

access to electrical power at wells is likely an over-estimate of the fraction of wells with access to electric power.

For sites with electric power onsite, information suggests the least expensive option for retrofitting pneumatic devices onsite is to install instrument air. *See* NMED Exhibit 99 – EPA OAR: Natural Gas Star, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air* (October 2006). This involves installing a compressor, air dryer, air tanks, controls, and plumbing to replace the available compressed natural gas that currently powers the onsite pneumatic devices with compressed atmospheric air. Existing pneumatic devices are left in place and the site is re-plumbed to bring compressed air to each pneumatic device. Reductions in VOC emissions resulting from replacement of existing natural gas-powered pneumatic devices with instrument air-powered pneumatic devices are assumed to be 100% because the instrument air is compressed ambient air. ERG assumed that intermittent bleed, low bleed, and high-bleed pneumatic devices could be powered with instrument air systems. This latter assumption is supported by data in the EPA GHGRP for Petroleum and Natural Gas Systems (40 CFR 98, Subpart W) indicating that natural gas processing plants, which all have access to electrical power, already have 100-percent non-emitting controllers and pumps.

For sites without electric power onsite, available information indicates that the least expensive option for retrofitting pneumatic devices onsite is to install solar electric controller systems or solar-powered pumps. This approach is based on: (1) a technical paper prepared by Carbon Limits for EPA's Office of Air Quality Standards, *Zero Emissions Technologies for Pneumatic Controllers in the USA* (2016), attached as NMED Exhibit 110; and (2) EPA's Technical Support Document for NSPS Subpart OOOOa (NMED Exhibit 70). Solar electric systems involve installing solar panels, battery banks and a system controller, and replacing the

pneumatic controllers with electric powered controllers. Reductions in VOC emissions resulting from replacement of existing pneumatic devices with solar electric controllers and pumps are assumed to be 100%. ERG assumed that intermittent bleed, low bleed, and high-bleed pneumatic devices could be powered with solar electric systems. This latter assumption is supported by data from the EPA GHGRP for Petroleum and Natural Gas Systems (40 CFR 98, subpart W) indicating that natural gas processing plants, which all have access to electrical power, already have 100-percent non-emitting controllers and pumps and that commercial line electrical power is equivalent to solar electric power.

The Pneumatics Reductions and Costs Spreadsheet compiled by ERG allows the user to select which reduction options they wish to model for both VOC reductions (tpy) and costs of replacements ($). *See* NMED Exhibit 95, "Emissions and Costs" tab. For each scenario in the spreadsheet (i.e., combinations of Permian/San Juan; Wellhead/Gathering and Boosting/Natural Gas Processing/Transmission and Compression; Low-bleed/intermittent-bleed/high-bleed/pump; Sites with electric/Sites without electric), the user can choose whether to add new replacement controls by selecting '1' or '0' in the spreadsheet. The spreadsheet then generates estimates of the percent reduction in VOC emissions and the cost of that option. This flexibility and programmability allowed ERG to estimate the reductions and costs as the requirements in 20.2.50.122.B(4)(c) are phased in over time. Although there is no single set of choices that fulfils those proposed requirements, ERG modeled a set of choices that roughly approximate the long-term objective of the requirements, specifically, an 80% or greater reduction in the number of emitting controllers at well sites, tank batteries, and gathering/boosting stations and a 98% reduction in the number of emitting controllers at natural gas compression/transmission stations and natural gas processing plants.

Costs of VOC Reductions from Pneumatic Controllers and Pneumatic Pumps

ERG estimated the annualized costs of reducing VOC emissions from the estimated 112,500 emitting pneumatic devices to meet the January 1, 2030 standard proposed in Tables 1 and 2 of 20.2.50.122.B(3) (approximately a 95% reduction in the number of emitting pneumatic devices) is estimated at $86,038,000 per year. ERG estimated that the proposed standard will reduce VOC emissions from pneumatic devices by 90.6% from the baseline of 34,600 tpy VOC.

In estimating costs and emission reductions for emitting pneumatic devices, it is important to note that the estimated total number of pneumatic devices at well sites/tank batteries is essentially an order of magnitude higher than the estimated total number of pneumatic devices at gathering and boosting stations, which is essentially an order of magnitude higher than the estimated total number of pneumatic devices at transmission/compression stations, and it is estimated that there are no emitting pneumatic devices currently in use at natural gas processing plants. Thus, achieving significant reductions in VOC emissions will require replacement of emitting devices primarily at the upstream end of the production chain.

Section 20.2.50.123 – Storage Vessels

Applicability

Section 20.2.50.123 applies to new and existing storage vessels with a PTE equal to or greater than 2 tpy of volatile organic compounds (VOC) and located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or natural gas compressor stations.

Description of Equipment and Process

Storage vessels, commonly referred to as “storage tanks” or “tanks,” are used throughout the oil and gas industry for storing a variety of liquids including crude oil, condensates, and produced water. These tanks are associated with oil and gas production, gathering, processing,

and disposal and are significant sources of VOC emissions. Storage vessels can be installed as a single unit or in a grouping of similar or identical vessels, commonly referred to as a "tank battery." The reason for temporary storage is for feasibility of takeaway via pipeline or truck.

While underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed, and any oil and water remain together) or a three-phase separator (where the associated gas is removed, and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released as vapors in the storage vessels.

Hydrocarbon emissions from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into a storage vessel at atmospheric pressure from a processing vessel (e.g., a separator) operated at a higher pressure. In general, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and the expansion and contraction of stored fluids resulting from increased or decreased pressures associated with environmental and weather-related fluctuations. Working losses occur when vapors are displaced due to the emptying and filling of a storage vessel.

The mass of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming off of the oil. The composition of the vapors from storage vessels varies, and the largest component is methane, but may also include ethane, butane, propane, and hazardous air pollutants such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane.

Control Options for Storage Vessels

The methods typically used to reduce VOC emissions from storage tanks are:

(1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled or recovered (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite; and/or

(2) route emissions from the storage vessel to a combustion device.

One of the clear advantages the "recycling and recovery" option has over the combustion device option is that it results in a cost savings associated with the recycled, recovered, and reused natural gas and other hydrocarbon vapor, rather than the loss and destruction of the natural gas and vapor by combustion. Combustion and partial combustion of organic pollutants also create secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide and smoke/particulates.

The emission control methods are described below along with their emission reduction control effectiveness.

Routing Emissions to a Process via a Vapor Recovery Unit

One option for controlling storage vessel emissions is to route vapors from the storage vessel back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbons for beneficial use, such as use as a fuel. Where a compressor is used to boost the recovered vapors into the line, it is often referred to as a vapor recovery unit ("VRU"). With a typical VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and then piped to a separator or suction scrubber to collect any condensed liquids, which are usually recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various end uses such as a sales line or for use onsite as fuel.

Types of VRUs include conventional VRUs, venturi ejector vapor recovery units ("EVRUTM"), and vapor jet VRUs. Decisions on what type of VRU to use are based on the applicability needs (e.g., an EVRUTM is recommended where there is a high-pressure gas compressor with excess capacity, whereas a vapor jet VRU is recommended where there is produced water, less than 75 million cubic feet (MMcf)/day gas, and discharge pressures below 40 pounds per square inch gauge (psig)). The reliability and integrity of the compressor and suction scrubber and the integrity of the lines that connect the tank to the compressor will impact the effectiveness of the VRU system to collect and recycle vapors. A conventional VRU is equipped with a control pilot to shut down the compressor and allow the back flow of vapors into the tank in order to prevent the creation of a vacuum in the top of a tank when liquid is withdrawn and the liquid level drops. Vapors are then either sent to the pipeline for sale or used as onsite fuel. Figure 1 presents a diagram of a conventional VRU installed on a single crude oil storage vessel (multiple tank installations are also common).

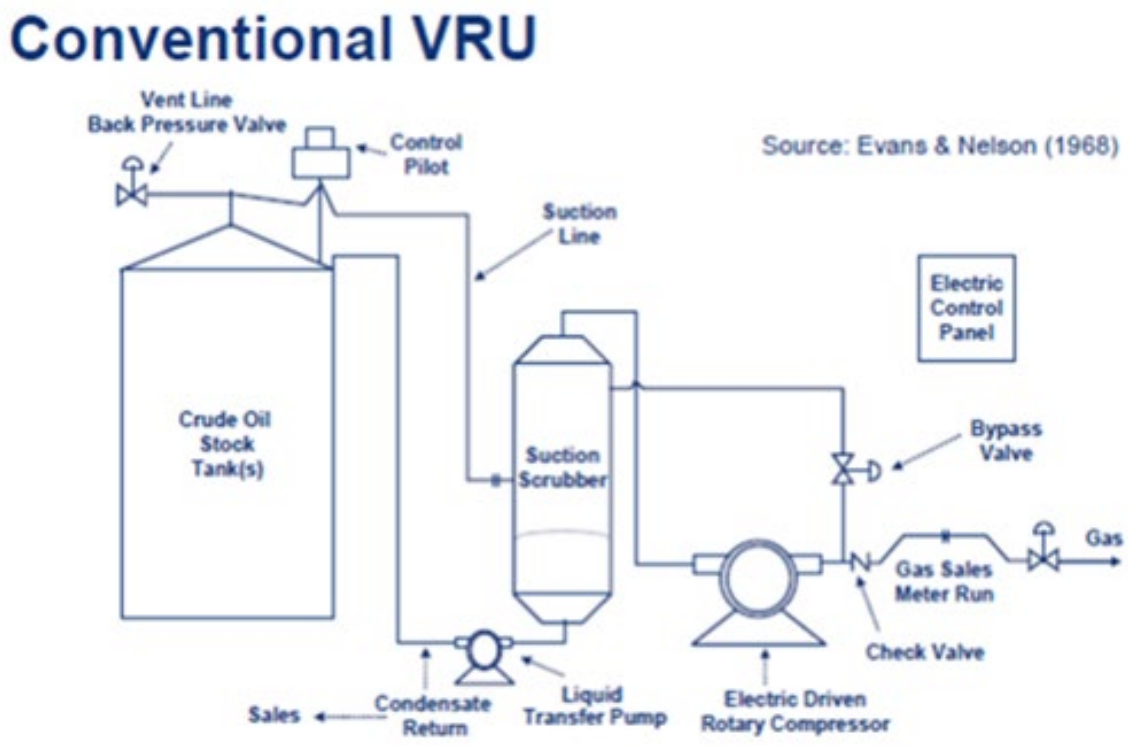


Figure 1. Conventional Vapor Recovery System

Routing Emissions to a Combustion Device

Combustors (e.g., enclosed combustion devices, thermal oxidizers, and flares) are also used to control emissions from storage vessels. Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and the fraction of inert (i.e., noncombustible or unreactive) gas species. For purposes of this analysis, it was assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95% control efficiency on a continuing basis. Note that combustion devices can be designed to meet 98% control efficiencies, and can control on average emissions by 98% on average, or more in practice when properly operated. Combustion devices that are designed to meet a 98% control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions. A typical combustor

used to control emissions from storage vessels in the oil and natural gas industry is an enclosed combustion system. The basic components of an enclosed combustion system include: (1) piping for collecting emission source gases; (2) a single- or multiple-burner unit; (3) a stack enclosure; (4) a pilot flame to ignite the mixture of emission source gas and air; and (5) combustor fuel/piping (as necessary). Figure 2 presents a schematic of a typical dual-burner enclosed combustion system.

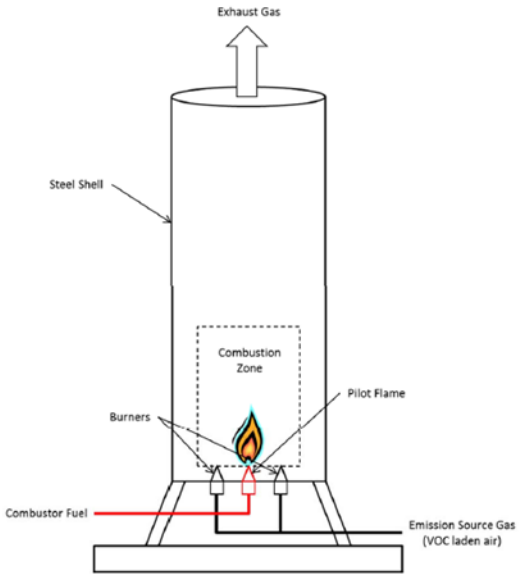


Figure 2. Schematic of a Typical Enclosed Combustion System

Thermal oxidizers, also referred to as direct flame incinerators, thermal incinerators, or afterburners, are also used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC-laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted (i.e., vented) to the atmosphere. *See* NMED Exhibit 34 (EPA CTG).

Proposed Rule Requirements for Storage Vessels

Section 20.2.50.123 requires owners and operators of existing storage vessels with a PTE equal to or greater than 2 tpy and less than 10 tpy of VOCs to maintain a combined VOC capture and control efficiency of at least 95% no later than three years after the effective date of Part 50. Owners and operators of existing storage vessels with a PTE equal to or greater than 10 tpy are required to maintain a combined VOC capture and control efficiency of at least 98% no later than one year after the effective date of Part 50.

Owners and operators of new storage vessels with a PTE equal to or greater than 2 tpy and less than 10 tpy of VOCs are required to maintain a combined VOC capture and control efficiency of at least 95% percent upon startup. Owners and operators of new storage vessels with a PTE equal to or greater than 10 tpy are required to maintain a combined VOC capture and control efficiency of at least 98% upon startup.

The requirements of Section 20.2.50.123 will cease to apply if the uncontrolled actual annual VOC emissions decrease to less than 2 tpy.

Should an owner or operator fail to install a control device by the specified dates, they may comply with the emission standards by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device has been installed and operational.

Owners or operators that employ a control device to comply with the emission standards of Section 20.2.50.123 NMAC are also required to comply with the control device operational requirements of 20.2.50.115 NMAC.

Owners or operators of a new or existing storage vessel equipped with a thief hatch are required to install a device that allows the thief hatch to open sufficiently to relieve vessel

overpressure, and to automatically close once the vessel overpressure has been relieved. The thief hatch must be equipped with a manual lock-open safety device to ensure that the hatch remains open during times of human ingress, and shall only be engaged when an owner or operator is present and during active human ingress.

Owners or operators of any storage vessel subject to this Section must install an EMT on the storage vessel in accordance with Section 20.2.50.112 NMAC.

Owners or operators of a storage vessel subject to Part 50 must comply with certain monitoring requirements, including monthly monitoring of the total monthly liquid throughput and the upstream separator pressure; conducting an AVO inspection on a weekly basis; monthly inspections of the vessel to ensure compliance with Section 20.2.50.123; scanning the EMT and entering the required monitoring data in accordance with the requirements in Section 20.2.50.112; complying with the monitoring requirements in Section 20.2.50.115 if using a control device; and complying with the general monitoring requirements in Section 20.2.50.112.

The recordkeeping requirements in Section 20.2.50.123 include: monthly records of the vessel location and identification number; monthly liquid throughput and the most recent date of measurement; average monthly upstream separator pressure; data and methodology used to calculate the PTE of VOCs; the controlled and uncontrolled VOC emissions; and the type, make, model, and identification number of any control device.

A record of liquid throughput must be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

An owner or operator is required to maintain records of inspections conducted in accordance with Section 20.2.50.123; records required by Section 20.2.50.115 if using a control

device to comply with the emission standards of this Section; and the recordkeeping requirements contained in Section 20.2.50.112.

An owner or operator must comply with the general reporting requirements in Section 20.2.50.112, and must also comply with the reporting requirements of Section 20.2.50.115 if using a control device.

Basis for Proposed Rule Requirements

The proposed requirements are based on similar rules for new and existing storage vessels in Pennsylvania GP-5 and GP-5A, Colorado Reg. 7, and NSPS Subpart OOOOa.[24] *See* NMED Exhibits 37, 38, and 39, respectively.

The applicability threshold in Section 20.2.50.123 is based on Colorado Reg. 7, Section I.D.1.a. The proposed emission standard in 20.2.50.123.B(1) and (3), requiring all existing and new storage vessels with a PTE equal to or greater than 2 tpy VOC to have a combined capture and control efficiency of 95 percent for VOC emissions, is based on Pennsylvania GP-5A, Section E.1.(b) and Colorado Reg. 7, Section I.D.3.a.(i). Pennsylvania GP-5 and GP-5A require an owner or operator to equip the storage vessel with a cover and route all vapor through a closed vent system to a control device that reduces VOC emissions by 95% or more. Colorado Reg. 7 requires owners and operators of existing and new storage vessels with uncontrolled actual emissions of VOCs equal to or greater than 2 tpy to collect emissions and route them to pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC. NSPS Subpart OOOOa has similar requirements, requiring owners or operators of storage vessels with a PTE

[24] U.S. EPA, New Source Performance Standards for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced after September 18, 2015, June 2016. Available at: https://www.epa.gov/stationary-sources-air-pollution/crude-oil-and-natural-gas-facilities-which-construction

equal to or greater than 6 tpy of VOC to reduce VOC emissions by 95%. *See* NMED Exhibit 36, at Sections 60.5365a(e) and 60.5395a(a)(2).

The proposed emission standards in Section 20.2.50.123.B(2) and (4) require that existing and new storage vessels with a PTE equal to or greater than 10 tpy of VOC have a combined capture and control efficiency of 98% for VOC emissions. The standards are based on the requirements of the Pennsylvania GP-5A, Section E.1.(b) and Colorado Reg. 7, Section I.D.3.a.(i), but were adjusted to require additional VOC emissions reductions for those storage vessels with higher VOC emissions (PTE greater than 10 tpy VOC).

Estimated Emissions Reductions

Based on the NMED Equipment Data, ERG identified 3,921 affected storage tanks in the Subject Counties for the year 2020. Of these, 2,059 are uncontrolled and unregulated by NSPS Subpart OOOO and NSPS Subpart OOOOa. Of these 2,059 storage vessels, 53% (1,040 storage vessels) have allowable emissions equal to or greater than 2 tpy of VOC and would be subject to the requirement to control emissions under Part 50.

The proposed rule requires a 95% reduction of VOC emissions for tanks with a PTE equal to or greater than 2 tpy of VOC, and a 98% reduction for tanks with a PTE equal to or greater than 10 tpy of VOC. Emission reductions were not calculated for those tanks that already have a VOC control device (e.g., condenser, VRU, or flare), that are already subject to NSPS Subparts OOOO or OOOOa, or that have allowable VOC emissions less than 2 tpy. Applying these emission reductions results in estimated VOC emission reductions of 8,585 tons per year for an overall reduction of 53%. See NMED Exhibit 100 – Storage Tanks Reductions and Costs VOC Spreadsheet.

Costs of VOC Reductions from Storage Vessels

The annualized costs of reducing VOC emissions from the estimated 2,059 uncontrolled and unregulated storage vessels is approximately $16,039,252. This annualized cost includes capital and installation costs, as well as operation and maintenance costs for installing combustors at 495 sites, and also includes the costs for retrofitting tanks to add the vent system and piping to route emissions to the control device. Because multiple tanks are typically installed at one location, the services of a combustor are assumed to be shared amongst all the tanks.

The capital and annual costs per combustor are based on cost figures provided in Table 4-5 - Total Capital Investment and Total Annual Costs of a Combustor in the EPA CTG (NMED Exhibit 34). The cost effectiveness estimates (measured in cost per ton of VOC reduced) for routing VOC emissions from an existing uncontrolled storage vessel to a combustion device are based on cost figures in Table 4-6 of EPA CTG.

Costs were updated to reflect 2019 costs using the CEPCI of $584.6 for 2012 and $607.5 for 2019. The 2019 annualized cost ratio is therefore estimated as:

607.5/584.6 = 1.04

The Storage Tanks Reductions and Costs Spreadsheet provides a detailed breakdown of costs. *See* NMED Exhibit 100.

Section 20.2.50.124 – Well Workovers

Applicability

Section 20.2.50.124 applies to workovers performed at oil and natural gas wells.

Description of Process

Some wells require supplementary maintenance to maintain production or minimize the decline in production. These operations are referred to as workovers. Typical workovers include

rod, tubing and casing repairs; siphon string or artificial lift installation paraffin removal; and pump repairs.

Workovers are performed on wells that have previously been completed and have produced some reservoir fluids (water, oil, and/or natural gas). These wells have to be prepared before workover operations can begin. If the well is still producing and/or has pressure, the well will need to be blown down (i.e., vented) before it is safe to remove the tubing head and install the blowout preventers ("BOPs"). The well pressure can be decreased by venting to the atmosphere or by opening the casing to the sales line or the suction of a wellsite compressor. In many cases, the fluids in the wellbore will build up to the point the well "dies" – this refers to the instance where the hydrostatic pressure of the accumulated fluids is equal to the reservoir pressure. In some cases, it will be necessary to pump water or other fluids into the wellbore to "kill" the well. As a safety precaution, after the BOPs are installed, the well is usually vented to atmosphere via a tank.

Workovers are usually short duration projects that only last a few days or weeks at the most. After the well is prepared (i.e., blown down and BOPs installed), the workover operations can begin. For the safety of the rig crew, the well is usually allowed to vent to atmosphere via a tank for the duration of the workover. Since these operations are typically performed during daylight hours, the well is shut in or returned to the sales line at the end of the day.

Control Options

Best management practices are the best means of reducing emissions during well workovers. These include reducing wellhead pressure before blowdown to minimize the volume of natural gas vented; monitoring manual venting at the well until the venting is complete; and routing natural gas to the sales line, whenever possible.

Proposed Rule Requirements for Well Workovers

The owner or operator of an oil or natural gas well must use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering practices: (1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented; (2) monitor manual venting at the well until the venting is complete; and (3) route natural gas to the sales line, if possible.

During a well workover, an owner or operator is required to monitor wellhead pressure, natural gas venting flow rate, and elapsed venting time in order to calculate the volume and mass of VOC vented during a well workover. For each workover, the owner or operator must record the identification number and location of the well; date; wellhead pressure; flow rate or maximum potential flow rate; duration of venting; best management practices used; and the quantity of VOC emissions released. When venting cannot be avoided, the owner and operator must notify all residents located within one-quarter mile of the well at least three days before the workover by certified mail. In addition, the owner or operator shall comply with the general monitoring, recordkeeping, and reporting requirements in Section 20.2.50.112.

Basis for Proposed Rule Requirements

The proposed requirements for workover operations are based on requirements in Colorado Reg. 7 and Wyoming's Permitting Guidance. *See* NMED Exhibits 39 and 40, respectively.

Colorado Reg. 7, Section II.G requires owners and operators to use best management practices to minimize hydrocarbon emissions associated with downhole well maintenance, well liquids unloading, and well plugging unless emitting is necessary for safety. The Colorado rule

also requires the owner or operator be present onsite and minimize emissions to the maximum extent practicable.

Wyoming's Permitting Guidance requires minimizing emissions to the extent practicable during manual and automated blowdown/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, and other well operations. The guidance requires personnel to remain onsite to ensure minimal gas venting occurs, and also requires that operators estimate the duration of venting episodes and the amount of VOC emitted during such events. *See* NMED Exhibit 40, at pp. 13, 19, and 24.

EPA did not regulate emissions from well workovers or blowdown operations in NSPS Subparts OOOO or OOOOa. The EPA CTG did not address emissions from these operations. *See* NMED Exhibit 34.

Estimated Emissions Reductions

Emission estimates for workover operations are not currently available in the modeling emissions inventory or found in the NMED Equipment Data. Therefore, no estimate of emissions reductions is currently available.

Estimated Costs

Section 20.2.50.124 specifies certain best management practices that must be used when conducting well workover operations, but does not require the use of emission control devices. It is expected that these practices will require personnel to manage the well during the workover operation, but no capital costs are anticipated. Costs associated with well workover best management practices are expected to be minimal as personnel will already be onsite conducting the well workover and any additional training may be incorporated into existing personnel training programs.

Section 20.2.50.126 – Produced Water Management Units

Applicability

Section 20.2.50.126 applies to produced water management units ("PWMU"), which are defined in Section 20.2.50.7.II as follows:

> [A] recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 bbls.

Description of Process

The majority of oil- and gas-bearing formations also contain naturally occurring water, often referred to as "formation" or "connate" water. When oil or gas is extracted, this "produced water" is also extracted as a by-product. The actual amount of produced water varies widely depending on factors such as location or stage in the lifetime of a particular well. In addition to reflecting the chemical makeup of the geologic formation from which it is extracted, produced water will also contain suspended solids, dissolved solids, varying amounts of oil residues and organics containing VOCs, and the various chemicals used in the production process. Produced water from gas production typically has higher contents of low molecular-weight aromatic hydrocarbons, such as benzene, toluene, ethylbenzene, and xylene ("BTEX") than produced water from oil production.

Conventional Oil and Gas

On average, about 7 to 10 barrels, or 280 to 400 gallons, of water are produced for every barrel of crude oil. Oil reservoirs commonly contain larger volumes of water than gas reservoirs

because gas is stored and produced from less porous reservoirs that contain source rock with a lower water capacity. Produced water generation commonly increases over time in conventional reservoirs as the oil and gas is depleted during hydrocarbon production. *See* U.S. Dept. of Interior, Bureau of Reclamation Science and Technology Program Report No. 157, *Oil and Gas Produced Water Management and Beneficial Use in the Western United States* (September 2011).[25]

Unconventional Oil and Gas

Produced water from most unconventional resources, besides coal bed methane, is minimal due to tighter reservoir formations such as tight sands, oil shale, and gas shale reservoirs. Producers commonly import water to these operations for onsite use in drilling, fracturing, and production. Fresh water used in drilling applications for fracturing is contaminated by the saline water in the reservoir. Fresh water brought onsite for use in operations, such as flow back or water returning from fracturing applications ("frac water"), also is managed as a waste stream. This waste stream is commonly associated with the initial phase of well development and production. In most unconventional oil and gas operations, frac water is considered the largest waste stream of production.

Control Options

VOC emissions from PWMU can be reduced by treating the produced water to remove hydrocarbons before the water enters the recycling facility or impoundment. The emissions are reduced when produced water is processed through three-phase separators and storage vessels, which separates the hydrocarbons from the produced water prior to sending to a PWMU.

Proposed Rule Requirements for Produced Water Management Units

[25] Available at: https://www.usbr.gov/research/dwpr/reportpdfs/report157.pdf

Section 20.2.50.126 requires owners and operators to employ best management and good engineering practices to minimize emissions of VOC from produced water management units. VOC emissions must be controlled to less than two tons per year.

Owners and operators must also comply with monitoring, recordkeeping, and reporting requirements that ensure the affected units are being properly operated and maintained in a manner that meets the emissions reduction requirements in the rule. The monitoring requirements include calculating a monthly rolling 12-month total of VOC emissions from each unit. Owners and operators are required to use this monthly rolling total to control VOC emissions to less than two tons per year. The proposed rule requires monthly monitoring of best management and engineering practices applied at each unit to ensure reduced emissions and effectiveness of the practice.

Owners and operators are required to maintain records for each produced water unit including its name or identification number; UTM coordinates; county in which its located; description of best management and engineering practices used to minimize VOC releases; and a record of the monthly rolling 12-month total VOC emissions.

Produced water management units are also subject to the general monitoring, recordkeeping and reporting requirements in Section 20.2.50.112.

Estimated Emission Reductions and Cost

Section 20.2.50.126 specifies that best management practices and good engineering practices must be used to minimize VOC emissions at PWMUs, but does not require the use of emission control devices. It is expected that these practices will require personnel to manage the minimization of emissions PWMUs, but no capital costs are anticipated. Costs associated with best management and good engineering practices are expected to be minimal as personnel will

already be onsite at the facility, and any additional training may be incorporated into existing personnel training programs.

PWMUs are unregulated under the federal Clean Air Act and its implementing regulations, and EPA has not published emission factors specific to this type of operation.

NMED's Ongoing Review

The Department continues to review scientific and technical information in published literature, engage in discussions with EPA, and review data submitted by owners and operators of PWMUs to determine the most effective and enforceable control strategy to reduce VOC emissions, while preventing unintended public health and environmental consequences that could arise from disincentivizing the recycling and reuse of produced water in the oil and gas industry. NMED is evaluating alternative emission standards to achieve important emissions reductions while continuing to encourage the use of produced water instead of freshwater resources throughout the industry.

Section 20.2.50.127 – Credible Evidence Provisions

Section 20.2.50.127 contains provisions regarding enforcement for violations of Part 50. Subsection A expressly states what is implicit in any mandatory requirement of an air quality regulation under the CAA or the AQCA: that failure to comply with any of the requirements in Part 50 within the specified timeframes constitutes a violation of Part 50 that is subject to enforcement action under the AQCA. This Section provides clear notice to the regulated community that failure to comply with the provisions of Part 50 will be subject to enforcement.

Subsection B provides that if the Department obtains credible information indicating that a source is not in compliance with Part 50, the source will be presumed to be in violation unless and until the owner or operator provides credible evidence or information demonstrating that

there is no violation. Subsection C establishes a similar presumption of violation if the Department receives credible information from a member of the public. These provisions establish a presumption of a violation of Part 50 when the Department comes into possession of credible information – either obtained by the Department pursuant to an inspection or records request, or provided to the Department by an outside person – that indicates noncompliance. This presumption can then be rebutted by the owner or operator through credible evidence or information showing that no violation occurred.

By placing the burden on the regulated entity to affirmatively show that it is in compliance with Part 50, the provisions of Section 20.2.50.127 give the Department an important tool in ensuring that the public health and the environmental protections of Part 50 are actually realized. Regulations have little benefit if they cannot be enforced. These provisions help alleviate the staffing and resource constraints that limit the Department's ability to physically inspect sources and identify violations. Further, Subsection C allows the Department to take advantage of the increasing access that the public has to advanced emissions monitoring technologies that can be used to monitor and record a facility's operations and that can be used as evidence in enforcement cases. Such technologies include infrared cameras. Surveillance monitoring and infrared imaging conducted by non-governmental organizations can be compelling, and has been used by the Department to support allegations of air quality violations in past enforcement actions.

Importantly, the provisions of Section 20.2.50.127 do ***not*** establish that any evidence or information received or obtained by the Department is presumed to be credible. The Department still has the authority to determine that information is "credible" before any violation will be presumed based on that information. The term "credible evidence" is widely used throughout

environmental and other regulatory provisions. As used in Subsection 20.2.50.127, the term "credible" is intended to have the same meaning as explained by EPA in the background to its "Credible Evidence Rule" at 62 Fed. Reg. 8314. *See* NMED Exhibit 101. As explained by EPA in pertinent part:

> The Federal Rules of Evidence govern the admission of evidence in all federal district court litigation, including CAA enforcement actions . . . . Similar evidentiary rules govern federal administrative and state environmental actions. Our legal system provides that a federal or administrative law judge will be the ultimate, independent arbitrator of the evidence's admissibility and credibility.
>
> Credible evidence is far from a new concept in judicial and administrative actions. In private lawsuits such as contract disputes, and in governmental and citizen enforcement actions brought under environmental laws other than the CAA, litigants can and do use a wide variety of information to prove their claims, or to refute the claims of opposing parties. In all these lawsuits, the judge acts as the final, independent arbitrator of what constitutes credible and admissible evidence.
>
> It should be emphasized that the determination that evidence or information is credible is merely a threshold determination that the evidence or information in question is technically relevant, and therefore, legally admissible in an enforcement action. In light of [Clean Air Act] section 113(a) providing that the Administrator may bring an enforcement action based on "any information", EPA believes that Congress intended this threshold to be a low one.

Id. at 8317-8318.

Like the Clean Air Act, the AQCA provides that the Secretary of the Department may bring an enforcement action based on "any information." *See* NMSA 1978, § 74-2-12(A).

Brian Palmer
Senior Scientist



A experienced scientist with expertise in characterizing and managing emissions from the oil and gas (O&G) sector

- Since May 2020, has been developing a proposed rule to reduce VOC and NOx emissions from oil and gas production and transmission operations in New Mexico.
- Developed proposed amendments to 40 CFR part 98, subpart W, Mandatory Greenhouse Gas Reporting for Petroleum and Natural Gas Systems.
- Led regulatory development projects for 15 source categories, including developing baseline emission inventories and estimating emission reductions.
- Has supported numerous projects related to 40 CFR part 98, Mandatory Greenhouse Gas Reporting.

EMPLOYMENT

1996–present
Senior Environmental Scientist, ERG, Morrisville, NC

1991–1996
Environmental Scientist, Radian International LLC, Morrisville, NC

EDUCATION

M.A., Ecology, University of North Carolina at Chapel Hill, 1991

B.S., Biology, Bates College, 1984

RELEVANT PROJECTS

New Mexico Ozone Precursor Rule for the Oil and Natural Gas Sector
Client: New Mexico Environment Department (NMED). Developing a proposed rule to reduce emissions of VOC and NOx from oil and natural gas production in New Mexico. Identifying achievable control levels for each emission source types using federal NSPS, CTGs, and other state rules. The proposed rule will cover engines and turbines, compressor seals, equipment leaks, gas well liquids unloading, glycol dehydrators, process heaters, liquid transfers from storage tanks to trucks and rail cars, pig launching and receiving, pneumatic controllers and pumps, storage tanks, well workovers, and evaporation ponds for produced water disposal. For each source type, estimating the potential percent emission reductions and the control costs, accounting for the number of sources that already have controls or that are already subject to a NSPS or NESHAP that would require the same level of control as the proposed rule. Analyzed equipment data for permitted facilities provided by NMED. For the cost and emission reductions, reviewed pre-existing cost and emission reduction analyses completed for other federal and state rulemakings, and adapted them for the information available in the equipment data sheets from the NMED. Coordinated the QA of the emission reduction and cost impact analyses and prepared the documentation for the control technology, emission reduction, and cost impact analyses.

Oil and Natural Gas Systems (40 CFR 98, Subpart W) Amendments
Client: EPA/CCD. Oil and Natural Gas Systems (40 CFR 98, Subpart W) Amendments. Directed the preparation of two proposal packages to amend subpart W. In the first package, directed the completion of a proposed rule to amend Subpart W to revise certain calculation methods, monitoring methods, and data reporting requirements. The changes also clarified terms and definitions and corrected certain technical and editorial errors. Directed the completion of the preamble and amendatory text and the technical support documents. Directed the initiation of a second rulemaking to add GHG reporting requirements for completions and workovers of hydraulically fractured oil wells, the natural gas gathering and boosting segment (including equipment located on gathering pipelines, such as compressors, acid gas removal units, dehydrators, metering and valve stations), natural gas transmission pipeline blow downs, and the addition of API Well Numbers to the reporting requirements.

Federal Implementation Plan (FIP) for Oil and Gas Development in Indian Tribal Areas.

Client: EPA/OAQPS/SPPD. Oversaw the development of control options to reduce emissions from oil and gas development on tribal lands to be used as the basis for a FIP and to provide a streamlined permitting option for oil and gas development on tribal lands to avoid the burden on oil and gas developers and permitting agencies of case-by-case permits associated with NSR or PSD. The FIP also considered additional controls for wells located on tribal areas that were in ozone non-attainment areas. Control options were developed for the following oil and gas sources: oil and gas well completions with hydraulic fracturing; oil, gas, and water separators; heater treaters, amine treatment systems; glycol dehydration systems; centrifugal compressors; pneumatic controllers and pneumatic pumps; blowdown venting; equipment leaks; flash tanks; storage tanks; flares (including pit flares, utility flares, and enclosed combustors); truck loading; reciprocating internal combustion engines; external combustion units and process heaters. Controls included the use of flares and closed vent systems, and leak detection and repair programs. Emissions were estimated using data on the actual number of wells on tribal lands compiled from the Drilling Info database using API Well Numbers and well production data. Costs were estimated using cost efficiency data developed from the NSPS for oil and gas development (40 CFR 60, subpart OOOO).

Support for Compliance Monitoring and Assistance for the GHG Reporting Program

Client: EPA/CCD. Coordinates all support activities related to compliance monitoring and assistance for the entire GHGRP, including tracking of expected reporters and dropped reporters, analyzing applicability for expected reporters and comparing them to reporting thresholds, performing outreach to expected and dropped reporters to help bring them into compliance, and performing QA of data and analyses related to compliance monitoring to identify expected and dropped reporters (including comparisons between non-EPA lists of GHG emitting facilities and the EPA database of expected reporters and facilities already reporting to the GHGRP).

Electronics Manufacturing (40 CFR 98, Subpart I) Amendments and Implementation

Client: EPA/CCD. Directed the preparation of a proposed and final rule to amend Subpart I to address the issues raised by the Semiconductor Industry Association (SIA) in a petition for reconsideration. The amendments removed the requirement for certain large facilities to develop and use recipe-specific emission factors for fluorinated GHG (F-GHG) and N_2O emissions from semiconductor manufacturing facilities. The amendments also added a new method for determining emissions from all electronics facilities using stack testing methods, including FTIR, to measure emissions. Developed and presented a Microsoft PowerPoint webinar to explain the new rule amendments to industry GHG reporters.

Implementation included working with other EPA contractors to develop and test the calculation tool and reporting form used by reporters, and developing and testing validation checks for completed forms, and verification checks for reported data. Verification of the data submitted under subpart I in the 2011 to 2013 reporting years, including checks that reporting forms were completed correctly, emissions were estimated and reported consistent with subpart I, and communicating with facilities to ensure that verification issues were resolved. Implementation also included analysis of reported data to identify trends in the data, comparing reported data to other publicly available data sources, identifying variables that could predict emissions, and determining the fraction of total industry emissions represented by the reported emissions, and extrapolating the reported data to the whole industry.

Coordinated the design and testing of a new web-based reporting form to replace the existing spreadsheet-based reporting form. Worked with another EPA contractor to develop a design requirements document, a mock-up of the web form in Excel, and then test the new web form in an EPA staging environment and provide feedback. Developed and presented a PowerPoint webinar explaining to GHG reporters how to use the new web-based form.

GHG Emission Reductions

Client: EPA/CCD. Directed a task in which ERG scientists estimated the potential for future GHG emission reductions from several energy intensive source categories, including pulp and paper plants, refineries, and iron and steel mills. The team estimated potential emission reductions based on recent and forecasted trends in energy consumption for each category and an evaluation of emerging technologies that could affect energy consumption and GHG emitting processes in each category. Estimates included the lower and upper bounds of the emission estimates.

Air Emission Standard Regulatory Development Support

Client: EPA/OAQPS/SPPD. Directed the development of national air emission standards for numerous source categories, including National Emission Standards for Hazardous Air Pollutants, New Source Performance Standards, National VOC Rules, and Control Techniques Guideline Documents. Directed development of new

emission standards for 11 source categories and also risk and technology reviews of standards for 10 source categories that had already been developed and implemented. Has provided technical support for development and implementation of standards for multiple other source categories.

Collected information on each source category from visits to industrial facilities and in meetings between industry representatives and the EPA. Directed the development of an inventory of emission sources and an estimate of baseline emissions. Identified add-on control technologies, work practices, and process modifications that can be used to reduce emissions. Estimated the cost and potential emission reductions of those options. Documented the methodology and results of each analysis. Developed supporting documentation for proposed and final rules, and the preamble and regulatory language. Summarized public comments on proposed rule and developed final rules and supporting preambles.



Control Techniques Guidelines for the Oil and Natural Gas Industry

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EPA-453/B-16-001

October 2016

Control Techniques Guidelines for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, North Carolina

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This report has been reviewed by EPA's Office of Air Quality Planning and Standards and has been approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use.

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
ACA	Air Compliance Advisor
ANGA	America's Natural Gas Alliance
APCD	Air Pollution Control District
API	American Petroleum Institute
AQMD	Air Quality Management District
ARCADIS	a global consulting firm
bbl/day	barrels per day
boe/day	barrels of oil equivalent per day
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
Btu/scf	British thermal unit per standard cubic feet
CAA	Clean Air Act
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
Cfm	cubic foot per minute
CFR	Code of Federal Regulations
CH4	methane
CMSA	Consolidated Metropolitan Statistical Area
CO	carbon monoxide
CO_2	carbon dioxide
CTG	Control Techniques Guidelines
E&P Tanks Program	is a personal computer-based software designed to use site-specific information to predict emission from petroleum production storage tanks
ERG	Eastern Research Group
EVRU	ejector vapor recovery units
FIP	Federal Implementation Plan
FR	Federal Register
FRED	Federal Reserve Economic Data
G	Gram
GDP	gross domestic product
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
HAP	hazardous air pollutants

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Acronyms/Abbreviations	Description
HPDI database	provides production data and web-enabled analytical software tools for a wide range of oil and gas related customers
H_2S	hydrogen sulfide
ICF International	a firm that provides professional services and technology solutions in strategy and policy analysis, program management, project evaluation, and other services
IR	infrared
kg/hr/comp	kilogram per hour per component
kg/hr/source	kilogram per hour per source
kPa	kilopascals
kW	kilowatt
LAER	lowest achievable emission rate
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf/yr	million cubic feet per year
NA	Nonattainment
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NOx	nitrogen oxide
NSPS	New Source Performance Standards
O&M	operation & maintenance
OAQPS	Office of Air Quality Planning and Standards
OCCM	OAQPS Control Cost Manual
OEL	open-ended lines
OGI	optical gas imaging
OTR	Ozone Transport Region
OVA	organic vapor analyzer
PG&E	Pacific Gas & Electric
PNAS	Proceedings of the National Academy of Sciences
ppm	parts per million
Ppmv	parts per million by volume
PRV	pressure relief valve
Psi	pounds per square inch
Psia	pounds per square inch absolute
Psig	pounds per square inch gauge
PTE	potential to emit
RACT	reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
Scf	standard cubic feet
Scfh	standard cubic feet per hour

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Acronyms/Abbreviations	Description
scfh-cylinder	standard cubic feet per hour-cylinder
Scfm	standard cubic feet per minute
SIP	State Implementation Plan
SO_2	sulfur dioxide
STSD	supplemental technical support document
THC	total hydrocarbons
TOC	total organic compounds
Tpy	tons per year
TSD	technical support document
TVA	toxic vapor analyzer
U.S.	United States
U.S. EIA	U.S. Energy Information Administration
U.S. EPA	U.S. Environmental Protection Agency
VOC	volatile organic compound
VRU	vapor recovery unit

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1.0 INTRODUCTION

Section 172(c)(1) of the Clean Air Act (CAA) provides that state implementation plans (SIPs) for nonattainment areas must include "reasonably available control measures" including "reasonably available control technology" (RACT), for existing sources of emissions. CAA Section 182(b)(2)(A) provides that for Moderate ozone nonattainment areas, states must revise their SIPs to include RACT for each category of volatile organic compound (VOC) sources covered by control techniques guidelines (CTG) documents issued between November 15, 1990, and the date of attainment. Section 182(c) through (e) applies this requirement to states with ozone nonattainment areas classified as Serious, Severe, and Extreme. CAA Section 184(b) requires that states in ozone transport regions must revise their SIPs to implement RACT with respect to all sources of VOC in the state covered by a CTG issued before or after November 15, 1990. CAA Section 184(a) establishes a single Ozone Transport Region (OTR) comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.

The U.S. Environmental Protection Agency (EPA) defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 FR 53761 (September 17, 1979).

This CTG provides recommendations to inform state, local, and tribal air agencies (hereafter, collectively referred to as air agencies) as to what constitutes RACT for select oil and natural gas industry emission sources. Air agencies can use the recommendations in the CTG to inform their own determination as to what constitutes RACT for VOC for the emission sources presented in this document in their Moderate or higher ozone nonattainment area or state in the OTR. The information contained in this document is provided only as guidance. This guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself. This document does not impose any requirements on facilities in the oil and natural gas industry. It provides only recommendations for air agencies to consider in determining RACT. Air agencies may implement other

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technically-sound approaches that are consistent with the CAA, the EPA's implementing regulations, and policies on interpreting RACT.

The recommendations contained in this CTG are based on data and information currently available to the EPA. The EPA evaluated the sources of VOC emissions in the oil and natural gas industry and the available control approaches for addressing these emissions, including the costs of such approaches. The recommendations contained in this CTG may not be appropriate for every situation based upon the circumstances of a specific source (e.g., VOC content of the gas, safety concerns/reasons). Regardless of whether an air agency chooses to adopt rules implementing the recommendations contained herein, or to issue rules that adopt different approaches for RACT for VOC from oil and natural gas industry sources, air agencies must submit their RACT rules to the EPA for review and approval using the SIP process. The EPA will evaluate the RACT determinations and determine, through notice and comment rulemaking, whether these determinations in the submitted rules meet the RACT requirements of the CAA and the EPA's regulations. To the extent an air agency adopts any of the recommendations in this guidance into its RACT rules, interested parties can raise questions and objections about the appropriateness of the application of this guidance to a particular situation during the development of these rules and the EPA's SIP process. Such questions and objections can relate to the substance of this guidance.

Section 182(b)(2) of the CAA requires that a CTG document issued between November 15, 1990, and the date of attainment include the date by which states subject to CAA section 182(b) must submit SIP revisions. Accordingly, the EPA is setting forth a 2-year period, from the date of publication of the notice of availability of this CTG in the *Federal Register* for the required SIP submittal.

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2.0 BACKGROUND AND OVERVIEW

There have been several federal and state actions to reduce VOC emissions from certain emission sources in the oil and natural gas industry. A summary of these actions is provided below.

2.1 History of New Source Performance Standards that Regulate Emission Sources in the Oil and Natural Gas Industry

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). Since the 1979 listing, the EPA has promulgated performance standards to regulate VOC emissions from production, processing, transmission, and storage as well as sulfur dioxide (SO_2) emissions from natural gas processing emission sources and, more recently, greenhouse gases (GHG). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for natural gas processing plants that addressed VOC emissions from leaking components (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for natural gas processing plants that regulated SO_2 emissions (40 CFR part 60, subpart LLL). On August 16, 2012 (77 FR 49490) (2012 NSPS), the EPA finalized its review of NSPS standards for the listed oil and natural gas source category and revised the NSPS for VOC from leaking components at natural gas processing plants, and the NSPS for SO_2 emissions from natural gas processing plants. At that time, the EPA also established standards for certain oil and natural gas emission sources not covered by the existing standards. In addition to the emission sources that were covered previously, the EPA established new standards to regulate VOC emissions from hydraulically fractured gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, and storage vessels. In 2013 (78 FR 58416) (2013 NSPS Reconsideration) and 2014 (79 FR 79018), the EPA amended the standards set in 2012 in order to improve implementation of the standards. In 2016 (81 FR 35824, June 3, 2016), the EPA finalized new standards to regulate GHG and VOC emissions across the oil and natural gas source category. Specifically, the EPA finalized both GHG standards (in the form of limitations on methane emissions) and VOC standards for several emission sources not previously covered by the NSPS (i.e., hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations).

In addition, the EPA finalized GHG standards for certain emission sources that were regulated for only VOC (i.e., hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers and equipment leaks at natural gas processing plants). With respect to certain equipment that are used across the industry, 40 CFR part 60 subpart OOOO regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The final amendments established GHG standards (40 CFR part 60 subpart OOOOa) for these equipment and extended the current VOC standards to previously unregulated equipment. Although not regulated under the oil and natural gas NSPS, stationary reciprocating internal combustion engines and combustion turbines used in the oil and natural gas industry are covered under separate NSPS specific to engines and turbines (40 CFR part 60, subparts IIII, JJJJ, GG, KKKK).

In addition to NSPS issued to regulate VOC emissions from the oil and gas industry, the EPA also published a CTG document that recommended the control of VOC emissions from equipment leaks from natural gas processing plants in 1983 (1983 CTG; 49 FR 4432; February 6, 1984).[1] This 2016 CTG is the only CTG document issued since 1983 for the oil and natural gas industry.

2.2 State and Local Regulations

Several states regulate VOC emissions from storage vessels in the oil and natural gas industry. There are also a few states (e.g., Colorado, Wyoming, and Montana) that have established specific permitting requirements or regulations that control VOC emissions from emission sources in the oil and natural gas industry (e.g., compressors, pneumatics, fugitive emission components):

(1) The Colorado Department of Public Health and Environment, Air Quality Control Commission has developed emission regulations 3, 6, and 7 that apply to oil and natural gas industry emission sources in Colorado. (https://www.colorado.gov/pacific/cdphe/summary-oil-and-gas-emissions-requirements.)

(2) Montana requires oil and gas well facilities to control emissions from the time the well is completed until the source is registered or permitted (Registration of Air Contaminant

[1] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

Sources Rule, Rule 17.8.1711, Oil or Gas Well Facilities Emission Control Requirements). (http://www.mtrules.org/gateway/ruleno.asp?RN=17%2E8%2E1711.)

(3) The Wyoming Department of Environmental Quality limits VOC emissions from existing sources in ozone nonattainment areas and has issued specific permitting guidance that apply to oil and natural gas facilities. (Chapter 6, Section 2 Permitting Guidance, last revised in September 2013).

(4) The San Joaquin Valley Air Pollution Control District requires control of VOC emissions from several VOC oil and natural gas emission sources, including, but not limited to, (a) storage vessels, (b) crude oil production sumps, (c) components at light crude oil production facilities, natural gas production facilities and natural gas processing facilities, and (d) in-situ combustion well vents.

In some states, general permits have been developed for oil and natural gas facilities. General permits are permits where all the terms and conditions of the permit are developed for a given industry and authorize the construction, modification, and/or operation of facilities that meet those terms and conditions. For example, West Virginia, Ohio, and Pennsylvania have developed General Air Permits for the oil and natural gas industry. The Pennsylvania Department of Environmental Protection has issued a General Permit, General Plan Approval and Permit Exemption 38 for natural gas dispensing facilities and oil and gas exploration, development, and production operations. Pennsylvania also applies conditions on flaring of emissions. Under the Permit 38 exemptions, there are criteria set out for the oil and natural gas industry that include unconditionally exempt and conditionally exempt criteria. Unconditionally exempt operations/equipment include conventional wells, conventional wellheads and associated equipment, well drilling, completion and work-over activities, and non-road engines. Unconventional wells, wellheads and associated equipment (including equipment components, storage vessels) are conditionally exempt. Conditions include compliance with 40 CFR part 60, subpart OOOO and Pennsylvania's General Permit 5 (GP-5) and a demonstration that the combined VOC emissions from all sources at a facility are less than 2.7 tons per year

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(tpy) on a 12-month rolling basis. For oil and natural gas facilities that do not meet these conditions, a case-by-case plan approval is required.[2]

There may also be local permit requirements for control of VOC emissions from existing sources of VOC emissions in the oil and natural gas industry, such as those required by the Bay Area Air Quality Management District (BAAQMD) for pneumatic controllers. The BAAQMD requires that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in their permit application. Facilities that use high-bleed devices might be required to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where emissions are high from high-bleed devices, BAAQMD might require that the facility conduct fugitive monitoring and/or control requirements under conditions of their permit to operate[3] on a case-by-case basis.

We conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and identified several draft and final permits that covered some of the sources evaluated for RACT in this CTG. The controls specified in these permits are similar to the control options evaluated in this CTG.[4]

We considered these existing state and local requirements limiting VOC emissions from the oil and natural gas industry in preparing this guideline.

2.3 Development of this CTG

As discussed in section 2.1 of this chapter, the NSPS established VOC emission standards for certain new and modified sources in the oil and gas industry. This CTG addresses existing sources of VOC emissions and provides recommendations for RACT for the oil and natural gas industry. We developed our RACT recommendations after reviewing the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on costs, emissions and available VOC emission control technologies. In April 2014, the EPA released five technical white papers on potentially significant sources of emissions in the oil and natural gas industry. The white papers focused on

[2] Pennsylvania Department of Environmental Protection. *Comparison of Air Emission Standards for the Oil & Natural Gas Industry* (Well Pad Operations, Natural Gas Compressor Stations, and Natural Gas Processing Facilities). May 23, 2014.
[3] Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities.* Bay Area Air Quality Management District. September 16, 2013.
[4] RACT/BACT/LAER Clearinghouse website: http://cfpub.epa.gov/RBLC/.

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technical issues covering emissions and mitigation techniques that target methane and VOC. We reviewed the white papers, along with the input we received from the peer reviewers and the public, when evaluating and recommending RACT.

This CTG reflects the evaluation of potential RACT options for emission sources that are regulated under the oil and natural gas NSPS. This CTG did not evaluate hydraulically fractured oil and natural gas well completions performed on existing wells because these operations are addressed in the NSPS.

Several of the technical support documents (TSDs) prepared in support of the NSPS actions for the oil and natural gas industry include data and analyses considered in developing RACT recommendations in this CTG. To the extent that the data and analyses are also relevant to control options for existing sources, they are referred to throughout this guidance document as follows:

(1) The TSD for the 2011 NSPS proposal, published in July, 2011 is referred to as the "2011 NSPS TSD".[5]

(2) The supplemental TSD for the 2012 final NSPS standards, published in April, 2012, is referred to as the "2012 NSPS TSD" or "2012 NSPS STSD"[6]

(3) The TSD for the 2015 proposal NSPS standards, published August, 2015, is referred to as the "2015 NSPS TSD".[7]

(4) The TSD for the 2016 final NSPS standards, published in May, 2016, is referred to as the "2016 NSPS TSD"[8]

Additionally, emission information and counts for various emission sources were summarized from facility-level data submitted to the Greenhouse Gas Reporting Program

[5] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA-453/R-11002.

[6] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. Docket ID No. EPA-HQ-OAR-2010-0505-4550.

[7] U.S. Environmental Protection Agency. *Oil and Natural Gas Source Category: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards.* August 2015. (See Docket No. EPA-HQ-OAR-2010-0505-5021; regulations.gov).

[8] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources – Background Technical Support Document for the Final New Source Performance Standards*. May 2016.

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(GHGRP)[9] and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory).[10] For the purposes of this document, these data sources are referred to as the "GHGRP" and the "GHG Inventory". The most recent published data from the GHG Inventory when we prepared the draft CTG was for 2013, and was used for some of the analyses included in this document. Between the time we issued the draft CTG and the final CTG, GHGRP data was released that covers 2011 through 2014 and the most recent available GHG Inventory covers data from 1990 through 2014. These new activity data have been reviewed for this CTG and incorporated into our RACT analyses, as appropriate.

Most of the VOC emission estimates presented in this document are based on methane emissions data because we only had methane emissions information for the evaluated sources. We calculated VOC emissions using ratios of methane to VOC in the gas for the different segments of the industry. These ratios, and the procedures used to calculate them, are documented in a memorandum characterizing gas composition developed during the NSPS process. [11] Herein, we refer to this memorandum as the "2011 Gas Composition Memorandum". Because methane emissions are the basis for most of our VOC emission estimates, in several instances where we provide VOC emissions per source/model plant, we also provide the methane emissions that are the basis for our VOC emission estimates.

The remainder of this document is divided into seven chapters and an appendix. Chapter three describes the oil and natural gas industry and a summary of our RACT recommendations presented in this CTG. Chapters four through nine describe the oil and natural gas emission sources that we evaluated for our RACT recommendations (i.e., storage vessels, compressors, pneumatic controllers, pneumatic pumps, equipment component leaks from natural gas processing plants, and fugitive emissions from well sites and gathering and boosting stations), available control and regulatory approaches (including existing federal, state and local requirements) and the potential emission reductions and costs associated with available control and regulatory approaches for a given emission source. The appendix provides example model

[9] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014. (Reported Data: http://www.epa.gov/ghgreporting/). The Greenhouse Gas Reporting Program has particular definitions of "facility" for certain petroleum and natural gas systems industry segments. See 40 CFR 98.238.
[10] U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2014.* Washington, DC. EPA 430-R-15-004. Available online at https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014.
[11] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.

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rule language that can be used by air agencies as a starting point in the development of their SIP rules if they choose to adopt the recommended RACT presented in this document.

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3.0 OVERVIEW OF THE OIL AND NATURAL GAS INDUSTRY AND SOURCES SELECTED FOR RACT RECOMMENDATIONS

Section 3.1 presents an overall description of the oil and natural gas industry and section 3.2 presents the VOC emission sources for which we are recommending RACT within the oil and natural gas industry. Table 3-1 provides a summary of recommendations for controlling VOC emissions from oil and natural gas industry emission sources.

3.1 Overview of the Oil and Natural Gas Industry

The oil and natural gas industry includes oil and natural gas operations involved in the extraction and production of crude oil and natural gas, as well as the processing, transmission, storage, and distribution of natural gas. For oil, the industry includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the industry includes all operations from the well to the customer. For purposes of this document, the oil and natural gas operations are separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution. We briefly discuss each of these segments below. For purposes of this CTG, oil and natural gas production includes only onshore operations.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head, and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices, and dehydrators. Production operations also include well drilling, completion, and recompletion processes, which include all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the "pads" where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production segment also includes the low-pressure, small diameter, gathering pipelines and related components that collect and transport the oil, natural gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

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There are two basic types of wells: oil wells and natural gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar, or pipeline. The oil refinery sector is considered separately from the oil and natural gas industry. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen, and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids (NGL) or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid, and other processes such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

The pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment. Pipelines in the natural gas transmission and storage segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

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In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration, and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of natural gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas industry. Primarily, these emissions are organic compounds such as methane, ethane, VOC, and organic hazardous air pollutants (HAP). Figure 3-1 presents a schematic of oil and natural gas sector operations.

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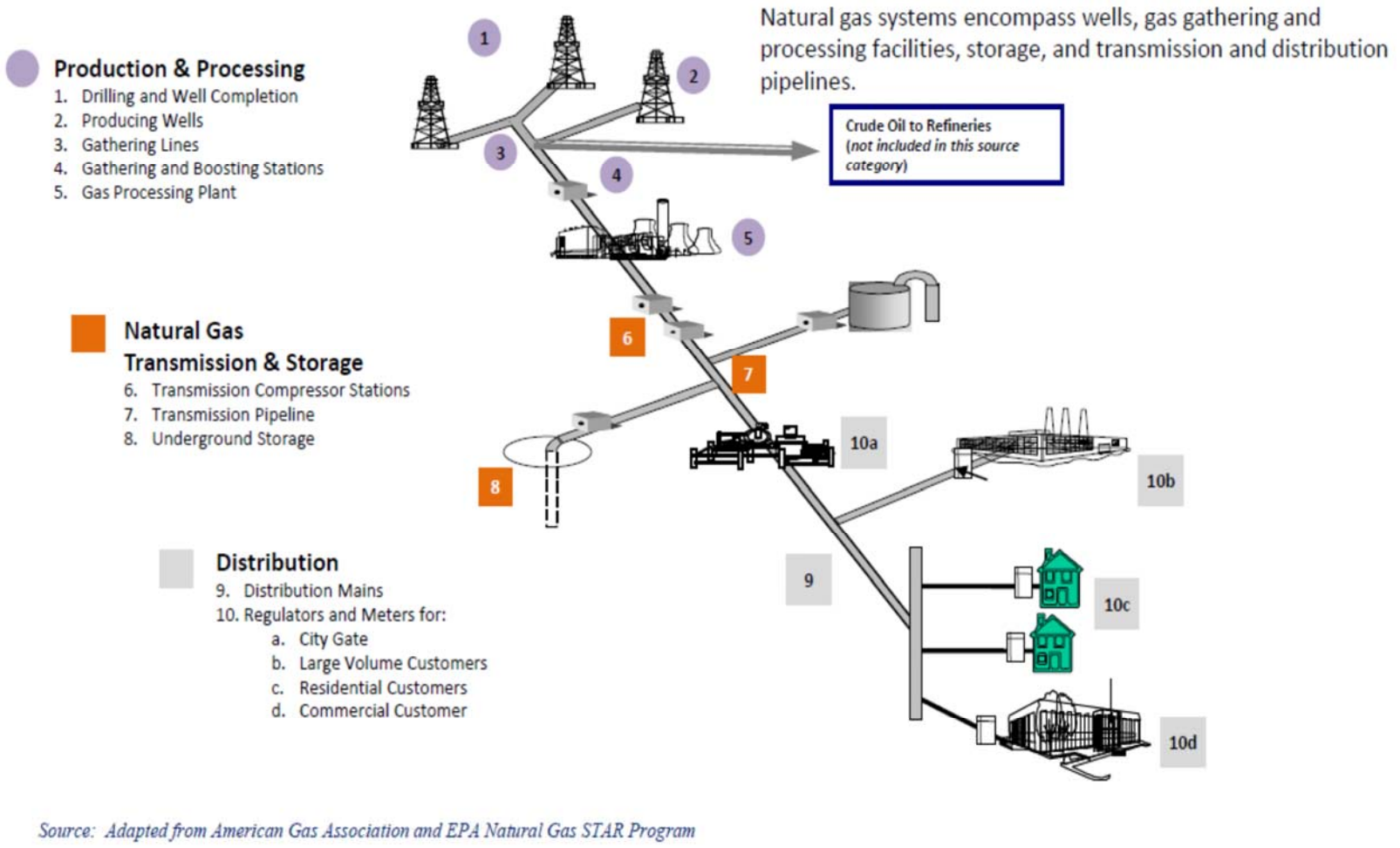


Figure 3-1. Oil and Natural Gas Sector Operations

3.2 Sources Selected For RACT Recommendations

This CTG covers select sources of VOC emissions in the onshore production and processing segments of the oil and natural gas industry (i.e., pneumatic controllers, pneumatic pumps, compressors, equipment leaks, fugitive emissions) and storage vessel VOC emissions in all segments (except distribution) of the oil and natural gas industry. These sources were selected for RACT recommendations because current information indicates that they are significant sources of VOC emissions. As mentioned in section 2.3, the VOC RACT recommendations contained in this document were made based on the review of the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on emissions, available VOC emission control technologies, and costs.

In considering costs, we compared control options and estimated costs and emission impacts of multiple emission reduction options under consideration. Recommendations are presented in this CTG for the subset of existing sources in the oil and natural gas industry where the application of controls is judged reasonable, given the availability of demonstrated control technologies, emission reductions that can be achieved, and the cost of control.

Table 3-1 presents a summary of the oil and natural gas emission sources and recommended RACT included in this CTG.

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Table 3-1. Summary of the Oil and Natural Gas Industry Emission Sources and Recommended RACT Included in this CTG

Emission Source	Applicability	RACT Recommendations
Storage Vessels	Individual storage vessel with a potential to emit (PTE) greater than or equal to 6 tpy VOC.	95 percent reduction of VOC emissions from storage vessels. OR Maintain less than 4 tpy uncontrolled actual VOC emissions after having demonstrated that the uncontrolled actual VOC emissions have remained less than 4 tpy, as determined monthly, for 12 consecutive months.
Pneumatic Controllers	Individual continuous bleed, natural gas-driven pneumatic controller located at a natural gas processing plant.	Natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).
	Individual continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.	Natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).
Pneumatic Pumps	Individual natural gas-driven diaphragm pump located at a natural gas processing plant.	Zero VOC emissions.
	Individual natural gas-driven diaphragm pump located at a well site.	Require routing of VOC emissions from the pneumatic pump to an existing onsite control device or process.
		Require 95 percent control unless the onsite existing control device or process cannot achieve 95 percent.
		If onsite existing device or process cannot achieve 95 percent, maintain documentation demonstrating the percent reduction the control device is designed to achieve.

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Emission Source	Applicability	RACT Recommendations
		If there is no existing control device at the location of the pneumatic pump, maintain records that there is no existing control device onsite.
	Individual natural gas-driven diaphragm pump located at a well site that is in operation for any period of time each calendar day for less than a total of 90 days per calendar year.	RACT would not apply.
Compressors (Centrifugal and Reciprocating)	Individual reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions by replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement. Alternatively, route rod packing emissions to a process through a closed vent system under negative pressure.
	Individual reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95 percent.
	Individual centrifugal compressor using wet seals located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using dry seals.	RACT would not apply.
Equipment Leaks	Equipment components in VOC service located at a natural gas processing plant.	Implement the 40 CFR part 60, subpart VVa leak detection and repair (LDAR) program for natural gas processing plants.
Fugitive Emissions	Individual well site with wells with a gas to oil ratio (GOR) greater than or equal to 300, that produce, on average, greater than 15 barrel equivalents per well per day.	Develop and implement a semiannual optical gas imaging (OGI) monitoring and repair plan that covers the collection of fugitive emissions components at well sites within a company defined area. Method 21 can be

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Emission Source	Applicability	RACT Recommendations
		used as an alternative to OGI at a 500 ppm repair threshold level.
	Individual gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline.	Develop and implement a quarterly OGI monitoring and repair plan that covers the collection of fugitive emissions components at gathering and boosting stations within a company defined area. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.
	Individual well site with a GOR less than 300.	RACT would not apply.

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4.0 STORAGE VESSELS

Storage vessels are significant sources of VOC emissions in the oil and natural gas industry. This chapter provides a description of the types of storage vessels present in the oil and natural gas industry, and provides VOC emission estimates for storage vessels, in terms of mass of emissions per throughput, for both crude oil and condensate storage vessels. This chapter also presents control techniques used to reduce VOC emissions from storage vessels, along with their costs and potential emission reductions. Finally, this chapter provides a discussion of our recommended RACT for storage vessels.

4.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to a tank or other vessel in the oil and natural gas industry that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) that provide structural support. The emissions and emission controls discussed herein would not apply to the following vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), and are intended to be located at a site for less than 180 consecutive days.

(2) Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.[12]

4.2 Process Description and Emission Sources

4.2.1 Process Description

Storage vessels in the oil and natural gas industry are used to hold a variety of liquids including crude oil, condensates, produced water, etc. While still underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the

[12] It is acknowledged that even pressure vessels designed to operate without emissions have a small potential for fugitive emissions at valves. Valves are threaded components that would be subject to leak detection and repair requirements.

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surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed and any oil and water remain together) or a three-phase separator (where the associated gas is removed and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the hydrocarbons from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into an atmospheric storage vessel from a processing vessel (e.g., a separator) operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and other equilibrium effects. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also may include ethane, butane, propane, and HAP such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane.

4.2.2 Emissions Data

4.2.2.1 Summary of Major Studies and Emissions

There are numerous studies and reports available that estimate storage vessel emissions. We consulted several of these studies and reports to evaluate the emissions and emission

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reduction options for storage vessels. Table 4-1 presents a summary of the references for these reports, along with an indication of the type of information available in each reference.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data[a,b]

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[e]
VOC Emissions from Oil and Condensate Storage Tanks	Texas Environmental Research Consortium	2009	Regional	X	X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economic Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number 7	Colorado Air Quality Control Commission	2008	NA		X
E&P TANKS	API		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[c]	EPA	Annual	National	X	
Greenhouse Gas Reporting Program (Annual Reporting: Current Data Available for 2011-2013)[d]	EPA	2014	Facility-Level	X	X

NA = Not Applicable.

[a] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No. EPA-HQ-OAR-2010-0505-4550.

[b] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Technical Support*. July 2011. EPA-453/R-11-002.

[c] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[d] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

[e] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

4.2.2.2 Representative Storage Vessel Baseline Emissions

Storage vessels vary in size and throughputs. In support of the 2013 NSPS Reconsideration,[13] average storage vessel emissions, in terms of mass of emissions per throughput, were developed for both crude oil and condensate storage vessels.[14] We also developed mass emissions per throughput estimates using the American Petroleum Institute's (API's) E&P TANKS program and more than 100 storage vessels across the country with varying characteristics.[15] The VOC emissions per throughput estimates used for this analysis are:

(1) Uncontrolled VOC Emissions from Crude Oil Storage Vessels = 0.214 tpy VOC/barrel per day (bbl/day); and

(2) Uncontrolled VOC Emissions from Condensate Storage Vessels = 2.09 tpy VOC/bbl/day.

On a nationwide basis, there are a wide variety of storage vessel sizes, as well as rates of throughput for each tank. Emissions are directly related to the throughput of liquids for a given storage vessel; therefore, in support of the 2013 NSPS Reconsideration, we adopted production rate brackets developed by the U.S. Energy Information Administration (U.S. EIA) for our emission estimates. To estimate the emissions from an average storage vessel within each production rate bracket, we developed average production rates for each bracket. This average was calculated using the U.S. EIA published nationwide production per well per day for each production rate bracket from 2006 through 2009. Table 4-2 presents the average oil production and condensate production in barrels per well per day. For this analysis, we considered the liquid produced (as reported by the U.S. EIA) from oil wells to be crude oil and from gas wells to be condensate. Table 4-2 presents the average VOC emissions for each storage vessel within each production rate bracket calculated by applying the average production rate (bbl/day) to the VOC emissions per throughput estimates (tpy VOC/bbl/day).

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[13] 78 FR 58416, September 23, 2013. The EPA issued final updates to its 2012 VOC performance standards for storage tanks used in crude oil and natural gas production and transmission. The amendments reflected updated information that responded to issues raised in several petitions for reconsideration of the 2012 standards.

[14] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

[15] American Petroleum Institute. *Production Tank Emissions Model. E&P Tank Version 2.0. A Program for Estimating Emissions from Hydrocarbon Production Tanks*. Software Number 4697. April 2000.

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Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[16]

Production Rate Bracket (BOE/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	Condensate Storage Vessel VOC Emissions (tpy)[c]
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.

[a] BOE=Barrels of Oil Equivalent

[b] Oil and condensate production rates published by U.S. EIA. "United States Total Distribution of Wells by Production Rate Bracket."

[c] Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.

[d] There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

[16] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

4.3 Available Controls and Regulatory Approaches

In analyzing available controls for storage vessels, we reviewed information obtained in support of the 2012 NSPS[17] and the 2013 NSPS Reconsideration actions, control techniques identified in the Natural Gas STAR program, and existing state regulations that require control of VOC emissions from storage vessels in the oil and natural gas industry. Section 4.3.1 presents a non-exhaustive discussion of available VOC emission control methods for storage vessels. Section 4.3.2 includes a summary of the federal, state, and local regulatory approaches that control VOC emissions from crude oil and condensate storage vessels.

4.3.1 Available VOC Emission Control Options

The options generally used as the primary means to limit the amount of VOC vented are to: (1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – "route to a process" (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite and/or (2) route emissions from the storage vessel to a combustion device. While EPA explored these options within the document, there may be other emission controls that sources may wish to employ to ensure continuous compliance with EPA's RACT recommendation. Regardless of the type of emission control method that a source may choose to utilize, the recommended RACT level of control explained more fully below is meant to apply at all times. One of the clear advantages the first option has over the second option is that it results in a cost savings associated with the recycled, recovered and reused natural gas and other hydrocarbon vapor, rather than the loss and destruction of the natural gas and vapor by combustion. Combustion and partial combustion of organic pollutants also creates secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide and smoke/particulates. These emission control methods are described below along with their emission reduction control effectiveness as they apply to storage vessels in the industry and the potential costs associated with their installation and operation.

[17] *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.

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4.3.1.1 Routing Emissions to a Process via a Vapor Recovery Unit (VRU)

Description

One option for controlling storage vessel emissions is to route vapors from the storage vessel back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbon fluids for beneficial use, such as use as a fuel. Where a compressor is used to boost the recovered vapors into the line, this is often referred to as a VRU.[18] Typically with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are usually recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite.

Types of VRUs include conventional VRUs and venturi ejector vapor recovery units (EVRU^{TM}) or vapor jet systems.[19] Decisions on the type of VRU to use are based on the applicability needs (e.g., an EVRU^{TM} is recommended where there is a high-pressure gas compressor with excess capacity and a vapor jet VRU is suggested where there is produced water, less than 75 million cubic feet (MMcf)/day gas and discharge pressures below 40 pounds per square inch gauge (psig)). The reliability and integrity of the compressor and suction scrubber and integrity of the lines that connect the tank to the compressor will affect the effectiveness of the VRU system to collect and recycle vapors.[20]

A conventional VRU is equipped with a control pilot to shut down the compressor and permit the back flow of vapors into the tank in order to prevent the creation of a vacuum in the top of a tank when liquid is withdrawn and the liquid level drops. Vapors are then either sent to the pipeline for sale or used as onsite fuel. Figure 4.1 presents a diagram of a conventional VRU installed on a single crude oil storage vessel (multiple tank installations are also common).[21]

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[18] American Petroleum Institute. Letter to Bruce Moore, SPPD/OAQPS/EPA from M. Todd, API. *Re: Oil and Natural Gas Sector Consolidated Rulemaking*. Docket ID No. EPA-HQ-OAR-2010-0505.
[19] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units.* Natural Gas STAR Program. Source Reduction Training to Interstate Oil and Gas Compact Commission Presentation. February 27, 2009.
[20] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks*. Natural Gas STAR Program. October 2006.
[21] Ibid.

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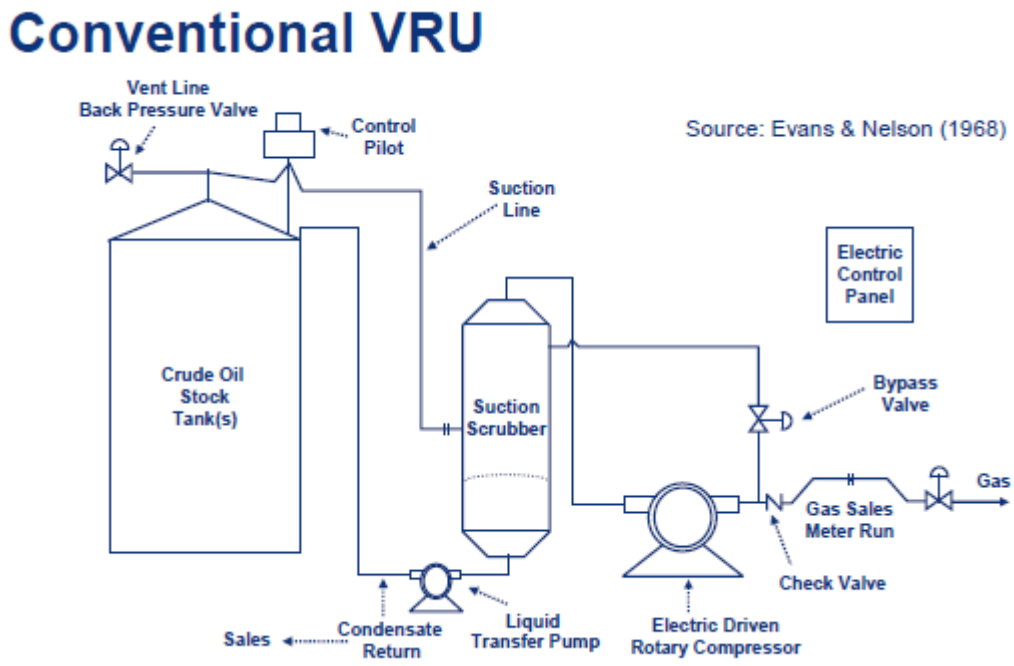


Figure 4-1. Conventional Vapor Recovery System

Control Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by over 95 percent.[22] When operating properly, VRUs generally approach 100 percent efficiency. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, our analysis assumes a 95 percent reduction in VOC emissions for a VRU. A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU cannot be used in all instances. Conditions that affect the feasibility of the use of a VRU include: the availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

[22] Ibid.

Cost Impacts

Cost data for a VRU obtained from an initial economic impact analysis prepared for proposed state-only revisions to a Colorado regulation are presented here.[23] We assumed cost information contained in the Colorado economic impact analysis to be given in 2012 dollars. According to the Colorado economic impact analysis, the cost of a VRU was estimated to be $90,000. Including costs associated with freight and design, and the cost of VRU installation, we estimated costs to be $102,802 ($90,000 plus $12,802). We also added an estimated storage vessel retrofit cost of $68,736 assuming that the cost of retrofitting an existing storage vessel was 75 percent of the purchased equipment cost (i.e., VRU capital cost and freight and design cost).[24] Based on these costs, we estimated the total capital investment of the VRU to be $171,538. These cost data are presented in Table 4-3. We estimated total annual costs using 2012 dollars to be $28,230 per year without recovered natural gas savings. The uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities.

In order to assess the cost of control of a VRU for uncontrolled storage vessels that emit differing emissions, we evaluated the cost of routing VOC emissions from an existing uncontrolled storage vessel to a VRU for a storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy, and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU and converting the reduced VOC emissions to natural gas savings. Table 4-4 presents the estimated natural gas savings and the VOC cost per ton of VOC reduced with and without savings.

[23] Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.
[24] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks.* Natural Gas STAR Program. October 2006.

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Table 4-3. Total Capital Investment and Total Annual Costs of a Vapor Recovery Unit System

Cost Item[a]	Cost ($2012)
Capital Cost Items	
VRU[a]	$90,000
Freight and Design[a]	$1,648
VRU Installation[a]	$11,154
Storage Vessel Retrofit[b]	$68,736
Total Capital Investment	$171,538
Annual Cost Items	
Maintenance	$9,396
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$18,834
Total Annual Costs w/o Savings ($/yr)	***$28,230***

[a] Cost data from the Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.
[b] Assumes the storage vessel retrofit cost is 75 percent of the purchased equipment price (assumed to include vent system and piping to route emissions to the control device). Retrofit assumption from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, *Installing Vapor Recovery Units on Storage Tanks*. October 2006.

Table 4-4. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)		
	Without Savings	Natural Gas Savings (Mscf/yr)[a]	With Savings[b]
2	$14,858	59	$14,734
4	$7,429	118	$7,305
6	$4,953	177	$4,828
8	$3,714	236	$3,590
10	$2,972	295	$2,847
12	$2,476	353	$2,352
25	$1,189	736	$1,065

[a] The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.
[b] Assumes a natural gas price of $4.00 per Mcf.

Additionally, if a VRU is used to control VOC emissions from multiple storage vessels, the VOC emissions cost of control would be reduced because the cost for the additional storage vessel(s) would only include the storage vessel retrofit costs, and the overall VOC emission reductions would increase.

4.3.1.2 Routing Emissions to a Combustion Device

Description and Control Effectiveness

Combustors (e.g., enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) are also used to control emissions from storage vessels. Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[25] For this analysis, we assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuing basis.[26] We note that combustion devices can be designed to meet 98 percent control efficiencies, and can control, on average, emissions by 98 percent or more in practice when properly operated.[27] We also recognize that combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions.

A typical combustor used to control emissions from storage vessels in the oil and natural gas industry is an enclosed combustion system. The basic components of an enclosed combustion system include (1) piping for collecting emission source gases, (2) a single- or multiple-burner unit, (3) a stack enclosure, (4) a pilot flame to ignite the mixture of emission source gas and air and (5) combustor fuel/piping (as necessary). Figure 4-2 presents a schematic of a typical dual-burner enclosed combustion system.

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[25] U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I, *Chapter 13.5 Industrial Flares*. Office of Air Quality Planning & Standards. 1991.

[26] U.S. Environmental Protection Agency. *Air Pollution Control Technology Fact Sheet: FLARE*. Clean Air Technology Center.

[27] The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed that they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. The EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

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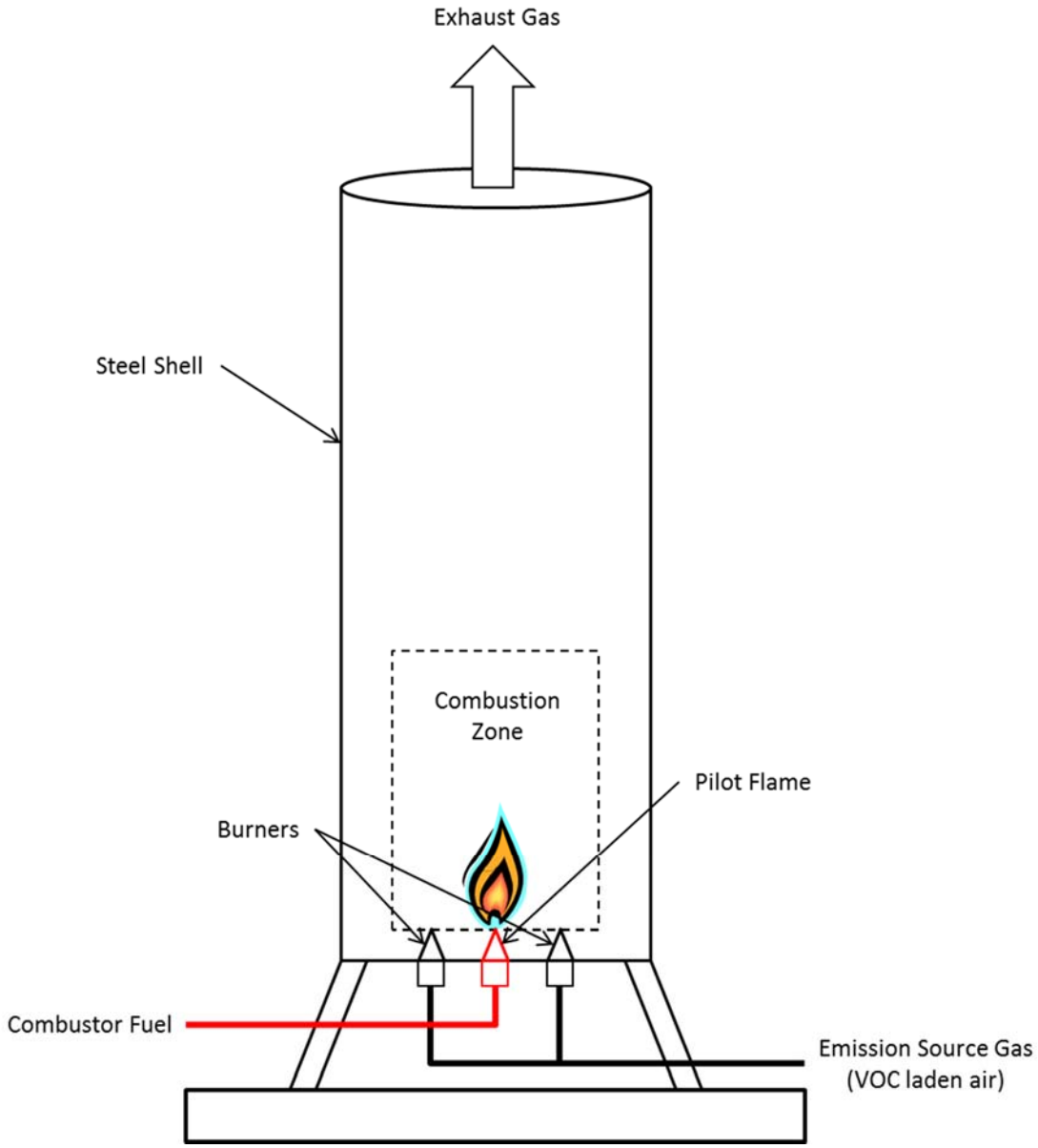


Figure 4-2. Schematic of a Typical Enclosed Combustion System

Thermal oxidizers, also referred to as direct flame incinerators, thermal incinerators, or afterburners, could also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted to the atmosphere. Figure 4-3 provides a basic schematic of a thermal oxidizer.[28]

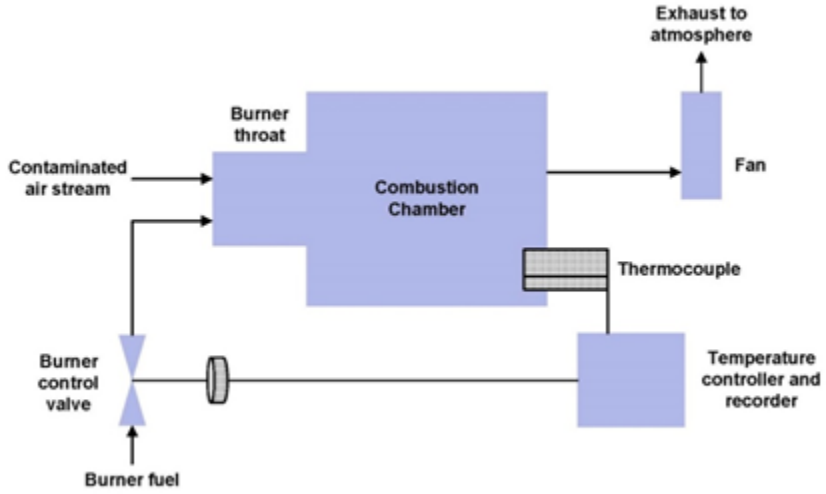


Figure 4-3. Basic Schematic of a Thermal Oxidizer

Cost Impacts

For combustion devices, we obtained cost data from the initial economic impact analysis prepared for state-only revisions to the Colorado regulation.[29] In addition to these cost data, we added line items for operating labor, a surveillance system and data management. This is consistent with the guidelines outlined in the EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (OCCM) for combustion devices and the cost analysis prepared for the 2012 NSPS.[30,31] However, OCCM guidelines specify 630 operating labor hours

[28] U.S. Environmental Protection Agency. Technology Transfer Network. Clearinghouse for Inventories and Emission Factors. *Thermal Oxidizer*. Website: https://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControlID=17.
[29] Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.
[30] *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.
[31] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

per year for a combustion device, which we believe is unreasonable because many of these sites are unmanned and would most likely be operated remotely. Therefore, we assumed that the operating labor would be more similar to that estimated for a condenser in the OCCM, 130 hours per year. We estimated a total capital investment of $100,986 and total annual costs of $25,194 per year. The total capital investment cost includes a storage vessel retrofit cost of $68,736 (as discussed previously for VRUs) to accommodate the use of a combustion device. These cost data are presented in Table 4-5.

Table 4-5. Total Capital Investment and Total Annual Costs of a Combustor[32]

Cost Item[a]	Cost ($2012)
Capital Cost Items	
Combustor[a]	$18,169
Freight and Design[a]	$1,648
Auto Ignitor[a]	$1,648
Surveillance System[b,c,d]	$3,805
Combustor Installation[a]	$6,980
Storage Vessel Retrofit[e]	$68,736
Total Capital Investment	$100,986
Annual Cost Items	
Operating Labor[f]	$5,155
Maintenance Labor[f]	$4,160
Non-Labor Maintenance[a]	$2,197
Pilot Fuel	$1,537
Data Management[c]	$1,057
Capital Recovery (7 percent interest, 15 year equipment life) ($/yr)	$11,088
Total Annual Cost ($/yr)	$25,194

[a] Cost data from Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.

[b] Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.

[32] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[c] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No.EPA-HQ-OAR-2010-0505-4550.
[d] Cost obtained from 2012 NSPS TSD and escalated using the change in GDP: Implicit Price Deflator from 2008 to 2012 (percent)(which was 5.69 percent). Source: FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (http://research.stlouisfed.org/fred2/series/GDPDEF/#).
[e] Retrofit cost obtained from Storage Vessel Retrofit in Table 4-3 (assumed to include vent system and piping to route emissions to the control device).
[f] Operating labor consists of labor resources for technical operation of device (130 hr/yr) and supervisory labor (15 percent of technical labor hours). Maintenance labor hours are assumed to be the same as operating labor (130 hr/yr). Labor rates are $32.00/hr (for technical and maintenance labor) and $51.03 (supervisory labor) and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics, Employer Costs for Employee Compensation, December 2012. Labor rates account for total compensation (wages/salaries, insurance, paid leave, retirement and savings, supplemental pay and legally required benefits).

As noted previously, storage vessels vary in size and throughputs and the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and cost of control. In order to assess the cost of control of combustion for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. Table 4-6 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-6. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a Combustion Device ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)
2	$13,260
4	$6,630
6	$4,420
8	$3,315

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Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)
10	$2,652
12	$2,411
25	$2,210

4.3.1.3 Routing Emissions to a VRU with a Combustion Device as Backup

Industry practice also includes the primary operation of a VRU and secondary operation of a combustion device during VRU maintenance and other times requiring VRU downtime. Using the costs for a VRU and combustion device presented in sections 4.3.1.1 and 4.3.1.2, and assuming the VRU is operated 95 percent of the year and a combustion device is operated 5 percent of the year, we estimated total annual costs using 2012 dollars to be $32,006 per year without recovered natural gas savings. As stated previously, the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities, as well as the percent of time that a VRU is down during the year where emissions are routed to a combustion device. In order to assess the cost of control of a VRU with the use of a combustion device during downtime for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a VRU/combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU (used 95 percent of the year) and converting the reduced VOC emissions to natural gas savings. Table 4-7 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a VRU/combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-7. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU/Combustion Device ($/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced ($2012)		
	Without Savings	Natural Gas Savings (Mscf/yr)[a]	With Savings[b]
2	$16,845	56	$16,728
4	$8,423	112	$8,305
6	$5,615	168	$5,497
8	$4,211	224	$4,094
10	$3,369	280	$3,251
12	$2,808	336	$2,690
25	$1,348	699	$1,230

[a] The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.
[b] Assumes a natural gas price of $4.00 per Mcf.

4.3.2 Existing Federal, State and Local Regulations

4.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2013 NSPS Reconsideration, new or modified storage vessels with PTE VOC emissions of 6 tpy or more must reduce VOC emissions by at least 95 percent, or demonstrate emissions from a storage vessel have dropped to less than 4 tpy of VOC without emission controls for 12 consecutive months.

4.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions[33]

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and how the source must be operated. To ensure that sources

[33] Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector.* 2013.

follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

The environmental regulations in nine of the top oil and natural gas producing states (sometimes with varying local ozone nonattainment area/concentrated area development requirements) (see Table 4-8) require the control of VOC emissions from storage vessels in the oil and natural gas industry. These states include California, Colorado, Kansas, Louisiana, Montana, North Dakota, Oklahoma, Texas, and Wyoming. All except Wyoming require 95 percent emission control with the application of a VRU or combustion (Wyoming requires 98 percent control of emissions using a VRU or combustion).

Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Table 4-8 presents a brief summary of the storage vessel emission control applicability cutoffs in regulations from these nine states. Four states (Colorado, Montana, Texas, and Wyoming) have applicability thresholds in terms of VOC emissions. The remaining five states have storage vessel regulations that are in terms of tank characteristics, such as vapor pressure, tank size, or tank contents. Equivalency of applicability thresholds based on tank and stored liquid characteristics and applicability thresholds based on VOC emissions cannot be determined. We analyzed the varying state VOC emission thresholds (based on a range of 2 tpy to 25 tpy) as part of our cost of control analysis for VRUs and combustion devices in section 4.3.1 of this chapter.

Table 4-8. Summary of Storage Vessel Applicability Thresholds from Nine States

State/Local Authority	Applicability Threshold
Texas	Applies to storage vessels with VOC emissions greater than 25 tpy.
California Bay Area AQMD	Applies to storage vessels with capacity greater than 264 gallons.
California Feather River AQMD	Applies to storage vessels with capacity greater than 39,630 gallons.
California Monterey Bay Unified APCD	Applies to storage vessels with capacity greater than 39,630 gallons.

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State/Local Authority	Applicability Threshold
California Sacramento Metropolitan AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
California San Joaquin Valley Unified APCD	Applies to storage vessels with capacity greater than 1,100 gallons.
California Santa Barbara County APCD	Applies to all storage vessels in tank battery (including wash tanks, produced water tanks, and wastewater tanks).
California South Coast AQMD	Applies to storage vessels with capacity greater than 39,630 gallons with a true vapor pressure of 0.5 psia or greater and storage vessels with a capacity greater than 19,815 gallons with a true vapor pressure of 1.5 psia or greater.
California Ventura County APCD	Applies to all storage vessels. Requirements depend on gallon capacity and true vapor pressure of material contained in vessel.
California Yolo-Solano AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
North Dakota	NDAC 33-15-07: submerged filling requirements to control VOC for tanks >1,000 gallons.
Federal Implementation Plan (FIP): Fort Berthold Indian Reservation	Applies to all storage vessels (except those covered by NSPS subpart OOOO). There is no minimum threshold under the final FIP.
Louisiana	Applies to storage vessels more than 250 gallons up to 40,000 gallons with a maximum true vapor pressure of 1.5 psia or greater.
Oklahoma	Applies to storage vessels with capacity greater than 40,000 gallons (in ozone nonattainment areas).
Wyoming – Statewide	Applies to storage vessels with greater than or equal to 10 tpy VOC within 60 days of startup/modification.
Wyoming – Concentrated Development Area	Applies to storage vessels with greater than or equal to 8 tpy VOC within 60 days of startup/modification.
Kansas	Permanent fixed roof storage tanks >40,000 gallons and external floating roof storage tanks.
Colorado	Condensate tanks with uncontrolled VOC emissions > 20 tpy (2 tpy located at gas processing plants in ozone non-attainment areas).

State/Local Authority	Applicability Threshold
Montana	Applies to oil or condensate storage tanks with a PTE greater than 15 tpy VOC.

4.4 Recommended RACT Level of Control

As discussed in section 4.3.2 of this chapter, existing federal and state and local regulations already require the reduction of VOC emissions from storage vessels in the oil and natural gas industry at or greater than 95 percent. Further, we note that combustion devices can be designed to meet 98 percent control efficiencies and can control, on average, emissions by 98 percent or more in practice when properly operated.[34] We also recognize that combustion devices designed to meet 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as the variability of field conditions. Therefore, the recommendations specify that devices should be required to continuously meet at least 95 percent VOC control efficiency. In light of the above considerations, a continuous 95 percent reduction of VOC emissions from storage vessels in the oil and natural gas industry is a reasonable recommended RACT level of control.

Although sources may have a choice on how they meet the recommended RACT level of control, if air agencies choose to adopt the recommended RACT contained in this CTG, the technologies that may be used to meet the recommended RACT level of control for oil and natural gas industry storage vessels are capturing and routing emissions to the process via a VRU and/or routing emissions to a combustion device.

As discussed in section 4.2.2 of this chapter, the VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility, and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric

[34] The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

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pressure where it would not be cost-effective to require emission control requirements. Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Based on information gathered under the 2012 NSPS, [35] throughput and capacity of a storage vessel is not always the best indicator of a storage vessel's emissions, and we believe that the PTE of an individual storage vessel is preferable to use as an applicability threshold for storage vessels.

Based on our analyses conducted in support of the 2012 NSPS, 6 tpy was determined to be the applicability threshold for requiring 95 percent control of VOC emissions from new storage vessels (estimated to cost, on average, approximately $3,400 per ton of VOC reduced). Our analyses conducted for our RACT recommendation also found 6 tpy to be the applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels (estimated to cost, on average, between $4,400 and $5,000 per ton of VOC reduced). Based on these analyses, we recommend that the 95 percent VOC emission control of storage vessels only apply to storage vessels that have a PTE greater than or equal to 6 tpy of VOC emissions. The VOC cost of control per ton of VOC reduced would be less if a combustion device or VRU is used to control VOC emissions from multiple storage vessels because the cost for the additional storage vessels would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

We recommend an alternative RACT level of control for storage vessels that have a PTE VOC at or greater than 6 tpy that have actual emissions less than that on a continuing basis. For these storage vessels, if it can be demonstrated that the storage vessel has actual emissions less than 4 tpy for 12 consecutive months, we recommend that they be allowed to maintain and show continued compliance that their emissions are below 4 tpy in lieu of requiring 95 percent control. This alternative recommendation acknowledges that there are storage vessels that have a PTE greater than or equal to 6 tpy whose actual emissions have declined over time, usually because of declining production. This alternative RACT recommendation is informed by the 2012 NSPS, where we concluded that, based on "the cost-effectiveness, the secondary environmental impacts

[35] 77 FR 49490, August 16, 2012.

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and the energy impacts…BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained (i.e., for 12 consecutive months) uncontrolled emission rates fall below 4 tpy."[36]

In summary, we recommend the following as RACT for storage vessels in the oil and natural gas industry:

(1) RACT for Condensate Storage Vessels: Reduce emissions by 95 percent continuously from condensate storage vessels with a PTE ≥ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.[37]

(2) RACT for Crude Oil Storage Vessels: Reduce emissions by 95 percent continuously from crude oil storage vessels with a PTE ≥ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.[38]

4.5 Factors to Consider in Developing Storage Vessel Compliance Procedures

4.5.1 Compliance Recommendations When Using a Control Device

Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emission control. We believe that such efforts on the part of owners and operators can result in more effective control of VOC emissions from storage vessels.

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a storage vessel when using a control device or other

[36] Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards Final Amendments. Federal Register Notice. (78 FR 58429, September 23, 2013).
[37] We recommend that, prior to allowing the use of the uncontrolled 4 tpy actual VOC emissions rate for compliance purposes, air agencies require sources demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy for 12 consecutive months. After such demonstration, we recommend that air agencies require that sources demonstrate continued compliance with the uncontrolled actual VOC emission rate each month.
[38] See footnote 37.

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control measure (such as routing to a process), the storage vessel should be equipped with a cover that is connected through a closed vent system that captures and routes emissions to the control device (or process). We recommend cover, closed vent system and control device design and compliance measures to ensure that control measures meet the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 4.5.1.1 and 4.5.1.2. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in sections 4.5.1.3 and 4.5.1.4. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

4.5.1.1 Recommendations for Cover Design

The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) should form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel. Each cover opening should be secured in a closed, sealed position (gasket lid or cap) whenever material is in the unit except when it is necessary to open as follows:

(1) To add material to or remove material from the unit (including openings necessary to equalize or balance the internal pressure of the unit following changes in the level of material in the unit);

(2) To inspect or sample the material in the unit;

(3) To inspect, maintain, repair, or replace equipment located in the unit; or

(4) To vent liquids, gases or fumes from the unit through a closed vent system designed and operated in accordance with specified closed vent system requirements (see section 4.5.1.2) or to a process.

It is recommended that air agencies require the storage vessel thief hatch be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated. It is recommended that air agencies require the gasket material for the hatch be selected based on composition of the fluid in the storage vessel and weather conditions.

It is also recommended that air agencies require monthly olfactory, visual and auditory inspections of covers for defects that could result in air emissions. Any detected defects should be required to be repaired as soon as practicable.

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4.5.1.2 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (which can be monitored by monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, it is recommended that air agencies require owners and operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

4.5.1.3 Recommendations When "Routing to a Process" or to a VRU

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product and/or recovered. Vapor recovery units and flow lines that "route emissions to a process" would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 4.5.1.1 and 4.5.1.2 would apply.

4.5.1.4 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, it is recommended that air agencies require that the device

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operate at all times when gases, vapors, and fumes are vented from the storage vessel subject to VOC emission requirements through the closed vent system to the control device.

For control devices used to meet the recommended RACT, it is recommended that air agencies require owners and operators follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

If an owner or operator complies with the recommended RACT by using a combustion device, it is recommended that air agencies require initial and periodic performance testing (no later than 60 months after the initial performance test) to demonstrate initial and continued compliance with the recommended RACT level of control. Additionally, for each combustion device used to comply with the recommended continuous 95 percent VOC emission reduction, it is recommended that air agencies require owners and operators conduct the following control device compliance assurance measures: (1) Monthly visual inspections or monitoring to confirm that the pilot is lit when vapors are routed to it. (2) Monthly inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of part 60. It is recommended that the observation period be 15 minutes and that devices be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. (3) Monthly olfactory, visual and auditory inspections associated with the combustion device to ensure system integrity.

4.5.2 Compliance Recommendations When Complying with the 4 tpy VOC Emissions Alternative Limitation

If the alternative RACT recommendation to determine and maintain the uncontrolled actual VOC emissions from a storage vessel that has a PTE to emit greater than or equal to 6 tpy at less than 4 tpy without considering control is used, it is recommended that air agencies first require that a source demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, it is recommended that air agencies require that the source determine the uncontrolled actual VOC emission rate each month using a generally accepted model or calculation methodology. It is also recommended that such calculations be based on the average throughput for the month. If the monthly emissions determination indicates that VOC emissions from a storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not

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associated with fracturing or refracturing of a well feeding the storage vessel, it is recommended that air agencies require that the source comply with the 95 percent VOC emission reduction RACT level of control recommendation or that emissions be routed to a VRU.

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5.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the sources of VOC emissions from these compressors. This chapter also provides control techniques used to reduce VOC emissions from these compressors, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the associated VOC emission reductions and costs for both reciprocating and centrifugal compressors.

5.1 Applicability

For the purposes of this CTG, the emissions and emission reductions discussed herein would apply to centrifugal and reciprocating compressors in the oil and natural gas industry located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. As noted in section 3.2 of this document, we did not evaluate RACT for compressors located at a well site, or an adjacent well site and servicing more than one well site.

5.2 Process Description and Emission Sources

5.2.1 Process Description

5.2.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packaging system needs to be

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replaced to prevent excessive leaking from the compression cylinder. See Figure 5-1 for a depiction of a typical rod compressor packing system configuration.[39]

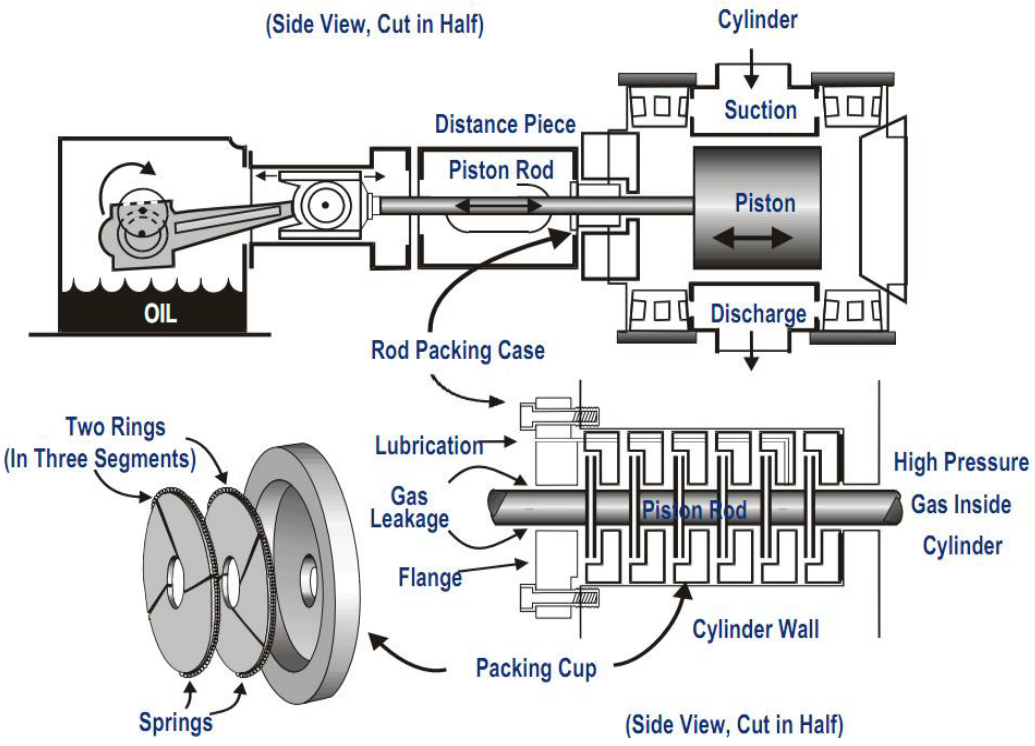


Figure 5-1. Typical Reciprocating Compressor Rod Packing System Diagram

5.2.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and

[39] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

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adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Figure 5-2 illustrates the wet seal compressor configuration.[40]

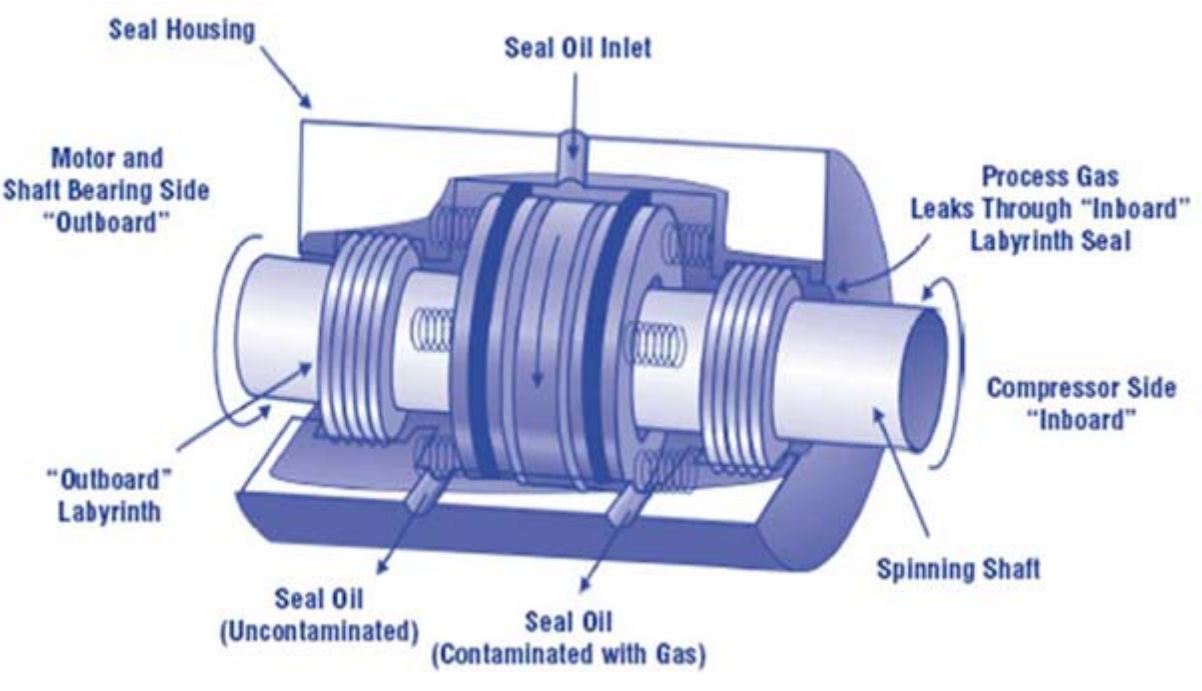


Figure 5-2. Typical Centrifugal Compressor Wet Seal

Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs (see Figure 5-3). The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed natural gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This natural gas is pumped between the grooves in the rotating and stationary rings. The opposing force of high-pressure natural gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little natural gas can leak. While the compressor is operating, the rings are not in

[40] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR Program. October 2006.

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contact with each other and, therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.[41]

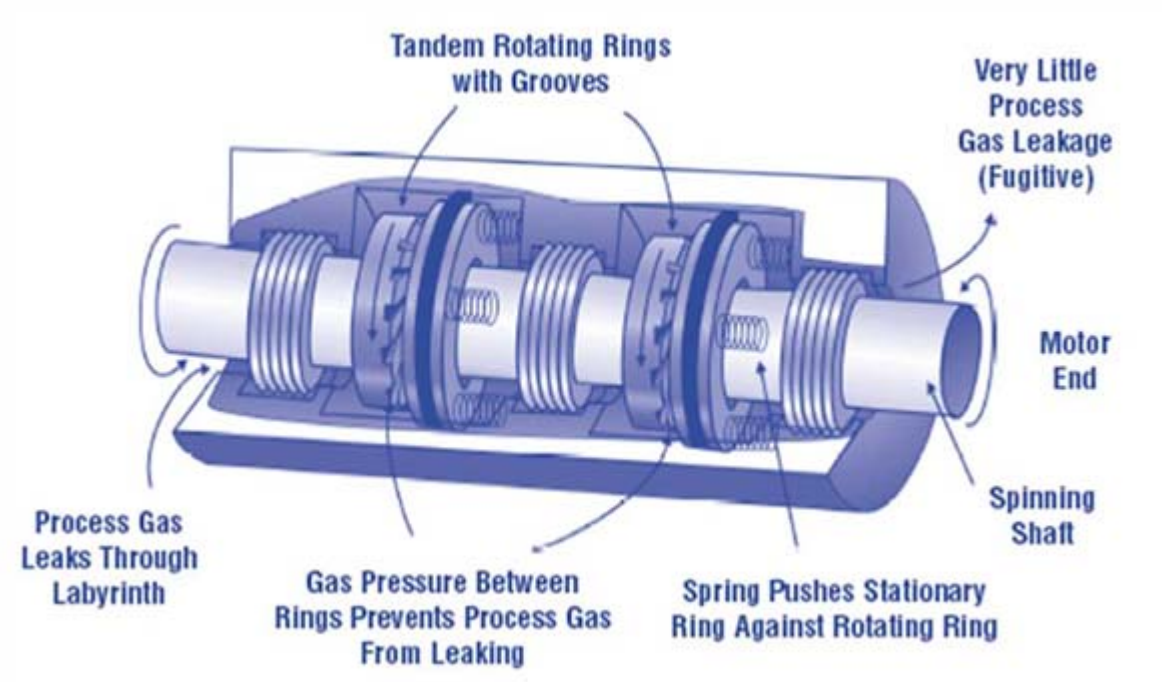


Figure 5-3. Typical Centrifugal Compressor Tandem Dry Seal

Natural gas emissions from wet seal centrifugal compressors have been found to be higher than dry seal compressors primarily due to the off-gassing of the entrained natural gas from the oil. This natural gas is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. In addition to lower natural gas leakage (and therefore lower emissions), dry seals have been found to have lower operation and maintenance costs than wet seal compressors because they are a mechanically simpler design, require less power to operate, and are more reliable. For the same reasons we explained in the 2012 NSPS and the 2015 NSPS proposal, we are not recommending RACT for dry seal compressors and instead include the use of a dry seal in place of a wet seal system as an available control option for reducing VOC emissions from wet seal centrifugal compressors (discussed in section 5.3.1.2 of this chapter). During the rulemakings for the 2012 NSPS and 2016 NSPS, we found that the dry seal system and the option of routing to a process both had at least a 95 percent control efficiency.

[41] Ibid.

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5.2.2 Emissions Data

5.2.2.1 Summary of Major Studies and Emissions

Several studies have been conducted that provide leak estimates from reciprocating and centrifugal compressors. Table 5-1 lists these studies, along with the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Compressors."[42]

Table 5-1. Major Studies Reviewed for Emissions Data[43]

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[j]
Inventory of Greenhouse Gas Emissions and Sinks[a]	EPA	Annual	Nationwide	X	
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013)[b]	EPA	2014	Facility-Level	X	X
Methane Emissions from the Natural Gas Industry[c]	EPA/Gas Research Institute (GRI)	1996	Nationwide	X	
Natural Gas STAR Program[d,e]	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry Methane Emission Factor Improvement Study[f]	URS Corporation, UT Austin, and EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses[g]	API/ANGA	2012	Regional	X[h]	
Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[i]	ICF International (Prepared for the Environmental Defense Fund (EDF)	2014	Regional	X	X

[42] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Compressors. Report for Oil and Natural Gas Sector Compressors Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

[43] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

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[a] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[b] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.
[c] U.S. Environmental Protection Agency/GRI. National Risk Management Research Laboratory. Research and Development. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.
[d] U.S. Environmental Protection Agency. *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR. Environmental Protection Agency. 2006.
[e] U.S. Environmental Protection Agency. *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR. Environmental Protection Agency. October 2006.
[f] URS Corporation/University of Texas at Austin. 2011. *Natural Gas Industry Methane Emission Factor Improvement Study, Final Report*. December 2011. http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.
[g] American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA). *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses*. Final Report. September 21, 2012.
[h] The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emission information was included.
[i] ICF International. *Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. Prepared for the Environmental Defense Fund. March 2014.
[j] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

5.2.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The centrifugal compressor methane emission factors used for processing are based on emission factor data for wet seals and dry seals from a sampling of wet seal and dry seal centrifugal compressor data that was used to calculate emissions in the GHG Inventory.

For gathering and boosting station reciprocating compressors, the 2011 NSPS TSD emission factors were used because they are considered to be the best representative emission factors at this time. Emission factors in the Clearstone study,[44] which are expressed in thousand standard cubic feet per cylinder, were multiplied by the average number of cylinders per gathering and boosting station reciprocating compressor. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the reciprocating compressor methane

[44] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.

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emission factors used for this analysis is presented in Table 5-2. Once the mass methane emission rate was calculated, ratios were used to estimate VOC emissions using the methane to VOC pollutant ratios developed in the 2011 Gas Composition Memorandum. The specific ratio that was used to convert methane emissions to VOC emissions is 0.278 pounds VOC per pound of methane for the production and processing segments. Table 5-3 presents a summary of the estimated methane and VOC emissions per reciprocating and centrifugal compressor (in tpy) for the production and processing segments.

Table 5-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors[45]

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scfh-cylinder)	Average Number of Cylinders	Pressurized Factor (Percent of Hours/Year Compressor Pressurized)	Wet Seal Methane Emission Factor (scfm)	Dry Seal Methane Emission Factor (scfm)
Gathering & Boosting Stations	25.9[a]	3.3	79.1%	N/A[c]	N/A[c]
Processing	57[b]	2.5	89.7%	47.7[d]	6[d]

[a] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.
[b] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks*. Table 4-14.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 11 – Compressor Driver Exhaust*. 1996 Report does not report any centrifugal compressors in the production or gathering/boosting segments, therefore no emission factor data were published for those two segments.
[d] U.S Environmental Protection Agency. *Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2012*. Washington, DC. April 2014.

[45] U.S. Environmental Protection Agency/GRI. Research and Development, National Risk Management Research Laboratory. *Methane Emissions from the Natural Gas Industry*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

Table 5-3. Baseline VOC Emission Estimates for Reciprocating and Centrifugal Compressors[a]

Industry Segment/Compressor Type	Baseline Emission Estimates (tpy)	
	Methane	VOC
Reciprocating Compressors		
Gathering and Boosting Stations	12.3	3.42
Processing	22	6.12
Centrifugal Compressors (Wet seals)		
Processing	210.53	19.1
Centrifugal Compressors (Dry seals)		
Processing	26	2.4

[a] For centrifugal compressors, it was assumed that 75 percent of the natural gas that is compressed is pipeline quality gas and 25 percent of the natural gas is production quality.

5.3 Available Controls and Regulatory Approaches

5.3.1 Available VOC Emission Control Options

Available controls for reducing VOC emissions from reciprocating and centrifugal compressors are presented in sections 5.3.1.1 and 5.3.1.2 of this chapter.

5.3.1.1 Reciprocating Compressors

Potential control options for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. These options include: (1) increasing or specifying the frequency of the replacement of the compressor rod packing, (2) increasing or specifying the frequency of the replacement of the piston rod, (3) specifying the refitting or realignment of the piston rod, and (4) routing of emission to a process through a closed vent system under negative pressure. In addition to these options, there are emerging control techniques where specific analyses have not yet been conducted. For example, there may be potential for reducing VOC emission by updating rod packing components made from newer materials which can help improve the life and performance of the rod packing system (economic rod packing replacement) and capturing gas from the reciprocating compressor and routing it back to the compressor engine to be used as fuel. These emerging VOC emissions control techniques are discussed briefly below, along with our

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evaluation of the frequency of compressor rod packing/piston rod replacement and piston rod refitting and realignment control options.

We do not believe that combustion is a technically feasible control option because, as detailed in the 2011 NSPS TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. While considering the option of routing of emissions to a process through a closed vent system under negative pressure, we determined that the negative pressure requirement not only ensures that all the emissions are conveyed to the process, it also avoids the issue of inducing back pressure on the rod packing and the resultant safety concerns. Although this option can be used in some circumstances, it cannot be applied in every installation. As a result, these options (i.e., routing of emissions to a control device, routing of emissions to a process through a closed vent system under negative pressure) were not further considered under this CTG.

Frequency of Rod Packing Replacement

For reciprocating compressors, one of the options for reducing VOC emissions is a maintenance task that would increase or specify the frequency of replacement of the rod packing in order to reduce the leakage of natural gas past the piston rod. Over time, the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces VOC emissions. Therefore, this control technique is considered to be an available VOC emission control technique for reciprocating compressors.

Description

As noted previously, reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed natural gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the "nose gasket" around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed natural gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod. [46]

[46] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

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Control Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions for gathering and boosting stations and the processing segment were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing.

Based on industry information from the Natural Gas STAR Program, we have determined that the additional cost of shortening the replacement period more frequently than every three years or every 26,000 hours would not be justified based on the additional emission reductions that would be achieved.[47] Therefore, we analyzed emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every three years or every 26,000 hours. For the baseline, we assumed that rod packing is replaced every four years. The analysis uses Equation 1 for estimating gathering and boosting station emission reductions, and Equation 2 for estimating processing segment emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every 3 years or every 26,000 hours.[48]

Equation 1

$$R_{WP}^{G\&B} = \frac{Comp_{Existing}^{G\&B}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6}$$

Where:

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting stations by replacing worn packing with newly installed packing, in million cubic feet per year (MMcf/year);

$Comp_{Existing}^{G\&B}$ = Number of existing gathering and boosting station compressors;

$E_{G\&B}$ = Methane emission factor for gathering and boosting stations, in cubic feet per hour per cylinder (25.9 scfh-cylinder);

[47] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews. 40 CFR Parts 60 and 63. Response to Public Comments on Proposed Rule*. August 23, 2011 (76 FR 52738). pg. 102.

[48] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

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E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[49] for this analysis;

C = Average number of cylinders for gathering and boosting stations (i.e., 3.3);

O = Percent of time during the calendar year the average gathering and boosting station is in the operating and standby pressurized modes, 79.1 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Equation 2 $$R_P = \frac{Comp^P_{Existing}(E_P - E_{New}) \times C \times O \times 8760}{10^6}$$

Where:

R_P = Potential methane emission reductions from processing compressors replacing worn packing to newly installed packing, in million cubic feet per year (MMcf/year);

$Comp^P_{Existing}$ = Number of existing processing compressors;

E_P = Methane emission factor for processing compressors, in cubic feet per hour per cylinder, 57 scfh-cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[50] for this analysis;

C = Average number of cylinders for processing compressors (i.e., 2.5);

O = Percent of time during the calendar year the average processing compressor is in the operating and standby pressurized modes, 89.7 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Table 5-4 presents a summary of the potential emission reductions for reciprocating compressor rod packing replacement for gathering and boosting stations and processing segment compressors based on the percent natural gas reduction calculated from the above equations. The emissions of VOC were estimated using the methane emissions calculated

[49] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.
[50] Ibid.

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above and the methane-to-VOC ratio developed for each of the segments in the 2011 Gas Composition Memorandum.

Table 5-4. Estimated Annual Reciprocating Compressor Emission Reductions from Increasing the Frequency of Rod Packing Replacement

Oil and Natural Gas Segment	Individual Compressor Emission Reductions (tons/compressor-year)	
	Methane	VOC
Gathering and Boosting	6.84	1.9
Processing	17.58	4.89

Cost Impacts

Costs for the specified frequency of replacement of reciprocating compressor rod packing documented in the 2011 NSPS TSD were obtained from a Natural Gas STAR Lessons Learned document which estimated the cost to replace the packing rings to be $1,712 per cylinder (converted from 2008 dollars to 2012 dollars). It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and, therefore, no additional travel costs would be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing replacement is based on the number of hours that the compressor operates or the period of time since the previous replacement. The 2011 NSPS TSD analysis assumed that, at baseline, the replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. The cost impacts are based on the replacement frequency of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

The 26,000 hour replacement frequency used for the cost impacts in the 2011 NSPS TSD was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. Assuming an interest rate of 7 percent, the capital recovery factors (based on replacing the rod packing every 3 years or 26,000 hours) were calculated to be 0.3122 and 0.3490 for gathering and boosting stations and the processing segment, respectively. The capital

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costs were calculated using the average rod packing cost of $1,712 (converted from $1,620 in 2008 dollars to 2012 dollars) and the average number of cylinders per compressor (assumed to be 3.3 cylinders for gathering and boosting stations and 2.5 cylinders for processing segment compressors).[51] The annual costs were calculated using the capital costs and the capital recovery factors. Table 5-5 presents a summary of the capital and annual costs for gathering and boosting stations and the processing segment.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement. Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[52] Table 5-5 presents the annual costs with savings and cost of control for reciprocating rod packing replacement for gathering and boosting stations and the processing segment.

Reciprocating compressor rod packing replacement prevents the escape of natural gas from the piston rod. In addition to reducing VOC emissions, there would be a co-benefit of reducing other emissions (such as methane) as a result of increasing the frequency of rod packing replacement.

Table 5-5. Cost of Control for Increasing the Frequency of Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost ($2012)[a]	Annual Costs per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Gathering and Boosting	$5,650	$2,153	$566	$1,131	$298
Processing	$4,280	$1,631	($2,443)	$334	($500)

[a] 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent).

[51] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

[52] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price. U.S. Energy Information Administration Natural Gas Navigator*. Retrieved online on December 12, 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.

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Frequency of Replacement and/or Realignment/Retrofitting of the Piston Rod

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[53] Rods wear "out-of-round" or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. We assume that operators will choose, at their discretion, when to replace/realign or retrofit the rod as part of regular maintenance procedures and replace the rod when appropriate when the compressor is out of service for other maintenance such as rod packing replacement. Therefore, we did not consider this option any further.

Updated Rod Packing Material

Although specific analyses have not been conducted, there may be potential for reducing VOC emissions by updating rod packing components made from newer materials, which can help improve the life and performance of the rod packing system. One option is to replace the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod.[54] Although changing the rod packing material has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry.

Economic Rod Packing Replacement

Another option facilities can use that has the potential to reduce costs and emissions is for facilities to use specific financial objectives and monitoring data to determine emission levels at which it is cost-effective to replace rings and rods. Benefits of calculating and utilizing this "economic replacement threshold" include VOC emission reductions and natural gas cost savings. Using this approach, one Natural Gas STAR partner reportedly achieved savings of over

[53] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.
[54] Ibid.

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$233,000 annually at 2006 gas prices. An economic replacement threshold approach would also result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings.[55]

Gas Recovery (Routing of Emissions to a Process)

Description

Another control option for reciprocating compressors includes control techniques that recover natural gas leaking past the piston rod packing. We are aware of a system that captures the natural gas that would otherwise be vented and routes it back to the compressor engine to be used as fuel.[56] The vent gases are passed through a valve train that includes a demister and then are injected into the engine intake air after the air filter. In general, the technology consists of recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The system's computerized air/fuel control system would then adjust the normal fuel supply to accommodate the increased fuel made available from the recovered emissions and thereby take advantage of the recovered emissions while avoiding an overly rich fuel mixture.

Subpart OOOO, as well as subpart OOOOa, provide a compliance option for reciprocating compressors that allows collecting emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and routing the rod packing emissions to a process through a closed vent system. Both of the above systems, if installed using a cover and closed vent system meeting the subpart OOOO and subpart OOOOa requirements, could potentially be used for this compliance option.

Control Effectiveness

One estimate obtained by the EPA states that the gas recovery system can result in the elimination of over 99 percent of VOC emissions that would otherwise occur from the venting of the emissions from the compressor rod packing.[57] The emissions that would have been vented are combusted in the compressor engine to generate power.

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[55] Ibid.

[56] REM Technology Inc. and Targa Resources. *Reducing Methane and VOC Emissions*. Presentation for the 2012 Natural Gas STAR Annual Implementation Workshop.

[57] REM Technology Inc., et al. *Profitable Use of Vented Emission in Oil & Gas Production*. Prepared with support from the Climate Change and Emissions Management Corporation (CCEMC). 2013.

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If the facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95-100 percent of emissions. If the gas is routed to a flare, approximately 95 percent of the VOC emissions could be reduced.

Cost Impacts

One estimate reported that the cost per engine would be approximately $12,000 (does not include installation costs). Some costs would be mitigated by fuel gas savings, as using the captured gas to displace some of the purchased fuel would require less fuel to be purchased in order to run the compressor engine. The fuel cost saving based on a 4-throw compressor with moderate leak rate would be an estimated $6,500 per year.[58] This technique is discussed further in the Natural Gas STAR PRO Fact Sheet titled "Install Automated Air/Fuel Ratio Controls".[59] This document reported an average fuel gas savings of 78 Mcf/day per engine with the gas recovery system installed. Based on our review of information on this technology, we conclude that this technology has merit and would provide better emission reductions than increasing the replacement of rod packing from every 4 years to every 3 years since the emissions would be captured under negative pressure, allowing all emissions to be routed to the engine. It is our understanding that this technology may not be applicable to every compressor installation and situation.

For a VRU, assuming the proper equipment is already available at the facility, capturing the rod packing emissions would require minimal costs. The investment would only need to include the cost of piping and installation. While we have not obtained a cost estimate specifically for routing rod packing vents to a VRU, this process has been studied for dehydrators and would be similar for rod packing systems. According to the Natural Gas STAR PRO Fact Sheet titled "Pipe Glycol Dehydrator to Vapor Recovery Unit,"[60] the cost for planning and installing additional piping is approximately $2,000. Routing to a VRU also provides additional incentive as there is a value associated with recovered gas. However, the installation of a VRU to only capture rod packing emissions may not be economically viable if an additional compressor system is required. If the VRU is already present at the facility, the incremental cost

[58] REM Technology Inc. Presentation to the U.S. Environmental Protection Agency on December 1, 2011. EPA Docket ID No. EPA-HQ-OAR-2010-0505.
[59] U.S. Environmental Protection Agency. Gas STAR PRO No. 104. *Install Automated Air/Fuel Ratio Controls*. 2011.
[60] U.S. Environmental Protection Agency. Gas STAR PRO No. 203. *Pipe Glycol Dehydrator to Vapor Recovery Unit*. 2011.

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to capture the rod packing vent gas can be recovered from the value of the additional captured natural gas.

Although gas recovery has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its availability as a reasonably available control option for reducing reciprocating compressor VOC emissions. However, we recommend that air agencies consider this technology as a compliance option when considering the RACT recommendations presented in section 5.4 of this chapter.

5.3.1.2 Centrifugal Compressors Equipped with Wet Seals

Potential control options to reduce emissions from centrifugal compressors equipped with wet seals include control techniques that limit the leaking of natural gas across the rotating shaft, and capture and destruction of the emissions by routing emissions to a process (e.g., a compressor or fuel gas system) or to a combustion device (discussed in detail in sections 4.3.1.2 of chapter 4). We evaluate below three available control options: (1) converting wet seals to dry seals, (2) routing emissions to a fuel gas system or compressor (process), and (3) routing emissions to a combustion device.

Converting Wet Seals to Dry Seals

Description

We evaluated the use of centrifugal compressor dry seals as an available VOC control option for wet seal centrifugal compressors. As noted in section 5.2 of this chapter, the VOC emission profile from the use of dry seals is considerably less than from the use of wet seals. Replacing wet seals with dry seals can, therefore, substantially reduce VOC emissions across the rotating shaft compared to wet seals, while simultaneously reducing operating costs and enhancing compressor efficiency compared to wet seals. During normal operation, dry seals leak at a rate of 6 scfm methane per compressor.[61] While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is recirculated is usually vented to the atmosphere,

[61] U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

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bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[62,63] It is not practical or feasible in all situations, however, to retrofit an existing wet seal compressor with a dry seal compressor. We have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission for the conversion period.

Control Effectiveness

The emission reductions that would occur by replacing wet seal compressors with a dry seal compressor were calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. We used the centrifugal compressor emission factors in Table 5-2 and estimated that VOC emissions would be reduced by 16.7 tpy per compressor.

Cost Impacts

The Natural Gas STAR Program estimated the cost of retrofitting dry seals on a centrifugal compressor equipped with wet seals to be $324,000 ($342,439 in 2012 dollars) for a two-seal dry seal system, which includes the cost of both seals and the dry gas conditioning, monitoring, control console and installation.[64] The annual costs were calculated as the capital recovery of the capital cost assuming a 20-year equipment life and 7 percent interest, which is approximately $32,324 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of a dry seal compressor is $88,300 ($93,325 in 2012 dollars) in comparison to a wet seal compressor. In addition, the installation of dry seals reduces natural gas emissions by 10,721 Mscf/yr[65] which results in an estimated natural gas savings of $42,883 per year assuming a natural gas price of $4/Mcf. A summary of the capital and annual costs for replacing a wet seal compressor with a dry seal compressor is presented in Table 5-6 along with the VOC cost of control. As noted above, we

[62] U.S. Environmental Protection Agency, et al. *Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry*. World Gas Conference 10/2009.

[63] U.S Environmental Protection Agency. *Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems*. *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2012*. Washington, DC. Annex 3. Table A-129.

[64] U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

[65] The natural gas savings was calculated by using the 16.7 tpy VOC reduction and dividing by the VOC/methane weight ratio of 0.278 to determine the amount of methane reduction that would be reduced (60.1 tpy). The methane emission reductions were converted to volumetric natural gas reductions assuming a natural gas density of 0.02082 tons/Mcf and an 82.9 volume percent conversion factor of methane to natural gas.

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have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission during the conversion period. Because of this, a facility may have to provide a temporary compressor in the interim that would add additional costs to the cost estimates we present in Table 5-6.

Table 5-6. Cost of Control of Replacing a Wet Seal Compressor with a Dry Seal Compressor

Oil & Natural Gas Segment	Capital Cost ($2012)	Annual Costs Per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings [a]	With O&M and Natural Gas Savings [b]	Without Savings	With O&M and Natural Gas Savings
Processing	$342,439	$32,324	($103,884)	$1,931	($6,205)

[a] Includes only the annualized capital cost of the retrofit of the dry seal system (20 years, 7 percent interest).
[b] Includes the annualized capital cost, annual operation and maintenance (O&M) savings and annual natural gas savings.

Routing Emissions to a Compressor or Fuel Gas System (Process)

Description

One option for reducing VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system or other beneficial use (referred to collectively as routing to a process). Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Emissions that are routed to a process can result in the same or greater emission reductions as would have been achieved had the emissions been routed through a closed vent system to a combustion device. Table 5-7 presents a summary of the estimated emission reductions from routing emissions from the wet seal fluid degassing system to a process. For purposes of this analysis, we assume that routing VOC emissions from a wet seal fluid degassing

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system to a process reduces VOC emissions greater than or equal to a combustion device (i.e., greater than or equal to 95 percent).

Table 5-7. Estimated Annual Centrifugal Compressor VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Process[66,67]

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	≥ 18.1

Cost Impacts

The capital cost of a system to route the seal oil degassing system to a process is estimated to be $23,252,[68] converting to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[69] The estimated costs include an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The annual costs were estimated to be $2,553 assuming a 15-year equipment life at 7 percent interest.

Potential natural gas savings for this option were estimated to be 12 Mcf/yr and assumes that greater than or equal to 95 percent of the 47.7 scfm methane emissions are controlled, an annual operating factor of 43.6 percent, and the 82.9 volume percent conversion factor of methane to natural gas. Assuming a natural gas savings of $4/Mcf, the natural gas savings equates to approximately $47,553 per year. Table 5-8 presents a summary of the cost of control for routing emissions to a process.

[66] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.
[67] Ibid.
[68] Ibid.
[69] U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF]*, retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/GDPDEF/ March, 26, 2015.

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Table 5-8. VOC Cost of Control for Routing Wet Seal Fluid Degassing System to a Process[a]

Oil and Gas Segment	Capital Cost ($2012)[a]	Annual Costs per Compressor ($/compressor-year)		VOC Cost of Control ($/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Processing	$23,252	$2,553	($47,553)	$141	($2,621)

[a] 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[70]

Routing Emissions to a Combustion Device

Description

Combustion devices are commonly used in the oil and natural gas industry to combust VOC emission streams. Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. Similar to the analysis of storage vessels, for this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of VOC. The wet seal emissions in Table 5-2 were used along with the control efficiency to calculate the emission reductions. Table 5-9 presents a summary of the estimated emission reductions from routing emissions from the wet seal to a combustion device.

Table 5-9. Estimated Annual VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Combustion Device[71]

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	18.1

[70] Ibid.

[71] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

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Cost Impacts

Routing the captured gas from the centrifugal compressor wet seal degassing system to an existing combustion device or installing a new combustion device has associated capital and operating costs. The capital and annual costs of the combustion device (an enclosed flare for the analysis) were calculated using the methodology in the EPA Control Cost Manual.[72] The heat content of the gas stream was calculated using information from the 2011 Gas Composition Memorandum. Table 5-10 presents a summary of the capital and annual costs for wet seals routed to a flare, as well as the VOC cost of control. There is no cost savings estimated for this option because the recovered natural gas is combusted.

Table 5-10. Cost of Control for Routing Wet Seal Fluid Degassing System to a Combustion Device

Industry Segment	Capital Cost ($)		Annual Cost per Compressor ($/compressor-year)		VOC Cost of Control New CD ($/ton)	VOC Cost of Control Existing CD ($/ton)
	New CD	Existing CD	New CD	Existing CD		
Processing	$71,783	$23,252	$114,146	$3,311	$6,292	$183

CD = Control Device

5.3.2 Existing Federal, State and Local Regulations

5.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, reciprocating compressors are required to limit VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the previous rod packing replacement. Alternatively, an owner or operator is allowed to route rod packing emissions to a process through a closed vent system under negative pressure. For centrifugal compressors in the processing segment, the 2012 NSPS and 2016 NSPS require that VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95 percent.

[72] U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

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5.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

Montana requires oil and natural gas well facilities to control emissions from the time the well is completed until the source is registered or permitted. Each piece of oil or natural gas well facility equipment, with VOC vapors of 200 Btu/scf or more with a PTE greater than 15 tpy, is required to (1) capture and route emissions to a natural gas pipeline, (2) route to a smokeless combustion device equipped with an electronic ignition device or a continuous burning pilot system meeting the requirements of 40 CFR 60.18 and operating at 95 percent or greater control efficiency, or (3) route to air pollution control equipment with equal or greater control efficiency than a smokeless combustion device. This includes the control of emissions from compressor engines used for transmission of natural gas (Registration of Air Contaminant Sources, Rule 17.8.1711 Oil or Gas Well Facilities Emission Control Requirements).

Colorado (Regulation 7, XVII.B.3.b and c) requires that uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors be controlled by at least 95 percent, unless the centrifugal compressor is subject to 40 CFR part 60, subpart OOOO. Additionally, Regulation 7 requires that rod packing on any reciprocating compressor located at a natural gas compressor station be replaced every 26,000 hours of operation or every 36 months, unless the reciprocating compressor is subject to 40 CFR part 60, subpart OOOO.

5.4 Recommended RACT Level of Control

For reciprocating compressors, there are federal and state regulations that require the periodic replacement of reciprocating compressor packing. The federal regulations (the 2012 NSPS and 2016 NSPS) require the replacement of reciprocating compressor rod packing every 3 years or on or before 26,000 hours of operation. The state regulation (Colorado) requires the

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replacement of reciprocating compressor rod packing every 26,000 hours of operation or every 36 months. The 2012 NSPS and 2016 NSPS also provide the alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

As noted in section 5.3 of this chapter, the most significant volume of VOC emissions are associated with piston rod packing systems. We found that, under the best conditions, regular rod packing replacement, when carried out approximately every three years, effectively controls emissions and helps prevent excessive rod wear. The cost of control for requiring the replacement of reciprocating packing at this frequency was estimated to be $1,132 per ton of VOC reduced without savings and $298 per ton of VOC reduced considering savings for gathering and boosting station compressors, and about $334 per ton of VOC reduced without savings, and an overall net savings per ton of VOC reduced for processing segment reciprocating compressors considering savings. Based on the emission reductions, costs (considering gas savings) and existing and currently implemented regulations that require the replacement of the reciprocating compressor packing every 36 months or on or before 26,000 hours of operation, we recommend this control option as RACT for reciprocating compressors in the production and processing segments (excluding compressors at the well site). We also recommend that air agencies provide operators the compliance alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

For centrifugal compressors, there are already federal, state and local regulations that require the capture and 95 percent control of emissions from wet seal fluid degassing systems from centrifugal compressors. Although dry seal systems have low VOC emissions and the option of routing to a process has at least a 95 percent control efficiency, the replacement of wet seals with dry seals and routing to a process may not be technically feasible or practical options for some centrifugal compressors. The integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, and, in the case of capture of emissions with routing to a process, there may not be downstream equipment capable of handling a low-pressure fuel source. As a result of our evaluation of the technical feasibility and practicality of existing available controls, we recommend RACT be 95 percent control of emissions from the wet seal degassing system, which can be achieved by using a closed vent system and routing emissions to a combustor or routing the emissions back to the compressor or fuel line (routing to the process). For the processing segment, we assume that

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there is an existing combustion device onsite and the estimated cost of control would be about $183 per ton of VOC reduced for facilities to route emissions to the existing combustion device, or about $141 per ton of VOC reduced for facilities to route the captured emissions back to the compressor or fuel line.

In summary, we recommend the following as RACT for compressors:

(1) RACT for Reciprocating Compressors Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each reciprocating compressor reduce VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the last rod packing replacement. We also recommend that an alternative be provided to allow routing of rod packing emissions to a process via a closed vent system under negative pressure in lieu of the specified rod packing replacement periods. We do not recommend that RACT apply to individual reciprocating compressors located at a well site, or an adjacent well site and servicing more than one well site.

(2) RACT for Centrifugal Compressors Using Wet Seals Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each centrifugal compressor using wet seals reduce VOC emissions from each wet seal fluid gassing system by reducing VOC emissions by 95 percent. We do not recommend that RACT apply to individual centrifugal compressors using wet seals located at a well site, or an adjacent well site and servicing more than one well site.

5.5 Factors to Consider in Developing Compressor Compliance Procedures

5.5.1 Reciprocating Compressor Compliance Recommendations

In order to ensure and demonstrate compliance with the recommended RACT for reciprocating compressors, we recommend that air agencies require facilities to maintain a record of the date of the most recent reciprocating compressor rod packing replacement, monitor and keep records of the number of hours of operation and/or track the number of months since the last rod packing replacement for each reciprocating compressor (to meet the requirement that the packing is changed out on or before the total number of hours of operation reaches 26,000 hours

or the number of months since the most recent rod packing replacement reaches 36 months) and maintain records of instances where the reciprocating compressor was not operated in compliance with RACT. This may require the installation of an operating hours meter on the engine to track the number of hours of operation. We also recommend that air agencies require annual reports of the cumulative hours of operation or number of months since packing replacement for each reciprocating compressor and instances when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT.

For applications in which operators choose to opt for the alternative of routing of rod packing emissions to a process via a closed vent system under negative pressure, it is recommended that air agencies require facilities to maintain records of the date of installation of a rod packing emissions collection system and closed vent system and maintain records of instances of deviations in cases where the reciprocating compressor was not operated in compliance with requirements. We also recommend that air agencies require annual reports for each reciprocating compressor complying with this option indicating when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4.

The appendix to this document presents example model rule language that incorporates compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.2 Centrifugal Compressor Equipped with a Wet Seal Recommendations

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a centrifugal compressor equipped with a wet seal when using a control device or other control measure (such as routing to a process), the centrifugal compressor should be equipped with a cover that is connected through a closed vent system that routes emissions to the control device (or process) that meets the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in section 5.5.5.

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The appendix of this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.3 Recommendations for Cover Design

The cover and all openings on the cover should form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system (for centrifugal compressors), and of the rod packing emissions collection system (for reciprocating compressors). Each cover opening should be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(1) To inspect, maintain, repair, or replace equipment; or

(2) To vent gases or fumes from the unit, through a closed vent system designed and operated in accordance with closed vent system requirements (see section 5.5.4), to a control device or to a process.

It is recommended that air agencies require olfactory, visual and auditory inspections of covers for defects that could result in air emissions on a monthly basis. We recommend air agencies require that any detected defects be repaired as soon as practicable.

5.5.4 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of Part 60, and ongoing monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open

such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

5.5.5 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, we advise that the device be required to operate at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. The following paragraphs present select emission control options and suggested operation and monitoring requirements, as appropriate to ensure compliance with the recommended RACT level of control.

Enclosed Combustion Devices

If an enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) is used to meet the 95 percent VOC emission reduction RACT level of control, it should be designed to reduce the mass content of VOC emissions by 95 percent or greater and be: (1) maintained in a leak free condition, (2) installed and operated with a continuous burning pilot flame, and (3) operated with no visible emissions.

It is recommended that the visible emissions test (using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7) be performed at least once every calendar month. If a combustion device fails the visible emissions test, sources should be required to follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. It is recommended that all inspection, repair and maintenance activities for each unit be recorded in a maintenance and repair log that can be made available for inspection. Following return to operation from maintenance or repair activity, each device should be required to pass a Method 22, 40 CFR part 60, appendix A-7 visual emissions test.

It is recommended that air agencies require that sources meeting the 95 percent VOC emission reduction RACT level of control by routing emissions to a combustion device conduct performance tests and/or design analyses that demonstrate that the combustion device being used meets the required 95 percent VOC emission reduction RACT level of control (see section F of

the appendix to this document for performance testing procedures for control devices that we recommend be used to demonstrate performance requirements).

Routing to a Process

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Vapor recovery units and flow lines that "route emissions to a process" would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 5.5.3 and 5.5.4 would apply.

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6.0 PNEUMATIC CONTROLLERS

The oil and natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic, (2) electrical, or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are pneumatic devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves and may be actuated using pressurized natural gas (natural gas-driven) or may be actuated by another means such as a pressurized gas other than natural gas, solar, or electric. This chapter describes pneumatic controllers that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also presents control techniques used to reduce VOC emissions from these pneumatic controllers, along with costs and emission reductions. Finally, this chapter discusses our recommended RACT and the associated VOC emission reductions and costs for pneumatic controllers.

6.1 Applicability

For the purposes of this CTG, a pneumatic controller is an automated instrument used to maintain a process condition such as liquid level, pressure, pressure differential and temperature. The emissions and emission controls discussed herein would apply to natural gas-driven pneumatic controllers in the oil and natural gas industry located from the wellhead to a natural gas processing plant (including the natural gas processing plant) or from the wellhead to the point of custody transfer to an oil pipeline.

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6.2 Process Description and Emission Sources

6.2.1 Process Description[73]

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this CTG, they are characterized primarily by their emission characteristics:

(1) *Continuous bleed pneumatic controllers* are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time. Continuous bleed controllers are further subdivided into two types based on their bleed rate:

   a. *Low-bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).

   b. *High-bleed*, having a bleed rate of greater than 6 scfh.

(2) *Intermittent bleed or snap-acting pneumatic controllers* release gas only when they open or close a valve or as they throttle the gas flow.

(3) *Zero-bleed pneumatic controllers* do not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Pneumatic controllers often make use of available high-pressure natural gas to operate or control a valve. The supply gas pressure is modulated by a process condition, and then flows to the valve controller where the signal is compared with the process set point to adjust gas pressure in the valve actuator. In these natural gas-driven pneumatic controllers, natural gas may be released intermittently with every actuation of the valve. In other designs, natural gas may be released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady state rates when operated under similar conditions. It is our understanding that self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. "Closed loop" systems are applicable only in instances with very low pressure[74] and may not be suitable to

[73] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[74] Memorandum to Bruce Moore, U.S. Environmental Protection Agency, from Denise Grubert, EC/R Incorporated. *Meeting Minutes from EPA Meeting with the American Petroleum Institute (API)*. October 2010.

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replace many applications of continuous or intermittent bleed pneumatic devices. Therefore, this CTG does not address these self-contained devices further.

Intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the controller's bleed stream. Since actuation emissions serve the controller's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 6.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation. Intermittent controllers are assumed to have zero bleed emissions. For most applications (but not all), intermittent controllers serve functionally different purposes than bleed devices. Therefore, because the total emissions are dependent on the application in which they are used, we do not consider their use to be a technically practical control option for all continuous bleed controllers.

As previously indicated, not all pneumatic controllers are natural gas driven. At sites with a continuous and reliable source of electricity, controllers can be actuated by an instrument air system that uses compressed air instead of natural gas. These sites may also use mechanical or electrically powered pneumatic controllers. In some instances, solar-powered controllers may be feasible. Because these devices are not natural gas driven, they do not directly release natural gas or VOC. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. To our knowledge, natural gas processing plants are the only facilities in the oil and natural gas industry that are likely to have electrical service sufficient to power an instrument air system, and most existing natural gas processing plants use instrument air instead of natural gas-driven devices.[75]

[75] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R/-96-080k. June 1996.

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6.2.2 Emissions Data

6.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic controllers and the potential options available to reduce VOC emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."[76]

Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[l]
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013)[a]	EPA	2014	Facility-Level	X	X
Inventory of Greenhouse Gas Emissions and Sinks[b]	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry[c]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry[d]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the U.S. Oil Industry[e]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[f]	WRAP	2005	Regional	X	
Natural Gas STAR Program[g]	EPA	2000 – 2010	Voluntary	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States[h]	Multiple Affiliations, Academic and Private	2013	Nationwide	X	

[76] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel.* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[l]
Determining Bleed Rates for Pneumatic Devices in British Columbia[i]	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas[j]	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[k]	ICF International	2014	Nationwide	X	X

[a] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC.
[b] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report.* EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.
[d] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry. Draft Report*. June 14, 1996.
[e] ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.
[f] ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States.* Prepared for Western Governors Association. December 27, 2005.
[g] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[h] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.
[i] U.S. Environmental Protection Agency. *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas Star. Washington, DC. 2006.
[j] U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.
[k] Canadian Environmental Technology Advancement Corporation (CETAC)-WEST. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Prepared for the Canadian Association of Petroleum Producers. May 2008.

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[1] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

6.2.2.2 Representative Pneumatic Controller Device Emissions

For purposes of this CTG, continuous bleed pneumatic controllers are classified into two types based on their emissions rates: (1) high-bleed controllers, and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 scfh, while low-bleed devices bleed at a rate less than or equal to 6 scfh.[77]

In support of the development of the 2012 NSPS and 2016 NSPS, and this CTG, we consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, subpart W of the GHGRP, the GHG Inventory, as well as pneumatic controller vendor information used during the development of the 2012 NSPS.[78] The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic controller model (or model family). All pneumatic controllers that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although, by definition, a low-bleed device can emit up to 6 scfh, through vendor research, a typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have bleed rates from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high-bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[79,80] While the vendor data provided useful information on specific makes and models, it did not yield sufficient information about the prevalence of each model type in the population of devices in the oil and

[77] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed rates' of 0.1 to 0.5 cubic feet per minute are considered to be 'high-bleed' types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[78] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

[79] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program.* Washington, DC. November 2010.

[80] All rates are listed at an assumed supply gas pressure of 20 psig.

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natural industry, which is an important factor in developing a representative emission factor. Therefore, in support of this CTG, we have determined that the best available emission estimates for pneumatic controllers in the production segment are from the GHGRP. For the natural gas processing segment, we determined that the quantified representative methane emissions from a continuous bleed pneumatic controller based on natural gas emission rates presented in Volume 12 of the EPA/GRI report used in the 2012 NSPS TSD is the best available emissions information.[81]

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from an average high-bleed and low-bleed pneumatic controller in the production and processing segments and then estimate methane and VOC emissions using a representative gas composition from the 2011 Gas Composition Memorandum. A bleed rate of 1.39 scfh was used for a low-bleed controller, and a bleed rate of 37.3 scfh was used for a high-bleed controller. The specific gas composition ratio used for the production and processing segments was 0.278 pounds VOC per pound methane. Table 6-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment (for production and processing segments) and device type.

Table 6-2. Average Emission Rates for High-Bleed and Low-Bleed Pneumatic Controllers in the Oil and Natural Gas Industry[a]

Industry Segment	High-Bleed (tpy)		Low-Bleed (tpy)	
	Methane	VOC	Methane	VOC
Oil and Natural Gas Production[b,c]	5.3	1.47	0.2	0.06
Natural Gas Processing[d]	1.00	0.28	1.0	0.28

[a] The conversion factor used in this analysis is 1 Mcf of methane is equal to 0.0208 tons methane.
[b] Natural gas production methane emissions are derived from the GHGRP (subpart W).
[c] Oil production methane emissions are derived from the GHGRP (subpart W). It is assumed only continuous bleed devices are used in oil production.
[d] Natural gas processing segment methane emissions are derived from Volume 12 of the 1996 EPA/GRI report. Emissions from devices in the processing segment were determined based on data available for snap-acting and continuous bleed devices. Further distinction between high-

[81] GRI/EPA Research and Development. Methane Emissions from the Natural Gas Industry; Volume 12: Pneumatic Devices. (1996) EPA-600/R-96-0801. Table 4-11, page 56.

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and low-bleed could not be determined based on available data. For the natural gas processing segment, it is assumed that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

6.3 Available Controls and Regulatory Approaches

6.3.1 Available VOC Emission Control Options

Although pneumatic controllers have relatively small emissions individually, due to the large population of these devices, the cumulative VOC emissions for the industry are significant. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic controllers. The following sections provide a summary of options for reducing VOC emissions from pneumatic controllers including: (1) replacing high-bleed controllers with low-bleed controllers or zero-bleed controllers; (2) driving controllers with instrument air rather than natural gas, using non-gas-driven controllers; and (3) enhanced maintenance.

Sections 6.3.1.1 and 6.3.1.2 discuss the control of VOC emissions by replacing a high-bleed device with a low-bleed device, and driving controllers with instrument air rather than natural gas, including the estimated costs of these options. Given applicability, efficiency and the expected costs, other options (i.e., mechanical controls and enhanced maintenance) are only briefly discussed in sections 6.3.1.3 and 6.3.1.4.

6.3.1.1 Install a Low-Bleed Device in Place of a High-Bleed Device

Description

As discussed previously, low-bleed controllers generally provide the same operational function as a high-bleed controller, but have lower continuous bleed emissions.

Control Effectiveness

We estimate on average that 1.41 tons of VOC will be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device. There are certain situations in which replacing and retrofitting devices are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high-bleed rate to

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actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, we assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production segment.

Applicability of low-bleed controllers may depend on the function carried out by the controller. Low-bleed pneumatic controllers may not be applicable for replacement of high-bleed devices because a process condition may require a fast or precise control response to minimize deviation from the desired set point. A slower acting low-bleed controller could potentially result in damage to equipment and/or become a safety issue because it may not be able to respond as quickly as a high-bleed controller. An example of this is a compressor where pneumatic controllers may monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady state) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can typically accommodate control from a low-bleed device, which is slower acting and less precise.

Cost Impacts

Costs were based on vendor research as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers.[82] As Table 6-3 indicates, the average cost for a low-bleed pneumatic controller is $2,698, while the average cost for a high-bleed pneumatic controller is $2,471.[83] In order to analyze cost impacts, the average cost to install a new low-bleed pneumatic controller was annualized for a 15-year period using a 7 percent interest rate. This equates to an annualized cost of around $271 per low-bleed device for the production segment.

[82] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[83] Costs are estimated in 2012 U.S. dollars.

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Table 6-3. Cost Projections for Representative Pneumatic Controllers[a]

Device	Minimum Cost ($2012)	Maximum Cost ($2012)	Average Cost ($2012)
High-Bleed Controller	$387	$7,398	$2,471
Low-Bleed Controller	$554	$9,356	$2,698

[a] 2011 NSPS TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent). During the development of the 2012 NSPS, major pneumatic controller vendors were surveyed for costs, emission rates and any other pertinent information.

Monetary savings associated with retaining natural gas that would have been emitted was estimated based on a natural gas value of $4.00 per Mcf.[84] The use of a low-bleed pneumatic controller is estimated to reduce methane emissions by 5.1 tpy (245 Mcf/yr) (using the conversion factor of 0.0208 tons methane per 1 Mcf) over the use of a high-bleed pneumatic controller. Assuming natural gas in the production segment is 82.8 percent methane by volume, this equals 296 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic controller in the production segment is approximately $1,184. Table 6-4 presents the estimated cost of control per ton of VOC reduced for replacing a high-bleed pneumatic controller with a new low-bleed pneumatic controller in the production segment of the oil and natural gas industry.

Table 6-4. VOC Cost of Control for Replacing an Existing High-Bleed Pneumatic Controller with a New Low-Bleed Pneumatic Controller

Segment	Average Capital Cost per Unit ($2012)[a,c]	Total Annual Costs per Unit ($2012/yr)[b,c]		VOC Cost of Control ($2012/ton)[c]	
		Without Savings	With Savings	Without Savings	With Savings
Oil and Natural Gas Production	$2,698	$296	($886)	$209	($625)

[a] Average capital cost of a low-bleed device as summarized in Table 6-3.
[b] Annualized cost assume a 7 percent interest rate over a 15-year equipment lifetime.
[c] Cost data from the 2011 TSD converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflater (5.69 percent).

[84] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price. U.S. Energy Information Administration. Natural Gas Navigator*. Retrieved online on 12 Dec 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.

6.3.1.2 Instrument Air Systems

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator and volume tank. The following is a description of each component as described in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air":[85]

(1) Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

(2) A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, natural gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be cost-effective for remote locations, and reduce both VOC emissions and energy consumption. Small natural gas-driven fuel cells are also being developed.

(3) Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

[85] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006.

(4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. The use of instrument air eliminates natural gas emissions from natural gas-driven pneumatic controllers. All other parts of a natural gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available. Figure 6-1 illustrates a diagram of a natural gas pneumatic control system. Figure 6-2 illustrates a diagram of a compressed instrument air control system. [86]

Control Effectiveness

The use of instrument air eliminates natural gas emissions from the pneumatic controllers; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is access to high Btu gas, a high concentration of pneumatic control valves and the presence of an operator who can ensure the system is properly functioning.[87]

For natural gas processing plants, we believe that instrument air systems are typically used to power pneumatic controllers and that any natural gas-driven pneumatic controllers in use are required for safety and functional reasons. The use of an instrument air system would reduce VOC emissions from a natural gas-driven pneumatic controller by 100 percent.

Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressurized air. The size of the compressor depends on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas

[86] Ibid.
[87] Ibid.

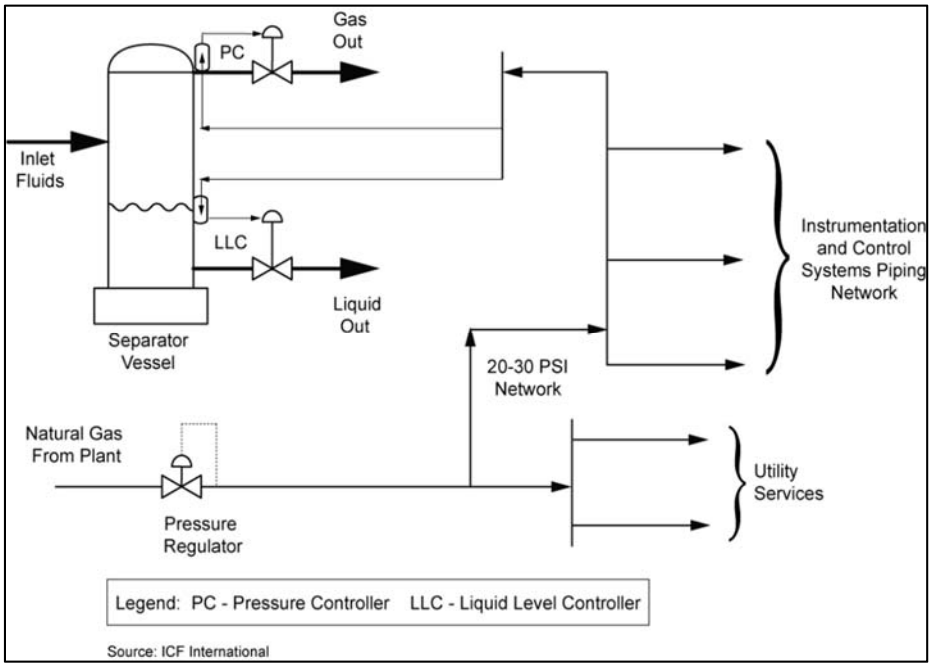


Figure 6-1. Natural Gas Pneumatic Control System

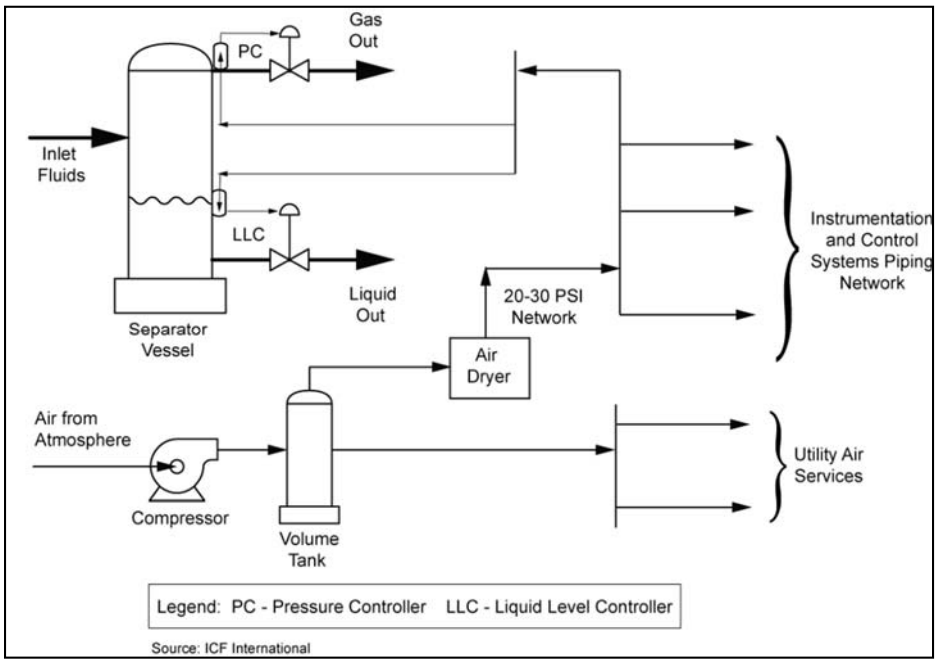


Figure 6-2. Compressed Instrument Air Control System

used to run the existing instrumentation, adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power and a backup system to operate the controllers in the event of interruption of the electrical supply. Table 6-5 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 6-5. Compressor Power Requirements and Costs for Representative Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate (cfm)	Control Loops (Loops/Compressor)	Power Costs ($/yr)
Size of Unit	Hp	kW			
Small	10	13.3	30	15	$7,758
Medium	30	40	125	63	$23,332
Large	75	100	350	175	$58,329

[a] Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Natural Gas STAR Program. Washington, DC. 2006.
[b] Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and the related equipment and operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator, gas supply piping, control instruments, valve actuators and a storage vessel. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air" and are summarized in Table 6-6.[88]

[88] Ibid.

Table 6-6. Estimated Capital and Annual Costs of Representative Instrument Air Systems ($2012)

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital Cost[a]	Annualized Capital Cost[b]	Labor Cost	Total Annual Cost[c]	Annualized Cost of Instrument Air System
Small	$3,987	$797	$2,391	$17,938	$2,554	$1,410	$9,168	$11,722
Medium	$19,928	$2,391	$7,173	$77,716	$11,065	$4,580	$27,912	$38,977
Large	$35,071	$4,783	$15,941	$143,476	$20,428	$6,340	$64,669	$85,097

[a] Total Capital Cost includes the cost for two compressors, two tanks, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the 2012 NSPS TSD.
[b] These costs have been converted to 2012 dollars (from 2008 dollars) using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent).[89]
[c] The annualized cost was estimated using a 7 percent interest rate and 10-year equipment life. Annual cost includes the cost of electrical power, as listed in Table 6-5, and labor.

[89] U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF]*, retrieved from FRED, Federal Reserve Bank of St. Louis. https://research.stlouisfed.org/fred2/series/GDPDEF/ March, 26, 2015.

For new natural gas processing plants, the cost-effectiveness of the three representative instrument air system sizes was evaluated in the 2015 NSPS Proposal TSD based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems. For existing natural gas processing plants, it is our understanding that these plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. The cost of converting the pneumatic controllers to instrument air includes the capital cost of $2,000 for the ductwork and annual cost of $285 (assuming a 10-year equipment life at 7 percent interest). The VOC cost of control for converting pneumatic controllers to instrument air for processing plants that already have instrument air ranges from $6 to $68 per ton of VOC removed, depending on the size of the instrument air system.

For natural gas processing, the cost of control of the three representative instrument air systems was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per controller basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems.

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Table 6-7. Cost of Control of Representative Instrument Air Systems in the Natural Gas Processing Segment ($2012)

System Size	Number of Control Loops	VOC Annual Emission Reduction (tpy)[a]	Value of Product Recovered ($2012/year)[b]	Annualized Cost of System		VOC Cost of Control ($2012/ton)	
				Without Savings	With Savings	Without Savings	With Savings
Small	15	4.18	$3,485	$11,722	$8,236	$2,804	$1,970
Medium	63	17.5	$14,592	$38,977	$24,385	$2,227	$1,393
Large	175	48.7	$40,606	$85,097	$44,490	$1,747	$914

[a] Based on the emissions mitigated from the entire system, which includes multiple control loops.
[b] Value of recovered product assumes natural gas processing is 82.9 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

6.3.1.3 Electrically Powered Systems in Place of Bleed Devices

Description

Mechanical controls have been widely used in the oil and natural gas industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages.[90] Another device that is increasing in use is electrically powered controls. Small electrical motors (including solar powered) have been used to operate valves and have no VOC emissions. Solar-powered control systems are driven by solar-power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Control Effectiveness[91]

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems may have difficulty handling larger flow fluctuations. Electrically powered valves are only reliable with a constant supply of electricity. These controllers can achieve a 100 percent reduction in VOC emissions where applicable.

Cost Impacts

Depending on supply of power, mechanical and solar-power system costs can range from below $1,000 to $10,000 for an entire system.[92]

[90] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[91] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[92] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

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6.3.1.4 Enhanced Maintenance of Natural Gas-Driven Pneumatic Controllers

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age and wear of the device.[93] Examples of circumstances or factors that can contribute to this increase include:[94,95]

(1) Nozzle corrosion resulting in more flow through a larger opening;

(2) Broken or worn diaphragms, springs (e.g., spring broken that holds the supply pilot plug on its seat), bellows, fittings (e.g., leaking tubing/tubing-fittings) and nozzles;

(3) Corrosives in the gas leading to erosion and corrosion of control loop internals;

(4) Improper installation;

(5) Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals);

(6) Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle;

(7) Foreign material lodged in the pilot seat;

(8) Debris/deposits on vent pilot plug. Material on the vent pilot can allow the controller to exhaust gas during the activation cycle;

(9) Debris/deposits on the supply pilot plug. Material on the supply pilot can cause the introduction of gas while the vent is open; or

(10) Wear in the seal seat.

The EPA prepared a white paper titled "Oil and Natural Gas Sector Pneumatic Devices," in 2014, requesting specific comment on available emissions data for pneumatic devices. One of the comments received regarding data presented in "Measurements of Methane Emissions at Natural Gas Production Sites in the United States"[96] was that the data set reported was dominated by extreme values. The commenter noted that the highest emitting controllers are simply controllers emitting at a large rate, regardless of their service or design type. These

[93] Ibid.
[94] Ibid.
[95] American Petroleum Institute (API). *Pneumatic Controllers*. Webinar Prepared and Presented to the U.S. Environmental Protection Agency. March 25, 2014.
[96] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

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controllers can have high emissions because of factors, other than design, related to maintenance, malfunction, or defect.[97]

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Eliminating unnecessary valve positioners can save up to 18 scfh per device.[98]

6.3.2 Existing Federal, State and Local Regulations

6.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, new or modified continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants are subject to a VOC emission limit of zero (equivalent to non-natural gas-driven pneumatic controllers). Continuous bleed natural gas-driven pneumatic controllers in the production segment must have a bleed rate of 6 scfh or less.

6.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

For pneumatic controllers, Colorado and Wyoming have existing control requirements similar to those required under the 2012 NSPS and 2016 NSPS. Other states have permitting and

[97] Allen, David. Comments Provided to the EPA on *Oil and Natural Gas Sector Pneumatic Devices-Peer Review Document*. University of Texas at Austin. June 2014.
[98] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

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registration rules for controlling fugitive VOC emissions (which would include non-bleed emissions from pneumatic controllers).

Colorado requires that no- or low-bleed pneumatic controllers with a bleed rate of 6 scfh or less be installed for all new and existing applications (unless approved for use due to safety and/or process purposes) statewide (Regulation 7, XVIII.C.2). Where technically and economically feasible, Colorado requires no-bleed pneumatic controllers at facilities that are connected to the electric grid and using electricity to power equipment.

Wyoming requires the installation of low- or no-bleed pneumatic controllers with a bleed rate of 6 scfh or less at all new facilities. Upon modification of facilities, new pneumatic controllers must be low- or no-bleed and existing controllers must be replaced with no- or low-bleed controllers (at well site facilities only and not at natural gas processing plants).

Although some local rule requirements do not specifically require the control of VOC emissions from pneumatic controllers, local permit requirements (such as those required by the Bay Area Air Quality Management District) may require that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in a permit application. Under some situations where facilities use high-bleed devices, the permitting authority might require an owner or operator to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where high-bleed devices must be used, the permitting authority may require that the facility conduct fugitive monitoring and/or implement control requirements under conditions of their permit to operate.[99]

6.4 Recommended RACT Level of Control

Sections 6.4.1 and 6.4.2 present the recommended RACT level of control for continuous bleed natural gas-driven pneumatic controllers located at natural gas processing plants and continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

[99] Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities.* Bay Area Air Quality Management District. September 16, 2013.

6.4.1 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located at a Natural Gas Processing Plant

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the "Oil and Natural Gas Sector Pneumatic Devices" white paper, and existing regulations that control VOC emissions from pneumatic controllers, we recommend that VOC emissions from an individual continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant be controlled by RACT. As noted in section 6.3.2, both Colorado and Wyoming require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting at least 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers at natural gas processing plants have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). For existing individual continuous bleed pneumatic controllers at natural gas processing plants, our RACT recommendation is that controllers have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). Our rationale for selecting a natural gas bleed rate of 0 scfh (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 6.3.1.2 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. Therefore, the use of instrument air eliminates natural gas and VOC emissions from pneumatic controllers and supports a natural gas bleed rate of 0 scfh.

In order to meet an emission limit of 0 scfh, natural gas processing plants would likely need to use an instrument air system. The use of instrument air eliminates natural gas and VOC emissions from natural gas-driven pneumatic controllers. We believe that most natural gas processing plants already meet the recommended RACT level of control by driving controllers with instrument air or other non-gas-driven controls unless there is a specific need for a high-bleed pneumatic controller. Nonetheless, for those natural gas processing plants that do not have an installed instrument air system, the cost of control of installing three representative instrument air systems was evaluated under the 2012 NSPS and 2016 NSPS based on the emissions

mitigated from the number of control loops the system can provide (see section 6.3.1.2 of this chapter). Based on this analysis, the cost of this option was considered to be reasonable for natural gas processing plants (see Table 6-7 of section 6.3.1.2 of this chapter). The cost of control per ton of VOC reduced was estimated at $1,700 - $2,800 without savings and $910 - $2,000 with savings. For determining potential cost impacts, a major assumption made was that processing plants are constructed at locations with sufficient electrical service to power the instrument air compression systems.

In summary, we recommend the following RACT for each continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant:

> RACT for Each Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant:[100] Each continuous bleed natural gas driven pneumatic controller located at a natural gas processing plant must have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).

6.4.2 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the "Oil and Natural Gas Sector Pneumatic Devices" white paper, and existing regulations that control VOC emissions from pneumatic controllers, we are recommending a natural gas bleed rate less than or equal to 6 scfh with limited exceptions described below as the RACT for controlling VOC emissions from continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline. We are also recommending that no requirements apply under RACT for pneumatic controllers that have a natural gas bleed rate less than or equal to 6 scfh that are located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

[100] In the NSPS, we excluded from the NSPS affected facility status non-natural gas-driven pneumatic controllers located at natural gas processing plants. Natural gas-driven controllers exempt from the zero VOC emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

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As indicated in section 6.2.2 of this chapter, low-bleed pneumatic controllers can emit up to 6 scfh. Both Colorado and Wyoming conditionally require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting greater than 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers have a bleed rate of 6 scfh or less (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh). For purposes of this CTG, and consistent with the definition of high-bleed controller used for the 2012 NSPS, 2016 NSPS, and both the Wyoming and Colorado state regulations, a high-bleed pneumatic device is defined as emitting greater than 6 scfh to the atmosphere.

Although both Wyoming and Colorado specifically require low-bleed or no-bleed pneumatic controllers in place of high-bleed controllers (where technically and economically feasible), we are recommending a RACT emission limit of 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh) apply to each continuous bleed pneumatic controller. This approach allows flexibility in how a source chooses to limit VOC emissions from an applicable individual pneumatic controller and acknowledges that there may be circumstances where it is not practical to meet a 6 scfh limit. By requiring a limit be met, facilities have the option of controlling emissions by one or more options presented in section 6.3.1 of this chapter (e.g., replace a high-bleed device with a low-bleed device and implement enhanced monitoring to mitigate increased VOC emissions from poor maintenance/poor operation) depending on site-specific circumstances. We are including this flexibility in our recommended RACT to address the varied control options and applicability issues (e.g., instrument air systems require access to electrical power or a backup pneumatic controller and access to electric power or backup pneumatic controllers may not be available in remote locations) presented in section 6.3.1 of this chapter.

Although facilities would have flexibility in how they meet the recommended RACT level of control, by establishing an emission limit equal to the design bleed rate for a low-bleed device (6 scfh), we believe that most facilities would likely replace high-bleed controllers with low-bleed controllers (it is assumed about 80 percent of high-bleed devices can be replaced with

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low-bleed devices).[101] For the production segment, we estimated that, on average, 1.41 tons of VOC would be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device.

As presented in section 6.3.1.1 of this chapter, the cost of replacing a high-bleed device with a new low-bleed device is on the order of $2,698 per device, and the cost of control in the production segment is estimated to be $210 per ton of VOC emissions reduced without savings. Considering the cost savings of gas recovered from installing a low-bleed device in place of a high-bleed device, it is estimated that there would be an overall net savings.

In summary, we recommend the following RACT for each single continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

> RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller[102] must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).

[101] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

[102] In the NSPS, we excluded from NSPS pneumatic controller affected facility status continuous bleed natural gas-driven pneumatic controllers with a bleed rate not greater than 6 scfh (low-bleed controllers) located in the production segment. Continuous bleed natural gas-driven controllers exempt from the 6 scfh bleed rate emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

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6.5 Factors to Consider in Developing Pneumatic Controller Compliance Procedures

6.5.1 Oil and Natural Gas Production (Individual Continuous Bleed Pneumatic Controller with a Natural Gas Bleed Rate Greater than 6 scfh Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline)

To ensure that each continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline is operated with a natural gas bleed rate less than or equal to 6 scfh (the recommended RACT level of control), we recommend that regulating agencies specify operating, recordkeeping and reporting requirements to document compliance. It is recommended that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to manufacturer's documentation.

It is recommended that air agencies require owners and operators of continuous bleed natural gas-driven pneumatic controllers that are subject to RACT maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) if applicable, provide a demonstration as to why the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required (the recommended RACT level of control); and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include (1) if applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 standard cubic feet per hour is required and the reasons why; and (2) the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

6.5.2 Natural Gas Processing Segment (Individual Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant)

To ensure each continuous bleed natural gas-driven pneumatic controller at natural gas processing plants is operated with a natural gas bleed rate of zero (the recommended RACT level of control), we suggest that air agencies specify operating, recordkeeping and reporting requirements to document compliance. We also suggest that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to the manufacturer's documentation. It is recommended that air agencies require owners and operators of pneumatic controllers maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) document that the natural gas bleed rate is zero; and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

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7.0 PNEUMATIC PUMPS

The oil and natural gas industry uses a variety of pneumatic gas-driven pumps where there is no reliable electrical power to "control processing problems and protect equipment."[103] Pneumatic pumps are "small positive displacement, reciprocating units used throughout the oil and natural gas industry to inject precise amounts of chemicals into process streams or for freeze protection glycol circulation."[104] Most chemical injection pumps fall into two main types: (1) diaphragm pumps, generally used for heat tracing; or (2) plunger/piston, generally used for chemical and methanol injection. Pneumatic pumps driven by natural gas emit natural gas, which contains VOC. Other types of pneumatic pumps may be driven by gases other than natural gas and, therefore, do not emit VOC. The focus of this CTG is natural gas-driven pneumatic pumps. This chapter provides a description of pneumatic pumps that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also provides control techniques used to reduce VOC emissions from pneumatic pumps, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT for pneumatic pumps and the associated VOC emission reductions and costs.

7.1 Applicability

For the purposes of this CTG, a pneumatic pump is a positive displacement reciprocating unit used for injecting precise amounts of chemicals into a process stream or for glycol circulation. The pneumatic pump may use natural gas or another gas to drive the pump. The emissions and emission control options discussed herein would apply to natural gas-driven chemical/methanol and diaphragm pumps located at natural gas processing plants and well sites.

[103] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps*. EPA-600/R-96-080b. June 1996.
[104] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

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7.2 Process Description and Emission Sources

7.2.1 Process Description

As noted above, pneumatic pumps are "positive displacement, reciprocating units used for injecting precise amounts of chemicals into a process stream or for glycol circulation."[105] Pneumatic pumps often make use of gas pressure where electricity is not readily available.[106] In the production segment, the supply gas is mostly produced natural gas, whereas in the processing segment, the supply gas may be compressed air. For natural gas-driven pneumatic pumps, characteristics that affect VOC emissions include the frequency of operation, the size of the unit, the supply gas pressure, and the inlet natural gas composition.[107]

Pneumatic pumps are generally used for one of three purposes: glycol circulation in dehydrators, hot oil circulation for heat tracing/freeze protection, or chemical injection. Glycol dehydrator pumps may recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.[108] Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels, and tanks. Chemical injection pumps (i.e., piston/plunger pumps or small diaphragm pumps) inject small amounts of chemicals, such as methanol, to prevent hydrate formation or corrosion inhibitors into process streams to regulate operations of a plant and protect the equipment.

Pneumatic pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of

[105] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[106] Ibid.
[107] Ibid.
[108] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices*. *Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel.* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.[109]

Chemical injection pumps are positive displacement, reciprocating units designed to inject precise amounts of chemical into a process stream. Positive displacement pumps work by allowing a fluid to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged.[110]

Typical chemicals injected in an oil or natural gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H_2S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Because the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.[111]

Diaphragm pumps are positive displacement pumps, meaning they use contracting and expanding cavities to move fluids. Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid.[112]

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[109] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.
[110] Ibid.
[111] Ibid.
[112] GlobalSpec. *Diaphragm Pumps Information*. Available online - http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

Not all pneumatic pumps are natural gas driven. At sites without electrical service sufficient or reliable enough to power an instrument air compressor control system, mechanical or electrically powered pneumatic pumps may be used. Where reliable electrical service is available, sources of power other than pressurized natural gas, such as compressed instrument air may be used. Because these devices are not natural gas driven, they do not directly release natural gas or VOC emissions. Instrument air systems are feasible only at oil and natural gas industry locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power a compressor. This analysis assumes that natural gas processing plants are likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of natural gas-driven pumps.[113] The application of electrical controls is discussed further in section 7.3 of this chapter.

7.2.2 Emissions Data

7.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic pumps and the potential options available to reduce these emissions, numerous studies were consulted. Table 7-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."[114]

[113] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.
[114] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf.

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Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[g]
Greenhouse Gas Reporting Program[a]	EPA	2014	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks[b]	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry[c,d]	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry[e]	EPA	1999	Nationwide	X	
Natural Gas STAR Program[f]	EPA	2012	Study Specific	X	X

[a] U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.
[b] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.
[c] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report.* EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology.* EPA-600/R-96-080c. June 1996.
[d] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.
[e] U.S. Environmental Protection Agency. *Methane Emissions from the U.S. Petroleum Industry. Final Report*. Prepared for the U.S. Environmental Protection Agency by Radian International LLC. EPA-600/R-99-010. February 1999.
[f] U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry.* Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[g] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

7.2.2.2 Representative Pneumatic Pump Emissions

For this analysis, we consulted information in the appendices of Natural Gas STAR lessons learned documents on pneumatic pumps,[115,116] the GHGRP, the GHG Inventory, and

[115] U.S. Environmental Protection Agency. Lessons Learned: *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.
[116] U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. September 2004.

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U.S. EPA/GRI Report.[117] The GHGRP and GHG Inventory use emission factors from the U.S. EPA/GRI Report. Similarly, we determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA/GRI Report.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in the production and processing segments and then estimate VOC and HAP emissions using the gas composition factors from the 2011 Gas Composition Memorandum. The specific gas composition ratio used for this analysis was 0.278 lbs VOC per pound methane in the production and processing segment. Table 7-2 summarizes the estimated average emission factors for a representative pneumatic pump for the production and processing segments for both methane and VOC.

Table 7-2. Average Emission Estimates per Pneumatic Device

Segment/Pump Type	Emission Factor Methane (scf/day) [a]	Emission Factor Methane (Mcf/yr)[b]	Emission Factor Methane (tpy)[c]	Emission Factor VOC (tpy)[d]
Production				
Diaphragm	446	163	3.46	0.96
Piston	48.9	18	0.38	0.11
Processing				
Small Diaphragm	446	163	3.46	0.96
Medium Diaphragm	446	163	3.46	0.96
Large Diaphragm	446	163	3.46	0.96
Small Piston	48.9	18	0.38	0.11
Medium Piston	48.9	18	0.38	0.11
Large Piston	48.9	18	0.38	0.11

[a] Data Source: EPA/GRI. *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*. June 1996 (EPA-600/R -96-080m), Sections 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps.
[b] Assumes 365 days/yr operation in natural gas production and processing.
[c] Assumes density of methane is 19.26 g/scf.
[d] Assumes 0.278 VOC content per pound of methane.

[117] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps.* June 1996 (EPA-600/R -96-080m).

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7.3 Available Controls and Regulatory Approaches

7.3.1 Available VOC Emission Control Options

Natural gas-driven pneumatic pumps emit VOC emissions as part of their normal operation. Depending on the type of pump and the constraints of the location, companies can utilize a variety of technologies that have been developed over the years. In situations where the replacement of natural gas-driven pumps with electric, solar and instrument air pumps is not feasible, emissions can be captured and routed to a VRU or to a combustion device.

Sections 7.3.1.1 and 7.3.1.2 discuss the control of VOC emissions by replacing natural gas-driven pumps with solar pumps and electric pumps. Section 7.3.1.3 discusses the use of an instrument air system to drive the pneumatic pump in order to eliminate VOC emissions. Lastly, section 7.3.1.4 discusses reducing VOC emissions by routing emissions from the pump to a combustion device, and section 7.3.1.5 discusses capturing VOC emissions using a VRU.

7.3.1.1 Solar Pumps

Description

Solar pumps provide the same functionality as natural gas-driven pumps and can be utilized at remote sites where electricity is not available. However, peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices" noted that they predominantly operated solar-powered pneumatic pumps for chemical injection and the pumps failed as early as after two to three cloudy days due to insufficient battery charge.[118] When solar pumps are properly charged, a solar-charged DC pump can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 psig and have no VOC emissions. Converting natural gas-driven chemical pumps can reduce methane emissions by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump for all segments of the oil and natural gas industry.[119] Based on the gas composition for natural gas in the production segment, we estimate that replacement of a pneumatic pump with a solar-powered pump will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy for a piston pump.

[118] Reese, Carrie, Environmental Compliance Manager. Comments on the Oil and Natural Gas Sector Pneumatic Devices. Pioneer Natural Resources.
[119] U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

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Control Effectiveness

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Although, as stated above, solar-powered pumps are capable of pumping up to 100 gallons per day, they are typically used for low volume applications to inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to the low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

Cost Impacts

The primary costs associated with conversion to solar pumps are the initial capital expenditures. Solar pumps generally have low maintenance costs, which are typically lower than natural gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar-powered pumps includes the capital cost of the pump and its associated operating costs. The operating costs are estimated to be 10 percent of the capital cost. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"[120] the capital (purchase) cost for a solar-powered electric pump is approximately $2,000 with solar panels having a lifespan of 15 years and electric motors lasting 5 years. The total capital cost, including installation and labor is $2,227 (2012 dollars). We estimate there would be no additional annual operating costs for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a pneumatic pump with a solar pump is $317. In addition, the use of solar pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on $4.00 per Mcf would be $786 per year per diaphragm pump and $87 per year per piston pump.

[120] U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

7.3.1.2 Electric Pumps

Description

Electric pumps provide the same functionality as natural gas-driven pumps, and are only restricted by the use of reliable power. Electric pumps have no VOC emissions, and converting a natural gas-driven pneumatic pump to an electric pump can reduce VOC emissions by an estimated 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Control Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in VOC emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at natural gas processing plants or large dehydration facilities that have access to reliable electric power.

Cost Impacts

The primary costs associated with converting natural gas-driven pumps to electric pumps are the initial capital expenditures, installation and ongoing operation and maintenance. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"[121] the cost of an electric pump to replace a diaphragm pump is $4,647 and to replace a piston pump is $1,819 in 2012 dollars depending on the horsepower of the unit.[122] The annual operating costs for an electric pump are estimated to be $293. Based on these costs annualized over the life expectancy of the pump at a 7 percent discount rate, the annualized cost for an electric pump to replace a diaphragm pump is $954, and $552 to replace a piston pump. In addition, the use of electric pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on $4.00 per Mcf would be $786 per year per diaphragm pump and $87 per year per piston pump.

[121] Ibid.

[122] U.S. Environmental Protection Agency. *Lessons Learned. Replacing Gas-Assisted Glycol Pumps with Electric Pumps*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006. October 2006.

7.3.1.3 Instrument Air System

Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same pneumatic pumps can be used for natural gas and compressed air, without altering any of the parts of the pneumatic pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to an adequate and reliable source of electricity can install an instrument air system. The following, taken from the Natural Gas STAR document, "PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air,"[123] describes the major components of an instrument air system:

(1) Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical emission rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.

(2) A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, natural gas-driven pneumatic systems can run uninterrupted on a 24-hour, 7- day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be feasible for remote locations, which would both reduce VOC emissions and energy consumption. Small natural gas-powered fuel cells are also being developed.

[123] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

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(3) Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

(4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Control Effectiveness

Instrument air eliminates all emissions from natural gas-driven pneumatic pumps, but can only be utilized in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more economical and, therefore, more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning.[124] Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump. Based on the gas composition for natural gas in the production segment, we estimate that converting a natural gas-driven pneumatic pump to instrument air will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Cost Impacts

As stated previously, instrument air conversions require a compressor with a capacity based on the number of control loops at the location. The compressor size is equivalent to the volume of gas used by the control loops after adjusting for gas losses during drying, plus any utility air necessary at the facility. This volume can either be calculated via a meter or utilizing a rule of thumb of one cubic foot per minute (cfm) of instrument air per control loop.[125]

The costs associated with instrument air systems are primarily capital costs for the compressor(s), air dryer and the volume tank, but also include operational costs for electricity to

[124] Ibid.

[125] U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

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drive the compressor motor. Other components of the instrument air system, including piping, control instruments and valve actuators, would already be in place for a gas system. We assume that existing processing plants have an instrument air system in place, including backup systems, and that the cost of increasing air load on the system would be confined to the incremental cost associated with upgrading or replacing the compressor and connecting the pumps to the system. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps. Table 7-3 summarizes cost estimates to replace various size compressors in an existing instrument air system.

Table 7-3. Cost of Compressor Replacement for Existing Instrument Air System ($2012)

Compressor Size	Total Capital Cost[a]	Annualized Cost[b]	Total O&M Cost[c]	Annual Cost[d]
Small	$5,999	$854	$9,197	$10,051
Medium	$29,989	$4,270	$28,002	$32,271
Large	$52,779	$7,515	$64,880	$72,394

[a] 2016 NSPS TSD.
[b] Annualized capital cost using a 7 percent interest rate and an equipment life of 10 years.
[c] The total O&M includes both the annual labor cost and the annual power cost.
[d] The total annual cost includes the annualized capital cost and the total O&M cost.

7.3.1.4 Route Emissions to an Existing or New Combustion Device

Description

Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. It is assumed that most processing plants and large dehydration facilities have at least one existing combustion device onsite.

Control Effectiveness

Routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas discharged from the pump, but rather combusts the gas. Based on the gas composition for natural gas in the production segment, we estimated that routing emissions to a combustion device would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

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Cost Impacts

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital and operating costs. Based on costs for a combustion device provided in the 2015 NSPS TSD, the capital cost for installing a new combustion device to control emissions is estimated to cost $34,250 and the annual operating cost is $17,001 in 2012 dollars. Based on the life expectancy for a combustion device, we estimate the annualized cost of installing a new combustion device to be approximately $21,877, using a 7 percent discount rate. The capital cost for routing emissions to an existing control device to control emissions is estimated to be $5,433 with an annualized cost of $774, using a 7 percent discount rate. Because the natural gas captured is combusted there is no gas savings associated with the use of a combustion device to reduce VOC emissions. Table 7-4 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing combustion device. Table 7-5 presents the cost of control for routing natural gas-driven pump emissions to a new combustion device.

Table 7-4. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)
Diaphragm Pumps			
Production	0.91	$774	$847
Processing	0.91	$774	$847
Piston Pumps			
Production	0.10	$774	$7,709
Processing	0.10	$774	$7,709

Table 7-5. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)
Diaphragm Pumps			
Production	0.91	$21,877	$23,944
Processing	0.91	$21,877	$23,944
Piston Pumps			
Production	0.10	$21,877	$218,017
Processing	0.10	$21,877	$218,017

7.3.1.5 Route Emissions to a Vapor Recovery Unit (VRU)

Description

Vapor recovery units capture low-pressure vapor streams, increase the pressure by means of a compressor, and then route the vapor stream to a process or other useful purpose. These systems typically include a backup compressor system to allow for shutdowns and repairs. Vapor recovery units are more economical for facilities with multiple natural gas emission sources that can be routed to the VRU. Some of these other emission sources can include tanks, dehydrators, and compressors and as a result, VRUs are more common at natural gas processing plants. Vapor recovery units are discussed in greater detail in section 4.3.1.1 of chapter 4 of this document.

Control Effectiveness

Use of a vapor recovery technology has the potential to reduce the VOC emissions from natural gas-driven pumps by 100 percent if all vapor is recovered. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, we estimate that routing emissions from a natural gas-driven pump to an existing or newly installed VRU can reduce the VOC emitted by approximately 95 percent (accounting for any reduced efficiency that may occur) while, at the same time, capturing the natural gas for beneficial use. We estimate that methane emission reductions for routing gas to a VRU to be 3.29 tpy for a diaphragm pump and 0.36 tpy for a piston pump. Based on the gas composition for natural gas in the production segment, we

estimate that routing emissions to a VRU can reduce VOC emissions by 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Based on costs for a VRU provided in the 2015 NSPS TSD, we estimate the capital cost of installing a VRU to be $104,111 and the annual operation and maintenance cost to be $9,932 in 2012 dollars. The total annualized cost of a new VRU is estimated to be $24,755 based on a 7 percent discount rate.

If a VRU is already onsite, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. We estimated the cost of routing emissions to an existing VRU to be $5,433 in 2012 dollars. The annualized cost of routing natural gas emissions to an existing VRU is estimated to be $774 based on a 7 percent discount rate. In addition, there is potential for beneficial use of natural gas recovered through the VRU. We estimated the annual natural gas recovered to be 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The resulting natural gas savings is estimated to be $749 per diaphragm pump and $84 per piston pump, per year based on a value of $4.00 per Mcf of natural gas recovered. Table 7-6 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing VRU. Table 7-7 presents the estimated VOC cost of control for routing gas-driven pump emissions to a new VRU.

Table 7-6. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	$774	$847	$27
Processing	0.91	$774	$847	$27
Piston Pumps				
Production	0.10	$774	$7,709	$6,876
Processing	0.10	$774	$7,709	$6,876

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Table 7-7. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost ($2012)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	$24,755	$27,094	$26,275
Processing	0.91	$24,755	$27,094	$26,275
Piston Pumps				
Production	0.10	$24,755	$246,697	$245,864
Processing	0.10	$24,755	$246,697	$245,864

7.3.2 Existing Federal, State and Local Regulations

7.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

The EPA has finalized federal requirements for natural gas-driven pneumatic pumps under subpart OOOOa. Under subpart OOOOa, each natural gas-driven diaphragm pump located at a natural gas processing plant must have zero natural gas emissions, and each natural gas-driven diaphragm pump located at a well site must capture and route emissions to a control device or process if there is an existing control device or process available onsite. Subpart OOOOa requires that VOC and methane emissions be reduced by 95 percent or greater unless the existing control device or process is not capable of reducing emissions by 95 percent or greater, unless (1) there is no control device onsite, (2) it is technically infeasible, or (3) the control device cannot achieve 95 percent control. Subpart OOOOa also includes an exemption from control requirements where a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year.

7.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source may be operated. To ensure that

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sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

At least one state (Wyoming) requires emissions associated with the discharge streams from all natural gas-operated pneumatic pumps be controlled by at least 98 percent or routed into a closed-loop system (e.g., sales line, collection line, fuel supply line). Several states also have registration rules for controlling fugitive VOC emissions (which may include fugitive emissions from pneumatic pumps).

7.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices." Based on our evaluation of these data and information, we recommend that VOC emissions from pneumatic pumps be controlled.

Our recommended RACT for an existing individual natural gas-driven diaphragm pump located at the well site is to capture and route VOC emissions to a control device or process where there is an existing control device or process available onsite. Our rationale for this recommendation is that, although the production segment includes both well sites and gathering and boosting stations, we currently only have reliable information for pumps located at well sites. We have determined that the cost of control for routing VOC emissions to an existing onsite control device or process would be reasonable. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be $847 per ton of VOC reduced for diaphragm pumps, without gas savings, and $27 per ton of VOC reduced for diaphragm pumps if a VRU is used and gas savings are considered. We do not consider requiring control where there is not an existing control device or process onsite to be reasonably available technology, and the cost per ton of VOC reduced was estimated at greater than $20,000 for diaphragm pumps. While we are not recommending that the owner or operator be required to install a control device to control pneumatic pump emissions if one is not already available, we note that control devices will likely be installed onsite for other purposes under RACT or other regulations and will be available to control emissions from pneumatic pumps to a 95 percent control level.

For purposes of our recommended RACT, a natural gas-driven diaphragm pump is a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of our recommended RACT. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

We do not recommend RACT apply to an existing individual natural gas-driven piston pump because currently available information (including information received on the draft CTG and 2015 NSPS proposal) indicates that piston pumps are low emitting because of their small size, design and usage patterns. We determined piston pumps have emission rates between 2.2 to 2.5 scf/hr based on a joint report from the EPA and the Gas Research Institute on methane emissions from the natural gas industry. This approach is consistent with the manner in which we addressed low-bleed pneumatic controllers. After considering the low emission rates of low-bleed pneumatic controllers, we do not recommend RACT apply to these sources. Similarly, based upon the information that we have on the low emission rates of piston pumps, we are not recommending RACT apply to these sources because VOC emissions are low and would not be reasonable to control in the same manner that we recommend for diaphragm pumps. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be $7,709 per ton of VOC reduced for piston pumps, without gas savings, and $6,876 per ton of VOC reduced for piston pumps if a VRU is used and gas savings are considered. Requiring control where there is not an existing control device or process onsite was estimated to cost more than $200,000 per ton of VOC reduced for piston pumps.

For existing natural gas-driven diaphragm pumps at well sites, we recommend that air agencies require VOC emissions be controlled by 95 percent. Our rationale for recommending this level of emission reduction is supported by the control level achievable on a continuing basis by control devices and processes already located onsite or later installed onsite to control other emissions under RACT or other regulations. We expect that newly-installed control devices will achieve emission reductions because owners or operators are installing them to meet control requirements for other sources. In the unlikely circumstance where a control device that can achieve a 95 percent reduction is not available onsite, we recommend that owners and operators

still be required to control VOC emissions to the level achievable by the control device. We recommend that owners and operators in those instances be required to maintain documentation of the percent control the onsite control device is designed to achieve. We make this additional recommendation because it will achieve emission reductions with regard to pneumatic pumps even in the unlikely circumstance that the only available control device cannot achieve a 95 percent reduction.

We also recommend that air agencies allow for an exemption based on technical infeasibility. We recommend a technical infeasibility exemption be allowed based on information we received from industry that indicates that there may be circumstances where there is insufficient gas pressure or control device capacity, making it technically infeasible to capture and route pneumatic pump emissions to a control device or process.

We recommend that, at well sites, if a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year, the pump not be subject to the recommended control requirements. We make this recommendation to account for those intermittently used pumps/portable pumps where VOC emissions would be lower than assumed in our analysis (i.e., our analysis assumes that diaphragm pumps are operated 40 percent of the time evenly throughout the year) and not reasonable to control.

Our recommended RACT for existing diaphragm pumps located at natural gas processing plants is that they have zero VOC emissions (or 100 percent control) (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring an emission rate greater than zero). Our rationale for selecting a VOC emission rate of zero (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 7.3.1.3 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic system. Therefore, the use of instrument air eliminates VOC emissions from each gas-driven diaphragm pump and supports a VOC emission rate of zero.

In summary, we recommend the following RACT for pneumatic pumps in the oil and natural gas industry:

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(1) Each Diaphragm Pump Located at a Natural Gas Processing Plant: Require zero VOC emissions (or 100 percent control). This can be achieved by use of an instrument air system in place of natural gas-driven pump.

(2) Each Diaphragm Pump Located at a Well Site: Require that VOC emissions be captured and routed to an existing control device or process that is located onsite, unless it is technically infeasible to route emissions to the existing control device or process. Require 95 percent control of VOC emissions, unless the existing control device or process cannot achieve 95 percent control. If the existing control device cannot achieve a 95 percent control, still require the emissions to be routed to the existing onsite control device to control emissions to the extent achievable and maintain documentation of the percent control the onsite control device is designed to achieve. If there is no existing control device at the location of the pump, submit a certification that there is no device. If a control device is subsequently added to the site where the pump is located, then the VOC emissions from the pump must be captured and routed to the newly installed control device.

Although sources have a choice on how they meet the RACT level of control, the technologies that will likely be used to meet the RACT level of control for each natural gas-driven diaphragm pump at a well site are either capturing and routing the VOC emissions to an onsite existing combustion device (or a subsequently installed combustion device) or capturing and routing the VOC emissions to a process using an onsite existing VRU (or a subsequently installed VRU).

Similarly, the technology that will likely be used to meet the RACT level of control for each diaphragm pump located at a natural gas processing plant is the use of an existing instrument air system assumed to already exist onsite at natural gas processing plants.

7.5 Factors to Consider in Developing Pneumatic Pump Compliance Procedures

7.5.1 Oil and Natural Gas Production Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at well sites that meet RACT by capturing emissions and routing to a control device be connected through a closed vent system and that the closed vent system be designed with no

detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of part 60, and ongoing monthly, olfactory and auditory inspections). We recommend that you require that owners and operators conduct an assessment and certify that the closed vent system is of sufficient design and capacity to ensure that emissions are routed to the control device. We recommend air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm or initiates notification via remote alarm to the nearest field office when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

Secondly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites provide certifications for when (1) there is no existing control device or process onsite, or (2) capturing and routing to an existing control device or process is not technically feasible.

Lastly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites maintain records documenting where (1) intermittently-used/portable diaphragm pumps operate for any period of time each calendar day for less than a total of 90 calendar days per year, (2) an onsite control device or process is designed to achieve less than 95 percent reduction, and (3) a diaphragm pump is routed to a control device or a process and the control device or process is subsequently removed.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

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7.5.2 Natural Gas Processing Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at natural gas processing plants maintain records documenting (1) the location and manufacturer's specifications of each pneumatic pump, (2) that the natural gas bleed rate is zero, and (3) deviations in cases where a pneumatic pump was not operated in compliance with RACT. We also recommend that air agencies require owners and operators submit annual reports that include records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

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8.0 EQUIPMENT LEAKS FROM NATURAL GAS PROCESSING PLANTS

This chapter presents the causes for equipment leaks from natural gas processing plants, and provides emission estimates for "model" facilities in the processing segment of the oil and natural gas industry. Methods that are designed to reduce equipment leak emissions are presented, along with our recommended RACT, and the associated VOC emission reductions and cost impacts for equipment leaks from natural gas processing plants.

This CTG and the recommended RACT included in this CTG replaces the following: *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

8.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to the group of all equipment (except compressors and sampling connection systems) within a process unit located at a natural gas processing plant in VOC service or in wet gas service, and any device or system that is used to control VOC emissions (e.g., a closed vent system). For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, the piece of equipment must contain or contact the field gas before the extraction step at a natural gas processing plant. Equipment is defined as each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service.

8.2 Process Description and Emission Sources

8.2.1 Process Description

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In

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addition, centrifugal and/or reciprocating compressors are used to pressurize and move the natural gas from the processing facility to the transmission stations.

There are several potential sources of equipment leak emissions at natural gas processing plants. Equipment such as pumps, pressure relief devices, valves, flanges, and other connectors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and valves may leak for reasons other than faulty seals, such as an improperly installed cap on an open-ended line. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following subsections describe potential equipment leak sources and the magnitude of the VOC emissions from natural gas processing plants.

Due to the large number of valves, pumps, and other equipment within natural gas processing plants, VOC emissions from leaking equipment can be significant (chapter 2.2 of the 1983 CTG[126] presents a description of these equipment components and is not repeated here).

8.2.2 Equipment Leak Emission Data and Emission Factors

8.2.2.1 Summary of Major Studies and Emission Factors

The 2012 NSPS TSD evaluated emissions data from equipment leaks collected from chemical manufacturing and petroleum production to assist in the development of control strategies for reducing VOC emissions from these sources.[127,128,129] Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Leaks."[130]

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[126] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.* December 1983. EPA-450/3-83-007.

[127] Memorandum from David Randall, RTI and Karen Schaffner, RTI to Randy McDonald, U.S. Environmental Protection Agency. *Control Options and Impacts for Equipment Leaks: Chemical Manufacturing Area Source Standards*. September 2, 2008.

[128] Memorandum from Kristen Parrish, RTI and David Randall, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC on SOCMI*. October 30, 2007.

[129] Memorandum from Kristen Parrish, RTI, David Randall, RTI, and Jeff Coburn, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC in Petroleum Refineries*. October 30, 2007.

[130] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks. Report for Oil and Natural Gas Sector Leaks Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014.

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Table 8-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[r]
Protocol for Equipment Leak Emission Estimates[a]	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks[b]	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program[c]	EPA	2014	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks[d]	EPA	Annual	Nationwide	X	
Methane Emissions from the Natural Gas Industry[e,f,g,h]	EPA/GRI	1996	Nationwide	X	X
Methane Emissions from the U.S. Petroleum Industry[i]	EPA	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry[j]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[k]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories[l]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[m]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements[n]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities[o]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[p]	U.S. Energy Information Administration	2007-2009	Nationwide		

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[r]
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations[q]	EPA	1999		X	X

[a] U.S. Environmental Protection Agency, *Protocol for Equipment Leak Emission Estimates.* Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.

[b] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* June 1996 (EPA-600/R-96-080h).

[c] U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.

[d] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[e] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996.

[f] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.

[g] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996.

[h] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 6: Vented and Combustion Source Summary Emissions*. EPA-600/R-96-080f. June 1996.

[i] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry, Draft Report*. June 14, 1996.

[j] ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.

[k] ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States*. Prepared for Western Governors' Association. December 27, 2005.

[l] ENVIRON International Corporation. *Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories Prepared for Central States Regional Air Partnership*. November 2008.

[m] Independent Petroleum Association of America. *Oil and Gas Producing Industry in Your State*.

[n] Armendariz, Al. *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*. Prepared for Environmental Defense Fund. January 2009.

[o] Eastern Research Group, Inc. *Emissions from Oil and Gas Production Facilities*. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.

[p] U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.

[q] Eastern Research Group, Inc. *Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operation*. Prepared for the U.S. Environmental Protection Agency. September 1999.

[r] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

8.2.2.2 Natural Gas Processing Model Plant

Natural gas processing plants can consist of a variety of combinations of process equipment and components. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, the 2011 NSPS TSD and the 2012 NSPS TSD used a model plant approach.

Information related to equipment counts were obtained from a natural gas industry report.[131] This document provided average equipment counts for gas production and gas processing segments. These average counts were used to develop a model plant. These equipment counts are consistent with those contained in the EPA's analysis to estimate methane emissions conducted in support of the GHGRP. The natural gas processing model plant is discussed in the following section. A summary of the model plant production equipment counts for a gas processing facility is provided in Table 8-2.

Table 8-2. Equipment Counts for Natural Gas Processing Model Plant

Equipment	Equipment Count (non-compressor equipment)
Valves	1,392
Connectors	4,392
Open-Ended Lines (OEL)	134
Pressure Relief Valve (PRV)	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

8.2.2.3 Natural Gas Processing Model Plant Emissions

Overview of Approach

The EPA gathered equipment leak data and cost information for the development of the proposed National Uniform Emission Standards for Equipment Leaks rule (58 FR 17898, March 26, 2012). These Uniform Standards data were used to estimate baseline emissions for a natural

[131] U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Table 4-13, June 1996. (EPA-600/R-96-080h).

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gas processing model plant for the 2012 NSPS STSD and provide the baseline and controlled emission options for processing plants presented in this CTG.[132,133]

The baseline emissions were defined as being equivalent to a 40 CFR part 60, subpart VV (subpart VV) leak detection and repair (LDAR) program, which represents the same set of requirements that apply to natural gas processing plants under 40 CFR part 60, subpart KKK (subpart KKK). The 2012 NSPS requires the implementation of 40 CFR part 60, subpart VVa (subpart VVa) and currently applies to natural gas processing plants constructed or modified after August 23, 2011. It is assumed that natural gas processing plants constructed, reconstructed or modified on or before August 23, 2011 currently still comply with subpart KKK, which is similar to the control level of subpart VV. We evaluated requiring a similar subpart VVa level of control to these plants as was required under the 2012 NSPS. We used leak frequency data (refers to the estimated percentage of equipment that will be found leaking at a given leak definition) to calculate emission estimates, in addition to several other sources of information (including the Protocol for Equipment Leak Emissions Estimates and industry data).[134] Table 8-3 provides a summary of the equipment leak frequency data used for the natural gas processing model plant. Emission factors are the estimated leak rates for an equipment type at a given leak definition and are normally given in kg/hr/piece of equipment. Table 8-4 provides a summary of the VOC equipment leak emission factors representing the subpart VVa level of control that was used for the natural gas processing model plant.

[132] Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS. *Analysis of Emission Reduction Techniques for Equipment Leaks*. December 21, 2011.
[133] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.
[134] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. November 1995. EPA-453/R-95-017.

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Table 8-3. Summary of Equipment Leak Frequency for Natural Gas

LDAR Program[a]	Valves	Connectors
Baseline	1.18/1.18	NA
Valves	5.95/1.91	NA
Connectors	NA	1.70/0.81

NA = Not Applicable; no equipment leak frequency percent data were available.
Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 5.
[a] The leak frequencies provided in the tables are presented as initial leak frequency and subsequent leak frequency under the subpart VVa level of control.

Table 8-4. Summary of VOC Equipment Leak Emission Factors for the Natural Gas Processing Model Plant

Component	Uncontrolled (kg/comp-hr)	Baseline (kg/comp-hr)[a]	Subpart VVa Control Level (kg/comp-hr)[b]
Valves	3.71E-04	2.24E-04	8.85E-05
Connectors	1.04E-04	1.04E-04	3.95E-05
OEL	2.30E-03	7.34E-05	NA
PRV	1.60E-01	9.80E-02	NA

NA = Not Applicable
Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 7.
[a] The baseline option is assumed to be equivalent to a subpart VV LDAR program.
[b] Assumed to be equivalent to a subpart VVa LDAR program.

8.3 Available Controls and Regulatory Approaches

8.3.1 Available VOC Emission Control Options

The EPA has determined that leaking equipment, such as valves, pumps, and connectors are a significant source of VOC emissions from natural gas processing plants. The following subsections describe the techniques used to reduce emissions from these sources.

8.3.1.1 Leak Detection and Repair Program

The most commonly employed control technique for equipment leaks is the implementation of an LDAR program. Emission reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators,

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decrease exposure of hazardous chemicals to the surrounding community, and reduce emissions fees. An effective LDAR program will target leaking equipment by establishing leak definitions and require work practices to mitigate the leaks, such as monitoring frequencies for specific types of equipment (i.e., valves, pumps, and connectors). Other elements of an effective LDAR program include:

(1) Identifying Equipment,
(2) Monitoring Equipment,
(3) Repairing Equipment,
(4) Recordkeeping, and
(5) Reporting.

The primary sources of equipment leak emissions from natural gas processing plants are valves and connectors because these are the most prevalent equipment and can number in the thousands (see Table 8-2). The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, equipment type, and service (e.g., light liquid, heavy liquid, gas/vapor). Most NSPS regulations that were promulgated prior to 2007 have a valve leak definition of 10,000 ppm, while many National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations use a 500 ppm leak definition for valves or 1,000-ppm leak definition for other equipment such as pumps. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around equipment), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking equipment is EPA Reference Method 21 (40 CFR part 60, appendix A-7). Method 21 is a procedure used to detect VOC leaks from equipment using a toxic vapor analyzer (TVA) or organic vapor analyzer (OVA).

A second method for monitoring to detect leaking components is optical gas imaging (OGI) using an infrared (IR) camera. The IR camera may be passive or active. The operator uses the passive IR cameras to scan an area to produce images of equipment leaks from a number of sources. Active IR cameras point or aim an IR beam at a potential source to indicate the presence of gaseous emissions (equipment leaks). An equipment leak is any emissions that are visualized

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by an OGI instrument. The optical imaging camera can be very efficient in monitoring multiple pieces of equipment in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of the equipment leak.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are monitored separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

In addition, other monitoring tools, such as soap solution and electronic screening devices, can be used to find equipment leaks from certain types of equipment. Other factors that can improve the efficiency of an LDAR program include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

Subpart VVa LDAR Program

One LDAR option to control VOC emissions from natural gas processing plant equipment leaks is the implementation of the subpart VVa LDAR program. This program is similar to the subpart VV monitoring program (requirements are cross-referenced in subpart KKK), but finds more leaks due to the lower leak definition, increased monitoring frequency, and the addition of connectors to the components being monitored, thereby achieving better emission reductions.

Description

The subpart VVa LDAR program requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measures the concentration of the organics if the component is leaking. Connectors and valves have a leak definition of 500 ppm. Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves must be monitored within five days after a pressure release event to ensure they are operating without any detectable

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emissions (e.g. at a concentration less than 500 ppm above background). Compressors are not included in this leak detection and repair option and are regulated separately.

Control Effectiveness

The control effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. The control effectiveness of a leak program can vary from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition.[135] Descriptions of the frequency of monitoring and leak definition are described further below.

*Monitoring Frequenc*y. The monitoring frequency is the number of times each piece of equipment is checked for leaks over a given period of time. With more frequent monitoring, leaks are found and repaired sooner, thus providing higher control effectiveness.

Leak Definition. The leak definition describes the local VOC concentration at the surface of an equipment source where indications of VOC emissions are present. The leak definition is an instrument meter reading, in parts per million based on a reference compound. Decreasing the leak definition generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The 2012 NSPS STSD calculated incremental emission reductions from the baseline requirements (assuming that an LDAR program equivalent to the subpart VV/subpart KKK LDAR program is currently implemented at natural gas processing plants), and the leak frequency and emission factors from a supporting document for the Equipment Leak Uniform Standards were used to calculate the emission reductions and costs. The natural gas processing plant component counts (see Table 8-2) were obtained from an EPA/GRI document.[136] The incremental VOC emission reductions for implementing a subpart VVa leak detection and repair program (as determined in the 2012 NSPS STSD) for the natural gas processing model plant was calculated to be 13 percent.

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[135] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

[136] GRI/EPA Research and Development. *Methane Emissions from the Natural Gas Industry; Volume 8: Equipment Leaks*. June 1996. EPA-600/R-96-080h.

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Cost Impacts

Table 8-5 presents a summary of the incremental capital and annual costs and the cost of control (estimated in the 2012 NSPS STSD) from baseline (subpart VV) to implementing subpart VVa for the gas processing model plant. The costs obtained from the 2012 NSPS TSD have been converted to 2012 dollars from 2008 dollars using the Federal Reserve Economic Data GDP Price Deflater (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).[137]

Table 8-5. Summary of the Gas Processing Model Plant VOC Cost of Control for the Subpart VVa Option

Annual VOC Emission Reductions (tpy)	Capital Cost ($2012)	Annual Cost ($2012/year)	VOC Cost of Control ($2012/ton)	
			Without savings	With savings[a]
4.56	$8,499	$12,959	$2,844	$2,010

[a] With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of $4/Mscf. The VOC/methane ratio was assumed to be 0.278.

Table 8-6 provides a summary of the capital and annual costs and the cost of control on a component basis for the natural gas processing model plant.

Table 8-6. Summary of the Gas Processing Component VOC Cost of Control for the Subpart VVa Option

Component	Annual VOC Emission Reductions (tpy)	Capital Cost ($2012)	Annual Cost ($2012/year)	VOC Cost of Control ($2012/ton)	
				Without Savings	With Savings[a]
Valves	1.82	$5,231	$9,280	$5,095	$4,261
Connectors	2.74	$8,374	$4,405	$1,610	$776

[a] With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of $4/Mscf. The VOC/methane ratio was assumed to be 0.278.

8.3.1.2 Leak Detection and Repair Program with Optical Gas Imaging

Another option to control VOC emissions is the implementation of a program that uses OGI to detect equipment leaks. The alternative work practice for equipment leaks in §60.18(g) of

[137] U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator (GDPDEF), retrieved from FRED, Federal Reserve Bank of St. Louis https://research.stlouisfed.org/fred2/series/GDPDEF. March, 26, 2015.

40 CFR part 60, subpart A allows the use of an OGI instrument to monitor equipment for leaks. This option is currently available for monitoring equipment leaks from valves, pumps, connectors and other equipment that is subject to monitoring in subpart VVa.

The alternative work practice requires periodic monitoring, based on the detection sensitivity level (grams per hour), of the affected equipment using OGI and an annual monitoring survey of the affected equipment using a Method 21. Method 21 monitoring allows the facility to determine the concentration of a leak and to then use emission factors found in the EPA's emissions leak protocol to quantify emissions from equipment leaks, because the OGI system can only provide the presence of the equipment leaks.

Modeling results, conducted in support of the alternative work practice standard, showed a work practice repeated bimonthly with a detection limit of 60 g/hr range was equivalent to existing Method 21 work practices. The model generated different detection limits for the 500 and 10,000 ppm thresholds in existing rules. Based on modeling, the alternative work practice standard reflects the mass detection limit for 500 ppm, thus, providing equivalency for both 500 and 10,000 ppm thresholds.[138] The alternative work practice option is assumed to have the same control effectiveness as the subpart VVa monitoring program.

8.3.2 Existing Federal, State and Local Regulations

8.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Federal regulations that regulate VOC emissions from equipment leaks at natural gas processing plants include 40 CFR part 60 subpart OOOOa, subpart OOOO, and subpart KKK; and the 1983 CTG document (established a recommended RACT for VOC for natural gas processing plants at a level of control equivalent to subpart KKK).

8.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed,

[138] 73 FR 78199, December 22, 2008.

what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

We assume that all states currently regulate equipment leaks at existing natural gas processing plants at the 1983 CTG document and subpart VV level of control.

8.4 Recommended RACT Level of Control for Equipment Leaks from Equipment at Natural Gas Processing Plants

As discussed in section 8.3.2 of this chapter, existing federal, state and local regulations already require the reduction of VOC emissions using an LDAR program. The 2012 NSPS requires a 40 CFR part 60 subpart VVa LDAR monitoring program for processing plants. The 2012 NSPS reported a cost of control for natural gas processing plants to be $2,844 per ton of VOC removed for the 40 CFR part 60 subpart VVa option.

Based on costs and existing LDAR programs that are already employed at natural gas processing plants, we recommend that RACT for natural gas processing plants be the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service. This RACT recommendation would increase the stringency from the currently implemented LDAR programs at most existing natural gas processing plants (that were built prior to 2012) in VOC service by lowering the leak definitions, increasing the monitoring frequency, and including additional equipment. The subpart VVa leak detection and repair program requires the annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (less than 500 ppm above background). The estimated annual incremental VOC emission reductions for the recommended RACT for a natural gas processing plant was estimated to be 4.56 tpy (see Table 8-5 of this chapter). The annual VOC emission reductions assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. Table 8-5 presents the gas processing model plant VOC cost of control for the recommended RACT. The costs assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. The

recommended RACT VOC cost of control is estimated to be $2,844 per ton of VOC reduced without savings and $2,010 with savings.

In summary, we recommend the following RACT for equipment leaks at natural gas processing plants:

RACT for Equipment Leaks at Natural Gas Processing Plants: We recommend the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service.

8.5 Factors to Consider in Developing Equipment Leak Compliance Procedures

Existing natural gas processing plants that would be subject to the recommended RACT are already subject to an LDAR program and the basic elements of the LDAR program for the facility are in place. However, the LDAR program would need to be modified to increase the stringency from the currently implemented LDAR program by requiring annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), and lowering the leak definition for valves (500 ppm). As with the currently implemented LDAR program, to ensure that equipment in VOC service that leak at natural gas processing plants are properly monitored and repaired under the LDAR RACT recommendations, we suggest that air agencies specify monitoring frequency, equipment repair, and recordkeeping and reporting requirements to document compliance.

Monitoring frequencies vary according to the applicable regulation, but are typically weekly, monthly, quarterly and yearly. The monitoring frequency depends on the equipment type and periodic leak rate for the equipment. For each piece of equipment that is found to be leaking, the first attempt at repair should be made within a reasonable period of time, such as no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

(1) Tightening of bonnet bolts,
(2) Replacement of bonnet bolts,
(3) Tightening of packing gland nuts, and
(4) Injection of lubricant into lubricated packing.

Once the equipment is repaired, it should be re-monitored over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair equipment is to replace the leaking equipment with a "leakless" equipment or other technologies.

When implementing an LDAR program, we recommend that air agencies consider including recordkeeping requirements that require owner/operators of subject facilities to maintain a list of identification numbers for all equipment subject to an equipment leak regulation. A list of equipment that is designated as "unsafe to monitor" should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

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9.0 FUGITIVE EMISSIONS FROM WELL SITES AND GATHERING AND BOOSTING STATIONS

Fugitive emissions from components in the oil and natural gas industry are a source of VOC emissions. This chapter discusses the sources of fugitive emissions, and provides VOC emission estimates for well sites and gathering and boosting stations in the production segment (located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline). This chapter also presents a description of programs that are designed to reduce fugitive emissions, along with costs, and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the estimated VOC emission reductions and costs for fugitive emissions from well sites and gathering and boosting stations in the production segment.

9.1 Applicability

For purposes of this CTG, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at well sites with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents)[139] and the collection of fugitive emissions components at gathering and boosting stations in the production segment.

For the purposes of this CTG, fugitive emission reduction recommendations would not apply to well sites that only contain wellheads.

Fugitive emissions, for the purposes of applicability of this CTG, means those emissions from a stationary source that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Equipment leak emissions at natural gas processing plants are covered under chapter 8 of this document.

[139] Natural gas production converted to barrel equivalents uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet of natural gas. Based upon conversion factor used for the no longer in service U.S. EIA Financial Reporting System for Major Energy Producers.

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9.2 Fugitive Emissions Description and Data

9.2.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas industry. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure, temperature, or mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves, or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission.

For the purposes of our RACT analysis for fugitive emissions from components and equipment, we differentiated between the definition of "equipment" for purposes of controlling equipment leaks for oil and natural gas processing plants in subpart OOOO[140] and the definition we use for the purposes of addressing fugitive emissions from oil and natural gas well sites and gathering and boosting stations. For purposes of our RACT analysis, "fugitive emissions component(s)" are the focus of our analysis for fugitive emissions from oil and natural gas well sites and gathering and boosting stations. The definition for "fugitive emissions component" is as follows:

> *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not already subject to equipment and fugitive emissions monitoring, thief hatches or other openings on a controlled storage vessel, compressors, instruments and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions

[140] The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

components, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

9.2.2. Emission Data and Emission Factors

9.2.2.1 Summary of Major Studies and Emission Factors

In April of 2014, we published a white paper[141] which summarized our current understanding of VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities (referred to herein as the "equipment leaks white paper"). The equipment leaks white paper also outlined our understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

The equipment leaks white paper provided a summary of fugitive emission studies at oil and natural gas well sites and gathering and boosting stations in the production segment. Throughout the development of this CTG, the EPA evaluated a variety of emissions data and emission reduction options for fugitive emissions. Many of the studies in the equipment leaks white paper were consulted. Table 9-1 presents a list of the studies consulted along with an indication of the type of information contained in each study.

Table 9-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[m]
Protocol for Equipment Leak Emission Estimates[a]	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks[b]	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program[c]	EPA	2013	Facility	X	
Inventory of Greenhouse Gas Emissions and Sinks[d]	EPA	Annual	Regional	X	
Measurements of Methane Emissions at Natural Gas	Multiple Affiliations,	2013	Nationwide	X	X

[141] U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

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Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options[m]
Production Sites in the United States[e]	Academic and Private				
City of Fort Worth Natural Gas Air Quality Study, Final Report[f]	City of Fort Worth	2011	Fort Worth, TX	X	X
Measurements of Well Pad Emissions in Greeley, CO[g]	ARCADIS/Sage Environmental Consulting/ EPA	2012	Colorado	X	X
Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras[h]	Carbon Limits	2013	Canada and the U.S.	X	X
Mobile Measurement Studies in Colorado, Texas, and Wyoming[i]	EPA	2012 and 2014	Colorado, Texas, and Wyoming	X	X
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[j]	ICF International	2014	Nationwide	X	X
Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants[k]	Clearstone Engineering, Ltd.	2002	4 gas processing plants	X	X
Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites[l]	Clearstone Engineering, Ltd.	2006	5 gas processing plants, 12 well sites	X	X

[a] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf.

[b] U.S. Environmental Protection Agency/GRI. Research and Development, *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

[c] U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.

[d] U.S Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[e] Allen, David, T., et al. *Measurements of methane emissions at natural gas production sites in the United States*. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs.

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[f] ERG and Sage Environmental Consulting, LP. *City of Fort Worth Natural Gas Air Quality Study, Final Report*. Prepared for the City of Fort Worth, Texas. July 13, 2011. Available at http://fortworthtexas.gov/gaswells/default.aspx?id=87074.

[g] Modrak, Mark T., et al. *Understanding Direct Emissions Measurement Approaches for Upstream Oil and Gas Production Operations. Air and Waste Management Association 105th Annual Conference and Exhibition*, June 19-22, 2012 in San Antonio, Texas.

[h] Carbon Limits. *Quantifying cost-effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras*. December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATF-Carbon_Limits_Leaks_Interim_Report.pdf.

[i] Thoma, Eben D., et al. *Assessment of Methane and VOC Emissions from Select Upstream Oil and Gas Production Operations Using Remote Measurements, Interim Report on Recent Studies. Proceedings of the 105th Annual Conference of the Air and Waste Management Association*, June 19-22, 2012 in San Antonio, Texas.

[j] ICF International. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S.* Onshore Oil and Natural Gas Industries. ICF International (Prepared for the Environmental Defense Fund). March 2014.

[k] Clearstone Engineering Ltd. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. June, 2002.

[l] Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. March 2006.

[m] An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

9.2.2.2 Model Plants

Facilities in the oil and natural gas industry consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where "surface sites" can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce fugitive emissions from well sites and gathering and boosting stations, a model plant approach was used. The following sections discuss the creation of these model plants.

Oil and Natural Gas Production Well Sites

Oil and natural gas production varies from one site to the next. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well site. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation, and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions

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associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Model plants were developed using the average number of wells associated with a well site using data from the Drillinginfo HPDI database.[142] Baseline fugitive emissions from well sites depend upon the quantity of equipment and components, which in turn is based on this estimate of wells per pad. To estimate the average number of wells co-located on the same site as a new well completion or recompletion, the EPA developed a pair of algorithms that identified new and existing wells within a given distance of a new well completion or recompletion. This distance was assumed to represent the distance that, if other wells were within the distance, the wells would likely be co-located with the well under examination on the same site. The algorithms were written in the open source R programming language.[143]

The HPDI well and production data used to estimate the average number of well co-located on a well site drew upon the latitude and longitude of new well completions and recompletions as well as the coordinates of all wells producing oil or natural gas in 2012. The first algorithm estimated the distances between each new completion and recompletion and all producing wells, which also includes wells newly completed and producing in 2012 within the same county as the completed well. If the distance between the completed well and producing well was less than the assumed size of a typical well site, we assumed the two wells were co-located. This algorithm progressed county by county across the U.S. where oil and natural gas production occurred in 2012 to identify all co-located wells in the U.S. The number of new well completions and recompletions in 2012 was about 44,000, which includes oil and natural gas wells whether they were hydraulically fractured or not. Wells producing in 2012 numbered about 1.27 million. The second algorithm processed the results of the first such that a well can only appear once on a modelled well site.

Once these algorithms were complete and produced a results file, we converted the results into a "kml" file that enabled the visual inspection of the results within Google Earth. We did not visually inspect every site in the U.S. linked to a 2012 completion or recompletion as

[142] Drilling Information, Inc. 2011. *DI Desktop.* 2011 Production Information Database.
[143] See the website <http://www.r-project.org/> for more information on R (The R Project for Statistical Computing). R is a free software environment for statistical computing and graphics.

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they numbered greater than 20,000. Instead, we examined sites randomly across a range of oil and natural gas production regions. The results of this visual examination indicated the algorithms were functioning as intended.

We estimated the number of wells per site assuming sites of one, two and three acres, based upon input from petroleum industry data analysts. Table 9-2 shows the high-level results of these analyses.

Table 9-2. Estimated Average Number of Wells per Site of New Well Completion in 2012

Assumed Well Site Size	No. of Well Sites	No. of Wells at Sites	Average of Wells Per Site
One Acre	29,213	50,599	1.73
Two Acres	28,938	52,422	1.81
Three Acres	28,710	53,981	1.88

For assumed well sites of two acres, the analysis identified 28,938 independent well sites that contained 52,422 wells (including both single and multi-well sites). The total number of wells identified as being co-located with new well completions and recompletions exceeds the total number of completions and recompletions because the sites include about 8,500 existing wells producing in 2012.

However, the high level summary presented in Table 9-3 masks variation by basins and well types. Table 9-3 presents more detail along these dimensions for the assumed two-acre well site.

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Table 9-3. Estimated Average Number of Wells per Two-Acre Site of New Well Completions and Recompletions in 2012, by HPDI Basin and Type of Well (Oil or Natural Gas, Hydraulically Fractured or Not)

		Oil Well Completions			Natural Gas Well Completions			
HPDI Basin	No. Of Sites	HF	Not HF	All	HF	Not HF	All	Total
Los Angeles	23	N/A	13.07	13.07	N/A	N/A	N/A	13.07
Piceance	111	2.00	1.00	1.75	6.72	11.75	10.14	9.84
Arctic Ocean	2	N/A	5.50	5.50	N/A	N/A	N/A	5.50
Green River	164	2.23	1.57	2.01	4.37	1.13	4.19	3.88
Unidentified	226	1.18	3.57	3.38	1.00	1.77	1.44	3.22
San Joaquin Basin	1,745	1.56	3.46	3.21	2.61	1.42	2.24	3.16
Arkoma Basin	374	4.00	1.33	2.00	3.06	1.00	3.01	3.00
Denver Julesburg	826	2.63	3.10	2.75	1.48	3.14	1.72	2.46
Ft. Worth Basin	1,305	2.05	1.86	1.91	3.27	1.10	2.93	2.33
Central Western Overthrust	7	1.50	N/A	1.50	2.60	N/A	2.60	2.29
Ventura Basin	1	N/A	2.00	2.00	N/A	N/A	N/A	2.00
Arctic Slope	42	N/A	2.13	2.13	N/A	1.65	1.65	1.99
Ouachita Folded Belt	181	2.01	1.90	1.99	1.50	1.00	1.43	1.97
Salina Basin	13	N/A	1.92	1.92	N/A	N/A	N/A	1.92
Palo Duro Basin	81	1.42	1.97	1.89	1.00	N/A	1.00	1.86
Uinta	548	1.16	1.33	1.32	N/A	3.33	3.33	1.83
Texas & Louisiana Gulf Coast	3,994	2.03	1.82	1.96	1.37	1.14	1.28	1.79
Central Kansas Uplift	450	N/A	1.78	1.78	N/A	1.53	1.53	1.77
Permian Basin	8,507	1.66	1.76	1.69	1.50	1.57	1.52	1.68
Sedgwick Basin	240	N/A	1.67	1.67	1.67	1.55	1.55	1.62
Las Animas Arch	25	1.00	1.64	1.61	N/A	1.50	1.50	1.60
Nemaha Anticline	38	N/A	1.55	1.55	N/A	N/A	N/A	1.55
Arkla Basin	811	1.09	1.57	1.49	1.47	1.09	1.42	1.46
Chautauqua Platform	461	1.36	1.57	1.49	1.64	1.03	1.35	1.45
Cook Inlet Basin	9	N/A	2.00	2.00	N/A	1.29	1.29	1.44
Appalachian	2,496	1.14	1.05	1.10	2.28	1.10	1.77	1.43
Williston	1,570	1.36	1.00	1.35	1.43	1.00	1.39	1.35
Cherokee Basin	271	1.17	1.29	1.29	N/A	1.69	1.69	1.35
San Juan	158	1.00	1.00	1.00	1.38	1.20	1.37	1.31
East Texas Basin	618	1.25	1.74	1.52	1.22	1.06	1.21	1.31
Forest City Basin	172	N/A	1.28	1.28	N/A	N/A	N/A	1.28
Anadarko Basin	2,663	1.17	1.77	1.37	1.09	1.29	1.13	1.27
South Oklahoma Folded Belt	167	1.17	1.36	1.30	1.11	1.11	1.11	1.24
Chadron Arch	49	N/A	1.22	1.22	N/A	N/A	N/A	1.22

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HPDI Basin	No. Of Sites	Oil Well Completions HF	Oil Well Completions Not HF	Oil Well Completions All	Natural Gas Well Completions HF	Natural Gas Well Completions Not HF	Natural Gas Well Completions All	Total
Sacramento Basin	13	N/A	N/A	N/A	N/A	1.15	1.15	1.15
Mississippi & Alabama Gulf Coast	132	1.00	1.18	1.14	1.00	1.00	1.00	1.14
Central Montana Uplift	10	1.13	1.00	1.10	N/A	N/A	N/A	1.10
Big Horn	30	1.10	1.11	1.11	1.00	N/A	1.00	1.10
Powder River	232	1.15	1.03	1.12	1.05	1.00	1.04	1.10
Sweet Grass Arch	17	1.00	1.08	1.05	1.50	1.00	1.33	1.10
Paradox	13	1.00	1.10	1.09	1.00	N/A	1.00	1.08
Black Warrior Basin	57	1.00	1.00	1.00	1.00	1.75	1.07	1.05
Wind River	63	1.00	1.02	1.02	1.00	1.00	1.00	1.02
Wasatch Uplift	1	N/A	1.00	1.00	N/A	N/A	N/A	1.00
North Park	2	1.00	1.00	1.00	N/A	N/A	N/A	1.00
Raton	20	N/A	N/A	N/A	1.00	1.00	1.00	1.00
Grand Total	**28,938**	**1.64**	**1.99**	**1.79**	**1.90**	**1.76**	**1.86**	**1.81**

The data presented in Table 9-3 indicates that the concentration of wells at production sites varies greatly by basin. However, the analysis also indicates that most wells sites have relatively few or no co-located wells, which brings the national average of wells per new completion or recompletion site to 1.81 for the two-acre well site. While the analysis shows variation by basin, at the national level, there is relatively little variation across oil and natural gas well completion sites and whether the new wells were completed or recompleted using hydraulic fracturing. For example, oil well sites averaged 1.79 wells per site while natural gas wells averaged 1.86.

As a result of this analysis, we decided to use the two-acre well site as the assumed maximum size of a site to estimate the number of wells co-located at sites of new completions and recompletions. Also, to simplify analysis of costs and emissions at well sites, we rounded the 1.81 national average wells per site to 2.

While we are confident that the assumed two-acre well site is a reasonable size to capture most co-located wells in 2012, it is by no means a perfect assumption. First, industry and state regulatory trends indicate that well drilling will likely become increasingly concentrated on sites, potentially leading to an increase in the average number of wells per well site. However, it is not possible at this point to forecast this increasing concentration, especially with the variations by

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fields described above. Also, it is possible that two acres is too small to accurately estimate the number of co-located wells for large well sites in some fields. As a result, the algorithms might result in an underestimate of the average number of wells at a site and identify more than one site when in actuality there is only one. Alternatively, the assumed two acres might overestimate the size of sites in some fields and, as a result, pull in more than one site, overestimating the number of wells on the site. We also noted that the latitude and longitude values on many wells were likely incorrect or exact duplicates of other wells. Despite these caveats, we believe that the well site analysis described here produces a reasonable estimate of national average of number of wells on new well completion and recompletion sites in 2012. Therefore, based on this analysis, the model plants for oil and natural gas well sites are based on a well site with 2 wells.

Baseline model plant emissions for natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from the GHG Inventory, derived from GHGRP, EPA/GRI and 40 CFR part 98, subpart W tables, and the component oil and natural gas production emission factors from AP-42.[144] Annual emissions were calculated assuming 8,760 hours of operation each year. We used equipment count data from the EPA GHG Inventory to calculate the average counts of production equipment located at a well site. The types of production equipment located at a well site include: gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of components that are associated with these production equipment types include: valves, connectors, open-ended lines, and pressure relief valves. Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S. and the Western U.S. Fractions of components were rounded up to the nearest integer.

For natural gas well sites, the model plant was developed using the average equipment and fugitive emissions components counts for natural gas production data from the EPA/GRI report and the 2016 GHG Inventory. The average equipment count for a natural gas well was estimated by using the average equipment counts per well in the 2016 GHG Inventory (based on GHGRP data), and by weighing the average component counts per equipment for the Eastern and Western U.S. data sets for gas production equipment. This resulted in 2 separators, 3 meters/piping, 1 in-line heater, and 1 dehydrator per well. The total natural gas well site

[144] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Table 2-4. November 1995. EPA-453/R-95-017.

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equipment counts were calculated by multiplying the average well equipment values by the average number of wells per well site (2), and rounding the product to the nearest integer. Average component counts for each of the equipment items were calculated using the average component counts for production equipment in the Eastern U.S. and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per equipment and rounding to the nearest integer. Table 9-4 presents a summary of the fugitive emissions component counts for natural gas well sites.

For oil well sites, two model plants were developed in order to account for emissions variability. One oil well model plant was developed for oil wells with a gas-to-oil ration less than 300 standard cubic feet of gas per stock barrel of oil (GOR less than 300) and another model plant was developed for oil wells with a gas-to-oil ratio greater than or equal to 300 standard cubic feet of gas per stock of barrel oil (GOR greater than or equal to 300).

The equipment count for the oil well model plant with a GOR less than 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater. These equipment counts were obtained from 2016 GHG Inventory data. The component counts for these equipment types were obtained from Table W-1C of subpart W and are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S.

The equipment count for the oil well model plant with a GOR greater than or equal to 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater and 3 meters/piping. These equipment counts for separators, headers, and heater/treaters were obtained from the 2016 GHG Inventory data for petroleum systems, while the meter/piping counts were obtained from the 2016 GHG Inventory data for natural gas systems to reflect gas production at the sites.

The component counts for these equipment types were obtained from Table W-1C of subpart W for all but meters/piping, which were obtained from Table W-1B of subpart W. The component counts are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S. The total number of fugitive emissions components for oil well sites equipment (for both model plants) was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. Table 9-5 presents a summary of the fugitive emissions component counts for oil well site model plants.

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Table 9-4. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment[a]				Average Component Count per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
					Total	138.9	509.4	14.3	6.9
					Rounded up Total	139	510	15	7.0

[a] Data Source: EPA/GRI. *CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

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Table 9-5. Average Fugitive Emissions Component Count for Oil Well Site Model Plants

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment[a]					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR)[a]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
						Total	29	54	42	0	2
Oil Well Model Plant (≥ 300 GOR)[b]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
						Total	68	54	186	2	4

[a] Oil well (<300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Table W-1C.
[b] Oil well (≥300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Tables W-1B and W-1C.

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The baseline emissions for the natural gas well site and oil well model plants were calculated using equipment counts for the natural gas well site model plant and the oil and natural gas production AP-42 total organic compound (TOC) emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to VOC using VOC/TOC weight rations in the 2011 Gas Composition Memorandum.[145]. The fugitive VOC emissions for the natural gas well site model plant were determined to be 1.53 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR less than 300 was determined to be 0.33 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR greater than or equal to 300 was determined to be 0.73 tpy of VOC. The VOC emission estimates were used to evaluate the potential emission reductions and cost of control of a fugitive emission reduction program. Table 9-6 presents the emission factors for the natural gas and oil production segments. A summary of the equipment counts, average TOC emission factors and VOC emissions for natural gas well and oil well sites are provided in Tables 9-7 and 9-8, respectively.

Table 9-6. Oil and Natural Gas Production Operations Average TOC Emission Factors

Component Type	Component Service	TOC Emission Factor[a] (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

[a] Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

[145] Memorandum to Bruce Moore from Heather Brown. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. EC/R, Incorporated. July, 2011.

Table 9-7. Estimated Fugitive VOC Emissions for Natural Gas Production Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled TOC Emission Factor[b] (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)[c]
Valves	139	0.0045	1.166
Connectors	510	0.0002	0.190
OELs	15	0.002	0.056
PRVs	7	0.0088	0.115
		Total	1.53

[a] Fugitive emissions component count values for model plant are based on a 2-wellhead site and are rounded to the nearest integer.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Table 9-8. Estimated Fugitive VOC Emissions for Oil Well Site Model Plants

Oil Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled Emission Factor[b] (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)[c]
Oil Well Model Plant (< 300 GOR)			
Valves	29	0.0045	0.243
Flanges	54	0.00039	0.039
Connectors	42	0.0002	0.016
OELs	0	0.002	0
PRVs	2	0.0088	0.033
		Total	0.33
Oil Well Model Plant (≥ 300 GOR)			
Valves	68	0.0045	0.571
Flanges	54	0.00039	0.039
Connectors	186	0.0002	0.069
OELs	2	0.002	0.007
PRVs	4	0.0088	0.066
		Total	0.75

[a] Fugitive emissions component count values for model plant are based on a 2-wellhead pad and are rounded to the nearest integer.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Gathering and Boosting Stations

Gathering and boosting stations are sites that collect natural gas from well sites and direct them to the natural gas processing plants. These stations have similar equipment to well sites; however they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts

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for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in chapter 5 of this document. Table 9-9 presents a summary of the fugitive emissions component counts for oil and gas gathering and boosting stations.

Baseline emissions were calculated using the component counts and the TOC emission factors for oil and natural gas production (See Table 9-6). Table 9-10 summarizes the baseline emissions for gathering and boosting stations. The average fugitive emissions from a gathering and boosting station were determined to be 9.8 tpy of VOC. The VOC emission estimate was used to evaluate the potential emission reductions and cost of control of a fugitive emissions reduction program.

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Table 9-9. Average Component Count for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment[a]				Average Component Count per Model Plant			
		Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
					Total	906	2,864	83	48

[a] Data Source: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Tables 4-4 and 4-7, June 1996. (EPA- 600/R-96-080h).

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Table 9-10. Estimated Fugitive TOC and VOC Emissions for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Component	Model Plant Component Count[a]	Component TOC Emission Factor (kg/hr/ component)[b]	VOC Emissions (tons/yr)[c]
Valve	906	0.0045	7.6
Connectors	2,864	0.0002	1.1
OEL	83	0.002	0.3
PRV	48	0.0088	0.8
		Total	9.8

[a] Component counts from Table 9-9.
[b] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
[c] VOC emissions are the baseline which were calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

9.3 Available Controls and Regulatory Approaches

9.3.1 Available VOC Emission Control Options

The EPA has determined that fugitive emissions from components are a significant source of VOC emissions from well sites and gathering and boosting stations. Based on the review of public and peer review comments on the equipment leaks white paper and the Colorado and Wyoming state rules, the EPA has identified two options for reducing fugitive VOC emissions from components: a fugitive emissions monitoring program based on the use of OGI leak detection combined with repair of fugitive emission components, and a leak monitoring program based on individual component monitoring using Method 21 for leak detection combined with repair of fugitive emission components. These options, as currently being used by industry to reduce fugitive emissions in the oil and natural gas industry, are described below.

9.3.1.1 Fugitive Emission Detection and Repair with Optical Gas Imaging

Description

The reduction of fugitive emissions from oil and natural gas well sites and gathering and boosting stations involves the development and implementation of a fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites or gathering and boosting stations. Under this option, monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive

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emissions components at well sites or compressor stations within a company-defined area. An example monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

Control Effectiveness

Potential emission reduction percentages from the implementation of an OGI monitoring program varies from 40 to 99 percent.[146] The data supporting these emission reduction percentages are based on the gathering of individual OGI surveys at various oil and natural gas industry segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found (e.g., open thief hatches, open dump valves, etc.) during the OGI survey and assumptions made by the authors. However, the studies supporting these emission reduction percentages did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly, or monthly OGI monitoring and repair program. A report was found, after the publication of the white paper, from the Colorado Air Quality Control Commission,[147] which estimated (1) 40 percent reduction for annual OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy; (2) 60 percent reduction for quarterly OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy; and (3) 80 percent reduction for monthly OGI monitoring at well production tank batteries with uncontrolled VOC emissions greater than 50 tpy.

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, we expect the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado

[146] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks*, Office of Air Quality Planning and Standards. Research Triangle Park, NC. April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers.

[147] Colorado Air Quality Control Commission, *Cost-Benefit Analysis Submitted Per § 24-4-103(2.5), C.R.S. For Proposed Revisions to Colorado Air Quality Control Commission Regulations Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9).* February 7, 2014.

estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on information in the studies and EPA's engineering judgment, the potential emission reduction percentages are estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emission reductions for annual, semiannual and quarterly monitoring frequencies were calculated using the data from the EPA Protocol document.[148] For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500 ppm level, and achieves similar emission reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF[149] using data from subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers, and Jonah Energy LLC WCCA Spring Meeting Presentation determined the Year 3 fugitive emission reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semiannual and quarterly monitoring, respectively.

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[148] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, *Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program*. April 25, 2016.
[149] ICF International. *Leak Detection and Repair Cost-Effectiveness Analysis*. Prepared for Environmental Defense Fund. December 4, 2015. Revised May 2, 2016.

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On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency, as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emission reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emission reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.[150]

Cost Impacts

Costs (2012 dollars) for preparing an OGI emission monitoring and repair plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

(1) Labor cost for each of the monitoring plan elements was estimated to be $57.80 per hour.
(2) Reading of the rule and instructions would take one person four hours to complete at a cost of $231.
(3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of $3,468.
(4) Initial activities planning are estimated to take two people a total of 8 hours per monitoring event. Cost for annual monitoring was estimated to be $925, semiannual monitoring was estimated to be $1,850, and quarterly monitoring was estimated to be $3,699.
(5) Notification of compliance status was estimated to take one person one hour to complete at a cost of $58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be $58 per well site

[150] See Emission Reduction Comparison – Well Sites.xls, and Emission Reduction Comparison – Compressor Stations.xls in Docket Id. No. EPA-HQ-OAR-2015-0216 for more information.

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for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.

(6) Cost of a Method 21 monitoring device of $10,800; or cost for OGI monitoring using an outside contractor (assumed to be $600 for a well site and $2,300 for a gathering and boosting station for each survey).

Costs for implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

(1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.

(2) The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well site and $2,300 for a gathering and boosting station for each survey.

(3) Annual repair costs were estimated to be $299 for well sites and $3,436 for gathering and boosting stations per survey. These costs were estimated assuming that 1.18 percent of the components leak and 75 percent are repaired online and 25 percent are repaired offline.

(4) Cost for resurvey of components assumes five minutes per leak at $57.80 per hour for well sites and $2.00 per leak for gathering and boosting stations. This is based on the assumption that a company purchases Method 21 instrumentation (estimated to be $10,800[151]) and is able to perform the resurvey without needing contractors.

(5) Preparation of annual reports was estimated to take one person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for well sites was calculated by summing up the costs for reading the air agency rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. The total capital cost of these activities was calculated to be $16,696 per company-defined areas for annual monitoring,

[151] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180.

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$17,620 per company-defined areas for semiannual monitoring and $19,470 per company-defined areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area[152], the capital cost per well site was estimated to be $759 for annual monitoring, $801 for semiannual monitoring and $855 for quarterly monitoring. For gathering and boosting stations, the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation device was calculated to be $16,753 per facility. For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated seven gathering and boosting stations, and the capital cost for each of these stations was estimated to be $2,393.

For well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, OGI survey by an outside contractor, cost of repair of fugitive emissions found, preparation and submittal of an annual report and the amortized capital cost over 8 years at 7 percent interest. For our analyses, we calculated the annual cost for annual, semiannual and quarterly OGI surveys. The annual cost for annual, semiannual, and quarterly OGI surveying (inclusive of contractor costs, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for the production and processing segments. Tables 9-11 through 9-13 present summaries of the cost of control for VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly).

[152] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

Table 9-11. Summary of the Model Plant VOC Cost of Control for the Annual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy)[a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year)[c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	0.61	$759	$1,318	$809	$2,158	$1,324
Oil Well Site (GOR < 300)	0.13	$759	$1,318	$1,204	$9,953	$9,089
Oil Well Site (GOR ≥ 300)	0.30	$759	$1,318	$1,063	$4,380	$3,533
Gathering and Boosting Station	3.91	$2,393	$7,777	$4,518	$1,990	$1,156

[a] Assumes 40 percent reduction with the implementation of annual IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $1,191 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $7,736 and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

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Table 9-12. Summary of the Model Plant VOC Cost of Control for the Semiannual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	0.917	$801	$2,285	$1,521	$2,494	$1,660
Oil Well Site (GOR < 300)	0.199	$801	$2,285	$2,114	$11,503	$10,639
Oil Well Site (GOR ≥ 300)	0.451	$801	$2,285	$1,903	$5,062	$4,215
Gathering and Boosting Station	5.86	$2,393	$13,534	$8,646	$2,309	$1,475

[a] Assumes 60 percent reduction with the implementation of semiannual IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-13. Summary of the Model Plant VOC Cost of Control for the Quarterly OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
Natural Gas Well Site	1.222	$885	$4,220	$3,201	$3,453	$2,619
Oil Well Site (GOR < 300)	0.265	$885	$4,220	$3,991	$15,929	$15,064
Oil Well Site (GOR ≥ 300)	0.602	$885	$4,220	$3,710	$7,010	$6,163
Gathering and Boosting Station	7.81	$2,393	$25,049	$18,532	$3,205	$2,371

[a] Assumes 80 percent reduction with the implementation of quarterly IR camera monitoring.
[b] The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.
[c] Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

9.3.1.2 Fugitive Emission Detection and Correction with Method 21

Description

Another option that can be used to reduce fugitive emissions from well sites and gathering and boosting stations involves the development of a fugitive emissions monitoring plan using Method 21 to detect leaks from equipment and components. The plan would incorporate surveying of components at a specified interval and repair threshold using a Method 21 instrument, which also includes following the Method 21 requirements for monitoring, along with repair, recordkeeping and reporting requirements.

The plan would also include provisions for repair or replacement of components if evidence of fugitive emissions are discovered during the survey. The monitoring plan would include inspection of all fugitive emission components and would require repair where evidence

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of fugitive emissions is discovered (as soon as practicable, but generally no later than 30 calendar days after the Method 21 survey). In addition, all repairs or replacement of components would be re-surveyed immediately after repair or replacement to ensure the fugitive emissions are below the specified repair threshold.

A facility can use a company-defined area fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations. By using a company-defined area, owners and operators have flexibility in developing monitoring plans and determining which company-defined area can be covered under the specifications outlined in one monitoring plan, for ease of implementation and compliance.

Control Effectiveness

Potential control efficiencies for Method 21 monitoring were estimated to be 42 to 83 percent depending on repair threshold and monitoring frequency in the 2016 NSPS. The Method 21 control options included repair thresholds of 10,000 and 500 parts per million (ppm) and annual, semiannual, and quarterly monitoring frequencies. Tables 9-14 through 9-16 present the summaries of the estimated emission reductions for annual, semiannual and quarterly Method 21 monitoring for the two repair thresholds for the well site and the gathering and boosting station model plants.

Cost Impacts

Costs (2012 dollars) for preparing and implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the plan elements. The costs are based on the following assumptions:

(1) Labor cost for each of the monitoring plan elements was estimated to be $57.80 per hour.
(2) Reading of the air agency rule and instructions would take one person four hours to complete at a cost of $231.20.
(3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of $3,468.
(4) Initial activities planning are estimated to take two people a total of 16 hours per monitoring event. Cost for annual monitoring was estimated to be $925, semiannual monitoring was estimated to be $1,850, and quarterly monitoring was estimated to be $3,699.

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Table 9-14. Summary of the Model Plant VOC Cost of Control for the Annual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year)[c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	.645	$1,418	$2,300	$1,762	$3,568	$2,734
Oil Well Site (GOR < 300)	0.14	$1,418	$2,300	$2,179	$16,459	$15,595
Oil Well Site (GOR ≥ 300)	0.318	$1,418	$2,300	$2,031	$7,243	$6,396
Gathering and Boosting Station	4.12	$4,283	$9,803	$6,365	$2,378	$1,544
500 ppm Repair Threshold						
Natural Gas Well Site	1.043	$1,418	$2,300	1,430	$2,204	$1,371
Oil Well Site (GOR < 300)	0.226	$1,418	$2,300	$2,104	$10,169	$9,305
Oil Well Site (GOR ≥ 300)	0.514	$1,418	$2,300	$1,865	$4,475	$3,628
Gathering and Boosting Station	6.67	$4,283	$9,803	$4,239	$1,469	$635

[a] Assumes 42 percent reduction at 10,000 ppm repair threshold and 68 percent reduction at 500 ppm repair threshold with the implementation of annual Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-15. Summary of the Model Plant VOC Cost of Control for the Semiannual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	0.837	$1,460	$3,907	$3,209	$4,667	$3,833
Oil Well Site (GOR < 300)	0.181	$1,460	$3,907	$3,750	$21,530	$20,666
Oil Well Site (GOR ≥ 300)	0.412	$1,460	$3,907	$3,558	$9,475	$8,628
Gathering and Boosting Station	5.35	$4,415	$17,292	$12,828	$3,230	$2,396
500 ppm Repair Threshold						
Natural Gas Well Site	1.152	$1,460	$3,907	$2,946	$3,392	$2,558
Oil Well Site (GOR < 300)	0.250	$1,460	$3,907	$3,691	$15,648	$14,784
Oil Well Site (GOR ≥ 300)	0.567	$1,460	$3,907	$3,426	$6,887	$6,039
Gathering and Boosting Station	7.37	$4,415	$17,292	$11,150	$2,348	$1,514

[a] Assumes 55 percent reduction at 10,000 ppm repair threshold and 75 percent reduction at 500 ppm repair threshold with the implementation of semiannual Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program, which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

Table 9-16. Summary of the Model Plant VOC Cost of Control for the Quarterly Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) [a]	Capital Cost ($2012)[b]	Annual Cost ($2012/year) [c]		Cost of Control ($2012/ton)	
			Without savings	With savings [d]	Without savings	With savings [d]
10,000 ppm Repair Threshold						
Natural Gas Well Site	1.030	$1,544	$7,121	$6,262	$6,196	$6,083
Oil Well Site (GOR < 300)	0.223	$1,544	$7,121	$6,928	$31,906	$31,042
Oil Well Site (GOR ≥ 300)	0.507	$1,544	$7,121	$6,691	$14,042	$13,195
Gathering and Boosting Station	6.58	$4,679	$32,271	$26,780	4,901	$4,067
500 ppm Repair Threshold						
Natural Gas Well Site	1.26	$1,544	$7,121	$6,070	$5,651	$4,817
Oil Well Site (GOR < 300)	0.273	$1,544	$7,121	$6,885	$26,067	$25,202
Oil Well Site (GOR ≥ 300)	0.621	$1,544	$7,121	$6,595	$11,472	$10,624
Gathering and Boosting Station	8.06	$4,679	$32,271	$25,550	$4,004	$3,170

[a] Assumes 67 percent reduction at 10,000 ppm repair threshold and 83 percent reduction at 500 ppm repair threshold with the implementation of quarterly Method 21 monitoring.
[b] The capital cost for oil and natural gas well sites includes the cost of implementing the monitoring program of $32,120 divided by an average of 22 well sites per company.
[c] Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.
[d] Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as $4 Mcf.

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(5) Notification of compliance status was estimated to take one person one hour to complete at a cost of $58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be $58 per well site for each company-defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.

(6) Cost of a Method 21 monitoring device and data collection system was estimated at $25, 300 per company ($10,800 for the M21 monitoring device and $14,500 for the data collection system).

Costs for implementing a fugitive emission monitoring plan for a company-defined area for well sites and gathering and boosting stations were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

(1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.

(2) Method 21 monitoring was estimated to take two people a total of 16 hours to survey a well production site at a cost of $925 per survey. For gathering and boosting stations, Method 21 monitoring was estimated to take 2 people a total of 8 hours to survey the station at a cost of $925 per survey.

(3) Annual repair costs for well sites were estimated to be $299 using a repair threshold of 10,000 ppm and $5,400 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.

(4) Annual repair costs for gathering and boosting stations were estimated to be $3,436 using a repair threshold of 10,000 ppm and $52,900 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.

(5) Cost for resurvey of components assumes 5 minutes per leak at $57.80 per hour for well sites and $2.00 per leak for gathering and boosting stations.

(6) Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, acquisition of a Method 21 monitoring device and data collection system and notification of initial compliance status. The total capital cost of these activities was estimated to be $31,196 for annual monitoring, $32,120 for semiannual monitoring, and $33,970 for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area, the capital cost per well site was estimated to be $1,460.

For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210-mile radius of a central location, there would be an estimated seven gathering and boosting stations and the capital cost for these stations was estimated to be $29,982 for annual monitoring, $30,907 for semiannual monitoring, and $32,756 for quarterly monitoring. Assuming that there are 7 gathering and boosting stations in a company-defined area, the capital cost per station was estimated to be $4,283 for annual monitoring, $4,415 for semiannual monitoring, and $4,679 for quarterly monitoring.

For oil and natural gas well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. The annual cost for annual, semiannual, and quarterly Method 21 surveying (inclusive of cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for each of the industry segments. Tables 9-14 through 9-16 present summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000 and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual and quarterly).

9.3.2 Existing Federal, State and Local Regulations

9.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

For each well site and compressor station (including gathering and boosting stations), the EPA has finalized NSPS requirements that will require the development of a fugitive emissions monitoring plan that includes semiannual monitoring for well sites and quarterly monitoring for

compressor stations by OGI and repair of leaking fugitive emission components. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.

9.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions

States or local air districts may have regulations or permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements. A summary of some of the existing state regulations and permit programs that apply to the oil and natural gas industry is provided below.

Colorado Regulation 7

The State of Colorado has regulations that require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels. For well production facilities and compressor stations, the monitoring frequency is determined by the estimated uncontrolled actual VOC emissions leak from the highest emitting tank or, if no tanks are present, the controlled actual emissions from all permanent equipment. The monitoring frequency for fugitives at well production facilities varies depending on emissions. There is a one-time inspection (0-6 tpy VOC), annual inspections (6-12 tpy VOC), quarterly inspections (12-20 tpy VOC w/o tanks, 12-50 w/ tanks), or monthly inspections (> 20 TPY VOC w/o tanks, > 50 tpy VOC w/ tanks). Monthly AVO inspections are also required for well production facilities that do one-time, annual, and quarterly monitoring. For compressor stations, the monitoring frequency is annual (0-12 tpy VOC), quarterly (12-50 tpy VOC), or monthly (> 50 tpy VOC). A leak is defined as hydrocarbon concentration greater than 500 ppm. These regulations allow OGI inspections, Method 21 or other "[d]ivision approved instrument based monitoring device or method" to detect leaks (Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7). The first attempt to repair leaks found during monitoring must be made no later than five working days after discovery, unless parts are unavailable or the equipment requires shutdown to complete repair. If

parts are unavailable, they must be ordered promptly and the repair must be made within 15 working days of receipt of the parts. If a shutdown is required, the leak must be repaired during the next scheduled shutdown.

Wyoming Chapter 8

The Wyoming Department of Environmental Quality issued regulations in June 2015 for existing (as of January 1, 2014) PAD facility (location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location) and single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area[153]. The rule requires operators with fugitive emissions greater than or equal to 4 tons per year of VOC to develop and implement an LDAR protocol by January 1, 2017. Operators must monitor components (flanges, connectors (other than flanges), open-ended lines, pumps, valves, and "other" components listed in Table 2-4 of the EPA's Protocol for Equipment Leak Emissions Estimates) quarterly using a combination of Method 21, IR camera, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule. No specific repair timeframes are included in the regulation.

Utah General Approval Order

The Utah Department of Environmental Quality approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014[154]. This General Approval Order (GAO) requires LDAR for equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) based on annual throughput of crude oil and condensate. Annual inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 10,000 barrels or for sources that do not

[153] Wyoming regulations are available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.
[154] Utah regulations are available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.

have a crude oil or condensate storage tank onsite, and quarterly inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 25,000 barrels. For sources performing quarterly monitoring, provisions are provided for less frequent monitoring if no leaks are found during a year of monitoring. Repairs must be made within 15 days of finding a leak. A delay of repair is allowed if replacement parts are unavailable (must order parts within 5 days of detection and repair leak within 15 days after receipt of the parts) or technically infeasible to repair without a shutdown (shutdown must occur within 6 months of finding leak or operators must demonstrate emissions from shutdown would be greater than the uncontrolled leaking component).

The monitoring can be performed using Method 21, a tunable diode laser absorption spectroscopy (TDLAS) or an IR camera. A leak is defined as a reading of 500 ppm with Method 21 analyzer or TDLAS, or visible leak with IR camera.

Ohio General Permit

The Ohio EPA approved two types of general permits in May 2014 for oil and gas well site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT subpart HH)[155]. Each permittee is required to develop and implement an LDAR program for ancillary equipment (pumps, compressors, pressure relief devices, connectors, valves, flanges, vents, covers, any bypass in a closed vent system, and each storage vessel) that requires monitoring using a forward looking infrared (FLIR) camera or Method 21. Leak definitions vary depending on component (most are 500 or 10,000 ppm). Quarterly monitoring is required for the first year and varies after that depending on performance. Repairs must be made within 30 days of finding a leak but if leaks cannot be repaired within that time frame, the general permit references the delay of repair provisions allowed under NSPS subpart VVa.

Ohio has also proposed a general permit for natural gas compressor stations that have the potential to leak greater than 10 tons per year of VOC. The general permit requirements for

[155] Ohio regulations available at
http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf.
http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits.

compressor stations are similar to the LDAR requirements for oil and gas well site production operations. No emissions data were available for this LDAR program.

Pennsylvania General Permit 5 and Exemption Category No. 38

General Permit 5 is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are minor air contamination facilities[156]. Exemption Category No. 38 of the Air Quality Permit Exemption List applies to sources located at a well pad[157]. The general permit requires operators to conduct leak detection and repair programs monthly using AVO methods. Equipment to be monitored include: valves, flanges, connectors, storage vessels/storage tanks, and compressor seals. In addition, the general permit requires annual monitoring at wells and quarterly monitoring for compression and processing facilities. Operators must use a FLIR camera or approved device to detect gaseous hydrocarbons leaks. All leaks at production sites, compressor stations or processing facilities must be repaired within 15 days of finding the leak.

West Virginia Class II General Permit G70-B

General Permit G70-B is for natural gas production facilities[158]. The permit requires quarterly monitoring using AVO, Method 21 analyzers, IR cameras, or some combination. The AVO inspection shall include, but not be limited to, defects as visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. If a Method 21 analyzer is used, a leak (fugitive emissions of regulated air pollutants) is defined as no detectable emissions (less than 500 ppm). If an IR camera is used, no detectable emissions is defined as no visible leaks detected in accordance with U.S. EPA alternative IR camera work practices (40 CFR 60, subpart A). The first attempt at repair must be made within 5 calendar days of discovering the leak, and the final repair must be made within 15 calendar days of discovering the leak. No emissions data are available for this LDAR program.

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[156] Pennsylvania regulations are available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf.

[157] Pennsylvania regulations are available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.

[158] West Virginia regulations are available at http://www.dep.wv.gov/daq/permitting/Documents/G70-B%20Final/G70-B%20General%20Permit%20Signed2.pdf.

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San Joaquin Valley Air Pollution Control District Rule 4409

The San Joaquin Valley Air Pollution Control District requires the development of an operator management plan that establishes inspection, replacement, re-inspection requirements, maintenance, repair periods and replacement retrofit requirements for components at light crude oil production facilities, natural gas production facilities and natural gas processing plants[159].

For manned facilities, the District requires owners and operators to audio-visually inspect for leaks daily and, for unmanned sites, the District requires owners and operators to audio-visually inspect for leaks weekly. Additionally, the District requires owners and operators to conduct inspections for leaks quarterly using Method 21. Leaks discovered are required to be repaired within two to seven days of discovery, depending on the magnitude of the leak. An extension of up to seven days is allowed if the leak is minor. Owners and operators are also allowed to apply for written approval to change the Method 21 monitoring inspection frequency from quarterly to annually if they meet specified criteria. Components at oil production facilities and gas production facilities that exclusively handle gas/vapor or liquid with a VOC content of 10 percent by weight or less are exempt from requirements.

9.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's equipment leaks white paper. Based on our evaluation of this data and information about existing regulations that control VOC emissions from oil and natural gas production sites, this CTG provides RACT recommendations for the collection of fugitive emission components at well sites with an average production of greater than 15 barrel equivalents per well per day, and gathering and boosting stations. At this time, this CTG does not include a RACT recommendation for well sites with an average production of less than 15 barrel equivalents per well per day. However, we encourage air agencies to consider site-specific data from these sources in their RACT analyses.

We further recommend that RACT be the implementation of a monitoring plan that includes semiannual monitoring for well sites with a GOR greater than or equal to 300 and quarterly monitoring for gathering and boosting stations using OGI or Method 21 and repair of

[159] San Joaquin Valley APCD regulations available at http://www.arb.ca.gov/drdb/sju/cur.htm.

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components found to be leaking. The information currently available to EPA does not support applying the RACT recommendations related to fugitive monitoring contained in this chapter of the CTG to well sites with a GOR less than 300.

As discussed in section 9.3.2.2 of this chapter, some existing state and local regulations already require fugitive emissions monitoring of oil and natural gas production sites. The monitoring techniques listed in these requirements include the use of either Method 21 or OGI to locate fugitive emissions from equipment and components. In addition, peer review comments received on the equipment leaks white paper indicate that some companies are voluntarily monitoring their production sites using OGI to eliminate leaks from equipment. Monitoring and repair of equipment and components using OGI or Method 21 are the most viable methods for reducing fugitive emissions from equipment leaks in the production segment of the oil and natural gas industry.

Both Wyoming and Ohio require quarterly monitoring of components at production sites, and the cost of control per ton of VOC reduced is considered reasonable for OGI quarterly monitoring for natural gas well sites (about $3,450 per ton of VOC reduced). However, based on the information currently available regarding the necessary equipment, trained personnel and the planning necessary to implement a monitoring and repair program, we are concerned about the potential compliance burden that could be associated with quarterly monitoring of the large number of existing well sites. The VOC cost of control for semiannual monitoring using OGI was estimated to be $2,494 per ton of VOC reduced for natural gas well sites and $5,062 per ton of VOC reduced for oil wells sites with a GOR greater than or equal to 300.

We do not estimate that there would be a compliance burden associated with quarterly fugitive OGI monitoring at gathering and boosting stations because there are fewer existing gathering and boosting stations than well sites. Moreover, the cost of control per ton of VOC reduced is reasonable for quarterly OGI monitoring. The VOC cost of control for quarterly monitoring using OGI was estimated to be about $3,200 per ton of VOC reduced for gathering and boosting stations.

For well sites, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is generally more costly than the use of OGI where there are a large number of equipment components to be monitored. The cost for a natural gas well site was estimated to be $4,667 per ton of VOC reduced for semiannual monitoring. The cost for an oil well site with a

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GOR greater than 300 was estimated to be $9,475 per ton of VOC reduced for semiannual monitoring. As shown in section 9.3.1 of this chapter, the cost of control for the 500 ppm repair threshold options are higher than the 10,000 ppm repair threshold option. The use of a monitoring plan using Method 21 with a 10,000 ppm leak detection may, however, be a lower cost alternative to OGI where there are fewer equipment components to be monitored. For gathering and boosting stations, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is estimated to be $3,230 per ton of VOC reduced for semiannual monitoring and $3,205 for quarterly monitoring. The costs for semiannual monitoring using Method 21 for natural gas well sites, and quarterly monitoring using Method 21 for gathering and boosting stations were considered reasonable (about $4,670 for gas well sites and $3,200 for gathering and boosting stations). Based on our analyses that indicates that a monitoring plan using Method 21 at 500 ppm would meet the same level of control as semiannual monitoring using OGI, we recommend that air agencies allow owners and operators to comply by using Method 21 at 500 ppm as an alternative to semiannual monitoring using OGI.

Based on existing state and local fugitive emission requirements, economic feasibility, and the reasonableness of costs, we recommend that RACT for the collection of fugitive emission components at well sites with a GOR greater than or equal to 300 that produce, on average, greater than 15 barrel equivalents per well per day, be the implementation of a fugitive emissions monitoring and repair plan that includes semiannual monitoring using OGI or Method 21. For these same reasons, we recommend that RACT for the collection of fugitive emission components at gathering and boosting stations be the implementation of a fugitive emissions monitoring and repair plan that includes quarterly monitoring using OGI or Method 21.

In summary, we recommend the following RACT for the collection of fugitive emission components at well sites and gathering and boosting stations in the production segment:

(1) <u>RACT for the Collection of Fugitive Emission Components at Well Sites With a GOR Greater than or Equal to 300, that Produce, on Average, Greater than 15 Barrel Equivalents per Well per Day</u>: We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites. We further recommend that air agencies allow Method 21 with a repair threshold of 500 ppm as an alternative compliance means to OGI. We also

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recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

(2) RACT for the Collection of Fugitive Emission Components at Gathering and Boosting Stations in the Production Segment (Located from the Wellhead to the Point of Custody Transfer to the Natural Gas Transmission and Storage Segment or Oil Pipeline): We recommend the implementation of a monitoring plan that includes quarterly monitoring using OGI and repair of components that are found to be leaking at gathering and boosting stations. We further recommend allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We also recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

9.5 Factors to Consider in Developing Fugitive Emissions RACT Procedures

To ensure that fugitive emissions are properly monitored and repaired (as necessary) under the RACT recommendations, we suggest that air agencies specify OGI/Method 21 monitoring and equipment repair recordkeeping and reporting requirements to document compliance. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.5.1 Monitoring Recommendations

We recommend that air agencies require a fugitive emissions OGI/Method 21 monitoring plan that covers fugitive emission component sources that includes basic required monitoring plan elements. We recommend that air agencies require the monitoring plan be developed for a company-defined area and that it cover the collection of fugitive emissions components at well sites and gathering and boosting stations.

We suggest that the fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and gathering and boosting stations within each company-defined area include the following minimum elements:

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(1) Frequency for conducting surveys.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using OGI, you should also include the following: (i) Verification that your optical gas imaging equipment meets specification requirements (i.e., capable of imaging gases in a spectral range for the compound of highest concentration in the potential fugitive emissions, must be capable of imaging a gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 g/hr from a quarter inch diameter); (ii) Procedure for a daily verification check; (iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained; (iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold; (v) Procedures for conducting surveys; (vi) Training and experience needed prior to performing surveys; including how the operator will (a) ensure an adequate thermal background is present in order to view potential fugitive emissions, (b) deal with adverse monitoring conditions such as wind, (c) deal with interferences; and (vii) Procedures for calibration and maintenance.

(8) Procedures for calibration and maintenance should comply with those recommended by the manufacturer of monitoring device used.

(9) If you are using Method 21 of appendix A-7 of part 60, you should also include the following: (i) Verification that your monitoring equipment meets the requirements specified in section 6.0 of Method 21 at 40 CFR part 60, appendix A-7; and (ii) procedures for conducting surveys.

We suggest that you also require the following minimum elements in each fugitive emissions monitoring plan:

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(1) Sitemap.

(2) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using Method 21, the plan should also include a list of fugitive emission components to be monitored and method for determining location of fugitive emission components to be monitored in the field (e.g., tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan should also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor and unsafe-to-monitor.

We recommend a monitoring survey of each collection of fugitive emissions components at a well site be conducted semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend a monitoring survey of each collection of fugitive emissions components at a gathering and boosting station be conducted quarterly after the initial survey and that consecutive quarterly monitoring surveys be conducted at least two months apart.

9.5.2 Repair Recommendations

We recommend that air agencies require that any identified source of fugitive emissions identified by using OGI (indicated by visual emissions) or Method 21 instrument (indicated by a concentration of 500 ppm above background) be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. We also recommend that repaired or replaced fugitive emission components be required to be resurveyed as soon as practicable, but no later than 30 days after completion of the repair or replacement, to ensure that there is no leak. For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, we recommend that air agencies require that the operator resurvey the repaired fugitive emissions components using Method 21 (or alternative screening procedure based on soap bubble solution method (as specified under section 8.3.3 of Method 21)), or OGI no later than 30 days of being

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repaired. A fugitive emissions component is repaired when either the Method 21 instrument indicates a concentration of less than 500 ppm above background, or an OGI instrument shows no indication of visible emissions.

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Appendix

We include model rule language in this appendix for our recommended RACT for oil and natural gas industry sources. The intent of this language is to provide regulation language that states can use as a starting point in the development of their SIP. In some cases, the language may need to be revised to make it adequate for SIP approval purposes. Although we include model rule language for closed vent systems, control devices and performance tests (that apply across several model rule requirements for sources), it is acknowledged that states may have existing similar language in their programs that they may want to use in lieu of the model language provided. State implementation plans should specify enforceable test methods.

The model rule language does not specify rule compliance dates. These dates will be determined by air agencies (referred to within the model rule language as the "regulatory authority"). State and local government agencies are encouraged to search this model rule language for places where the "regulatory authority" will need to specify dates (e.g., compliance date) by searching for ("regulatory authority") in the model rule language.

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A Storage Vessels: VOC Emission Control Requirements

A.1 Applicability

(a) The VOC emissions control requirements of section A apply to each storage vessel located in the oil and natural gas industry (excluding distribution) that has the potential for VOC emissions equal to or greater than 6 tpy. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. Any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining applicability, provided you comply with the requirements in section A.1(a)(i) through (a)(iv).

(i) You meet the cover requirements specified in section A.2(c).

(ii) You meet the closed vent system requirements specified in section A.2(d).

(iii) You must maintain records that document compliance with paragraphs A.2(c) and (d).

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs A.2(c) and (d) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(b) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel.

(c) The storage vessel VOC emission control requirements specified in this section do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

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A.2 What VOC Emission Control Requirements Apply to Storage Vessels?

For each storage vessel, you must comply with the VOC emission control requirements of paragraphs (a) through (e) in this section by the compliance date established by your regulatory authority. Alternative requirements for storage vessels subject to VOC emission control requirements that meet certain conditions are presented in paragraph (i) of this section. Requirements for storage vessels removed from service are presented in paragraph (j) of this section.

(a) You must reduce VOC emissions from each storage vessel by 95.0 percent, unless you meet the conditions of paragraph (i) of this section.

(b) (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of paragraph (c) of this section, that is connected through a closed vent system that meets the requirements of paragraph (d) of this section and route to a control device that meets the conditions specified in paragraph (e) of this section, as applicable. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of 40 CFR 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Cover requirements for storage vessels.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system, designed and operated in accordance with the requirements of paragraph (d) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(d) *Closed vent system requirements for storage vessels*. For closed vent system requirements using a control device or routing emissions to a process, you must comply with the following:

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device or to a process that meets the requirements specified in paragraph (e) of this section, or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

(3) You must meet the requirements specified in paragraph (d)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (d)(3)(ii) of this section, you must comply with either paragraph (d)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section A.5(a)(9).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (d)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device or to a process and that the control device is of sufficient design and capacity to accommodate all emissions from the storage vessel and have it certified by a qualified professional engineer in accordance with paragraphs (d)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (d)(4)(i) of this section.

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(e) *Control device requirements for storage vessels*.

(1) Each control device used to meet the emission reduction standard in paragraph (a) of this section for your storage vessel must be installed according to paragraphs (e)(1)(i) through (iv) of this section, as applicable. As an alternative to paragraph (e)(1)(i) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e).

(i) For each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must follow the requirements in paragraphs (e)(1)(i)(A) through (D) of this section.

(A) Ensure that each enclosed combustion device is maintained in a leak free condition.

(B) Install and operate a continuous burning pilot flame.

(C) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in this paragraph.

(D) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (*1*) through (*4*) of this section.

(*1*) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b).

(*2*) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b).

(*3*) You must operate at a minimum temperature of 760°Celsius, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(*4*) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(ii) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(iii) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(iv) You must operate each control device used to comply with paragraph (a) of this section at all times when gases, vapors, and fumes are vented from the storage vessel through the closed vent system to the control device. You may vent more than one storage vessel to a control device used to comply with this subpart.

(2) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (e)(2)(i) and (ii) of this section.

(i) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (e)(1)(ii) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in section A.5(a)(10).

(ii) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (e)(2)(ii)(A) through (F) of this section.

(A) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(C) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(D) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(E) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(F) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(f) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each storage vessel as required in section A.3.

(g) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each storage vessel as required by section A.4.

(h) You must perform the required recordkeeping and reporting as required by section A.5.

(i) *Alternative requirements for storage vessels*. Maintain the uncontrolled actual VOC emissions from the storage vessel subject to VOC emission control requirements at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (i)(1) or (2) of this section.

(1) If a well feeding the storage vessel subject to VOC emission control requirements undergoes fracturing or refracturing, you must comply with paragraph (a) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel.

(2) If the monthly emissions determination required in this paragraph indicates that VOC emissions from your storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, you must comply with paragraph (a) of this section within 30 days of the monthly calculation.

(j) *Requirements for storage vessels that are removed from service or returned to service.* If you are the owner or operator of a storage vessel subject to the VOC emission control requirements that is removed from service, you must comply with paragraphs (j)(1) and (2) of

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this section. A storage vessel is not an affected source under this section for the period that it is removed from service.

(1) For a storage vessel to be removed from service, you must comply with the requirements of paragraph (j)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification in your next annual report, identifying each storage vessel removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel subject to VOC emission control requirements identified in paragraph (j)(1) of this section is returned to service during the reporting year, you must submit a notification in your next annual report identifying each storage vessel that has been returned to service and the date of its return to service.

A.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each storage vessel complying with section A.2 by complying with the requirements in paragraphs (a) through (h) of this section.

(a) You determine the potential VOC emission rate as specified in section A.1(a).

(b) You reduce VOC emissions from each storage vessel subject to VOC emission control requirements by 95.0 percent or greater as required in section A.2 and as demonstrated by section F.

(c) If you use a control device to reduce emissions, you must equip your storage vessel with a cover that meets the requirements of section A.2(c) that is connected through a closed vent system that meets the requirements of section A.2(d) and is routed to a control device that

meets the requirements of A.2(e). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(d) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(e) You conduct the initial cover and closed vent system inspections according to the requirements in section A.4(d) within 180 days after the compliance date established by your regulatory authority.

(f) You submit the initial annual report for your storage vessels as required in section A.5(b).

(g) You maintain the records as specified in section A.5(a).

(h) If you comply by using a floating roof, you submit a statement that you are complying with 40 CFR 60.112b(a)(1) or (2) in accordance with section A.2(b)(2) with the initial annual report specified in section A.5(b).

A.4 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each storage vessel subject to the VOC emission control requirements in section A.2 by meeting the requirements in paragraphs (a) through (f) of this section.

(a) For each storage vessel subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b) and (c) of this section.

(b) You must reduce VOC emissions from the storage vessel by 95.0 percent or greater.

(c) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section A.2(e) according to paragraphs (c)(1) through (4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with sections F(d)(2) through (10), which meets the

criteria in section F(d)(11), the reporting requirements in section F(d)(12), and the continuous compliance requirements in F(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (c)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (c)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices

for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified by A.5(a)(11).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in section F(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

(d) If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (d)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (d)(2) of this section, and inspect each bypass device according to the procedures of paragraph (d)(3) of this section. You must also comply with the requirements of (d)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (d)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(8).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or

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gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in section A.2(d)(3)(ii), you must meet the requirements of paragraphs (d)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to section A.5(a)(9).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to section A.5(a)(9).

(4) *Repairs*. In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (d)(4)(i) through (iii) of this section, except as provided in paragraph (d)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

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(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair*. Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements*. You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (d)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (d)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements*. You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (d)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(e) You must submit the annual reports for your storage vessels as required in section A.5(b).

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(f) You must maintain the records as specified in section A.5(a).

A.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* For each storage vessel, you must maintain the records identified in paragraphs (a)(1) through (12) of this section, as applicable, either onsite or at the nearest local field office for at least five years.

(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and sections A.4(d)(6)(ii) and A.4(d)(7)(ii), as applicable.

(2) Records of each VOC emissions determination for each storage vessel made under A.1(a) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(3) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in sections A.2 and F, as applicable.

(4) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, must be added to the count towards the number of consecutive days.

(5) Records of the identification and location of each storage vessel subject to emission control requirements.

(6) Except as specified in paragraph (a)(6)(vii) of this section, you must maintain the records specified in paragraphs (a)(6)(i) through (vi) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous

compliance requirements in section F(d) (e) and used to comply with section A.2(a) for each storage vessel.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(6)(vi)(A) through (E).

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(E) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) As an alternative to the requirements of paragraph (a)(6)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital

photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(7) Records of each closed vent system inspection required under section A.4(d)(1)(i).

(8) A record of each cover inspection required under section A.4(d)(2)(i).

(9) If you are subject to the bypass requirements of section A.4(d)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(10) For each carbon adsorber installed on a storage vessel, records of the schedule for carbon replacement (as determined by the design analysis requirements of section E.1(a)(2)) and records of each carbon replacement as specified in section E.1(c)(1).

(11) For each storage vessel subject to the control device requirements of section E.2(c) and (d), records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in section E.2(h). Records of section 11, EPA Method 22, 40 CFR part 60, appendix A-7 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A-7. Control device manufacturer operating instructions, procedures and maintenance schedule must be available for inspection.

(12) A log of records as specified in sections A.2(e)(1)(i)(C) and F(e)(4), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

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(b) *Reporting requirements*. For storage vessels, you must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section.

(1) An identification, including the location, of each storage vessel subject to VOC emission control requirements. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(2) Documentation of the VOC emission rate determination according to section A.1(a).

(3) Records of deviations specified in paragraph (a)(3) of this section that occurred during the reporting period.

(4) A statement that you have met the requirements specified in section A.3(b) and (c).

(5) You must identify each storage vessel that is removed from service during the reporting period as specified in section A.2(j)(1), including the date the storage vessel was removed from service.

(6) You must identify each storage vessel returned to service during the reporting period as specified in section A.2(j)(3), including the date the storage vessel was returned to service.

A.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

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(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a

production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified professional engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Removed from service means that a storage vessel subject to the VOC control requirements has been physically isolated and disconnected from the process for a purpose other than maintenance.

Returned to service means that a storage vessel subject to the VOC requirements that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel subject to the VOC requirements; or

(2) Installed in any location covered by this rule and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered for beneficial use.

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Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of section A.2(j)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this rule, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by section A.5(a)(4), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.

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B Pneumatic Controllers: VOC Emission Control Requirements

B.1 Applicability

The VOC emission control requirements specified in section B.2 apply to the pneumatic controllers specified in paragraphs (a) and (b) of this section.

(a) For natural gas processing plants, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller.

(b) At locations from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

B.2 What VOC Emission Control Requirements Apply to Pneumatic Controllers?

For each pneumatic controller, you must comply with requirements for VOC, as specified in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from these requirements.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required based on functional needs including, but not limited to, response time, safety and positive actuation. However, you must tag such pneumatic controller with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller, as required in section B.5(a)(2).

(b)(1) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant, as defined in section B.1(a), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller as required in section B.5(a)(3).

(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline, as defined in section B.1(b), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a).

(d) You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission reduction requirements that apply to pneumatic controllers as required by section B.3.

(e) You must demonstrate continuous compliance with VOC emission reduction requirements that apply to pneumatic controllers as required by section B.4.

(f) You must perform the required recordkeeping as required by B.5(a) and reporting as required by section B.5(b).

B.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for your pneumatic controller by complying with the requirements specified in paragraphs (a) through (f) of this section by the compliance date established by your regulatory authority, as applicable.

(a) You must demonstrate initial compliance by maintaining records as specified in section B.5(a)(2) of your determination that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required as specified in section B.2(a).

(b) You own or operate a pneumatic controller located at a natural gas processing plant and your pneumatic controller is a non-natural gas-driven pneumatic controller that emits zero natural gas and VOC.

(c) You own or operate a pneumatic controller located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(d) You must tag each pneumatic controller according to the requirements of section B.2(b)(2) or (c)(2).

(e) You must include the information in paragraph (a) of this section and a listing of the pneumatic controller sources specified in paragraphs (b) and (c) of this section in the initial annual report according to the requirements of section B.5(b)

(f) You must maintain the records as specified in section B.5(a) for each pneumatic controller subject to VOC emission control requirements.

B.4 Continuous Compliance Demonstration Requirements

For each pneumatic controller, you must demonstrate continuous compliance according to paragraphs (a) through (c) of this section.

(a) You must continuously operate each pneumatic controller as required in section B.2(a), (b), or (c).

(b) You must submit the annual reports as required in section B.5(b).

(c) You must maintain records as required in section B.5(a).

B.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*. For each pneumatic controller, you must maintain the records identified in paragraphs (a)(1) through (4) of this section onsite or at the nearest local field office for at least five years.

(1) Records of the date, location and manufacturer specifications for each pneumatic controller.

(2) If applicable, a record of the demonstration that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(4) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in section B.2.

(b) *Reporting requirements*. You must submit annual reports containing the information specified in paragraphs (b)(1) through (3) of this section.

(1) An identification of each existing pneumatic controller, including the identification information specified in section B.2(b)(2) or (c)(2).

(2) If applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) Records of deviations specified in paragraph (a)(4) of this section that occurred during the reporting period.

B.6 Definitions

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Underground storage vessel means a storage vessel stored below ground

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

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C Compressors: VOC Emissions Control Requirements

C.1 Applicability

(a) *Centrifugal compressors*. Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

C.2 What VOC Emission Control Requirements Apply to Centrifugal Compressors?

For each centrifugal compressor, you must comply with the VOC emissions control requirements in paragraphs (a) through (g).

(a) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(b) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of section D.1(a)(1). The cover must be connected through a closed vent system that meets the requirements of section D.1(b) and the closed vent system must be routed to a control device that meets the conditions specified in paragraph (d) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) For each control device used to comply with the VOC emission reduction control requirements in paragraph (a), you must install and operate a continuous parameter monitoring

system for each control device as specified in section E.2(a) through (f), except as provided for in section E.2(b).

(d) You must operate each control device installed on your centrifugal compressor in accordance with the requirements specified in paragraphs (d)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. You may vent more than one source to a single control device.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (f), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2), as applicable.

(e) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each centrifugal compressor as required by section C.4(a).

(f) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each centrifugal compressor as required by section C.5(a).

(g) You must perform the required recordkeeping and reporting as required by section C.6(a)(1) and (b)(1), as applicable.

C.3 What VOC Emission Control Requirements Apply to Reciprocating Compressors?

You must comply with the VOC emission control requirements in paragraphs (a) through (d) of this section for each reciprocating compressor.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning on the compliance date for your

reciprocating compressor as established by your regulatory authority, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the compliance date for a reciprocating compressor for which the rod packing has not yet been replaced.

(3) Route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b).

(b) You must demonstrate initial compliance with requirements that apply to reciprocating compressor sources as required by section C.4(b).

(c) You must demonstrate continuous compliance with requirements that apply to reciprocating compressor sources as required by section C.5(b).

(d) You must perform the required recordkeeping and reporting as required by section C.6(a)(2) and (b)(2).

C.4 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each centrifugal compressor by complying with the requirements in paragraph (a) of this section, and for each reciprocating compressor by complying with the requirements in paragraph (b) of this section.

(a) *Centrifugal compressors*. You have achieved initial compliance with the VOC emission control requirements for each centrifugal compressor if you have complied with paragraphs (a)(1) through (7) of this section.

(1) You reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required in section C.2(a) and as demonstrated by section F.

(2) You use a control device to reduce emissions, and you equip the wet seal fluid degassing system with a cover that meet the requirements of section D.1(a) that is connected through a closed vent system that meets the requirements of section D.1(b) and is routed to a control device that meets the requirements of section E.1. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(4) You conduct the initial cover and closed vent system inspections required in section D.2 within 180 days after the compliance date established by your regulatory authority.

(5) You install and operate the continuous parameter monitoring systems in accordance with section E.2(a) through (g).

(6) You submit the initial annual report for your centrifugal compressor as required in section C.6(b)(1).

(7) You maintain the records as specified in section C.6(a)(1).

(b) *Reciprocating compressors.* You have achieved initial compliance with the VOC emission control requirements for each reciprocating compressor if you have complied with paragraphs (b)(1) through (4) of this section.

(1) If complying with section C.3(a)(1) and (2), you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement, beginning on the compliance date established by your regulatory authority.

(2) If complying with section C.3(a)(3), you must route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b) by the compliance date established by your regulatory authority.

(3) You must submit the initial annual report for your reciprocating compressor as required in section C.6(b)(2).

(4) You maintain the records as specified in section C.6(a)(2).

C.5 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each centrifugal compressor by complying with the requirements of paragraph (a), and for each reciprocating compressor by complying with the requirements of paragraph (b).

(a) *Centrifugal compressors*. For each centrifugal compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (a)(1) through (4) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section C.2(a) using the procedures specified in paragraphs (a)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in section C.2(a), you may demonstrate compliance according to paragraph (a)(2)(viii) of this section. You may switch between compliance with paragraphs (a)(2)(i) through (vii) of this section and compliance with paragraph (a)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of section E.2(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with section E.2(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (a)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (a)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in section F(d), compliance with the operating parameter limit is achieved when the criteria in section F(e) are met.

(iv) You must operate the continuous monitoring system required in section E.2(a) at all times the source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

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(vii) If you use a combustion control device to meet the requirements of section C.2(a) and you demonstrate compliance using the test procedures specified in section F(b), or you use a flare designed and operated in accordance with 40 CFR 60.18(b), you must comply with paragraphs (a)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. A visible emissions test using section 11 of Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (a)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in section C.2(a)(1), you must demonstrate compliance using the procedures in paragraphs (a)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to section E.2(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with section E.2(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (a)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (a)(2)(viii)(A) of this section.

(D) You must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (a)(2)(viii)(C) of this section.

(1) If you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(2) After 120 days and no more than 364 days of operation, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days of operation where you have data. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (a)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by section C.6(b)(1) and maintain the records as specified in section C.6(a)(1).

(4) If you comply with this rule by equipping the wet seal fluid degassing system and route emissions to a control device or process as required by section C.2(b), you must comply with the cover and closed vent requirements in section D.1(a) and (b).

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(b) *Reciprocating compressors*. For each reciprocating compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b)(1) through (4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor or track the number of months or the date of the most recent reciprocating compressor rod packing replacement.

(2) You must submit the annual reports as required in section C.6(b)(2) and maintain records as required in section C.6(a)(2).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) If you comply with this rule by collecting and routing VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure as required by section C.3(a)(3), you must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent system requirements in section D.1(b).

C.6 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*.

(1) *Centrifugal compressors*. For each centrifugal compressor, you must maintain records of the information specified in paragraphs (a)(1)(i) and (ii) of this section, and, if required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (ix) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations where the centrifugal compressor was not operated in compliance with requirements specified in section C.2. Except as specified in paragraph (a)(1)(ii)(G) of this section, you must maintain the records in paragraphs (a)(1)(ii)(A) through (F) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets continuous compliance requirements in section F(e) and used to comply with section C.2(a) for each centrifugal compressor.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(1)(ii)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(*5*) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) As an alternative to the requirements of paragraph (a)(1)(ii)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(iii) Records of each closed vent system inspection required under section D.2(a) and (b).

(iv) A record of each cover inspection required under section D.2(c).

(v) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(vi) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(vii) For each centrifugal compressor, records of the schedule for carbon replacement (as determined by the design analysis requirements of section F(c)(2) or (3)) and records of each carbon replacement as specified in section E.1(c)(1).

(viii) For each centrifugal compressor subject to the control device requirements of section E.1, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(ix) A log of records for all inspection, repair and maintenance activities for each control device failing the visible emissions test as specified in section C.5(a)(2)(vii)(C).

(2) *Reciprocating compressors*. For each reciprocating compressor VOC emissions source, you must maintain the records in paragraphs (a)(2)(i) through (iv) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) Records of the cumulative number of hours of operation or number of months since the previous replacement of the reciprocating compressor rod packing. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in section C.3(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in section C.3.

(iv) If you comply by routing emissions from the rod packing to a process through a closed vent system under negative pressure. You must maintain the records in paragraphs (a)(2)(iv)(A) through (D) of this section.

(A) Records of each closed vent system inspection required under section D.2(a) and (b).

(B) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(C) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(D) A record of each cover inspection required under section D.2(c).

(b) *Reporting requirements*.

(1) *Centrifugal compressors*. For each centrifugal compressor, you must submit annual reports containing the information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (viii) of this section.

(iv) If complying with C.2(a) with a control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e), in the initial annual report, records specified in paragraphs (a)(1)(ii)(A) through (a)(1)(ii)(G) of this section for each centrifugal compressor using a wet seal system that is subject to this rule. In subsequent annual reports, records specified in paragraph (a)(1)(ii)(F) of this section along with information sufficient to link to the identifying information provided in the initial report.

(2) *Reciprocating compressors*. For each reciprocating compressor, you must submit annual reports containing the information specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since the compliance date, or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of deviations specified in paragraph (a)(2)(iii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.3(a)(3), the records specified in paragraphs (a)(2)(i) through (iv) of this section.

C.7 Definitions

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low-pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this rule.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of this rule.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

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D Cover and Closed Vent System Requirements

[Note: These requirements would not apply to covers and closed vent systems used on storage vessels.]

D.1 What Are My Cover and Closed Vent System Requirements?

You must meet the applicable requirements of this section for each cover and closed vent system where VOC emissions are routed to a control device or to a process.

(a) *Cover requirements*.

(1) Centrifugal compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a control device or to a process.

(2) Reciprocating compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the rod packing emissions collection system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a process.

(b) *Closed vent system requirements*.

(1) (i) Centrifugal compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a control device or to a process. For centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in section E.1(a) through (c).

(ii) Reciprocating compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a process.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by section D.2(e).

(3) You must meet the requirements specified in paragraph (b)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or process.

(i) Except as provided in paragraph (b)(3)(ii) of this section, you must comply with either paragraph (b)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in section D.2(d)(1) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (b)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the emission source are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the emission source and have it certified by a qualified professional engineer in accordance with paragraphs (b)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (b)(4)(i) of this section.

D.2 What Are My Initial and Continuous Cover and Closed Vent System Inspection and Monitoring Requirements?

Except as provided in paragraphs (e)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a) and (b) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c) of this section, and inspect each bypass device according to the procedures of paragraph (d) of this section.

(a) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1) and (2) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (e) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or the connection is unsealed. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(b) For closed vent system components other than those specified in paragraph (a) of this section, you must meet the requirements of paragraphs (b)(1) through (3) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions by the date established by your regulatory authority. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual inspections according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(3) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose

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connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results according to according to section C.6(a)(1)(vi) for centrifugal compressors, or H.5(a)(2)(i) for pneumatic pumps, as applicable.

(c) For each cover, you must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

(2) You must initially conduct the inspections specified in paragraph (c)(1) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e)(11) and (12) of this section. For centrifugal compressors, you must maintain records of the inspection results according to section C.6(a)(1)(iv). For reciprocating compressors, you must maintain records of the inspection results according to C.6(a)(2)(iv)(D).

(d) For each bypass device, except as provided for in section D.1(b)(3)(ii), you must meet the requirements of paragraphs (d)(1) or (2) of this section.

(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere.

(2) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(e) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover as specified in paragraphs (a), (b), or (c) of this section, you must meet the requirements of paragraphs (e)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21, 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21, 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in EPA Method 21, 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (e)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in EPA Method 21, 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (e)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (e)(6)(ii) of this section, the detection instrument must meet the performance criteria of EPA Method 21, 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 8.1.1 of EPA Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream.

For process streams that contain nitrogen, air, or other inerts that are not volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (e)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (e)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (e)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (e)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (e)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (e)(9)(i) and (ii) of this section, except as provided in paragraph (e)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

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(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a), (b), or (c) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (e)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in sections that reference this section.

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E VOC Emission Control Device Requirements

[These requirements do not apply to control devices used on storage vessels.]

E.1 Initial Control Device Compliance Requirements

You must meet the applicable requirements of this section for each control device used to comply with VOC emission reduction requirements.

(a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and the continuous compliance requirements in section F(e).

(1) Each combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b), with the exceptions noted in section F(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b), with the exceptions noted in section F(a).

(iii) You must operate at a minimum temperature of 760° Celsius for a control device, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

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(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of section F(c).

(3) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using EPA Method 22 of 40 CFR part 60, appendix A-7, to determine visible emissions.

(b) You must operate each control device installed to control VOC emissions from your emissions source in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from your VOC emissions source through the closed vent system to the control device. You may vent more than one source to a control device used to comply with this rule.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (g), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2) for centrifugal compressors, as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Following the compliance date established by your regulatory authority for the source using the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (a)(2) of this

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section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement.

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

E.2 Continuous Control Device Monitoring Requirements

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet VOC emission control requirements.

(a) For each control device used to comply with the VOC emission reduction requirements, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with section E.1(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel, or used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the

continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in 40 CFR 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in 40 CFR 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under section F(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater.

(vii) For a non-regenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in section F(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under section F(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of F(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A).

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of section E.1(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of section F(b) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of section F(c) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under section F(d) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of section F(b) to demonstrate that the condenser achieves the applicable performance requirements in section E.1(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of section F(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in section E.1(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this

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section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you meet section E.1(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in section C.5(a)(2)(viii)(D) is less than 95.0 percent.

(3) If you meet section E.1(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in section C.5(a)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to section D.1(b)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to section D.1(b)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under section F(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

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(i) The inlet gas flow rate exceeds the maximum established during the test conducted under section F(d).

(ii) Failure of the monthly visible emissions test conducted under section F(e)(3) occurs.

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F Performance Test Procedures

This section applies to the performance testing of control devices used to demonstrate compliance with your VOC emission control requirements. You must demonstrate that a control device achieves the performance requirements specified for your centrifugal compressor using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer, as relevant and allowed for compliance demonstration purposes.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) *A flare that is designed and operated in accordance with 40 CFR 60.18(b)*. You must conduct the compliance determination using EPA Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with 40 CFR 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of section E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of section E.1(a) or A.2(e)(1). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use EPA Method 1 or 1A, 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in EPA Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using EPA Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in section E.1(a)(1)(i) or (a)(2), or section A.2(e)(1)(i)(D)(*1*) or (e)(1)(ii), you must

use EPA Method 25A at 40 CFR part 60, appendix A-7. You must use EPA Method 4 at 40 CFR part 60, appendix A-3 to convert the EPA Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20°Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by EPA Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

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R_{cd} = Control efficiency of control device, percent.

$E_{i,}$ = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use EPA Method 25A, 40 CFR part 60, appendix A-7 to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in section E.1(a)(1)(ii) or section A.2(e)(1)(i)(D)(*2*). You may also use EPA Method 18, 40 CFR part 60, appendix A-6 to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the EPA Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use EPA Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the EPA Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the EPA Method 25A TOC, as propane, concentration for each run.

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(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of EPA Method 3A or 3B, 40 CFR 60, appendix A-2, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after the compliance date for your source as established by your regulatory authority.

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct

subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressors, if you do not continuously monitor the gas flow rate in accordance with section E.2(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in section E.1(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressors, you must establish a limit on temperature in accordance with section E.2(f) and continuously monitor the temperature as required by section E.2(d).

(c) *Control device design analysis to meet the requirements of section E.1(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon

used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the regulatory authority do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The regulatory authority may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent

of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with EPA Method 2A, 40 CFR part 60, appendix A-1 (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using EPA Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

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(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one

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equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using EPA Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and EPA Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by EPA Method 4, 40 CFR part 60, appendix A-3 following the procedure specified in paragraphs (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

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(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in EPA Method 3C, 40 CFR part 60, appendix A-2, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using EPA Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the EPA Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the integrated bag sample required by EPA Method 3C, 40 CFR part 60, appendix A-2, sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A-2, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only).

(8) Carbon monoxide must be determined using EPA Method 10, 40 CFR part 60, appendix A-4. Run the test simultaneously with EPA Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using EPA Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three EPA Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards".

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by EPA Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using EPA Method 22, 40 CFR part 60, appendix A-7. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date

and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from EPA Method 22, 40 CFR part 60, appendix A-7, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average EPA Method 25A, 40 CFR part 60, appendix A-7, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC required under this rule.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report. Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including

information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Officer; OAQPS CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to Oil_and_Gas_PT@EPA.GOV.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

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(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section and maintaining the records specified in A.5(a)(6) or E.2(a)(1)(ii).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

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(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

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G Equipment VOC Leaks at Natural Gas Processing Plants

G.1 Applicability

(a) The group of all equipment, except compressors and sampling connection systems, within a process unit located at an onshore natural gas processing plant.

(b) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by the requirements of section G.2 if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the requirements of section G.2.

(c) The equipment within a process unit subject to VOC emission control requirements located at onshore natural gas processing plants is exempt from this section if they are subject to and controlled according to subparts VVa or GGGa of 40 CFR part 60.

G.2 What VOC Emission Requirements Apply to Equipment at a Natural Gas Processing Plant?

(a) You must comply with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3.

(b) You may elect to comply with the requirements of sections G.6.1 and G.6.2, as an alternative.

(c) You must comply with the provisions of sections G.7 and G.8 of this section, except as provided in section G.3.

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G.3 What Exceptions Apply to the Equipment Leak VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

(a) You may comply with the following exceptions to the provisions of section G.2.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in section G.7(b) except as provided in paragraph (b)(4) of this section, and section G.5.2 of this rule.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in section G.5.7.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a non-fractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and section G.5.2(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a non-fractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(e) An owner or operator may use the following provisions instead of section G.7(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM Method D86-96.

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96.

G.4 How Do I Demonstrate Initial and Continued Compliance with the VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

For equipment subject to VOC emission control requirements at natural gas processing plants, initial and continuous compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3; G.6, as an alternative; and G.7 and G.8, except as provided in section G.3

G.5 What VOC Emission Control Requirements Apply to Equipment at Natural Gas Processing Plants

G.5.1 VOC Emission Control Requirements: General

(a) Each owner or operator subject to the provisions of this rule shall demonstrate compliance with the requirements of sections G.5.2 through G.5.8 for all equipment within 180 days and for G.5.9 within 12 months of the compliance date established by your regulatory authority.

(b) Compliance with sections G.5.2 to G.5.9 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in G.7.

G.5.2 What Equipment VOC Emission Control Requirements Apply to Pressure Relief Devices in Gas/Vapor Service?

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in section G.7(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in section G.5.7.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in section G.7(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in section G.5.8 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in section G.5.7.

G.5.3 What Equipment VOC Emission Control Requirements Apply to Pumps in Light Liquid Service?

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in G.7(b), except as provided in paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in G.7(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of G.5.8; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

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(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in G.7(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

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(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in G.7(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of G.5.8, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in G.8(a)(6)(i), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

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G.5.4 What Equipment VOC Emission Control Requirements Apply to Open-Ended Valves or Lines?

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a) through (c) of this section.

(e) Open-ended valves or lines containing materials which would auto-catalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

G.5.5 What Equipment VOC Emission Control Requirements Apply to Valves in Gas/Vapor Service and in Light Liquid Service?

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in G.7(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii),

except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with section G.6.1 or section G.6.2, count the new valve as leaking when calculating the percentage of valves leaking as described in section G.6.2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in section G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

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(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in section G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in section G.7(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the permitting authority.

(g) Any valve that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in section G.8(a)(6)(ii), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

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(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

G.5.6 What Equipment VOC Emission Control Requirements Apply to Pumps, Valves, and Connectors in Heavy Liquid Service and Pressure Relief Devices in Light Liquid or Heavy Liquid Service?

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in section G.7(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in section G.5.7.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under sections G.5.3(c)(2) and G.5.5(e).

G.5.7 What Delay of Repair of Equipment Requirements Apply When Equipment Component Leaks Have Been Detected?

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with section G.5.8.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be

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allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

G.5.8 What VOC Emission Control Requirements Apply for Closed Vent Systems and Control Devices?

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this rule shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95.0 percent or greater.

(c) Each enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) shall be designed to reduce the mass content of VOC emissions by 95.0 percent or greater in accordance with the requirements of section F(b).

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this rule shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual inspections according to the procedures in section G.7(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in section G.8(a)(3).

(4) For each inspection conducted in accordance with section G.7(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this rule shall be operated at all times when emissions may be vented to them.

G.5.9 What VOC Emission Control Requirements Apply to Connectors in Gas/Vapor Service and in Light Liquid Service?

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks within12 months of the compliance date. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in section G.5.7 or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in section G.7(b) and, as applicable, section G.7(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6

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months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$$\%C_L = C_L / C_t * 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in G.7(b).

C_t = Total number of monitored connectors in the process unit.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as

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provided in section G.5.7. A first attempt at repair as defined in this rule shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors.* (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from recordkeeping and reporting requirements. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

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(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this rule. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this rule are identified as a group, and the number of connectors subject to the requirements is indicated.

G.6 Alternative Standards

G.6.1 Alternative Standards for Valves—Allowable Percentage of Valves Leaking

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the permitting authority that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in section G.8(b)(4).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the permitting authority.

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(3) If a valve leak is detected, it shall be repaired in accordance with section G.5.5(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements shall be monitored within one week by the methods specified in section G.7(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements.

(d) Owners and operators who elect to comply with this alternative standard shall not have a natural gas processing plant subject to the equipment component VOC emission control requirements with a leak percentage greater than 2.0 percent, determined as described in section G.7(h).

G.6.2 Alternative Standards for Valves—Skip Period Leak Detection and Repair

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the permitting authority before implementing one of the alternative work practices.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in section G.5.5.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in section G.5.5 but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in section G.7(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for a process unit following one of the alternative standards in this section must be monitored in accordance with section G.5.5(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

G.7 Equipment Leak Test Methods and Procedures

(a) In conducting the performance tests, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section.

(b) The owner or operator shall determine compliance with the standards in sections G.5.2 through G.5.9, and as follows:

(1) EPA Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in EPA Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring

instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in EPA Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in section G.8(a)(5)(v). Divide these readings by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in sections G.5.2, G.5.3(e), G.5.5(f), and G.5.8(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) EPA Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

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(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 must be used.

(2) Organic compounds that are considered by the permitting authority to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the permitting authority disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) EPA Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device[160] shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m4/(MJ-sec) (metric units) = 0.087 ft^4/(Btu-sec) (English units).

[160] The equivalent device must be reviewed and approved by EPA through the SIP review process.

(4) The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component "i," ppm

H_i = net heat of combustion of sample component "i" at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

(5) EPA Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382-76 or 88 or D4809-95 shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) EPA Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with section G.6.1 or section G.6.2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

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$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with section G.5.5(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

G.8 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements*. Each owner or operator subject to the VOC equipment leak requirements specified in section G shall maintain the records specified in paragraphs (a)(1) through (10), as applicable, onsite or at the nearest local field office for at least five years.

(1) An owner or operator of more than one facility subject to the requirements of section G may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(2) The owner or operator shall record the information specified in paragraphs (a)(2)(i) through (v) of this section for each monitoring event required by sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(3) When each leak is detected as specified in sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) Maximum instrument reading measured by EPA Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be non-repairable, except when a pump is repaired by eliminating indications of liquids dripping.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

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(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(4) The following information pertaining to the design requirements for closed vent systems and control devices described in section G.5.8 shall be recorded and kept in a readily accessible location:

(i) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(iii) A description of the parameter or parameters monitored, as required in section G.5.8(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(iv) Periods when the closed vent systems and control devices required in sections G.5.2 and G.5.3 are not operated as designed, including periods when a flare pilot light does not have a flame.

(v) Dates of startups and shutdowns of the closed vent systems and control devices required in sections G.5.2 and G.5.3.

(5) The following information pertaining to all equipment subject to the requirements in sections G.5.1 to G.5.9 shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for equipment subject to the requirements of this rule.

(ii)(A) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of sections G.5.3(e) and G.5.5(f).

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(B) The designation of equipment as subject to the requirements of sections G.5.3(e) or section G.5.5(f) shall be signed by the owner or operator. Alternatively, owner or operator may establish a mechanism[161] with their permitting authority that satisfies this requirement.

(C) A list of equipment identification numbers for pressure relief devices required to comply with section G.5.2.

(iii)(A) The dates of each compliance test as required in sections G.5.2, G.5.3(e), and G.5.5(f).

(B) The background level measured during each compliance test.

(C) The maximum instrument reading measured at the equipment during each compliance test.

(iv) A list of identification numbers for equipment in vacuum service.

(v) Records of the information specified in paragraphs (a)(5)(v)(A) through (F) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of EPA Method 21 of appendix A-7 of this part and section G.7(b).

(A) Date of calibration and initials of operator performing the calibration.

(B) Calibration gas cylinder identification, certification date, and certified concentration.

(C) Instrument scale(s) used.

(D) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of EPA Method 21 of appendix A-7 of this part.

[161] The mechanism must be reviewed and approved by EPA through the SIP review process.

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(E) Results of each calibration drift assessment required by section G.7(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(F) If an owner or operator makes their own calibration gas, a description of the procedure used.

(vi) The connector monitoring schedule for each process unit as specified in section G.5.9(b)(3)(v).

(vii) Records of each release from a pressure relief device subject to section G.5.2.

(6) The following information pertaining to all valves subject to the requirements of section G.5.5(g) and (h), all pumps subject to the requirements of section G.5.3(g), and all connectors subject to the requirements of section G.5.9(e) shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(ii) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(7) The following information shall be recorded for valves complying with section G.6.2:

(i) A schedule of monitoring.

(ii) The percent of valves found leaking during each monitoring period.

(8) The following information shall be recorded in a log that is kept in a readily accessible location:

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(i) Design criterion required in section G.5.3(d)(5) and explanation of the design criterion; and

(ii) Any changes to this criterion and the reasons for the changes.

(A) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions:

(*1*) An analysis demonstrating the design capacity of the natural gas processing plant,

(*2*) A statement listing the feed or raw materials and products from the processing plant(s) and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(*3*) An analysis demonstrating that equipment is not in VOC service.

(9) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(10) The following recordkeeping requirements apply to pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor service and light liquid service, pumps, valves and connectors in light heavy liquid service and pressure relief devices in light liquid or heavy liquid service, connectors in gas/vapor service and in light liquid service, and alternative standards for valves.

(i) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(ii) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

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(A) The instrument and operator identification numbers and the equipment identification number.

(B) The date the leak was detected and the dates of each attempt to repair the leak.

(C) Repair methods applied in each attempt to repair the leak.

(D) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(E) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(F) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(G) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(H) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(I) The date of successful repair of the leak.

(J) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of section G.5. The designation of equipment that has no detectable emissions that is subject to the provisions of section G.5 must be signed by the owner or operator.

(b) *Reporting requirements*. Each owner or operator subject to the VOC equipment leak requirements shall comply with the reporting requirements of paragraphs (b)(1) through (5).

(1) Each owner or operator subject to the equipment leak VOC emission control requirements of section G.5 shall submit semiannual reports to the permitting authority beginning 6 months after a facility becomes subject to VOC emission control requirements of section G.5.8.

(2) The initial semiannual report to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) Number of valves subject to the requirements of section G.5.5, excluding those valves designated for no detectable emissions under the provisions of section G.5.5(f).

(iii) Number of pumps subject to the requirements of section G.5.3, excluding those pumps designated for no detectable emissions under the provisions of section G.5.3(e) and those pumps complying with section G.5.3(f).

(iv) Number of connectors subject to the requirements of section G.5.9.

(v) Number of pressure relief devices subject to the requirements, except for those pressure relief devices designated for no detectable emissions under the provisions of section G.5.2 (a) and those pressure relief devices complying with section G.5.2 (c).

(3) All semiannual reports to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) For each month during the semiannual reporting period,

(A) Number of valves for which leaks were detected as described in section G.5.5(b) or section G.6.2,

(B) Number of valves for which leaks were not repaired as required in section G.5.5(d)(1),

(C) Number of pumps for which leaks were detected as described in section G.5.3(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

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(D) Number of pumps for which leaks were not repaired as required in section G.5.3(c)(1) and (d)(6),

(E) Number of compressors for which leaks were detected as described in section G.5.3(f),

(F) Number of connectors for which leaks were detected as described in section G.5.9(b)

(G) Number of connectors for which leaks were not repaired as required in section G.5.9(d), and

(H) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(iii) An owner or operator must include the following information in all semiannual reports:

(A) Number of pressure relief devices for which leaks were detected; and

(B) Number of pressure relief devices for which leaks were not repaired.

(iv) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(v) Revisions to items reported according to paragraph (b)(1) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(4) An owner or operator electing to comply with the provisions of section G.6.1 or section G.6.2 shall notify the permitting authority of the alternative standard selected 90 days before implementing either of the provisions.

(5) An owner or operator shall report the results of all performance tests to the permitting authority.

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G.9 Definitions

As used in this model rule, all terms not defined in section G for equipment leaks at natural gas processing plants shall have the meaning given them in subpart VVa of part 60 and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

Equipment, as used in the standards and requirements in this rule relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this rule.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in sections G.7(e) and G.3(e)(2).

In wet gas service means that a piece of equipment (except compressors and sampling connection systems) contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Non-fractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Underground storage vessel means a storage vessel stored below ground.

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H Pneumatic Pumps: VOC Emissions Control Requirements

H.1 Applicability

Each pneumatic pump, which is a natural gas-driven diaphragm pump located at:

(a) A natural gas processing plant; or

(b) A well site. A natural gas-driven diaphragm pump at a well site that is in operation less than 90 days per calendar year is not a source subject to VOC requirements under this rule provided that the owner/operator keeps records of the days of operation each calendar year and submits such records to the regulatory authority upon request. For the purposes of this rule, any period of operation during a calendar day counts toward the 90 calendar day threshold.

For purposes of the requirements specified in this section, we refer to these pumps as natural gas-driven pneumatic pumps.

H.2 What VOC Emission Reduction Requirements Apply to Natural Gas-Driven Pneumatic Pumps?

For each natural gas-driven pneumatic pump, you must comply with the VOC emission control requirements, based on VOC, in either paragraph (a) or (b)(1) of this section, as applicable.

(a) Each natural gas-driven pneumatic pump at a natural gas processing plant must have a VOC emission rate of zero.

(b)(1) For each natural gas-driven pneumatic pump at a well site, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(2), (3) and (4) of this section.

(2) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b)(1) of this section. If you do not

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have a control device installed on site by the compliance date established by your regulatory authority and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with section H.5(b)(1)(i) in your next annual report, certifying that there is no available control device or process on site and maintain the records in section H.5(a)(1)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to submit the certification in section H.2(b)(2)(i) and must submit the information in section H.5(b)(2) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2). You must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(3) If the control device available on site is unable to achieve a 95.0 percent reduction and there is no ability to route the emissions to a process, you must still route the natural gas-driven pneumatic pump's emissions to that existing control device. If you route the pneumatic pump to a control device installed on site that is designed to achieve less than a 95.0 percent reduction, you must submit the information specified in section H.5(b)(1)(iii) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2).

(4) If you determine, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraph (b)(4)(i) through (iv) of this section must be met.

(i) You must conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(4)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(4)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was

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prepared pursuant to the requirements of section H.2(b)(4)(iii) of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device on site or to a process must include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. You must prepare the assessment of technical infeasibility under the direction or supervision of the qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) You must maintain the records specified in section H.5(a)(1)(iv).

(5) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b)(1) of this section, and instead must comply with paragraph (b)(2) of this section and report the change in your next annual report in accordance with section H.5(b)(2)(iii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the natural gas-driven pneumatic pump subject to VOC emission control requirements through a closed vent system that meets the requirements of section D.1(b).

(d) You must demonstrate initial compliance with standards that apply to natural gas-driven pneumatic pumps subject to VOC emission requirements as required by section H.3.

(e) You must demonstrate continuous compliance with standards that apply to natural gas-driven pneumatic pump sources subject to VOC emission requirements as required by section H.4.

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(f) You must perform the reporting as required by section H.5(b) and the recordkeeping as required by H.5(a).

H.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission control requirements for natural gas-driven pneumatic pumps specified in paragraphs (a) through (h) of this section, as applicable.

(a) If you own or operate a pneumatic pump located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero VOC emissions.

(b) If you own or operate a natural gas-driven pneumatic pump located at a well site, you must reduce emissions in accordance with section H.2(b)(1), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(c) If you own or operate a natural gas-driven pneumatic pump located at a well site and there is no control device or process available on site, you must submit the certification in section H.5(b)(1)(i).

(d) If you own or operate a natural gas-driven pneumatic pump located at a well site, and you are unable to route to an existing control device due to technical infeasibility, and you are unable to route to a process, you must submit the certification in section H.5(b)(1)(ii).

(e) If you own or operate a natural gas-driven pneumatic pump located at a well site and you reduce emissions in accordance with section H.2(b)(3), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(f) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the initial closed vent system inspection required in section D.2 by the date established by your regulatory authority.

(g) You must include a listing of the natural gas-driven pneumatic pumps subject to VOC emission requirements specified in paragraphs (a) through (e) of this section in the initial annual report submitted for your natural gas-driven pneumatic pump according to the requirements of section H.5(b).

(h) You must maintain the records as specified in section H.5(a) for each natural gas-driven pneumatic pump subject to the VOC emission control requirements of section H.

H.4 Continuous Compliance Demonstration Requirements

For each natural gas-driven pneumatic pump you must demonstrate continuous compliance according to paragraphs (a) and (b) of this section.

(a) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the periodic closed vent system inspections required in section D.2, as applicable.

(b) You must submit the annual reports required by section H.5(b) and maintain the records as specified in section H.5(a).

H.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.*

(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (v) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the rule (as established by the regulatory authority), location and manufacturer specifications for each natural gas-driven pneumatic pump.

(ii) Records of deviations in cases where the natural gas-driven pneumatic pump was not operated in compliance with the requirements specified in section H.2.

(iii) Records on the control device used for control of emissions from a natural gas-driven pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than a 95.0 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to H.2(b)(4) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process, including the qualified professional engineer certification according to H.2(b)(4)(ii) and the records of the engineering assessment of technical infeasibility performed according to H.2.(b)(4)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the regulatory authority.

(2) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must maintain the records identified in paragraphs (a)(2)(i) through (iv) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of each closed vent system inspection required under section D.2(a) and (b).

(ii) If you are subject to the bypass requirements of section D.1(b)(3), a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(iii) If you are subject to the closed vent system no detectable emissions requirements of section D.2(e), records of the monitoring conducted in accordance with section D.2(e).

(iv) For each closed vent system routing to a control device or process, the records of the assessment conducted according to section D.1(b)(4):

(A) A copy of the assessment conducted according to section D.1(b)(4);

(B) A copy of the certification according to section D.1(b)(4)(i); and

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(C) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the regulatory authority.

(b) *Reporting Requirements*.

For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1) through (4) of this section.

(1) In the initial annual report, a certification that the natural gas-driven pneumatic pump meets one of the conditions described in paragraphs (b)(1)(i), (ii) or (iii) of this section.

(i) No control device or process is available on site.

(ii) A control device or process is available on site and the owner or operator has determined in accordance with H.2(b)(4) that it is technically infeasible to capture and route the emissions to the control device or process.

(iii) Emissions from the natural gas-driven pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95.0 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(2) For any natural gas-driven pneumatic pump which has been previously reported as required under paragraph (b)(1) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the natural gas-driven pneumatic pump and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(2)(i), (ii) or (iii) or (iv) of this section.

(i) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(iii) of this section.

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(ii) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(ii) of this section.

(iii) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump now report according to paragraph (b)(1)(i) of this section.

(iv) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with H.2(b)(4) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(3) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(4) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, the records specified in paragraphs (a)(2)(i), (ii), (iii) and (iv)(B) of this section.

H.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

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(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction

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with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Routed to a process or *route to a process* means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

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I Fugitive Emissions Components VOC Emissions Control Requirements

I.1 Applicability

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day. The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads. Whether a separate tank battery surface site is subject to this rule has no effect on the status of a well site that only contains wellheads.

(b) The collection of fugitive emission components at a gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline.

I.2 What VOC Emission Control Requirements Apply to the Collection of Fugitive Emission Components at a Well Site and a Gathering and Boosting Station?

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site and gathering and boosting station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (f) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and cover requirements in section D. The collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf of gas per barrel of oil produced are subject only to the requirements in paragraph (g) of this section.

(a) You must monitor all fugitive emission components, as defined in section I.6, in accordance with paragraphs (b) through (e) of this section and section I.2(a) and I.3(a). You must

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repair all sources of fugitive emissions in accordance with paragraph (f) of this section. You must keep records in accordance with section I.5(a) and report in accordance with section I.5(b). For purposes of this section, fugitive emissions are defined as: any visible emission from a fugitive emission component using optical gas imaging or an instrument reading of 500 ppm or greater using EPA Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, at a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.

(2) Technique for determining fugitive emissions (*i.e.*, EPA Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

(3) Manufacturer and model number of fugitive emission detection equipment to be used.

(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (f) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.*, steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using EPA Method 21 at 40 CFR part 60, appendix A-7, your plan must also include the elements specified in paragraphs (c)(8)(i) and (ii) of this section. For the purposes of complying with the fugitive emissions monitoring program using EPA Method 21, a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of EPA Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.*, 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of EPA Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(4) of this section, at a minimum, as applicable.

(1) Sitemap.

(2) If you are using OGI, a defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using EPA Method 21, your plan must also include a list of fugitive emissions components to be monitored and the method for determining location of fugitive

emissions components to be monitored in the field (*e.g.*, tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with section I.4(a)(3), and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with section I.4(a)(4).

(e) Each monitoring survey shall observe each fugitive emissions component, as defined section I.6, for fugitive emissions.

(f) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (f)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of sections A.4(d)(4) through (7) and D.2(e)(9) through (12), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a gathering and boosting station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next gathering and boosting station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than 30 days after being repaired or replaced, to ensure that there are no fugitive emissions.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using EPA Method 21 or optical gas imaging within 30 days of being repaired.

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(ii) For each repair or replacement that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use EPA Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the EPA Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of EPA Method 21 are used.

(B) Operators must use the EPA Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of EPA Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(g) For each well with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (g)(2) of this section.

(1) You must determine the gas to oil ratio of your well using generally accepted methods.

(2) You must maintain the records specified in section I.5 (a)(4)

I.3 Initial Compliance Demonstration

To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must comply with paragraphs (a) through (e) or (f), if applicable, of this section.

(a) You must develop a fugitive emissions monitoring plan as required in sections I.2(b), (c), and (d).

(b) You must conduct an initial monitoring survey as required in paragraphs (b)(1) and (2), as applicable

(1) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of becoming subject to VOC emission control requirements of section I.

(2) Each gathering and boosting station with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of being subject to VOC emission control requirements of section I.

(c) You must maintain the records specified in section I.5(a).

(d) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(e) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(f) You must determine the gas to oil ratio of your well using generally accepted methods and maintain the records specified in section I.5(a)(4).

I.4 Continuous Compliance Demonstration

For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must demonstrate continuous compliance with the fugitive emission standards specified in section I.2 according to paragraphs (a) through (d) or (e), if applicable, of this section.

(a) You must conduct periodic monitoring surveys of each collection of fugitive emissions components at a well site and a gathering and boosting station subject to VOC emission control requirements under section I at the frequencies specified in paragraphs (a)(1) and (a)(2) of this section, with the exceptions noted in paragraphs (a)(3) through (a)(5) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart.

(2) A monitoring survey of the collection of fugitive emissions components at a gathering and boosting station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (a)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (a)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (a)(2) of this section are waived for any collection of fugitive emissions components at a gathering and boosting station located within an area that has an average calendar month temperature below 0°Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The

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requirements of paragraph (a)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(b) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(c) You must maintain the records specified in section I.5(a).

(d) You must submit annual reports for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(e) You must recalculate the gas to oil ratio of your well using generally accepted methods annually and maintain the records as required in section I.5(a)(4).

I.5 Recordkeeping and Reporting Requirements

(a) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, the records identified in paragraphs (a)(1) through (3), and (a)(4), if applicable of this section shall be maintained onsite or at the nearest local field office for at least five years.

(1) The fugitive emissions monitoring plan as required in I.2(b), (c), and (d).

(2) The records of each monitoring survey as specified in paragraphs (a)(2)(i) through (ix) of this section.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. You must note the training and experience of the operator.

(iv) Monitoring instrument used.

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a gathering and boosting station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

(vi) Fugitive emissions component identification when EPA Method 21 is used to perform the monitoring survey.

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(viii) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(ix) Documentation of each fugitive emission, including the information specified in paragraphs (a)(2)(ix)(A) through (L) of this section.

(A) Location.

(B) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(C) Number and type of components for which fugitive emissions were detected.

(D) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(E) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 is used for monitoring.

(F) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(G) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii).

(H) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (a)(2)(v) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(I) Repair methods applied in each attempt to repair the fugitive emissions components.

(J) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(K) The date of successful repair of the fugitive emissions component.

(L) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(3) For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

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(4) For the collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf per stock barrel of oil produced, you must maintain:

(A) A record of the gas to oil ratio analyses documenting a gas to oil ratio of less than 300 scf per stock barrel of oil produced, conducted pursuant to sections I.3(f) and I.4(e).

(B) The location of the well and the United States Well ID Number.

(C) A record of the determination signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

(b) Annual reports shall be submitted for the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each gathering and boosting station within the company-defined area, that are subject to VOC emission control requirements under section I. Each annual report shall include the records of each monitoring survey including the information specified in paragraphs (b)(1) through (12) of this section. For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a gathering and boosting station subject to VOC emission control requirements under section I may be included in a single annual report.

(1) Date of the survey.

(2) Beginning and end time of the survey.

(3) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(5) Monitoring instrument used.

(6) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(7) Number and type of components for which fugitive emissions were detected.

(8) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(9) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(10) The date of successful repair of the fugitive emissions component.

(11) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(12) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

I.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

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(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Gathering and boosting station means any permanent combination of one or more compressors that collects natural gas from well sites and moves the natural gas at increased pressure into gathering pipelines to the natural gas processing plant or into the pipeline. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a gathering and boosting station for purposes of this section.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to section A.2(c) or (d) or section D, thief hatches or other openings on a controlled storage vessel not subject to section A, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at section I.1, *well site* also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.*, centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

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Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015

§60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas production source category that commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015.

[85 FR 57069, Sept. 14, 2020]

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§60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section that is located within the Crude Oil and Natural Gas Production source category, as defined in §60.5430 for which you commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015.

(a) Each gas well affected facility, which is a single natural gas well.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)(1) For the oil and natural gas production segment, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

(2) [Reserved]

(3) For natural gas processing plants, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel, and has the potential for VOC emissions equal to or greater than 6 tons per year (tpy) as determined according to this section by October 15, 2013, for Group 1 storage vessels and by April 15, 2014, or 30 days after startup (whichever is later) for Group 2 storage vessels, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for gas well affected facilities in §60.5375, including wells subject to §60.5375(f), you must determine the potential for VOC emissions within 30 days after startup of production.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in §60.5411(b).

(ii) You meet the closed vent system requirements specified in §60.5411(c).

(iii) You maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) The following requirements apply immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced.

(5) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423(c) but are not required to comply with §§60.5405 through 60.5407 and §§60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§60.5405 through 60.5407, 60.5410(g), 60.5415(g), and 60.5423 of this subpart.

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375 are met. For purposes of this provision, the dates specified in §60.5375(a) do not apply, and such facilities, as of October 15, 2012, must meet the requirements of §60.5375(a)(1) through (4).

(2) A well completion operation following hydraulic refracturing at a gas well facility not conducted pursuant to §60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) A gas well facility initially constructed after August 23, 2011, and on or before September 18, 2015 is considered an affected facility regardless of this provision.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58435, Sept. 23, 2013; 79 FR 79036, Dec. 31, 2014; 80 FR 48268, Aug. 12, 2015; 81 FR 35896, June 3, 2016; 85 FR 57069, Sept. 14, 2020]

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§60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

(d) You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.

[77 FR 49542, Aug. 16, 2012, as amended at 81 FR 35896, June 3, 2016]

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§60.5375 What standards apply to gas well affected facilities?

If you are the owner or operator of a gas well affected facility, you must comply with paragraphs (a) through (f) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing begun prior to January 1, 2015, you must comply with the requirements of paragraphs (a)(3) and (4) of this section unless a more stringent state or local emission control requirement is applicable; optionally, you may comply with the requirements of paragraphs (a)(1) through (4) of this section. For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b).

(1) For each stage of the well completion operation, as defined in §60.5430, follow the requirements specified in paragraph (a)(1)(i) and (ii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into the well or another well or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the

separation flowback stage, it is not technically feasible for a separator to function, you must comply with (a)(1)(i) of this section.

(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each gas well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in §60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas well affected facilities as required by §60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas well affected facilities as required by §60.5415.

(e) You must perform the required notification, recordkeeping and reporting as required by §60.5420.

(f)(1) For each gas well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure gas well or non-delineation low pressure gas well.

(2) Route the flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in §60.5420(c)(1)(iii) for wildcat, delineation and low pressure gas wells.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79037, Dec. 31, 2014]

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§60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411(b), that is connected through a closed vent system that meets the requirements of §60.5411(a) and routed to a control device that meets the conditions specified in §60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5410(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5415(b).

(d) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58436, Sept. 23, 2013]

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§60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of §60.5411(a).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79037, Dec. 31, 2014]

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§60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in §60.5420(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in §60.5420(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by §60.5420, except that you are not required to submit the notifications specified in §60.5420(a).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58436, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014]

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§60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (h) of this section, you must comply with the standards in this section for each storage vessel affected facility.

(a)(1) If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraph (b) of this section.

(2) If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraph (c) of this section.

(b) *Requirements for Group 1 storage vessel affected facilities.* If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraphs (b)(1) and (2) of this section.

(1) You must submit a notification identifying each Group 1 storage vessel affected facility, including its location, with your initial annual report as specified in §60.5420(b)(6)(iv).

(2) You must comply with paragraphs (d) through (g) of this section.

(c) *Requirements for Group 2 storage vessel affected facilities.* If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraphs (d) through (g) of this section.

(d) You must comply with the control requirements of paragraph (d)(1) of this section unless you meet the conditions specified in paragraph (d)(2) of this section.

(1) Reduce VOC emissions by 95.0 percent according to the schedule specified in (d)(1)(i) and (ii) of this section.

(i) For each Group 2 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2014, or within 60 days after startup, whichever is later, except as otherwise provided below in paragraph (f) of this section. For storage vessel affected facilities receiving liquids pursuant to the standards for gas well affected facilities in §60.5375, you must achieve the required emissions reductions within 60 days after startup of production as defined in §60.5430.

(ii) For each Group 1 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2015.

(2) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with

paragraph (d)(1) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (d)(2)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (d)(1) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (d)(1) of this section within 30 days of the monthly calculation.

(e) *Control requirements.* (1) Except as required in paragraph (e)(2) of this section, if you use a control device to reduce emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411(b) and is connected through a closed vent system that meets the requirements of §60.5411(c), and you must route emissions to a control device that meets the conditions specified in §60.5412(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(f) *Requirements for Group 1 and Group 2 storage vessel affected facilities that are removed from service or returned to service.* If you remove a Group 1 or Group 2 storage vessel affected facility from service, you must comply with paragraphs (f)(1) through (3) of this section. A Group 1 or Group 2 storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraph (f)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in §60.5420(b)(6)(vi) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (f)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in §60.5365(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in §60.5420(b)(6)(vii), identifying each storage vessel affected facility and the date of its return to service.

(g) *Compliance, notification, recordkeeping, and reporting.* You must comply with paragraphs (g)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by §60.5410(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by §60.5415(e)(3).

(3) You must perform the required notification, recordkeeping and reporting as required by §60.5420.

(h) *Exemptions.* This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

[78 FR 58436, Sept. 23, 2013, as amended at 79 FR 79038, Dec. 31, 2014]

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§60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401.

(b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402 of this subpart.

(d) You must comply with the provisions of §60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§60.486a and 60.487a of this part except as provided in §§60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

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§60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of §60.5400(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of §60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(g) An owner or operator may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79038, Dec. 31, 2014]

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§60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

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§60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by §60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

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§60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in §60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph §60.8(b).

(b) During a performance test required by §60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in §60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

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Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331×10^{-3} Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in §60.5408 or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in §60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (1005)\frac{\square}{S + E}$$

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(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

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Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals.

The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

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§60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of §60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) *The* H_2S *concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in §60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in §60.5406(b)(1).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.* You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of §60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) *A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere.* The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective

upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

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Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by §60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of §60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by §60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

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§60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H_2S per 100 cubic foot of gas = 100(D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

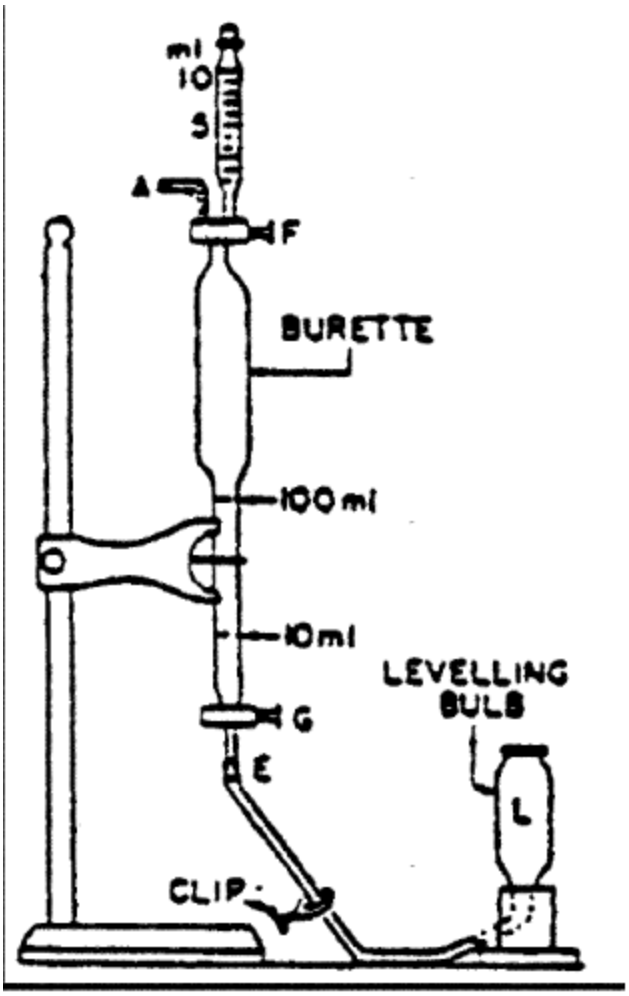


Figure 1. Tutwiler burette (lettered items mentioned in text).

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§60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the standards for each well completion operation conducted at your gas well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in §60.5420(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420(b).

(3) You must maintain a log of records as specified in §60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both §60.5375(a)(1) and (3), as an alternative to retaining the records specified in §60.5420(c)(1)(i) through (iv), you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by §60.5380 and as demonstrated by the requirements of §60.5413.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411(b) that is connected through a closed vent system that meets the requirements of §60.5411(a) and is routed to a control device that meets the conditions specified in §60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You must conduct an initial performance test as required in §60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in §60.5415(b)(1) through (3).

(4) You must conduct the initial inspections required in §60.5416(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with §60.5417(a) through (g), as applicable.

(6) [Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420(b)(3) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in §60.5420(c)(2).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with §60.5385(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with §60.5385(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of §60.5411(a).

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420(b).

(4) You must maintain the records as specified in §60.5420(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in §60.5390(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of §60.5390(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420(b).

(6) You must maintain the records as specified in §60.5420(c)(4) for each pneumatic controller affected facility.

(e) [Reserved]

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in §60.5405(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (5) of this section. For a Group 1 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2015, except as otherwise provided in paragraph (i) of this section. For a Group 2 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2014, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in §60.5365(e).

(2) You must reduce VOC emissions in accordance with §60.5395(d).

(3) If you use a control device to reduce emissions, or if you route emissions to a process, you must demonstrate initial compliance by meeting the requirements in §60.5395(e).

(4) You must submit the information required for your storage vessel affected facility as specified in §60.5420(b).

(5) You must maintain the records required for your storage vessel affected facility, as specified in §60.5420(c)(5) through (8) and §60.5420(c)(12) and (13) for each storage vessel affected facility.

(i) For each Group 1 storage vessel affected facility, you must submit the notification specified in §60.5395(b)(2) with the initial annual report specified in §60.5420(b)(6).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58437, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014; 81 FR 35896, June 3, 2016]

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§60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your storage vessel, reciprocating compressor or centrifugal compressor affected facility.

(a) *Closed vent system requirements for reciprocating compressors and for centrifugal compressor wet seal degassing systems.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the reciprocating compressor rod packing emissions collection system or the wet seal fluid degassing system to a control device or to a process that meets the requirements specified in §60.5412(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in §60.5416(a)(4) and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) *Cover requirements for storage vessels and centrifugal compressor wet seal degassing systems.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system designed and operated in accordance with the requirements of paragraph (a) or (c) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) *Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in §60.5412(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections. Each closed vent system that routes emissions to a process must be operational 95 percent of the year or greater.

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere and that either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58438, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014; 81 FR 35896, June 3, 2016]

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§60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) Each control device used to meet the emission reduction standard in §60.5380(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e).

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413.

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of §60.5413.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under §60.5413.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413. As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of §60.5413(c).

(3) You must design and operate a flare in accordance with the requirements of §60.5413.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility, as required under §60.5380(a), through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417(a) through (g), you must demonstrate compliance according to the requirements of §60.5415(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in §60.5395(d) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e).

(1) Each enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed to reduce the mass content of VOC emissions by 95.0 percent or greater. Each flare must be designed and operated in accordance with the requirements of §60.5413(a)(1). You must follow the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for

inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (d)(1)(iv)(A) through (D) of this section.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413.

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of §60.5413.

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413, that combustion zone temperature is an indicator of destruction efficiency.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58438, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

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§60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412(a) using the performance test methods and procedures specified in this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to both storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412(a). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A at 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in §60.5412(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device total TOC concentration limit specified in §60.5412(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D at 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412(a)(1)(i) or (a)(2), you must use Method 25A at 40 CFR part 60, appendix A-7. You must use the procedures in paragraphs (b)(3)(i) through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij} M_{ij}\right) Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

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Where:

E_i, E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A at 40 CFR part 60, appendix A-7 using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

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Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A at 40 CFR part 60, appendix A-7 to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion device total VOC concentration limit specified in §60.5412(a)(1)(ii). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=i}^{n} C_{ji}\right)}{x}$$

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Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B at 40 CFR part 60, appendix A, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

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Where:

C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420(b)(7).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420(b)(7). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in §60.5412(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) *Control device design analysis to meet the requirements of §60.5412(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the

requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) through (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A, 40 CFR part 60, appendix A-1, (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) through (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) through (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the Method 4, 40 CFR part 60, appendix A-3, moisture test following the procedure specified in (d)(7)(i)(A) through (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) through (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C, 40 CFR part 60, appendix A, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the Method 3C, 40 CFR part 60, appendix A-2, integrated bag sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A, equation 3B-1.

(8) Carbon monoxide must be determined using Method 10, 40 CFR part 60, appendix A. Run the test simultaneously with Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference as specified in §60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

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Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22, 40 CFR part 60, appendix A. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Method 22, 40 CFR part 60, appendix A, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average Method 25A, 40 CFR part 60, appendix A, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A control device meeting the criteria in paragraph (d)(11)(i)(A) through (D) of this section must demonstrate a destruction efficiency of 95 percent for VOC regulated under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report required by this section in accordance with §60.5420(b)(8).

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section and complying with the criteria specified in paragraphs (e)(1) through (7) of this section.

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

(7) Ensure that each enclosed combustion device is maintained in a leak free condition.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58439, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

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§60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420(b) and maintaining the records for each completion operation specified in §60.5420(c)(1).

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) through (3) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of §60.5412(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412(a)(2), you must demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, as required in §60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of §60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417 at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data

collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of §60.5412(a) and you demonstrate compliance using the test procedures specified in §60.5413(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in §60.5370, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance dates. You have demonstrated

compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in §60.5370, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual report required by 60.5420(b) and maintain the records as specified in §60.5420(c)(2).

(c) For each reciprocating compressor affected facility complying with §60.5385(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with §60.5385(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in §60.5420(b) and maintain records as required in §60.5420(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in §60.5416(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390(a), (b), or (c).

(2) You must submit the annual report as required in §60.5420(b).

(3) You must maintain records as required in §60.5420(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395(d)(1).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395(d).

(ii) For each control device installed to meet the requirements of §60.5395(d), you must demonstrate continuous compliance with the performance requirements of §60.5412(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416(c) for each cover and closed vent system.

(B) You must comply with §60.5417(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411(c)(2).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in §60.5405(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406(c)(1).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58442, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

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§60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor and reciprocating compressor affected facility, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) *Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility.* Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures

and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in §60.5420(c)(7).

(4) For each bypass device, except as provided for in §60.5411, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor or reciprocating compressor affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 at 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 at 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 at 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average

response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are

met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in §60.5420(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420(c)(6).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in §60.5411(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest

field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to §60.5420(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58443, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

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§60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in §60.5380, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under §60.5413 that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.8 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a performance test performed as specified in §60.5413(b). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under §60.5413(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under §60.5413(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412(a), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413(b) to demonstrate that the condenser achieves the applicable performance requirements in §60.5412(a), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of §60.5413(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you meet §60.5412(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415(e)(8)(iv) is less than 95.0 percent.

(3) If you meet §60.5412(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415(e)(8)(iv)(A) or (B) is less than 90.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) and (ii) of this section are met.

(i) For each bypass line subject to §60.5411(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under §60.5413(d).

(ii) Failure of the quarterly visible emissions test conducted under §60.5413(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in §60.5395(d)(1) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(3) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with §60.5413(d)(2) through (10), which meets the criteria in §60.5413(d)(11), the reporting requirement in §60.5413(d)(12), and meet the continuous compliance requirement in §60.5413(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A. The observation period shall be 15

minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in §60.5420(c)(13).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58443, Sept. 23, 2013]

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§60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in §60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility you are not required to submit the notifications required in §60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a gas well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) Reporting requirements. You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) or (8) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (6) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with §60.5380(a)(1), the records specified in paragraphs (c)(6) through (11) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to §60.5365(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) You must submit a notification identifying each Group 1 storage vessel affected facility in your initial annual report. You must include the location of the storage vessel, in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) A statement that you have met the requirements specified in §60.5410(h)(2) and (3).

(vi) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in §60.5395(f)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vii) You must identify each storage vessel affected facility returned to service during the reporting period as specified in §60.5395(f)(3), including the date the storage vessel affected facility was returned to service.

(7)(i) Within 60 days after the date of completing each performance test (see §60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in

§60.5413(d), you must submit the results of the performance tests required by this subpart to the EPA as follows. You must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*) existing at the time of the performance test to generate a submission package file, which documents the performance test. You must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

(ii) All reports, except as specified in paragraph (b)(8) of this section, required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in §60.4 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy).

(8) For enclosed combustors tested by the manufacturer in accordance with §60.5413(d), an electronic copy of the performance test results required by §60.5413(d) shall be submitted via email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

(c) *Recordkeeping requirements*. You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

(1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each gas well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.

(iii) Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each gas well affected facility required to comply with the requirements of §60.5375(a), you must record: The location of the well; the API well number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375(a)(1)(i); the date and time of each occurrence of returning to the initial flowback stage under §60.5375(a)(1)(i); and the date and time that the well

was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas well affected facility required to comply with the requirements of §60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each gas well facility for which you claim an exception under §60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each gas well affected facility required to comply with both §60.5375(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in §60.5410(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in §60.5380.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in §60.5385(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390.

(5) Except as specified in paragraph (c)(5)(v) of this section, for each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

(i) If required to reduce emissions by complying with §60.5395(d)(1), the records specified in §§60.5420(c)(6) through (8), 60.5416(c)(6)(ii), and 60.6516(c)(7)(ii) of this subpart.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§60.5395, 60.5411, 60.5412, and 60.5413, as applicable.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at the site. If a storage vessel is removed from the site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(6) Records of each closed vent system inspection required under §60.5416(a)(1) and (2) for centrifugal or reciprocating compressors or §60.5416(c)(1) for storage vessels.

(7) A record of each cover inspection required under §60.5416(a)(3) for centrifugal or reciprocating compressors or §60.5416(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of §60.5416(a)(4) for centrifugal or reciprocating compressors or §60.5416(c)(3) for storage vessels, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(9) If you are subject to the closed vent system no detectable emissions requirements of §60.5416(b) for centrifugal or reciprocating compressors, a record of the monitoring conducted in accordance with §60.5416(b).

(10) For each centrifugal compressor affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5413(c)(2) or (3)) and records of each carbon replacement as specified in §60.5412(c)(1).

(11) For each centrifugal compressor subject to the control device requirements of §60.5412(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412(d)(2)) and records of each carbon replacement as specified in §60.5412(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417(h). You must maintain records of EPA Method 22, 40 CFR part 60, appendix A, section 11 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §§60.5412(d)(1)(iii) and 60.5413(e)(4) for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58445, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016; 85 FR 57069, Sept. 14, 2020]

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§60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in §60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

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§60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3).

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§60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in §§60.5405(a) and (b) and 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(d) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with §60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

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§60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

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§60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: P = R × A, where

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

A = Y × (B ÷ 100);

(ii) The percent Y is determined from the following equation: Y = 1.0 − 0.575 log X, where X is 2011 minus the year of construction; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Crude Oil and Natural Gas Production source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production and processing, which includes the well and extends to, but does not include, the point of custody transfer to the natural gas transmission and storage segment.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility, a mainline pipeline, re-injection, or routed to a process or other useful purpose.

Flowback means the process of allowing fluids and entrained solids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term *flowback* also means the fluids and entrained solids that emerge from a natural gas well during the flowback process. The *flowback period* begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The *flowback period* ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well or natural gas well means an onshore well drilled principally for production of natural gas.

Group 1 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after August 23, 2011, and on or before April 12, 2013.

Group 2 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after April 12, 2013, and on or before September 18, 2015.

Hydraulic fracturing or refracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e) or §60.5401(g)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that vents non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the true vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Natural gas transmission and storage segment means the transport or storage of natural gas prior to delivery to a “local distribution company custody transfer station” (as defined in this section) or to a final end user (if there is no local distribution company custody transfer station). For the purposes of this subpart, natural gas enters the natural gas transmission and storage segment after the natural gas processing plant, when present. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage segment after the point of “custody transfer” (as defined in this section). A compressor station that transports natural gas prior to the point of “custody transfer” or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage segment.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with §60.5395(f)(1).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Returned to service means that a Group 1 or Group 2 storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The *separation flowback stage* ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395(f) until such time as such tank or other vessel has been returned to service. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395(f) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.

Well completion vessel means a vessel that contains *flowback* during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58447, Sept. 23, 2013; 79 FR 79040, Dec. 31, 2014; 80 FR 48268, Aug. 12, 2015; 81 FR 35898, June 3, 2016; 85 FR 57069, Sept. 14, 2020]

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Table 1 to Subpart OOOO of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9

$10 \leq Y < 20$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller	93.5	93.5
$Y < 10$	79.0	79.0	79.0	79.0

[78 FR 58447, Sept. 23, 2013]

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Table 2 to Subpart OOOO of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
$10 \leq Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

[78 FR 58447, Sept. 23, 2013]

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Table 3 to Subpart OOOO of Part 60—Applicability of General Provisions to Subpart OOOO

As stated in §60.5425, you must comply with the following applicable General Provisions:

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§60.1	General applicability of the General Provisions	Yes.	

§60.2	Definitions	Yes	Additional terms defined in §60.5430.
§60.3	Units and abbreviations	Yes.	
§60.4	Address	Yes.	
§60.5	Determination of construction or modification	Yes.	
§60.6	Review of plans	Yes.	
§60.7	Notification and record keeping	Yes	Except that §60.7 only applies as specified in §60.5420(a).
§60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
§60.9	Availability of information	Yes.	
§60.10	State authority	Yes.	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOO.
§60.12	Circumvention	Yes.	
§60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§60.14	Modification	Yes.	
§60.15	Reconstruction	Yes.	Except that §60.15(d) does not apply to gas wells, pneumatic controllers, centrifugal compressors, reciprocating compressors or storage vessels.
§60.16	Priority list	Yes.	
§60.17	Incorporations by reference	Yes.	
§60.18	General control device requirements	Yes	Except that the period of visible emissions shall not exceed a total of 1 minute during any 15-minute period instead of 5 minutes during any 2 consecutive hours as required in §60.18(c).
§60.19	General notification and reporting requirement	Yes.	

[77 FR 49542, Aug. 16, 2012, as amended at 81 FR 35898, June 3, 2016]

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NMED Exhibit 35 - 0071

NSPS Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

Contents

SOURCE: 81 FR 35898, June 3, 2016, unless otherwise noted.

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§60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of the rule is August 2, 2016.

(b) *Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

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§60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification, or reconstruction after September 18, 2015.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing. The provisions of this paragraph do not affect the affected facility status of well sites for the purposes of §60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to §60.5375a(a)(1) through (4) is a modification to the well.

(3) Except as provided in §60.5365a(i)(3)(iii), refracturing of a well, by itself, does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d) Each pneumatic controller affected facility:

(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority.

(1) For each new, modified or reconstructed storage vessel you must determine the potential for VOC emissions within 30 days after liquids first enter the storage vessel, except as provided in paragraph (e)(3)(iv) of this section. For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in §60.5411a(b).

(ii) You meet the closed vent system requirements specified in §60.5411a(c) and (d).

(iii) You must maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) The following requirements apply immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced.

(5) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) The group of all equipment within a process unit is an affected facility. (1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG, or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423a(c) but are not required to comply with §§60.5405a through 60.5407a and §§60.5410a(g) and 60.5415a(g).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a.

(h) Each pneumatic pump affected facility:

(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.

(2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump. A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90 calendar day threshold.

(i) Except as provided in §60.5365a(i)(2), the collection of fugitive emissions components at a well site, as defined in §60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of §60.5397a, a "modification" to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(j) The collection of fugitive emissions components at a compressor station, as defined in §60.5430a, is an affected facility. For purposes of §60.5397a, a "modification" to a compressor station occurs when:

(1) An additional compressor is installed at a compressor station; or

(2) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of §60.5397a.

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§60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than August 2, 2016 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

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§60.5375a What GHG and VOC standards apply to well affected facilities?

If you are the owner or operator of a well affected facility as described in §60.5365a(a) that also meets the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with paragraphs (a) through (g) of this section. If you own or operate a well affected facility as described in §60.5365a(a) that does not meet the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG and VOC emissions by complying with paragraphs (f)(3), (f)(4) or (g) for each well completion operation with hydraulic fracturing prior to November 30, 2016, and you must comply with paragraphs (a) through (g) of this section for each well completion operation with hydraulic fracturing on or after November 30, 2016.

(a) Except as provided in paragraph (f) and (g) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, as defined in §60.5430a, follow the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

(iii) You must have a separator onsite during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with §60.5375a(a)(1).

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in §60.5420a(b)(2) and maintain the records in §60.5420a(c)(1)(iii).

(2) [Reserved]

(3) If it is technically infeasible to route the recovered gas as required in §60.5375a(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in §60.5420a(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by §60.5410a(a).

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by §60.5415a(a).

(e) You must perform the required notification, recordkeeping and reporting as required by §60.5420a(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

(1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(2) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(3) You must comply with either paragraph (f)(3)(i) or (f)(3)(ii) of this section, unless you meet the requirements in paragraph (g) of this section. You must also comply with paragraph (b) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame. (4) You must submit the notification as specified in §60.5420a(a)(2), submit annual reports as specified in §60.5420a(b)(1) and (2) and maintain records specified in §60.5420a(c)(1)(iii) for each wildcat and delineation well. You must submit the notification as specified in §60.5420a(a)(2), submit annual reports as specified in §60.5420a(b)(1) and (2), and maintain records as specified in §60.5420a(c)(1)(iii) and (vii) for each low pressure well.

(g) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in §60.5420a(c)(1)(vi).

(2) You must submit reports specified in §60.5420a(b)(1) and (2).

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§60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

You must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and the closed vent system must be routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5410a(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5415a(b).

(d) You must perform the reporting as required by §60.5420a(b)(1) and (3), and the recordkeeping as required by §60.5420a(c)(2), (6) through (11), and (17), as applicable.

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§60.5385a What GHG and VOC standards apply to reciprocating compressor affected facilities?

You must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section, or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5410a(c).

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5415a(c).

(d) You must perform the reporting as required by §60.5420a(b)(1) and (4) and the recordkeeping as required by §60.5420a(c)(3), (6) through (9), and (17), as applicable.

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§60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in §60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and

identification information that allows traceability to the records for that controller as required in §60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410a(d).

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415a(d).

(f) You must perform the reporting as required by §60.5420a(b)(1) and (5) and the recordkeeping as required by §60.5420a(c)(4).

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§60.5393a What GHG and VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (a) or (b) of this section, as applicable, on or after November 30, 2016.

(a) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(b) For each pneumatic pump affected facility at a well site you must comply with paragraph (b)(1) or (2) of this section.

(1) If the pneumatic pump affected facility is located at a greenfield site as defined in §60.5430a, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3) and (4) of this section.

(2) If the pneumatic pump affected facility is not located at a greenfield site as defined in §60.5430a, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3), (4) and (5) of this section.

(3) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b)(1) or (b)(2) of this section. If you do not have a control device installed on site by the compliance date and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraphs (b)(3)(i) and (ii) of this section.

(i) Submit a certification in accordance with §60.5420a(b)(8)(i)(A) in your next annual report, certifying that there is no available control device or process on site and maintain the records in §60.5420a(c)(16)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph (b)(2)(i) of this section and must submit the information in §60.5420a(b)(8)(ii) in your next annual report and maintain the records in §60.5420a(c)(16)(i), (ii), and (iii). You must be in compliance with the requirements of paragraph (b)(2) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(4) If the control device available on site is unable to achieve a 95 percent reduction and there is no ability to route the emissions to a process, you must still route the pneumatic pump affected facility's emissions to that existing control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95 percent reduction, you must submit the information specified in §60.5420a(b)(8)(i)(C) in your next annual report and maintain the records in §60.5420a(c)(16)(iii).

(5) If an owner or operator at a non-greenfield site determines, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraph (b)(5)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(5)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(5)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer shall state: “I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) The owner or operator shall maintain the records §60.5420a(c)(16)(iv).

(6) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b)(1) or (b)(2) of this section, and instead must comply with paragraph (b)(3) of this section and report the change in next annual report in accordance with §60.5420a(b)(8)(ii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(d) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by §60.5410a(e).

(e) You must perform the reporting as required by §60.5420a(b)(1) and (8) and the recordkeeping as required by §60.5420a(c)(6) through (10), (16), and (17), as applicable.

(f) Pneumatic pumps at a well site are not subject to the requirements of paragraph (d) and (e) of this section from June 2, 2017, until August 31, 2017.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5395a What VOC standards apply to storage vessel affected facilities?

Except as provided in paragraph (e) of this section, you must comply with the VOC standards in this section for each storage vessel affected facility.

(a) You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements in paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for VOC emissions in accordance with §60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in §60.5375a(a)(1)(i) or (ii), you must achieve the required emissions reductions within 60 days after startup of production as defined in §60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the

month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.* (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c) and (d), and you must route emissions to a control device that meets the conditions specified in §60.5412a(c) or (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) Requirements for storage vessel affected facilities that are removed from service or returned to service. If you remove a storage vessel affected facility from service, you must comply with paragraphs (c)(1) through (3) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in §60.5420a(b)(6)(v) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (c)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in §60.5365a(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in §60.5420a(b)(6)(vi), identifying each storage vessel affected facility and the date of its return to service.

(d) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by §60.5410a(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by §60.5415a(e)(3).

(3) You must perform the required reporting as required by §60.5420a(b)(1) and (6) and the recordkeeping as required by §60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable.

(e) *Exemptions.* This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

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§60.5397a What fugitive emissions GHG and VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

For each affected facility under §60.5365a(i) and (j), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. These requirements are independent of the closed vent system and cover requirements in §60.5411a.

(a) You must monitor all fugitive emission components, as defined in §60.5430a, in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must keep records in accordance with paragraph (i) of this section and report in accordance with paragraph (j) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

(2) Technique for determining fugitive emissions (*i.e.,* Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using Method 21 of appendix A-7 of this part, your plan must also include the elements specified in paragraphs (c)(8)(i) and (ii) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.,* 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (4) of this section, at a minimum, as applicable.

(1) Sitemap.

(2) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using Method 21, your plan must also include a list of fugitive emissions components to be monitored and method for determining location of fugitive emissions components to be monitored in the field (*e.g.* tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with paragraph (g)(3)(i) of this section, and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with paragraph (g)(3)(ii) of this section.

(e) Each monitoring survey shall observe each fugitive emissions component, as defined in §60.5430a, for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 60 days of the startup of production, as defined in §60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 60 days of the first day of production for each collection of fugitive emission components after the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a well site located on the Alaskan North Slope, as defined in §60.5430a, that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the collection of fugitive emission components, or by the following June 30, whichever is later.

(2) You must conduct an initial monitoring survey within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive components at a compressor station, the initial monitoring survey must be conducted within 60 days of the modification or by June 3, 2017, whichever is later.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3) and (4) of this section.

(1) Except as provided herein, a monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart. A monitoring survey of each collection of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart.

(2) A monitoring survey of the collection of fugitive emissions components at a compressor station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (g)(2) of this section are waived for any collection of fugitive emissions components at a compressor station located within an area that has an average calendar month temperature below 0 °Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (h)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of §§60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (h)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 days after being repaired, to ensure that there are no fugitive emissions.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either Method 21 or optical gas imaging within 30 days of finding such fugitive emissions.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.,* the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(i) Records for each monitoring survey shall be maintained as specified §60.5420a(c)(15).

(j) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that

include the information specified in §60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

[81 FR 35898, June 3, 2016, as amended at 83 FR 10638, Mar. 12, 2018]

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§60.5398a What are the alternative means of emission limitations for GHG and VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG (in the form of a limitation on emission of methane) and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §§60.5375a, 60.5385a, and 60.5397a, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with §§60.5375a, 60.5385a, and 60.5397a. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities.

(d) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months to demonstrate the equivalence of the alternative means of emission limitation. The application must include the following information:

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (*i.e.,* method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) For affected facilities under §60.5397a, the action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(xi) Operation and maintenance procedures and other provisions necessary to ensure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under §60.5397a.

(xii) Initial and continuous compliance procedures, including recordkeeping and reporting.

(2) For each determination of equivalency requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(3) For each affected facility for which a determination of equivalency is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(e) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(f) An application submitted under this section will be evaluated as set forth in paragraphs (f)(1) and (2) of this section.

(1) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (d) of this section.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements. (g) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

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§60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

(b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402a.

(d) You must comply with the provisions of §60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§60.486a and 60.487a except as provided in §§60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

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§60.5401a What are the exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §§60.5400a(c) and in paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of §60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(g) An owner or operator may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

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§60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) An application submitted under paragraph (c) of this section must meet the following criteria:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) The application must include operation, maintenance and other provisions necessary to assure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard in paragraph (a) of this section by including the information specified in paragraphs (d)(1)(i) through (x) of this section.

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (i.e. method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) The action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(3) The application must include initial and continuous compliance procedures including recordkeeping and reporting.

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§60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?

(a) During the initial performance test required by §60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

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§60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in §60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) During a performance test required by §60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in §60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331×10^{-3} Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in §60.5408a or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the

result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in §60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$R = (100S)/(S + E)$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$E = C_e Q_{sd}/K_1$

Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A-1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m2 (54 ft2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A-4 of this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of appendix A of this part, you may use

ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(ii) You must use Method 15 of appendix A-5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A-6 of this part or Method 15 of appendix A-5 of this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A-1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

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§60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of §60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between

readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in §60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in §60.5406a(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of §60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric

ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:



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Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by §60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of §60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by §60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A-4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A-4 of this part, ASME PTC 19.10-1981 (incorporated by reference—see §60.17) may be used.

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§60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart.) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

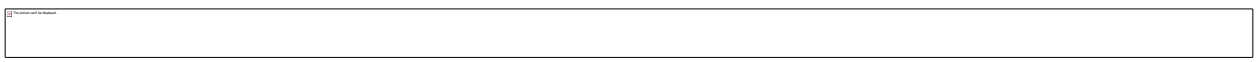
(3) *Starch solution.* Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure*. Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 (D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.



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§60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (j) of this section. The initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in §60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420a(b)(1) and (2).

(3) You must maintain a log of records as specified in §60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in §60.5420a(c)(1)(i) through (iv) and must maintain the record in §60.5420a(c)(1)(vi).

(4) For each well affected facility subject to both §60.5375a(a)(1) and (3), as an alternative to retaining the records specified in §60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with §60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment

connected and operating at each well completion operation with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by §60.5380a(a) and as demonstrated by the requirements of §60.5413a.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b) that is connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and is routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You must conduct an initial performance test as required in §60.5413a within 180 days after initial startup or by August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in §60.5415a(b).

(4) You must conduct the initial inspections required in §60.5416a(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with §60.5417a(a) through (g), as applicable.

(6)]Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420a(b)(1) and (3).

(8) You must maintain the records as specified in §60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with §60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with §60.5385a(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420a(b)(1) and (4).

(4) You must maintain the records as specified in §60.5420a(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with methane and VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in §60.5390a(b)(1) or (c)(1).

(2) If you own or operate a pneumatic controller affected facility located at a natural gas processing plant, your pneumatic controller must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(3) If you own or operate a pneumatic controller affected facility located other than at a natural gas processing plant, the controller manufacturer's design specifications for the controller must indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of §60.5390a(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420a(b)(1) and (5).

(6) You must maintain the records as specified in §60.5420a(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (7) of this section, as applicable.

(1) If you own or operate a pneumatic pump affected facility located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(2) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant, you must reduce emissions in accordance §60.5393a(b)(1) or (b)(2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(3) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant and there is no control device or process available on site, you must submit the certification in 60.5420a(b)(8)(i)(A).

(4) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant or a greenfield site, and you are unable to route to an existing control device due to technical infeasibility, and you are unable to route to a process, you must submit the certification in §60.5420a(b)(8)(i)(B).

(5) If you own or operate a pneumatic pump affected facility not located other than at a natural gas processing plant and you reduce emissions in accordance with §60.5393a(b)(4), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(c) and (d).

(6) You must submit the initial annual report for your pneumatic pump affected facility required in §60.5420a(b)(1) and (8).

(7) You must maintain the records as specified in §60.5420a(c)(6), (8) through (10), (16), and (17), as applicable, for each pneumatic pump affected facility.

(8) Pneumatic pump affected facilities at a well are not subject to the requirements of (e)(6) and (7) of this section from June 2, 2017, until August 31, 2017.

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC standards is demonstrated if you are in compliance with the requirements of §60.5400a.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in §60.5405a(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

(3) You must submit the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (6) of this section. You must demonstrate initial compliance by August 2, 2016, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in §60.5365a(e).

(2) You must reduce VOC emissions in accordance with §60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c) and (d) to a control device that meets the conditions specified in §60.5412a(d) within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in §60.5413a within 180 days after initial startup or within 180 days of August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in §60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility in your initial annual report as specified in §60.5420a(b)(1) and (6).

(6) You must maintain the records required for your storage vessel affected facility, as specified in §60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable, for each storage vessel affected facility.

(i) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with §60.112(b)(a)(1) or (2) in accordance with §60.5395a(b)(2) with the initial annual report specified in §60.5420a(b).

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in §60.5397a(b)(c), and (d).

(2) You must conduct an initial monitoring survey as required in §60.5397a(f).

(3) You must maintain the records specified in §60.5420a(c)(15).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in §60.5397a(h).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps and storage vessels except as provided in paragraph (e) of this section.

(a) Closed vent system requirements for reciprocating compressors, centrifugal compressor wet seal degassing systems and pneumatic pumps.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system, the wet seal fluid degassing system or pneumatic pump to a control device or to a process. For reciprocating and centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in §60.5412a(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416a(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in §60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control

device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) or (c), and (d), of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in §60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

(d) Closed vent systems requirements for centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels using a control device or routing emissions to a process.

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility and have it certified by a qualified professional engineer in accordance with paragraphs (d)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (d)(1)(i) of this section.

(2) [Reserved]

(e) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraph (a) of this section from June 2, 2017, until August 31, 2017.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, or storage vessel affected facility.

(a) Each control device used to meet the emission reduction standard in §60.5380a(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(iii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of §60.5413a(c).

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under §60.5380a(a)(1) through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417a(a) through (g), you must demonstrate compliance according to the requirements of §60.5415a(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) For each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b).

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b).

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

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§60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420(b)(9) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420a(b)(9) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a)(1) or (d)(1) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use Method 1 or 1A of appendix A-1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A-2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412a(a)(1)(i), (a)(2) or (d)(1)(iv)(A), you must use Method 25A of appendix A-7 of this part. You must use Method 4 of appendix A-3 of this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

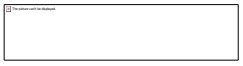
K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:



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Where:

R_{cd} = Control efficiency of control device, percent.

E_i, = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use Method 25A of appendix A-7 of this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You may also use Method 18 of appendix A-6 of this part to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 of this part, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:



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Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420a(b)(9).

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressor affected facilities, if you do not continuously monitor the gas flow rate in accordance with §60.5417a(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressor affected facilities, you must establish a limit on temperature in accordance with §60.5417a(f) and continuously monitor the temperature as required by §60.5417a(d).

(c) *Control device design analysis to meet the requirements of §60.5412a(a)(2) or (d)(2).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete

carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph (d) applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A-1 of this part (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A of appendix A-1 of this part. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89 (incorporated by reference as specified in §60.17).

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A-1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A-3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C of appendix A-2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A-3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A-2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A-2 of this part, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 of this part. Run the test simultaneously with Method 25A of appendix A-7 of this part using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A-7 of this part, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

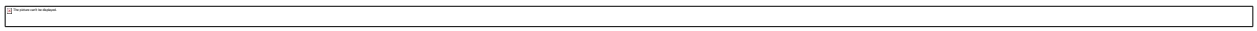
(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference as specified in §60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C of appendix A-2 of this part. You must use the following equation for this diluent concentration correction:



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Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95 percent for

THC, as propane, will meet the control requirement for 95 percent destruction of VOC and methane (if applicable) required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section in the test report required by this section in accordance with §60.5420a(b)(10). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Document Control Officer; Office of Air Quality Planning and Standards (OAQPS) CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to *Oil____and____Gas____PT@EPA.GOV*.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph (e) applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section, maintaining the records specified in §60.5420a(c)(2) or (c)(5)(vi) and submitting the report specified in §60.5420a(b)(10).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A-7 of this part as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via

email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

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§60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in §60.5420a(c)(1).

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section except as provided in paragraph (b)(4) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

(1) You must reduce methane and VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of §60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412a(a)(2), you may demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of §60.5417a(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417a(a) at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of §60.5412a(a)(1) and you demonstrate compliance using the test procedures specified in §60.5413a(b), or you use a flare designed and operated in accordance with §60.18(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section

11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in §60.5370a(a), if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in §60.5370a(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by 60.5420a(b)(1) and (3) and maintain the records as specified in §60.5420a(c)(2), (6) through (11), and (17), as applicable.

(4) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraphs (b)(3) of this section from June 2, 2017, until August 31, 2017.

(c) For each reciprocating compressor affected facility complying with §60.5385a(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with §60.5385a(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (4) and maintain records as required in §60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in §60.5416a(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390a(a), (b), or (c).

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (5).

(3) You must maintain records as required in §60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395a(a)(2).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395a(a)(2).

(ii) For each control device installed to meet the requirements of §60.5395a(a)(2), you must demonstrate continuous compliance with the performance requirements of §60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416a(c) for each cover and closed vent system.

(B) You must comply with §60.5417a(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411a(c)(2) and (3).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with methane and VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400a.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in §60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in §60.5397a according to paragraphs (h)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in §60.5397a(g).

(2) You must repair or replace each identified source of fugitive emissions as required in §60.5397a(h).

(3) You must maintain records as specified in §60.5420a(c)(15).

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor, reciprocating compressor and pneumatic pump affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section, except as provided in paragraph (d) of this section.

(a) Inspections for closed vent systems and covers installed on each centrifugal compressor, reciprocating compressor or pneumatic pump affected facility. Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(4) For each bypass device, except as provided for in §60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420a(c)(8).

(b) No detectable emissions test methods and procedures. If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor, reciprocating compressor, or pneumatic pump affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A-7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in §60.5420a(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in §60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere.

Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to §60.5420a(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to §60.5420a(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(d) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraphs (a) and (b) of this section from June 2, 2017, until August 31, 2017.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in §60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device which is not specifically listed in paragraph (d) of this section, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under §60.5413a(b) that combustion zone temperature is an accurate indicator of performance, a

temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in §60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under §60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of §60.5413a(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412a(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under §60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1), then your control device inlet gas flow rate must not exceed the maximum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in §60.5412a(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of §60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412a(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you are subject to §60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to §60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415a(b)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to §60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) of this section are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under §60.5413a(d).

(ii) Failure of the monthly visible emissions test conducted under §60.5413a(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with §60.5413a(d)(2) through (10), which meets the criteria in §60.5413a(d)(11), the reporting requirement in §60.5413a(d)(12), and meet the continuous compliance requirement in §60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in §60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in §60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

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§60.5420a What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in §60.5365a that was constructed, modified or reconstructed during the reporting period.

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit at an onshore natural gas processing plant, you must submit the notifications required in §60.7(a)(1), (3), and (4). If you

own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable, except as provided in paragraph (b)(13) of this section. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) of this section, except as provided in paragraph (b)(13) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section for all reports.

(i) The company name, facility site name associated with the affected facility, US Well ID or US Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each well affected facility, the information in paragraphs (b)(2)(i) through (iii) of this section.

(i) Records of each well completion operation as specified in paragraphs (c)(1)(i) through (iv) and (vi) of this section, if applicable, for each well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv) of this section, the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(iii) Records specified in paragraph (c)(1)(vii) of this section, if applicable, that support a determination under 60.5432a that the well affected facility is a low pressure well as defined in 60.5430a.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with §60.5380a(a)(2), the records specified in paragraphs (c)(6) through (11) of this section.

(iv) If complying with §60.5380a(a)(1) with a control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e), records specified in paragraph (c)(2)(i) through (c)(2)(vii) of this section for each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390a(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to §60.5365a(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) A statement that you have met the requirements specified in §60.5410a(h)(2) and (3).

(v) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in §60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vi) You must identify each storage vessel affected facility returned to service during the reporting period as specified in §60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(vii) If complying with §60.5395a(a)(2) with a control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e), records specified in paragraphs

(c)(5)(vi)(A) through (F) of this section for each storage vessel constructed, modified, reconstructed or returned to service during the reporting period.

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station within the company-defined area, the records of each monitoring survey including the information specified in paragraphs (b)(7)(i) through (xii) of this section. For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(v) Monitoring instrument used.

(vi) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(vii) Number and type of components for which fugitive emissions were detected.

(viii) Number and type of fugitive emissions components that were not repaired as required in §60.5397a(h).

(ix) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(x) The date of successful repair of the fugitive emissions component.

(xi) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(xii) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (iii) of this section.

(i) For each pneumatic pump that is constructed, modified or reconstructed during the reporting period, you must provide certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(8)(i)(A), (B) or (C) of this section.

(A) No control device or process is available on site.

(B) A control device or process is available on site and the owner or operator has determined in accordance with §60.5393a(b)(5) that it is technically infeasible to capture and route the emissions to the control device or process.

(C) Emissions from the pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(ii) For any pneumatic pump affected facility which has been previously reported as required under paragraph (b)(8)(i) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(8)(ii)(A), (B) or (C) or (D) of this section.

(A) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(8)(i)(C) of this section.

(B) A control device has been added to the location and the pneumatic pump affected facility now reports according to paragraph (b)(8)(i)(B) of this section.

(C) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump affected facility now report according to paragraph (b)(8)(i)(A) of this section.

(D) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with §60.5393a(b)(5) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(iii) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.

(9) Within 60 days after the date of completing each performance test (see §60.8) required by this subpart, except testing conducted by the manufacturer as specified in §60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*https://www3.epa.gov/ttn/chief/ert/ert____info.html*) at the time of the test, you must submit the results of the performance test to the EPA via the

Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/)*.) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

(10) For combustion control devices tested by the manufacturer in accordance with §60.5413a(d), an electronic copy of the performance test results required by §60.5413a(d) shall be submitted via email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/)*.) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

(12) You must submit the certification signed by the qualified professional engineer according to §60.5411a(d) for each closed vent system routing to a control device or process.

(13) The collection of fugitive emissions components at a well site (as defined in §60.5430a), the collection of fugitive emissions components at a compressor station (as defined in §60.5430a), and pneumatic pump affected facilities at a well site (as defined in §60.5365a(h)(2)) are not subject to the requirements of paragraph (b)(1) of this section from June 2, 2017, until August 31, 2017.

(c) *Recordkeeping requirements*. You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (16) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any

records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to 60.5375a(g), you must maintain the record in paragraph (c)(1)(vi), only.

(i) Records identifying each well completion operation for each well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375a.

(iii) Records required in §60.5375a(b) or (f)(3) for each well completion operation conducted for each well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of §60.5375a(a), you must record: The location of the well; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas to any of the four options specified in §60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in that subparagraph, including but not limited to; name and location of the nearest gathering line and technical considerations preventing routing to this line; capture, reinjection, and reuse technologies considered and aspects of gas or equipment preventing use of recovered gas as a fuel onsite; and technical considerations preventing use of recovered gas for other useful purpose that that a purchased fuel or raw material would serve.

(B) For each well affected facility required to comply with the requirements of §60.5375a(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(C) For each well affected facility for which you make a claim that it meets the criteria of §60.5375a(a)(1)(iii)(A), you must maintain the following:

(*1*) Records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record: The date and time of each attempt to direct flowback to a separator; the date and time of

each occurrence of returning to the initial flowback stage; duration of recovery and disposition of recovery (*i.e.* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve.

(*2*) If applicable, records that the conditions of §60.5375a(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(*3*) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under §60.5375a(a)(3), you must record: The location of the well; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both §60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in §60.5410a(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to 60.5375a(g), you must maintain:

(A) A record of the analysis that was performed in order the make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) The location of the well; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility for which you determine according to §60.5432a that it is a low pressure well, a record of the determination and supporting inputs and calculations.

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in §60.5380a. Except as specified in paragraph (c)(2)(vii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vi) of this section for each control device

tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(E) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or the previous replacement of the reciprocating compressor rod packing, whichever is

later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in §60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385a.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390a.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vi) of this section.

(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8), 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (F) of this section for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(*5*) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(6) Records of each closed vent system inspection required under §60.5416a(a)(1) and (2) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or §60.5416a(c)(1) for storage vessels.

(7) A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or §60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(9) If you are subject to the closed vent system no detectable emissions requirements of §60.5416a(b) for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with §60.5416a(b).

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(11) For each centrifugal compressor affected facility subject to the control device requirements of §60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412a(d)(2)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the

above information or use Figure 22-1 in EPA Method 22 of appendix A-7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §60.5412a(d)(1)(iii), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) through (iii) of this section.

(i) The fugitive emissions monitoring plan as required in §60.5397a(b), (c), and (d).

(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. You must note the training and experience of the operator.

(D) Monitoring instrument used.

(E) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

(F) Fugitive emissions component identification when Method 21 is used to perform the monitoring survey.

(G) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(H) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(I) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(I)(*1*) through (*12*) of this section.

(*1*) Location.

(*2*) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(*3*) Number and type of components for which fugitive emissions were detected.

(*4*) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(*5*) Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.

(*6*) Number and type of fugitive emissions components that were not repaired as required in §60.5397a(h).

(*7*) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in §60.5397a(h)(3)(ii).

(*8*) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in §60.5397a(h)(3)(ii). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (c)(15)(ii)(E) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(*9*) Repair methods applied in each attempt to repair the fugitive emissions components.

(*10*) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(*11*) The date of successful repair of the fugitive emissions component.

(*12*) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(iii) For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic pump constructed, modified or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a.

(iii) Records on the control device used for control of emissions from a pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than 95 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction achieved the control device is designed to achieve.

(iv) Records substantiating a claim according to §60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the qualified professional engineer certification according to §60.5393a(b)(5)(ii)and the records of the engineering assessment of technical infeasibility performed according to §60.5393a(b)(5)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to §60.5411a(d):

(i) A copy of the assessment conducted according to §60.5411a(d)(1);

(ii) A copy of the certification according to §60.5411a(d)(1)(i); and

(iii) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the delegated authority.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401a(b)(1).

(1) When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

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§60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

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§60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in §§60.5405a(a) and (b) and 60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The excess emissions report must be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) You must use the appropriate electronic report in CEDRI for this subpart

or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with §60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

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§60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

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§60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log \times$, where × is 2011 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of §60.5397a.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of GHG (in the form of methane) and VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Greenfield site means a site, other than a natural gas processing plant, which is entirely new construction. Natural gas processing plants are not considered to be greenfield sites, even if they are entirely new construction.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e) or §60.5401a(f)(2).

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure at the sales meter;

(2) The pressure of flowback fluid immediately before it enters the flow line, as determined under §60.5432a, is less than the flow line pressure at the sales meter; or

(3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under

this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with §60.5395a(c)(1).

Returned to service means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395a(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

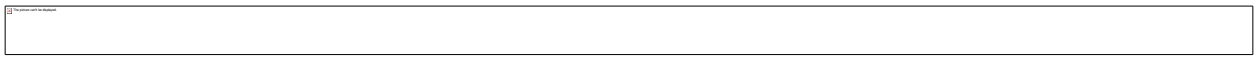
Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

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§60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to §60.5375a(f), you must determine whether the characteristics of the well are such that the well meets the definition of

low pressure well in §60.5430a. To determine that the well meets the definition of low pressure well in §60.5430a, you must use the low pressure well equation below:



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Where:

(1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;

(2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;

(3) $L$is the true vertical depth of the well, expressed in feet (ft);

(4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);

(5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;

(6) q_w is the flow rate of water in the well, expressed in cu ft/sec;

(7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).

(b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (b)(15) of this section.

(1) Determine the value of the bottom hole pressure, P_{BH} (*psia*), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (*psia*), in the following equation:

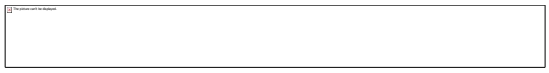


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(2) Determine the value of the bottom hole temperature, T_{BH} (*F*), based on available information at the well site, or by calculating it using the true vertical depth of the well, *L (ft)*, in the following equation:

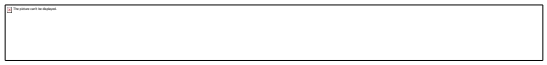
T_{BH} (*F*) = (0.014 × *L*) + 79.081

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs}, using the following equation with: Separator at standard conditions (pressure, *p* = 14.7 (*psia*), temperature, T = 60 (*F*)); the oil API gravity at the well site, γ_0; and the gas specific gravity at the separator under standard conditions, γ_{gp} = 0.75:



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(4) Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation with: The bottom hole pressure, P_{BH} (*psia*), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in (b)(3) of this section; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table A:



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Table A—Coefficients for the correlation for R_s

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, *Bo (bbl/STBO)*, using the following equation with: the bottom hole temperature, T_{BH} (*F*), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in paragraph (b)(3) of this section; the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, γo, at the well site; and the constants, C1, C2, and C3, found in Table B:



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Table B—Coefficients for the Correlation for B_o

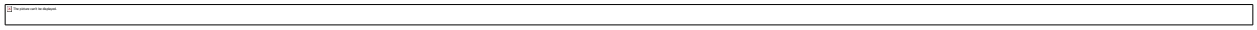
Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,



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using the following equation with the value of the oil API gravity, γo, at the well site:



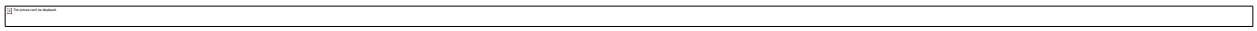
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(7) Calculate the density of oil at bottom hole conditions,



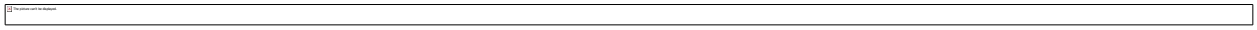
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using the following equation with: the dissolved GOR, Rs (scf/ STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, Bo (bbl/ STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,



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calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd} = 0.77$:



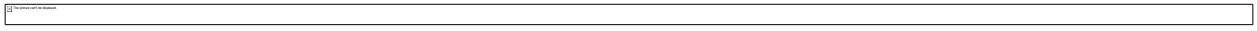
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(8) Calculate the density of oil in the well,



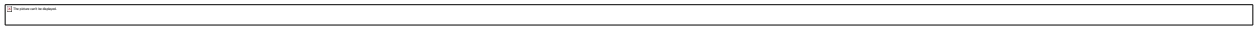
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using the following equation with the density of oil at the wellhead,



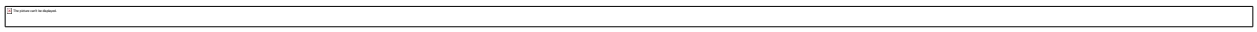
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calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,



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calculated in paragraph (b)(7) of this section:



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(9) Calculate the oil flow rate, q_o (*cu ft/sec,*) using the following equation with: the oil formation volume factor, *Bo* (bbl/ STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, *Qo* (STBO/ day):



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(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, $P = 14.7$ (*psia*), temperature, $T = 60$ (*F*)), $\gamma = 0.75$; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are $X_{N_2} = 0.168225$, $X_{CO_2} = 0.013163$, and $X_{H_2S} = 0.013680$, respectively:

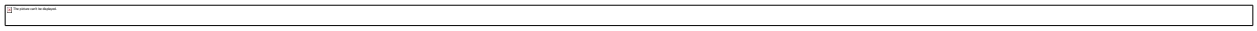
$$P_c(psia) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}$$

$$T_c(R) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N_2} - 88.3 \cdot X\mathrm{CO}_2 + 133.3 \cdot X_{H_2S}$$

(11) Calculate reduced pressure, P_r, and reduced temperature, T_r, using the following equations with: the bottom hole pressure, P_{BH}, as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), as determined in paragraph (b)(2) of this section in the following equations:

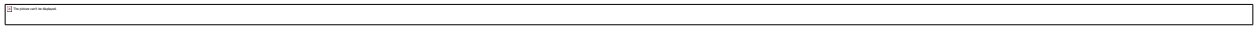


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(12)(i) Calculate the gas compressibility factor, *Z*, using the following equation with the reduced pressure, P_r, calculated in paragraph (b)(11) of this section:



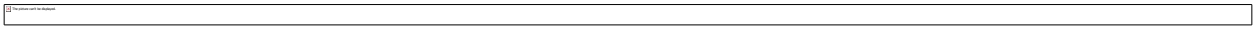
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(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r, and reduced temperature, T_r, calculated in paragraph (b)(11) of this section:



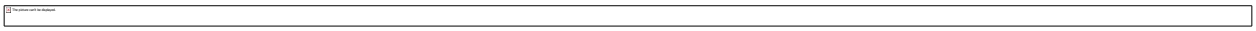
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(13) Calculate the gas formation volume factor,



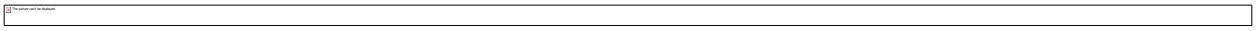
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using the bottom hole pressure, P_{BH} *(psia)*, as determined in paragraph (b)(1) of this section; and the bottom hole temperature, T_{BH} *(F)*, as determined in paragraph (b)(2) of this section:



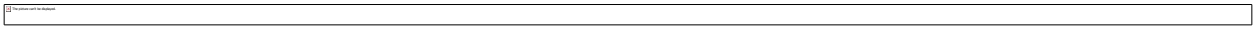
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(14) Calculate the gas flow rate,



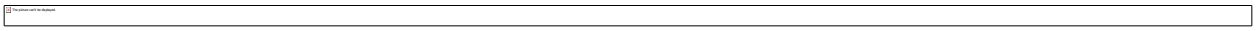
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using the following equation with: the value of gas formation volume factor,



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calculated in paragraph (b)(13) of this section; the estimated gas production rate, Qg (scf/ day); the estimated oil production rate, Qo (STBO/ day); and the dissolved GOR, Rs (scf/ STBO), as calculated in paragraph (b)(4) of this section:



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(15) Calculate the flow rate of water in the well, q_w (*cu ft/sec*), using the following equation with the water production rate Qw (bbl/day) at the well site:



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§§60.5433a-60.5499a [Reserved]

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Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	**5.0 < X < 15.0**	**15.0 < X < 300.0**	**X > 300.0**
Y > 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20 < Y < 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
10 < Y < 20	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller	93.5	93.5
Y < 10	79.0	79.0	79.0	79.0

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Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	**5.0 < X < 15.0**	**15.0 < X < 300.0**	**X > 300.0**
Y > 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20 < Y < 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
10 < Y < 20	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
Y < 10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial

performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in §60.5425a, you must comply with the following applicable General Provisions:

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Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5430a.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and record keeping	Yes	Except that §60.7 only applies as specified in §60.5420a(a).
§60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels, centrifugal compressors and pneumatic pumps.
§60.9	Availability of information	Yes	
§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOOa.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§60.14	Modification	Yes	To the extent any provision in §60.14 conflicts with specific provisions in subpart

			OOOOa, it is superseded by subpart OOOOa provisions.
§60.15	Reconstruction	Yes	Except that §60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors or storage vessels.
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device and work practice requirements	Yes	
§60.19	General notification and reporting requirement	Yes	

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pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT
BAQ-GPA/GP-5

Natural Gas Compression Stations, Processing Plants, and Transmission Stations

SECTION A. GENERAL REQUIREMENTS

1. Statutory/Regulatory Authority and General Description

In accordance with Section 6.1(f) of the Pennsylvania Air Pollution Control Act (APCA), 35 P.S. § 4006.1(f) and 25 Pa. Code Chapter 127, Subchapter H, the Department of Environmental Protection (Department or DEP) hereby issues this General Plan Approval and/or General Operating Permit (General Permit or GP-5) for new or modified natural gas compressor stations, processing plants, and transmission stations (facility or facilities) constructed, modified, or operated in this Commonwealth.

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3. Definitions

Words and terms that are not otherwise defined in this General Permit shall have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III including 25 Pa. Code § 121.1 unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Code of Federal Regulations (CFR), including 40 CFR Part 60, Subparts KKK, JJJJ, KKKK, OOOO, and OOOOa or 40 CFR Part 63, Subparts HH and ZZZZ, shall also apply to this General Permit.

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Coal Bed Methane – Methane that is extracted from a coal bed and the surrounding rock strata by extraction wells drilled in advance of a mining operation, which is typically of pipeline quality.

Fugitive Emissions Component – Any component that has the potential to emit fugitive emissions of methane, Volatile Organic Compounds (VOC), or Hazardous Air Pollutants (HAP) at a natural gas compressor station, processing plant, or transmission station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, compressors, instruments, meters, covers, and closed vent systems. Devices that vent as part of normal operations are not considered fugitive sources unless the emission originates from a place other than the vent.

Gob Gas – Methane that is mixed with air from a mine ventilation system due to the mining operation reaching the area of an extraction well, which is typically below pipeline quality.

Leak – A leak is defined as any release of gaseous hydrocarbons that is detected by Auditory, Visual, or Olfactory (AVO) inspection; an optical gas imaging (OGI) camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21 that detects a concentration of 500 ppm calibrated as methane or greater; or other leak detection methods approved by the Department's Division of Source Testing and Monitoring. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

Natural Gas Compressor Station – A facility that compresses and/or processes natural gas, coal bed methane, or gob gas prior to the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Natural Gas Processing Plant – A facility that engages in the extraction of natural gas liquids from field gas, the fractionation of mixed natural gas liquids to natural gas products, or both extracts and fractionates natural gas liquids.

Natural Gas Transmission Station – A facility that compresses and/or processes natural gas after the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Pigging Operations – The process of removing and collecting condensed liquids including condensate, intermediate hydrocarbons, or produced water, from a pipeline using a spherical or bullet-shaped device, known as a pig, forced through the pipeline by natural gas pressure. The liquids are then collected at their eventual destination in a storage tank, often referred to as a slug tank. This process also includes an operation conducted for a pipeline integrity evaluation.

Point of Custody Transfer – The location after the processing and/or treatment of natural gas in the production sector, typically after a natural gas processing plant, where control and/or ownership of the natural gas is transferred from one owner or operator to another.

Sour Gas – Natural gas where the Hydrogen Sulfide (H_2S) content is in excess of 4 ppmv at standard temperature and pressure.

4. Applicability/Scope

(a) This General Permit authorizes the construction, modification, and/or operation of a natural gas compressor station, processing plant, or transmission station. The applicability of this General Permit may include one or more of the following operations or emission sources:

- (i) Glycol Dehydration Units
- (ii) Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- (iii) Reciprocating Compressors
- (iv) Storage Vessels
- (v) Tanker Truck Load-Out Operations
- (vi) Fugitive Emissions Components
- (vii) Natural Gas-Driven Pneumatic Controllers
- (viii) Natural Gas-Driven Pneumatic Pumps
- (ix) Enclosed Flares and Other Emission Control Devices
- (x) Pigging Operations

SAMPLE

(xi) Natural Gas-Fired Combustion Units
(xii) Stationary Natural Gas-Fired Combustion Turbines
(xiii) Centrifugal Compressors

(b) An Application for Authorization to Use GP-5 may be submitted for the operation of an eligible source if the source is exempted from plan approval requirements under 25 Pa. Code § 127.14.

(c) If any source located at the facility cannot be regulated under this General Permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B and/or Subchapter F will be required.

5. Prohibited Use of GP-5

GP-5 may not be used for the construction, modification, or operation of any of the following air contamination sources:

(a) A proposed source located at a Title V facility including sources determined to be a single source Title V facility.

(b) A proposed source that is subject to Title V permitting requirements specified in 25 Pa. Code Chapter 127, Subchapters F and G; prevention of significant deterioration requirements specified in 25 Pa. Code Chapter 127 Subchapter D; or nonattainment new source review requirements specified in 25 Pa. Code Chapter 127 Subchapter E.

(c) A facility that produces or processes sour gas.

(d) *Circumvention.*

(i) The owner or operator of a facility may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying, or engaging in incremental construction over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.

(ii) No person may permit the use of a device, stack height that exceeds good engineering practice, dispersion technique, or other technique that, without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants that would otherwise be in violation of this General Permit, the APCA, or the regulations promulgated thereunder, except for those that are used for the control of malodors with the prior written approval of the Department.

6. Authorization to Use GP-5

(a) *Application for Authorization to Use GP-5.* Pursuant to 25 Pa. Code § 127.621, any person proposing to construct, operate, or modify a source listed in Section A, Condition 4 of this General Permit at a natural gas compressor station, processing plant, or transmission station shall submit an Application for Authorization to Use GP-5 to the Air Program Manager of the appropriate DEP Regional Office responsible for authorizing the use of the General Permit in the county in which the facility will be located. This application shall be submitted to DEP either through the e-Permitting system, by hand delivery, courier, or sent to DEP by certified mail, return receipt requested, in accordance with 25 Pa. Code § 127.621(b).

(b) *Terms of Authorization to Use GP-5.* This General Permit authorizes the construction and/or operation of the specific sources at the specific facility as described in the application for a term of five years from the date of authorization. The authorization to construct a source or facility will expire 18 months from the date of the authorization if the owner or operator fails to commence construction or if there is a lapse in construction of 18 months. The Department may extend the 18-month period upon an owner or operator providing satisfactory justification for an extension up to the original date of the five-year term. All requests for extension shall be submitted to the Department at least 30 days prior to the end of the 18-month period and are only valid upon receipt of written approval by the Department. The expiration of the authorization to construct will require a new Application for Authorization to Use GP-5 if an extension is not requested and granted.

(c) *Expiration of and Re-Authorization to Use GP-5.*

(i) The authorization granted by the Department to construct and/or operate under this General Permit shall terminate on the date of expiration unless a complete Application for Authorization to Use GP-5 is submitted to the Department at least 30 calendar days prior to the expiration date.

SAMPLE

(ii) Upon receipt by the Department of a timely, administratively and technically complete application for re-authorization to operate under this General Permit, the owner or operator may continue to operate the facility subject to final action by the Department provided that the sources and the facility are operated in compliance with the terms and conditions of this General Permit. The Authorization to Use GP-5 shall cease if the owner or operator fails to submit any additional information requested by the Department to process the application by the specified deadline.

(d) *Transfer of Ownership.* The Authorization to Use GP-5 may not be transferred from the owner or operator of a facility except when the change of ownership is demonstrated to the satisfaction of the Department and the Department approves the transfer in writing. Within 30 calendar days after a transfer of ownership of the facility, the new owner or operator shall submit an appropriate form or application to the Air Program Manager of the appropriate Regional Office. If the owner or operator is modifying any existing source or adding a new source at the facility currently authorized by the General Permit, the owner or operator shall submit an Application for Authorization to Use GP-5 in accordance with Condition 6(a) above. If there are equipment or activities located on the same site or on sites that share equipment and are within ¼ mile of each other, the owner or operator shall submit an Application for Authorization to use GP-5 as a General Plan Approval with a $1,000 application fee. If the owner or operator is not modifying any existing source, not adding a new source, or not subject to a new Single Source Determination based on the transfer of ownership, the owner or operator shall submit a Transfer of Ownership form with a $300 fee. The employer I.D. number (Federal IRS No.) shall be used as a test to determine if a transfer of ownership has occurred.

(e) *Administrative Amendment.* In the event of a change in the name, address, or telephone number of a person identified in the General Permit Application or a similar minor administrative change at the facility, the Department may authorize an administrative amendment. The owner or operator shall submit a brief description of the change and the date on which the change is to occur in a letter signed by the Responsible Official with the fee specified in Condition 7(e) to the Air Program Manager of the appropriate Regional Office.

(f) *Modification, Suspension, or Revocation of GP-5 or Authorizations to Use GP-5.*

(i) The Department may modify, suspend, or revoke and reissue this General Permit if it is determined that GP-5 does not comply with the Clean Air Act, the APCA, or regulations adopted under the acts.

(ii) This General Permit may be modified, suspended, or revoked if the Department determines that the natural gas compressor station, processing plant, or transmission station cannot be adequately regulated under this General Permit.

(iii) An Authorization to Use GP-5 may be suspended or revoked if the Department determines that, at any time, the owner or operator has failed to construct and/or operate the facility in compliance with the terms and conditions of this General Permit, the specifications in the Application for Authorization to Use GP-5, or the information provided in the supplemental material included with the application used to determine if the proposed sources will comply with the GP-5.

(iv) Upon suspension or revocation of an Authorization to Use GP-5, the owner or operator shall immediately cease construction and/or operation of the facility. The owner or operator of the facility shall not restart construction and/or operation prior to the receipt of written approval from the Department.

7. General Permit Fees

Each applicant seeking Authorization to Use GP-5 shall submit the applicable fees required under this Condition to the appropriate DEP Regional Office. The following fee schedules apply to this General Permit:

(a)	General Plan Approval Application Fee for Sources Subject to and Review of NSPS, payable upon submission of the application:	$1,700
(b)	General Plan Approval Application Fee with new Single Source Determination, payable upon submission of the application:	$1,000
(c)	General Operating Permit Application Fee, payable upon submission of the application:	$ 375
(d)	Annual Operating Permit Administration Fee, payable by March 1st for the previous calendar year:	$ 375
(e)	Administrative Amendment Fee, payable upon submission of the letter in Condition 6(e):	$ 300

SAMPLE

(f) The Department may increase the applicable fees for this General Plan Approval/General Operating Permit in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I, following notice in the *Pennsylvania Bulletin*.

8. Applicable Laws

(a) It is the duty of the Responsible Official, as defined in 25 Pa. Code § 121.1, to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations, including 25 Pa. Code, Subpart C, Article III. Nothing in this General Permit relieves the Responsible Official from this obligation to comply.

(b) Applicable federal regulations may include, but are not limited to, the following New Source Performance Standards (NSPS), codified at 40 CFR Part 60 and incorporated by reference in 25 Pa. Code § 122.3, and National Emission Standards for Hazardous Air Pollutants (NESHAP), codified at 40 CFR Part 63 and incorporated by reference in 25 Pa. Code § 127.35:

(i) **40 CFR Part 60, Subpart KKK** – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or before August 23, 2011.

(ii) **40 CFR Part 60, Subpart JJJJ** – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

(iii) **40 CFR Part 60, Subpart KKKK** – Standards of Performance for Stationary Combustion Turbines.

(iv) **40 CFR Part 60, Subpart OOOO** – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.

(v) **40 CFR Part 60, Subpart OOOOa** – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.

(vi) **40 CFR Part 63, Subpart HH** – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.

(vii) **40 CFR Part 63, Subpart ZZZZ** – National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

9. Best Available Technology Requirements

New sources are required to control the emission of air pollutants to the maximum extent, consistent with best available technology (BAT) as determined by the Department as of the date of issuance of the plan approval for the new source as required under 25 Pa. Code § 127.1. Condition 1 (BAT Compliance Requirements) of Sections B through N of this General Permit are determined to meet the BAT requirements.

10. Compliance Requirements and Compliance Certification

(a) The emissions from all sources and associated air pollution control equipment located at a natural gas compressor station, processing plant, or transmission station and other sources determined by the Department to be a single source shall not equal or exceed either of the following on a 12-month rolling sum basis:

(i) Nitrogen Oxides (NO_X) – 100 tons

(ii) Carbon Monoxide (CO) – 100 tons

(iii) Sulfur Oxides (SO_X) – 100 tons

(iv) Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}) – 100 tons

(v) Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$) – 100 tons

(vi) Volatile Organic Compounds (VOC) – 50 tons

(vii) Any individual Hazardous Air Pollutant (HAP) – 10 tons

(viii) Total Hazardous Air Pollutants (HAP) – 25 tons

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(ix) In addition, the emissions from all sources and associated air pollution control equipment located at a facility in Bucks, Chester, Delaware, Montgomery, or Philadelphia Counties shall not equal or exceed any of the following on a 12-month rolling sum basis:

(A) NO_X – 25 tons

(B) VOC – 25 tons

(b) The facility throughput, hours of operation, and/or emissions from sources at the facility shall be constrained as necessary to not exceed any facility-wide emissions cap required in (a) above.

(c) All sources and associated air pollution control equipment located at a facility shall be:

(i) Operated in such a manner as not to cause air pollution, as that term is defined in 25 Pa. Code § 121.1;

(ii) Operated and maintained in accordance with the manufacturer's specifications, procedures, and recommended maintenance schedule, as provided in the Application for Authorization to Use GP-5, or an alternate procedure approved by the Department that achieves equal or greater emissions reductions in accordance with 25 Pa. Code § 127.12b;

(iii) Operated and maintained in accordance with the fugitive emission requirements of 25 Pa. Code § 123.1 and § 123.2; **and**

(iv) Operated and maintained in such a manner that malodors are not detectable outside the property of the owner or operator on whose land the facility is being operated in accordance with 25 Pa. Code § 123.31.

(d) The owner or operator of an existing facility where a new source is installed or there is a modification of an existing source, shall comply with the applicable BAT requirements established in this General Permit.

(e) This General Permit cannot be used to relax BAT or other emission limitations or requirements previously established through the air quality permitting process.

(f) An owner or operator of a facility may apply to the Department for a plan approval for any air contamination source in lieu of seeking authorization to use the General Permit for natural gas compressor stations, processing plants, or transmission stations.

(g) The owner or operator authorized to use this General Permit shall comply with the specifications in the application and the terms and conditions of this General Permit.

(h) The owner or operator of the facility shall submit to the Air Program Manager of the appropriate DEP Regional Office an annual certification of compliance with the terms and conditions in the GP-5 for the previous year, including the emission limitations, standards, or work practices. This Compliance Certification Form must be included in the annual report as outlined in Condition 13(c)(vi).

11. Notification Requirements

(a) *Municipal Notification.* The facility owner or operator proposing to use this General Permit shall notify the local municipality and county where the air pollution source is to be located that they have applied for an Authorization to Use GP-5. The notification shall clearly describe the proposed sources and/or modifications.

(b) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office, in writing, at least five business days prior to the commencement of operation of a source of their intent to do so. The owner or operator shall also include the date of completion of construction of the source in the notice. When multiple sources at the facility are subject to different commencement of operation schedules, written notice shall be submitted to DEP prior to the commencement of operation of each source.

(c) *Malfunctions.*

(i) Any malfunction that poses an imminent danger to the public health, safety, or welfare or to the environment shall be reported by telephone to the County Emergency Management Agency and to the 24-hour Emergency Hotline at 1-800-541-2050 no later than one hour after the discovery of an incident. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within three business days.

(ii) Any malfunction that does not pose an imminent danger to the public health, safety, or welfare or to the environment shall follow the guidance provided in the GP-5 and GP-5A Malfunction Reporting Instructions

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and, if required to report, shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of discovery. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within five business days.

(iii) If the owner or operator is unable to provide notification by telephone to the Air Program Manager of the appropriate DEP Regional Office within 24 hours of the discovery of a malfunction due to a weekend or holiday, the notification shall be made to the Department no later than 4:00 pm on the first business day following the weekend or holiday.

(iv) Written notification shall include:

(A) The name, GP-5 authorization number, and location of the facility;

(B) The nature and cause of the malfunction or incident;

(C) The date and time when the malfunction, incident, or breakdown was first discovered;

(D) The expected duration of increased emissions;

(E) The estimated rate of emissions for all criteria, hazardous, and greenhouse gas pollutants; **and**

(F) Any changes to the equipment or modification of the procedures that will prevent reoccurrences of the malfunction.

(v) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of when corrective measures have been implemented.

(vi) Any emissions due to a malfunction are to be reported in the annual emissions inventory report required in Condition 13(d).

12. Recordkeeping Requirements

(a) All records required must be maintained onsite or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format.

(b) The owner or operator of the facility shall generate and maintain records that clearly demonstrate to the Department that the facility is not a Title V facility and that the facility is in compliance with facility-wide emission limitations. At a minimum, the records shall be maintained on a monthly basis, and the actual emissions shall be calculated on a 12-month rolling sum. The Department reserves the right to request additional information necessary to determine compliance with the General Permit.

(c) The owner or operator of the facility shall keep records of all written notifications required under permit conditions.

13. Reporting Requirements

(a) The owner or operator of a natural gas compressor station, processing plant, or transmission station shall submit to the Air Program Manager of the appropriate DEP Regional Office all requests, reports, applications, submittals, and other communications concerning applicable federal NSPS and NESHAP.

(b) In accordance with 40 CFR §§ 60.4 and 63.10, copies of all requests, reports, applications, submittals, and other communications shall also be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI) accessible at https://cdx.epa.gov unless electronic reporting is not available, in which case a copy shall be sent to the following address:

United States Environmental Protection Agency, Region III
Office of Air Enforcement and Compliance Assistance (3AP20)
1650 Arch St.
Philadelphia, PA 19103-2029

(c) The annual report is required to be submitted either in electronic format, by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office, the reporting period specified by the owner/operator shall be no later than one year from the start of operations of the facility, unless otherwise approved by the Department. The initial and subsequent annual reports shall be submitted within 60 days of the end of the reporting periods. General information required on all reports includes:

(i) Company Name;

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(ii) Facility Site Name;

(iii) The GP-5 authorization number;

(iv) Either:

(A) The address of the site; **or**

(B) A description of the site and the location using latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of 5 decimal degrees using the North American Datum of 1983;

(v) The beginning and ending dates of the reporting period;

(vi) The Certification Form described in Condition 10(h), which must include:

(A) The statement: "Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."; **and**

(B) The signature of the certifying Responsible Official;

(vii) Identification of each source included in the report;

(viii) The identification of each term or condition of the GP-5 that is the basis of the certification, the compliance status, and the methods used for determining the compliance status of the source, currently and over the reporting period as identified in Sections B through N of this General Permit; **and**

(ix) The records of the facility's emissions to demonstrate compliance with Condition 12(b).

(d) In accordance with 25 Pa. Code § 135.3, the owner or operator of a facility shall submit to the Department via AES*Online or AES*XML at www.depgreenport.state.pa.us/ by March 1st of each year, a facility inventory report for the preceding calendar year for all sources regulated under this General Permit. The inventory report shall include all emissions information for all sources operated during the preceding calendar year from the annual report required in (c) above. Emissions data including, but not limited, to the following shall be reported:

(i) NO_X;

(ii) CO;

(iii) SO_X;

(iv) PM_{10};

(v) $PM_{2.5}$;

(vi) VOC;

(vii) Speciated HAP including, but not limited to, benzene, ethyl benzene, formaldehyde, n-hexane, toluene, isomers and mixtures of xylenes, and 2,2,4-trimethylpentane;

(viii) Total HAP;

(ix) CO_2;

(x) CH_4; **and**

(xi) N_2O.

14. Source Testing Requirements

(a) In addition to the specific performance testing requirements included in this General Permit, the Department may require the owner or operator to conduct a source test if it is determined that the air contaminant emissions from a source operating under this General Permit are, or may be, in excess of an applicable air contaminant emission limitation.

(b) The Department may alter the frequency of performance test requirements for reauthorization based on available performance data from the source, unless required by federal regulation.

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(c) All testing, with the exception of periodic monitoring, shall be performed in accordance with any applicable federal regulations, 25 Pa. Code, Chapter 139, and the current version of the Department's Source Testing Manual, or an alternative test method as approved by the Department.

(d) All submittals, with the exception of periodic monitoring data, shall meet the applicable requirements specified in the most current version of the Department's Source Testing Manual.

(e) One electronic copy **and** one printed copy of all reports, protocols, and test completion notifications, with the exception of periodic monitoring data, shall be submitted either by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office **and** to the PSIMS Administrator for the Source Testing Section in DEP's Central Office.

(f) At least 60 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, a Test Protocol shall be submitted in accordance with (e) above for review and approval. An operator may request an approval from the Department for a test protocol that covers testing of all currently operated sources in service at that operator's various facilities. In such a request, the operator will submit the test protocol in accordance with (e) above for review and approval and include a list of currently permitted sources. If the owner or operator has a test protocol, previously approved by the Department, a new test protocol does not need to be submitted for review/approval, provided that there are no changes, including the testing contractor, and the owner/operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

(g) At least 30 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, written notification of the date and time of testing shall be provided to the Department's Division of Source Testing and Monitoring and the appropriate DEP Regional Office so that an observer may be present. The Department is under no obligation to accept the results of any testing performed without adequate advance written notice to the Department of such testing.

(h) Within 15 calendar days after completion of the on-site testing portion of an emission test program to demonstrate compliance required by this General Permit, if a complete test report has not yet been submitted, an electronic notification shall be submitted in accordance with (e) above indicating the completion date of the on-site testing.

(i) A complete test report shall be submitted in accordance with (e) above no later than 60 calendar days after completion of the on-site testing portion of an emission test program required by this General Permit. The complete test report shall include a summary at the beginning of the report which includes:

(i) A statement that the owner or operator has reviewed the report from the emissions testing company and agrees with the findings;

(ii) The GP-5 authorization number and conditions that are the basis for the evaluation;

(iii) A summary of results with respect to each applicable permit condition; **and**

(iv) A statement of compliance or non-compliance with each applicable permit condition.

15. De Minimis Emission Increases

(a) Additional equipment may be installed, or currently authorized equipment may be modified at the facility without additional authorization provided that the following conditions (i) through (iii) are met. Replacement unit as defined in 25 Pa. Code § 121.1 may be installed without additional authorization provided that the following conditions (ii) through (iii) are met.

(i) The owner or operator complies with the requirements of 25 Pa. Code § 127.449(a), (b), and (d) through (i);

(ii) The equipment being installed, modified, or replaced meets the current applicable BAT Compliance Requirements;

(iii) The owner or operator submits written notification in accordance with Condition 11(b), including the following additional information:

(A) The manufacturer, model, rated capacity, and serial number of the equipment;

(B) A certification from the owner or operator that the equipment will meet all applicable terms and conditions of this General Permit, including Condition 10(a);

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(C) The notification shall be signed by a Responsible Official and shall acknowledge that the certifying party is aware of the penalties for unsworn falsification to governmental authorities as established under 18 Pa. C.S. § 4904. The certification shall also state that based on information and belief formed after reasonable inquiry, that the information in the notice is true, accurate, and complete; **and**

(D) The notice shall identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase and provide emission rates in tons per year and in terms necessary to establish compliance with any applicable requirement.

(b) A new Authorization to Use GP-5 shall be required if an owner or operator chooses to employ Selective Catalytic Reduction (SCR) to comply with NO_X emission standards in Section C Condition 1(c) or Section M Condition 1(c).

SECTION B. GLYCOL DEHYDRATION UNITS

1. BAT Compliance Requirements

(a) For each glycol dehydration unit constructed and operated under an Authorization to Use GP-5 approved by the Department prior to February 2, 2013, with a total uncontrolled potential VOC emission rate greater than 10 tpy, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 85% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.

(b) For each glycol dehydration unit constructed and authorized to operate on or after February 2, 2013, but prior to August 8, 2018, with a total uncontrolled potential VOC emission rate of greater than 5 tpy, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 95% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.

(c) For each glycol dehydrator constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall control methane, VOC, and HAP emissions from the glycol dehydrator still vent stream by at least 95% using an enclosed flare or other combustion device or other air cleaning device approved by the Department that meets the applicable requirements in Section J.

(d) Associated equipment, such as natural gas-driven pneumatic controllers (Section H), natural gas-driven pneumatic pumps (Section I), and fugitive emissions components (Section G) are subject to the requirements of their respective Sections.

(e) If any glycol dehydration unit uses triethylene glycol for the dehydration process, has a natural gas throughput greater than 3 MMscf/d, **and** emits more than 1 tpy of benzene, the owner or operator must:

(i) Determine the natural gas throughput in accordance with 40 CFR § 63.772(b)(1).

(ii) Determine the actual average benzene or benzene, toluene, ethylbenzene and xylene (BTEX) emissions in accordance with 40 CFR § 63.772(b)(2).

(iii) If the glycol dehydration unit is located at a facility located within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(1).

(iv) If the glycol dehydration unit is located at a facility that is not within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(2).

(v) If an alternate circulation rate is required, the determination must be submitted in accordance with 40 CFR § 63.764(d)(2)(ii).

2. Recordkeeping Requirements

For each glycol dehydration unit, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The location of the glycol dehydration unit;

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(b) The calculation for the optimum glycol circulation rate or the alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), **if applicable**;

(c) The determination of the actual average benzene or BTEX emissions in accordance with 40 CFR § 63.774(d)(1), **if applicable**;

(d) The emissions calculations for each glycol dehydrator in accordance with 25 Pa. Code § 135.5; **and**

(e) Records of deviations and malfunctions in accordance with 40 CFR § 63.774(g), **if applicable**.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each glycol dehydration unit operated during the reporting period shall include:

(a) The records of the optimum or alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), **if applicable**; **and**

(b) The records of any deviations and malfunctions in accordance with 40 CFR § 63.775(c)(6), **if applicable**.

The emissions from each glycol dehydration unit operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION C. STATIONARY NATURAL GAS-FIRED SPARK IGNITION INTERNAL COMBUSTION ENGINES

1. BAT Compliance Requirements

(a) For each natural gas-fired spark ignition internal combustion engine constructed under and authorized to operate under GP-5 approved by the Department on or after March 10, 1997 but prior to February 2, 2013, the owner or operator shall:

(i) Operate or equip the engine with air cleaning devices to meet the following emission levels:

(A) NO_X (as NO_2) of 2.0 g/bhp-h while operating at rated bhp and speed;

(B) Non-Methane Non-Ethane Hydrocarbon (NMNEHC), as propane, excluding formaldehyde, of 2.0 g/bhp-h while operating at rated bhp and speed; **and**

(C) CO of 2.0 g/bhp-h while operating at rated bhp and speed.

(ii) Ensure that at operating conditions less than rated capacity, the engine shall on a lb/h basis emit no more than it would emit at rated bhp and speed.

(iii) Ensure the engine meets the applicable requirements of (d) below.

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(b) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate under GP-5 approved by the Department on or after February 2, 2013, but prior to August 8, 2018, the owner or operator shall:

(i) Ensure the engine does not exceed the emissions standards specified in the following table:

Engine Type	Rated bhp	NO_X	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Lean-Burn	>100 - ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	>500	0.50 g/bhp-h	47 ppmvd @ 15% O_2 **or** 93% reduction	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Rich-Burn	>100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

(ii) Ensure the engine meets the applicable requirements of (d) below.

(c) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

(i) Ensure the engine does not exceed the emission standards specified in the following table:

Engine Type	Rated bhp	NO_X	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	≥100 - ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h	-
Lean-Burn	>500 - <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Lean-Burn	≥2,370	0.30 g/bhp-h Uncontrolled **or** 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	
Rich-Burn	≥100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

(ii) Ensure that for engines that control NO_X emissions with a control technology that uses ammonia or urea as a reagent, the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15% O_2.

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(iii) Ensure the engine meets the applicable requirements of (d) below.

(d) The owner or operator of the engine shall also:

(i) Comply with the applicable requirements of 40 CFR Part 63, Subpart ZZZZ for engines constructed (as defined in Subpart ZZZZ) prior to June 12, 2006;

(ii) Ensure the engine meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43, by not exceeding the following limitations:

(A) Equal to or greater than 10% for a period or periods aggregating more than three minutes in any one hour; **and**

(B) Equal to or greater than 30% at any time

(iii) Install, operate, and maintain a non-resettable hour meter;

(iv) Limit the engine's time spent at idle during startup or shutdown to a period appropriate for the operation of the engine and air pollution control equipment consistent with good air pollution control practices, not to exceed 30 minutes, during which time the emissions standards in (b) through (d) do not apply.

(v) Conduct performance tests and periodic monitoring for the engine as detailed in Conditions 4 and 5 of this section on the following schedule:

Engine Size hp	Initial Compliance Performance Test	Continuous Compliance Performance Test	Periodic Monitoring
<100	None Required	None Required	Every 2,500 hours of operation
≥100 - ≤500	Within 180 days of startup of the engine	Within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and not subject (d)(i)	Within 180 days of startup of the engine	Every 8,760 hours of operation **or** every three years **and** within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and subject to (d)(i)	Not Applicable	Every year	Every 2,500 hours of operation

(A) For an engine greater than or equal to 100 hp and less than or equal to 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the performance testing requirements are waived.

(B) For an engine greater than 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the continuous compliance performance testing requirements every 8,760 hours of operation or every three years are waived.

(C) The Department may alter the frequency of periodic monitoring based on the test results. The frequency of periodic monitoring may be altered upon request of the owner or operator with written Departmental approval.

2. Recordkeeping Requirements

For each engine, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The GP-5 authorization number and the date each engine was authorized for use;

(b) The make, model, and serial number of each engine;

(c) Either a copy of the manufacturer's maintenance instructions **or** an alternative maintenance plan;

(d) Records of maintenance conducted on each engine and any installed air pollution control devices;

(e) A copy of the manufacturer's engine certification or vendor guarantees;

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(f) The results of each periodic monitoring;

(g) The summary for each complete test report described in Section A Condition 14(i); **and**

(h) The emissions calculations for each engine in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-fired spark ignition internal combustion engine operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Engine Performance Testing Requirements

(a) When conducting a performance test for an engine, the owner or operator must submit the test protocol described in Section A. Condition 14(f) for review and approval.

(b) The owner or operator should conduct the following test procedures:

(i) Conduct three test runs of at least one hour duration within 10% of 100% peak (or the highest achievable) load.

(ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter, or the sampling points selected according to 40 CFR Part 60, Appendix A-4, Method 7E Section 8.1.2.

(iii) Determine the effluent characteristics by either:

(A) Calculating the exhaust flow in accordance with 40 CFR Part 60, Appendix A-7, Method 19 and measuring the O_2 concentration using 40 CFR Part 60, Appendix A-2, Method 3A; **or**

(B) By measuring:

(1) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;

(2) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**

(3) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.

(iv) Simultaneous to the determination of the O_2 concentration in (iii)(A) or (B) above, determine:

(A) The NO_X concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E;

(B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10;

(C) The NMNEHC concentration, as propane, excluding formaldehyde of the exhaust gas using ALT-106; **and**

(D) The formaldehyde concentration of the exhaust gas, **if applicable**, using 40 CFR Part 63, Appendix A, Method 320.

(c) If at any time the owner or operator operates the engine in excess of the highest achievable load plus 10%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Engine Periodic Monitoring Requirements

(a) When conducting periodic monitoring on an engine, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.

(b) *Standardized Periodic Monitoring Procedure.*

(i) Conduct three test runs of at least 20 minutes duration within 10% of 100% peak (or the highest achievable) load.

(ii) Determine NO_X and CO emissions and O_2 concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and

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following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) (A) and (B) of this section.

(iii) If the measured NO_X or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test in accordance with the Performance Testing Requirements of Condition 4 within 180 days of the periodic monitoring.

(c) The 2,500 hours of operation count resets after any performance test performed in accordance with Condition 4 above.

(d) For engines constructed (as defined in that subpart) prior to June 12, 2006, that installed a continuous parametric monitoring system (CPMS) to monitor the catalyst inlet temperature, the owner or operator must install, operate, and maintain the CPMS according to 40 CFR § 63.6625(b)(1) through (6).

SECTION D. RECIPROCATING COMPRESSORS

1. BAT Compliance Requirements

The owner or operator of a reciprocating compressor must meet the applicable requirements of 40 CFR § 60.5385 or 40 CFR § 60.5385a.

2. Recordkeeping Requirements

For each reciprocating compressor, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(3) or § 60.5420a(c)(3) as applicable.

In addition, the emissions calculation for each reciprocating compressor must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each reciprocating compressor operated during the reporting period shall be submitted in accordance with 40 CFR § 60.5420(b)(4) or § 60.5420a(b)(4) as applicable.

The emissions from each reciprocating compressor operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d), including the emissions from scheduled and unscheduled blowdowns.

SECTION E. STORAGE VESSELS

1. BAT Compliance Requirements

(a) For each storage vessel constructed and authorized to operate on or after August 23, 2011, but prior to August 8, 2018, the owner or operator shall meet the applicable requirements of 40 CFR §§ 60.5365(e) and 60.5395(d) and (e).

(b) For each storage vessel constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall equip the storage vessel with a cover and route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable control, cover, and closed vent system requirements of Section J Condition 1(a) through (f) or any alternative method approved by the Department.

(c) Any storage vessel returned to service must meet the requirements of 40 CFR § 60.5395(f) or § 60.5395a(c).

(d) Any storage vessel with a capacity greater than or equal to 2,000 gallons and less than or equal to 40,000 gallons must meet the requirements of 25 Pa. Code § 129.57.

(e) Any storage vessel with a capacity greater than 40,000 gallons must meet the requirements of 25 Pa. Code § 129.56, **if applicable**.

2. Recordkeeping Requirements

For each storage vessel, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(5) or § 60.5420a(c)(5) as applicable.

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In addition, the emissions calculation for each storage vessel, which may be calculated using Department-approved methods such as direct measurement; modeling programs such as the most recent version of EPA TANKS, ProMax, and API E&P Tanks; process simulation software such as HYSIM, HYSIS, WINSIM, and PROSIM; or calculation methodologies such as the Vazquez-Beggs equation, must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each storage vessel operated during the reporting period shall be submitted in accordance with 40 CFR § 60.5420(b)(6) or § 60.5420a(b)(6) as applicable. The emissions from each storage vessel operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION F. TANKER TRUCK LOAD-OUT OPERATIONS

1. BAT Compliance Requirements

(a) For all truck load-out operations that service a storage vessel with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

(i) Use a vapor balancing system when removing liquids from the storage vessel; **and**

(ii) Ensure that each tanker truck that is used to remove liquids from the storage vessel has passed one of the following annual leak tests:

(A) A tanker truck that does not indicate more than 1" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum has passed a MACT-level test and is assumed to have a collection efficiency of 99.2%.

(B) A tanker truck that does not indicate more than 3" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum has passed an NSPS-level test and is assumed to have a collection efficiency of 98.7%.

(C) A tanker truck that has passed a leak test performed in accordance with 49 CFR § 180.407 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.

(D) A tanker truck that has passed a leak test performed in accordance with 40 CFR Part 60, Appendix A-8, Method 27 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.

(iii) As an alternative to (i) and (ii), VOC emissions must be controlled with 95% or greater efficiency.

2. Recordkeeping Requirements

For each tanker truck load-out operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The identification, location, and date of construction of each vapor recovery load-out system;

(b) Records of each tanker truck load-out operation including the date and time of the liquids load-out, the type and volume of liquids loaded, and the truck collection efficiency based on the annual leak test; and

(c) The emissions calculation for each tanker truck load-out operation in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from tanker truck load-out operations during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

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SECTION G. FUGITIVE EMISSIONS COMPONENTS

1. BAT Compliance Requirements

(a) For each fugitive emissions component constructed and authorized to operate under GP-5 approved by the Department on or after February 2, 2013, but prior to August 8, 2018, the following applies:

(i) The owner or operator of the natural gas compression and/or processing facility shall, at a minimum, on a monthly basis perform a leak detection and repair program that includes audible, visual, and olfactory (AVO) inspections.

(ii) Within 180 days after the initial startup of a source, the owner or operator of the facility shall at a minimum, on a quarterly basis, use forward looking infrared (FLIR) cameras or other leak detection monitoring devices approved by the Department for the detection of fugitive leaks. The Department may grant an extension for use of FLIR camera upon receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.

(iii) If any leak is detected, the owner or operator of the facility shall repair the leak as expeditiously as practicable, but no later than fifteen (15) calendar days after the leak is detected, except as provided in 40 CFR §§ 60.482-60.489. The owner or operator shall record each leak detected and the associated repair activity. The records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.

(b) For each fugitive emissions component constructed and authorized to operate on or after August 8, 2018, the following applies:

(i) No later than 30 days after an emission source commences operation, and at least monthly thereafter, the owner or operator of a facility shall conduct an AVO inspection.

(ii) No later than 60 days after initial startup, and quarterly thereafter, the owner or operator shall conduct an LDAR program using either an OGI camera, a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, or other leak detection methods approved by the Division of Source Testing and Monitoring.

(A) The owner or operator may request, in writing, an extension of the LDAR inspection interval from the Air Program Manager of the appropriate DEP Regional Office.

(B) Any fugitive emissions components that are difficult-to-monitor or unsafe-to-monitor must be identified in the monitoring plan described in Condition 2(a) below.

(iii) The detection devices must be operated and maintained in accordance with manufacturer-recommended procedures, as required by the test method, or a Department-approved method.

(iv) A leak is defined as:

(A) Any positive indication, whether audible, visual, or odorous, determined during an AVO inspection;

(B) Any visible emissions detected by an OGI camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; **or**

(C) A concentration of 500 ppm calibrated as methane or greater detected by an instrument reading.

(v) For quarterly inspections using a gas leak detector in accordance with 40 CFR Part 60, Appendix A-7, Method 21, the owner or operator may choose to adjust the detection instrument readings to account for the background organic concentration level as determined according to the procedures in Section 8.3.2.

(vi) Any leak detected from a fugitive emission component shall be repaired by the owner or operator of the facility as expeditiously as practicable. A first attempt at repair must be attempted within 5 calendar days of detection, and repair must be completed no later than 15 calendar days after the leak is detected **unless**:

(A) The owner or operator must purchase parts, in which case the repair must be completed no later than 10 calendar days after the receipt of the purchased parts; **or**

(B) The repair or replacement is technically infeasible, would require a vent blowdown, a compressor station, processing plant or transmission station shutdown, or would be unsafe to repair during operation of the unit, in which case the repair or replacement must be completed during the next

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scheduled compressor station, processing plant or transmission station shutdown, after a planned vent blowdown or within 2 years, whichever is earlier.

(vii) Once a fugitive emission component has been repaired or replaced, the owner or operator must resurvey the component as soon as practicable, but no later than 30 calendar days after the leak is repaired.

(A) For repairs that cannot be made during the monitoring survey when the leak is initially found, either a digital photograph must be taken of the component or the component must be tagged for identification purposes.

(B) A leak is considered repaired if:

(1) There are no detectable emissions consistent with Section 8.3.2 of 40 CFR Part 60, Appendix A-7, Method 21;

(2) A leak concentration of less than 500 ppm as methane is detected when the gas leak detector probe inlet is placed at the surface of the component;

(3) There is no visible leak image when using an OGI camera calibrated at a detection sensitivity level of 60 grams/hour; or

(4) There is no bubbling at the leak interface using a soap solution bubble test specified in Section 8.3.3 of 40 CFR Part 60, Appendix A-7, Method 21.

(c) The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own, be preventing or interfering with the attainment or maintenance of an ambient air quality standard.

2. Recordkeeping Requirements

For fugitive emissions components, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The fugitive emissions monitoring plan in accordance with 40 CFR § 60.5397a(b) through (d).

(b) Records of each monitoring survey which must include:

(i) The facility name and location;

(ii) The GP-5 authorization number;

(iii) The date, start time, and end time of the survey;

(iv) The name of the operator(s) performing the survey;

(v) The monitoring instrument used;

(vi) The ambient temperature, sky conditions, and maximum wind speed at the time of the survey;

(vii) Any deviations from the monitoring plan or a statement that there were none; **and**

(viii) Documentation of each fugitive emission including:

(A) The identification of each component from which fugitive emissions were detected;

(B) The instrument reading of each fugitive emissions component that meets the leak definition in Condition 1(b)(iv)(C) of this section;

(C) The status of repair of each component including:

(1) The repair methods applied in each attempt to repair the component;

(2) The tagging or digital photographing of each component not repaired during the monitoring survey in which the fugitive emissions were discovered;

(3) The reasons a component was placed on delay of repair;

(4) The date of successful repair of the component; **and**

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(5) The information on the instrumentation or method used to resurvey the component after repair, if it was not completed during the monitoring survey in which the fugitive emissions were discovered.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the records of each monitoring survey conducted during the reporting period shall be included.

The emissions from fugitive emissions components during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION H. NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS

1. BAT Compliance Requirements

(a) For pneumatic controllers constructed and authorized to operate on or after August 23, 2011, the owner or operator must meet the applicable requirements of 40 CFR § 60.5390(a) and (b)(1) or (c)(1) or § 60.5390a(a) and (b)(1) or (c)(1).

(b) Each controller must be tagged in accordance with 40 CFR § 60.5390(b)(2) and (c)(2) or § 60.5390a(b)(2) and (c)(2) as applicable.

2. Recordkeeping Requirements

For each controller, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(4) or § 60.5420a(c)(4) as applicable.

In addition, the emissions calculation for each pneumatic controller must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each controller during the reporting period shall be done in accordance with 40 CFR § 60.5420(b)(5) or § 60.5420a(b)(5) as applicable.

The emissions from each pneumatic controller during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION I. NATURAL GAS-DRIVEN PNEUMATIC PUMPS

1. BAT Compliance Requirements

(a) For each natural gas-driven pneumatic diaphragm pump constructed and authorized to operate on or after September 18, 2015, but prior to August 8, 2018, the owner and operator shall meet the applicable requirements of 40 CFR § 60.5365a(h)(1) and § 60.5393a(a) and (c) through (e).

(b) For each natural gas-driven pneumatic pump constructed and authorized to operate on or after August 8, 2018, the owner or operator of a pump with:

(i) A methane emission rate of less than 200 tpy, a VOC emission rate of less than 2.7 tpy, a single HAP emission rate less than 0.5 tpy, and a total HAP emission rate less than 1.0 tpy, shall meet the applicable requirements of 40 CFR § 60.5365a(h)(1) and § 60.5393a(a) and (c) through (e).

(ii) A methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, shall route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable requirements of Section J.

2. Recordkeeping Requirements

For each natural gas-driven pneumatic diaphragm pump, the owner or operator shall maintain the following records in accordance with Section A Condition 12:

(a) The location, date of installation, and manufacturer's specifications for each pump.

(b) The emissions calculation for each pneumatic pump must be kept in accordance with 25 Pa. Code § 135.5.

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3. Reporting Requirements

The emissions from each natural gas-driven pneumatic diaphragm pump during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION J. ENCLOSED FLARES AND OTHER EMISSION CONTROL DEVICES

1. BAT Compliance Requirements

(a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*

(i) The owner or operator of an enclosed flare or other enclosed combustion control device shall meet the requirements of 40 CFR § 60.5412(d)(1) and § 60.5415(e) or 40 CFR § 60.5412a(d)(1) and § 60.5415a(e) as applicable. The Department may allow open flares at remote locations and for infrequent operations, provided the flare is installed and operated consistent with 40 CFR § 60.18.

(ii) The owner or operator must conduct a performance test in accordance with Condition 4 within 180 days of initial startup of the affected facility **unless:**

(A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.6413a(d); **or**

(B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement.

(iii) The owner or operator must conduct performance tests in accordance with Condition 4 within 180 days of each reauthorization **unless**:

(A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d);

(B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement;

(C) The Department uses EPA's National Stack Testing Guidance for stack test waivers. **or**

(D) The combustion control device established a correlation between the outlet TOC performance level and the firebox or combustion chamber temperature during the initial performance test.

(iv) The owner or operator of any combustion control device that is a manufacturer tested model shall meet the requirements of 40 CFR § 60.5413(e) or § 60.5413a(e) as applicable.

(b) *Vapor Recovery Devices.*

(i) The owner or operator of a vapor recovery device constructed prior to August 8, 2018, shall meet the requirements of 40 CFR § 60.5412(d)(2) and § 60.5415(e) or 40 CFR § 60.5412a(d)(2) and § 60.5415a(e) as applicable.

(ii) The owner or operator shall conduct a performance test in accordance with Condition 4 and 40 CFR § 60.5413(b)(5) or § 60.5413a(b)(5) as applicable.

(iii) The owner or operator of any vapor recovery device shall conduct a monthly AVO inspection in accordance with 40 CFR § 60.5417(h)(2) or § 60.5417a(h)(2) as applicable.

(iv) If the vapor recovery device is a carbon adsorption unit, the owner or operator shall meet the requirements of 40 CFR § 60.5412(c) or § 60.5412a(c) as applicable.

(c) *External Floating Roof.*

(i) An external floating roof shall meet the requirements of 40 CFR § 60.112b(a)(2) and 25 Pa. Code § 129.56(b) as applicable.

(ii) Perform a gap measurement test in accordance with 40 CFR § 60.113b for mechanical shoe or liquid-mounted primary seals.

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(iii) Perform a gap measurement test in accordance with 25 Pa. Code § 129.56(b)(iii) for a vapor-mounted primary seal.

(d) *Internal Floating Roof.*

(i) An internal floating roof shall meet the requirements of 40 CFR § 60.112b(a)(1) and 25 Pa. Code § 129.56(c) as applicable.

(ii) Visually inspect the internal floating roof, primary seal, and secondary seal (if equipped) in accordance with 40 CFR § 60.113b(a).

(e) *Covers.*

(i) The cover and all openings on the cover shall meet the requirements of 40 CFR § 60.5411(b) and § 60.5416(a)(3) or 40 CFR § 60.5411a(b) and § 60.5416a(a)(3) as applicable.

(ii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(b)(i). Defects include, but are not limited to, visible cracks, holes, or gaps in the cover or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

(iii) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(b)(vi) and (vii).

(f) *Closed Vent Systems.*

(i) The owner or operator shall conduct an assessment in accordance with 40 CFR § 60.5411a(d), **if applicable**.

(ii) The owner or operator shall design and operate the closed vent system with no detectable emissions, as determined in accordance with 40 CFR § 60.5411(a) and (c) and § 60.5416(a) through (c) or 40 CFR § 60.5411a(a) and (c) and § 60.5416a(a) through (c) as applicable.

(iii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(b)(i). Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; and broken or missing caps or other closure devices.

(iv) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(b)(vi) and (vii).

2. Recordkeeping Requirements

For each control device, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including:

(a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*

(i) For non-manufacturer-tested models, the owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(13) and (14) or § 60.5420a(c)(13) and (14) as applicable.

(ii) For manufacturer-tested models, the owner or operator must maintain records in accordance with 40 CFR § 60.5413(d)(12) and (e) or § 60.5413a(d)(12) and (e) as applicable.

(iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable**.

(b) *Vapor Recovery Devices.*

(i) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(12) through (14) or § 60.5420a(c)(12) through (14) as applicable.

(ii) The design analysis in accordance with 40 CFR § 60.5413(c) or § 60.5413a(c), as applicable.

(iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable**.

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(c) *External Floating Roof.*

(i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and

(ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable**.

(d) *Internal Floating Roof.*

(i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and

(ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable**.

(e) *Covers.*

(i) The owner or operator must maintain records in accordance with Section G Condition 2(b).

(f) *Closed Vent Systems.*

(i) The owner or operator must maintain records in accordance with Section G Condition 2(b).

(ii) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(8) and (9).

(iii) The owner or operator must maintain records of the assessment, including the engineer's certification, in accordance with 40 CFR § 60.5420a(c)(17), **if applicable**.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each control device in operation during the reporting period shall be done in accordance with 40 CFR § 60.5420(b) or § 60.5420a(b) as applicable.

4. Control Device Performance Testing Requirements

When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14 (f) for review and approval. The owner or operator should conduct the following test procedures:

(a) Conduct three test runs of at least one-hour duration while operating the control device within 5% of the required operating temperature.

(b) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter.

(i) If demonstrating compliance with a percent reduction requirement, sampling sites must be located at the inlet of the first control device and the outlet of the final control device; **or**

(ii) If demonstrating compliance with an outlet concentration requirement, the sampling site must be located at the outlet of the control device.

(c) Determine the effluent characteristics including:

(i) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;

(ii) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**

(iii) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.

(d) To demonstrate compliance with (b)(i), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the Total Organic Compounds (TOC) and then convert to dry basis using the moisture content from (c)(iii) above and calculate the inlet and outlet mass rates as propane and the percent reduction.

(e) To demonstrate compliance with (b)(ii), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the TOC and 40 CFR Part 60, Appendix A-6, Method 18 to determine the methane and ethane concentration, and then correct the TOC concentration, minus methane and ethane, for percent oxygen from (c)(ii) above.

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5. Control Device Periodic Monitoring Requirements

The owner or operator that installs a CPMS must install, operate, and maintain the CPMS according to 40 CFR § 60.5415 and § 60.5417 or 40 CFR § 60.5415a and § 60.5417a as applicable.

SECTION K. PIGGING OPERATIONS

1. BAT Compliance Requirements

(a) The owner or operator that conducts pigging operations shall employ best management practices to minimize the liquids present in the pig receiver chamber and to minimize emissions from the pig receiver chamber including, but not limited to, installing liquids ramps, installing liquids drain, routing high-pressure chambers to a low-pressure line or vessel, using ball valve type chambers, or using multiple pig chambers. The selection of the appropriate best management practices must be documented in the application.

(b) For pigging operations with a methane emission rate of 200 tpy or greater, or a VOC emission rate of 2.7 tpy or greater, or a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, after employing best management practices, the owner or operator shall control methane, VOC, and HAP emissions from all pigging operations by at least 95% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device, or any alternative method approved by the Department that meets the applicable requirements in Section J.

2. Recordkeeping Requirements

For each pigging operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The identification, location, and date of construction of each pig launcher or receiver;

(b) Records of each pigging operation including the identification of the pig chamber used, the date and time of the pigging operation, and the type and volume of liquids cleared; **and**

(c) The emissions calculation for each pig chamber, using the Department's spreadsheet found at http://files.dep.state.pa.us/ or other equivalent method.

3. Reporting Requirements

The emissions from each pigging operation conducted during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION L. NATURAL GAS-FIRED COMBUSTION UNITS

1. BAT Compliance Requirements

(a) Combustion units including, but not limited to, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers constructed and authorized to operate on or after August 8, 2018, shall have a rated heat input less than 50 MMBtu/h each and only be fired on natural gas.

(b) For combustion units with a rated heat input of greater than or equal to 10 MMBtu/h, the owner or operator shall:

(i) Ensure that the emission limits in the following table are met:

Constructed or Modified After:	NO_X (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)	PM (lb/MMBtu)	Opacity (No more than 3 minutes in an hour)	Opacity (At any time)
December 2, 1995	30	300	0.4	20%	60%
August 8, 2018	30	130	0.4	10%	30%

(ii) Conduct a performance test for NOx and CO in accordance with Condition 4 below within 180 days of initial startup;

(iii) Conduct either a performance test in accordance with Condition 4 below within 180 days of reauthorization of the GP-5 **or** conduct periodic monitoring in accordance with Condition 5 below;

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(iv) Ensure the combustion unit meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43; and

(v) Conduct, within 180 days of re-authorization of GP-5, a tune-up/inspection which at a minimum shall include:

(A) Inspecting the burner and cleaning or replacing any components of the burner as necessary;

(B) Inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer's specifications or good combustion engineering practices;

(C) Inspecting the system air-to-fuel ratio controller and ensuring it is calibrated and functioning properly;

(D) Optimizing total emissions of CO consistent with the NO_X requirement and the manufacturer's specifications or good combustion engineering practices; **and**

(E) Measuring the concentrations in the effluent stream of CO in ppmv and O_2 in volume percent before and after adjustments are made in accordance with Condition 5 (b)(ii) below.

(c) Integrated equipment, such as natural gas-driven pneumatic controllers (Section H), natural gas-driven pneumatic pumps (Section I), and any fugitive emissions components (Section G) are subject to the requirements of their respective Sections. Emissions from these sources are not required to be included in the uncontrolled emissions calculations for the combustion units in this section.

2. Recordkeeping Requirements

For each combustion unit, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The location of the combustion unit;

(b) Either the summary for each complete test report described in Section A Condition 14(i); **or** the results of each periodic monitoring;

(c) The tune-up/inspection records, which shall at a minimum include:

(i) The date the tune-up/inspection was conducted;

(ii) The concentrations in the effluent stream of CO in ppmv and O_2 in volume percent as determined in Condition 5(b)(ii); and

(iii) A description of any corrective actions taken as part of the tune-up; **and**

(d) The emissions calculations for the combustion unit in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each combustion unit operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Combustion Unit Performance Testing Requirements

(a) When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14 (f) for review and approval.

(b) The owner or operator should conduct the following test procedures.

(i) Conduct three test runs of at least one-hour duration within 10% of 100% peak (or the highest achievable) load.

(ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter.

(iii) Determine the effluent characteristics including:

(A) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;

(B) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**

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(C) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.

(iv) Simultaneous to the determination of the O_2 concentration in (iii)(B) above, determine:

(A) The NO_X concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E; **and**

(B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10.

(c) If at any time the owner or operator operates the combustion unit in excess of the highest achievable load plus 10%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Combustion Unit Periodic Monitoring Requirements

(a) When conducting periodic monitoring on a combustion unit, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.

(b) *Standardized Periodic Monitoring Procedure.*

(i) Conduct three test runs of at least 20-minutes duration within 10% of 100% peak (or the highest achievable) load.

(ii) Determine NO_X and CO emissions and O_2 concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) of this section.

(iii) If the measured NO_X or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test within 180 days of the periodic monitoring.

SECTION M. STATIONARY NATURAL GAS-FIRED COMBUSTION TURBINES

1. BAT Compliance Requirements

(a) For each natural gas-fired combustion turbine constructed and authorized to operate prior to February 1, 2013, the owner or operator shall abide by the terms and conditions of the applicable plan approval or operating permit under which they were authorized.

(b) For each natural gas-fired combustion turbine constructed and authorized to operate under GP-5 approved by the Department on or after February 1, 2013, but prior to August 8, 2018, the owner or operator shall:

(i) Ensure the turbine does not exceed the emissions standards specified in the following table:

Turbine Rating (bhp)	**NO_X (ppmvd @ 15% O_2)**	**CO (ppmvd @ 15% O_2)**	**NMNEHC (as propane) (ppmvd @ 15% O_2)**	**Total PM (lb/MMBtu)**
≥1,000 and <5,000	25	25	9	0.03
≥5,000 and <15,000	15	25	9	0.03
≥15,000	15	10 **or** 93% reduction	5 **or** 50% reduction	0.03

(ii) Ensure the turbine meets the requirements of (d) below.

SAMPLE

(c) For each natural gas-fired combustion turbine constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

(i) Ensure the turbine does not exceed the emission standards specified in the following table:

Turbine Rating (bhp)	**NO_X (ppmvd @ 15% O_2)**	**CO (ppmvd @ 15% O_2)**	**NMNEHC (as propane) (ppmvd @ 15% O_2)**	**Total PM (lb/MMBtu, HHV)**
≥1,000 and <5,000	25	25	9.0	0.03
≥5,000 and <15,900	15	10	5.0	0.03
≥15,900	9.0 Uncontrolled **or** 2.0 with Control	10 Uncontrolled **or** 1.8 with Control	5.0	0.03

(ii) Ensure that, for turbines that control NO_X emissions with a control technology that uses ammonia or urea as a reagent, the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15% O_2.

(iii) Demonstrate that the vendor's guarantee assures compliance with the total PM emission limits.

(iv) Ensure the turbine meets the requirements of (d) below.

(d) The owner or operator of the turbine shall also:

(i) Ensure the turbine meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43, by not exceeding the following limitations:

(A) Equal to or greater than 10% for a period or periods aggregating more than three minutes in any one hour; **and**

(B) Equal to or greater than 30% at any time.

(ii) Install, operate, and maintain a non-resettable hour meter.

(iii) Limit the turbine's time spent at idle during startup or shutdown to a period appropriate for the operation of the turbine and air pollution control equipment consistent with good air pollution control practices, not to exceed 30 minutes, during which time the emissions standards in (a) through (c) do not apply.

(iv) Operate the turbine and air pollution control equipment consistent with good air pollution control practices during periods of low ambient air temperature (at or below 0 °F), during which time the emissions standards in (a) through (c) do not apply.

(v) Conduct performance tests for the turbine as detailed in Condition 4 below within 180 days of initial startup and within 180 days of reauthorization of this General Permit and periodic monitoring for the turbine every 2,500 hours of operation. The Department may alter the frequency of periodic monitoring based on the test results. The frequency of periodic monitoring may be altered upon request of the owner or operator with written Departmental approval.

2. Recordkeeping Requirements

For each turbine, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The location of each turbine;

(b) The GP-5 authorization number and the date each turbine was authorized for use;

(c) The make, model, and serial number of each turbine;

(d) A copy of the manufacturer's maintenance instructions **or** an alternative maintenance plan;

(e) Records of maintenance conducted on each turbine and any installed air pollution control devices;

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(f) A copy of the vendor's emission guarantees;

(g) The results of each periodic monitoring;

(h) The summary for each complete test report described in Section A Condition 14(i);

(i) Representative fuel sampling data in accordance with 40 CFR § 60.4365(b);

(j) The results of all compliance calculations in accordance with 40 CFR § 60.7(f), **if applicable**; **and**

(k) The emissions calculations for each turbine in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-fired combustion turbine operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Turbine Performance Testing Requirements

(a) When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14 (f) for review and approval.

(b) The owner or operator should conduct the following test procedures:

(i) Conduct three test runs of at least one hour duration within plus or minus 25% of 100% of peak load or at the highest achievable load point.

(ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter, or the sampling points selected in accordance with 40 CFR Part 60, Appendix A-4, Method 7E, Section 8.1.2.

(iii) Determine the effluent characteristics by either:

(A) Calculating the exhaust flow in accordance with 40 CFR Part 60, Appendix A-7, Method 19 and measuring the O_2 concentration using 40 CFR Part 60, Appendix A-2, Method 3A; **or**

(B) By measuring:

(1) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;

(2) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**

(3) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.

(iv) Simultaneous to the determination of the O_2 concentration in (iii)(A) or (B) above, determine:

(A) The NO_X concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E;

(B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10; **and**

(C) The NMNEHC concentration, as propane, of the exhaust gas using ALT-106.

(c) If at any time the owner or operator operates the turbine in excess of the highest achievable load plus 25%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Turbine Periodic Monitoring Requirements

(a) When conducting periodic monitoring on a turbine, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.

(b) *Standardized Periodic Monitoring Procedure.*

(i) Conduct three test runs of at least 20 minutes duration within plus or minus 25% of 100% of peak load or at the highest achievable load point,

SAMPLE

(ii) Determine NO_X and CO emissions and O_2 concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) (B) of this section.

(iii) If the measured NO_X or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test within 180 days of the periodic monitoring.

(c) The 2,500 hours of operation count resets after any performance test performed in accordance with Condition 4 above.

(d) For turbines that control NO_X emissions:

(i) Using water or steam injection, the owner or operator shall install, calibrate, maintain, and operate the appropriate continuous monitoring system in accordance with 40 CFR § 60.4335.

(ii) Using methods other than water or steam injection, the owner or operator shall install, calibrate, maintain, and operate the appropriate continuous monitoring system in accordance with 40 CFR § 60.4340(b).

(iii) The owner or operator that installs, calibrates, maintains, and operates a CPMS shall develop a site-specific parameter monitoring plan in accordance with 40 CFR § 60.4355.

6. Turbine Core Replacement Requirements

Turbine core replacement is allowed for a turbine, provided the following conditions are met:

(a) The owner or operator shall provide thirty (30) days written notification to the Department of a planned turbine core replacement, or within seven (7) days after an unplanned replacement is commenced.

(b) The written notice shall identify the location, the manufacturer, model, and serial number of the turbine, and the manufacturer, model, and serial number of the turbine core to be installed, or which has been installed, in the turbine and the air contaminant emission rates which will exist following the turbine core replacement, including NO_X, CO and NMNEHC.

(c) The written notice shall also contain a certification from the owner or operator that any turbine core to be installed has been manufactured by either the existing turbine manufacturer or other manufacturer and will be a lower emitting turbine core or, if the core will be replaced with an identical core, that a lower emitting core is not available. Existing turbine manufacturers shall include companies that maintain the turbine cores of the existing turbines at the facility. If the permittee decides to install a turbine core obtained from a manufacturer other than the existing turbine manufacturer, the notice shall contain a certification, signed by a "responsible official" as defined in 25 Pa. Code Section § 121.1, that the permittee has examined the turbine cores that are available from all such manufacturers and will install, or has installed, the lowest emitting turbine core available from any manufacturer.

(d) The core to be installed, or which has been installed, shall be an identical turbine core or lower emitting turbine core.

(e) The notice shall be accompanied by a vendor-provided guarantee of the achievable air contaminant emission rates of the new turbine core. If such a guarantee is not available, the notice shall include certification that the permittee attempted to obtain such guarantee and an explanation as to why the vendor will not provide such a guarantee.

(f) All certifications shall be signed by a responsible official and shall acknowledge that the certifying party is aware of the penalties for unsworn falsification to governmental authorities as established under 18 Pa.C.S. § 4904. The certification shall also state that based on information and belief formed after reasonable inquiry, that the information in the notice are true, accurate and complete.

(g) For purposes of this General Permit, a turbine core is a "Lower Emitting Turbine Core" if it is commercially available, has the same operating characteristics as the core being removed and the rate of NO_X emissions, expressed as either parts per million by volume dry basis ("ppmvd") or pounds per hour ("lb/h") would be lower than the rates of emission achievable by any commercially available alternative turbine core when the respective turbine was operating at the same level of performance. If the horsepower, firing rate and operating speed of the core being removed falls within the ranges of horsepower, firing rate, and operating speed for the Lower Emitting Turbine Core, the Lower Emitting Turbine Core is considered to have the same operating characteristics as the

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core being removed. A turbine core is an "Identical Turbine Core" if the rate of NO_X emissions is no higher than the emission rates of the turbine core being replaced when the respective turbine is operating at the same level of performance.

(h) After a turbine core has been replaced, the permittee shall perform NOx, CO, and NMNEHC emissions testing for the respective turbine compressor engine(s) within one-hundred twenty (120) days of completing the replacement. Stack testing shall be performed in accordance with Condition 4 of this Section.

SECTION N. CENTRIFUGAL COMPRESSORS

1. BAT Compliance Requirements

For a centrifugal compressor constructed and authorized to operate on or after August 23, 2011, the owner or operator shall meet the requirements of 40 CFR § 60.5380 or § 60.5380a as applicable.

2. Recordkeeping Requirements

For each centrifugal compressor, the owner or operator shall maintain the following records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(2) or § 60.5420a(c)(2) as applicable.

In addition, the emissions calculation for each centrifugal compressor must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each centrifugal compressor operated during the reporting period shall be done in accordance with 40 CFR § 60.5420(b)(3) or § 60.5420a(b)(3) as applicable.

The emissions from each centrifugal compressor operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d), including the emissions from scheduled and unscheduled blowdowns.

Issued by: _____

Krishnan Ramamurthy
Director
Bureau of Air Quality

Date Issued: _____

Date Effective: _____

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GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT
BAQ-GPA/GP-5A

Unconventional Natural Gas Well Site Operations and Remote Pigging Stations

SECTION A. GENERAL REQUIREMENTS

1. Statutory/Regulatory Authority and General Description

In accordance with Section 6.1(f) of the Pennsylvania Air Pollution Control Act (APCA), 35 P.S. § 4006.1(f) and 25 Pa. Code Chapter 127, Subchapter H, the Department of Environmental Protection (Department or DEP) hereby issues this General Plan Approval and/or General Operating Permit (General Permit or GP-5A) for new or modified unconventional natural gas well site operations and remote pigging stations (facility or facilities) constructed, modified, or operated in this Commonwealth.

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3. Definitions

Words and terms that are not otherwise defined in this General Permit shall have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III including 25 Pa. Code § 121.1 unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Code of Federal Regulations (CFR) including 40 CFR Part 60, Subparts JJJJ, OOOO, and OOOOa or 40 CFR Part 63, Subparts HH and ZZZZ shall also apply to this General Permit.

Fugitive Emissions Component – Any component that has the potential to emit fugitive emissions of methane, Volatile Organic Compounds (VOC), or Hazardous Air Pollutants (HAP) at an unconventional natural gas well site or remote pigging station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, compressors, instruments, meters, covers, and closed vent systems. Devices that vent as part of normal operations are not considered fugitive sources unless the emission originates from a place other than the vent.

Leak – A leak is defined as any release of gaseous hydrocarbons that is detected by Auditory, Visual, or Olfactory (AVO) inspection; an optical gas imaging (OGI) camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21 that detects a concentration of 500 ppm calibrated as methane or greater; or other leak detection methods approved by the Department's Division of Source Testing and Monitoring. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

Pigging Operations – The process of removing and collecting condensed liquids including condensate, intermediate hydrocarbons, or produced water, from a pipeline using a spherical or bullet-shaped device, known as a pig, forced through the pipeline by natural gas pressure. The liquids are then collected at their eventual destination in a storage tank, often referred to as a slug tank. This process also includes operation conducted for pipeline integrity evaluation.

Remote Pigging Station – A facility where pigging operations are conducted that is not located at an unconventional natural gas well site, natural gas compressor station, natural gas processing plant, or natural gas transmission station and which meets or exceeds the exemption criteria in Category 38(c) of the Air Quality Permit Exemptions List.

Sour Gas – Natural gas where the Hydrogen Sulfide (H_2S) content is in excess of 4 ppmv at standard temperature and pressure.

Start of Production – The beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water. A well whose owner or operator is selling gas through temporary equipment designed for flowback shall not be considered in production until either the sales continue through the temporary equipment for more than 30 days or the gas is routed to a permanent production separator.

Unconventional Natural Gas Well – A well drilled to produce natural gas from shale formations below the Elk Sandstone or its geologic equivalent stratigraphic interval, where recovery of the natural gas is generally not economic without the bores being stimulated by hydraulic fracturing, multilateral well bores, or other techniques to expose more of the formation to the well bore.

Unconventional Natural Gas Well Site – A location with one or more unconventional natural gas wells at which unconventional natural gas well site operations are conducted.

Unconventional Natural Gas Well Site Operations – Equipment and processes at unconventional natural gas well sites including, but not limited to, gas dehydration, tanker truck load-out, wellbore liquid unloading, gas compression, pigging, and storage.

Wellbore Liquids Unloading – The process of removing accumulated liquids from a natural gas well in order to restore well pressure and natural gas production.

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4. Applicability/Scope

(a) This General Permit authorizes the construction, modification, and/or operation of sources listed below at an unconventional natural gas well site or remote pigging station. The applicability of this General Permit may include one or more of the following operations or emissions sources:

- (i) Glycol Dehydration Units
- (ii) Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- (iii) Reciprocating Compressors
- (iv) Storage Vessels
- (v) Tanker Truck Load-Out Operations
- (vi) Fugitive Emissions Components
- (vii) Natural Gas-Driven Pneumatic Controllers
- (viii) Natural Gas-Driven Pneumatic Pumps
- (ix) Enclosed Flares and Other Emission Control Devices
- (x) Pigging Operations
- (xi) Wellbore Liquids Unloading Operations

(b) An Application for Authorization to Use GP-5A may be submitted for the operation of an eligible source if the source is exempted from plan approval requirements under 25 Pa. Code § 127.14.

(c) If any source located at the facility cannot be regulated under this General Permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B and/or Subchapter F will be required.

5. Prohibited Use of GP-5A

GP-5A may not be used for the construction, modification, or operation of any of the following air contamination sources:

(a) A proposed source located at a Title V facility including sources determined to be a single source Title V facility.

(b) A proposed source that is subject to Title V permitting requirements specified in 25 Pa. Code Chapter 127, Subchapters F and G; prevention of significant deterioration requirements specified in 25 Pa. Code Chapter 127 Subchapter D; or nonattainment new source review requirements specified in 25 Pa. Code Chapter 127 Subchapter E.

(c) A facility that produces or processes sour gas.

(d) *Circumvention.*

(i) The owner or operator of a facility may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying, or engaging in incremental construction over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.

(ii) No person may permit the use of a device, stack height that exceeds good engineering practice, dispersion technique, or other technique that without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants that would otherwise be in violation of this General Permit, the APCA, or the regulations promulgated thereunder, except for those that are used for the control of malodors with the prior written approval of the Department.

6. Authorization to Use GP-5A

(a) *Application for Authorization to Use GP-5A.* Pursuant to 25 Pa. Code § 127.621, any person proposing to construct, operate, or modify a source listed in Section A, Condition 4 of this General Permit at an unconventional natural gas well site or remote pigging station shall submit an Application for Authorization to Use GP-5A to the Air Program Manager of the appropriate DEP Regional Office responsible for authorizing the use of general permits in the county in which the facility will be located. This application shall be submitted to DEP either through the ePermitting system, by hand delivery, courier, or sent to DEP by certified mail, return receipt requested, in accordance with 25 Pa. Code § 127.621(b).

(b) *Terms of Authorization to Use GP-5A.* This General Permit authorizes the construction and/or operation of the specific sources at the specific facility as described in the application for a term of five years from the date of authorization. The authorization to construct a source or facility will expire 18 months from the date of the authorization if the owner or operator fails to commence construction or if there is a lapse in construction of 18 months. The Department may extend the 18-month period upon an owner or operator providing satisfactory justification for an extension up to the original date of the five-year term. All requests for extension shall be submitted to the Department at least 30 days prior to the end of the 18-month period and are only valid upon receipt of written approval by the Department. The expiration of the authorization to construct will require a new Application for Authorization to Use GP-5A if an extension is not requested and granted.

(c) *Expiration of and Re-Authorization to Use GP-5A.*

(i) The authorization granted by the Department to construct and/or operate under this General Permit shall terminate on the date of expiration unless a complete Application for Authorization to Use GP-5A is submitted to the Department at least 30 calendar days prior to the expiration date.

(ii) Upon receipt by the Department of a timely, administratively and technically complete application for re-authorization to operate under this General Permit, the owner or operator may continue to operate the facility subject to final action by the Department provided that the sources and the facility are operated in compliance with the terms and conditions of this General Permit. The Authorization to Use GP-5A shall cease if the owner or operator fails to submit any additional information requested by the Department to process the application by the specified deadline.

(d) *Transfer of Ownership.* The Authorization to Use GP-5A may not be transferred from the owner or operator of a facility except when the change of ownership is demonstrated to the satisfaction of the Department and the Department approves the transfer in writing. Within 30 calendar days after a transfer of ownership of the facility, the new owner or operator shall submit an appropriate form or application to the Air Program Manager of the appropriate Regional Office. If the owner or operator is modifying any existing source or adding a new source at the facility currently authorized by the General Permit, the owner or operator shall submit an Application for Authorization to Use GP-5A in accordance with Condition 6(a) above. If there are equipment or activities located on the same site or on sites that share equipment and are within ¼ mile of each other, the owner or operator shall submit an Application for Authorization to Use GP-5A as a General Plan Approval with a $1,000 application

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fee. If the owner or operator is not modifying any existing source, not adding a new source, or not subject to a new Single Source Determination based on the transfer of ownership, the owner or operator shall submit a Transfer of Ownership form with a $300 fee. The employer I.D. number (Federal IRS No.) shall be used as a test to determine if a transfer of ownership has occurred.

(e) *Administrative Amendment.* In the event of a change in the name, address, or telephone number of a person identified in the General Permit Application or a similar minor administrative change at the facility, the Department may authorize an administrative amendment. The owner or operator shall submit a brief description of the change and the date on which the change is to occur in a letter signed by the Responsible Official with the fee specified in Condition 7(e) to the Air Program Manager of the appropriate Regional Office.

(f) *Modification, Suspension, or Revocation of GP-5A or Authorizations to Use GP-5A.*

(i) The Department may modify, suspend, or revoke and reissue this General Permit if it is determined that GP-5A does not comply with the Clean Air Act, the APCA, or regulations adopted under the acts.

(ii) This General Permit may be modified, suspended, or revoked if the Department determines that the unconventional natural gas well site operation or remote pigging station cannot be adequately regulated under this General Permit.

(iii) An Authorization to Use GP-5A may be suspended or revoked if the Department determines that, at any time, the owner or operator has failed to construct and/or operate the facility in compliance with the terms and conditions of this General Permit, the specifications in the Application for Authorization to Use GP-5A, or the information provided in the supplemental material included with the application used to determine if the proposed sources will comply with the GP-5A.

(iv) Upon suspension or revocation of an Authorization to Use GP-5A, the owner or operator shall immediately cease construction and/or operation of the facility. The owner or operator of the facility shall not restart construction and/or operation prior to the receipt of written approval from the Department.

7. General Permit Fees

Each applicant seeking Authorization to Use GP-5A shall submit the applicable fees required under this Condition to the appropriate DEP Regional Office. The following fee schedules apply to this General Permit:

(a)	General Plan Approval Application Fee for Sources Subject to and Review of NSPS, payable upon submission of the application:	$1,700
(b)	General Plan Approval Application Fee with new Single Source Determination, payable upon submission of the application:	$1,000
(c)	General Operating Permit Application Fee, payable upon submission of the application:	$ 375
(d)	Annual Operating Permit Administration Fee, payable by March 1st for the previous calendar year:	$ 375
(e)	Administrative Amendment Fee, payable upon submission of the letter in Condition 6(e):	$ 300

(f) The Department may increase the applicable fees for this General Plan Approval/General Operating Permit in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I following notice in the *Pennsylvania Bulletin*.

8. Applicable Laws

(a) It is the duty of the Responsible Official, as defined in 25 Pa. Code § 121.1, to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations, including 25 Pa. Code, Subpart C, Article III. Nothing in this General Permit relieves the Responsible Official from this obligation to comply.

(b) Applicable federal regulations may include, but are not limited to, the following New Source Performance Standards (NSPS), codified at 40 CFR Part 60 and incorporated by reference in 25 Pa. Code § 122.3, and National Emission Standards for Hazardous Air Pollutants (NESHAP), codified at 40 CFR Part 63 and incorporated by reference in 25 Pa. Code § 127.35:

(i) **40 CFR Part 60, Subpart JJJJ** – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

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(ii) **40 CFR Part 60, Subpart OOOO** – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.

(iii) **40 CFR Part 60, Subpart OOOOa** – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.

(iv) **40 CFR Part 63, Subpart HH** – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.

(v) **40 CFR Part 63, Subpart ZZZZ** – National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

9. Best Available Technology Requirements

New sources are required to control the emission of air pollutants to the maximum extent, consistent with best available technology (BAT) as determined by the Department as of the date of issuance of the plan approval for the new source as required under 25 Pa. Code § 127.1. Condition 1 (BAT Compliance Requirements) of Sections B through L of this General Permit are determined to meet the BAT requirements.

10. Compliance Requirements and Compliance Certification

(a) The emissions from all sources and associated air pollution control equipment located at an unconventional natural gas well site or remote pigging station and other sources determined by the Department to be a single source shall not equal or exceed either of the following on a 12-month rolling sum basis:

(i) Nitrogen Oxides (NO_X) – 100 tons

(ii) Carbon Monoxide (CO) – 100 tons

(iii) Sulfur Oxides (SO_X) – 100 tons

(iv) Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}) – 100 tons

(v) Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$) – 100 tons

(vi) Volatile Organic Compounds (VOC) – 50 tons

(vii) Any individual Hazardous Air Pollutant (HAP) – 10 tons

(viii) Total Hazardous Air Pollutants (HAP) – 25 tons

(ix) In addition, the emissions from all sources and associated air pollution control equipment located at a facility in Bucks, Chester, Delaware, Montgomery, or Philadelphia Counties shall not equal or exceed any of the following on a 12-month rolling sum basis:

(A) NO_X – 25 tons

(B) VOC – 25 tons

(b) The facility throughput, hours of operation, and/or emissions from sources at the facility shall be constrained as necessary to not exceed any facility-wide emissions cap required in (a) above.

(c) All sources and associated air pollution control equipment located at a facility shall be:

(i) Operated in such a manner as not to cause air pollution, as that term is defined in 25 Pa. Code § 121.1;

(ii) Operated and maintained in accordance with the manufacturer's specifications, procedures, and recommended maintenance schedule, as provided in the Application for Authorization to Use GP-5A, or an alternate procedure approved by the Department that achieves equal or greater emissions reductions in accordance with 25 Pa. Code § 127.12b;

(iii) Operated and maintained in accordance with the fugitive emission requirements of 25 Pa. Code § 123.1 and § 123.2; **and**

(iv) Operated and maintained in such a manner that malodors are not detectable outside the property of the owner or operator on whose land the facility is being operated in accordance with 25 Pa. Code § 123.31.

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(d) The owner or operator of an existing facility where a new well is drilled, hydraulically fractured, hydraulically refractured or where a new equipment is installed or an existing source is modified shall comply with applicable BAT requirements established in this General Permit.

(e) This General Permit cannot be used to relax BAT or other emission limitations or requirements previously established through the air quality permitting process.

(f) An owner or operator of a facility may apply to the Department for a plan approval for any air contamination source in lieu of seeking authorization to use the General Permit for unconventional natural gas well sites or remote pigging stations.

(g) The owner or operator authorized to use this General Permit shall comply with the specifications in the application and the terms and conditions of this General Permit.

(h) The owner or operator of the facility shall submit to the Air Program Manager of the appropriate DEP Regional Office an annual certification of compliance with the terms and conditions in the GP-5A for the previous year, including the emission limitations, standards, or work practices. This Compliance Certification Form must be included in the annual report as outlined in Condition 13(c)(vii).

11. Notification Requirements

(a) *Municipal Notification.* The facility owner or operator proposing to use this General Permit shall notify the local municipality and county where the air pollution source is to be located that they have applied for an Authorization to Use GP-5A. The notification shall clearly describe the proposed sources and/or modifications.

(b) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office, in writing, at least five business days prior to the commencement of operation of a source of their intent to do so. The owner or operator shall also include the date of completion of construction of the source in the notice. When multiple sources at the facility are subject to different commencement of operation schedules, written notice shall be submitted to DEP prior to the commencement of operation of each source. The owner or operator may submit a single written notice for multiple sources.

(c) *Malfunctions.*

(i) Any malfunction that poses an imminent danger to the public health, safety, or welfare or to the environment shall be reported by telephone to the County Emergency Management Agency and to the 24 hour Emergency Hotline at 1-800-541-2050 no later than one hour after the discovery of an incident. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within three business days.

(ii) Any malfunction that does not pose an imminent danger to the public health, safety, or welfare or to the environment shall follow the guidance provided in the GP-5 and GP-5A Malfunction Reporting Instructions and, if required to report, shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of discovery. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within five business days.

(iii) If the owner or operator is unable to provide notification by telephone to the Air Program Manager of the appropriate DEP Regional Office within 24 hours of the discovery of a malfunction due to a weekend or holiday, the notification shall be made to the Department no later than 4:00 pm on the first business day following the weekend or holiday.

(iv) Written notification shall include:

(A) The name, GP-5A authorization number, and location of the facility;

(B) The nature and cause of the malfunction or incident;

(C) The date and time when the malfunction, incident, or breakdown was first discovered;

(D) The expected duration of increased emissions;

(E) The estimated rate of emissions for all criteria, hazardous, and greenhouse gas pollutants; **and**

(F) Any changes to the equipment or modification of the procedures that will prevent future reoccurrences of the malfunction.

SAMPLE

(v) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of when corrective measures have been implemented.

(vi) Any emissions due to a malfunction are to be reported in the annual emissions inventory report required in Condition 13(d).

12. Recordkeeping Requirements

(a) All records required must be maintained onsite or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format.

(b) The owner or operator of the facility shall generate and maintain records that clearly demonstrate to the Department that the facility is not a Title V facility and that the facility is in compliance with facility-wide emission limitations. At a minimum, the records shall be maintained on a monthly basis, and the actual emissions shall be calculated on a 12-month rolling sum. The Department reserves the right to request additional information necessary to determine compliance with the General Permit.

(c) The owner or operator of the facility shall keep records of all written notifications required under permit conditions.

13. Reporting Requirements

(a) The owner or operator of an unconventional natural gas well site or remote pigging station shall submit to the Air Program Manager of the appropriate DEP Regional Office all requests, reports, applications, submittals, and other communications concerning applicable federal NSPS and NESHAP.

(b) In accordance with 40 CFR §§ 60.4 and 63.10, copies of all requests, reports, applications, submittals, and other communications shall also be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI) accessible at https://cdx.epa.gov unless electronic reporting is not available, in which case a copy shall be sent to the following address:

United States Environmental Protection Agency, Region III
Office of Air Enforcement and Compliance Assistance (3AP20)
1650 Arch St.
Philadelphia, PA 19103-2029

(c) The annual report is required to be submitted either in electronic format, by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office, The reporting period specified by the owner/operator shall be no later than one year from the start of operations of the facility, unless otherwise approved by the Department. The initial and subsequent annual reports shall be submitted within 60 days of the end of the reporting periods. General information required on all reports includes:

(i) Company Name;

(ii) Facility Site Name;

(iii) The GP-5A authorization number;

(iv) US Well ID(s);

(v) Either:

(A) The address of the site; **or**

(B) A description of the site and the location using latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of 5 decimal degrees using the North American Datum of 1983;

(vi) The beginning and ending dates of the reporting period;

(vii) The Certification Form described in Condition 10(h), which must include:

(A) The statement: “Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.”; **and**

(B) The signature of the certifying Responsible Official;

(viii) Identification of each source included in the report;

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(ix) The identification of each term or condition of the GP-5A that is the basis of the certification, the compliance status, and the methods used for determining the compliance status of the source, currently and over the reporting period as identified in Sections B through L of this General Permit; **and**

(x) The records of the facility's emissions to demonstrate compliance with Condition 12(b).

(d) In accordance with 25 Pa. Code § 135.3, the owner or operator of a facility shall submit to the Department via AES*Online or AES*XML at www.depgreenport.state.pa.us/ by March 1st of each year, a facility inventory report for the preceding calendar year for all sources regulated under this General Permit. The inventory report shall include all emissions information for all sources operated during the preceding calendar year from the annual report required in (c) above. Emissions data including, but not limited, to the following shall be reported:

(i) NO_X;

(ii) CO;

(iii) SO_X;

(iv) PM_{10};

(v) $PM_{2.5}$;

(vi) VOC;

(vii) Speciated HAP including, but not limited to, benzene, ethyl benzene, formaldehyde, n-hexane, toluene, isomers and mixtures of xylenes, and 2,2,4-trimethylpentane;

(viii) Total HAP;

(ix) CO_2;

(x) CH_4; **and**

(xi) N_2O.

14. Source Testing Requirements

(a) In addition to the specific performance testing requirements included in this General Permit, the Department may require the owner or operator to conduct a source test if it is determined that the air contaminant emissions from a source operating under this General Permit are, or may be, in excess of an applicable air contaminant emission limitation.

(b) The Department may alter the frequency of performance test requirements for reauthorization based on available performance data from the source, unless required by federal regulation.

(c) All testing, with the exception of periodic monitoring, shall be performed in accordance with any applicable federal regulations, 25 Pa. Code, Chapter 139 and the current version of the Department's Source Testing Manual, or an alternative test method as approved by the Department.

(d) All submittals, with the exception of periodic monitoring data, shall meet the applicable requirements specified in the most current version of the Department's Source Testing Manual.

(e) One electronic copy **and** one printed copy of all reports, protocols, and test completion notifications, with the exception of periodic monitoring data, shall be submitted either by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office **and** to the PSIMS Administrator for the Source Testing Section in DEP's Central Office.

(f) At least 60 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, a test protocol shall be submitted in accordance with (e) above for review and approval. An operator may request an approval from the Department for a test protocol that covers testing of all currently operated and future sources in service at that operator's various facilities. In such a request, the Operator will submit the test protocol in accordance with (e) above for review and approval and include a list of currently permitted engines (to be updated as necessary when engines are installed or removed). If the owner or operator has a test protocol, previously approved by the Department, a new test protocol does not need to be submitted for review/approval, provided that there are no changes, including the testing contractor, and the owner/operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

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(g) At least 30 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, written notification of the date and time of testing shall be provided to the Department's Division of Source Testing and Monitoring and the appropriate DEP Regional Office so that an observer may be present. The Department is under no obligation to accept the results of any testing performed without adequate advance written notice to the Department of such testing.

(h) Within 15 calendar days after completion of the on-site testing portion of an emission test program to demonstrate compliance required by this General Permit, if a complete test report has not yet been submitted, an electronic notification shall be submitted in accordance with (e) above indicating the completion date of the on-site testing.

(i) A complete test report shall be submitted in accordance with (e) above no later than 60 calendar days after completion of the on-site testing portion of an emission test program required by this General Permit. The complete test report shall include a summary at the beginning of the report which includes:

(i) A statement that the owner or operator has reviewed the report from the emissions testing company and agrees with the findings;

(ii) The GP-5A authorization number and conditions that are the basis for the evaluation;

(iii) A summary of results with respect to each applicable permit condition; **and**

(iv) A statement of compliance or non-compliance with each applicable permit condition.

15. De Minimis Emission Increases

(a) Additional equipment may be installed, or currently authorized equipment may be modified at the facility without additional authorization provided that the following conditions (i) through (ii) are met. Replacement unit as defined in 25 Pa. Code § 121.1 may be installed without additional authorization provided that the following conditions (ii) through (iii) are met.

(i) The owner or operator complies with the requirements of 25 Pa. Code § 127.449(a), (b), and (d) through (i);

(ii) The equipment being installed, modified, or replaced meets the current applicable BAT Compliance Requirements;

(iii) The owner or operator submits written notification in accordance with Condition 11(b), including the following additional information:

(A) The manufacturer, model, rated capacity, and serial number of the equipment;

(B) A certification from the owner or operator that the equipment will meet all applicable terms and conditions of this General Permit, including Condition 10(a);

(C) The notification shall be signed by a Responsible Official and shall acknowledge that the certifying party is aware of the penalties for unsworn falsification to governmental authorities as established under 18 Pa. C.S. § 4904. The certification shall also state that based on information and belief formed after reasonable inquiry, that the information in the notice is true, accurate, and complete; **and**

(D) The notice shall identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase and provide emission rates in tons per year and in terms necessary to establish compliance with any applicable requirement.

(b) A new Authorization to Use GP-5A shall be required if an owner or operator chooses to employ Selective Catalytic Reduction (SCR) to comply with NO_X emission standards in Section C Condition 1(c).

SECTION B. GLYCOL DEHYDRATION UNITS

1. BAT Compliance Requirements

(a) For each glycol dehydration unit constructed and authorized to operate under GP-5 approved by the Department prior to February 2, 2013, with a total uncontrolled potential VOC emission rate greater than 10 tpy, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 85% with a

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condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.

(b) For each glycol dehydration unit constructed and authorized to operate on or after August 10, 2013, but prior to August 8, 2018, with a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 95% with a condenser, enclosed flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.

(c) For each glycol dehydrator constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, an single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall control methane, VOC, and HAP emissions from the glycol dehydrator still vent stream by at least 95% using an enclosed flare or other combustion device or other air cleaning device approved by the Department that meets the applicable requirements in Section J.

(d) Associated equipment, such as natural gas-driven pneumatic controllers (Section H), natural gas-driven pneumatic pumps (Section I), and fugitive emissions components (Section G) are subject to the requirements of their respective Sections.

(e) If any glycol dehydration unit uses triethylene glycol for the dehydration process, has a natural gas throughput greater than 3 MMscf/d, **and** emits more than 1.0 tpy of benzene, the owner or operator must:

(i) Determine the natural gas throughput in accordance with 40 CFR § 63.772(b)(1).

(ii) Determine the actual average benzene or benzene, toluene, ethylbenzene and xylene (BTEX) emissions in accordance with 40 CFR § 63.772(b)(2).

(iii) If the glycol dehydration unit is located at a facility located within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(1).

(iv) If the glycol dehydration unit is located at a facility that is not within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(2).

(v) If an alternate circulation rate is required, the determination must be submitted in accordance with 40 CFR § 63.764(d)(2)(ii).

2. Recordkeeping Requirements

For each glycol dehydration unit, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The location of the glycol dehydration unit;

(b) The calculation for the optimum glycol circulation rate or the alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), **if applicable**;

(c) The determination of the actual average benzene or BTEX emissions in accordance with 40 CFR § 63.774(d)(1), **if applicable**;

(d) The emissions calculations for each glycol dehydrator in accordance with 25 Pa. Code § 135.5; **and**

(e) Records of deviations and malfunctions in accordance with 40 CFR § 63.774(g), **if applicable**.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each glycol dehydration unit operated during the reporting period shall include:

(a) The records of the optimum or alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), **if applicable; and**

(b) The records of any deviations and malfunctions in accordance with 40 CFR § 63.775(c)(6), **if applicable**.

The emissions from each glycol dehydration unit in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

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SECTION C. STATIONARY NATURAL GAS-FIRED SPARK IGNITION INTERNAL COMBUSTION ENGINES

1. BAT Compliance Requirements

(a) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate under GP-5 approved by the Department on or after March 10, 1997 but prior to February 2, 2013, the owner or operator shall:

(i) Operate or equip the engine with air cleaning devices to meet the following emission levels:

(A) NO_X (as NO_2) of 2.0 g/bhp-h while operating at rated bhp and speed;

(B) Non-Methane Non-Ethane Hydrocarbon (NMNEHC) as propane, excluding formaldehyde, of 2.0 g/bhp-h while operating at rated bhp and speed; **and**

(C) CO of 2.0 g/bhp-h while operating at rated bhp and speed.

(ii) Ensure that at operating conditions less than rated capacity, the engine shall on a lb/h basis emit no more than it would emit at rated bhp and speed.

(iii) Ensure the engine meets the applicable requirements of (d) below.

(b) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate under GP-5 approved by the Department on or after February 2, 2013, but prior to August 8, 2018, the owner or operator shall:

(i) Ensure the engine does not exceed the emissions standards specified in the following table:

Engine Type	Rated bhp	NO_X	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Lean-Burn	>100 - ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	>500	0.50 g/bhp-h	47 ppmvd @ 15% O_2 **or** 93% reduction	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Rich-Burn	>100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

(ii) Ensure the engine meets the applicable requirements of (d) below.

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(c) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

(i) Ensure the engine does not exceed the emission standards specified in the following table:

Engine Type	Rated bhp	NO_X	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	≥100 - ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h	-
Lean-Burn	>500 - <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Lean-Burn	≥2,370	0.30 g/bhp-h Uncontrolled **or** 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	
Rich-Burn	≥100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

(ii) Ensure that for engines that control NO_X emissions with a control technology that uses ammonia or urea as a reagent, the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15% O_2.

(iii) Ensure the engine meets the applicable requirements of (d) below.

(d) The owner or operator of the engine shall also:

(i) Comply with the applicable requirements of 40 CFR Part 63, Subpart ZZZZ for engines constructed (as defined in Subpart ZZZZ) prior to June 12, 2006;

(ii) Ensure the engine meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43, by not exceeding the following limitations:

(A) Equal to or greater than 10% for a period or periods aggregating more than three minutes in any one hour; **and**

(B) Equal to or greater than 30% at any time

(iii) Install, operate, and maintain a non-resettable hour meter;

(iv) Limit the engine's time spent at idle during startup or shutdown to a period appropriate for the operation of the engine and air pollution control equipment consistent with good air pollution control practices, not to exceed 30 minutes, during which time the emissions standards in (b) through (d) do not apply.

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(v) Conduct performance tests and periodic monitoring for the engine as detailed in Conditions 4 and 5 of this section on the following schedule:

Engine Size hp	Initial Compliance Performance Test	Continuous Compliance Performance Test	Periodic Monitoring
<100	None Required	None Required	Every 2,500 hours of operation
≥100 - ≤500	Within 180 days of startup of the engine	Within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and not subject to (d)(i)	Within 180 days of startup of the engine	Every 8,760 hours of operation **or** every three years **and** within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and subject to (d)(i)	Not Applicable	Every year	Every 2,500 hours of operation

(A) For an engine greater than or equal to 100 hp and less than or equal to 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the performance testing requirements are waived.

(B) For an engine greater than 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the continuous compliance performance testing requirements every 8,760 hours of operation or every three years are waived.

(C) The Department may alter the frequency of periodic monitoring based on the test results. The frequency of periodic monitoring may be altered upon request of the owner or operator with written Departmental approval.

2. Recordkeeping Requirements

For each engine, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The GP-5A authorization number and the date each engine was authorized for use;

(b) The make, model, and serial number of each engine;

(c) Either a copy of the manufacturer's maintenance instructions **or** an alternative maintenance plan;

(d) Records of maintenance conducted on each engine and any installed air pollution control devices;

(e) A copy of the manufacturer's engine certification or vendor guarantees;

(f) The results of each periodic monitoring;

(g) The summary for each complete test report described in Section A Condition 14(i); **and**

(h) The emissions calculations for each engine in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-fired spark ignition internal combustion engine in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Engine Performance Testing Requirements

(a) When conducting a performance test for an engine, the owner or operator must submit the test protocol described in Section A Condition 14(f) for review and approval.

(b) The owner or operator should conduct the following test procedures:

(i) Conduct three test runs of at least one-hour duration within 10% of 100% peak (or the highest achievable) load.

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(ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter, or the sampling points selected according to 40 CFR Part 60, Appendix A-4, Method 7E Section 8.1.2.

(iii) Determine the effluent characteristics by either:

(A) Calculating the exhaust flow in accordance with 40 CFR Part 60, Appendix A-7, Method 19 and measuring the O_2 concentration using 40 CFR Part 60, Appendix A-2, Method 3A; **or**

(B) By measuring:

(1) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;

(2) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**

(3) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.

(iv) Simultaneous to the determination of the O_2 concentration in (iii)(A) or (B) above, determine:

(A) The NO_X concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E;

(B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10;

(C) The NMNEHC concentration, as propane, excluding formaldehyde of the exhaust gas using ALT-106 **and**

(D) The formaldehyde concentration of the exhaust gas, **if applicable**, using 40 CFR Part 63, Appendix A, Method 320.

(c) If at any time the owner or operator operates the engine in excess of the highest achievable load plus 10%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Engine Periodic Monitoring Requirements

(a) When conducting periodic monitoring on an engine, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.

(b) *Standardized Periodic Monitoring Procedure.*

(i) Conduct three test runs of at least 20 minutes duration within 10% of 100% peak (or the highest achievable) load.

(ii) Determine NO_X and CO emissions and O_2 concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) B) of this section.

(iii) If the measured NO_X or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test in accordance with the Performance Testing Requirements of Condition 4 above, within 180 days of the periodic monitoring.

(c) The 2,500 hours of operation count resets after any performance test performed in accordance with Condition 4 above.

(d) For engines constructed (as defined in that subpart) and authorized to operate prior to June 12, 2006, that installed a continuous parametric monitoring system (CPMS) to monitor the catalyst inlet temperature, the owner or operator must install, operate, and maintain the CPMS according to 40 CFR § 63.6625(b)(1) through (6).

SAMPLE

SECTION D. RECIPROCATING COMPRESSORS

1. BAT Compliance Requirements

The owner or operator of a reciprocating compressor constructed and authorized to operate on or after August 8, 2018, shall either:

(a) Replace the reciprocating compressor rod packing either:

(i) On or before 26,000 hours of operation from the initial startup date or most recent rod packing replacement; **or**

(ii) Prior to 36 months from the initial startup date of the reciprocating compressor or the date of the most recent rod packing replacement; **or**

(b) Collect the methane, VOC, and HAP emissions from the rod packing using a collection system that operates under negative pressure and routes the emissions to a process through a closed vent system that meets the applicable requirements of Section J.

2. Recordkeeping Requirements

For each reciprocating compressor, the owner or operator shall maintain records in accordance with Section A Condition 12, including information on:

(a) The location of the reciprocating compressor;

(b) The US Well Number the reciprocating compressor is associated with;

(c) The date and time of the initial startup of the reciprocating compressor;

(d) The date and time of the most recent rod packing replacement;

(e) The cumulative number of hours of operation or number of months since the initial startup of the reciprocating compressor or most recent rod packing replacement; and

(f) The date and time of installation of a rod packing emissions collection system and closed vent system.

In addition, records of the emissions calculation for each reciprocating compressor must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each reciprocating compressor operated during the reporting period shall include either:

(a) The records of the cumulative number of hours of operation or number of months since the startup of the reciprocation compressor or most recent rod packing replacement; **or**

(b) A statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

The emissions from each reciprocating compressor in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d), including the emissions from scheduled and unscheduled blowdowns.

SECTION E. STORAGE VESSELS

1. BAT Compliance Requirements

(a) For each storage vessel constructed and authorized to operate on or after August 23, 2011, but prior to August 10, 2013, the owner or operator shall meet the applicable requirements of 40 CFR §§ 60.5365(e) and 60.5395(d) and (e).

(b) For each storage vessel constructed and authorized to operate on or after August 10, 2013, but prior to August 8, 2018, with a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall equip the storage vessel with a cover and route all vapor through a closed vent system to a control device that reduces VOC emissions by 95% or more

SAMPLE

by meeting the applicable control, cover, and closed vent system requirements of Section J Condition 1(a) through (f) or any alternative method approved by the Department.

(c) For each storage vessel constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall equip the storage vessel with a cover and route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable control, cover, and closed vent system requirements of Section J Condition 1(a) through (f) or any alternative method approved by the Department.

(d) Any storage vessel returned to service must meet the requirements of 40 CFR § 60.5395(f) or § 60.5395a(c).

(e) Any storage vessel with a capacity greater than or equal to 2,000 gallons and less than or equal to 40,000 gallons must meet the requirements of 25 Pa. Code § 129.57.

(f) Any storage vessel with a capacity greater than or equal to 40,000 gallons must meet the requirements of 25 Pa. Code § 129.56, **if applicable**.

2. Recordkeeping Requirements

For each storage vessel, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(5) or § 60.5420a(c)(5) as applicable.

In addition, the emissions calculation for each storage vessel, which may be calculated using Department-approved methods such as direct measurement; modeling programs such as the most recent version of EPA TANKS, ProMax, and API E&P Tanks; process simulation software such as HYSIM, HYSIS, WINSIM, and PROSIM; or calculation methodologies such as the Vazquez-Beggs equation, must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each storage vessel in operation during the reporting period shall be submitted in accordance with 40 CFR § 60.5420(b)(6) or § 60.5420a(b)(6) as applicable.

The emissions from each storage vessel operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION F. TANKER TRUCK LOAD-OUT OPERATIONS

1. BAT Compliance Requirements

(a) For all truck load-out operations that service a storage vessel with a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed and authorized to operate on or after August 10, 2013, but prior to August 8, 2018, the owner or operator shall:

(i) Use a vapor balancing system when removing liquids from the storage vessel; **and**

(ii) Ensure that each tanker truck that is used to remove liquids from the storage vessel has passed one of the following annual leak tests:

(A) A tanker truck that does not indicate more than 1" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum has passed a MACT-level test and is assumed to have a collection efficiency of 99.2%.

(B) A tanker truck that does not indicate more than 3" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum has passed an NSPS-level test and is assumed to have a collection efficiency of 98.7%.

(C) A tanker truck that has passed a leak test performed in accordance with 49 CFR § 180.407 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.

(D) A tanker truck that has passed a leak test performed in accordance with 40 CFR Part 60, Appendix A-8, Method 27 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.

(iii) As an alternative, VOC emissions must be controlled with 95% or greater efficiency.

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(b) For all truck load-out operations that service a storage vessel with a total methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

(i) Use a vapor balancing system when removing liquids from the storage vessel; **and**

(ii) Ensure that each tanker truck that is used to remove liquids from the storage vessel has passed one of the following annual leak tests:

(A) A tanker truck that does not indicate more than 1" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum has passed a MACT-level test and is assumed to have a collection efficiency of 99.2%.

(B) A tanker truck that does not indicate more than 3" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum has passed an NSPS-level test and is assumed to have a collection efficiency of 98.7%.

(C) A tanker truck that has passed a leak test performed in accordance with 49 CFR § 180.407 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.

(D) A tanker truck that has passed a leak test performed in accordance with 40 CFR Part 60, Appendix A-8, Method 27 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.

(iii) As an alternative to (i) and (ii), VOC emissions must be controlled with 95% or greater efficiency.

2. Recordkeeping Requirements

For each tanker truck load-out operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The identification, location, and date of construction of each vapor recovery load-out system;

(b) Records of each tanker truck load-out operation including the date and time of the liquids load-out, the type and volume of liquids loaded, and the truck collection efficiency based on the annual leak test; and

(c) The emissions calculation for each tanker truck load-out operation in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from tanker truck load-out operations during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION G. FUGITIVE EMISSIONS COMPONENTS

1. BAT Compliance Requirements

(a) No later than 30 days after an emission source commences operation, and at least monthly thereafter, the owner or operator of a facility shall conduct an Auditory, Visual, or Olfactory (AVO) inspection.

(b) No later than 60 days after the start of production, and quarterly thereafter, the owner or operator shall conduct an LDAR program using either an OGI camera, a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, or other leak detection methods approved by the Division of Source Testing and Monitoring.

(i) The owner or operator of a well that is temporarily shut-in is not required to perform LDAR until 60 days after the well is put into production or the next quarterly inspection.

(ii) The owner or operator may request, in writing, an extension of the LDAR inspection interval from the Air Program Manager of the appropriate DEP Regional Office.

(iii) Any fugitive emissions components that are difficult-to-monitor or unsafe-to-monitor must be identified in the monitoring plan described in Condition 2(a).

(iv) The owner or operator may track the number of leaking components in the LDAR records and decrease the LDAR inspection interval from quarterly to semi-annually if the percentage of leaking components is

SAMPLE

less than 2.0% for two consecutive quarterly LDAR inspections. If the percentage of leaking components is higher than 2.0% in any inspection, a quarterly LDAR inspection interval must be resumed or maintained.

(c) The detection devices must be operated and maintained in accordance with manufacturer-recommended procedures, as required by the test method, or a Department-approved method.

(d) A leak is defined as:

(i) Any positive indication, whether audible, visual, or odorous, determined during an AVO inspection;

(ii) Any visible emissions detected by an OGI camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; **or**

(iii) A concentration of 500 ppm calibrated as methane or greater detected by an instrument reading.

(e) For quarterly inspections using a gas leak detector in accordance with 40 CFR Part 60, Appendix A-7, Method 21, the owner or operator may choose to adjust the detection instrument readings to account for the background organic concentration level as determined according to the procedures in Section 8.3.2.

(f) Any leak detected from a fugitive emission component shall be repaired by the owner or operator of the facility as expeditiously as practicable. A first attempt at repair must be attempted within 5 calendar days of detection, and repair must be completed no later than 15 calendar days after the leak is detected **unless**:

(i) The owner or operator must purchase parts, in which case the repair must be completed no later than 10 calendar days after the receipt of the purchased parts; **or**

(ii) The repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled well shutdown, well shut-in, after a planned vent blowdown or within 2 years, whichever is earlier.

(g) Once a fugitive emission component has been repaired or replaced, the owner or operator must resurvey the component as soon as practicable, but no later than 30 calendar days after the leak is repaired.

(i) For repairs that cannot be made during the monitoring survey when the leak is initially found, either a digital photograph must be taken of the component or the component must be tagged for identification purposes.

(ii) A leak is considered repaired if:

(A) There are no detectable emissions consistent with Section 8.3.2 of 40 CFR Part 60, Appendix A-7, Method 21;

(B) A leak concentration of less than 500 ppm as methane is detected when the gas leak detector probe inlet is placed at the surface of the component;

(C) There is no visible leak image when using an OGI camera calibrated at a detection sensitivity level of 60 grams/hour; **or**

(D) There is no bubbling at the leak interface using a soap solution bubble test specified in Section 8.3.3 of 40 CFR Part 60, Appendix A-7, Method 21.

(h) The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own, be preventing or interfering with the attainment or maintenance of an ambient air quality standard.

2. Recordkeeping Requirements

For fugitive emissions components, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The fugitive emissions monitoring plan in accordance with 40 CFR § 60.5397a(b) through (d).

(b) Records of each monitoring survey which must include:

(i) The facility name and location;

(ii) The GP-5A authorization number;

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(iii) The date, start time, and end time of the survey;

(iv) The name of the operator(s) performing the survey;

(v) The monitoring instrument used;

(vi) The ambient temperature, sky conditions, and maximum wind speed at the time of the survey;

(vii) Any deviations from the monitoring plan or a statement that there were none; **and**

(viii) Documentation of each fugitive emission including:

(A) The identification of each component from which fugitive emissions were detected;

(B) The instrument reading of each fugitive emissions component that meets the leak definition in Condition 1(d)(iii) of this section;

(C) The status of repair of each component including:

(1) The repair methods applied in each attempt to repair the component;

(2) The tagging or digital photographing of each component not repaired during the monitoring survey in which the fugitive emissions were discovered;

(3) The reasons a component was placed on delay of repair;

(4) The date of successful repair of the component; **and**

(5) The information on the instrumentation or method used to resurvey the component after repair, if it was not completed during the monitoring survey in which the fugitive emissions were discovered.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the records of each monitoring survey conducted during the reporting period shall be included.

The emissions from fugitive emissions components during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION H. NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS

1. BAT Compliance Requirements

(a) For pneumatic controllers constructed and authorized to operate on or after August 23, 2011, the owner or operator must meet the applicable requirements of 40 CFR § 60.5390(a) and (c)(1) or 40 CFR § 60.5390a(a) and (c)(1).

(b) Each controller must be tagged in accordance with 40 CFR § 60.5390(b)(2) and (c)(2) or 40 CFR § 60.5390a(b)(2) and (c)(2) as applicable.

2. Recordkeeping Requirements

For each controller, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(4) or § 60.5420a(c)(4) as applicable.

In addition, the emissions calculation for pneumatic controllers must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each controller during the reporting period shall be done in accordance with 40 CFR § 60.5420(b)(5) or § 60.5420a(b)(5) as applicable.

The emissions from each pneumatic controller in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

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SECTION I. NATURAL GAS-DRIVEN PNEUMATIC PUMPS

1. BAT Compliance Requirements

(a) For each natural gas-driven pneumatic diaphragm pump constructed and authorized to operate on or after September 18, 2015, but prior to August 8, 2018, the owner and operator shall meet the applicable requirements of 40 CFR § 60.5365a(h)(2) and § 60.5393a(b) and (e).

(b) For each natural gas-driven pneumatic pump constructed and authorized to operate on or after August 8, 2018, the owner or operator of a pump with:

(i) A methane emission rate of less than 200 tpy, a VOC emission rate of less than 2.7 tpy, a single HAP emission rate less than 0.5 tpy, and a total HAP emission rate less than 1.0 tpy, shall meet the applicable requirements of 40 CFR § 60.5365a(h)(1) and § 60.5393a(a) and (e).

(ii) A methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, shall route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable requirements of Section J.

2. Recordkeeping Requirements

For each natural gas-driven pneumatic diaphragm pump, the owner or operator shall maintain the following records in accordance with Section A Condition 12 and 40 CFR § 5420a(c)(16) as applicable.

(a) The location, date of installation, and manufacturer's specifications for each natural gas-driven pneumatic diaphragm pump.

(b) The emissions calculation for each natural gas-driven pneumatic diaphragm pump must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-driven pneumatic diaphragm pump in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION J. ENCLOSED FLARES AND OTHER EMISSION CONTROL DEVICES

1. BAT Compliance Requirements

(a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*

(i) The owner or operator of an enclosed flare or other enclosed combustion control device shall meet the requirements of 40 CFR § 60.5412(d)(1) and § 60.5415(e) or 40 CFR § 60.5412a(d)(1) and § 60.5415a(e) as applicable. The Department may allow open flares at remote locations and for infrequent operations, provided the flare is installed and operated consistent with 40 CFR § 60.18.

(ii) The owner or operator must conduct a performance test in accordance with Condition 4 within 180 days of initial startup of the affected facility **unless**:

(A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d);

(B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement;

(iii) The owner or operator must conduct performance tests in accordance with Condition 4 within 180 days of each reauthorization **unless**:

(A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d);

(B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement;

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(C) The Department uses EPA's National Stack Testing Guidance for stack test waivers; **or**

(D) The combustion control device established a correlation between the outlet TOC performance level and the firebox or combustion chamber temperature during the initial performance test.

(iv) The owner or operator of any combustion control device that is a manufacturer-tested model shall meet the requirements of 40 CFR § 60.5413(e) or § 60.5413a(e) as applicable.

(b) *Vapor Recovery Devices.*

(i) The owner or operator of a vapor recovery device shall meet the requirements of 40 CFR § 60.5412(d)(2) and § 60.5415(e) or 40 CFR § 60.5412a(d)(2) and § 60.5415a(e) as applicable.

(ii) The owner or operator shall conduct a performance test in accordance with Condition 4 and 40 CFR § 60.5413(b)(5) or § 60.5413a(b)(5) as applicable.

(iii) The owner or operator of any vapor recovery device shall conduct a monthly AVO inspection in accordance with 40 CFR § 60.5417(h)(2) or § 60.5417a(h)(2) as applicable.

(iv) If the vapor recovery device is a carbon adsorption unit, the owner or operator shall meet the requirements of 40 CFR § 60.5412(c) or § 60.5412a(c) as applicable.

(c) *External Floating Roof.*

(i) An external floating roof shall meet the requirements of 40 CFR § 60.112b(a)(2) and 25 Pa. Code § 129.56(b) as applicable.

(ii) Perform a gap measurement test in accordance with 40 CFR § 60.113b for mechanical shoe or liquid-mounted primary seals.

(iii) Perform a gap measurement test in accordance with 25 Pa. Code § 129.56(b)(iii) for a vapor-mounted primary seal.

(d) *Internal Floating Roof.*

(i) An internal floating roof shall meet the requirements of 40 CFR § 60.112b(a)(1) and 25 Pa. Code § 129.56(c) as applicable.

(ii) Visually inspect the internal floating roof, primary seal, and secondary seal (if equipped) in accordance with 40 CFR § 60.113b(a).

(e) *Covers.*

(i) The cover and all openings on the cover shall meet the requirements of 40 CFR § 60.5411(b) and § 60.5416(a)(3) or 40 CFR § 60.5411a(b) and § 60.5416a(a)(3) as applicable.

(ii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(a). Defects include, but are not limited to, visible cracks, holes, or gaps in the cover or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

(iii) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(f) and (g).

(f) *Closed Vent Systems.*

(i) The owner or operator shall conduct an assessment in accordance with 40 CFR § 60.5411a(d), **if applicable.**

(ii) The owner or operator shall design and operate the closed vent system with no detectable emissions, as determined in accordance with 40 CFR § 60.5411(a) and (c) and § 60.5416(a) through (c) or 40 CFR § 60.5411a(a) and (c) and § 60.5416a(a) through (c) as applicable.

(iii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(a). Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; and broken or missing caps or other closure devices.

(iv) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(f) and (g).

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2. Recordkeeping Requirements

For each control device, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*

(i) For non-manufacturer tested models, the owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(13) and (14) or § 60.5420a(c)(13) and (14) as applicable.

(ii) For manufacturer tested models the owner or operator must maintain records in accordance with 40 CFR § 60.5413(d)(12) and (e) or § 60.5413a(d)(12) and (e) as applicable.

(iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable**.

(b) *Vapor Recovery Devices.*

(i) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(12) through (14) or § 60.5420a(c)(12) through (14) as applicable.

(ii) The design analysis in accordance with 40 CFR § 60.5413(c) or § 60.5413a(c), as applicable.

(iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable**.

(c) *External Floating Roof.*

(i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and

(ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable**.

(d) *Internal Floating Roof.*

(i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and

(ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable**.

(e) *Covers.*

(i) The owner or operator must maintain records in accordance with Section G Condition 2(b).

(f) *Closed Vent Systems.*

(i) The owner or operator must maintain records in accordance with Section G Condition 2(b).

(ii) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(8) and (9).

(iii) The owner or operator must maintain records of the assessment, including the engineer's certification, in accordance with 40 CFR § 60.5420a(c)(17), **if applicable**.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each control device in operation during the reporting period shall be done in accordance with 40 CFR § 60.5420(b) or § 60.5420a(b) as applicable.

4. Control Device Performance Testing Requirements

(a) When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14(f) for review and approval. The owner or operator should conduct the following test procedures. Conduct three test runs of at least one-hour duration while operating the control device within 5% of required operating temperature.

SAMPLE

(b) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter.

(i) If demonstrating compliance with a percent reduction requirement, sampling sites must be located at the inlet of the first control device and the outlet of the final control device; **or**

(ii) If demonstrating compliance with an outlet concentration requirement, the sampling site must be located at the outlet of the control device.

(c) Determine the effluent characteristics including:

(i) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;

(ii) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**

(iii) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.

(d) To demonstrate compliance with (b)(i), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the Total Organic Compounds (TOC) and then convert to dry basis using the moisture content from (c)(iii) above and calculate the inlet and outlet mass rates as propane and the percent reduction.

(e) To demonstrate compliance with (b)(ii), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the TOC and 40 CFR Part 60, Appendix A-6, Method 18 to determine the methane and ethane concentration, and then correct the TOC concentration, minus methane and ethane, for percent oxygen from (c)(ii) above.

5. Control Device Periodic Monitoring Requirements

The owner or operator that installs a CPMS must install, operate, and maintain the CPMS according to 40 CFR § 60.5415 and § 60.5417 or 40 CFR § 60.5415a and § 60.5417a as applicable.

SECTION K. PIGGING OPERATIONS

1. BAT Compliance Requirements

(a) The owner or operator that conducts pigging operations shall employ best management practices to minimize the liquids present in the pig receiver chamber and to minimize emissions from the pig receiver chamber including, but not limited to, installing liquids ramps, installing liquids drain, routing high-pressure chambers to a low-pressure line or vessel, using ball valve type chambers, or using multiple pig chambers. The selection of the appropriate best management practices must be documented in the application.

(b) For pigging operations with a methane emission rate of 200 tpy or greater, or a VOC emission rate of 2.7 tpy or greater, or a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, after employing best management practices, the owner or operator shall control methane, VOC, and HAP emissions from all pigging operations by at least 95% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device, or any alternative method approved by the Department that meets the applicable requirements in Section J.

2. Recordkeeping Requirements

For each pigging operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

(a) The identification, location, and date of construction of each pig launcher or receiver;

(b) Records of each pigging operation including the identification of the pig chamber used, the date and time of the pigging operation, and the type and volume of liquids cleared; **and**

(c) The emissions calculation for each pig chamber, using the Department's spreadsheet found at http://files.dep.state.pa.us/ or other equivalent method.

3. Reporting Requirements

The emissions from each pigging operation conducted during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

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SECTION L. WELLBORE LIQUIDS UNLOADING OPERATIONS

1. BAT Compliance Requirements

The owner or operator that conducts wellbore liquids unloading operations shall use best management practices including, but not limited to, plunger lift systems, soaping, swabbing, unless venting is necessary for safety to mitigate emissions during liquids unloading activities. In all cases, where technically feasible and safe, the owner or operator shall direct the gas generated during liquids unloading to a control device, a gas production line or existing separator or storage vessel which is controlled. The selection of the appropriate best management practices must be documented in the application.

2. Recordkeeping Requirements

For each well, the owner or operator shall maintain records of each unloading operation that results in emissions to the atmosphere in accordance with Section A Condition 12 containing the following information:

(a) The US Well number and location of the well;

(b) The date and time of each wellbore liquids unloading operation;

(c) The wellbore liquids unloading technique used during each unloading operation;

(d) The disposition of the associated gas from each wellbore liquids unloading operation;

(e) The duration of the wellbore liquids unloading operation; **and**

(f) The emissions calculation for each wellbore liquids unloading operation in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each wellbore liquids unloading operation conducted during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

Issued by: _____

Krishnan Ramamurthy
Director
Bureau of Air Quality

Date Issued: _____

Date Effective: _____

SAMPLE

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS
(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

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PART F Statements of Basis, Specific Statutory Authority and Purpose

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Pursuant to Colorado Revised Statutes Section 24-4-103 (12.5), materials incorporated by reference are available for public inspection during normal business hours, or copies may be obtained at a reasonable cost from the Air Quality Control Commission (the Commission), 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.govinfo.gov. Materials incorporated by reference are those editions in existence as of the date indicated and do not include any later amendments.

PART A Applicability and General Provisions

I. Applicability

I.A.

I.A.1. The provisions of this regulation shall apply as follows:

I.A.1.a. All provisions of this regulation apply to the Denver 1-hour ozone attainment/maintenance area, to any nonattainment area for the 1-hour ozone standard, and to the 8-hour Ozone Control Area.

I.A.1.b. (State Only) All provisions of this regulation apply to any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Section I.A.1.c. Colorado's ozone nonattainment or attainment maintenance area maps and chronologies of attainment status are identified in Appendix A of this regulation.

I.A.1.c. The provisions of Part B, Sections III., IV.B.1. and 2., V.C., and Part D, Sections II., III., IV., and V. apply statewide. The provisions of Part D, Sections II., III., and any other sections marked by (State Only) are not federally enforceable, unless otherwise identified.

I.A.2. REPEALED

I.A.3. REPEALED

I.B. Sources

I.B.1. New Sources

I.B.1.a. New sources, defined as any sources which either (1) submit a complete permit application on or after October 30, 1989, or (2) if no permit is required, commence operation on or after October 30, 1989, must comply with the provisions of this regulation upon commencement of operation.

I.B.1.b. (State Only) New sources are any sources which commenced construction on or after the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989. New sources shall comply with the requirements of this regulation by whichever date comes later:

I.B.1.b.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.1.b.(ii) (State Only) February 1, 2009, if they are located in an 8-Hour Ozone Control Area and outside of the 1-hour ozone nonattainment or attainment maintenance area; or

I.B.1.b.(iii) (State Only) Upon commencement of operation, if located within an ozone nonattainment or attainment maintenance area.

I.B.1.c. This Section I.B.1. does not apply to oil and gas operations subject to Part D, Section I., stationary and portable engines subject to Part E, Section I.A. through C., or natural gas actuated pneumatic controllers subject to Part D, Section III.

I.B.2. Existing Sources

I.B.2.a. Existing sources are (1) those sources for which a complete permit application was submitted prior to October 30, 1989, or (2) those sources, which commenced operation prior to October 30, 1989.

I.B.2.b. (State Only) Existing sources are those sources which commenced construction prior to the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989.

I.B.2.c. Existing sources shall not be required to comply with requirements of this regulation until on and after October 30, 1991. All existing sources shall comply with the requirements set forth in Exhibit A until October 30, 1991.

I.B.2.d. (State Only) Existing sources shall be required to comply with requirements of this regulation by whichever date comes later:

I.B.2.d.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.2.d.(ii) (State Only) February 1, 2009, if they are located in an 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area; or

I.B.2.d.(iii) (State Only) the date on which the area is first designated as being in nonattainment for ozone, if located within that ozone nonattainment or attainment maintenance area.

I.B.2.e. On and after October 30, 1991, all existing sources shall comply with the requirements of this regulation, and Exhibit A shall no longer be applicable.

I.B.2.f. Repealed.

I.B.2.g. Repealed.

I.B.2.h. This Section I.B.2. does not apply to oil and gas operations subject to Part D, Section I., or stationary and portable engines subject to Part E, Section I.A. through C.

I.C. Once a source subject to this regulation exceeds an applicable threshold limit, the requirements of this regulation are irrevocably effective unless the source obtains a federally enforceable permit limiting emissions to levels below the threshold limit by restricting production capacity or hours of operation.

I.D. The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

II. General Provisions

II.A. Definitions

II.A.1. "8-Hour Ozone Control Area" means the Counties of Adams, Arapahoe, Boulder (includes part of Rocky Mountain National Park), Douglas, and Jefferson; the Cities and Counties of Denver and Broomfield; and the following portions of the Counties of Larimer and Weld:

II.A.1.a. For Larimer County (includes part of Rocky Mountain National Park), that portion of the county that lies south of a line described as follows: Beginning at a point on Larimer County's eastern boundary and Weld County's western boundary intersected by 40 degrees, 42 minutes, and 47.1 seconds north latitude, proceed west to a point defined by the intersection of 40 degrees, 42 minutes, 47.1 seconds north latitude and 105 degrees, 29 minutes, and 40.0 seconds west longitude, thence proceed south on 105 degrees, 29 minutes, 40.0 seconds west longitude to the intersection with 40 degrees, 33 minutes and 17.4 seconds north latitude, thence proceed west on 40 degrees, 33 minutes, 17.4 seconds north latitude until this line intersects Larimer County's western boundary and Grand County's eastern boundary.

II.A.1.b. For Weld County, that portion of the county that lies south of a line described as follows: Beginning at a point on Weld County's eastern boundary and Logan County's western boundary intersected by 40 degrees, 42 minutes, 47.1 seconds north latitude, proceed west on 40 degrees, 42 minutes, 47.1 seconds north latitude until this line intersects Weld County's western boundary and Larimer County's eastern boundary.

II.A.2. "Denver 1-Hour Ozone Attainment/Maintenance Area" means the Counties of Jefferson and Douglas, the Cities and Counties of Denver and Broomfield, Boulder County (excluding Rocky Mountain National Park), Adams County west of Kiowa Creek, and Arapahoe County west of Kiowa Creek.

II.A.3. "Capture System" means the equipment used to contain, capture, or transport a pollutant to a control device.

II.A.4. "Capture System Efficiency (vapor gathering system efficiency)" means the percent by weight of VOC emitted by an operation subject to this regulation, which is captured by the capture system and sent to the control device; i.e., (mass flow of VOC captured)/(mass flow of VOC emitted by the operation) x 100%.

II.A.5. "Carbon Adsorption System" means a device containing adsorbent material, an inlet and outlet for exhaust gases and a system to regenerate the saturated adsorbent.

II.A.6. "Condenser" means any heat transfer device used to liquefy vapors by removing their latent heats of vaporization. Such devices include, but are not limited to, shell and tube, coil, surface, or contact condensers.

II.A.7. "Control Device" means a carbon adsorber, refrigeration system, condenser, flare, firebox or other device, which will reduce the concentration of VOC in a gas stream by adsorption, combustion, condensation, or other means of removal.

II.A.8. "Control Device Efficiency" means the percent removal by weight of VOC by a control device; i.e., (mass flow of VOC into control device - mass flow of VOC out of control device)/(mass flow of VOC into control device) x 100%.

II.A.9. "Gasoline" means a petroleum distillate having a Reid vapor pressure between 208 and 1040 torr (4-20 psi), which is used as fuel for internal combustion engines.

II.A.10. "Highly Volatile Organic Compound" is defined as a Volatile Organic Compound or mixture of such compounds with a true vapor pressure in excess of 570 torr (11 psia) at 20 C.

II.A.11. “Organic Material” means a chemical compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.

II.A.12. (State Only) “Ozone Nonattainment Area” means any area designated as not in attainment with the ozone National Ambient Air Quality Standard as determined by the Environmental Protection Agency.

II.A.13. “Petroleum Refinery” means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

II.A.14. “Reid Vapor Pressure” means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquefied petroleum gases as determined by the American Society for Testing and Materials, Part 17, 1973, D-323-72 (Reapproved 1977).

II.A.15. “True Vapor Pressure” means the equilibrium partial pressure exerted by petroleum (or other) liquid. This may be determined by the methods described in American Petroleum Institute Bulletin 2517, “Evaporation Loss from Floating Roof Tanks,” 1962.

II.A.16. “Vapor Recovery System” means a system that prevents release to the atmosphere of organic compounds emitted during the operation of any transfer, storage, or processing equipment.

II.A.17. "Volatile Organic Compound (VOC)" means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions, except those listed in Section II.B. as having negligible photochemical reactivity. VOC may be measured by a reference method, an equivalent method, an alternative method, or by procedures specified under 40 CFR Part 60 (September 14, 1989). A reference method, an equivalent method, or an alternative method, however, may also measure nonreactive organic compounds. In such cases, an owner or operator may exclude the compounds listed in Section II.B. when determining compliance with a standard if the amount of such compounds is accurately quantified, and such exclusion is approved by the Division. As a precondition to excluding such compounds as VOC, or at any time thereafter, the Division may require an owner or operator to provide monitoring or testing methods and results demonstrating, to the satisfaction of the Division, the amount of negligible-reactive compounds in the source's emissions.

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation. However, the hydrocarbon threshold in Part D, Section I.L. and natural gas emissions standards in Part D, Sections III.C.1. and III.C.2. are used as indicators for the volatile organic compound emission reduction measures in Part D, Sections I.L., III.C.1., and III.C.2., and are enforceable provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Part D.

II.C. General Emission Limitation

II.C.1. Existing Sources (State Only: Located in any Ozone Nonattainment Area or Attainment Maintenance Area)

II.C.1.a. All existing sources shall comply with the requirements set forth in this regulation.

II.C.1.a.(i) Existing sources of VOC which are not subject to specific emission limitations set forth in this regulation, and which have the potential to emit 100 tons per year or more of VOC, shall utilize Reasonably Available Control Technology (RACT).

II.C.1.a.(ii) The potential to emit of such sources shall be based on design capacity or maximum production rate, whichever is greater, 8,760 hours'/year operation, and before add-on controls.

II.C.1.a.(iii) Owners or operators of such sources with potential emissions of 100 tons per year or more, but with actual emissions less than 100 tons per year may obtain a federally enforceable permit limiting emissions to actual rates by restricting production capacity or hours of operation, thus avoiding RACT requirements.

The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

II.C.1.a.(iv) Such sources with potential emissions of 100 tons per year or more but with actual emissions of less than 50 tons per year, on a rolling 12-month total, may avoid RACT and permit requirements if the following requirements are met:

II.C.1.a.(iv)(A) The owner or operator shall submit revised Air Pollutant Emission Notices (APENs) by April 1 of each year, which demonstrate that the 50 tons per year threshold has not been exceeded.

II.C.1.a.(iv)(B) The owner or operator shall maintain records on site which include monthly VOC use and monthly VOC emissions. The records shall include calculation of total emissions for each rolling 12-month period. The records shall be made available to the Division for inspection upon request.

II.C.1.a.(v) (State Only) Existing sources that are modified – undergo any physical change, or changed in the method of operation of a stationary source which increase VOC or NOx emissions – on or after March 30, 2008, shall utilize RACT control technologies pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. upon recommencing operation.

II.C.1.b. Provided however, that no existing source of VOC emissions employing emission controls on or within the six-month period preceding the effective date of this regulation may reduce its level of control of VOC emissions below that level of control actually achieved, even though such source may otherwise be subject to less stringent control requirements, except that no existing source shall be required to control emissions to an extent greater than that level of control which RACT would achieve.

II.C.1.c. (State Only) Existing sources with potential emissions equal to or greater than 100 tons per year of volatile organic compound emissions shall submit a permit modification application that includes a revised APEN (or APENs) and a RACT analysis, to the Division, as follows:

II.C.1.c.(i) (State Only) By October 30, 1991 if located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area; or

II.C.1.c.(ii) (State Only) By April 30, 2009 or within one year after the date on which the area is first designated as being in nonattainment for ozone, whichever comes later, if they are located in the 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area.

II.C.1.d. (State Only) Existing sources shall utilize RACT pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. by whichever date comes later:

II.C.1.d.(i) (State Only) October 30, 1991, if they are located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area;

II.C.1.d.(ii) (State Only) November 21, 2011, if they are located in the 8-hour Ozone Control Area, and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area;

II.C.1.d.(iii) (State Only) Three years after the date on which the area is first designated as being in nonattainment for ozone; or

II.C.1.d.(iv) (State Only) Two years after Division determination of case-by-case RACT pursuant to this Section II.C.1. The Division shall be deemed to have approved the RACT analysis for purposes of this Section II.C.1.d.(iv) if it does not object after eighteen months from having received a complete permit application.

II.C.2. New Sources

All new sources shall utilize controls representing RACT, pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D., upon commencement of operation.

II.D. Alternative Control Plans and Test Methods

II.D.1. Sources subject to specific requirements of this regulation shall submit for approval as a revision to the State Implementation Plan:

II.D.1.a. Any alternative emission control plan or compliance method other than control options specifically allowed in the applicable regulation. Such alternative control plans shall provide control equal to or greater than the emission control or reduction required by the regulation, unless the source contends that the control level required by the regulation does not represent RACT for their specific source.

II.D.1.b. Any alternative test method or procedure not specifically allowed in the applicable regulation.

II.D.2. No alternative submitted pursuant to this Section II.D. is effective until the alternative is approved as a revision to the State Implementation Plan.

II.E. REPEALED

II.F. Provisions for Specific Processes

II.F.1. The Gates Rubber Company Provision – REPEALED

Appendix A Colorado Ozone Nonattainment or Attainment Maintenance Areas

I. Chronology of Attainment Status

Denver Metropolitan Area Only

1978	Denver 1-hour Ozone Nonattainment Area designation first becomes effective in 7-county Denver Metropolitan Area
10/11/01	Denver 1-hour Ozone Attainment Maintenance Area designation replaces non-attainment designation and becomes effective in 7-county Denver Metropolitan Area
9/2/05	1-hour Ozone National Ambient Air Quality Standard is Revoked in Colorado except for the Denver 1-hour Ozone Attainment Maintenance Area.

Denver Metropolitan Area and North Front Range

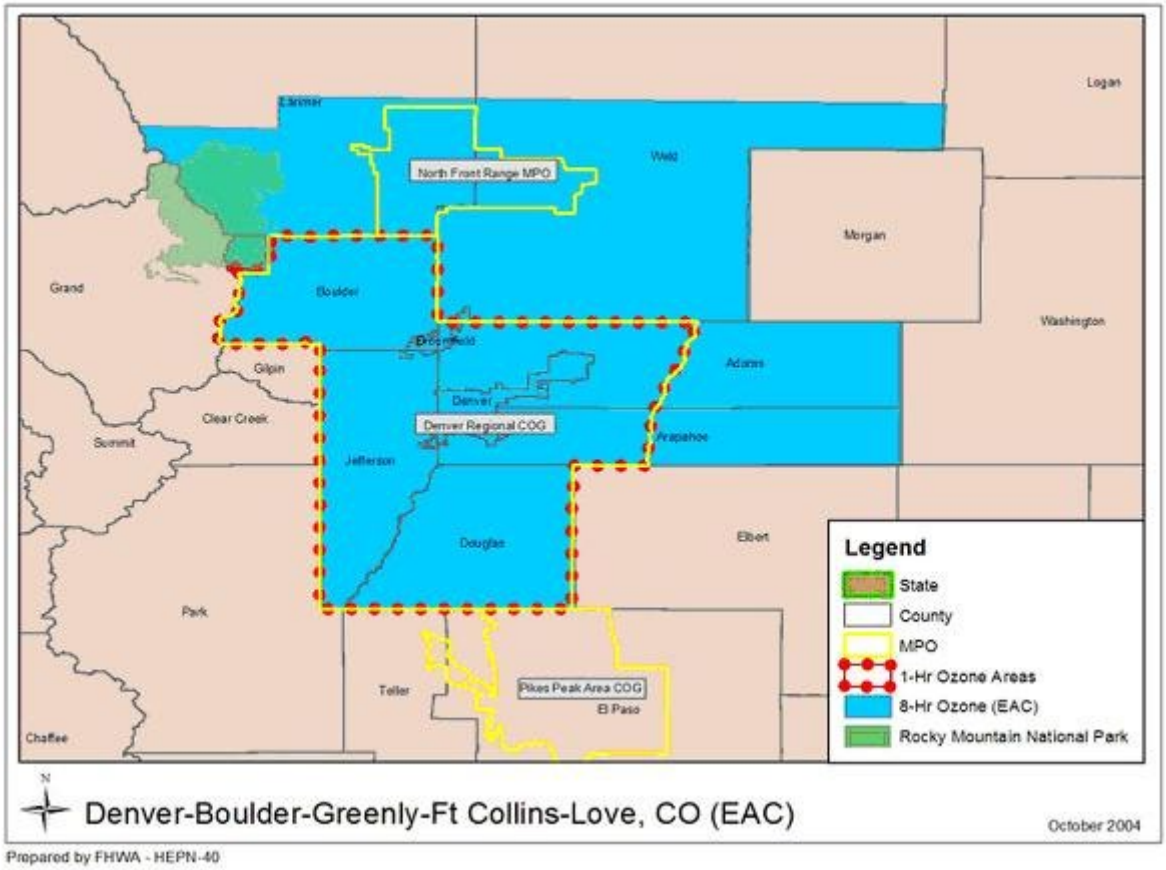
10/11/01 1-hour attainment maintenance area replaces non-attainment designation for the Denver Metro Area/North Front Range Area

4/15/04 EPA designates the Denver Metro Area/North Front Range region as an 8-hour ozone non-attainment area, designation deferred due to the implementation of the Early Action Compact

11/20/07 Denver 8-hour ozone non-attainment designation becomes effective in 9 county Denver Metropolitan Area

II. Maps

Denver Metropolitan Area and North Front Range



PART B Storage, Transfer, and Disposal of Volatile Organic Compounds and Petroleum Liquids and Petroleum Processing and Refining

I. General Requirements for Storage and Transfer of Volatile Organic Compounds

I.A. Maintenance and Operation of Storage Tanks and Related Equipment

All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing and monitoring shall be conducted as in Part B, Section VI.C.3.

I.B. Transfer (excluding Petroleum Liquids)

Except as otherwise provided in this regulation, all volatile organic compounds transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

I.C. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of Section I.B.

II. Storage of Highly Volatile Organic Compounds

II.A. Highly volatile organic compounds shall be stored:

II.A.1. In a pressure tank which is at all times capable of maintaining working pressures sufficient to prevent vapor loss to the ambient air; or

II.A.2. With methods and/or equipment approved by the Division in writing pursuant to the request of the person owning or operating the storage facility.

II.B. Vapor loss shall be determined visually, by presence of frost or condensation at the point of leakage, or using a portable hydrocarbon analyzer. When an analyzer is used, vapor loss means a VOC concentration exceeding 10,000 ppm and testing and monitoring procedures shall be conducted as in Part B, Section VI.C.3.

III. Disposal of Volatile Organic Compounds

III.A. No person shall dispose of volatile organic compounds by evaporation or spillage unless RACT is utilized.

III.B. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

IV. Storage and Transfer of Petroleum Liquid

IV.A. General Requirements

IV.A.1. No person shall build, install, or permit the building or installation of any rotating pump or compressor handling any type of petroleum liquid unless said pump or compressor is equipped with mechanical seals or other equipment of equal efficiency. If reciprocating-type pumps and compressors are used, they shall be equipped with packing glands properly installed, in good working order, and properly maintained so that no detectable emissions occur from the drain recovery systems.

IV.A.2. Definitions

For the purpose of this section, the following definitions apply:

IV.A.2.a. Repealed.

IV.A.2.b. "Crude Oil" means a naturally occurring mixture which consists of hydrocarbons, sulfur, nitrogen or oxygen derivatives of hydrocarbons, and which is a liquid at standard conditions.

IV.A.2.c. "Custody Transfer" means the transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

IV.A.2.d. "EFR Tank" means a storage vessel having an external floating roof.

IV.A.2.e. "External Floating Roof" means a storage vessel cover in an open top tank consisting of a double deck or pontoon single deck which rests upon and is supported by the petroleum liquid being contained and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

IV.A.2.f. “Liquid-Mounted Seal" means a primary seal mounted in continuous contact with the contained liquid and which occupies an annular space between the inner tank wall and the perimeter of the floating roof.

IV.A.2.g. "Petroleum Liquid" means crude oil, condensate and any finished or intermediate product manufactured or extracted in a petroleum refinery.

IV.A.2.h. "Shoe Seal" means a primary seal employing a metallic band (called a shoe) which is held against the vertical inner-wall of the tank, concentric with the perimeter of the floating roof.

IV.A.2.i. "Vapor Balance System" means a combination of pipes or hoses that create a closed system between the vapor spaces of an unloading tank and a receiving tank such that vapors displaced from the receiving tank are transferred to the tank being unloaded.

IV.A.2.j. “Vapor Collection System” means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.

IV.A.2.k. "Vapor-Mounted Seal" means a primary seal mounted so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the liquid surface, the floating roof, and the tank wall (thus excluding shoe seals).

IV.A.2.l. "Waxy, Heavy Pour Crude Oil" means a crude oil with a pour point of 10°C (50°F) or higher as determined by the American Society for Testing and Materials Standard D97-66, "Test for Pour Point of Petroleum Oils."

IV.B. Storage of Petroleum Liquid

IV.B.1. Exemptions

IV.B.1.a. Tanks or other containers used to store the following liquids are exempt from the provisions of Sections IV.B.2. and IV.B.3.:

IV.B.1.a.(i) Diesel Fuels 1-D, 2-D, and 4-D as defined in ASTM D975-78.

IV.B.1.a.(ii) Fuel Oils #1, #2, #3, #4, and #5, as defined in ASTM D396-78.

IV.B.1.a.(iii) Gas Turbine Fuels 1-GT through 4-GT as defined in ASTM D2880-78.

IV.B.1.b. The following underground storage facilities are exempt from Section IV.B.2.:

IV.B.1.b.(i) Underground tanks if the annual sum total of the volume of liquid removed from the tank plus the sum of the volume of liquid added to it does not exceed twice the operational volume of the tank (i.e., a maximum of one turnover per year is allowed).

IV.B.1.b.(ii) Subsurface caverns or porous rock reservoirs.

IV.B.1.b.(iii) Horizontal underground tanks storing JP-4 Jet Fuel.

IV.B.2. Storage of petroleum liquid in tanks greater than 151,412 liters (40,000 gallons)

IV.B.2.a. Storage of petroleum liquid in fixed-roof tanks.

IV.B.2.a.(i) The owner or operator of a fixed-roof tank used for storage of petroleum liquids which have a true vapor pressure greater than 33.6 torr (0.65 psia) at 20°C (or, alternatively, a Reid vapor pressure greater than 1.30 pounds - (67.2 torr) but not greater than 570 torr (11.0 psia) at 20°C, and which are stored in any tank or other container of more than 151,412 liters (40,000 gallons) shall ensure that the tank at all times meets the following conditions:

IV.B.2.a.(i)(A) The tank has been equipped with a pontoon-type, or double-deck type, floating roof or an internal floating cover which rests on the surface of the liquid contents and which is equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and tank walls; or

IV.B.2.a.(i)(B) The tank has been equipped with a vapor gathering system capable of collecting the petroleum liquid vapors discharged, together with a vapor recovery or disposal system capable of processing such vapors so as to prevent their emission into the atmosphere.

IV.B.2.a.(i)(C) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections III.A.3.a., b., c., and e., and III.A.8.a. and b.

IV.B.2.a.(i)(D) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.B.2.a.(i)(E) The owner or operator shall maintain records for at least two years of the type, average monthly storage temperature, and true vapor pressure of all petroleum liquids stored in tanks not equipped with an internal floating roof or cover or other control pursuant to Regulation Number 7, Sections IV.B.2.a.(i)(A) or IV.B.2.a.(i)(B) or Part A, Section II.D.

IV.B.2.a.(ii) No owner or operator of a fixed-roof tank equipped with an internal floating roof or cover shall permit the use of such tank unless:

IV.B.2.a.(ii)(A) The tank is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; and

IV.B.2.a.(ii)(B) All openings, except stub drains, are equipped with covers, lids, or seals such that:

IV.B.2.a.(ii)(B)(1) The cover, lid, or seal is in the closed position at all times except when in actual use;

IV.B.2.a.(ii)(B)(2) Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports; and

IV.B.2.a.(ii)(B)(3) Rim vents, if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

IV.B.2.a.(iii) The operator of a fixed-roof tank equipped with an internal floating roof shall:

IV.B.2.a.(iii)(A) Perform a routine inspection through the tank roof hatches at least once every six months;

IV.B.2.a.(iii)(A)(1) During the routine inspection, the operator shall measure for detectable vapor loss inside the hatch. Detectable vapor loss means a VOC concentration exceeding 10,000 ppm, using a portable hydrocarbon analyzer.

IV.B.2.a.(iii)(B) Perform a complete inspection of the cover and seal whenever the tank is out of service, whenever the routine inspection required in Section IV.B.2.a.(iii)(A) reveals detectable vapor loss, and at least once every ten years, and shall notify the Division in writing before such an inspection.

IV.B.2.a.(iii)(C) Ensure during inspections that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; that the cover is floating uniformly on or above the liquid surface; that there are no visible defects in the surface of the cover or liquid accumulated on the cover; and that the seal is uniformly in place around the circumference of the cover between the cover and the tank wall. If these items are not met, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this section cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Division in writing. Such a request must document that alternative storage capacity is unavailable and specify a schedule of actions the owner or operator will take that will assure that the items will be repaired or the vessel will be emptied as soon as possible;

IV.B.2.a.(iii)(D) Maintain records for at least two years of the results of all inspections.

IV.B.2.b. Above ground storage tanks used for the storage of petroleum liquid shall have all external surfaces coated with a material which has a reflectivity for solar radiation of 0.7 or more. Methods A or B of ASTM E424 shall be used to determine reflectivity. Alternatively, any untinted white paint may be used which is specified by the manufacturer for such use.

This provision shall not apply to written symbols or logograms applied to the external surface of the container for purposes of identification provided such symbols do not cover more than 20% of the exposed top and side surface area of the container or more than 18.6 square meters (200 square feet), whichever is less.

IV.B.2.c. Seals on External Floating Roof Tanks

IV.B.2.c.(i) General Provisions

IV.B.2.c.(i)(A) Applicability

This section applies to all petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 150,000 liters (40,000 gallons) that are located in ozone nonattainment areas.

IV.B.2.c.(i)(B) Exemptions

IV.B.2.c.(i)(B)(1) Total Exemption

The following categories of EFR tanks are exempt from the requirement of Section IV.B.2.c., except for the applicable recordkeeping requirements of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(1)(a) EFR tanks which store any material whose true vapor pressure as stored never exceeds 67 torr (1.3 psia).

IV.B.2.c.(i)(B)(1)(b) Tanks less than 1,600,000 liters (10,000 barrels) which are used to store crude oil and condensate prior to custody transfer.

IV.B.2.c.(i)(B)(2) Limited Exemptions

The following are exempt from both secondary seal and secondary seal inspection requirements but shall meet the equipment/procedure provisions in Section IV.B.2.c.(ii)(A)(1), the semi-annual inspection provisions of Section IV.B.2.c.(ii)(B), and the record keeping provisions of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(2)(a) Those tanks storing petroleum liquid between 67 and 207 torr (1.3 to 4.0 psia) maximum true vapor pressure (as stored) which are of welded construction and which have one of the following primary seals:

IV.B.2.c.(i)(B)(2)(a)(I) metallic shoe seal

IV.B.2.c.(i)(B)(2)(a)(II) liquid mounted, resilient seal

IV.B.2.c.(i)(B)(2)(a)(III) liquid mounted, liquid filled seal

IV.B.2.c.(i)(B)(2)(b) Any tank storing waxy, heavy-pour crude oil.

IV.B.2.c.(ii) General Requirements

IV.B.2.c.(ii)(A) An operator of an EFR tank storing petroleum liquids with true vapor pressure (as stored) above 67 torr (1.3 psia) shall equip the tank as follows and observe the following procedures:

IV.B.2.c.(ii)(A)(1) Equipment

IV.B.2.c.(ii)(A)(1)(a) Drains: roof drains which are designed to empty directly into the stored product shall be provided with slotted-membrane fabric covers or equivalent covers which cover at least 90 percent of the area of the opening.

IV.B.2.c.(ii)(A)(1)(b) Openings: except for automatic bleeder vents, rim space vents, and leg sleeves, all openings shall be equipped with:

IV.B.2.c.(ii)(A)(1)(b)(I) Projections into the tank which remain below the liquid surface at all times; and

IV.B.2.c.(ii)(A)(1)(b)(II) Covers, seals, or lids.

IV.B.2.c.(ii)(A)(2) Procedures

IV.B.2.c.(ii)(A)(2)(a) Covers, seals and lids shall be kept closed except when the openings are in actual use.

IV.B.2.c.(ii)(A)(2)(b) Automatic bleeder vents shall be kept closed at all times except when the roof is floated off or landed on roof leg supports.

IV.B.2.c.(ii)(A)(2)(c) Rim vents shall be set to open at the manufacturer's recommended setting or, alternatively, only when the roof is being floated off the leg supports.

IV.B.2.c.(ii)(B) Inspections

The operator of an EFR tank subject to this Section IV.B.2.c. shall:

IV.B.2.c.(ii)(B)(1) Perform routine inspections at least once every six months in order to ensure compliance with Section IV.B.2.c.(ii)(B)(2). The inspections shall include a visual inspection of the secondary seal gap if equipped with a secondary seal.

IV.B.2.c.(ii)(B)(2) Ensure that all seal closure devices meet the following requirements:

IV.B.2.c.(ii)(B)(2)(a) There are no visible holes, tears, or other openings in the seal(s) or seal fabric; and

IV.B.2.c.(ii)(B)(2)(b) The seal(s) are intact and uniformly in place around the circumference of the floating roof and the tank wall.

IV.B.2.c.(ii)(C) Records

IV.B.2.c.(ii)(C)(1) Operators shall:

IV.B.2.c.(ii)(C)(1)(a) Maintain records of the average monthly storage temperature, the Reid vapor pressure of the liquid and the type of liquid stored for all EFR tanks lacking secondary seals and receiving petroleum liquids with a true vapor pressure of 1.0 psi (7.0kPa) or greater; and

IV.B.2.c.(ii)(C)(1)(b) Maintain records of the results of the inspections required herein.

IV.B.2.c.(ii)(C)(2) Copies of all records specified by this Section IV.B.2.c.(ii)(C) shall be retained by the operator for a minimum of two years after the date on which the record was made.

IV.B.2.c.(iii) Secondary Seal Requirements

IV.B.2.c.(iii)(A) General

No owner or operator of an EFR tank (storing petroleum liquids) not specifically exempted in Section IV.B.2.c.(i)(B) shall store that petroleum liquid unless such vessel is equipped with a continuous secondary seal extending from the rim of the floating roof to the tank wall (i.e., a rim-mounted secondary seal).

IV.B.2.c.(iii)(B) Vapor-Mounted Seals

For EFR tanks required to have a secondary seal and which have a vapor-mounted primary seal:

IV.B.2.c.(iii)(B)(1) An annual inspection shall be made of the total gap area between the secondary seal and the wall of the tank in accordance with the method in IV.B.2.c.(iii)(B)(3).

IV.B.2.c.(iii)(B)(2) This total gap area shall not exceed 21.2 cm2/meter diameter (1.0 in2/ft. diameter).

IV.B.2.c.(iii)(B)(3) Method to determine gap area:

IV.B.2.c.(iii)(B)(3)(a) Physically measure the length and width of all gaps around the entire circumference of the secondary seal in each place where a 0.32 cm (1/8 in.) uniform diameter probe passes freely (without forcing or binding against the seal) between the seal and the tank wall; and,

IV.B.2.c.(iii)(B)(3)(b) Sum the area of the individual gaps.

IV.B.3. Storage of petroleum liquid in tanks of or less than 151,412 liters (40,000 gallons) capacity.

IV.B.3.a. Tanks or containers used to store liquids with true vapor pressure at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) at 20°C are exempt from the provisions of this Section IV.B.3.

IV.B.3.b. The owner or operator of storage tanks at a gasoline dispensing facility (service station) or other facility not addressed in Sections IV.C.2. or IV.C.3., which receives and stores petroleum liquid, shall not allow the transfer of petroleum liquid from any delivery vessel into any tank unless the tank is equipped with a submerged fill pipe and all vapors displaced from the storage tank are transferred to the delivery vessel being unloaded using a properly maintained, functioning, and leak-tight vapor collection system, as in accordance with applicable provisions of Appendix B and Section VII., if the tank:

IV.B.3.b.(i) Has a rated manufacturer's capacity of 2,082 liters (550 gallons) or more and was installed after November 7, 1973, (except for storage tanks below 550-gallon capacity used exclusively for agricultural use; however, these must have a submerged fill pipe), or

IV.B.3.b.(ii) Has a rated manufacturer's capacity of 7,571 liters (2,000 gallons) or more and was installed before November 7, 1973.

IV.B.3.c. Tanks equipped with a submerged fill pipe shall meet the specifications of Appendix B.

IV.B.3.d. The owner or operator of storage tanks at a gasoline dispensing facility must install and operate one or more of the following

IV.B.3.d.(i) A vapor collection system designed and operated in accordance with a vapor-tight line from the storage tank to delivery vessel.

IV.B.3.d.(ii) A refrigerator-condensation system or equivalent designed to recover at least 90 percent by weight of the organic compounds in the displaced vapor.

IV.B.3.e. The owner or operator shall ensure that operating procedures are used so that gasoline cannot be transferred into the tank unless the vapor collection system is installed and operated to ensure the system is leak-tight during gasoline transfer.

IV.B.3.f. The vapor collection system shall meet the specifications of Appendix B and applicable requirements of Section VII.

IV.B.3.g. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

IV.B.3.h. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.C. Transfer of Petroleum Liquid

IV.C.1. Exemptions

Transfer operations involving petroleum liquid with true vapor pressures at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) shall be exempt from the provisions of this Section IV.C.

IV.C.2. Loading Facilities Classified as Terminals

IV.C.2.a. A terminal is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of more than 76,000 liters of gasoline (20,000 gallons), which is loaded directly into transport vehicles. A rolling, 30-day average of throughput shall be used to determine the applicability of this Section IV.C.2.

IV.C.2.b. The owner or operator of a terminal subject to this section shall equip the terminal with proper loading equipment and shall follow the loading procedures listed:

IV.C.2.b.(i) Install dry-break loading couplings to prevent petroleum liquid loss during uncoupling from vehicles.

IV.C.2.b.(ii) Install a vapor collection and disposal system which gathers vapor transferred from vehicles being loaded. The system shall include devices to prevent the release of vapor from vapor recovery hoses not in use.

IV.C.2.b.(iii) Use operating procedures to ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

IV.C.2.b.(iv) Provide for the prevention of overfilling of transport vehicles with loading pump shut-offs, set stop meters, or comparable equipment.

IV.C.2.b.(v) Operate all recovery and disposal equipment at a back pressure less than the pressure relief valve setting of transport vehicles.

IV.C.2.b.(vi) Prevent the release of petroleum liquid on the ground from transport vehicles. Provision shall be made to remove any undelivered petroleum liquid with closed drainage devices.

IV.C.2.b.(vii) Maintain and operate final recovery and disposal equipment or control devices so as to emit no more than 80 milligrams of volatile organic compounds per liter of gasoline being loaded. Such disposal devices shall be approved by the Division.

IV.C.2.b.(viii) Prevent loading of petroleum liquid into transport vehicles which do not have valid leak-tight test certification as required in Section IV.D.

IV.C.2.b.(ix) Follow all control procedures to prevent leaks as specified in Section VII.

IV.C.2.c. Control devices shall meet the applicable requirements, including recordkeeping of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

IV.C.2.d. The applicable methods of 40 CFR 60. 503 (September 14, 1989), or EPA reference methods 1 through 4, 25A, and 25B of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.C.2.e. The method set forth in Appendix A of "Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals" October 1977, EPA-450/2-77-026 shall be used to test emission points other than control devices.

IV.C.3. Loading Facilities Classified as Bulk Plants

IV.C.3.a. A bulk plant is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of 76,000 liters of gasoline (20,000 gallons) or less, which is loaded directly into transport trucks. (As used herein, "bulk plant" does not include service stations nor separate operations within petroleum liquid distribution facilities which pump only into fuel tanks fueling motor vehicles. Both such operations are regulated by Section IV.B.3.). A rolling 30-day average of throughput shall be used to determine the applicability of this regulation.

IV.C.3.b. The owner or operator of a bulk storage plant subject to this section shall install a vapor balance system to return vapors to the incoming transport trucks during the filling of tanks controlled under Section IV.B.3. The vapor balance system must be designed and operated in accord with the provisions of Appendix C.)

IV.C.3.c. The owner or operator of a bulk plant which serves storage tanks which are required to collect and recover vapor as prescribed in Section IV.B.3. shall:

IV.C.3.c.(i) Install and operate vapor collection and return equipment on any transport vehicles used to deliver to controlled tanks, and

IV.C.3.c.(ii) Install and operate vapor collection and return equipment at loading facilities to collect vapors during loading of tank compartments of outbound transport trucks and return these vapors to the bulk plant storage tanks, using a vapor balance system.

IV.C.3.c.(iii) Assure that transport trucks and loading facilities conform to the applicable provisions of Sections IV.C.2. and IV.C.4.

IV.C.3.d. The owner or operator of a bulk plant which serves only storage tanks exempted from the provisions of Section IV.B.3.b. by reason of their small size or location in an attainment area shall load outbound transport trucks using equipment that provides for top loading of the petroleum liquid into the vehicle tank compartments through an extended fill tube which reaches within 15.24 cm (6 in.) of the bottom of the tank compartment.

IV.C.3.e. The owner or operator of a bulk plant subject to this section shall ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

IV.C.3.f. The owner or operator of a bulk plant subject to this section shall follow all procedures to prevent leaks as specified in Section VII.

IV.C.4. Transport Vehicles

IV.C.4.a. Rail cars shall be loaded only at facilities which allow for the following:

IV.C.4.a.(i) A submerged fill pipe which reaches within 15.24 cm (6 in.) of the bottom of the tank.

IV.C.4.a.(ii) Vapor collection and/or disposal equipment designated and operated to recover vapors displaced during the loading of the rail car.

IV.C.4.a.(iii) A vapor-tight seal around the tank car hatch and the loading equipment.

IV.C.4.b. The owner or operator of petroleum transport trucks which serve locations required to be equipped with vapor recovery equipment shall load only at facilities capable of disposing of collected vapors. The owner or operator shall assure that such vehicles possess the proper equipment and that work practices are followed so that:

IV.C.4.b.(i) Dry-break loading and unloading nozzles are used and are compatible with those required at loading facilities.

IV.C.4.b.(ii) Vapor recovery hoses are connected at all times during unloading or loading of petroleum distillate.

IV.C.4.b.(iii) Transport trailers and vehicle tanks are operated and maintained to prevent detectable hydrocarbon vapor loss during loading, transport and delivery.

IV.C.4.b.(iv) Compartment dome lids are closed and locked during transfers of petroleum liquid. Such lids may be opened for the purpose of certifying the accuracy of a delivery only prior to and after such delivery.

IV.C.4.b.(v) Hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loading or unloading.

IV.D. Control of Volatile Organic Compound Leaks from Gasoline Transport Trucks

IV.D.1. General Provisions

IV.D.1.a. Applicability

This section is applicable to all gasoline transport trucks equipped for gasoline vapor collection which receive or dispense gasoline at terminals, bulk plants, or gasoline dispensing facilities located in the nonattainment areas.

IV.D.1.b. Definitions

For the purpose of this section, the following definitions apply:

IV.D.1.b.(i) "Gasoline Transport Truck" means a tank truck or tank trailer equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants, or gasoline terminals.

IV.D.1.b.(ii) "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into a vessel being unloaded or into a vapor holding tank.

IV.D.2. Provisions for Specific Processes

IV.D.2.a. No terminal operator, when monitoring the gasoline loading operation and no owner or operator of a gasoline transport truck shall allow a gasoline transport truck subject to this Section IV.D. to be filled with a VOC with Reid Vapor Pressure of 4.0 or greater unless the gasoline tank truck:

IV.D.2.a.(i) Is tested annually according to the test procedure in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). Testing must be completed prior to the onset of the summer ozone season (test October through April). In addition, a visual inspection, as detailed in Section IV.D.3.b. must be performed at least once every six months.

IV.D.2.a.(i)(A) The test must be conducted using a time period (t) for the pressure and vacuum tests of 5 minutes.

IV.D.2.a.(i)(B) The initial pressure (P_i) for the pressure test must be 460 mm H_2O (18 in. H_2O), gauge.

IV.D.2.a.(i)(C) The initial vacuum (V_i) for the vacuum test must be 150 mm H_2O (6 in. H_2O), gauge.

IV.D.2.a.(i)(D) The maximum allowable pressure and vacuum changes must not exceed the values in Table 1.

IV.D.2.a.(i)(E) After completing the tests under Sections IV.D.2.a.(i)(A) through (D), the tank's internal vapor valve must be pressure tested.

IV.D.2.a.(i)(E)(1) Use the procedures in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000) to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge.

IV.D.2.a.(i)(E)(2) Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

IV.D.2.a.(i)(E)(3) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line.

IV.D.2.a.(i)(E)(4) After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

Table 1 - Allowable Cargo Tank Test Pressure or Vacuum Change

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change in 5 minutes, mm H2O (in. H2O)	Allowable pressure change in 5 minutes at any time, mm H2O (in. H2O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

IV.D.2.a.(ii) Passes a retest within twenty (20) days if it does not meet the criteria of Section IV.D.2.a.(i).

IV.D.2.b. Monitoring

IV.D.2.b.(i) The Division may, at any time, monitor a gasoline tank truck vapor collection system to confirm continued compliance with Section IV.D.2.a.

IV.D.2.b.(ii) Within fifteen (15) days after an exceedance is detected a tank shall pass a pressure/vacuum test per EPA Method 27 (40 CFR Part 60, Appendix A-8 (October 17, 2000)).

IV.D.3. Testing and Monitoring

IV.D.3.a. The owner or operator of a gasoline transport truck shall at their own expense, demonstrate compliance with Section IV.D.2, by methods of EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). All tests shall be made by, or under the direction of, a person qualified by training and/or experience in the field of air pollution testing or gasoline transport truck maintenance.

IV.D.3.b. The owner or operator of a gasoline transport truck must conduct a visual inspection of the gasoline transport truck at least once every six months. The entire tank, including domes, dome vents, cargo tank, piping, hose connections, hoses and delivery elbows, must be inspected for wear, damage, or misadjustment that could be a potential leak source. Inspect all rubber fittings except those in piping which are not accessible. Any part found to be defective must be adjusted, repaired, or replaced as necessary.

IV.D.4. Recordkeeping and Reporting

IV.D.4.a. The owner or operator of a gasoline transport truck subject to this Section IV.D. shall maintain records of all certification testing and repairs. The records shall identify the gasoline transport truck, the date of the test or repairs and, if applicable, the type of repair and the date of retest. The written record shall include entries of any pre-test repairs, adjustments, or modifications. These shall also include the part name, number, and vendor name of any part removed and of any part installed. The records shall be maintained in legible, readily available form for at least two (2) years after the date the testing or repair was completed and shall be made available to the Division for inspection upon request.

IV.D.4.b. The records of certification tests required by Section IV.D.2.a. must, as a minimum, contain all of the following entries:

IV.D.4.b.(i) The gasoline transport truck owner’s name and address;

IV.D.4.b.(ii) The gasoline transport truck/tank identification number;

IV.D.4.b.(iii) The nature of repair work and when performed in relation to vapor tightness testing.

IV.D.4.b.(iv) The following data for each test:

IV.D.4.b.(iv)(A) Test pressure.

IV.D.4.b.(iv)(B) Pressure or vacuum change, mm of water.

IV.D.4.b.(iv)(C) Time period of test.

IV.D.4.b.(iv)(D) Number of leaks found with instrument.

IV.D.4.b.(iv)(E) Leak definition.

IV.D.4.b.(v) The size of each of the compartments within the tank and whether such compartment was manifolded or was tested separately during pressure and vacuum tests.

IV.D.4.b.(vi) At the top of each report page shall be the company name and the date and location of the test results recorded on that page; and

IV.D.4.b.(vii) Name and title of the person conducting the test.

IV.D.4.b.(viii) For the vapor valve test required in Section IV.D.2.a.(ii)(A), the initial test pressure and time of reading.

IV.D.4.c. The records of the visual inspections required by Section IV.D.3.b.

IV.D.4.d. The owner or operator of a gasoline transport truck subject to this regulation must annually certify to the Division that the gasoline transport truck has been tested by the applicable method(s) referenced in Section IV.D.3. The certification must include:

IV.D.4.d.(i) The name and address of the company and the name and telephone number of responsible company representative over whose signature the certification is submitted; and,

IV.D.4.d.(ii) A copy of the information recorded to comply with Section IV.D.4.b.

IV.D.4.e. The records of certification tests must be kept with the tank or at the transport company office at all times and must be shown to Division personnel upon their request. Copies of all records and reports required by the provisions of this Section IV.D. must be made available to the Division upon oral or written request.

V. Crude Oil

V.A. General Exemptions

V.A.1. Storage tanks of 151,412 liters (40,000 gallons) or less used to store crude oil is exempt from the provisions of this section.

V.A.2. Storage tanks with capacities of less than 1,590 cubic meters (10,000 barrels) used to store crude oil and condensate prior to lease custody transfer are exempt from the provisions of this Regulation Number 7 other than Part D, Sections I. and II.

V.B. Equipment

Pumps and compressors handling crude oil shall be subject to the provisions of Section IV.A.

V.C. Storage

Except as provided in Section V.A.2., crude oil stored in tanks greater than 151,412 liters (40,000 gallons) shall be subject to the provisions of Sections IV.B.1.b. and IV.B.2.

NMED Exhibit 39 - 0026

VI. Petroleum Processing and Refining

VI.A. Wastewater (Oil/Water) Separators

VI.A.1. Definitions

VI.A.1.a. "Forebays" mean the primary sections of a wastewater separator.

VI.A.1.b. "Wastewater (oil/water) separator" means any device or piece of equipment which utilizes the difference in density between oil and water to remove oil and associated chemicals from water, or any device, such as a flocculation tank, clarifier, etc., which removes petroleum derived compounds from wastewater.

VI.A.2. The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall:

VI.A.2.a. Equip the forebays and separator sections of the wastewater separators with one or more of the following emission control devices, ensuring that such device is properly installed, in good working order and properly maintained:

VI.A.2.a.(i) A solid cover with all openings sealed and the liquid contents totally enclosed.

VI.A.2.a.(ii) A pontoon-type or double-deck type floating roof, or internal floating cover. The floating roof or cover must rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and the wall(s) of the compartment.

VI.A.2.a.(iii) A vapor recovery system consisting of a vapor gathering device capable of collecting the volatile organic compound vapors discharged and a vapor disposal device capable of processing such volatile organic vapors so as to prevent their emission into the atmosphere.

VI.A.2.a.(iii)(A) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

VI.A.2.a.(iii)(B) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

VI.A.2.b. Equip all openings in covers, separators, and forebays with lids or seals such that the lids or seals are in the closed position at all times except when in actual use. Access for gauging and sampling shall be minimized.

VI.B. Emissions from Petroleum Refineries

VI.B.1. Definitions

VI.B.1.a. "Firebox" means the chamber or compartment of a boiler or furnace in which materials are burned but does not mean the combustion chamber of an incinerator.

VI.B.1.b. "Turnaround" means the procedure of shutting a refinery unit down after a run to do necessary maintenance and repair work and then putting the unit back on stream.

VI.B.2. Process unit turnarounds

The owner or operator of a petroleum refinery shall develop and submit to the Division for approval a detailed procedure for minimization of volatile organic compound emissions during process unit turnaround. As a minimum, the procedure shall provide for:

VI.B.2.a. Depressurization venting of the process unit or vessel to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency;

VI.B.2.b. No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 17.2 psia or less; and

VI.B.2.c. Recordkeeping of the following items. Records shall be kept for at least two years and shall be made available to the Division for review upon request.

VI.B.2.c.(i) Every date that each process unit is shut down,

VI.B.2.c.(ii) The approximate vessel volatile organic compound concentration when the volatile organic compounds were first discharged to the atmosphere, and

VI.B.2.c.(iii) The approximate total quantity of volatile organic compounds emitted to the atmosphere.

VI.B.3. Venting of blowdown systems and safety pressure relief valves

All blowdown systems, process equipment vents, and pressure relief valves shall be vented to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency.

VI.B.4. Vacuum-Producing Systems

VI.B.4.a. The owner or operator of any vacuum-producing system at a petroleum refinery shall not permit the emission of any noncondensible volatile organic compounds from the condensers, hot wells or accumulators of the system. This emission limit shall be achieved by:

VI.B.4.a.(i) Venting the noncondensible vapors to a flare or other combustion device, or,

VI.B.4.a.(ii) Compressing the vapors and adding them to the refinery fuel gas.

VI.B.5. All sampling, testing, and measuring ports, hatches, and access openings shall be kept in a closed sealed position except during actual sampling or access.

VI.B.6. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

VI.B.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

VI.C. Petroleum Refinery Equipment Leaks

VI.C.1. Definitions

For the purpose of this section, the following definitions apply:

VI.C.1.a. "Accessible Component" means a component which can be reached, if necessary, by safe and proper use of portable ladders such as are acceptable to OSHA, as well as by built-in ladders and walkways. "Accessible" also includes components which can be reached by the safe use of an extension on the monitoring probe.

VI.C.1.b. "Component" means any piece of equipment, which has the potential to leak volatile organic compounds when tested in the manner described in Section VI.C.3. These sources include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open ended pipes. Excluded from these sources are valves which are not externally regulated.

VI.C.1.c. "Gaseous Service" means equipment which processes, transfers or contains a volatile organic compound or mixture of volatile organic compounds in the gaseous phase.

VI.C.1.d. "In Heavy VOC Liquid Service" means that the piece of equipment is not in gaseous service or in light VOC liquid service.

VI.C.1.e. "In Light Liquid VOC Service" Equipment is in light liquid service if the following conditions apply:

VI.C.1.e.(i) the true vapor pressure of one or more of the components is greater than 0.3 kPa at 20°C. True vapor pressures may be obtained from standard reference texts or may be determined by ASTM D-2879.

VI.C.1.e.(ii) the total concentration of the pure components have a true vapor pressure greater than 0.3 kPa at 20°C, is equal to or greater than 20 percent by weight; and

VI.C.1.e.(iii) the fluid is a liquid at operating conditions.

VI.C.1.f. "Refinery Unit" means a set of components which are a part of a basic process operation, such as, distillation, hydrotreating, cracking, or reforming of hydrocarbons.

VI.C.1.g. "Water Draw" means a routinely used valve or system employing a valve which allows non-VOC material (usually water) to be separated from VOC.

VI.C.2. Provisions for Specific Processes

VI.C.2.a. The owner or operator of a petroleum refinery complex subject to this regulation shall:

VI.C.2.a.(i) Develop a monitoring program consistent with the provisions in Section VI.C.3.

VI.C.2.a.(ii) Conduct a monitoring program consistent with the provisions in Section VI.C.4.a.

VI.C.2.a.(iii) Record all leaking components which have a VOC concentration exceeding 10,000 ppm when tested according to Section VI.C.3., and place an identifying tag on each component consistent with the provisions in Section VI.C.4.a.(iii).

VI.C.2.a.(iv) Repair and retest leaking components, as defined in Section VI.C.2.a.(iii), as soon as possible, but no later than fifteen (15) days after the leak is found, excepting those specified in Sections VI.C.2.a.(v) and VI.C.2.a.(vi).

VI.C.2.a.(v) Identify all leaking components as defined in Section VI.C.2.a.(iii), which cannot be repaired until the unit is shut down for turnaround, and repair and retest as in Section VI.C.2.a.(iv) when the unit is back on stream.

VI.C.2.a.(vi) When a component leak cannot be fixed within fifteen (15) working days solely because parts are not available, the following shall be noted in an "awaiting parts log:"

VI.C.2.a.(vi)(A) component identification and tag number

VI.C.2.a.(vi)(B) date part was ordered

VI.C.2.a.(vi)(C) date part was received

VI.C.2.a.(vi)(D) date repair was made

VI.C.2.b. Except for safety pressure relief valves, no owner or operator of a petroleum refinery shall install or operate a valve at the end of a pipe or line containing volatile organic compounds unless the pipe or line is sealed with a second valve, a blind flange, a plug, or a cap. The sealing device may be removed only when a sample is being taken or when the valve is otherwise in use.

VI.C.2.c. The Division, at its discretion, may require early unit turnaround based on the number and severity of tagged leaks awaiting turnaround provided:

VI.C.2.c.(i) The requirement does not exceed reasonable available control technology due to cost per ton of emissions reduction achieved by the early turnaround or other reasonable analysis.

VI.C.2.c.(ii) The Division provides the owner or operator of a petroleum refinery with written notification at least 180 days before requiring

an early turnaround. The owner or operator will have 30 days from the date of the Division's notification to contest the requirement by submitting a demonstration that the requirement is beyond reasonable available control technology. If no demonstration is made, it will be assumed the requirement is reasonable. If a demonstration is submitted by the owner or operator, the Division will either approve the demonstration or disapprove the demonstration with a justification regarding the disapproval within 30 days of the date the demonstration is submitted to the Division.

VI.C.2.c.(iii) The requirement is not contested by the owner or operator. Should the requirement be contested, the requirement for early unit turnaround will be delayed until 180 days after the demonstration discussed in Section VI.C.2.c.(ii) is disapproved by the Division.

VI.C.2.d. Piping valves and pressure relief valves in gaseous VOC service shall be marked in some manner that will be readily obvious to both refinery personnel performing monitoring and the Division, to identify them as components which are monitored quarterly.

VI.C.3. Testing and Monitoring Procedures

Testing and calibration procedures to determine compliance with this regulation shall be consistent with EPA reference method 21 of 40 CFR Part 60 (September 14, 1989). The reference compound may be methane or hexane. A leak is defined as a reading of 10,000 ppmv of the reference compound.

VI.C.4. Monitoring, Recordkeeping, Reporting

VI.C.4.a. Monitoring

VI.C.4.a.(i) The owner or operator of a petroleum refinery subject to this regulation shall conduct a monitoring program consistent with the following provisions:

VI.C.4.a.(i)(A) Monitor yearly by the method referenced in Section VI.C.3., all:

VI.C.4.a.(i)(A)(1) Pump seals; and

VI.C.4.a.(i)(A)(2) Piping valves in light liquid VOC service; and

VI.C.4.a.(i)(A)(3) Process drains; and

VI.C.4.a.(i)(A)(4) Heat-exchanger body flanges; and

VI.C.4.a.(i)(A)(5) Other accessible flanges in VOC service.

VI.C.4.a.(i)(A)(6) Components in heavy liquid VOC service are exempt from requirements of this Section VI.C.4.a.(i)(A).

VI.C.4.a.(i)(B) Monitor quarterly by the method referenced in Section VI.C.3., all:

VI.C.4.a.(i)(B)(1) Compressor seals; and

VI.C.4.a.(i)(B)(2) Piping valves in gaseous service; and

VI.C.4.a.(i)(B)(3) Pressure relief valves in gaseous service.

VI.C.4.a.(i)(C) Monitor at least weekly by visual methods all pump seals.

VI.C.4.a.(i)(D) Monitor within 24 hours with a VOC detector and make record of any component from which VOC liquids are observed leaking.

VI.C.4.a.(i)(E) Components in heavy liquid VOC service shall be monitored by the method referenced in Section VI.C.3. within five days if evidence of a potential leak is found by visual, audible, olfactory, or any other detectable method.

VI.C.4.a.(ii) Inaccessible valves and flanges shall be monitored annually or, as a minimum, at unit shutdown using the procedures of VI.C.2.a.(v). Pressure relief devices which are connected to an operating flare header or vapor recovery device, storage tank valves, and valves that are not externally regulated are exempt from the monitoring requirements in Section VI.C.4.a.(i).

VI.C.4.a.(iii) The owner or operator of a petroleum refinery, upon the detection of a leaking component as defined in Section VI.C.2.a.(iii), shall affix a weatherproof and readily visible tag, bearing an identification number and the date the leak is located, to the leaking component. This tag shall remain in place until the leaking component is repaired. In addition, the owner or operator shall log the leak (including those leaks immediately repaired), per the requirements of Sections VI.C.4.b.(i) through (iii).

VI.C.4.b. Recordkeeping

VI.C.4.b.(i) The owner or operator of a petroleum refinery shall maintain a leaking components monitoring log which shall contain at a minimum, the following data:

VI.C.4.b.(i)(A) The name of the process unit where the component is located.

VI.C.4.b.(i)(B) The type of component (e.g., valve, seal).

VI.C.4.b.(i)(C) The tag number of the component.

VI.C.4.b.(i)(D) The date on which a leaking component is discovered.

VI.C.4.b.(i)(E) The date on which a leaking component is repaired.

VI.C.4.b.(i)(F) The date and instrument reading found during the recheck procedure subsequent to repairing a leaking component.

VI.C.4.b.(i)(G) A record of the calibration of the monitoring instrument.

VI.C.4.b.(i)(H) Those leaks that cannot be repaired until turnaround.

VI.C.4.b.(i)(I) The total number of components checked and the total number of components found leaking.

VI.C.4.b.(i)(J) The total number of components subject to Section VI.C.2.a.(v) which upon retest were still leaking as defined in Section VI.C.3.

VI.C.4.b.(ii) Copies of the monitoring log shall be retained by the owner or operator for a minimum of two (2) years after the date on which the record was made or report prepared.

VI.C.4.b.(iii) Copies of the monitoring log shall be made available to the Division upon oral or written request.

VI.C.4.c. Reporting

The owner or operator of a petroleum refinery, upon the completion of each yearly and/or quarterly monitoring procedure, shall:

VI.C.4.c.(i) Submit a report to the Division by the 15th day of February, May, August, and November that lists all leaking components that were located during the previous three (3) calendar months (quarter), but not repaired within fifteen (15) working days, all leaking components awaiting unit turnaround, the total number of components inspected, and the total number of components found leaking.

VI.C.4.c.(ii) Submit a signed statement with the report attesting to the fact that, with the exception to those leaking components listed in Section VI.C.4.b.(i)(H), all monitoring and repairs were performed as stipulated in the monitoring program.

VII. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities

VII.A. General Provisions

VII.A.1. Applicability

This section is applicable to all gasoline terminals, gasoline bulk plants, and gasoline dispensing facilities (e.g., service stations) which are located in ozone nonattainment areas and which must have a vapor collection system pursuant to Section IV. and other applicable rules.

VII.A.2. Exemptions

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This section is not applicable to those operations involving transfer of gasoline from gasoline dispensing facilities to motor vehicle fuel tanks nor to other dispensing operations at such facilities.

VII.A.3. Definitions

For the purpose of this section, the following definitions apply:

VII.A.3.a. "Gasoline Dispensing Facility" means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks, (e.g., service stations, fleet pumps, etc.)

VII.A.3.b. "Gasoline Transport Truck" means tank trucks or trailers equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants or gasoline terminals.

VII.A.3.c. "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.

VII.B. Specific Provisions

VII.B.1. The operator of a vapor collection system at a facility subject to the provisions of this section shall operate the vapor collection system and the gasoline loading equipment in a manner that prevents:

VII.B.1.a. Gauge pressure from exceeding 33.6 torr (18 inches of H2O) and vacuum from exceeding gauge pressure of minus 11.2 torr (minus 6 inches of H2O) at the point where the vapor return line on the truck connects with the vapor collection line of the facility.

VII.B.1.b. A reading equal to or greater than 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 centimeters from a known or potential leak source when measured by the procedures described in Appendix B of "Control of Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems," December 1978, EPA-450/2-78-051, during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

VII.B.1.c. Avoidable liquid or vapor leaks from the system during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

VII.B.1.d. Division representatives may monitor for excessive back pressure as defined by Section VII.B.1.a. and vapor leakage as is defined by Section VII.B.1.b. or by detection methods incorporating sight, sound, and smell.

VII.B.2. Repairs and Modifications

VII.B.2.a. The operator shall within fifteen (15) days, repair and retest a vapor collection system that exceeds the pressure limits (Section VII.B.1.a.), excepting that;

VII.B.2.b. Should an applicable facility require modification or repairs that will take longer than fifteen (15) days to complete, the operator shall submit to the Division for approval a schedule which includes dates of commencement and completion.

Appendix B Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks

I. Drop Tube Specifications. Submerged fill is specifically required. The drop tube must extend to within 15.24 cm (6 in.) of the tank bottom.

II. Vapor Hose Return. Vapor return line and any manifold must be minimum 7.6 cm (3 in.) ID. All tanks must be provided with individual overfill protection. (Liquid must not be allowed in the vent line or vapor recovery line.) Disconnect on liquid line should assure that all liquid in the hose is drained into the storage tank. The requirements for overfill protection as specified may be waived for existing storage tanks when it is demonstrated to the satisfaction of the appropriate local Fire Marshal, and where applicable, the State Oil Inspection Office that the installation of overfill protection devices on existing tanks is physically not possible.

III. Size of Vapor Line Connections. For separate vapor lines, nominal three inch (7.6 cm) or larger connections must be utilized at the storage tank and truck. However, short lengths of 2-inch (5.1 cm) vertical pipe no greater than 91.4 cm (3 ft.) long are permissible if the fuel delivery rate is less than 400 gallons per minute.

Where concentric (coaxial) connections are utilized, a 45 cm2 (7 sq. in.) area for vapor return shall be provided. Four-inch concentric designs are acceptable only when using a venturi-shaped outer tube or where normal drop rate of 1,700 liters per minute (450 gpm) is reduced by at least 25%. Six-inch (15.24 cm) risers should be installed in new stations with concentric connections.

IV. Type of Liquid Fill Connection. Vapor tight caps are required for the liquid fill connection for all systems. A positive closure utilizing a gasket is necessary to prevent vapors from being emitted at ground level. Cam-lock closures meet this requirement. Dry break closures are preferred.

V. Tank Truck Inspection. Tank trucks are specifically required to be vapor-tight and to have valid leak-tight certification. The visual inspection procedure must be conducted at least once every six months to ensure properly operating manifolding and relief valves, using the test procedure of Section IV.D.3.b.

VI. Dry Break on Underground Tank Vapor Riser. Dry-break closures are required to assure transfer of displaced vapors to the truck and to prevent ground-level, gasoline-vapor emissions caused by failure to connect the vapor return line to the underground tanks (closure on riser to mate with opening on hose). These devices keep the tank sealed until the hose is connected to the underground tank. Concentric couplers without dry-breaks are required to have a dry-break on the vapor line connection to the coupler itself, rather than on the rise pipe from the storage tank. The liquid fill riser should be provided with a gap having a positive closure (threaded or latched).

VII. Equipment Ensuring Vapor-Hose Connection during Gasoline Deliveries. An equipment system aboard the tank truck shall insure (barring deliberate tampering) that a vapor return hose is connected from the truck's vapor return line to the tank receiving gasoline.

VIII. Vent Line Restriction Devices. Vent line restriction devices are required. If the liquid fill line were attached to the underground tank and the vapor return line were disconnected, then dry break closures would seal the vapor return path to the truck, forcing all vapors out the vent line. In such instances, a restriction device on this vent line greatly reduces fill rate, warning the operator that the vapor line is not connected.

Pressure/vacuum (PV) vent valves installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water.

IX. Fire and Safety Regulations. All new or modified installations must comply in their entirety with all code requirements including NFPA, Pamphlet 30 (fiberglass is preferred for new manifold lines). For any questions concerning compliance, please contact State Oil Inspection or your local Fire Marshal.

X. State Oil Inspection. Requirements of the State Oil Inspection office make accurate measurements of the liquid in the underground tank necessary. Vapor-tight gauging devices will be required in all systems designed such that a pressure other than atmospheric will be held or maintained in the storage tank. The volume of liquid in the tanks maintained at atmospheric pressure may be determined with a stick through the submerged drop tube or through a separate submerged gauging tube extending to within 15.24 cm (6 in.) of the tank bottom.

Appendix C Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants

I. Storage Tank Requirements:

A. Drop Tube Specification: Underground tanks must contain a drop tube that extends to within six inches (15.24 cm) of the tank bottom. All top loaded above-ground tanks must contain a similar drop tube. Above-ground tanks using bottom loading, where the inlet is flush with the tank bottom, must meet the submerged fill requirement.

B. Size of Vapor Lines from Storage Tanks to Loading Rack: See nomograph (Attachment 1). NOTE: Affected sources are free to choose a pipe diameter different from the one suggested by the nomograph if sufficient justification and documentation is presented.

C. Pressure Relief Valves: All pressure relief valves and valve connections must be checked periodically for leaks, and be repaired as required. The relief valve pressures should be set in accordance with Sections 2-2.5.1 and 2-2.7.1 inclusive of the current National Fire Protection Agency Pamphlet Number 30.

D. Liquid Level Check Port: Access for checking liquid level by other than a vapor-tight gauging system shall be vapor-tight when not being used. Tank level shall be checked prior to filling to avoid overfills.

E. Miscellaneous Tank Openings: All other tank openings, e.g., tank inspection hatches, must be vapor tight when not being used, and must be closed at all times during transfer of fuel.

F. Storage Tank Overfill Protection: Except for concentric (coaxial) delivery systems, underground tanks must have ball check valves (stainless steel ball). Tanks with concentric delivery systems must have Division-approved overfill protection, (e.g., cutoff pressure-switch in vent line).

II. Loading Rack Requirements:

A. Loading Specification: A vapor-tight bottom-loading or top-loading system using submerged fill with a positive seal, e.g., the Wiggins (tm) system, is required. NOTE: Bulk plants delivering solely to exempt accounts are required to have submerged fill, but loading need not be vapor-tight.

B. Dry-Break on Storage Tank Vapor Return Line: A dry-break is required to prevent ground-level gasoline vapor emissions during periods when gasoline transfer is not being made. This device keeps the tank sealed until the vapor return hose is connected.

III. Tank Truck* Requirements:

A. Vapor Return Modification: Tank trucks must be modified to recover vapors during loading and unloading operations. NOTE: Tank trucks making deliveries solely to exempt accounts do not require this modification. However, 97% submerged fill is required when top loading.

B. Loading Specifications: Bottom loading or top loading using submerged fill with a positive seal is required for tank trucks modified for vapor recovery. NOTE: When loading a tank truck with this modification without the vapor return hose connected (this is allowed at bulk plants servicing exempt accounts returning without collected vapors in the tank), the requirements of National Fire Protection Agency Pamphlet Number 385, "Loading and Unloading Venting Protection in Tank Vehicles, Section 2219, Paragraph c", must be met.

C. Vapor Return Hose Size: A minimum three-inch (7.6 cm) ID vapor return hose is required.

D. Tank Truck Inspection: Tank trucks are required to be vapor-tight and have valid leak-tight certification. Periodic visual inspection is necessary to insure properly operating manifolding and relief valves.

* The term "tank truck" is meant to include all trucks with tanks used for the transport of gasoline, such as tank wagons, account trucks and transport trucks.

PART C Surface Coating, Solvents, Asphalt, Graphic Arts and Printing, and Pharmaceuticals

I. Surface Coating Operations

I.A. General Provisions

I.A.1. Definitions, unless otherwise specified in Sections I.B. through I.O.

I.A.1.a. "Coating" means a protective, functional or decorative film applied in a thin layer to a surface. This term often applies to paints such as lacquers or enamels, but is also used to refer to films applied to paper, plastics, or foils.

I.A.1.b. "Coating Applicator" means an apparatus used to apply a surface coating.

I.A.1.c. "Coating Line" means an operation which includes both (1) a coating applicator and (2) device(s) and/or area(s) to accomplish one or more of the following processes: flash-off, drying, curing, heat-setting and/or polymerization.

I.A.1.d. "Coating Solids" means that portion of a surface coating, which remains after volatile components have escaped.

I.A.1.e. "Final Repair Application" means that application of surface coating specifically intended to repair damage and imperfections in existing surface coats.

I.A.1.f. "Finished Coating Solids" means those coating-solids that remain on a coated substance after completion of all production processes.

I.A.1.g. "Flash-off Area" means the space between the application area and the oven.

I.A.1.h. "Prime Coat" (also termed "primer") means the first film of coating applied in a multiple-coat operation.

I.A.1.i. "Single Coat" means a single film of coating applied directly to the metal substrate, omitting the primer application.

I.A.1.j. "Surface Coating" means a liquid, liquefiable, or mastic composition which is converted to a solid (or semi-solid) protective, decorative, or adherent film or deposit after application as a thin layer or by impregnation. In a machine which has both coating and printing units, all units shall be considered as performing a printing operation. Such a machine is subject to the standards governing graphic arts, and thus is not covered by coating standards.

I.A.1.k. "Surface Coating Oven" means a chamber within which heat is used to bake, cure, polymerize, and/or dry a surface coating.

I.A.1.l. "Topcoat" means the final film of coating applied in a multiple-coat operation.

I.A.2. Abbreviations

I.A.2.a. Kg/lc shall be the abbreviation for: kilograms of solvent VOC per liter of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).

I.A.2.b. Lb/gc shall be the abbreviation for: (avoirdupois) pounds of solvent VOC per gallon of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).

I.A.3. Test Methods and Procedures

I.A.3.a. The owner or operator of any VOC source required to comply with this section shall, at their own expense, demonstrate compliance using EPA reference method 24 of 40 CFR Part 60 (September 14, 1989) for surface coatings, and reference method 25 and reference methods 1 through 4 (September 14, 1989) for add-on controls.

I.A.3.b. The test protocol should be in accordance with the requirements of the Air Pollution Control Division Compliance Test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No test shall be conducted without prior approval from the Division.

I.A.3.c. The Division may use independent tests to verify test data submitted by the source operator or owner. The test methods shall be those listed in Section I.A.3.a. and the Division test results shall take precedence.

I.A.3.d. The Division may accept, instead of the testing required in this section, a certification by the manufacturer of the composition of the coatings if supported by actual batch formulation records. The owner or operator of the VOC source required to comply with this section shall obtain certification from the coating manufacturer(s) that the test method(s) used for determination of VOC content meet the requirements specified in Section I.A.3.a. The owner or operator shall have this certification readily available to Division personnel, in order to allow the results to be used in the daily compliance calculations specified in Section I.A.10.

I.A.3.e. The performance of add-on control device equipment shall be established with the required test methods of I.A.3.a. at equipment startup, and after major modification to the control equipment. Baseline operating parameters shall be established during the satisfactory (i.e. in-compliance) operation of the control equipment, including operation during all anticipated ranges of process throughput. During subsequent process operation, the owner or operator shall maintain the operating conditions of the add-on controls as close to these baseline conditions as possible. If serious operational problems with an add-on control system are evidenced from the daily monitoring required by Section I.A.8.b. (such problems may be indicated by changes from baseline conditions), repeat performance tests may be required by the Division, as necessary.

I.A.4. Sampling

To determine compliance with applicable surface coating standards, samples shall be taken from the coating as freshly delivered to the reservoir of the coating applicator.

I.A.5. Alternative compliance methods for processes and operations

For each process specified in Sections I.B. through I.N. the emission limits designated for that process shall be achieved by:

I.A.5.a. Use of coatings with proportions of VOC less than or equal to the maximums specified by the applicable section of this regulation; or

I.A.5.b. Use of the specified equipment and procedures prescribed by the applicable section of this regulation; or

I.A.5.c. Use of an alternative means of control which satisfies the requirements of Section I.A.5.e., I.A.5.f., and Part A, Section II.D.; or

I.A.5.d. Use of crossline averaging. The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met. In addition, the following requirements apply:

I.A.5.d.(i) The actual reduction shall be equivalent to the actual reduction that would be achieved on a line-by-line basis.

I.A.5.d.(ii) Credit shall not be received for downtime, however, credit is allowed for enforceable production limits.

I.A.5.d.(iii) Crossline averaging shall be used only across lines in the same control technique guidance group.

I.A.5.d.(iv) The emission trading policy shall be met on a daily weighted average.

I.A.5.d.(v) Sources subject to best available control technology (BACT) and lowest achievable emission rate (LAER) requirements shall not use cross line averaging.

I.A.5.d.(vi) VOC emissions shall be expressed as lbs/gallons solids to determine reduction over baseline (lb VOC/lb solids for graphic arts).

I.A.5.d.(vii) Organisol and plastisol coatings shall not be used to bubble emissions from vinyl surface or automobile topcoating operations.

I.A.5.d.(viii) Before crossline averaging may be used, the control methodology shall be approved as a revision to the State Implementation Plan.

I.A.5.e. The design, operation and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Unless the capture system meets the requirements for a total enclosure as specified in the New Source Performance Standard for the Magnetic Tape Manufacturing Industry, 53FR38892, October 3, 1988, or unless Division approved material balance techniques are used to adequately determine overall VOC capture and destruction/recovery efficiency, the efficiency of the capture system shall be determined by test methods approved as a revision to the State Implementation Plan. Testing for capture efficiency shall be performed on a case-by-case basis as required by the Division. The requirements of Sections I.A.3.e. and I.A.8.b. shall apply to the capture and control device system. When capture and control device efficiency must be independently determined, the overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

I.A.5.f. Sources which use add-on controls, crossline averaging, or an approved alternative control strategy instead of low solvent technology to meet the applicable emission limit shall meet the equivalent VOC emission limit, on the basis of solids applied (lb VOC/gal solids applied, or lb VOC/lb solids applied, for graphic arts sources). Appendix E sets forth the procedure for converting emission limits and lists equivalent limits for various coating operations.

I.A.5.g. Owners or operators of sources which use a carbon adsorption system shall provide for the proper disposal or reuse of all VOC recovered.

I.A.6. Exemptions

I.A.6.a. The requirements of this Section I. do not apply to sources used exclusively for chemical or physical analysis or determination of product quality and commercial acceptance, provided;

I.A.6.a.(i) the operation of the source is not an integral part of the production process; and

I.A.6.a.(ii) the emissions from the source do not exceed 363 kilograms (800 lbs.) in any calendar month; and

I.A.6.a.(iii) the exemption is approved in writing by the Division.

I.A.6.b. The requirements of Sections I.C., D., E., F., G., H., I., L. and M. are not applicable to sources whose actual emissions, including fugitive emissions, before add-on controls, are less than 6.8 kilograms (15 lbs.) per day and less than 1.4 kilograms (3 lbs.) per hour. Emissions from all sources within the same control technique guidance group shall be totaled to determine actual emissions.

I.A.7. Fugitive emission control

I.A.7.a. Control techniques and work practices shall be implemented at all times to reduce VOC emissions from fugitive sources. Control techniques and work practices include, but are not limited to:

I.A.7.a.(i) tight-fitting covers for open tanks;

I.A.7.a.(ii) covered containers for solvent wiping cloths;

I.A.7.a.(iii) proper disposal of dirty cleanup solvent.

I.A.7.b. Emissions of organic material released during clean-up operations, disposal, and other fugitive emissions shall be included when determining total emissions, unless the source owner or operator documents that the VOCs are collected and disposed of in a manner that prevents evaporation to the atmosphere.

I.A.8. Recordkeeping, Reporting, and Monitoring

I.A.8.a. If add-on control equipment is used, continuous monitors of the following parameters shall be installed, calibrated, and operated at all times that the associated control equipment is operating:

I.A.8.a.(i) exhaust gas temperature of all incinerators;

I.A.8.a.(ii) temperature rise across a catalytic incineration bed;

I.A.8.a.(iii) breakthrough of VOC on a carbon adsorption unit;

I.A.8.a.(iv) any other monitoring and/or recording device, maintenance and/or control-media-replacement schedule(s) specified on a case-by-case basis by the Division.

I.A.8.b. If add-on control equipment is used, in addition to the requirements of Section I.A.8.a., the following information and any other necessary information, as determined applicable for each source by the Division, shall be monitored and recorded daily in order to assure continuous compliance. The substitution of continuous recordings for daily recording may be allowed by the Division.

I.A.8.b.(i) For the capture system: fan power use, duct flow, duct pressure.

I.A.8.b.(ii) For carbon adsorbers: bed temperature, bed vacuum pressure, pressure at the vacuum pump, accumulated time of operation, concentration of VOC in the outlet gas, solvent recovery.

I.A.8.b.(iii) For refrigeration systems: compressor discharge and suction pressures, condenser fluid temperature, solvent recovery.

I.A.8.b.(iv) For incinerator systems: exhaust gas temperature, temperature rise across a catalytic incinerator bed, flame temperature, accumulated time of incinerator.

I.A.8.c. Recordkeeping procedures shall follow the guidance in "Recordkeeping Guidance Document for Surface Coating Operations and the Graphic Arts Industry," July 1989, EPA 340/1-88-003.

I.A.9. Required and Prohibited Acts

I.A.9.a. No owner or operator of a source of VOCs subject to this section shall operate, cause, allow or permit the operation of the source, unless:

I.A.9.a.(i) For each category of surface coating as specified in Sections I.B. through I.M., the owner or operator of a surface coating line or facility subject to that section does not cause, allow or permit the discharge into the atmosphere of any VOCs in excess of the specified emission limit, calculated as delivered to the coating applicator or as applied to the substrate, whichever is greater.

I.A.9.a.(ii) The owner or operator of a surface coating operation maintains and operates surface coating operations in a manner consistent with good air pollution control practices for minimizing emissions, such as, but not limited to, coating application methods capable of achieving a transfer efficiency achieved by HVLP spraying.

I.A.10. Compliance Calculation Procedures

I.A.10.a. Compliance with this section shall be determined on a daily basis. Sources may request a revision to the State Implementation Plan for longer times for compliance determination.

I.A.10.b. Compliance calculation procedures shall follow the guidance in "Procedure for Certifying Quantity of Volatile Organic Compounds Emitted by Paint, Ink, and Other Coatings," December 1984, EPA-450/3-84/019. In addition, for add-on controls or other compliance alternatives, calculation procedures shall follow the guidance of Section I.A.5.f.

I.A.11. The requirements of Sections I.A.1. through I.A.10. apply to each category of surface coating as specified in Sections I.B. through I.M. The requirements of Sections I.A.7. through I.A.10. apply to the category in Section I.N. The requirements of Sections I.A.1. through I.A.9 apply to the category in Section I.O.

I.A.12. The Division shall approve utilization of alternative compliance methods to the following sources pursuant to this Section I.

I.A.12.a. Lexmark International, Inc. shall be allowed to utilize the alternative compliance method of crossline averaging for processes and operations within the Manufactured Metal Parts and Metal products (Subgroup L) and within the Plastic Film Coating Operations (Subgroup J). The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met, and utilization of the alternative compliance method shall be subject to the following generic conditions, which shall be written and specifically described as enforceable permit terms and conditions in its permits:

I.A.12.a.(i) The alternative compliance method shall result in an actual reduction that is equivalent to the actual reduction that would otherwise be achieved on a line-by-line basis pursuant to this Regulation Number 7.

I.A.12.a.(ii) Credit shall not be received for downtime; however, credit is allowed for emission reductions from enforceable production limits.

I.A.12.a.(iii) Cross line averaging shall be used only across lines of the same control technique guidance group. Lexmark shall use cross line averaging between Metal Parts and Metal Products lines or between Plastic Film Coating lines. Lexmark shall not use cross line averaging where the emissions from Plastic film coating lines are averaged with Metal Parts and Metal Products lines.

I.A.12.a.(iv) The emission trading policy set forth in Regulation Number 3, Part A, Section V., shall be met on a daily weighted average.

I.A.12.a.(v) Sources subject to Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) shall not use cross line averaging.

I.A.12.a.(vi) To determine reduction over baseline, VOC emissions shall be expressed according to Section I.A.5.f., as lbs/gallons solids.

I.A.12.a.(vii) Monthly records shall be kept at the source to verify ongoing compliance with these conditions. The recordkeeping format shall be approved by the Division.

I.A.12.a.(viii) An annual report demonstrating ongoing compliance with this regulation and all permit terms shall be filed with the Division. The report format shall be approved by the Division and specifically described in the permit.

I.A.12.a.(ix) The Division shall issue a permit with federally enforceable terms and conditions to Lexmark limiting Lexmark's alternative compliance method emissions to those allowable under Section I.L. and Section I.J.

I.A.12.a.(x) Commercial and Product quality control laboratory equipment are exempt from APEN filing and construction permit requirements under Regulation Number 3, Part A, Section II.D.1.(i), and Regulation Number 3, Part B, Section II.D.1.a.; and from construction permit requirements under Regulation Number 3, Part B, Section II.D.1.(i). Qualifying sources shall be exempt from Regulation Number 7, Section I. A.6.

I.A.12.a.(xi) Nothing in the alternative compliance method is intended to relax any emissions limitation of this Regulation Number 7.

I.B. Automobile and Light-Duty Truck Assembly Plants

I.B.1. Definitions

I.B.1.a. "Application Area" means the area where the surface coating is applied by spraying, dipping or flow coating.

I.B.1.b. "Automobile" means a passenger motor-vehicle or a derivative of same, capable of seating twelve (12) or fewer passengers, and having at least two driven wheels.

I.B.1.c. "Automobile Assembly Facility" means a facility where parts (including assembled or partially assembled components) of automobiles are received, and finished automobiles are produced, partially or wholly by an assembly line.

I.B.1.d. "Light-Duty Truck" means any motor vehicle rated at 8,500 pounds (3,855 kilograms) gross vehicle weight or less, and having at least two driven wheels, which is designed primarily for purposes of transportation of property or is a derivative of such vehicles. It includes, but is not limited to, pickup trucks, vans, and window vans rated at 8,500 pounds' gross vehicular weight or less.

I.B.1.e. "Light-Duty Truck Assembly Facility" means a facility where parts (including assembled or partially assembled components) of light-duty trucks are received, and finished light-duty trucks are produced, partially or wholly by an assembly line.

I.B.2. Applicability

This section applies to all assembly and subassembly lines in an automobile or light-duty truck assembly facility, including those for frames, small parts, wheels, and main body parts. This section applies only to the manufacture of new vehicles.

I.B.3. Emission Limitations

	Kg/lc	Lb/gc
Prime application, flashoff area, and oven	0.23	1.9
Topcoat application area, flashoff area, and oven	0.34	2.8
Final repair application, flashoff area and oven	0.58	4.8

I.B.4. Coatings other than primer, surfacer (guidecoat), topcoat and final repair shall be considered under the miscellaneous metal parts Section I.L.

I.B.5. For topcoat application, if a complying coating is not used to meet the emission limit of Section I.B.3, then:

I.B.5.a. the alternate method shall meet an emission limit of 15.1 lb VOC/gal. solids deposited on the coated part; and

I.B.5.b. compliance shall be determined on a daily weighted average basis.

I.B.6. Topcoat operation shall include all spray booths, flash-off areas and ovens in which topcoat is applied, dried and cured, except for final offline repair.

I.C. Can Coating Operations

I.C.1. Definitions

I.C.1.a. "Can Coatings" means any coatings containing organic materials and applied -- or intended for application -- by spray, roller, or other means onto the inside and/or outside surfaces of formed cans and components of cans.

I.C.1.b. "End Sealing Compound" means a substance which is coated onto can ends and which functions as a seal when the end is assembled onto the can.

I.C.1.c. "Exterior Base Coat" means a coating applied to the exterior of a can to provide protection to the metal and/or to provide background for any lithographic or printing operation.

I.C.1.d. "Interior Base Coat" means the initial coating applied to the interior surface of a can by roller coater or spray.

I.C.1.e. "Interior Body Spray" means a coating sprayed onto the interior surface of the can body to provide a protective film between the can and its contents.

I.C.1.f. "Overvarnish" means a coating applied directly over ink to reduce the coefficient of friction, provide gloss, protect against abrasion, enhance product quality, and protect against corrosion.

I.C.1.g. "Three-Piece Can Side Seam Spray" means a coating sprayed onto the interior and/or exterior of a can body seam on a three-piece can to protect the exposed metal.

I.C.1.h. "Two-Piece Can Exterior End Coat" means a coating applied to the exterior of the bottom end of a two-piece can.

I.C.2. Applicability

This section applies to coating applicator(s), and oven(s) of sheet can or end coating lines involved in sheet basecoat (exterior and interior) and over varnish, two-and three-piece can interior body spray, two-piece can exterior end (spray or roll coat), three-piece can side-seam spray, and end sealing compound operations.

I.C.3. Emission Limitations

Can Coating	**Kg/lc**	**Lb/gc**
Sheet base coat (exterior and interior) and overvarnish two-piece can exterior (base coat and overvarnish)	0.34	2.8
Two and three-piece can interior body spray, two-piece can exterior end (spray or roll coat)	0.51	4.2
Three-piece can side-seam spray	0.66	5.5
End sealing compound	0.44	3.7
Any additional coats	0.51	4.2

I.D. Coil Coating Operations

I.D.1. Definitions

I.D.1.a. "Coil Coating" means any surface coating applied by spray, roller, or other means onto one or both surfaces of flat metal sheets or strips that come in rolls or coils.

I.D.1.b. "Quench Area" means a chamber where the hot metal exiting the oven is cooled by either a spray of water or a blast of air followed by water cooling.

I.D.2. Applicability

This section applies to the coating applicator(s), oven(s), and quench area(s) of coil coating operations involved in primer, intermediate, top-coat or single-coat operations.

I.D.3. Emission Limitations:

Coil Coating	Kg/lc	Lb/gc
Any coat (primer, intermediate coat, topcoat, single coat)	0.31	2.6

I.E. Fabric Coating Operations

I.E.1. Definitions

I.E.1.a. “Fabric Coating" means the process of coating or impregnating the full, usable surface of a fabric web or sheet to impart properties that are not initially present such as strength, stability, water or acid repellency, or appearance. "Fabric Coating" excludes those processes normally included under fabric finishing (e.g. dyeing, treating for stain and wrinkle resistance, etc.).

I.E.2. Applicability

This section applies to fabric coating lines which includes, but is not limited to, coaters and drying ovens.

I.E.3. Emission Limitations

	Kg/lc	Lb/gc
Fabric Coating Line	0.35	2.9

I.F. Large Appliance Coating Operations

I.F.1. Definition

I.F.1.a. "Large Appliances” includes doors, cases, lids, panels, interior support parts, and any other large (greater than one square decimeter (15.5 square inches)) coated surfaces of residential and commercial washers, dryers, ovens, ranges, refrigerators, freezers, water heaters, dishwashers, trash compactors, air conditioners, and all other products under SIC Code 363 according to the "Standard Industrial Classification Manual", Executive Office of the President, Office of Management and Budget, designated by convention of the industry as large appliances.

I.F.2. Applicability

This section applies to all large appliance coating lines.

I.F.3. Emission Limitations

	Kg/lc	Lb/gc
Large Appliance Coating Line; prime, single or topcoat application area, flashoff area, and oven	0.34	2.8

I.G. Magnet Wire Coating Operations

I.G.1. Definition

I.G.1.a. "Magnet Wire Coating" means those operations which apply a coating of electrically insulating varnish or enamel (or similar substance) to wire which is known as "magnet wire." Magnet wire is usually copper or aluminum, and is used for electric motors, generators, transformers, magnets, and related products.

I.G.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of magnet wire coating operations.

I.G.3. Emission Limitations

	Kg/lc	Lb/gc
Magnetic wire coating operation	0.20	1.7

I.H. Metal Furniture Coating Operations

I.H.1. Definitions

I.H.1.a. "Metal Furniture" means furnishings commonly considered furniture, for domestic, business, and/or institutional use, which have one or more essential, major components made of metal. "Metal furniture" includes, but is not limited to, tables, chairs, wastebaskets, beds, desks, lockers, shelving, cabinets, room dividers, clothing racks, chests of drawers, and sofas.

I.H.1.b. "Metal Furniture Coating" means applying a "surface coating" to "metal furniture" as defined. It excludes coating of non-metal components.

I.H.2. Applicability

This section applies to all metal furniture coating lines.

I.H.3. Emission Limitations

	Kg/lc	**Lb/gc**
Metal Furniture Coating Line: All coats (including prime, single, and topcoat)	0.36	3.0

I.I. Paper Coating Operations

I.I.1. Definition

"Paper Coating" means impregnating or applying a uniform layer of "surface coating" to paper. It includes, but is not limited to, the production of: coated, glazed, decorated, and varnished paper; carbon and pressure-sensitive copy papers; paper adhesive-labels and tapes; blue-print; photographic and copier paper. It also includes coating of metal foil such as gift wrap and packaging. Paper coating does not include impregnation using a batch dipping process.

I.I.2. Applicability

This section applies to paper coating lines, which includes, but is not limited to, coaters and drying ovens.

I.I.3. Emission Limitations

	Kg/lc	**Lb/gc**
Paper Coating Line	0.35	2.9

I.J. Plastic-Film Coating Operations

I.J.1. Definition

I.J.1.a. "Plastic-Film Coating" means applying a uniform layer of "surface coating" to a flexible web or sheet of thin plastic substance, excluding all rubbers and vinyl's* (polyvinyl chloride) except for the following two categories of vinyl products: (1) vinyl tapes and (2) vinyl's coated with an adhesive or pressure-sensitive coating. It includes, but is not limited to: plastic typewriter ribbons, photographic film, adhesive tapes, and magnetic recording tapes. (*see Section I.K.)

I.J.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of plastic-film coating lines.

I.J.3. Emission Limitations

	Kg/lc	Lb/gc
Plastic-Film Coating Line	0.35	2.9

I.K. Vinyl Coating Operations

I.K.1. Definition

"Vinyl Coating" means applying a uniform layer, decorative or protective topcoat to a vinyl (polyvinyl chloride) coated fabric or vinyl sheet. It includes printing of same. Excluded are*: (1) the coating of same with adhesive or pressure-sensitive coatings and (2) vinyl tapes. (*see Section I.J.)

I.K.2. Application

This section applies to vinyl coating lines which includes, but is not limited to, coaters and drying ovens.

I.K.3. Emission Limitations

	Kg/lc	Lb/gc
Vinyl Coating Line	0.45	3.8

I.L. Manufactured Metal Parts and Metal Products

I.L.1. General Provisions

I.L.1.a. Applicability

This section applies to the application area(s), flashoff area(s), oven(s), and drying areas including (but not limited to) air and forced air drier(s) used in the surface coating of the metal parts and products listed below. This section applies to prime coat, top coat, and single coat operations. This section is applicable to surface coating of manufactured metal parts and metal products which include:

I.L.1.a.(i) Large farm machinery (harvesting, fertilizing, and planting machines, tractors, combines, etc.);

I.L.1.a.(ii) Small-farm, lawn and garden machinery (lawn and garden tractors, lawn mowers, rototillers, etc.);

I.L.1.a.(iii) Small appliances (fans, mixers, blenders, crock pots, dehumidifiers, vacuum cleaners, etc.);

I.L.1.a.(iv) Commercial machinery (office equipment, computers and auxiliary equipment, typewriters, calculators, vending machines, etc.);

I.L.1.a.(v) Industrial machinery (pumps, compressors, conveyor components, fans, blowers, transformers, etc.);

I.L.1.a.(vi) Fabricated metal products (metal covered doors, frames, etc.);

I.L.1.a.(vii) Furniture hardware made of metal for use with non-metal furniture; and

I.L.1.a.(viii) Any other industrial category which coats metal parts or products under the standard industrial classification code of major group 33 (primary metal industries), major group 34 (fabricated metal products), major group 35 (non-electric machinery), major group 36 (electrical machinery), major group 37 (transportation equipment), major group 38 (miscellaneous instruments), and major group 39 (miscellaneous manufacturing industries), according to the "Standard Industrial Classification Manual" Executive Office of the President, Office of Management and Budget.

I.L.1.b. Exemptions

I.L.1.b.(i) This Section I.L. is not applicable to the surface coating of the following metal parts and products inasmuch as these are previously covered in Sections I.B., C., D., F., G., and H., respectively:

I.L.1.b.(i)(A) Automobiles and light-duty trucks

I.L.1.b.(i)(B) Metal cans

I.L.1.b.(i)(C) Flat metal sheets and strips in the form of rolls or coils

I.L.1.b.(i)(D) Large appliances

I.L.1.b.(i)(E) Magnet wire for use in electrical machinery

I.L.1.b.(i)(F) Metal furniture

I.L.1.b.(ii) This Section I.L. is not applicable to the following special purpose coatings:

I.L.1.b.(ii)(A) Division-approved exemptions for high performance coatings on a case-by-case basis.

I.L.1.b.(ii)(B) Full exterior repainting of automobiles and light-duty trucks if fewer than 18 vehicles are painted per day.

I.L.1.c. Definitions

For the purpose of this section, the following definitions apply:

I.L.1.c.(i) "Air Dried Coating" means coatings which are dried by the use of air or forced warm air at temperatures up to 90°C (194°F);

I.L.1.c.(ii) "Clear Coat" means a coating, which lacks color and opacity or a coating which is transparent;

I.L.1.c.(iii) "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, flashoff areas, air dryers and ovens;

I.L.1.c.(iv) "Extreme Environmental Conditions" means exposure to any of the following: temperatures consistently above 95°C, detergents, abrasive and scouring agents, solvents, and corrosive environments;

I.L.1.c.(v) "Extreme Performance Coatings" means coatings designed for extreme environmental conditions.

I.L.2. Provisions for Specific Processes

I.L.2.a. No owner or operator of a facility or operation engaging in the surface coating of manufactured metal parts or metal products may operate a coating application system subject to this regulation that emits VOC in excess of:

I.L.2.a.(i) Clear coatings: 0.52 kg/lc (4.3 lb/gc)

I.L.2.a.(ii) Extreme Performance Coatings: 0.42 kg/lc (3.5 lb/gc)

I.L.2.a.(iii) Air-Dried Coatings: 0.42 kg/lc (3.5 lb/gc)

I.L.2.a.(iv) Other coatings and systems: 0.36 kg/lc (3.0 lb/gc) delivered to a coating applicator for all other coatings and coating application systems.

I.L.2.b. If more than one emission limitation in Section I.L.2.a. applies to a specific coating, then the least stringent emission limitation shall be applied.

I.L.2.c. Pioneer Metal Finishing, Inc., a surface coating operation, is authorized pursuant to Regulation Number 3, Part A, Section V. and Regulation Number 7, Part A, Section II.D.1.a. to use up to twenty (20) tons of certified emission reduction credits of volatile organic compounds (VOC) as an alternative compliance method to satisfy the surface coating emission limitations of Regulation Number 7 in accordance with and upon demonstration of the conditions set forth below:

I.L.2.c.(i) Certified emission reduction credits for VOCs (methanol) to be used in this transaction were formerly owned by the Coors Brewing Company, registered and issued in Emissions Reduction Credit Permit 91AR120R on July 25, 1994;

I.L.2.c.(ii) Those emission reduction credits were originally obtained by Coors from Verticel, a company that produced honeycomb packaging material and was located within five miles of the PMF facility;

I.L.2.c.(iii) The use of these VOC emission reduction credits identified above shall be used to satisfy VOC limitations of certain specified surface coatings in excess of Control Technique Guidance as specified in Regulation Number 7, Section I.L.2.a. and Section I.A.6.b., and applicable to the Pioneer Metal finishing operations;

I.L.2.c.(iv) Such emission reduction credits identified above will be used by PMF to achieve compliance with Regulation Number 7 to compensate for ozone precursor emission of VOCs from non-compliant coatings which meet the emission trading requirements of Regulation Number 3, Part A, Section V. In order to satisfy the photochemical reactivity equivalency requirement of VOC trades, the methanol VOC ERCs will be reduced on a ratio of 1.1:1 for VOCs of toluene, ethylbenzene, xylene and ketones emitted from non-compliant coatings. All other VOCs involved in this transaction are considered to be of the same degree of photochemical reactivity;

I.L.2.c.(v) The requirement in Regulation Number 3, Part A, Section V.F.2. shall not apply to this transaction;

I.L.2.c.(vi) This transaction is only valid within the Denver/Boulder nonattainment area as described at 40 CFR 81, Subchapter C - Air Programs, Subpart C, Section 107 - Attainment Status Designations, Section 81.306 (February 16, 1995);

I.L.2.c.(vii) This transaction shall be calculated upon a pound for pound basis and averaged over a maximum 24-hour period.

I.L.2.c.(viii) This transaction shall be effective upon approval by the U.S. Environmental Protection Agency as a revision to the Colorado State Implementation Plan and after issuance of a State Construction Permit incorporating, but not limited to, the conditions and requirements of the Section;

I.L.2.c.(ix) This transaction may not be used to satisfy any current or future requirements of NSPS, BACT, LAER, or MACT requirements of HAPs which may apply to PMF, except that this transaction may be used to satisfy control technique guidance or RACT requirements contained in Regulation Number 7 which are applicable to PMF;

I.L.2.c.(x) This transaction shall not interfere with any applicable requirement concerning attainment and reasonable further progress in the Colorado State Implementation Plan or any other applicable requirements of the Clean Air Act;

I.L.2.c.(xi) This transaction shall be registered and enforced through a State Construction Permit issued to Pioneer Metal Finishing, Inc. containing, but not limited to the conditions and limitations set forth in this Section;

I.L.2.c.(xii) Such state Construction Permit issued to Pioneer Metal Finishing, Inc. shall specify, among other, things the necessary monitory, recordkeeping and reporting requirements to insure that the emission reduction credits are applied in accordance with the conditions and requirements of this Section;

I.L.2.c.(xiii) The state Construction Permit shall allow a daily maximum limitation of 160 lbs. of VOC emissions from non-compliant surface coatings and an annual limitation of 40,000 lbs. of non-compliant VOC emissions. The annual limitation shall be calculated on a 12-month rolling total calculated on the first day of each month using the previous 12 months.

I.L.2.c.(xiv) The state Construction Permit shall limit the VOC-HAP emissions to less than ten (10) per year of any one HAP or twenty-five (25) tons per year of any combination of HAP emissions; and

I.L.2.c.(xv) PMF will maintain records of daily and monthly totals of non-compliant surface coatings used in its operation and report such usages on an annual basis to the Division or as otherwise requested.

I.M. Flat Wood Paneling Coating.

I.M.1. Definitions

I.M.1.a. "Class II Hardboard Paneling Finish" means finishes which meet the specifications of Voluntary Product Standard PS-59-73 as approved by the American National Standards Institute.

I.M.1.b. "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, conveyers, flashoff areas, air dryers and ovens.

I.M.1.c. "Hardboard" is a panel manufactured primarily from inter-felted ligno-cellulosic fibers which are consolidated under heat and pressure in a hot press.

I.M.1.d. "Hardboard Plywood" is plywood whose surface layer is a veneer of hardwood.

I.M.1.e. "Natural Finish Hardwood Plywood Panels" means panels whose original grain pattern is enhanced by essentially transparent finishes frequently supplemented by fillers and toners.

I.M.1.f. "Printed Interior Panels" means panels whose grain or natural surface is obscured by fillers and basecoats upon which a simulated grain or decorative pattern is printed.

I.M.1.g. "Thin Particleboard" is a manufactured board 1/4 inch or less in thickness made of individual wood particles which have been coated with a binder and formed into flat sheets by pressure.

I.M.1.h. "Tileboard" means paneling that has a colored waterproof surface coating.

I.M.2. Applicability

This section applies to all flat wood manufacturing and surface finishing facilities that manufacture printed interior panels made of hardwood plywood and thin particle board; natural finish hardwood plywood panels, or hardboard paneling with Class II finishes. This section does not apply to the manufacture of exterior siding, tileboard, or particleboard used as a furniture component.

I.M.3. Emission Limitations

I.M.3.a. 2.9 kg per 100 square meters of coated finished product (6.0 lb/1,000 sq. ft.) from printed interior panels, regardless of the number of coats applied;

I.M.3.b. 5.8 kg per 100 square meters of coated finished product (12.0 lb/1,000 sq. ft.) from natural finish hardwood plywood panels, regardless of the number of coats applied; and

I.M.3.c. 4.8 kg per 100 square meters of coated finished product (10.0 lb/1,000 sq. ft.) from Class II finishes on hardboard panels, regardless of the number of coats applied.

I.N. Manufacture of Pneumatic Rubber Tires

I.N.1. Definitions

I.N.1.a. "Bead Dipping" means the dipping of an assembled tire bead into a solvent-based cement.

I.N.1.b. "Green Tires" means assembled tires before holding and curing have occurred.

I.N.1.c. "Green Tire Spraying" means the spraying of green tires, both inside and outside, with release compounds which help remove air from the tire during molding and prevent the tire from sticking to the mold after curing.

I.N.1.d. "Pneumatic Rubber Tire Manufacture" means the production of pneumatic rubber, passenger type tires on a mass production basis.

I.N.1.e. "Passenger Type Tire" means agricultural, airplane, industrial, mobile home, light and medium duty truck, and passenger vehicle tires with a bead diameter up to 20.0 inches and cross section dimension up to 12.8 inches.

I.N.1.f. "Tread End Cementing" means the application of a solvent-based cement to the tire tread ends.

I.N.1.g. "Undertread Cementing" means the application of a solvent-based cement to the underside of a tire tread.

I.N.1.h. "Water Based Sprays" means release compounds, sprayed on the inside and outside of green tires, in which solids, water, and emulsifiers have been substituted for organic solvents.

I.N.2. Applicability

This section applies to VOC emissions from the following operations in all pneumatic rubber tire facilities: undertread cementing, tread end cementing, bead dipping, and green tire spraying.

The provisions of this section do not apply to the production of specialty tires for antique or other vehicles when produced on an irregular basis or with short production runs. This exemption applies only to tires produced on equipment separate from normal production lines for passenger type tires.

I.N.3. Provisions for Specific Processes

I.N.3.a. The owner or operator of an undertread cementing, tread end cementing, or bead dipping operation subject to this regulation shall:

I.N.3.a.(i) Install and operate a capture system, designed to achieve maximum reasonable capture, up to 85 percent by weight of VOC emitted, from all undertread cementing, tread end cementing and bead dipping operations. Maximum reasonable capture shall be consistent with the following documents:

I.N.3.a.(i)(A) Industrial Ventilation, A Manual of Recommended Practices, 17th Edition, American Federation of Industrial Hygienists, 1982.

I.N.3.a.(i)(B) Recommended Industrial Ventilation Guidelines, U.S. Department of Health, Education and Welfare, National Institute of Occupational Safety and Health, January 1976.

I.N.3.a.(ii) Install and operate a control device that meets the requirements of one of the following:

I.N.3.a.(ii)(A) A carbon adsorption system designed and operated in a manner such that there is at least a 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.3.a.(ii)(B) An incineration system that oxidizes at least 90.0 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) which enter the incinerator to carbon dioxide and water.

I.N.4. The owner or operator of a green tire spraying operation subject to this regulation must implement one of the following means of reducing volatile organic compound emissions:

I.N.4.a. Substitute water-based sprays for the normal solvent-based mold release compound; or,

I.N.4.a.(i) Install a capture system designed and operated in a manner that will capture and transfer at least 90.0 percent of the VOC emitted by the green tire spraying operation to a control device; and,

I.N.4.a.(ii) In addition to Section I.N.4.a.(i), install and operate a control device that meets the requirements of one of the following:

I.N.4.a.(ii)(A) a carbon adsorption system designed and operated in a manner such that there is at least 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.4.a.(ii)(B) an incineration system that oxidizes at least 90 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) to carbon dioxide and water.

I.N.5. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

I.N.6. Control devices shall meet the applicable requirements, including recordkeeping, of Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

I.N.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

I.O. Wood Products Coating

I.O.1. Definitions

I.O.1.a. “As Applied” means the VOC and solids content of the finishing material that is actually used for coating the substrate. It includes the contribution of materials used for in-house dilution of the finishing material.

I.O.1.b. “Cleaning Operation” means operations in which organic solvent is used to remove coating materials from equipment used in wood furniture manufacturing operations.

I.O.1.c. “Conventional Air Spray” means a spray coating method in which the coating is atomized by mixing it with compressed air at an air pressure greater than 10 pounds per square inch (gauge) at the point of atomization. Airless and air assisted spray technologies are not conventional air spray because the coating is not atomized by mixing it with compressed air. Electrostatic spray technology is also not considered conventional air spray because an electrostatic charge is employed to attract the coating to the workplace.

I.O.1.d. “Equipment Leak” means emissions of VOCs from pumps, valves, flanges, or other equipment used to transfer or apply finishing materials or organic solvents.

I.O.1.e. “Finishing Material” means a coating used in the wood furniture industry including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats.

I.O.1.f. “Finishing Operation” means those activities in which a finishing material, including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats, is applied to a substrate and is subsequently air-dried, cured in an oven, or cured by radiation.

I.O.1.g. “Organic Solvent” means a liquid containing VOCs that is used for dissolving or dispersing constituents in a coating, adjusting the viscosity of a coating, cleaning, or washoff. When used in a coating, the organic solvent evaporates during drying and does not become part of the dried film.

I.O.1.h. “Sealer” means a finishing material used to seal the pores of a wood substrate before additional coats of finishing material are applied. Washcoats, which are used in some finishing systems to optimize aesthetics, are not sealers.

I.O.1.i. “Strippable Booth Coating” means a coating that is applied to a booth wall to provide a protective film to receive overspray during finishing operations that is subsequently peeled off and disposed, and reduces or eliminates the need to use organic solvents to clean booth walls.

I.O.1.j. “Topcoat” means the last film-building finishing material applied in a finishing system. Non-permanent final finishes are not topcoats.

I.O.1.k. “Washcoat” means a transparent special purpose coating that has a solids content by weight of 12 percent or less. Washcoats are applied over initial stains to protect and control color and to stiffen the wood fibers in order to aid sanding.

I.O.1.l. “Washoff Operation” means those operations in which organic solvent is used to remove coating from a substrate.

I.O.1.m. “Wood Furniture” means any product made of wood, a wood product such as rattan or wicker, or an engineer wood product such as particleboard.

I.O.1.n. “Wood Furniture Component” means any part that is used in the manufacture of wood furniture including, but not limited to, drawer sides, cabinet doors, seat cushions, and laminated tops.

I.O.1.o. “Wood Furniture Manufacturing Operation” means the finishing, cleaning, and washoff operations associated with the production of wood furniture or wood furniture components.

I.O.2. Applicability

This section applies to wood furniture manufacturing operations with uncontrolled actual VOC emissions greater than or equal to 25 tons per calendar year.

Beginning July 1, 2021, this section applies to other wood products coating operations with uncontrolled actual VOC emissions greater than or equal to 50 tons per year (as of January 27, 2020, located in the 8-Hour Ozone Control Area).

I.O.3. Emission Limitations

I.O.3.a. The owner or operator of a wood furniture manufacturing or other wood products coating operation must limit VOC emissions from finishing operations by:

I.O.3.a.(i) Using topcoats with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids); or

I.O.3.a.(ii) Using a finishing system of:

I.O.3.a.(ii)(A) Sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids), as applied; and

I.O.3.a.(ii)(B) Topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied; or

I.O.3.a.(iii) For sources using acid-cured alkyd amino vinyl sealers or acid-cured alkyd amino conversion varnish topcoats:

I.O.3.a.(iii)(A) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and an acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied; or

I.O.3.a.(iii)(B) Use acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied, and sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids); or

I.O.3.a.(iii)(C) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied.

I.O.3.b. The owner or operator of a wood furniture manufacturing or other wood products coating operation must use strippable booth coatings with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids), as applied.

I.O.3.c. The owner or operator of a wood furniture manufacturing or other wood products coating operation must use compounds containing equal to or less than 8.0 percent by weight of VOC for cleaning spray booth components other than conveyors, continuous coaters and their enclosures, and/or metal filters, unless the spray booth is being refurbished. If the spray booth is refurbished (i.e., spray booth coating or other material used to cover the booth is being replaced), the owner or operator must use equal to or less than 1.0 gallon of organic solvent to prepare the booth prior to applying the booth coating.

I.O.4. Work Practices

I.O.4.a. In addition to complying with Sections I.A.7. and I.A.9., the owner or operator of a wood furniture manufacturing or other wood products coating operation must:

I.O.4.a.(i) Develop an operator training program that includes, at a minimum, appropriate application techniques, appropriate cleaning and washoff procedures, appropriate equipment setup and adjustment to minimize finishing material usage and overspray, and appropriate management of cleanup wastes;

I.O.4.a.(ii) Conduct monthly visual inspections of all equipment used to transfer or apply finishing materials or organic solvents for equipment leaks and repair equipment leaks within 15 working days, or within 3 months if the leaking equipment must be replaced by a new purchase;

I.O.4.a.(iii) Collect cleaning and washoff solvents into closed containers;

I.O.4.a.(iv) Use conventional air spray guns only to:

I.O.4.a.(iv)(A) Apply finishing materials with a VOC content equal to or less than 1.0 lb VOC/lb solids (1.0 kg VOC/kg solids), as applied;

I.O.4.a.(iv)(B) Touch-up and repair after completion of the finishing operation, after stain and before other finishing material, or to apply stain on a part for which it is technically or economically infeasible to use any other spray application technology.

I.O.5. Recordkeeping

I.O.5.a. The owner or operator of a wood furniture manufacturing or other wood products coating operation must keep the following records for five (5) years and make them available for inspection by the Division upon request:

I.O.5.a.(i) Records of calendar year VOC emission estimates demonstrating whether the wood furniture manufacturing operation means or exceeds the applicability threshold in Section I.O.2.;

I.O.5.a.(ii) Records of the operator training program;

I.O.5.a.(iii) Records of the date and results of the monthly equipment inspections and any repairs that were made;

I.O.5.a.(iv) Records such as, but not limited to, data sheets documenting how the as applied values were determined and safety data sheets or other analytical data from the manufacturer showing the VOC content of each sealer, topcoat, strippable booth coating, or cleaning booth compound subject to the emission limits in Section I.O.3.; and

I.O.5.a.(v) Monthly records of the quantity and type of organic cleaning and washoff solvent used.

II. Solvent Use

II.A. General Provisions

II.A.1. Applicability

The provisions of this section apply to cold cleaners, non-conveyorized vapor degreasers, conveyorized degreasers, industrial cleaning solvent operations, and other operations that use

solvents. Open top vapor degreasers are a subset of non-conveyorized vapor degreasers. The owner or operator of a unit subject to this section shall ensure that no such unit is used unless the requirements of this section are satisfied. Section II.E. requirements are effective on January 1, 2017. Section II.F. requirements are effective on May 1, 2021.

II.A.2. Definitions

II.A.2.a. "Cold-Cleaner" means a container of non-aqueous liquid solvent held below its boiling point, which is designed, used, or intended for cleaning solid objects in a batch-loaded process. A "cold-cleaner" may have provisions for heating the solvent. It does not include vapor degreasers or continuously loaded conveyorized degreasers.

II.A.2.b. "Composite Partial Vapor Pressure" means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the "i"th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the "i"th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the "i"th VOC compound at 20°C(68°F), in mm Hg

II.A.2.c. "Conveyorized Degreaser" means an apparatus that performs degreasing or other cleaning functions through the use of non-aqueous liquid solvent and/or solvent vapors within a container, and which has a conveyor mechanism allowing continuous loading of items conveyed into and out of the solvent.

II.A.2.d. "Freeboard" in a vapor degreaser means the vertical distance from the top of the vapor zone (as established by normal operations within the specifications of the degreaser manufacturer) to the top of the degreaser. For cold-cleaners "freeboard" means the vertical distance from the surface of the solvent liquid to the top of the degreaser. If all sides are not even, the vertical distance to the top of the lowest side shall be used to make the determination of freeboard.

II.A.2.e. "Freeboard Ratio" means the ratio of the freeboard to the width of the solvent surface.

II.A.2.f. "Industrial Cleaning Solvent" means a VOC-containing liquid used to perform industrial cleaning solvent operations.

II.A.2.g. “Industrial Cleaning Solvent Operation” means the use of an industrial cleaning solvent for cleaning industrial operations such as spray gun cleaning, spray booth cleaning, large manufactured parts cleaning, equipment cleaning, floor cleaning, line cleaning, parts cleaning, tank cleaning, and small manufactured parts cleaning. Residential and janitorial cleaning are not considered industrial cleaning solvent operations.

II.A.2.h. "Non-Conveyorized Vapor Degreaser” means an apparatus, which uses non-aqueous solvent vapors within some type of container to degrease or otherwise clean solid objects in a batch-loaded process. It excludes continuously loaded conveyorized degreasers.

II.A.2.i. “Residential and Janitorial Cleaning” means the cleaning of a building or building components including, but not limited to, floors, ceilings, wall, windows, doors, stairs, bathrooms, furnishings, and exterior surfaces of office equipment, excluding the cleaning of work areas where manufacturing or repair activity is performed.

II.A.2.j. "Solvent Metal Cleaning" means the process of cleaning soils from metal surfaces by cold cleaning, conveyorized degreasing, or non-conveyorized vapor degreasing.

II.A.3. Transfer of waste solvent and used solvent

In any disposal or transfer of waste or used solvent, at least 80 percent by weight of the solvent/waste liquid shall be retained (i.e., no more than 20 percent of the liquid solvent/solute mixture shall evaporate or otherwise be lost during transfers).

II.A.4. Storage of waste solvent and used solvent

Waste or used solvent shall be stored in closed containers unless otherwise required by law.

II.A.5. Any control device shall meet the applicable requirements of Sections I.A.3.a., b., c., e., and I.A.8.a. and b.

II.B. Control of Solvent Cold-Cleaners

II.B.1. Control Equipment

II.B.1.a. Covers

II.B.1.a.(i) All cold-cleaners shall have a properly fitting cover.

II.B.1.a.(ii) Covers shall be designed to be easily operable with one hand under any of the following conditions:

II.B.1.a.(ii)(A) Solvent true vapor pressure is greater than 15 torr (0.3 psia) at 38°C (100°F).

II.B.1.a.(ii)(B) The solvent is agitated by an agitating mechanism.

II.B.1.a.(ii)(C) The solvent is heated.

II.B.1.b. Drainage Facility

II.B.1.b.(i) All cold-cleaners shall have a drainage facility that captures the drained liquid solvent from the cleaned parts.

II.B.1.b.(ii) For cold-cleaners using solvent which has a vapor pressure greater than 32 torr (0.62 psia) measured at 38°C (100°F) either:

II.B.1.b.(ii)(A) There shall be an internal drainage facility within the confines of the cold-cleaner, so that parts are enclosed under the (closed) cover to drain after cleaning, or if such a facility will not fit within;

II.B.1.b.(ii)(B) An enclosed, external drainage facility that captures the drained solvent liquid from the cleaned parts.

II.B.1.c. A permanent, clearly visible sign shall be mounted on or next to the cold-cleaner. The sign shall list the operating requirements.

II.B.1.d. Solvent spray apparatus shall not have a splashing, fine atomizing, or shower type action but rather should produce a solid, cohesive stream. Solvent spray shall be used at a pressure that does not cause excessive splashing.

For solvents with a true vapor pressure above 32 torr (0.62 psia) at 38°C (100°F), or, for solvents heated above 50°C (120°F), one of the following techniques shall be used:

II.B.1.d.(i) A freeboard ratio greater than or equal to 0.7.

II.B.1.d.(ii) A water or a non-volatile liquid cover. The cover liquid shall not be soluble in the solvent and shall not be denser than the solvent and the depth of the cover liquid shall be sufficient to prevent the escape of solvent vapors.

II.B.2. Operating requirements

II.B.2.a. The cold-cleaner cover shall be closed whenever parts are not being handled within the cleaner confines.

II.B.2.b. Cleaned parts shall be drained for at least 15 seconds and/or until dripping ceases. Any pools of solvent shall be tipped out on the clean part back into the tank.

II.C. Control of Non-Conveyorized Vapor Degreasers

II.C.1. Control Equipment

II.C.1.a. The non-conveyorized vapor degreaser shall have a cover which shall be designed and operated so that it can be easily opened and closed through the use of mechanical assists such as spring loading, counterweights, etc.; opening and closing the cover shall not disturb the vapor zone.

II.C.1.b. Safety Switches

The following two types of switches shall be installed on vapor degreasers:

II.C.1.b.(i) Condenser flow switch and thermostat - (shuts off sump heat if the condenser coolant is either not circulating or is too warm); and

II.C.1.b.(ii) Spray safety switch - (shuts off spray pump if the vapor level drops more than four (4) inches).

II.C.1.c. Control Device

II.C.1.c.(i) For non-conveyorized vapor degreasers with an open area (with the cover open) of one square meter (10.8 ft_2) or less, either the freeboard ratio shall be greater than or equal to 0.75, or one of the control devices in II.C.1.c.(ii) shall be used.

II.C.1.c.(ii) For non-conveyorized vapor degreasers with an open area (with the cover open) greater than one (1) square meter, (10.8 ft_2), at least one of the following control systems shall be used:

II.C.1.c.(ii)(A) Both a powered cover and a freeboard ratio greater than or equal to 0.75.

II.C.1.c.(ii)(B) A refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix C.

II.C.1.c.(ii)(C) An enclosed design: A system where the cover(s) or door(s) opens only when a dry part is entering or exiting the degreaser.

II.C.1.c.(ii)(D) A carbon adsorption system with ventilation greater than or equal to 15 cubic meters each minute per square meter (50 cfm/ft_2) of air/vapor area (when the cover(s) is [are] open), exhausting less than 25 parts per million (by volume) of solvent averaged over one complete adsorption cycle.

II.C.1.d. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.C.2. Operating Requirements

II.C.2.a. Keep cover closed at all times except when processing work loads into or out of the degreaser.

II.C.2.b. The following operations shall be performed to minimize solvent carry-out:

II.C.2.b.(i) Rack parts to allow full drainage.

II.C.2.b.(ii) Move parts as slowly as is practicable in and out of the degreaser. A maximum of one foot every five seconds by hand or a maximum of 5.5 cm/sec. (10.8ft/min) for a mechanically operated system.

II.C.2.b.(iii) Allow the workload to clean in the vapor zone at least 30 seconds or until condensation ceases.

II.C.2.b.(iv) Tip out any pools of solvent that remain on the cleaned parts before removal from the vapor zone.

II.C.2.b.(v) Allow parts to dry within the degreaser at least 15 seconds and/or until visually dry.

II.C.2.c. Solvents shall not be used to clean porous or absorbent materials; for example, cloth, leather, wood, rope, etc.

II.C.2.d. Workloads shall not occupy more than half of the degreaser's open top area.

II.C.2.e. Spraying shall not be done above the vapor level.

II.C.2.f. Solvent leaks shall be repaired immediately, or the degreaser shall be shut down.

II.C.2.g. Exhaust ventilation shall not exceed twenty (20) cubic meters per minute per square meter (65.6 cfm per sq. ft.) of degreaser open area, unless greater exhaust rates are necessary to meet Occupational and Safety Health Act requirements. Ventilation fans shall not be used near the degreaser opening, unless necessary to meet Occupational and Safety Health Act requirements.

II.C.2.h. The water separator shall function so that no visible water is present in the solvent exiting the separator.

II.D. Control of Conveyorized Degreasers

II.D.1. Control Equipment

II.D.1.a. Control Device

For all conveyorized degreasers with a solvent surface area greater than two (2) square meters (21.5 square feet), the degreasing shall be controlled by at least one of the following:

II.D.1.a.(i) Carbon adsorption system, with ventilation greater or equal to 15 cubic meters per minute per square meter (49.2 cfm/ft_2) of air/vapor interface for vapor degreasers (of air/liquid interface for non-vapor types) when down-time covers are open, and exhausting less than 25 parts per million of solvent (by volume) averaged over a complete adsorption cycle.

II.D.1.a.(ii) For vapor degreasers only: a refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix D.

II.D.1.b. Prevention of Carry-out

A drying tunnel, tumbling basket(s), or other demonstrably effective method(s) shall be employed to prevent cleaned parts from carrying out solvent liquid or vapor.

II.D.1.c. Safety Switches

II.D.1.c.(i) The following two (2) switch-circuits (or equivalent) shall be installed.

II.D.1.c.(i)(A) A spray safety switch shall shut off the spray pump and/or the conveyor if the vapor level drops more than four (4) inches.

II.D.1.c.(i)(B) A vapor level control thermostat shall shut off sump heat when the vapor level rises too high.

II.D.1.c.(ii) All conveyorized degreasers shall have a condenser thermostat and flow-detector switch (or equivalent) which shuts off sump heat if coolant is too warm or is not circulating.

II.D.1.d. Minimized Openings: Degreaser entrance and exit openings shall silhouette workloads so that the average clearance between parts (or parts-and the edge of the degreaser opening) is either:

II.D.1.d.(i) less than 10 centimeters (4 inches) or;

II.D.1.d.(ii) less than 10 percent of the width of the opening

II.D.1.e. Covers shall be provided to close off all the entrance(s) and exit(s) when the conveyor is not in use.

II.D.1.f. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.D.2. Operating Requirements

II.D.2.a. Exhaust ventilation shall not exceed 20 m^3/minute per square meter of degreaser opening (65.6 cf/m per square foot), unless necessary to meet OSHA requirements. Work place fans shall not be located near, nor directed at degreaser openings, unless necessary to meet OSHA requirements. Exhaust flow shall be measured by EPA reference methods 1 and 2 of 40 CFR Part 60 (September 14, 1989).

II.D.2.b. Carry-out emissions shall be minimized by:

II.D.2.b.(i) Racking parts in such a manner to achieve best drainage.

II.D.2.b.(ii) Maintaining the vertical component of conveyor speed at less than 3.3 meters per minute (10.8 feet per minute).

II.D.2.c. Repair solvent leaks immediately, or shut down the degreaser.

II.D.2.d. The water separator shall function with an efficiency sufficient to prevent water from being visible in the solvent exiting the separator.

II.D.2.e. Down-time cover(s) shall be placed over entrances and exits of conveyorized degreasers immediately after the conveyor and exhaust are shut down. Covers shall be retained in position until immediately before start-up.

II.E. Control of Industrial Cleaning Solvent Operations

II.E.1. Control Requirements

The owner or operator of an industrial cleaning solvent operation with total combined uncontrolled actual VOC emissions equal to or greater than three (3) tons per calendar year (excluding VOC emissions from solvents used for cleaning operations that are exempt under Section II.E.4.) must:

II.E.1.a. Limit the VOC content of cleaning solvents to less than or equal to 0.42 lb of VOC/gal (50 grams VOC/liter); or

II.E.1.b. Limit the composite partial vapor pressure of the cleaning solvent to 8 millimeters of mercury (mmHg) at 20 degrees Celsius (68 degrees Fahrenheit); or

II.E.1.c. Reduce VOC emissions with an emission control system having a control efficiency of 90% or greater.

II.E.2. Work Practice Requirements

The owner or operator of an industrial cleaning solvent operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

II.E.2.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

II.E.2.b. Properly dispose of used solvent and shop towels; and

II.E.2.c. Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintaining cleaning equipment to be leak free.

II.E.3. Monitoring, Recordkeeping and Reporting Requirements

II.E.3.a. The owner or operator of an industrial cleaning solvent operation must keep the following records for two (2) years and make them available for inspection by the Division upon request:

II.E.3.a.(i) If applicable, records demonstrating that a listed exemption to this Section II.E. applies.

II.E.3.a.(ii) If applicable, monthly records such as safety data sheets or other analytical data from the industrial cleaning solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent cleaning operations to demonstrate compliance with the control requirements in Sections II.E.1.a. and II.E.1.b.

II.E.3.a.(iii) If applicable, monthly records sufficient to demonstrate compliance with the control requirement in Section II.E.1.c.

II.E.3.a.(iv) Records of calendar year VOC emission estimates demonstrating whether the industrial cleaning solvent operation meets or exceeds the applicability threshold in Section II.E.1.

II.E.3.b. Compliance with the control requirements in Section II.E.1. must be demonstrated using one of the following methods as applicable:

II.E.3.b.(i) Safety data sheets or other analytical data from the industrial cleaning solvent manufacturer to demonstrate compliance with Sections II.E.1.a. and II.E.1.b.;

II.E.3.b.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with Section II.E.1.c.; or

II.E.3.b.(iii) A performance test conducted during representative operations using one of the following methods, as applicable:

II.E.3.b.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content;

II.E.3.b.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.

II.E.4. Exemptions

II.E.4.a. Industrial cleaning solvent operations are not subject to Section II.E. if they are subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT.

II.E.4.b. The VOC control requirements in Section II.E.1. do not apply to:

II.E.4.b.(i) Cleaning of electrical and electronic components;

II.E.4.b.(ii) Cleaning of precision optics;

II.E.4.b.(iii) Cleaning of numismatic dies;

II.E.4.b.(iv) Stripping of cured inks, coatings, and adhesives;

II.E.4.b.(v) Cleaning of resin, coating, ink, and adhesive manufacturing, mixing, molding, and application equipment;

II.E.4.b.(vi) Cleaning of research and development laboratories;

II.E.4.b.(vii) Cleaning of medical device or pharmaceutical manufacturing equipment;

II.E.4.b.(viii) Performance testing to determine coating, adhesive, ink or ink performance;

II.E.4.b.(ix) Cleaning of equipment and materials used in testing for quality control or quality assurance purposes;

II.E.4.b.(x) Cleaning of digital printing operations; and

II.E.4.b.(xi) Cleaning of screen printing operations.

II.E.4.c. In lieu of compliance with Section II.E.1. and II.E.2., the owner or operator of an area source aerospace facility, as defined in 40 CFR Part 63, Section 63.742

(November 17, 2016), may implement the solvent cleaning provisions of the National Emission Standards for Hazardous Air Pollutants for Aerospace Manufacturing and Rework facilities contained in 40 CFR Part 63, Section 63.744 (November 17, 2016) along with the applicable definitions contained in 40 CFR Part 63, Section 63.742 (November 17, 2016), except that:

II.E.4.c.(i) VOC-containing solvents which meet the definition of "non-HAP materials" in 40 CFR Part 63, Section 63.742 (November 17, 2016) are not excluded from the housekeeping measures contained in 40 CFR Part 63, Section 63.744(a) (November 17, 2016); and

II.E.4.c.(ii) The baseline reduction compliance option contained in 40 CFR Part 63, Section 63.744(b)(3) (November 17, 2016) is not available for purposes of compliance with this VOC control rule.

II.F. General Solvent Use

II.F.1. Applicability

II.F.1.a. Within the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to two (2) tons per year that existed at major sources of VOC (greater than or equal to 50 tpy VOC) as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.1.b. (State Only) Outside the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to five (5) tons per year that existed at sources of VOC greater than or equal to 50 tpy VOC as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.2. Exemptions

The requirements of this Section II.F. do not apply to:

II.F.2.a. Operations that are subject to a solvent work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that constitutes RACT, or;

II.F.2.b. Solvent use where the solvent does not contain VOCs.

II.F.3. Work practice requirements

The owner or operator of operations that use solvents must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

II.F.3.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

II.F.3.b. Properly dispose of used solvent and solvent contaminated waste (e.g. shop towels and carbon filtration or other control device media), and;

II.F.3.c. Implement good air pollution control practices that minimize emissions, including but not limited to:

II.F.3.c.(i) Using low or no-VOC solvents, if possible;

II.F.3.c.(ii) Using only volumes of solvent necessary for operations;

II.F.3.c.(iii) Using submerged fill pipes in storage tanks and containers;

II.F.3.c.(iv) Using closed loop systems to minimize solvent loss during transfer and use of solvents;

II.F.3.c.(v) Maintaining solvent storage, transfer, and use operations equipment in such a way that it minimizes evaporation loss and remains leak free, and;

II.F.3.c.(vi) Owners or operators of sources that use a carbon adsorption system must provide for the proper disposal or reuse of all VOC recovered.

II.F.4. Control of general solvent use

The owner or operator of operations that use solvents with uncontrolled actual VOC emissions greater than or equal to twenty-five (25) tons per year on a calendar year basis, and that are located in the 8-Hour Ozone Control Area, must reduce solvent use VOC emissions by 90%.

II.F.5. Monitoring requirements

II.F.5.a. The owner or operator of operations that use solvents that utilize a closed-loop system for emission control must inspect the control system using audio, visual, olfactory (AVO) on a monthly basis for perceptible emissions. First attempt to repair must be made upon detection if feasible, but no later than three (3) calendar days from detection.

II.F.5.b The owner or operator of operations that use solvents that utilize a control device must operate and maintain the control device consistent with the manufacturer's specifications.

II.F.5.c. The owner or operator of operations that use solvents that are subject to the 90% control requirement in Section II.F.4. must:

II.F.5.c.(i) Complete a performance test once every three (3) years during representative operations to verify compliance with Section II.F.4. using one of the following methods, as applicable:

II.F.5.c.(i)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content.

II.F.5.c.(i)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.

II.F.5.c.(ii) Conduct all performance tests in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

II.F.5.c.(iii) Comply with control device and monitoring system manufacturers' specifications for operation and maintenance for equipment used to demonstrate compliance with Section II.F.4.

II.F.6. Recordkeeping

II.F.6.a. Records of calendar year VOC emission estimates demonstrating whether the solvent operation meets or exceeds the applicability threshold in Section II.F.1.

II.F.6.b. If applicable, records demonstrating that an exemption to Section II.F.2. applies.

II.F.6.c. Monthly solvent losses based on beginning and ending inventories, solvent received, inventory adjustments, solvent destroyed in a control device, solvent recovered, and any volume of solvent normally retained in recovery equipment. Solvent losses must be totaled on a rolling 12-month basis.

II.F.6.d. Monthly records such as safety data sheets or other analytical data from the solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent operations.

II.F.6.e. Records of negative pressure ranges, and other records necessary to demonstrate compliance with Section II.F.3.

II.F.6.f. Manufacturer guarantee of the control equipment's emission control efficiency to demonstrate compliance with Section II.F.4.

II.F.6.g. If applicable, monthly records of operation and maintenance of control device and monitoring system according to manufacturer's specifications to demonstrate compliance with Sections II.F.4. and II.F.5.

II.F.6.h. If applicable, Records of performance tests conducted to demonstrate compliance with Section II.F.5.

II.F.6.i. If applicable, monthly records of AVO inspections including:

II.F.6.i.(i) The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.F.6.i.(ii) A list of the leaks requiring repair,

II.F.6.i.(iii) The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

II.F.6.i.(iv) The date the leak was repaired and type of repair method applied.

II.F.6.j. Records must be maintained for two (2) years and made available for inspection by the Division upon request.

III. Use of Cutback Asphalt

III.A. Definitions

III.A.1. “Asphalt or Asphalt Cement” The dark-brown to black cementitious material (solid, semi-solid, or liquid in consistency) of which the main constituents are bitumen’s which occur naturally or as a residue of petroleum refining.

III.A.2. “Asphalt Concrete” A waterproof and durable paving material composed of dried aggregate, which is evenly coated with hot asphalt cement.

III.A.3. “Cutback Asphalt or Cutback Asphalt Cement” Any asphalt which has been liquefied by blending with a VOC, such as a petroleum solvent diluents or, in the case of some slow cure asphalts (Road Oils), which has been produced directly from the distillation of petroleum.

III.A.4. “Emulsified Asphalt” Asphalt emulsions produced by combining asphalt and water with emulsifying agent. Emulsified Asphalt or any other coating or sealant, including but not limited to those produced from petroleum or coal, which contain more than five (5) percent of oil distillate as determined by ASTM Method D-244 is included in this definition.

III.A.5. “Penetrating Prime Coat” An application of low-viscosity liquid asphalt to an absorbent surface in order to prepare it for overlaying with a layer or layers of asphalt cement or asphalt emulsion and mineral aggregate paving materials.

III.B. Limitations

III.B.1. Applicability

The provisions of this Section III. apply to the use and storage of cutback asphalt for the paving and maintenance of all public roadways (including alleys), private roadways, parking lots, and driveways only within ozone nonattainment areas.

III.B.2. Storage

Stockpiles of aggregate mixed with cutback asphalt are permitted October 1 through February 28 (29). Such storage is not permitted March 1 through September 30 except where it can be demonstrated to the Division that such storage is necessary.

III.B.3. Use

Cutback asphalt may be used for any paving purpose October 1 through February 28 (29). No person shall use cutback asphalt or any coating included in the definition of cutback asphalt in Section III.A.3. March 1 through September 30 except as provided:

III.B.3.a. If used solely as a penetrating prime coat, or

III.B.3.b. If the user can demonstrate to the Division that under the conditions of its intended use, there will be no emissions of volatile organic compounds to the ambient air.

III.C. Recordkeeping

During the months of March through September, the person responsible for the use or storage of any cutback asphalt as permitted in Sections III.B.3.a., III.B.3.b., and Section III.B.2. shall keep records of same, including type and amount of solvent(s) used.

IV. Graphic Arts and Printing

IV.A. Packaging Rotogravure, Publication Rotogravure, and Flexographic Printing

IV.A.1. Definitions

For the purpose of this section, the following definitions apply:

IV.A.1.a. "Flexographic Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique in which the pattern to be applied is raised above the printing roll and the image carrier is made of rubber or other elastomeric materials.

IV.A.1.b. "Packaging Rotogravure Printing" means rotogravure printing upon paper, paperboard, metal foil, plastic film, and other substrates, which are, in subsequent operations, formed into packaging products and labels for articles to be sold.

IV.A.1.c. "Publication Rotogravure Printing" means rotogravure printing upon paper, which is subsequently formed into books, magazines, catalogues, brochures, directories, newspaper supplements, and other types of printed materials.

IV.A.1.d. "Roll Printing" means the application of words, designs, and pictures to a substrate usually by means of a series of hard rubber or steel rolls each with only partial coverage.

IV.A.1.e. "Rotogravure Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique, which involves an intaglio or recessed image areas in the form of cells.

IV.A.2. Applicability

IV.A.2.a. This section applies to all packaging rotogravure, publication rotogravure, and flexographic printing facilities whose potential emissions of volatile organic compounds before control (determined at design capacity and 8760 hrs/year, or at maximum production, and accounting for any capacity or production limitations in a federally-enforceable permit) are equal to or more than 90,000 Kg per year (100 tons/year). Potential emissions are to be estimated by extrapolating historical records of actual consumption of solvent and ink. (e.g., the historical use of 20 gallons of ink for 4,000 annual hours would be extrapolated to 43.8 gallons for 8760 hours.) The before-control volatile organic compound emissions calculations shall be the summation of all volatile organic compounds in the inks and solvents (including cleaning liquids) used.

IV.A.3. Provisions for Specific Processes

IV.A.3.a. No owner or operator of a facility subject to this section and employing VOC-containing ink shall operate, cause, allow, or permit the operation of the facility unless:

IV.A.3.a.(i) The volatile fraction of ink, as it is applied to the substrate, contains 25.0 percent or less (by volume) of VOC and 75.0 percent or more (by volume) of water; or

IV.A.3.a.(ii) The ink (minus water) as it is applied to the substrate, contains 60.0 percent or more (by volume) non-volatile material; or

IV.A.3.a.(iii) The owner or operator installs and operates a control device and capture system in accordance with Sections IV.A.3.b. and IV.A.3.c.; or

IV.A.3.a.(iv) A combination of solvent-borne inks and low solvent inks that achieve a 70% (volume) overall reduction of solvent usage (compared to an all solvent borne ink usage) is used; or

IV.A.3.a.(v) Flexographic and packaging rotogravure printing facilities limit emissions to 0.5 pounds of VOC per pound of solids in the ink. The limit includes all solvent added to the ink: solvent in the purchased ink, solvent added to cut the ink to achieve desired press viscosity, and solvent added to ink on the press to maintain viscosity during the press run. (Publication rotogravure facilities shall not use this option); or

IV.A.3.a.(vi) Crossline averaging is used. The requirements of Section I.A.5.d. apply.

IV.A.3.b. A capture system shall be used in conjunction with the emission control system in Section IV.A.3.a. The design and operation of a capture system shall be consistent with good engineering practice, and in conjunction with control equipment shall be required to provide for an overall reduction in volatile organic compound emissions of at least:

IV.A.3.b.(i) 75.0 percent where a publication rotogravure process is employed;

IV.A.3.b.(ii) 65.0 percent where a packaging rotogravure process is employed; or

IV.A.3.b.(iii) 60.0 percent where a flexographic printing process is employed.

IV.A.3.c. The design, operation, and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Testing of any capture system may be required by the Division on a case-by-case basis, in cases where a total enclosure is not used or when material balance results are questionable. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

IV.A.3.d. The overall reduction in VOC emissions specified in Section IV.A.3.b. shall be calculated by material balance methods approved by the Division, or by determination of capture and control device efficiencies. The overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

IV.A.4. Testing and Monitoring

The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Part C, Sections I.A.3., I.A.7, I.A.9., and I.A.10. In Part C, Section I.A.3., EPA reference method 24A shall be the test method used for publication rotogravure inks, while EPA Reference method 24 data is acceptable for all other inks. Test methods as set forth in Appendix A, Part 60, Chapter I, Title 40, of the Code of Federal Regulations (CFR), in effect July 1, 1993.

IV.A.5. The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Section I.A.8. "A Guideline for Graphic Arts Calculations" shall be used for compliance determination.

IV.B. Lithographic and Letterpress Printing

IV.B.1. General Provisions

IV.B.1.a. Definitions

IV.B.1.a.(i) “Alcohol” means any of the hydroxyl-containing organic compounds with a molecular weight equal to or less than 74.12, which includes methanol, ethanol, propanol, and butanol.

IV.B.1.a.(ii) “Alcohol substitute” means nonalcohol additives that contain VOCs and are used in the fountain solution to reduce the surface tension of water or prevent ink piling.

IV.B.1.a.(iii) “Cleaning material” means a VOC-containing material used to remove ink and debris from the printing press area, operating surfaces of the printing press and, printing press parts. Blanket wash is a type of cleaning material.

IV.B.1.a.(iv) “Composite partial vapor pressure” means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the “i”th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the “i”th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the “i”th VOC compound at 20°C(68°F), in mm Hg

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IV.B.1.a.(v) “Fountain solution” means a mixture of water, nonvolatile printing chemicals, and a liquid additive that reduces the surface tension of the water so that it spreads easily across the printing plate surface. The fountain solution wets the non-image areas so that the ink is maintained within the image areas.

IV.B.1.a.(vi “Heatset” means any lithographic or letterpress printing operation where printing inks are set by the evaporation of the ink oils in a heatset dryer.

IV.B.1.a.(vii) “Heatset dryer” means a hot air dryer used in heatset lithography to heat the printed substrate and to promote the evaporation of ink oils.

IV.B.1.a.(viii) “Lithographic printing” means a planographic printing process where the image and non-image areas are chemically differentiated (the image area is oil receptive and the non-image area is water receptive). This printing process differs from other conventional printing methods, where the image is a raised or recessed surface.

IV.B.1.a.(ix) “Letterpress printing” means a printing process in which the image area is raised relative to the non-image area and the paste ink is transferred to the substrate directly from the image surface.

IV.B.1.a.(x) “Non-heatset” means any printing operation where the printing inks are set without the use of heat. For the purpose of Section IV.B., ultraviolet-cured and electron beam-cured inks are considered non-heatset.

IV.B.1.a.(xi) “Offset lithographic printing” means a printing process that transfers the ink film from the lithographic plate to an intermediary surface (blanket), which in turn transfers the ink film to the substrate.

IV.B.1.a.(xii) “Press” means a printing production assembly composed of one or more print units used to produce a printed substrate including any associated coating, spray powder application, heatset web dryer, ultraviolet or electron beam curing units, or infrared heating units.

IV.B.1.a.(xiii) “Sheet-fed printing” means a printing process where individual sheets of paper or substrate are fed into the printing press.

IV.B.1.a.(xiv) “Web printing” means a printing process where continuous rolls of substrate material are fed to the press and rewound or cut to size after printing.

IV.B.1.b. Applicability

IV.B.1.b.(i) The provisions of this Section IV.B. apply to fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses. These materials are not subject to the requirements of Sections I. and II.

IV.B.1.b.(ii) The work practice requirements in Section IV.B.1.c. apply to all lithographic and letterpress printing operations.

IV.B.1.b.(iii) The VOC content limit for inks in Section IV.B.1.d. applies to lithographic and letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(iv) The cleaning material requirements in Section IV.B.2. apply to letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(v) The cleaning material and fountain solution requirements in Sections IV.B.2. and IV.B.3. apply to offset lithographic printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(vi) The control requirements in Section IV.B.4. apply to each heatset web offset lithographic and heatset web letterpress printing press with the potential to emit from the dryer, prior to controls, at least 25 tons per calendar year of VOC (petroleum ink oil) from heatset inks.

IV.B.1.c. Work Practice Requirements

Lithographic and letterpress printing operations must implement the following work practices at all times to reduce VOC emissions from fugitive sources:

IV.B.1.c.(i) Cover open containers and keep cleaning materials in closed containers when not in use;

IV.B.1.c.(ii) Properly dispose of used cleaning materials, fountain solutions, and used shop towels; and

IV.B.1.c.(iii) Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintain cleaning equipment to repair cleaning materials leaks.

IV.B.1.d. VOC Content Limit for Inks

IV.B.1.d.(i) Lithographic and letterpress printing operations, excluding heatset web offset and heatset web letterpress printing operations, must use low-VOC inks, which average less than 30% (by weight) VOC on a monthly basis.

IV.B.1.d.(ii) Heatset web offset lithographic and heatset web letterpress printing operations must use low-VOC inks, which average less than 40% (by weight) VOC on a monthly basis.

IV.B.2. Offset lithographic printing and letterpress printing operations must comply with the following cleaning materials requirements;

IV.B.2.a. All cleaning materials must contain less than 70% (by weight) VOC or have a VOC composite vapor pressure less than 10 mmHg at 20°C.

IV.B.2.b. Exemptions

The following materials and operations are exempt from the cleaning material requirements in Section IV.B.2.a.:

IV.B.2.b.(i) Cleaners used on electronic components of a press.

IV.B.2.b.(ii) Pre-press cleaning operations.

IV.B.2.b.(iii) Post-press cleaning operations.

IV.B.2.b.(iv) Floor cleaning supplies (other than those used to clean dried ink).

IV.B.2.b.(v) Cleaning performed in parts washers or cold cleaners that are subject to Section II.

IV.B.2.c. Use of non-compliant cleaning materials

Cleaning materials not meeting the limits in Section IV.B.2.a. are limited to less than or equal to 110 gallons per calendar year.

IV.B.3. Offset lithographic printing operations must comply with the following fountain solution requirements:

IV.B.3.a. Heatset web offset lithographic printing operations must:

IV.B.3.a.(i) Use a fountain solution containing 1.6% alcohol (by weight) or less as applied;

IV.B.3.a.(ii) Use a fountain solution containing 3% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

IV.B.3.a.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

IV.B.3.b. Sheet-fed printing operations must

IV.B.3.b.(i) Use a fountain solution containing 5% alcohol (by weight) or less as applied;

IV.B.3.b.(ii) Use a fountain solution containing 8.5% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

IV.B.3.b.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

IV.B.3.b.(iv) The following are exempt from the fountain solution requirements in Section IV.B.3.b.:

IV.B.3.b.(iv)(A) Fountain solution use associated with a sheet-fed printing press with maximum sheet size 11x17 inches or smaller.

IV.B.3.b.(iv)(B) Fountain solution use associated with a sheet-fed printing press having a total fountain solution reservoir less than one (1) gallon.

IV.B.3.c. Non-heatset web printing must use a fountain solution containing 5% alcohol substitute (by weight) or less and no alcohol.

IV.B.4. Heatset web offset lithographic and heatset web letterpress printing operations must comply with the following control requirements:

IV.B.4.a. Heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 90% or greater.

IV.B.4.b. If the control device was first installed on or after January 1, 2017, heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 95% or greater.

IV.B.4.c. Where inlet VOC concentration is low and a 90 or 95% control efficiency is not achievable due to low inlet concentrations or measurable due to equipment configuration, heatset web offset lithographic and heatset web letterpress printing operations may reduce the control device outlet concentration to 20 ppmv (as hexane on a dry basis).

IV.B.4.d. The following are exempt from the control requirements in Section IV.B.4.:

IV.B.4.d.(i) Heatset presses used for book printing.

IV.B.4.d.(ii) Heatset presses with maximum web width of 22 inches or less.

IV.B.4.d.(iii) Waterborne or radiation (ultra-violet or electron beam) cured materials that are not heatset.

IV.B.5. Monitoring, Recordkeeping and Reporting

IV.B.5.a. The owner or operator of a heatset web offset lithographic or heatset web letterpress printing operation required to demonstrate compliance with Section IV.B.4. must install, calibrate, maintain, and operate a temperature monitoring device, according to the manufacturer's specifications.

IV.B.5.b. The owner or operator of a lithographic and letterpress printing operations subject to Sections IV.B.1.d. and IV.B.2. through IV.B.4. must keep the following records for two (2) years and make them available for inspection by the Division upon request:

IV.B.5.b.(i) If applicable, records demonstrating that a listed exemption to this Section IV.B. applies.

IV.B.5.b.(ii) If applicable, monthly records of the type, alcohol content or alcohol substitute content, and total volume of fountain solution used in printing operations.

IV.B.5.b.(iii) If applicable, monthly records of the type, VOC content or composite vapor pressure, and total volume of the cleaning materials used in printing operations.

IV.B.5.b.(iv) If applicable, monthly records of the type, VOC content, and total volume of inks (including varnishes) and coatings used in printing operations.

IV.B.5.b.(v) If applicable, monthly records demonstrating compliance with the control requirements in Section IV.B.4.

IV.B.5.b.(vi) Records of calendar year VOC emission estimates demonstrating whether the printing operation meets or exceed the applicability thresholds in Section IV.B.1.b.

IV.B.5.c. Compliance with control requirements must be demonstrated using the following methods as applicable:

IV.B.5.c.(i) Safety data sheets or other analytical data from the ink, cleaning material, or fountain solution manufacturer to demonstrate compliance with VOC content limit for inks in Section IV.B.1.d., the cleaning material requirements in Section IV.B.2., and the fountain solution requirements in Section IV.B.3.;

IV.B.5.c.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with the control equipment requirements in Section IV.B.4.; or

IV.B.5.c.(iii) A performance test conducted during representative conditions using one of the following methods as applicable:

IV.B.5.c.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content for inks, fountain solutions and cleaning materials; or

IV.B.5.c.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency or outlet concentration of the emission control equipment.

V. Pharmaceutical Synthesis

V.A. General Provisions

V.A.1. Applicability

This section applies to all sources of volatile organic compounds associated with pharmaceutical manufacturing activities, including, but not limited to, reactors, distillation units, dryers, storage of VOCs, extraction equipment, filters, crystallizers, and centrifuges.

V.A.2. Exemptions

Extraction of organic substances from animal or vegetable material; fermentation and culturing; formulation and packaging of pharmaceutical or medicinal products.

V.A.3. Definitions

For the purpose of this section, the following definitions apply:

V.A.3.a. "Control System" means any number of control devices, including condensers, which are designed and operated to reduce the quantity of VOC emitted to the atmosphere.

V.A.3.b. "Pharmaceutical" means a medicine or drug which appears in the United States Pharmacopoeia National Formulary, or which is so designated by the National Drug Code of the United States FDA Bureau of Drugs.

V.A.3.c. "Production Equipment Exhaust System" means a device for collecting and directing out of the work area VOC fugitive emissions from reactor openings, centrifuge openings, and other vessel openings for the purpose of protecting workers from excessive VOC exposure.

V.A.3.d. "Reactor" means a vat or vessel, which may be jacketed to permit temperature control, designed to contain chemical reactions.

V.A.3.e. "Separation Operation" means a process that separates a mixture of compounds and solvents into two or more components. Specific mechanisms include, but are not limited to, extraction, centrifugation, filtration, distillation, and crystallization.

V.A.3.f. "Synthesized Pharmaceutical Manufacturing" means manufacture of pharmaceutical products by chemical synthesis. It includes the manufacture of chemical intermediates (of sufficient purity) which are typically used by the pharmaceutical industry as precursors to finished mixtures of chemicals. (Thus, it excludes those chemical processes which are not directed at creating finished pharmaceutical or chemical intermediates to finished pharmaceuticals.)

V.B. Provisions for Specific Processes

V.B.1. The owner or operator of a facility subject to this section shall control the volatile organic compound emissions from each vent which has the potential to emit 6.80 kg/day (l5 lb./day) or more of VOC from reactors, distillation operations, crystallizers, centrifuge and vacuum dryers. Surface condensers or equivalent controls shall be used, provided that, if surface condensers are used, the condenser outlet gas temperature shall not exceed the following values:

VOCs True Vapor Pressure* at 20° in torr (and psia) from (minimum) up to ** (maximum)	Maximum temperature of Gas Stream immediately exiting the condenser
0-26(0-0.5)	35°C (95°F)
26-52(0.5-1.0)	25°C(77°F)
52-78(1.0-1.5)	10°C(50°F)
78-150(1.5-2.9)	0°C(32°F)
150-300(2.9-5.8)	-15°C(5°F)
Greater than 300(Greater than 5.8)	-25°C(-13°F)

*The calculation methods for gases containing more than one condensable component are complex. As a simplification, the temperature necessary for control by condensation can be roughly approximated by the weighted average of the temperatures necessary for condensation of each VOC considered separately but at concentrations equal to the total organic concentration.

**But not including the maximum value of the range.

V.B.2. Division approval shall be required for control equipment used to control VOCs of 570 torr (11 psia) and above.

V.B.3. The owner or operator of a facility subject to this section shall reduce the VOC emissions from each air dryer and production equipment exhaust system:

V.B.3.a. By at least 90 percent if emissions are 150 kg/day (330 lbs/day) or more of VOC, or,

V.B.3.b. To 15.0 kg/day (33 lb/day) or less if emissions are less than 150 kg/day (330 lb/day) of VOC.

V.B.4. The owner or operator of a facility subject to this section shall:

V.B.4.a. Provide a vapor balance system or equivalent control that is at least 90.0 percent effective in reducing emissions from truck or railcar deliveries to storage tanks with capacities greater than 7,570 liters (2,000 gallons) that store VOC with true vapor pressure greater than 210 torr (4.1 psia) at 20°C; and,

V.B.4.b. Install pressure/vacuum conservation vents set at plus or minus 0.2 kPa on all storage tanks that store VOC with true vapor pressures greater than 10.0 kPa (1.5 psi) at 20°C.

V.B.5. The owner or operator of a facility subject to this section shall enclose all centrifuges, rotary vacuum filters, and other filters having an exposed liquid surface, where the liquid contains VOC and exerts a total VOC true vapor pressure of 26 torr (0.5 psia) or more at 20°C.

V.B.6. The owner or operator of a synthesized pharmaceutical facility subject to this section shall install covers on all in-process tanks containing a volatile organic compound at any time. These covers shall remain closed unless sampling, maintenance, short-duration production procedures or inspection procedures require access.

V.B.7. The owner or operator of a facility subject to this section shall repair all leaks from which a liquid, containing VOC, can be observed running or dripping. The repair shall be completed the first time the equipment is off-line for a period of time long enough to complete the repair, except that no leak shall go unrepaired for more than 14 days after initial detection unless the Division issues written approval.

V.B.8. Each surface condenser shall have at least one temperature indicator with its sensor located in the outlet gas stream.

V.C. Testing and Monitoring

V.C.1. Sources subject to the requirements of this section are also subject to the requirements of Sections I.A.3., I.A.7., I.A.8., and I.A.9.

Appendix D Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers

The specifications in this Appendix apply only to vapor degreasers that have both condenser coils and refrigerated freeboard chillers. (The coolant in the condenser coils is normally water.) The amount of refrigeration capacity is expressed in Calories/Hour per meter of perimeter. This perimeter is measured at the air/vapor interface.

For refrigerated chillers operated below 0°C., the following requirements apply:

DEGREASER WIDTH	*CALORIES/HR METER OF PERIMETER	BTU/HR FOOT OF PERIMETER
Less than 1.1 meters (3.5 ft.)	165	200
1.1 - 1.8 meters (3.5 - 6.0 ft.)	250	300
1.8 - 2.4 meters (6.0 - 8.0 ft.)	335	400
2.4 - 3.0 meters (8.0 - 10.0 ft.)	145	500
Greater than 3.0 meters (10 ft.)	500	600

* Kilocalories (1 Kilocalorie = 4184.0 joules)

For refrigerated chillers operating above 0°C., there shall be at least 415 Calories/Hr. - meter of perimeter (500 BTU/Hr-ft.), regardless of size.

Definition: "Air/Vapor Interface" - means the surface defined by the top of the solvent vapor layer within the confines of a vapor degreaser.

Appendix E Emission Limit Conversion Procedure

The following procedure shall be used to convert emission limits expressed as lb VOC/gallon coating less water and exempt solvents to limits expressed as lb VOC/gallon solids. This example uses the emission limit of 3.7 lb VOC/gallon coating.

Assume VOC density of the `Presumptive' RACT coating is 7.36 pounds per gallon because this same value was used to determine the "Presumptive" recommended RACT emission limits from volume solids data.

(3.7) LB VOC / GAL COATING LESS WATER x l GAL VOC x 100 / 7.36 LB VOC = (50) V0L% VOC
100 - (50) V0L% VOC = (50) V0L% SOLIDS
(3.7) LB VOC / GAL COATING LESS H2O x 100 GAL COATING / (50) GAL SOLIDS = (7.4) LB VOC / GAL SOLIDS

See "A Guideline for Surface Coating Calculations" EPA - 340/1-86-0l6 for additional examples.

The following table lists equivalent mass VOC/volume solids emission limits for various coating operations.

Equivalency Data for Surface Coating Processes (VOC Density = 7.36 lb/gal)

Industrial Finishing Categories	Lb VOC per Gallon Coating less water	Lb VOC per Gallon of Solids	Kg VOC per Liter of Solids
Can Industry			
Sheet Basecoat (Exterior and Interior) and over-varnish; two-piece can exterior (base-coat and over-varnish)	2.8	4.5	0.55
Two- and three-piece can interior body spray, two-piece can exterior end spray or roll coat	4.2	9.8	1.19
Three-piece can side-seam spray	5.5	21.7	2.61
End sealing compound	3.7	7.4	0.88
Any additional coats	4.2	9.8	1.19
Coil Coating			
Any coat	2.6	4.0	0.48

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Fabric Coating			
Fabric coating line	2.9	4.8	0.58
Vinyl coating line	3.8	7.9	0.93
Paper Coating			
Coating line	2.9	4.8	0.58
Automotive and Light-Duty Truck Assembly Plant			
Primer (electrodeposition) application, flashoff area and oven	1.9	2.6	0.31
Topcoat application, flashoff area and oven	2.8	4.5	0.55
Final repair application, flashoff area and oven	4.8	13.8	1.67
Metal Furniture			
Coating line	3.0	5.1	0.61
Magnet Wire			
Wire coating operation	1.7	2.2	0.26
Large Appliances			
Prime, single, or topcoat application area, flashoff area and oven	2.8	4.5	0.55
Miscellaneous Metal Parts and Products			
Air-dried items	3.5	6.7	0.80
Clear-coated items	4.3	10.3	1.25
Extreme performance coatings	3.5	6.7	0.80
Other coatings and systems	3.0	5.1	0.61
Plastic Film Coating			
Plastic film coating line	2.9	4.8	0.58

PART D Oil and Natural Gas Operations

I. Volatile Organic Compound Emissions from Oil and Gas Operations

I.A. Applicability

I.A.1. Except as provided in Section I.A.2., this section applies to oil and gas operations that collect, store, or handle hydrocarbon liquids or produced water in the 8-hour Ozone Control Area (State Only: or any ozone nonattainment or attainment/maintenance area) and that are located at or upstream of a natural gas plant.

I.A.2. Oil refineries are not subject to Section I.

I.B. Definitions specific to Section I.

I.B.1. "Affected Operations" means oil and gas exploration and production operations, natural gas compressor stations and natural gas drip stations, to which Section I. applies.

I.B.2. "Air Pollution Control Equipment", as used in Section I., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment, pollution prevention devices, and processes that comply with the requirements of Section I.D.4. that are approved by the Division.

I.B.3. "Approved Instrument Monitoring Method" means an infra-red camera, EPA Method 21, or other instrument based monitoring method or program approved in accordance with Section I.L.8. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection, recordkeeping, and reporting program for such operations.

I.B.4. "Atmospheric Storage Tanks or Atmospheric Condensate Storage Tanks" means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.

I.B.5. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

I.B.6. "Calendar Week" means a week beginning with Sunday and ending with Saturday.

I.B.7. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

I.B.8. "Condensate Storage Tank" means any tank or series of tanks that store condensate and are either manifolded together or are located at the same well pad.

I.B.9. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

I.B.10. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that

contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

I.B.11. “Connector” means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

I.B.12. “Custody Transfer” means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

I.B.13. “Downtime” means the period of time when a well is producing and the air pollution control equipment is not in operation.

I.B.14. “Existing” means any atmospheric condensate storage tank that began operation before February 1, 2009, and has not since been modified.

I.B.15. “Glycol Natural Gas Dehydrator” means any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

I.B.16. “Hydrocarbon liquids” means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquids does not include produced water.

I.B.17. “Infra-red Camera” means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

I.B.18. “Modified or Modification” means any physical change or change in operation of a stationary source that results in an increase in actual uncontrolled volatile organic compound emissions from the previous calendar year that occurs on or after February 1, 2009. For atmospheric condensate storage tanks (and beginning March 1, 2020, for all storage tanks), a physical change or change in operation includes but is not limited to drilling wells and recompleting, refracturing or otherwise stimulating existing wells.

I.B.19. “Natural Gas Compressor Station” means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

I.B.20. “Natural Gas-Driven Diaphragm Pump” means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

I.B.21. “Natural Gas Processing Plant” means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

I.B.22. “New” means any atmospheric condensate storage tank that began operation on or after February 1, 2009.

I.B.23. “Produced Water” means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

I.B.24. “Reciprocating Compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

I.B.25. “Stabilized” when used to refer to stored hydrocarbon liquids, means that the hydrocarbon liquids have reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as “working and breathing losses”.

I.B.26. “Storage tank” means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

I.B.27. “Storage vessel” means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

I.B.28. (State Only) “Surveillance System” means monitoring pilot flame presence or temperature in a combustion device either by visual observation or with an electronic device to record times and duration of periods where a pilot flame is not detected at least once per day.

I.B.29. “System-Wide Control Strategy” means the collective emissions and emission reductions from all atmospheric condensate storage tanks under common ownership within the 8-hour Ozone Control Area for which uncontrolled actual volatile organic compound emissions are equal to or greater than two tons per year.

I.B.30. “Well Production Facility” means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

I.C. General Provisions

I.C.1. General Requirements

I.C.1.a. All air pollution control equipment used to demonstrate compliance with this Section I. must be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates required by this Section I. and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

I.C.1.b. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable.

I.C.1.c. All air pollution control equipment used to demonstrate compliance with Sections I.D., I.J., and I.K. must meet a control efficiency of at least 95%. Failure to properly install, operate, and maintain air pollution control equipment is a violation of this regulation.

I.C.1.d. If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly.

I.C.1.e. All combustion devices used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. must be equipped with and operate an auto-igniter as follows:

I.C.1.e.(i) (State Only) For condensate storage tanks that are constructed or modified after May 1, 2009, and before January 1, 2017, and controlled by a combustion device, auto-igniters must be installed and operational, beginning the date of first production after any new tank installation or tank modification.

I.C.1.e.(ii) (State Only) For all existing condensate storage tanks controlled by a combustion device in order to comply with the emissions control requirements of Section I.D.1., auto-igniters must be installed and operational beginning May 1, 2009, for condensate storage tanks with actual uncontrolled emissions of greater than or equal to 50 tons per year, and beginning May 1, 2010, for all other existing condensate storage tanks controlled by a combustion device, or within 180 days from first having installed the combustion device, whichever date comes later.

I.C.1.e.(iii) All combustion devices installed on or after January 1, 2017, must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.e.(iv) All combustion devices installed on or after January 1, 2018, and used to comply with Sections I.J. or I.K. must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.f. (State Only) If a combustion device is used to control emissions of volatile organic compounds, surveillance systems must be employed and operational as follows:

I.C.1.f.(i) (State Only) Beginning May 1, 2010, for all existing condensate storage tanks with uncontrolled actual emissions of 100 tons per year or more based on data from the previous twelve consecutive months.

I.C.1.f.(ii) (State Only) For all new and modified condensate storage tanks controlled by a combustion device for the first 90 days surveillance systems must be employed and operational beginning 180 days from commencement of operation after the tank was newly installed, or after the well was newly drilled, re-completed, re-fractured or otherwise stimulated, if uncontrolled actual emissions projected for the first twelve months based on data from the first 90 days of operation from the condensate storage tank are 100 tons or more of uncontrolled VOCs.

I.C.2. The emission estimates and emission reductions required by Section I.D. must be demonstrated using one of the following emission factors:

I.C.2.a. In the 8-Hour Ozone Control Area

I.C.2.a.(i) For atmospheric condensate storage tanks at oil and gas exploration and production operations, a default emission factor of 13.7 pounds of volatile organic compounds per barrel of condensate must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii). The Division may require a more specific emission factor that complies with Section I.C.2.a.(iii).

I.C.2.a.(ii) For atmospheric condensate storage tanks at natural gas compressor stations and natural gas drip stations a source may use a specific emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003. The Division may, however, require the source to develop and use a more recent specific emission factor pursuant to Section I.C.2.a.(iii) if such a more recent emission factor would be more reliable or accurate.

I.C.2.a.(iii) Except as otherwise provided in Section I.C.2.a.(i), a specific emission factor is one for which the Division has no objection, and which is based on collection and analysis of a representative sample of the hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.a.(iv) For storage tanks storing produced water or hydrocarbon liquids other than condensate, the most recent Division-approved default emission factors must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii).

I.C.2.a.(v) If the Division has reason to believe that a specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require the use of an alternative emission factor that complies with Section I.C.2.a.(iii).

I.C.2.b. (State Only) For any other Ozone Nonattainment Area or Attainment/Maintenance Areas

I.C.2.b.(i) (State Only) For storage tanks at oil and gas exploration and production operations, the source must use a default basin-specific uncontrolled volatile organic compound emission factor established by the Division unless a site-specific emission factor has been established pursuant to Section I.C.2.b.(iii). If the Division has established no default emission factor, if the Division has reason to believe that the default emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(ii) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, the source must use a site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.(iii). If the Division has reason to believe that the site-specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(iii) (State Only) Establishment of or Updating Approved Emission Factors

I.C.2.b.(iii)(A) (State Only) The Division may require the source to develop and/or use a more recent default basin-specific or site-specific volatile organic compound emission factor pursuant to Section I.C.2.b., if such emission factor would be more reliable or accurate.

I.C.2.b.(iii)(B) (State Only) For storage tanks at oil and gas exploration and production operations, the source may use a site-specific volatile organic compound emission factor for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.b.(iii)(C) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, a source may use a volatile organic compound emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003, or an alternative site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.

I.C.2.b.(iii)(D) (State Only) A default basin-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water or an alternative method, pursuant to a test method approved by the Division, except as otherwise provided in I.C.2.b.(i).

I.C.2.b.(iii)(E) (State Only) A site-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.D. Storage Tank Emission Controls

I.D.1. System-Wide Control Strategy for Condensate Storage Tanks

I.D.1.a. Beginning May 1, 2011, through April 30, 2020, owners and operators of all atmospheric condensate storage tanks that emit greater than or equal to two tons per year of actual uncontrolled volatile organic compounds must employ air pollution control equipment to reduce emissions of volatile organic compounds from atmospheric condensate storage tanks by 90% from uncontrolled actual emissions on a calendar weekly basis May 1 through September 30 and 70% from uncontrolled actual emissions on a calendar monthly basis during October 1 through April 30.

Emission reductions are not required for each and every unit, but instead shall be based on overall reductions in uncontrolled actual emissions from all the atmospheric condensate storage tanks associated with the affected operations for which the owner or operator filed, or was required to file, an APEN pursuant to Regulation Number 3, Part A, due to either having exceeded reporting thresholds or retrofitting with air pollution control equipment in order to comply with the system-wide control strategy.

I.D.1.b. The system-wide control strategy does not apply to natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.

I.D.1.c. The system-wide control strategy does not apply to any owner or operator where the APENs for all of the atmospheric condensate storage tanks associated with the affected operations owned or operated by such person in calendar year 2019 or January 1, 2020, through April 30, 2020, reflect a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the 8-Hour Ozone Control Area.

I.D.2. New and Modified Condensate Tanks

I.D.2.a. Beginning February 1, 2009, through March 1, 2020, owners or operators of any new or modified atmospheric condensate storage tank at exploration and production sites shall collect and control emissions by routing emissions to and operating air pollution control equipment pursuant to Section I.D. The air pollution control equipment shall have a control efficiency of at least 95%, and shall control volatile organic compounds during the first 90 calendar days after commencement of operation of the storage tank, or after the well was re-completed, re-fractured or otherwise stimulated. The air pollution control equipment and associated monitoring equipment required pursuant to Section I.C.1. may be removed after the first 90 calendar days as long as the source can demonstrate compliance with the applicable system-wide standard.

I.D.3. Storage Tank Control Strategy

I.D.3.a. Applicability

I.D.3.a.(i) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.a.(ii) (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total and not subject to Section I.D.3.a.(i) must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.b. Compliance Deadlines

I.D.3.b.(i) A storage tank subject to Section I.D.3.a.(i) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(ii) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(iii) A storage tank subject to Section I.D.3.a.(i) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(iv) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(v) A storage tank subject to Section I.D.3.a.(i) and not otherwise subject to Sections I.D.3.b.(i). or I.D.3.b.(iii) that increases uncontrolled actual emissions to four (4) tons per year VOC or more on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded four (4) tons per year on a rolling twelve-month basis.

I.D.3.b.(vi) (State Only) A storage tank subject to Section I.D.3.a.(ii) and not otherwise subject to Sections I.D.3.b.(ii) or I.D.3.b.(iv) that increases uncontrolled actual emissions to two (2) tons per year VOC based on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded two (2) tons per year on a rolling twelve-month basis.

I.D.3.b.(vii) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iii) or I.D.3.b.(v), compliance with Section I.D.3.a.(i) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iii) or I.D.3.b.(v) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(viii) (State Only) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iv) or I.D.3.b.(vi), compliance with Section I.D.3.a.(ii) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iv) or I.D.3.b.(vi) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(ix) This Section I.D.3. does not apply to storage tanks at natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.

I.D.4. Alternative emissions control equipment and pollution prevention devices and processes installed and implemented after June 1, 2004, shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and/or vapor recovery units to achieve the emission reductions required by this Section I.D., if the following conditions are met:

I.D.4.a. The owner or operator obtains a construction permit authorizing such use of the alternative emissions control equipment or pollution prevention device or process. The proposal for such equipment, device or process shall comply with all regulatory provisions for construction permit applications and shall include the following:

I.D.4.a.(i) A description of the equipment, device or process;

I.D.4.a.(ii) A description of where, when and how the equipment, device or process will be used;

I.D.4.a.(iii) The claimed control efficiency and supporting documentation adequate to demonstrate such control efficiency;

I.D.4.a.(iv) An adequate method for measuring actual control efficiency; and

I.D.4.a.(v) Description of the records and reports that will be generated to adequately track emission reductions and implementation and operation of the equipment, device or process, and a description of how such matters will be reflected in the records and reports required by Section I.F.

I.D.4.b. Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.D.4.c. EPA approves the proposal. The Division shall transmit a copy of the permit application and any other materials provided by the applicant, all public comments, all Division responses and the Division's permit to EPA Region 8. If EPA fails to approve or disapprove the proposal within 45 days of receipt of these materials, EPA shall be deemed to have approved the proposal.

I.E. Monitoring of Storage Tanks and Air Pollution Control Equipment

I.E.1. Applicability

I.E.1.a. The owner or operator of any storage tank that is being controlled pursuant to this Section I. (except storage tanks subject to Section I.D.3.a.(ii)).

I.E.1.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii).

I.E.2. Monitoring Requirements

I.E.2.a. The owner or operator of any storage tank controlled by air pollution control equipment other than a combustion device must follow manufacturer's recommended maintenance. Air pollution control equipment must be periodically inspected to ensure proper maintenance and operation according to the Division-approved operation and maintenance plan.

I.E.2.b. Beginning January 1, 2017, through April 30, 2020, owners or operators of atmospheric condensate storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must conduct and document audio, visual, olfactory (AVO) inspections of the storage tank at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days.

I.E.2.c. Weekly Monitoring Requirements

The owner or operator must inspect or monitor the air pollution control equipment at least weekly to ensure that it is operating properly. The inspection must include and document the following

I.E.2.c.(i) For combustion devices, a check that the pilot light is lit by either visible observation or other means approved by the Division. For devices equipped with an auto-igniter, a check that the auto-igniter is properly functioning.

I.E.2.c.(ii) For combustion devices, a check that the valves for piping of gas to the pilot light are open.

I.E.2.c.(iii) (State Only) In addition to complying with Sections I.E.2.c.(i). and I.E.2.c.(ii)., the owner or operator of tanks controlled pursuant to Section I.D. that have installed combustion devices may use a surveillance system to maintain records on combustion device operation.

I.E.2.c.(iv) For combustion devices, the owner or operator must visually check for the presence or absence of smoke and that the burner tray is not visibly clogged.

I.E.2.c.(v) For vapor recovery units, the owner or operator must check that the unit is operating and that vapors from the storage tank are being routed to the unit.

I.E.2.c.(vi) For all control devices, the owner or operator must check that the valves for the piping from the storage tank to the air pollution control equipment are open.

I.E.2.c.(vii) For all storage tanks, the owner or operator must check that the thief hatch is closed and latched, the pressure relief valve is properly seated, and all vent lines are closed.

I.E.2.c.(viii) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.c.(ix) (State Only) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks subject to Section I.D.3.a.(ii) must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.d. (State Only) For storage tanks equipped with a surveillance system or other Division-approved monitoring system, the owner or operator must check weekly that the system is functioning properly and that necessary information is being collected. Any loss of data or failure to collect required data may be treated by the Division as if the data were not collected.

I.F. Storage Tank Recordkeeping and Reporting

I.F.1. Recordkeeping and Reporting for Tanks Subject to the System-Wide Control Strategy (through April 30, 2020)

The owner or operator shall, at all times, track the emissions and specifically volatile organic compound emissions reductions on a calendar weekly and calendar monthly basis to demonstrate compliance with the applicable emission reduction requirements of the system-wide control strategy. This shall be done by maintaining a Division-approved spreadsheet of information describing the affected operations, the air pollution control equipment being used, and the emission reductions achieved, as follows.

I.F.1.a. The Division-approved spreadsheet shall:

I.F.1.a.(i) List all atmospheric condensate storage tanks subject to the system-wide control strategy by name and AIRS number, or if no AIRS number has been assigned the site location. The spreadsheet also shall list the monthly production volumes for each tank. The spreadsheet shall list the most recent measurement of such production at each tank, and the time period covered by such measurement of production.

I.F.1.a.(ii) List the emission factor used for each atmospheric condensate storage tank. The emission factors shall comply with Section I.C.2.

I.F.1.a.(iii) List the location and control efficiency value for each unit of air pollution control equipment. Each atmospheric condensate storage tank being controlled shall be identified by name and an AIRS number.

I.F.1.a.(iv) List the production volume for each tank, expressed as a weekly and monthly average based on the most recent measurement available. The weekly and monthly average shall be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the refinery purchaser for delivery of condensate from such tank, over the time such delivered condensate was collected. The weekly and monthly average from the most recent measurement will be used to estimate weekly and monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

I.F.1.a.(v) Show the calendar weekly and calendar monthly-uncontrolled actual emissions and the calendar weekly and calendar monthly controlled actual emissions for each atmospheric condensate storage tank.

I.F.1.a.(vi) Show the total system-wide calendar weekly and calendar monthly-uncontrolled actual emissions and the total system-wide calendar weekly and calendar monthly controlled actual emissions.

I.F.1.a.(vii) Show the total system-wide calendar weekly and calendar monthly percentage reduction of emissions.

I.F.1.a.(viii) Note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the spreadsheet shall record the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

I.F.1.a.(ix) Be maintained in a manner approved by the Division and shall include any other information requested by the Division that is reasonably necessary to determine compliance with the system-wide control strategy.

I.F.1.a.(x) Be updated on a calendar weekly and calendar monthly basis and shall be promptly provided by e-mail or fax to the Division upon its request. The U.S. mail may also be used if acceptable to the Division.

I.F.1.b. Failure to properly install, operate, and maintain air pollution control equipment at the locations indicated in the spreadsheet shall be a violation of this regulation.

I.F.1.c. A copy of each calendar weekly and calendar monthly spreadsheet shall be retained for five years. A spreadsheet may apply to more than one week if there are no changes in any of the required data and the spreadsheet clearly identifies the weeks it covers. The spreadsheet may be retained electronically. However, the Division may treat any loss of data or failure to maintain the Division-approved spreadsheet, as if the data were not collected.

I.F.1.d. Each owner or operator shall maintain records of the inspections required pursuant to Section I.E. and retain those records for five years. These records shall include the time and date of the inspection, the person conducting the inspection, a notation that each of the checks required under Sections I.C. and I.E. were completed and a description of any problems observed during the inspection, and a description and date of any corrective actions taken.

I.F.1.e. (State Only) Each owner or operator shall maintain records of required surveillance system or other monitoring data and shall make these records available promptly upon Division request.

I.F.1.f. (State Only) Each owner or operator shall maintain records on when an atmospheric condensate storage tank is newly installed, or when a well is newly drilled, re-completed, re-fractured or otherwise stimulated. Records shall be maintained per well associated with each tank and the date of first production associated with these activities.

I.F.1.g. Reporting for Tanks Subject to the System-Wide Control Strategy.

On or before April 30, 2020, each owner or operator shall submit a report describing the air pollution control equipment used during calendar year 2019 and how each company complied with the system-wide control strategy during calendar year 2019. On or before August 30, 2020, each owner or operator must submit a report describing the air pollution control equipment used from January 1, 2020, through April 30, 2020, and how each company complied with the system-wide control strategy during that time period. Such reports shall be submitted to the Division on a Division-approved form provided for that purpose.

I.F.1.g.(i) The report shall list all condensate storage tanks subject or used to comply with the system-wide control strategy and the production volumes for each tank. Production volumes may be estimated by the amounts shown on the receipt from refinery purchasers for delivery of condensate from such tanks.

I.F.1.g.(ii) The report shall list the emission factor used for each tank. The emission factors shall comply with Section I.C.2.

I.F.1.g.(iii) The report shall list the location and control efficiency value for each piece of air pollution control equipment, and shall identify the atmospheric condensate storage tanks being controlled by each.

I.F.1.g.(iv) The April 30 report shall show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, 2020.

I.F.1.g.(v) The April 30 report shall show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, 2020.

I.F.1.g.(vi) The April 30 report shall show the calendar monthly total system-wide percentage reduction of emissions for May 1 through September 30 of the previous year, and for the combined periods of January 1 through April 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide percentage reduction of emissions for January 1 through April 30, 2020.

I.F.1.g.(vii) The report shall note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating should be recorded in the report.

I.F.1.g.(viii) The report shall state whether the required emission reductions were achieved on a calendar monthly basis during the preceding year for the April 30 report and for January 1 through April 30, 2020, for the August 30 report. If the required emission reductions were not achieved, the report shall state why not, and shall identify steps being taken to ensure subsequent compliance.

I.F.1.g.(ix) The report shall include any other information requested by the Division that is reasonably necessary to determine compliance with this Section I.

I.F.1.g.(x) A copy of each semi-annual report shall be retained for five years.

I.F.1.g.(xi) In addition to submitting the semi-annual reports, on or before the 30th of each month commencing in June 2007 and ending April 30, 2020, the owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to Sections I.A. and I.D. shall notify the Division of any instances where the air pollution control equipment was not properly functioning during the previous month. The report shall include the time and date that the equipment was not properly operating, the time and date that the equipment was last observed operating properly, and the date and time that the problem was corrected. The report shall also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number of each of the condensate tanks being controlled by the equipment or if no AIRS number has been assigned the site name, and the estimated production from those tanks during the period of non-operation.

I.F.1.g.(xii) Commencing in 2007, on or before April 30 of each year (ending on April 30, 2020), the owner or operator shall submit a list identifying by name and AIRS number or if no AIRS number has been assigned the site name, each condensate storage tank that is being controlled to meet the requirements set forth in Section I.D.1. On the 30th of each month during ozone season (May through September) and on November 30 and February 28 (ending on February 28, 2020), the owner or operator shall submit a list identifying any condensate storage tank whose control status has changed since submission of the previous list.

I.F.1.g.(xiii) (State Only) Semi-annual report submittals shall be signed by a responsible official who shall also sign the Division-approved

compliance certification form for atmospheric condensate storage tanks. The compliance certification shall include both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions shall be identified separately from compliance certifications required under the State Implementation Plan.

I.F.1.g.(xiv) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

I.F.1.h. The record-keeping and reporting required in Sections I.F.1. shall not apply to the owner or operator of any natural gas compressor station or natural gas drip station that is authorized to operate pursuant to a construction permit or Title V operating permit issued by the Division if the following criteria are met:

I.F.1.h.(i) Such permits are obtained by the owner or operator on or after the effective date of this provision and contain the provisions necessary to ensure the emissions reductions required by Section I.D.;

I.F.1.h.(ii) The owners and operators of such natural gas compressor stations or natural gas drip stations do not own or operate any exploration and production operation(s); and

I.F.1.h.(iii) Total emissions from atmospheric condensate storage tanks associated with such natural gas compressor stations or drip stations subject to APEN reporting requirements under Regulation Number 3, Part A owned or operated by the same person do not exceed 30 tons per year in the 8-hour Ozone Control Area.

I.F.2. Recordkeeping for storage tanks subject to Section I.D.3.

I.F.2.a. The owner or operator of any storage tank subject to control pursuant to Section I.D.3. (except storage tanks subject to Section I.D.3.a.(ii)) must maintain records and make them available to the Division upon request.

I.F.2.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii) must maintain records and make them available to the Division upon request.

I.F.2.c. Records maintained under this Section I.F.2. must include:

I.F.2.c.(i) The AIRS number for the storage tank. The AIRS number assigned by the Division must be marked on all storage tanks required to file an APEN.

I.F.2.c.(ii) If air pollution control equipment is required to comply with Section I.D.3. visible signage must be located with the control equipment identifying the AIRS number for each storage tank that is being controlled by that equipment.

I.F.2.c.(iii) Records of the inspections required in Section I.E.

I.F.2.c.(iii)(A) The time and date of each inspection.

I.F.2.c.(iii)(B) The person conducting the inspection.

I.F.2.c.(iii)(C) A notation that each of the checks required under Section I.E. were completed.

I.F.2.c.(iii)(D) A description of any problems observed during the inspection, description and date of any corrective actions taken, and name of individual performing corrective actions.

I.F.2.c.(iv) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month totals for each storage tank subject to control under Section I.D.3.

I.F.2.c.(v) The emission factor used for each storage tank. The emission factors must comply with Section I.C.2. and the owner or operator must use the most recent emission factor on file with the Division (i.e., either the default emission factor or the specific emission factor established pursuant to Section I.C.2.a.(iii)).

I.F.2.c.(vi) The control efficiency of each unit of air pollution control equipment and the AIRS number of the storage tank being controlled.

I.F.2.d. (State Only) The owner or operator of each storage tank subject to Section I.D.3. must maintain records of

I.F.2.d.(i) The monthly production volumes for each storage tank, based on the most recent measurement available. The monthly average must be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the purchaser for delivery of hydrocarbon liquids or produced water from such tank, over the time such delivered hydrocarbon liquids or produced water was collected. The monthly average from the most recent measurement will be used to estimate monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

I.F.2.d.(ii) Any downtime of air pollution control equipment, including the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

I.F.2.d.(iii) Any required surveillance system or other monitoring data.

I.F.2.d.(iv) When a storage tank is installed, or when a well is drilled, re-completed, re-fractured, or otherwise stimulated. Records must be maintained per well associated with each storage tank and the date of commencement of operation associated with these activities.

I.F.3. Reporting for storage tanks subject to Section I.D.3.

I.F.3.a. On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks (except storage tanks subject to Section I.D.3.a.(ii)) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.b. (State Only) On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks subject to Section I.D.3.a.(ii) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.c. The report under this Section I.F.3. must include:

I.F.3.c.(i) The report must list all storage tanks (by AIRS number and location name) controlled pursuant to Section I.D.3. during the previous calendar year (starting calendar year 2020) and

I.F.3.c.(i)(A) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month total for each storage tank.

I.F.3.c.(i)(B) The emission factor used for each storage tank for each month.

I.F.3.c.(i)(C) The control efficiency for the air pollution control equipment for each storage tank.

I.F.3.c.(ii) (State Only) The report must identify any storage tank whose control status has changed, and the date of the change, since submission of the previous report.

I.F.3.c.(iii) (State Only) The report must list the production volume for each storage tank. Production volumes may be estimated by the amounts shown on the receipt from the purchaser.

I.F.3.c.(iv) (State Only) The report must list any downtime of air pollution control equipment, including the date, time, and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating must be recorded in the report.

I.F.3.c.(v) (State Only) The report must list any instances where the air pollution control equipment was not properly functioning, including the date and time the equipment was not properly operating, the date and time the equipment was last observed operating properly, and the date and time the problem was corrected. The report must also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number, or site name if no AIRS number has been assigned, of each storage tank being controlled by the equipment and the estimated production from those storage tanks during the period of non-operation.

I.F.3.c.(vi) (State Only) Reports must be signed by a responsible official who must also sign the Division-approved compliance certification form for storage tanks. The compliance certification includes both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, the certification must include the citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions must be identified separately from compliance certifications required under the State Implementation Plan.

I.F.3.c.(vii) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. must contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

I.G. Natural gas-processing plants located in the 8-hour Ozone Control Area (State Only: or any specific Ozone Nonattainment or Attainment/Maintenance Area) shall comply with requirements of this Section I.G., as well as the requirements of Sections I.B., I.C.1.a., I.C.1.b., I.H., I.J., I.K., and Part E, Section I.A. through C.

I.G.1. For fugitive volatile organic compound emissions from leaking equipment, the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart OOOO (July 1, 2017) applies, regardless of the date of construction of the affected facility, unless subject to the LDAR program provided at 40 CFR Part 60, Subpart OOOOa (July 1, 2017).

I.G.2. Air pollution control equipment shall be installed and properly operated to reduce emissions of volatile organic compounds from any atmospheric condensate storage tank (or tank battery) used to store condensate that has not been stabilized that has uncontrolled actual emissions of greater than or equal to two tons per year. Such air pollution control equipment shall have a control efficiency of at least 95%.

I.G.3. Natural gas processing plants within the 8-hour Ozone Control Area constructed before January 1, 2018, must comply with the requirements of Section I.G. beginning January 1, 2019. (State Only: Existing natural gas processing plants within any new Ozone Nonattainment or Attainment/Maintenance Area shall comply with this regulation within three years after the nonattainment designation.)

I.G.4. The provisions of Sections I.B., I.C.1.a., I.C.1.b., I.G., I.H., I.J., I.K., and Part E, Section I.A. through C., apply upon the commencement of operations to any natural gas processing plant that commences operation in the 8-Hour Ozone Control Area or Ozone Nonattainment (State Only: or Attainment/Maintenance Area) after the effective date of this section.

I.H. Emission Reductions from glycol natural gas dehydrators

I.H.1. Beginning May 1, 2005, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in the 8-Hour Ozone Control Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.2. (State Only) Beginning January 30, 2009, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in any Ozone Nonattainment or Attainment/Maintenance Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.3. The control requirements of Sections I.H.1. and I.H.2. apply where:

I.H.3.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than one ton per year; and

I.H.3.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than one ton per year.

I.H.4. For purposes of Section I.H., emissions from still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator shall be calculated using a method approved in advance by the Division.

I.H.5. Monitoring and recordkeeping

I.H.5.a. Beginning January 1, 2017, owners or operators of glycol natural gas dehydrators subject to the control requirements of Sections I.H.1. or I.H.2. must check on a weekly basis that any condenser or air pollution control equipment used to control emissions of volatile organic compounds is operating properly, and document:

I.H.5.a.(i) The date of each inspection;

I.H.5.a.(ii) A description of any problems observed during the inspection of the condenser or air pollution control equipment; and

I.H.5.a.(iii) A description and date of any corrective actions taken to address problems observed during the inspection of the condenser or air pollution control equipment.

I.H.5.b. The owner or operator must check and document on a weekly basis that the pilot light on a combustion device is lit, that the valves for piping of gas to the pilot light are open, and visually check for the presence or absence of smoke.

I.H.5.c. The owner or operator must document the maintenance of the condenser or air pollution control equipment, consistent with manufacturer specifications or good engineering and maintenance practices.

I.H.5.d. The owner or operator must retain records for a period of five years and make these records available to the Division upon request.

I.H.6. Reporting

I.H.6.a. On or before November 30, 2017, and semi-annually by April 30 and November 30 of each year thereafter, the owner or operator must submit the following information for the preceding calendar year (April 30 report) and for May 1 through September 30 (November 30 report) using Division-approved format

I.H.6.a.(i) A list of the glycol natural gas dehydrator(s) subject to Section I.H.;

I.H.6.a.(ii) A list of the condenser or air pollution control equipment used to control emissions of volatile organic compounds from the glycol natural gas dehydrator(s); and

I.H.6.a.(iii) The date(s) of inspection(s) where the condenser or air pollution control equipment was found not operating properly or where smoke was observed.

I.I. The requirements of Sections I.D. through I.F. do not apply to the owner or operator of any natural gas compressor station or natural gas drip station located in an Ozone Nonattainment or Attainment/Maintenance Area if:

I.I.1. Air pollution control equipment is installed and properly operated to reduce emissions of volatile organic compounds from all atmospheric condensate storage tanks (or tank batteries) that have uncontrolled actual emissions of greater than or equal to two tons per year;

I.I.2. The air pollution control equipment is designed to achieve a VOC control efficiency of at least 95% on a rolling 12-month basis and meets the requirements of Sections I.C.1.a. and I.C.1.b;

I.I.3. The owner or operator of such natural gas compressor station or natural gas drip station does not own or operate any exploration and production facilities in the Ozone Non-attainment or Attainment-maintenance Area; and

I.I.4. The owner or operator of such natural gas compressor station or natural gas drip station does the following and maintains associated records and reports for a period of five years:

I.I.4.a. Documents the maintenance of the air pollution control equipment according to manufacturer specifications;

I.I.4.b. Conducts an annual opacity observation once each year on the air pollution control equipment to verify opacity does not exceed 20% during normal operations;

I.I.4.c. Maintains records of the monthly stabilized condensate throughput and monthly actual VOC emissions; and

I.I.4.d. Reports compliance with these requirements to the Division annually.

I.I.5. A natural gas compressor station or natural gas drip station subject to Section I.I. at which a glycol natural gas dehydrator and/or natural gas-fired stationary or portable engine is operated is subject to Sections I.H., I.J., and/or Part E, Section I. A natural gas compressor station subject to Section I.I. is also subject to Section I.L.

I.J. Compressors

I.J.1. Centrifugal compressor

I.J.1.a. Beginning January 1, 2018, uncontrolled actual volatile organic compound emissions from wet seal fluid degassing systems on wet seal centrifugal compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be reduced by at least 95%. A centrifugal compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.1.

I.J.1.b. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must equip the wet seal fluid degassing system with a continuous, impermeable cover that is connected through a closed vent system that routes the emissions from the wet seal fluid degassing system to the process or control device.

I.J.1.c. The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.1.d. The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.1.e. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.1.f. Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.1.f.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.1.f.(ii) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.1.f.(iii) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.1.f.(iv) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.1.g. The owner or operator must conduct monthly inspections of a combustion device used to reduce emissions to ensure the device is operating with no visible emissions.

I.J.1.h. Recordkeeping

I.J.1.h.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.1.h.(i)(A) Identification of each centrifugal compressor using a wet seal system;

I.J.1.h.(i)(B) Each combustion device visible emissions inspection and any resulting responsive actions;

I.J.1.h.(i)(C) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.1.h.(i)(D) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.1.i. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.1.c. through I.J.1.f., I.J.1.h.(i)(C), and I.J.1.h.(i)(D), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.1.j. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.1.a. through I.J.1.i., the owner or operator may comply with wet seal centrifugal compressors emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.J.2. Reciprocating compressor

I.J.2.a. Beginning January 1, 2018, the rod packing on reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be replaced every 26,000 hours of operation or every thirty-six (36) months. A reciprocating compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.2.

I.J.2.a.(i) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed before January 1, 2018, must

I.J.2.a.(i)(A) Begin monitoring the hours of operation starting January 1, 2018; or

I.J.2.a.(i)(B) Conduct the first rod packing replacement required under Section I.J.2. prior to January 1, 2021.

I.J.2.a.(ii) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed after January 1, 2018, must begin monitoring the hours or months of operation upon commencement of operation of the reciprocating compressor.

I.J.2.b. As an alternative to the requirement described in Section I.J.2.a., beginning May 1, 2018, the owner or operator may collect rod packing volatile organic compound emissions using a rod packing emissions collection system that operates under negative pressure and routes the rod packing emissions through a closed vent system to a process.

I.J.2.b.(i) The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.2.b.(ii) The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.2.b.(iii) In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.2.b.(iv) Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.2.b.(iv)(A) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.2.b.(iv)(B) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.2.b.(iv)(C) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.2.b.(iv)(D) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.2.c. Recordkeeping

I.J.2.c.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.2.c.(i)(A) Identification of each reciprocating compressor;

I.J.2.c.(i)(B) The hours of operation or the number of months since the previous rod packing replacement, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure;

I.J.2.c.(i)(C) The date of each rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system;

I.J.2.c.(i)(D) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.2.c.(i)(E) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.2.d. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.2.b., I.J.2.c.(i)(D), and I.J.2.c.(i)(E), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.2.e. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.2.a. through I.J.2.d., the owner or operator may comply with reciprocating compressor emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.K. Pneumatic pumps

I.K.1. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a natural gas processing plant must ensure the pneumatic pump has a volatile organic compound emission rate of zero.

I.K.2. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a well production facility must reduce volatile organic compound emissions from the pneumatic pump by 95% if it is technically feasible to route emissions to an existing control device or process at the well production facility. Natural gas-driven diaphragm pneumatic pumps that are in operation during any period of time during a calendar day less than 90 days per calendar year are not subject to Section I.K.2.

I.K.2.a. If the control device available onsite is unable to achieve a 95% emission reduction and it is not technically feasible to route the emissions to a process at the well production facility, the owner or operator must still route the pneumatic pump emissions to the existing control device.

I.K.2.b. If the owner or operator subsequently installs a control device or it becomes technically feasible to route the emissions to a process, the owner or operator must reduce volatile organic compound emissions from the pneumatic pump by 95% within thirty (30) days of startup of the control device or of the feasibility of routing emissions to a process at the well production facility.

I.K.2.c. The owner or operator is not required to control pneumatic pump emissions if, through an engineering assessment by a qualified professional engineer, routing a pneumatic pump to a control device or process at the well production facility is shown to be technically infeasible.

I.K.2.d. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must connect the pneumatic pump through a closed vent system that routes the pneumatic pump emissions to the process or control device.

I.K.2.e. The owner or operator must conduct annual visual inspections of the closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices.

I.K.2.f. The owner or operators must conduct annual EPA Method 21 inspections of the closed vent system to determine whether the closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.K.2.g. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.K.2.h. Owners or operators may delay inspection or repair of a closed vent system if:

I.K.2.h.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.K.2.h.(ii) The closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.K.2.h.(iii) The closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.K.2.h.(iv) The closed vent system is inaccessible to inspect or repair because the closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.K.3. Recordkeeping

I.K.3.a. Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.K.3.a.(i) Identification of each natural gas-driven diaphragm pneumatic pump;

I.K.3.a.(ii) For natural gas-driven diaphragm pneumatic pumps in operation less than 90 days per calendar year, records of the days of operation each calendar year;

I.K.3.a.(iii) Records of control devices designed to achieve less than 95% emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve;

I.K.3.a.(iv) Records of the engineering assessment and certification by a qualified professional engineer that routing natural gas-driven diaphragm pneumatic pump emissions to a control device or process is technically infeasible;

I.K.3.a.(v) Each closed vent system inspection and any resulting responsive actions; and

I.K.3.a.(vi) Each closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such closed vent system.

I.K.4. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.K.2.e. through I.K.2.h., I.K.3.a.(v), and I.K.3.a.(vi), the owner or operator may inspect, repair, and document the closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.K.5. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.K.1. through I.K.4., the owner or operator may comply with natural gas-driven diaphragm pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.L. Leak detection and repair program for well production facilities and natural gas compressor stations located in the 8-hour Ozone Control Area.

I.L.1. Natural gas compressor stations

I.L.1.a. Beginning June 30, 2018, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method at least quarterly.

I.L.1.b. Owners or operators of natural gas compressor stations constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no later than ninety (90) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted at least quarterly.

I.L.2. Well production facilities

I.L.2.a. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least annually.

I.L.2.b. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

I.L.2.c. For purposes of Sections I.L.2.a. and I.L.2.b., the estimated uncontrolled actual volatile organic compound emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual volatile organic compound emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

I.L.2.d. Owners or operators of well production facilities constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted in accordance with Sections I.L.2.a. and I.L.2.b.

I.L.3. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

I.L.3.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

I.L.3.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

I.L.3.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

I.L.4. Leaks requiring repair: Only leaks from components exceeding the thresholds in Section I.L.4. require repair under Section I.L.5.

I.L.4.a. For EPA Method 21 monitoring, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.b. For infra-red camera monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.c. For other approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in an approval under Section I.L.8.

I.L.4.d. For leaks identified using an approved non-quantitative instrument monitoring method, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section I.L.5. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section I.L.4.a., the leak must be repaired and remonitored in accordance with Section I.L.5.

I.L.4.e. Owners or operators must maintain and operate approved non-quantitative instrument monitoring methods according to manufacturer recommendations.

I.L.5. Repair and remonitoring

I.L.5.a. First attempt to repair a leak must be made no later than five (5) working days after discovery and completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

I.L.5.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

I.L.5.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.L.5.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

I.L.5.b. Within fifteen (15) working days of completion of a repair the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

I.L.5.c. Leaks discovered pursuant to the leak detection methods of Section I.L.4. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section I.L.5. or keep required records in accordance with Section I.L.6.

I.L.6. Recordkeeping

I.L.6.a. Documentation of the initial approved instrument monitoring method inspection for well production facilities and natural gas compressor stations;

I.L.6.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

I.L.6.c. A list of the leaks requiring repair and the monitoring method(s) used to determine the presence of the leak;

I.L.6.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

I.L.6.e. The date the leak was repaired and type of repair method applied;

I.L.6.f. The delayed repair list, including the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list;

I.L.6.g. The date the leak was remonitored and the results of the remonitoring; and

I.L.6.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section I.L.3., an explanation stating why the component is so designated, and the schedule for monitoring such component(s).

I.L.6.i. Records must be maintained for a minimum of five years and made available to the Division upon request.

I.L.7. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section I.L. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

I.L.7.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

I.L.7.b. The total number of inspections performed per inspection frequency tier of well production facilities and the total number of inspections performed at natural gas compressor stations;

I.L.7.c. The total number of identified leaks requiring repair broken out by component type, monitoring method, and inspection frequency tier of well production facility as reported in Section I.L.7.b. and the total number of identified leaks requiring repair at natural gas compressor stations broken out by component type and monitoring method;

I.L.7.d. The total number of leaks repaired for each inspection frequency tier of well production facilities as reported in Section I.L.7.b. and the total number of leaks repaired for natural gas compressor stations;

I.L.7.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facility as reported in Section I.L.7.b. or natural gas compressor station, and the basis for each delay of repair;

I.L.7.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

I.L.7.g. Each report shall be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

I.L.8. Alternative approved instrument monitoring methods may be used in lieu of, or in combination with an infra-red camera, EPA Method 21, or other approved instrument

monitoring method to inspect for leaks as required by Section I.L., if the following conditions are met:

I.L.8.a. The proponent of the alternative approved instrument monitoring method applies for a determination of an alternative approved instrument monitoring method or program. The application must include, at a minimum, the following:

I.L.8.a.(i) The proposed alternative approved instrument monitoring method manufacturer information;

I.L.8.a.(ii) A description of the proposed alternative approved instrument monitoring method including, but not limited to:

I.L.8.a.(ii)(A) Whether the proposed alternative approved instrument monitoring method is a quantitative detection method, and how emissions are quantified, or qualitative leak detection method;

I.L.8.a.(ii)(B) Whether the proposed alternative approved instrument monitoring method is commercially available;

I.L.8.a.(ii)(C) Whether the proposed alternative approved instrument monitoring method is approved by other regulatory authorities and for what application (e.g., pipeline monitoring, emissions detected);

I.L.8.a.(ii)(D) The leak detection capabilities, reliability, and limitations of the proposed alternative approved instrument monitoring method, including, but not limited to, the ability to identify specific leaks or locations, detection limits, and any restrictions on use, as well as supporting data;

I.L.8.a.(ii)(E) The frequency of measurements and data logging capabilities of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(F) Data quality indicators for precision and bias of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(G) Quality control and quality assurance procedures necessary to ensure proper operation of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(H) A description of where, when, and how the proposed alternative approved instrument monitoring method will be used; and

I.L.8.a.(ii)(I) Documentation (e.g., field or test data, modeling) adequate to demonstrate the proposed alternative approved instrument monitoring method or program is capable of achieving emission reductions that are at least as effective as the emission reductions achieved by the leak detection and repair provisions in Section I.L.

I.L.8.a.(iii) The Division will transmit a copy of the complete application and any other materials provided by the applicant to EPA.

I.L.8.a.(iv) Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.L.8.a.(v) The Division and the EPA approves the proposal. The Division will transmit a copy of the application and any other materials provided by the applicant, all public comments, all Division responses and the Division's approval to EPA Region 8. If EPA fails to approve or disapprove the proposal within six (6) months of receipt of these materials, EPA will be deemed to have approved the proposal.

II. (State Only) Statewide Controls for Oil and Gas Operations

II.A. (State Only) Definitions

II.A.1. "Air Pollution Control Equipment," as used in this Section II., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section II.B.2.e.

II.A.2. "Approved Instrument Monitoring Method," means an infra-red camera, EPA Method 21, or other Division approved instrument based monitoring method or program. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations.

II.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions.

II.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

II.A.5. "Class II Disposal Well Facility" means a facility that injects underground fluids which are brought to the surface in connection with natural gas storage operations or oil or natural gas production and that may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Class II disposal well facilities do not include wells which inject fluids for enhanced recovery of oil or natural gas or for storage of hydrocarbons which are liquid at standard temperature and pressure.

II.A.6. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

II.A.7. “Component” means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

II.A.8. “Connector” means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

II.A.9. “Dump Valve” means a liquid-control valve in a separator that controls liquid level within the separator vessel.

II.A.10. “Dump Event” means the opening of a dump valve allowing liquid to flow from a separator equipped with a dump valve to a storage tank.

II.A.11. “Glycol Natural Gas Dehydrator” means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

II.A.12. “Infra-red Camera” means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

II.A.13. “Hydrocarbon Liquid” means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquid does not include produced water.

II.A.14. “Natural Gas Compressor Station” means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

II.A.15. “Normal Operation” means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

II.A.16. “Occupied Areas” means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

II.A.17. “Open-Ended Valve or Line” means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

II.A.18. “Produced Water” means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

II.A.19. “Reciprocating Compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

II.A.20. “Stabilized” when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

II.A.21. “Storage Tank” means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

II.A.22. “Storage Tank Measurement System” means equipment and methods used to determine the quantity and quality of the liquids inside a storage tank without requiring direct access through the storage tank thief hatch.

II.A.23. “Storage Vessel” means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

II.A.24. “Visible Emissions” means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation, pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor.

II.A.25. “Vapor Collection and Return System” means a closed system designed to control the release of VOCs displaced from a vessel during transfer of hydrocarbon liquids by using the transferred hydrocarbon liquids for direct displacement to force vapors from the vessel being loaded into either the storage tank being unloaded or to air pollution control equipment.

II.A.26. “Well Production Facility” means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

II.B. (State Only) General Provisions

II.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.B.1.a. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

II.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

II.B.2. General requirements for air pollution control equipment used to comply with Section II.

II.B.2.a. All air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of VOCs and other hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

II.B.2.b. If a combustion device is used to control emissions of VOCs and other hydrocarbons, it must be enclosed, have no visible emissions during normal operation, and be designed so that an observer can, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

II.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

II.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons must be equipped with and operate an auto-igniter as follows

II.B.2.d.(i) All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device.

II.B.2.d.(ii) All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

II.B.2.e. Alternative emissions control equipment will qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section II., if the Division approves the equipment, device, or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section II.

II.B.3. Requirements for compressor seals and open-ended valves or lines

II.B.3.a. Beginning January 1, 2015, each open-ended valve or line at well production facilities and natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line. Alternatively, an open-ended valve or line may be treated as if it is a "component" as defined in Section II.A.7., and may be monitored under the provisions of Section II.E.

II.B.3.b. Beginning January 1, 2015, uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter.

II.B.3.c. Beginning January 1, 2015, the rod packing on any reciprocating compressor located at a natural gas compressor station must be replaced every 26,000 hours of operation or every thirty-six (36) months, unless the reciprocating compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

II.B.4. Oil refineries are not subject to Section II.

II.B.5. Glycol natural gas dehydrators that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63 (December 17, 2006), a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 (December 17, 2006) are not subject to Section II., except for the leak detection and repair requirements in Section II.E.

II.C. Emission reduction from storage tanks at oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.C.1. Control and monitoring requirements for storage tanks

II.C.1.a. (State Only) Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that has a control efficiency of at least 95% for VOCs.

II.C.1.b. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.

II.C.1.b.(i) (State Only) Control requirements of Section II.C.1.b. must be achieved in accordance with the following schedule:

II.C.1.b.(i)(A) A storage tank constructed on or after May 1, 2014, must be in compliance within ninety (90) days of the date that the storage tank commences operation.

II.C.1.b.(i)(B) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

II.C.1.b.(i)(C) A storage tank not otherwise subject to Sections II.C.1.b.(i)(A) or II.C.1.b.(i)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve-month basis after May 1, 2014, must be in compliance within sixty (60) days of discovery of the emissions increase.

II.C.1.b.(ii). Control requirements within ninety (90) days of commencement of operation.

II.C.1.b.(ii)(A) Beginning May 1, 2014, through March 1, 2020, owners or operators of storage tanks at well production facilities must collect and control emissions by routing emissions to operating air pollution control equipment during the first ninety (90) calendar days after commencement of operation. The air pollution control equipment must achieve a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. This control requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after commencement of operation.

II.C.1.b.(ii)(B) The air pollution control equipment and any associated monitoring equipment required pursuant to Section II.C.1.c.(i) may be removed at any time after the first ninety (90) calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank will be below the threshold in Section II.C.1.b.

II.C.1.c. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to March 1, 2020.

II.C.1.c.(i) Control requirements of Section II.C.1.c. must be achieved in accordance with the following schedule

II.C.1.c.(i)(A) A storage tank constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

II.C.1.c.(i)(B) A storage tank constructed before March 1, 2020, that is not already controlled under Sections I.D. or II.C.1.b. must be in compliance by May 1, 2021.

II.C.1.c.(i)(C) A storage tank not otherwise subject to Sections II.C.1.c.(i)(A) or II.C.1.c.(i)(B) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B) must be in compliance within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.1.c.(ii) If air pollution control equipment is not installed by the applicable compliance date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C), compliance with Section II.C.1.c. may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

II.C.1.c.(iii) Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.

II.C.1.d. (State Only) Beginning May 1, 2014, or the applicable compliance date in Sections II.C.1.b.(i) or II.C.1.c.(i), whichever comes later, owners or operators of storage tanks subject to Section II.C.1. must conduct audio, visual, olfactory (AVO) and additional visual inspections of the storage tank and any associated equipment (e.g., separator, air pollution control equipment, or other pressure reducing equipment) at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days. Monitoring is not required for storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e. The additional visual inspections must include, at a minimum:

II.C.1.d.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly sealed.

II.C.1.d.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment.

II.C.1.d.(iii) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

II.C.1.d.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open.

II.C.1.d.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

II.C.1.d.(vi) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, visual observation of the dump valve(s) of the last separator(s) before the storage tank(s) to ensure the dump valve is free of debris and not stuck open. The owner or operator is not required to observe the actuation of the dump valve during this inspection; however, if a dump event occurs during the inspection, the owner or operator must confirm proper operation of the valve.

II.C.1.d.(vii) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, a check for the presence of liquids in liquid knockout vessels that do not drain automatically, underground lines, and aboveground piping.

II.C.1.d.(vii)(A) For liquid knockout vessels for which a procedure exists to check liquid level, check for the presence of liquids. If liquids are present above the low level indication point, drain liquids.

II.C.1.d.(vii)(B) For liquid knockout vessels for which no procedure exists to check liquid level, drain liquids.

II.C.1.d.(vii)(C) For underground lines and aboveground piping that is not sloped to a liquid knockout or tank and for which a procedure exists to check for the presence of liquids accumulation, check for the presence of liquids and drain liquids as needed.

II.C.1.d.(vii)(D) For underground lines and aboveground piping that is not sloped to a liquid knockout vessel or tank and for which no written procedure exists to check for the presence of liquids accumulation, drain liquids quarterly.

II.C.1.e. (State Only) If storage tanks or associated equipment is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor such equipment until it becomes feasible to do so.

II.C.1.e.(i) Difficult to monitor means it cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

II.C.1.e.(ii) Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.C.1.e.(iii) Inaccessible to monitor means buried, insulated, or obstructed by equipment or piping that prevents access by monitoring personnel.

II.C.2. (State Only) Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections I.D. or II.C.1.

II.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator compiles with Section II.C.4.), or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section II.C.2.b.(ii).

II.C.2.a.(i) Venting is emissions from a controlled storage tank thief hatch, pressure relief device, or other access point to the storage tank, which:

II.C.2.a.(i)(A) Are primarily the result of over-pressurization, whether related to design, operation, or maintenance; or

II.C.2.a.(i)(B) Are the result of an open, unlatched, or visibly unseated pressure relief device (e.g., thief hatch or pressure relief valve), an open vent line, or an unintended opening in the storage tank (e.g., crack or hole).

II.C.2.a.(ii) When emissions from a controlled storage tank are observed, the Division may require the owner or operator to submit sufficient information demonstrating whether or not the emissions were primarily the result of over-pressurization. Absent a demonstration that such emissions were not primarily the result of over-pressurization, such emissions will be considered venting for purposes of Section II.C.2.a.

II.C.2.a.(iii) When venting is observed, the owner or operator must confirm within twenty-four (24) hours of taking action to return the storage tank to operation without venting that the action(s) taken was effective. If the venting was observed using an approved instrument monitoring method, the confirmation must be made using an approved instrument monitoring method.

II.C.2.b. Owners or operators of storage tanks subject to the control requirements of Sections I.D., II.C.1.a, II.C.1.b., or II.C.1.c. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section II.C.2.a. Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed.

II.C.2.b.(i) STEM plans must include selected control technologies, monitoring practices, operational practices, and/or other strategies; an analysis of the engineering design of the storage tank and air pollution control equipment; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with approved instrument monitoring methods following the applicable schedule in Section II.C.2.b.(ii).

II.C.2.b.(ii) Owners or operators must achieve the requirements of Sections II.C.2.a. and II.C.2.b. and begin implementing the required approved instrument monitoring method in accordance with the following schedule

II.C.2.b.(ii)(A) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed on or after May 1, 2014, must comply with the requirements of Section II.C.2.a. by the date the storage tank commences operation. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of the date that the storage tank commences operation.

II.C.2.b.(ii)(B) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed before May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2015.

II.C.2.b.(ii)(C) A storage tank subject to Section II.C.1.c. and constructed on or after March 1, 2020, must comply with the requirements of Section II.C.2.a. by commencement of operation of the storage tank. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of commencement of operation of the storage tank.

II.C.2.b.(ii)(D) A storage tank subject to Sections II.C.1.c. and I.D.3. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

II.C.2.b.(ii)(E) A storage tank subject to Section II.C.1.c. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2021. Approved instrument monitoring method inspections of the storage tank must begin in 2021.

II.C.2.b.(ii)(F) A storage tank with uncontrolled actual emissions of VOCs equal to or greater than six (6) and less than or equal to twelve (12) tons per year must begin semi-annual approved instrument monitoring method inspections in 2020.

II.C.2.b.(ii)(G) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) or II.C.2.b.(ii)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis..

II.C.2.b.(ii)(H) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) through II.C.2.b.(ii)(F) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B), must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.2.b.(ii)(I) Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the inspection frequency in Table 1.

Table 1 – Storage Tank Inspections

Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Method Inspection Frequency
≥ 2 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

II.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e.

II.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy(ies) are designed to minimize emissions from storage tanks and associated equipment at the facility(ies), including thief hatches and pressure relief devices.

II.C.3. (State Only) Recordkeeping: The owner or operator of each storage tank subject to Sections I.D. or II.C. must maintain records of STEM, if applicable, including the plan, any updates, and the certification, and make them available to the Division upon request. In addition, for a period of two (2) years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including

II.C.3.a. The AIRS ID for the storage tank.

II.C.3.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions, except for venting that is reasonably required for maintenance, gauging (unless use of a storage tank measurement system is required pursuant to and the operator complies with Section II.C.4.), or safety of personnel and equipment.

II.C.3.c. The date and duration of any period where the air pollution control equipment is not operating.

II.C.3.d. Records of the inspections required in Sections II.C.1.d. and II.C.2.b.(ii), including the time and date of each inspection and a description of any problems observed, description and date of any corrective action(s) taken, and name of employee or third party performing corrective action(s).

II.C.3.e. Where a combustion device is being used, the date and result of any EPA Method 22 test or investigation pursuant to Section II.C.1.d.(v).

II.C.3.f. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions, including the dates and results of action(s) taken and the monitoring used to confirm the action(s) were successful.

II.C.3.g. A list of equipment associated with the storage tank that is designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.C.1.e., an explanation stating why the equipment is so designated, and the plan for monitoring such equipment.

II.C.3.h. Records of any exemption, and associated documentation, applied for under Section II.C.1.c.(iii).

II.C.4. (State Only) Storage tank measurement system requirements at well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.4.a. Applicability

II.C.4.a.(i) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after May 1, 2020, and at any facilities that are modified on or after May 1, 2020, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quantity of liquids in the storage tank(s).

II.C.4.a.(ii) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after January 1, 2021, and at any facilities that are modified on or after January 1, 2021, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quality and quantity of liquids in the storage tank(s).

II.C.4.b. Owner or operators subject to the storage tank measurement system requirements in Section II.C.4.a., must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage tank(s).

II.C.4.c. Operators may inspect, test, and/or calibrate the storage tank measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Section II.C.4.b.

II.C.4.d. The owner or operator must install signage at or near the storage tank that indicates which equipment and method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.4.e. The owner or operator must develop and implement an annual training program for employees and/or third parties conducting activities subject to Section II.C.4. that includes, at a minimum, operating procedures for each type of system.

II.C.4.f. Owner or operators must retain records for at least two (2) years and make such records available to the Division upon request, including

II.C.4.f.(i) Date of construction of the storage vessel or facility.

II.C.4.f.(ii) Description of the storage tank measurement system used to comply with Section II.C.4.a.

II.C.4.f.(iii) Date(s) of storage tank measurement system inspections, testing, and/or calibrations pursuant to Section II.C.4. c.

II.C.4.f.(iv) Manufacturer specifications regarding storage tank measurement system inspections, and/or calibrations, if followed pursuant to Section II.C.4.c.

II.C.4.f.(v) Records of the annual training program, including the date and names of persons trained.

II.C.5. (State Only) Storage tank hydrocarbon liquids loadout requirements at Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.5.a. Owners or operators of well production facilities, natural gas compressor stations, and natural gas processing plants with a hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

Owners or operators of class II disposal well facilities with VOC emissions from hydrocarbon liquids loadout to transport vehicles greater than or equal to two (2) tons uncontrolled actual emissions per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

II.C.5.a.(i) Compliance with Section II.C.5. must be achieved in accordance with the following schedule

II.C.5.a.(i)(A) Facilities constructed or modified on or after May 1, 2020, must be in compliance by commencement of operation.

II.C.5.a.(i)(B) Facilities constructed before May 1, 2020, must be in compliance by May 1, 2021.

II.C.5.a.(i)(C) Class II disposal well facilities constructed or modified on or after January 1, 2021, must be in compliance by commencement of operation.

II.C.5.a.(i)(D) Class II disposal well facilities constructed before January 1, 2021, must be in compliance by May 1, 2021.

II.C.5.a.(i)(E) Facilities not subject to Sections II.C.5.a.(i)(A) or II.C.5.a.(i)(B) that exceed the hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from loadout upon exceeding the loadout threshold.

II.C.5.a.(i)(F) Facilities not subject to Sections II.C.5.a.(i)(C) or II.C.5.a.(i)(D) that exceed the hydrocarbon liquids loadout to transport vehicles emissions threshold of greater than or equal to two (2) tons uncontrolled actual VOC emissions per year on a rolling 12-month basis must control emissions from loadout within sixty (60) days of the first day of the month after which loadout emissions exceeded the loadout threshold.

II.C.5.a.(ii) Storage tanks must operate without venting at all times during loadout.

II.C.5.a.(iii) The owner or operator must, as applicable:

II.C.5.a.(iii)(A) Install and operate the vapor collection and return equipment to collect vapors during the loadout of hydrocarbon liquids to tank compartments of outbound transport vehicles and to route the vapors to the storage tank or air pollution control equipment.

II.C.5.a.(iii)(B) Include devices to prevent the release of vapor from vapor recovery hoses not in use.

II.C.5.a.(iii)(C) Use operating procedures to ensure that hydrocarbon liquids cannot be transferred to transport vehicles unless the vapor collection and return system is in use.

II.C.5.a.(iii)(D) Operate all recovery and disposal equipment at a back-pressure less than the pressure relief valve setting of transport vehicles.

II.C.5.a.(iii)(E) The owner or operator must inspect onsite loading equipment to ensure that hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loadout. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv) Loadout observations and operator training

II.C.5.a.(iv)(A) The owner or operator must observe loadout to confirm that all storage tanks operate without venting when loadout operations are active. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv)(B) If observation of loadout is not feasible, the owner or operator must document the annual loadout frequency and the reason why observation is not feasible and inspect the facility within 24 hours after loadout to confirm that all storage tank thief hatches (or other access point to the tank) are closed and latched.

II.C.5.a.(iv)(C) The owner or operator must install signage at or near the loadout control system that indicates which loadout control method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.5.a.(iv)(D) The owner or operator must develop and implement an annual training program for employees and/or third parties conducting loadout activities subject to Section II.C.5. that includes, at a minimum, operating procedures for each type of loadout control system.

II.C.5.a.(v) Owners or operators must retain records for at least two (2) years and make such records available to the Division upon request.

II.C.5.a.(v)(A) Records of the annual facility hydrocarbon liquids loadout to transport vehicles throughput.

II.C.5.a.(v)(B) Inspections, including a description of any problems found and their resolution, required under Sections II.C.5.a.(iii) and II.C.5.a.(iv) must be documented in a log.

II.C.5.a.(v)(C) Records of the infeasibility of observation of loadout.

II.C.5.a.(v)(D) Records of the frequency of loadout.

II.C.5.a.(v)(E) Records of the annual training program, including the date and names of persons trained.

II.C.5.a.(v)(F) Records of class II disposal well facility VOC emissions from hydrocarbon liquids loadout to transport vehicles on a rolling 12-month basis.

II.C.5.a.(vi) Air pollution control equipment used to comply with this Section II.C.5. must comply with Section II.B., be inspected in accordance with Sections II.C.1.d.(ii) through (v), and achieve a hydrocarbon control efficiency of 95%.

II.D. (State Only) Emission reductions from glycol natural gas dehydrators

II.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

II.D.2. The control requirement in Section II.D.1. apply where:

II.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

II.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

II.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:

II.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and

II.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.

II.D.4. The control requirement in Section II.D.3. apply where:

II.D.4.a. Uncontrolled actual emissions of VOCs from a glycol natural gas dehydrator constructed on or after May 1, 2015, are equal to or greater than two (2) tons per year. Such glycol natural gas dehydrators must be in compliance with Section II.D.3. by the date that the glycol natural gas dehydrator commences operation.

II.D.4.b. Uncontrolled actual emissions of VOCs from a single glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

II.D.4.c. For purposes of Sections II.D.3. and II.D.4.:

II.D.4.c.(i) Building Unit means a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

II.D.4.c.(ii) A Designated Outside Activity Area means an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government had established as a designated outside activity area by the COGCC; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

II.E. (State Only) Leak detection and repair program for well production facilities and natural gas compressor stations

II.E.1. The following provisions of Section II.E. apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

II.E.2. Owners or operators of well production facilities or natural gas compressor stations that monitor components as part of Section II.E. may estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

II.E.3. Beginning January 1, 2015, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method, in accordance with the following schedule

II.E.3.a. Approved instrument monitoring method inspections must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

II.E.3.a.(i) Annual approved instrument monitoring method inspections at natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015. Annual inspections must be conducted through calendar year 2019.

II.E.3.a.(ii) Beginning calendar year 2020, owners or operators of natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must conduct semi-annual approved instrument monitoring method inspections.

II.E.3.b. Approved instrument monitoring method inspections must begin within thirty (30) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than fifty (50) tons per year.

II.E.3.c. Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the Inspection Frequency in Table 2.

II.E.3.d. For purposes of Section II.E.3., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

Table 2 – Natural Gas Compressor Station Component Inspections

Fugitive VOC Emissions (rolling twelve-month tpy)	Inspection Frequency
> 0 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

II.E.4. Requirements for well production facilities

II.E.4.a. Owners or operators of well production facilities constructed on or after October 15, 2014, must identify leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. This initial test constitutes the first, or only for facilities subject to a one time approved instrument monitoring method inspection, of the periodic approved instrument monitoring method inspections. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequencies in Table 3.

II.E.4.b. Owners or operators of well production facilities constructed before October 15, 2014, must identify leaks from components using an approved instrument monitoring method within ninety (90) days of the Phase-In Schedule in Table 3; within thirty (30) days for well production facilities subject to monthly approved instrument monitoring method inspections; or by January 1, 2016, for well production facilities subject to a one time approved instrument monitoring method inspection. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table 3.

II.E.4.c. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) but less than or equal to twelve (12) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

II.E.4.d. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, and located within 1,000 feet of an occupied area must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 3.

II.E.4.e. The estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

Table 3 – Well Production Facility Component Inspections				
Thresholds (per II.E.4.d.)				
Well production facilities without storage tanks (rolling twelve-month tpy)	Well production facilities with storage tanks (rolling twelve-month tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency	Phase-In Schedule
> 0 and < 2	> 0 and < 2	One time	Monthly	January 1, 2016
≥ 2 and ≤ 12	≥ 2 and ≤ 12	Semi-annually	Monthly	* begins in 2020
> 2 and < 12, located within 1,000 feet of an occupied area	> 2 and < 12, located within 1,000 feet of an occupied area	Quarterly	Monthly	* begins in 2020
> 12 and ≤ 20	> 12 and ≤ 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area	> 12, located within 1,000 feet of an occupied area	Monthly		* begins in 2020
> 20	> 50	Monthly		January 1, 2015

II.E.5. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

II.E.5.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

II.E.5.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.E.5.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

II.E.6. Leaks requiring repair: Leaks must be identified utilizing the methods listed in Section II.E.6. Only leaks from components exceeding the thresholds in Section II.E.6. require repair under Section II.E.7.

II.E.6.a. For EPA Method 21 monitoring, at facilities constructed before May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 2,000 parts per million (ppm) not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation, except for well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.b. For EPA Method 21 monitoring, at facilities constructed on or after May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.c. For infra-red camera and AVO monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.d. For other Division approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in the Division's approval.

II.E.6.e. Except as provided in Section II.E.6.f., for leaks identified using an approved non-quantitative instrument monitoring method or AVO, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.a. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section II.E.6., the leak must be repaired in accordance with Section II.E.7.a. and remonitored in accordance with Section II.E.7.c.

II.E.6.f. Beginning on March 1, 2021, for leaks identified using an approved non-quantitative instrument monitoring method or AVO at a well production facility located within 1,000 feet of an occupied area, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.b. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Sections II.E.6.a. through II.E.6.d., the leak must be repaired as follows and remonitored in accordance with Section II.E.7.c.

II.E.6.f.(i) If EPA Method 21 indicates a leak greater than 500 ppm and less than 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.a.

II.E.6.f.(ii) If EPA Method 21 is not performed or indicates a leak greater than or equal to 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.b

II.E.7. Repair and remonitoring

II.E.7.a. Except as provided in Section II.E.7.b., the first attempt to repair a leak must be made no later than five (5) working days after discovery and repair of a leak discovered on or after January 1, 2018, completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

II.E.7.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

II.E.7.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

II.E.7.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

II.E.7.b. For leaks requiring repair pursuant to Section II.E.6.f., the first attempt to repair must be made as soon as practicable but no later than five (5) working days after discovery and completed within five (5) working days after discovery. If repair is not completed within five (5) working days after discovery, the owner or operator must use other means to stop the leak including, but not limited to, isolating the component or shutting in the well, unless such other means will cause greater emissions.

II.E.7.b.(i) If the owner or operator cannot repair or stop the leak within five (5) working days after discovery, the owner or operator must notify the local government with jurisdiction over the location and the Division as soon as possible, but no later than seven (7) working days after the leak is discovered. The notice must include

II.E.7.b.(i)(A) Identification of the facility, the leaking component, and contact information of the owner or operator representative;

II.E.7.b.(i)(B) The concentration of hydrocarbons using EPA Method 21, if available;

II.E.7.b.(i)(C) Instructions to access the infrared camera video footage of the leak, if available;

II.E.7.b.(i)(D) The approximate distance of the facility to the closest occupied area that is not an outdoor area;

II.E.7.b.(i)(E) The basis for the delay of repair and justification for not isolating the component or shutting in the well; and

II.E.7.b.(i)(F) The estimated date of repair.

II.E.7.c. Within fifteen (15) working days of completion of a repair, the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

II.E.7.d. Leaks discovered pursuant to the leak detection methods of Section II.E.6. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section II.E.7. or keep required records in accordance with Section II.E.8.

II.E.8. Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

II.E.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

II.E.8.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.E.8.c. A list of the leaking components requiring repair and the monitoring method(s) used to determine the presence of the leak;

II.E.8.d. The date and result of any EPA Method 21 monitoring relied upon to demonstrate a leak is not subject to Section II.E.7.b.;

II.E.8.e. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

II.E.8.f. The date the leak was repaired and for leaks discovered and repaired on or after January 1, 2018, the type of repair method applied;

II.E.8.g. Documentation of actions taken pursuant to Section II.E.7.b. to stop a leak that was not repaired within five (5) working days after discovery or documentation that such actions would cause greater emissions;

II.E.8.h. Copies of all notices submitted pursuant to Section II.E.7.b.(i) and the infrared camera video footage of leaks that required notice pursuant to Section II.E.7.b.(i);

II.E.8.i. The delayed repair list, including the basis for placing leaks on the list;

II.E.8.i.(i) For leaks discovered on or after January 1, 2018, the delayed repair list must include the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

II.E.8.i.(ii) For leaks discovered after March 1, 2021, that require repair pursuant to Section II.E.7.b., the delayed repair list must include the date and duration of leaks for which repairs were not completed within five (5) working days after discovery, and the schedule for repairing the leak.

II.E.8.j. The date the leak was remonitored and the results of the remonitoring;

II.E.8.k. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.E.5., an explanation stating why the component is so designated, and the schedule for monitoring such component(s); and

II.E.8.l. Documentation of the owner or operator's proximity analysis, if applicable, including the date of the initial and any subsequent analysis and a description of the methodology used for the analysis.

II.E.9. Reporting. The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must submit a single annual report using the Division-approved format on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

II.E.9.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

II.E.9.b. The total number of inspections performed per inspection frequency tier of well production facilities, including the number of facilities inspected in accordance with Section II.E.4.d., and inspection frequency tier of natural gas compressor stations;

II.E.9.c. The total number of identified leaks requiring repair, broken out by component type, monitoring method, and inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.d. The total number of leaks repaired for each inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations, and the basis for each delay of repair. This total does not include leaks that have been stopped through other means, as specified in Section II.E.7.b.;

II.E.9.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

II.E.9.g. Each report must be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete

II.F. Control of emissions from well production facilities

Well Operation and Maintenance: On or after August 1, 2014, gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well, must either be routed to a gas gathering line or controlled from commencement of operation by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

II.G. (State Only) Emissions during downhole well maintenance, well liquids unloading events, and well plugging

II.G.1. Beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for emissions from the well associated with downhole well maintenance, well liquids unloading, and well plugging (beginning January 31, 2020), unless emitting is necessary for safety.

II.G.1.a. During liquids unloading events, any means of creating differential pressure must first be used to attempt to unload the liquids from the well without emitting. If these methods are not successful in unloading the liquids from the well, the well may emit in order to create the necessary differential pressure to bring the liquids to the surface.

II.G.1.b. The owner or operator must be present on-site during any planned downhole well maintenance, well liquids unloading, or well plugging event and must ensure that any emissions from the well associated with the event are limited to the maximum extent practicable.

II.G.2. Recordkeeping

II.G.2.a. Through January 31, 2020, the owner or operator must keep records of the cause, date, time, and duration of venting events under Section II.G. Records must be kept for two (2) years and made available to the Division upon request.

II.G.2.b. Beginning January 31, 2020, or the date specified in Section II.G.2.b.(iii), the owner or operator must keep the following records for two (2) years and make records available to the Division upon request.

II.G.2.b.(i) The cause of emissions (i.e., downhole well maintenance, well liquids unloading, well plugging), date, time, and duration of emissions under Section II.G.

II.G.2.b.(ii) The best management practices used to minimize hydrocarbon emissions or the safety needs that prevented the use of best management practices.

II.G.2.b.(iii) Beginning July 1, 2020, the emissions associated with well liquids unloading, downhole well maintenance, and well plugging.

II.G.3. Reporting

II.G.3.a. The owner or operator must submit a single annual report using a Division-approved format on or before June 30th of each year (beginning June 30th, 2021) that includes the following information regarding each downhole well maintenance, well liquids unloading, and well plugging event conducted the previous calendar year that resulted in emissions.

II.G.3.a.(i) The API number of the well and the AIRS number of any associated storage tanks.

II.G.3.a.(ii) Whether the emissions occurred due to downhole well maintenance, well liquids unloading, or well plugging.

II.G.3.a.(iii) The date, time, and duration of the downhole well maintenance, well liquids unloading, or well plugging event.

II.G.3.a.(iv) The best management practices used to minimize emissions.

II.G.3.a.(v) Safety needs that prevented the use of best management practices to minimize emissions, if applicable.

II.G.3.a.(vi) An estimate of the volume of natural gas, VOC, NOx, N2), CO2, CO, ethane, and methane emitted from the well associated with well liquid unloading activities, downhole well maintenance, and well plugging event and the emission factor or calculation methodology used to determine the volume of natural gas and emissions.

III. Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

III.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B. Definitions

III.B.1. “Affected Operations” means pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B.2. “Continuous Bleed” means a continuous bleed rate of natural gas from a pneumatic controller that is designed to bleed natural gas continuously.

III.B.3. “Custody Transfer” means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

III.B.4. (State Only) “Enhanced Response” means to return a pneumatic controller to proper operation and includes but is not limited to, cleaning, adjusting, and repairing leaking gaskets, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

III.B.5. “High-Bleed Pneumatic Controller” means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

III.B.6. (State Only) “Intermittent pneumatic controller” means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release natural gas to the atmosphere as part of the actuation cycle.

III.B.7. “Low-Bleed Pneumatic controller” means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

III.B.8. "Natural Gas Processing Plant" means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

III.B.9. "No-Bleed Pneumatic Controller" means any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

III.B.10. (State Only) "Non-emitting Controller" means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.

III.B.11. "Pneumatic Controller" means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.

III.B.12. (State Only) "Routed Pneumatic Controller" means a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.

III.B.13. "Self-contained Pneumatic Controller" means a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere.

III.B.14. (State Only) "Wellhead" means the piping, casing, tubing and connected valves supporting or controlling the operation of an oil and/or natural gas well. The wellhead does not include other process equipment at the wellhead site.

III.C. Emission Reduction Requirements

Owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

III.C.1. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, must emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.1.c.

III.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section III.C.1.c.

III.C.1.c. All high-bleed pneumatic controllers that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator must submit justification for high-

bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009.

III.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.2. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located at a natural gas processing plant:

III.C.2.a. All pneumatic controllers placed in service on or after January 1, 2018, must have a natural gas bleed rate of zero, unless allowed pursuant to Section III.C.2.c.

III.C.2.b. All pneumatic controllers with a bleed rate greater than zero in service prior to January 1, 2018, must be replaced or retrofit such that the pneumatic controller has a natural gas bleed rate of zero by May 1, 2018, unless allowed pursuant to Section III.C.2.c.

III.C.2.c. All pneumatic controllers with a natural gas bleed rate greater than zero that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.2.c.(i) For pneumatic controllers with a natural gas bleed rate greater than zero in service prior to January 1, 2018, the owner or operator must submit justification for pneumatic controllers to remain in service due to safety and /or process purposes by May 1, 2018.

III.C.2.c.(ii) For pneumatic controllers with a natural gas bleed rate greater than zero placed in service on or after January 1, 2018, the owner or operator must submit justification for pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.3. (State Only) Statewide:

III.C.3.a. Owners or operators of all pneumatic controllers placed in service on or after May 1, 2014 and before May 1, 2021, must:

III.C.3.a.(i) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible.

III.C.3.a.(ii) If on-site electrical grid power is not being used or a no-bleed pneumatic controller is not technically and economically feasible, utilize pneumatic controllers that emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.a.(iii) For purposes of Section III.C.3.a.(ii), instead of a low-bleed pneumatic controller, owners or operators may utilize a natural gas-driven intermittent pneumatic controller.

III.C.3.a.(iv) Utilizing self-contained pneumatic controllers satisfies Section III.C.3.a.(i).

III.C.3.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, must be replaced or retrofitted by May 1, 2015, such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.3.c.(i) For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015.

III.C.3.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes thirty (30) days prior to installation.

III.C.4. (State Only) Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations

III.C.4.a. Except as provided in Section III.C.4.e.(i), the following facilities must use only non-emitting controllers:

III.C.4.a.(i) Well production facilities that commence operations on or after May 1, 2021;

III.C.4.a.(ii) Well production facilities that receive production from a well that first begins production or is recompleted or refractured on or after May 1, 2021; and

III.C.4.a.(iii) Natural gas compressor stations that commence operations or increase compression horsepower on or after May 1, 2021.

III.C.4.b. Each well production facility and natural gas compressor station with non-emitting controllers used to satisfy the requirements of Sections III.C.4.a.(i) through (iii) must contain on-site signage indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4. This Section III.C.4.b does not apply to operator's subject to Section III.C.4.d.(vi).

III.C.4.c. Company-Wide Non-Emitting Controller Program for Well Production Facilities That Commenced Operation Before May 1, 2021

III.C.4.c.(i) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 1.

III.C.4.c.(ii) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operations before May 1, 2021, must:

III.C.4.c.(ii)(A) Determine Historic Facility Production for each existing well production facility that commenced operation before May 1, 2021.

III.C.4.c.(ii)(A)(1) Historic Facility Production at each existing well production facility which first began production during 2018 or earlier must be based on total liquids production (summing total barrels of oil and water produced through the well production facility) for the calendar year 2019.

III.C.4.c.(ii)(A)(2) Notwithstanding Section III.C.4.c.(ii)(A)(1), for any well production facility to which a well first began production during 2019, 2020 or by May 1, 2021, historic facility production must be based on the production for the first twelve (12) months beginning with the date of first production of the latest well to begin production prior to May 1, 2021.

III.C.4.c.(ii)(A)(3) Notwithstanding Sections III.C.4.c.(ii)(A)(1) and (2), for any well production facility to which a well first began production during 2019, 2020, or by May 1, 2021, if twelve (12) months since date of first production of the latest well to begin production has not passed as of May 1, 2021, then the owner or operator must use an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

III.C.4.c.(ii)(B) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all existing well production facilities that commenced operation before May 1, 2021.

III.C.4.c.(ii)(C) Determine the percentage of total liquids production for each existing facility (the Facility Percent Production) by dividing the Historic Facility Production for that facility by the Total Historic Production.

III.C.4.c.(ii)(D) Determine the Historic Non-Emitting Facility Percent Production.

III.C.4.c.(ii)(D)(1) If the well production facility, including all wellheads flowing to the well production facility, uses only non-emitting controllers, then the Facility Percent Production should be designated as Historic Non-Emitting Facility Percent Production.

III.C.4.c.(ii)(D)(2) In making the determination in Section III.C.4.c.(ii)(D)(1), pneumatic controllers that meet the conditions in Section III.C.4.e.(i) need not be considered.

III.C.4.c.(ii)(E) Determine the Total Historic Non-Emitting Facility Percent Production percentage by summing the Historic Non-Emitting Facility Percent Production for all well production facilities that commenced operation prior to May 1, 2021. The Total Historic Non-Emitting Facility Percent Production determines an owner or operators' May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production, as set forth in Table 1.

III.C.4.c.(iii) Owners or operators must demonstrate compliance with Table 1's May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production through any combination of (1) retrofitting well production facilities to utilize non-emitting controllers or (2) plugging and abandoning an existing well production facility.

III.C.4.c.(iv) An owner or operator that demonstrates that its total statewide oil and natural gas production averages 15 barrels of oil equivalent or less per day per well is not subject to the requirements of Sections III.C.4.c.(i) through (iii). To calculate average statewide oil and natural gas production per day per well, an owner or operator must sum all oil and natural gas production for calendar year 2019 in barrels of oil equivalent, divide by three hundred and sixty-five, and divide by the number of wells the owner or operator operated statewide that produced hydrocarbons in 2019.

III.C.4.c.(v) If a well production facility for which production was included in a calculation of achieving a Total Required Non-Emitting Facility Percent Production target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the well production facility to show compliance with Table 1, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgment or certification within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the well production facility to show compliance with Table 1.

In each submission of the updated Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller

Compliance Plan, the owner or operator will provide the date (month and year) when a well production facility was transferred since the last submission and whether or not the well production facility contributed or will contribute towards achieving the Total Required Non-Emitting Facility Percent Production. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

III.C.4.c.(vi) For each facility designated as contributing to Historic Non-Emitting Facility Percent Production, the owner or operator will place signage on-site by October 1, 2021 indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4.c.

TABLE 1*—Well Production Facilities

Total Historic Non-Emitting Facility Percent Production	May 1, 2022 Additional Required Non-Emitting Facility Percent Production	May 1, 2022 Maximum Required Non-Emitting Facility Percent Production	May 1, 2023 Additional Required Non-Emitting Facility Percent Production	May 1, 2023 Maximum Required Non-Emitting Facility Percent Production	Total Additional Required Non-Emitting Facility Percent Production By May 1 2023
> 75 %	+5%	90%	+10%	96.5%	+15%
> 60-75 %	+5%	80%	+10%	90%	+15%
> 40-60 %	+10%	65%	+15%	75%	+25%
> 20-40 %	+15%	50%	+20%	65%	+35%
0-20 %	+15%	35%	+25%	55%	+40%

* Table 1 establishes minimum increases in the percentage of liquids produced (based on historic non-emitting controller use) from non-emitting facilities. Owners or operators do not need to go beyond the maximum required percentages set forth in Table 1, although they may choose to do so.

III.C.4.d. Company-Wide Non-Emitting Controller Compliance Program for Natural Gas Compressor Stations that Commenced Operation Before May 1, 2021.

III.C.4.d.(i) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 2.

III.C.4.d.(ii) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must:

III.C.4.d.(ii)(A) Determine Total Controller Count for all controllers at all of the owner or operator's natural gas compressor stations that commenced operation before May 1, 2021. The Total Controller Count must include all pneumatic controllers and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.

III.C.4.d.(ii)(B) Determine which controllers in the Total Controller Count are non-emitting and sum the total number of non-emitting controllers and designate those as Total Historic Non-Emitting Controllers.

III.C.4.d.(ii)(C) Determine the Total Historic Non-Emitting Percent Controllers by dividing the Total Historic Non-Emitting Controller Count by the Total Controller Count.

III.C.4.d.(iii) Owners or operators must demonstrate compliance with Table 2's May 1, 2022 and May 1, 2023 Additional Required Percentage of Non-Emitting Controllers through any combination of (1) retrofitting controllers at natural gas compressor stations to utilize non-emitting controllers or (2) permanently removing natural gas compressor stations from service.

III.C.4.d.(iv) Pneumatic controllers that emit natural gas to atmosphere at natural gas compressor stations with non-emitting controllers must be tagged, which will indicate that the controller may emit natural gas. The tags must differentiate between pneumatic controllers that are exempt under Sections IIII.C.4.e.(i)(A) through (C) and pneumatic controllers that emit natural gas to the atmosphere under the company-wide plan. Tagging pursuant to this Section III.C.4.d.(iv) must occur by May 1, 2022.

III.C.4.d.(v) If a natural gas compressor station for which the number of pneumatic controllers located at such compressor station was included in a calculation of achieving a Total Required Non-Emitting Percent Controllers target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgement or certification, within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2.

In each submission of the updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan, the owner or operator will provide the date (month and year) when the natural gas compressor station was transferred since the last submission and whether or not the compressor station contributed or will contribute towards achieving the Total Required Non-Emitting Percent Controllers. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Compressor Station Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Compressor Station Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

III.C.4.d.(vi) This section applies to owners or operators of natural gas compressor stations where all the owner or operator's active, operating natural gas compressor stations use only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers).

III.C.4.d.(vi)(A) No later than September 1, 2021, such owners or operators may file a one-time notification with the Division in lieu of the requirements in Sections III.C.4.d.(i) through (iii) that:

III.C.4.d.(vi)(A)(1) Lists each active, operating natural gas compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that, based on information and belief formed after reasonable inquiry, each of its active, operating natural gas compressor stations uses only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers); and

III.C.4.d.(vi)(A)(2) Lists each inactive, non-operating compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that after May 1, 2021, such compressor stations have not and subsequently will not operate with pneumatic controllers that emit natural gas to the atmosphere, except pneumatic controllers that qualify for exclusions set forth in subject to Sections III.C.4.e.(i)(A) through (C).

III.C.4.d.(vi)(B) If applicable, the notifications submitted under this section must list any pneumatic controllers that qualify for exclusions pursuant to Sections III.C.4.e.(i)(A) through (C) and identify the specific exemption applicable to each such pneumatic controller. Operators must tag any controller qualifying for the exclusions in Sections III.C.4.e.(i)(A) through (C) by October 1, 2021.

III.C.4.d.(vi)(C) The owner or operator must maintain a copy of the one-time notification required by Section III.C.4.d.(vi)(A) for five years.

TABLE 2* – Natural Gas Compressor Stations

Total Historic Percentage of Non-Emitting Controllers	May 1, 2022 Additional Required Percentage of Non-Emitting Controllers	May 1, 2022 Maximum Required Percentage of Non-Emitting Controllers	May 1, 2023 Additional Required Percentage of Non-Emitting Controllers	May 1, 2023 Maximum Required Percentage of Non-Emitting Controllers	Total Additional Required Percentage of Non-Emitting Controllers By May 1, 2023
> 75 %	+10%	90%	+15%	100%	+25%
>60-75 %	+10%	85%	+20%	92%	+30%
>40-60 %	+10%	70%	+25%	75%	+35%
>20-40 %	+15%	50%	+25%	65%	+40%
0-20 %	+20%	35%	+25%	60%	+45%

* Table 2 establishes minimum additional percentages of non-emitting controllers required by May 1, 2022 and May 1, 2023 based on a company's historic percentage of non-emitting controllers. Owners and operators need not go beyond the maximum required percentages specified in Table 2, although they may choose to do so.

III.C.4.e. Pneumatic Controllers That Emit Natural Gas to the Atmosphere Not Subject to Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations.

III.C.4.e.(i) Pneumatic controllers that emit natural gas to the atmosphere meeting any of the following conditions are not subject to the requirements in Section III.C.4.a. and are not required to be retrofit in order to count the facility or controller as non-emitting for compliance with the company-wide plans under Sections III.C.4.c. and III.C.4.d.

III.C.4.e.(i)(A) Pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas.

III.C.4.e.(i)(A)(1) Owners or operators that seek to rely on this exemption for facilities listed in Sections III.C.4.a.(i) through (iii) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to installation of emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(A)(2) Owners or operators that seek to rely on this exemption to maintain emitting controllers at facilities that are retrofit to meet requirements of Section III.C.4.c.(i) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(B) Pneumatic controllers that emit natural gas located on temporary or portable equipment that is used for well abandonment activities or used prior to or through the end of flowback.

III.C.4.e.(i)(C) Pneumatic controllers that emit natural gas located on temporary or portable equipment meeting the requirements of this Section III.C.4.e.(i)(C).

III.C.4.e.(i)(C)(1) Upon notice to the Division on a form developed by the Division, pneumatic controllers that emit natural gas other than those covered by Section III.C.4.e.(i)(B) located on temporary or portable equipment that is in use and onsite for sixty (60) days or less. However, this exemption for temporary or portable equipment does not apply to pneumatic controllers that emit natural gas used on temporary or portable equipment to temporarily increase throughput capacity of a facility.

III.C.4.e.(i)(C)(2) An owner or operator must obtain written approval from the Division for continued use beyond 60 days of pneumatic controllers that emit natural gas under Section III.C.4.e.(i)(C). The owner or operator must submit the request for an extension to the Division at least fourteen (14) days before the 60-day period expires. If the Division does not respond to the request before the 60-day period expires, the request will be deemed approved until such time as the Division may determine that the extension should be denied.

III.C.4.e.(i)(C)(2)(a) To request such an exemption, the owner or operator must submit a plan for Division approval which (1) identifies the temporary or portable equipment and number and type of pneumatic controllers that emit natural gas, (2) identifies how long the owner or operator plans to keep the equipment on site, (3) explains the need for an extension, and (4) other information as reasonably required by the Division.

III.C.4.e.(i)(C)(2)(b) In explaining the need for an extension, the operator must clearly identify the basis for extension; the anticipated schedule for use of the temporary or portable equipment; and the steps taken to minimize the length of the requested extension.

III.C.4.e.(i)(C)(3) The operator must inspect the pneumatic controllers using approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the associated well production facility or compressor station, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9.

III.C.4.e.(i)(D) Pneumatic controllers that emit natural gas to the atmosphere that are used as emergency shutdown devices and for artificial lift control located on a wellhead: (1) greater than one quarter mile from the associated production facilities for well production facilities that commenced operation on or after May 1, 2021; or (2) not located on the same surface disturbance as the associated production facilities for well production facilities that commenced operation before May 1, 2021.

III.C.4.e.(i)(D)(1) Owners or operators who seek to use a pneumatic controller at a qualifying wellhead at a facility listed in Sections III.C.4.a.(i) or (ii) that is not used as an emergency shutdown device or for artificial lift control must submit a justification for the use of such a pneumatic controller to the Division for approval forty-five (45) days prior to installation of the emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(D)(2) Owners or operators that seek to rely on this exemption to exclude emitting pneumatic controllers at a qualifying wellhead that are not used as an emergency shutdown device or for artificial lift control when determining their Total Historic Non-Emitting Facility Percent Production pursuant to Section III.C.4.c.(ii) must submit a justification to the Division for approval no later than July 1, 2021. If the Division does not respond to the justification by August 15, 2021, the justification will be deemed approved.

III.C.4.e.(i)(D)(3) Operators that utilize the exemption in Section III.C.4.e.(i)(D) must identify leaks from components using an approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the well production facility to which the well flows as set forth in Table 3 of Section II.E.4, or on a frequency no less than one time per year, whichever is greater, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9. For well production facilities that commenced operation before May 1, 2021 with wellheads utilizing this exemption, the requirement in this Section III.C.4.e.(i)(D)(3) must begin May 1, 2022.

III.C.4.e.(i)(D)(3)(a) An owner or operator that cannot reasonably access the wellhead site to conduct a monthly AIMM or AVO inspection due to circumstances beyond its control (including but not limited to the presence of crops, wildlife restrictions, or severe weather conditions) shall conduct an AVO or AIMM inspection, as applicable, within 14 days of the condition preventing inspection being resolved. Owners or operators that rely on this Section III.C.4.e.(i)(D)(3)(a) must maintain records pursuant to Section III.C.4.g.(vii) and report pursuant Section III.C.4.g.(viii).

III.C.4.e.(i)(D)(3)(b) Operators may use drone-mounted infra-red cameras that ensure line of sight and appropriate distance from the drone to all wellhead equipment and components to conduct the inspections required under Section III.C.4.e.(1)(D)(3). Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request.

III.C.4.e.(i)(D)(4) If a wellhead has on-site electrical grid power to operate an electric controller, then operators may not utilize the exemption in Section III.C.4.e.(i)(D) for any pneumatic controller at the wellhead for which it is technically feasible to utilize an electric controller.

III.C.4.e.(i)(D)(5) Operators may not utilize the exemption in Section III.C.4.e.(i)(D) where equipment with pneumatic controllers other than the wellhead is located at the wellhead site.

III.C.4.e.(ii) By October 1, 2021, each pneumatic controller at a well production facility that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) must be tagged, which will indicate that the controller may emit natural gas.

III.C.4.e.(iii) By October 1, 2021, each pneumatic controller at a natural gas compressor station that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (C) must be tagged, which will indicate that the controller may emit natural gas.

III.C.4.f. Company-Wide Well Production Facility and Natural Gas Compressor Station Reporting Requirements.

III.C.4.f.(i) Owners and operators of well production facilities subject to Sections III.C.4.c.(i) through (iii) must submit a Company-Wide Well Production Facility Pneumatic Controller Compliance Plan to the Division on the Division-approved form by September 1, 2021, and include all of the following elements:

III.C.4.f.(i)(A) A list of existing well production facilities as of May 1, 2021, including AIRS identification numbers and facility names.

III.C.4.f.(i)(B) The following for each well production facility:

III.C.4.f.(i)(B)(1) Historic Facility Production.

III.C.4.f.(i)(B)(2) Facility Percent Production.

III.C.4.f.(i)(B)(3) Historic Non-Emitting Facility Percent Production.

III.C.4.f.(i)(B)(4) The API number for each producing well included in the Total Historic Facility Production.

III.C.4.f.(i)(C) The following company-wide information:

III.C.4.f.(i)(C)(1) Total Historic Production.

III.C.4.f.(i)(C)(2) Total Historic Non-Emitting Facility Percent Production, including a list of facilities already using non-emitting controllers as determined in Section III.C.4.c.(ii)(E).

III.C.4.f.(i)(C)(3) Total Required Non-Emitting Facility Percent Production.

III.C.4.f.(i)(D) An indication of which and in what year well production facilities are expected to be retrofit with non-emitting controllers, or plugged and abandoned, to meet the required Additional Non-Emitting Facility Percent Production for each year listed in Table 1.

III.C.4.f.(ii) Owners or operators will submit an updated Company-Wide Facility Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 1, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Facility Percent Production in a previous year's plan. The updated plan will include all of the following elements:

III.C.4.f.(ii)(A) All elements set forth in Sections III.C.4.f.(i)(A) through (C).

III.C.4.f.(ii)(B) The date (month and year) that any well production facilities were retrofit or plugged and abandoned since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(i)(D).

III.C.4.f.(ii)(C) An update of information set forth in Section III.C.4.f.(i)(D) if the Total Required Non-Emitting Facility Percent Production required by Table 1 has not been met.

III.C.4.f.(ii)(D) For each submission, the owner or operator must list each existing well production facility that is utilizing non-emitting controllers and provide a demonstration that the required Additional Non-Emitting Facility Percent Production for the relevant year has been met.

III.C.4.f.(ii)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Facility Percent Production has been met.

III.C.4.f.(iii) Owners and operators of natural gas compressor stations subject to Sections III.C.4.d.(i) through (iii) must submit a Company-Wide Compressor Station Pneumatic Controller Compliance Plan to the Division on a Division-approved form by September 1, 2021, and include all of the following elements:

III.C.4.f.(iii)(A) A listing of existing natural gas compressor stations as of May 1, 2021, including AIRS identification numbers and facility names.

III.C.4.f.(iii)(B) The following company-wide information:

III.C.4.f.(iii)(B)(1) Total Controller Count, including a list of each pneumatic controller and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.

III.C.4.f.(iii)(B)(2) Total Historic Non-Emitting Controllers, including an indication as to which controllers are already non-emitting.

III.C.4.f.(iii)(B)(3) Total Required Non-Emitting Facility Percent Controllers.

III.C.4.f.(iii)(C) An indication of which and in what year controllers are expected to be retrofit with non-emitting controllers or removed from service (as applicable) to meet the required Additional Non-Emitting Percent Controllers for each year listed in Table 2.

III.C.4.f.(iv) Owners or operators will submit an updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 2, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Percent Controllers in a previous year's plan. The updated plan will include all of the following elements:

III.C.4.f.(iv)(A) All elements set forth in Sections III.C.4.f.(iii)(A) through (B).

III.C.4.f.(iv)(B) The date (month and year) that any controllers at natural gas compressor stations were retrofit or removed from service since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(iii)(C).

III.C.4.f.(iv)(C) The information set forth in Section III.C.4.f.(iii)(C) if the Total Required Non-Emitting Percent Controllers required by Table 2 has not been met.

III.C.4.f.(iv)(D) For each submission, the owner or operator must list total controllers and total non-emitting controllers at existing natural gas compressor stations and provide a demonstration that the required Additional Non-Emitting Percent Controllers for the relevant year has been met.

III.C.4.f.(iv)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Percent Controller has been met.

III.C.4.g. Recordkeeping and Reporting Requirements. The records in Sections III.C.4.g.(i) through (vii) must be kept for a period of five years and made available to the Division upon request.

III.C.4.g.(i) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date natural gas compressor station pneumatic controllers were retrofit or is taken out of service.

III.C.4.g.(ii) If claiming an exemption under Sections III.C.4.e.(i)(A) – (D), records for each pneumatic controller demonstrating that the exemption applies.

III.C.4.g.(iii) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans required to be submitted by Sections III.C.4.f.(i) – (iv).

III.C.4.g.(iv) For any owner or operator utilizing the provision in Section III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies for that provision.

III.C.4.g.(v) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.

III.C.4.g.(vi) Records required to be submitted to the Division pursuant to Sections III.C.4.c.(v) and III.C.4.d.(v).

III.C.4.g.(vii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) must maintain: (1) the date of the AIMM or AVO inspection at the production facility to which the well flows, (2) the date of the AIMM or AVO inspection of the wellhead site once the conditions preventing inspection has been resolved, and (3) records demonstrating the circumstances that prevented the wellhead site from being inspected.

III.C.4.g.(viii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) shall report annually by May 31 of each year, on a form approved by the Division, the number of wellhead sites for which the AIMM inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), the number of wellhead sites for which the AVO inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), and the total number of wellhead sites where inspections were delayed pursuant to Section III.C.4.e.(i)(D)(3)(a) for (1) 30 days or less, (2) greater than 30 days but less than or equal to 90 days, and (3) greater than 90 days.

III.D. Monitoring

This section applies to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

III.D.1. In the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.1.b. Effective May 1, 2009, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band, eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.2. In the 8-Hour Ozone Control Area and located at a natural gas processing plant:

III.D.2.a. Effective May 1, 2018, each pneumatic controller with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.2.b. Effective May 1, 2018, the owner or operator must inspect each pneumatic controller with a natural gas bleed rate greater than zero on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.3. (State Only) Statewide:

III.D.3.a. Effective May 1, 2015, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.3.b. Effective May 1, 2015, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.E. Recordkeeping

III.E.1. In the 8-Hour Ozone Control Area:

III.E.1.a. Continuous bleed, natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.E.1.a.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour.

III.E.1.a.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour. Owners or operators must use this information to update the estimate required in Section III.E.1.a.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

III.E.1.b. Continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant:

III.E.1.b.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero.

III.E.1.b.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero. Owners or operators must use this information to update the estimate required in Section III.E.1.b.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

III.E.1.c. Records must be maintained for a minimum of five years and made available to the Division upon request.

III.E.2. This section applies only to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

III.E.2.a. The owner or operator must maintain a log of the total number of pneumatic controllers and their associated controller numbers per facility, the total number of pneumatic controllers per company and the associated justification that the pneumatic controllers must be used pursuant to Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.). The log shall be updated on a monthly basis.

III.E.2.b. The owner or operator must maintain a log of necessary maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

III.E.2.c. Records of maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

III.F. (State Only) Pneumatic Controller Inspection and Enhanced Response

III.F.1. General Requirements

III.F.1.a. Beginning January 1, 2018, owners or operators of natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.1.b. Beginning May 1, 2020, owners or operators of natural gas-driven pneumatic controllers state-wide must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.2. Pneumatic controller inspection

III.F.2.a. Beginning June 30, 2018, through calendar year 2019, owners or operators of natural gas-driven pneumatic controllers at well production facilities in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.a.(i) Annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total.

III.F.2.a.(ii) Semi-annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.a.(iii) Quarterly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.a.(iv) Monthly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at well production facilities must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.b.(i) Annually at well production facilities in the 8-Hour Ozone Control Area with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than two (2) tons per year, based on a rolling twelve-month total.

III.F.2.b.(ii) Semi-annually at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than or equal to two (2) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.b.(iii) Quarterly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b.(iv) Monthly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.c. For purposes of Sections III.F.2.a. and III.F.2.b., the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

III.F.2.d. Beginning June 30, 2018, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.d.(i) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.d.(ii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.e. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations outside the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.e.(i) Semi-annually at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.e.(ii) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than twelve (12) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.e.(iii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.f. For purposes of Sections III.F.2.d. and III.F.2.e., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

III.F.2.g. Where detectable emissions from the pneumatic controller are observed, owners or operators must determine whether the pneumatic controller is operating properly within five (5) working days after detecting emissions. In making this determination, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.2.h. For pneumatic controllers not operating properly, the owner or operator must conduct enhanced response or follow manufacturer specifications to return the pneumatic controller to proper operation.

III.F.3. Enhanced response and remonitoring

III.F.3.a. Enhanced response must begin no later than five (5) working days and the pneumatic controller returned to proper operation no later than thirty (30) working days after determining the pneumatic controller is not operating properly, unless parts are unavailable, the equipment requires shutdown to complete enhanced response, or other good cause exists. If parts are unavailable, they must be ordered promptly and enhanced response conducted within fifteen (15) working days of receipt of the parts. If shutdown is required, enhanced response must be conducted during the next scheduled shutdown. If delay is attributable to other good cause, enhanced response must be completed within fifteen (15) working days after the cause of delay ceases to exist.

III.F.3.b. Within fifteen (15) working days of completion of enhanced response, the owner or operator must verify the pneumatic controller is operating properly. In verifying proper operation, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.3.c. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the Division unless the owner or operator fails to determine whether the pneumatic controller is operating properly in accordance with Section III.F.2., perform any necessary enhanced response in accordance with Section III.F.3., keep records in accordance with Section III.F.4., or submit reports in accordance with Section III.F.5.

III.F.4. Owners or operators must maintain the following records for a minimum of three (3) years and make records available to the Division upon request.

III.F.4.a. The date, facility name, facility AIRS ID or facility location if the facility does not have an AIRS ID, and approved instrument monitoring method used for each inspection;

III.F.4.b. A list of pneumatic controllers, including type, determined to be not operating properly;

III.F.4.c. For intermittent pneumatic controllers observed to have detectable emissions but determined to be operating properly, a brief explanation of the basis for concluding that the intermittent pneumatic controller was operating properly. The explanation can include, but is not limited to, an owner or operator's standard operating procedure detailing how to determine whether an intermittent pneumatic controller is operating properly, or an individual explanation;

III.F.4.d. The date(s) of enhanced response and a description of the actions taken to return the pneumatic controller to proper operation;

III.F.4.e. The date the owner or operator verified the pneumatic controller was returned to proper operation; and

III.F.4.f. The delayed repair list, including the date and duration of any period where the enhanced response was delayed beyond thirty (30) days after determining the pneumatic controller is not operating properly due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for returning the pneumatic controller to proper operation. Delay of enhanced response due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for pneumatic controller inspection and enhanced response compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

III.F.5. Owners or operators of pneumatic controllers at well production facilities or natural gas compressor stations must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019 for facilities in the 8-Hour Ozone Control Area and May 31st, 2021, for facilities outside the 8-Hour Ozone Control Area) that includes, at a minimum, the following information regarding pneumatic controller inspection and enhanced response activities at their subject facilities conducted the previous calendar year:

III.F.5.a. The total number and type of pneumatic controllers returned to proper operation, the types of actions taken to return the pneumatic controllers to proper operation, and the facility type (by inspection frequency tier of well production facility or natural gas compressor station);

III.F.5.b. The number and type of pneumatic controllers on the delayed repair list as of December 31st broken out by the facility type (by inspection frequency tier of well production facility or natural gas compressor station), and the basis for each delay; and

III.F.5.c. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year.

III.F.6. The provisions in Section III.F. will be reassessed by the Division and stakeholders in 2020.

IV. (State Only) Control of Emissions from the Natural Gas Transmission and Storage Segment

IV.A. Definitions

IV.A.1. "Best management practice" (BMP) means a demonstrated and commercially available or innovative emission-reducing technology or work practice.

IV.A.2. "Best management practices plan" (BMP plan) means a written plan that includes, but is not limited to, each natural gas transmission and storage segment owner or operator's planned and implemented BMPs to reduce methane emissions from its facilities within the natural gas transmission and storage segment.

IV.A.3. "Natural gas transmission and storage segment" (segment) includes onshore natural gas transmission pipelines, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, as these terms are defined in 40 CFR Part 98, Section 98.230 (October 22, 2015), that are physically located in Colorado.

IV.A.4. "Natural gas transmission and storage segment Colorado throughput" (segment throughput) means the total volume of natural gas, as adjusted for methane, transported through transmission pipelines in Colorado as reported to the Department of Energy's (DOE) Energy Information Administration (EIA) for Form 176, excluding net volumes stored as liquefied natural gas or in underground storage facilities.

IV.A.5. "Natural gas transmission and storage segment emissions inventory protocol" (inventory protocol) means the requirements by which natural gas transmission and storage segment owners or operators will quantify and report methane, ethane, carbon monoxide (CO), carbon dioxide (CO2), nitrous oxide (N2O), nitrogen oxides (NOx), and volatile organic compound (VOC) emissions. The protocol will specify the segment facilities and types of activity data collected, emissions quantification methodologies, throughput calculation methodologies, criteria for determining whether events are beyond the control of the owner or operator, and the process for designating and protecting confidential business information (CBI), consistent with Colorado law.

IV.A.6. "Performance-based program" means a program of BMPs implemented and documented by each natural gas transmission and storage segment owner or operator to reduce methane emissions in order to achieve the system-wide emissions intensity target.

IV.A.7. "Steering committee" means five members approved by the Division to serve as a technical working group for developing program guidance documents and evaluating progress against the system-wide emissions intensity target. The committee members will include two representatives from natural gas transmission and storage segment owners or operators (or industry trade organizations representing owners or operators), two members representing the general public (including but not limited to environmental organizations, local government groups, or citizens), and one Division member.

IV.A.8. “Segment-wide emissions intensity” means the natural gas transmission and storage segment methane emissions divided by the natural gas transmission and storage segment throughput.

IV.A.9. “Segment-wide emissions intensity target” (segment-wide target) means the target established by the steering committee reflected as annual segment-wide methane emissions from Colorado’s natural gas transmission and storage segment divided by the annual natural gas transmission and storage segment Colorado throughput.

IV.B. Beginning January 1, 2020, each segment owner or operator must participate in this performance based program to reduce segment-wide methane emissions.

IV.B.1. By April 1, 2020, a steering committee charter and the steering committee members will be approved by the Division.

IV.B.2. By September 30, 2020, the Division will publish the inventory protocol and any associated program guidance documents developed by the steering committee.

IV.B.3. By December 31, 2020, each segment owner or operator must develop a company-specific BMP plan. The BMP plan must contain each element from the BMP plan template chapter of the program guidance document, which will include, but is not limited to, a list of information the owner or operator must collect to demonstrate the BMPs performed. By December 31st of each year (beginning December 31st, 2021), each owner or operator must review and update, as appropriate, its company-specific BMP plan and document in the BMP plan any changes.

IV.B.4. Beginning January 1, 2021, each segment owner or operator will

IV.B.4.a. Implement company specific BMP plans.

IV.B.4.b. Collect emissions inventory data in accordance with the inventory protocol and its company-specific BMP plan.

IV.B.5. By May 1, 2022, the segment owners or operators will select a third-party contractor from a pool of qualified applicants to receive, safeguard, and aggregate company-specific reports as described in Sections IV.D.3. and IV.D.4. The steering committee will establish criteria for the selection of the third-party contractor. The segment owners and operators will use a competitive bidding process to solicit applications from contractors who meet the criteria and will provide an opportunity for the steering committee to reject unqualified applicants.

IV.B.6. By October 1, 2023, the steering committee will determine the segment-wide emissions intensity target using the 2021 and 2022 emissions inventory data. In developing the initial or updated segment-wide emissions intensity target and evaluating the program, the steering committee may request non-company specific information from the Division (in accordance with the Colorado Opens Record Act) or the third-party contractor to assist in setting such target or such evaluation. The steering committee may ask companies to explain emission factors and methodologies used to calculate or measure emissions.

IV.C. The segment-wide emissions intensity target must first be achieved by January 1, 2025, based on the 2024 reporting year.

IV.C.1. By October 1 of each year (beginning October 1, 2025), the steering committee will submit a compliance certification to the Division that the segment achieved the segment-wide emissions intensity target for the prior calendar year.

IV.C.2. If the steering committee cannot certify compliance with the segment-wide emissions intensity target, the steering committee will develop a plan (which may include amendments to program guidance documents) and timeline for the segment to achieve compliance with the segment-wide emissions intensity target.

IV.C.3. Beginning January 1, 2026, and every three (3) years thereafter if appropriate, the steering committee will assess the segment-wide emissions intensity target for continual improvement.

IV.D. Recordkeeping and reporting

IV.D.1. The Division will provide an update on the development of this program and initial implementation efforts to the Air Quality Control Commission during a scheduled Commission meeting on or after January 2021.

IV.D.2. Segment owners or operators must maintain BMP plans and emissions inventory reports for a period of five (5) years and make records available to the Division upon request.

IV.D.3. By June 30 of each year (beginning June 30, 2022), owners or operators of the natural gas transmission and storage segment will submit company-wide reports to the third-party contractor.

IV.D.3.a. Emissions claimed to be beyond the control of the owner or operator, using the criteria and methods established by the steering committee, must be included in the company-wide report but will not be used to set or determine compliance with the segment-wide emissions intensity target.

IV.D.3.b. Emissions and emission reductions associated with any requirements of the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Colorado Public Utilities Commission (CPUC), and/or the Federal Energy Regulatory Commission (FERC) must be included in the report and used for purposes of calculating compliance with the system-wide emissions intensity target, unless they qualify under Section IV.D.3.a., but this Section IV. does not supersede or alter these agencies applicable regulations or requirements.

IV.D.4. The third-party contractor must aggregate the company-wide reports into a segment-wide report and provide it to the steering committee by August 15 of each year (beginning August 15, 2022) on a form developed by the steering committee and approved by the Division. The segment-wide report must include, at a minimum

IV.D.4.a. The segment-wide emissions, apportioned by county,

IV.D.4.b. A report of the numbers and types of events subject to Section IV.D.3.a. and the segment-wide emissions resulting from each type of event.

IV.D.4.c. The BMPs implemented to mitigate or avoid emissions and a description of how the BMPs mitigate, reduce, and/or avoid emissions.

IV.D.4.d. The segment-wide segment throughput.

IV.D.4.e. The segment-wide emissions intensity. If the steering committee determines that one or more types of events reported under Section IV.D.4.b. were not beyond the control of the owner or operator, the steering committee will revise the segment-wide emissions intensity calculation to include the methane emissions from those events.

IV.D.5. Segment owners or operators must submit an annual certification to the Division by June 30 of each year (beginning June 30, 2021) that includes

IV.D.5.a. A certification that the company-specific BMP plan was developed or reviewed in accordance with Section IV.B.3.

IV.D.5.b. A certification that the company-wide report was submitted to the third-party contractor in accordance with Section IV.D.3.

IV.D.5.c. Beginning in 2022, a certification of company BMP plan compliance in accordance with Section IV.B.4., including

IV.D.5.c.(i) The company's implementation of the BMPs in the company-specific BMP plan.

IV.D.5.c.(ii) Instances of non-conformance with the company-specific BMP plan, reason(s) for non-conformance, and any modifications of the applicable element(s) of the BMP plan.

IV.D.5.c.(iii) Any use of alternative emission reduction approaches not specified in the company-specific BMP plan.

IV.D.5.d. With each submission under Sections IV.D.5.a. through IV.D.5.c., a certification by a responsible official that, based on information and belief after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

IV.D.6. The Division may provide an update briefing to the Air Quality Control Commission during a scheduled Commission meeting on or after October 1 of each year (beginning October 1, 2022). The update briefing will include any assessment of the segment-wide target, as specified in Section IV.C.3.

V. (State Only) Oil and Natural Gas Operations Emissions Inventory

V.A. Applicability

V.A.1. On or before June 30th, 2021 (and on June 30th each year thereafter), the owner or operator of oil and natural gas operations and equipment at or upstream of a natural gas processing plant in Colorado must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.A.2. On or before June 30th, 2022 (and on June 30th each year thereafter), the owner or operator or class II disposal well facilities that are not subject to reporting under Section IV. must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.B. General reporting requirements

V.B.1. The following information must be reported in accordance with Section V.A.

V.B.1.a. Company name, physical street address, and name and contact information of the company representative, for reporting purposes.

V.B.1.b. The date of submittal and the year covered by the report.

V.B.1.c. A list of the activities or equipment, as specified in Section V.C., for which emissions are reported.

V.B.1.d. The company's monthly actual emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), nitrous oxide (N2O), carbon dioxide (CO2), carbon monoxide (CO), methane, and ethane for each month of May through September.

V.B.1.e. The company's annual actual emissions of VOCs, NOx, N2O, CO2, CO, methane, and ethane for the entire calendar year.

V.B.1.f. The actual emissions of VOCs, NOx, N2), CO2, CO, methane, and ethane for each activity or equipment listed in Section V.C. per facility, or per pipeline between facilities where the pipeline is not located at a stationary source.

V.B.1.f.(i) The report must include the actual emissions from each activity or equipment per month for each month of May through September.

V.B.1.f.(ii) The report must include the actual emissions from each activity or equipment for the entire calendar year.

V.B.1.g. A certification by the company representative that supervised the development and submission of the inventory report that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

V.B.2. The owner or operator must submit a revised annual report after discovering that an annual report submitted within the previous two (2) years contained one or more substantive errors. A substantive error is a mass of emissions of any individual pollutant subject to reporting under Section V. that is at least 10% higher or lower than the mass of emissions of the pollutant reported across the owner or operator's activity or equipment, as listed in Section V.C., in Colorado. A refinement of or improvement to an emissions estimation technique or emission factor is not a substantive error but must be noted in the subsequent annual report after the refinement or improvement. Revised annual reports must be submitted by August 31 if the substantive error is discovered between January 1 and June 30, and by February 28 if the substantive error is discovered between July 1 and December 31 of the preceding calendar year.

V.C. Beginning July 1, 2020, and each calendar year thereafter, owners or operators must maintain the following information for inclusion in the annual report, except that beginning January 1, 2021, owners or operators must maintain the information described in Sections V.C.2.g. and V.C.2.h. Beginning May 1, 2021, owners or operators of class II disposal well facilities must maintain the following information for inclusion in the annual report.

V.C.1. AIRS number of the activity or equipment and associated facility or pipeline (if a pipeline between facilities) location, including latitude and longitude coordinates. If the activity or equipment does not have an AIRS number, a description of the activity or equipment.

V.C.2. Actual emissions from each activity or equipment listed below, unless otherwise specified in the Division-approved report format, and the emission factor(s), assumptions, and calculation methodology used to calculate the emissions.

V.C.2.a. Abnormal events, except those reported as malfunctions under the Common Provisions or in another activity or equipment.

V.C.2.b. Acid gas removal units.

V.C.2.c. Associated gas venting and flaring, aggregated per facility.

V.C.2.d. Blowdowns from facility equipment piping where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet, aggregated per activity below per facility.

V.C.2.d.(i) Pipeline venting within the facility boundary.

V.C.2.d.(ii) Compressors.

V.C.2.d.(iii) Scrubbers/strainers.

V.C.2.d.(iv) Pig launchers and receivers.

V.C.2.d.(v) Emergency shutdowns (regardless of equipment type).

V.C.2.d.(vi) All other equipment (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) with a physical volume between isolation valves greater than or equal to 50 cubic feet.

V.C.2.e. Boilers.

V.C.2.f. Centrifugal compressor leaks or vents, aggregated per facility.

V.C.2.g. Class II disposal well facility fluids accepted for injection. Owners or operators will take periodic, representative samples of the liquids for estimating emissions for the annual report.

V.C.2.h. Class II disposal well facility produced water ponds.

V.C.2.i. Drilling mud and mud pits.

V.C.2.j. Flares and enclosed combustion devices, where not otherwise reported in the emissions of another emissions source category.

V.C.2.k. Fugitive emissions from components, aggregated per facility.

V.C.2.l. Hydrocarbon liquid storage tanks.

V.C.2.m. Hydrocarbon liquid loadout.

V.C.2.n. Maintenance and safety, where not otherwise reported in the emissions of another emissions source category.

V.C.2.o. Natural gas dehydration (glycol and desiccant).

V.C.2.p. Natural gas pneumatic controllers, aggregated per facility.

V.C.2.q. Natural gas pneumatic pumps, aggregated per facility.

V.C.2.r. Non-road internal combustion engines.

V.C.2.s. Pipeline segments between facilities.

V.C.2.t. Process heaters.

V.C.2.u. Produced water storage tanks.

V.C.2.v. Produced water loadout.

V.C.2.w. Reciprocating compressor leaks or vents, aggregated per facility.

V.C.2.x. Separators (e.g., two-phase separators, three-phase separators, high/low pressure separators, heater-treaters, vapor recovery towers, etc.).

V.C.2.y. Stationary combustion turbines.

V.C.2.z. Stationary compression ignition internal combustion engines.

V.C.2.aa. Stationary spark ignition internal combustion engines.

V.C.2.bb. Temporary completion and/or workover equipment (e.g., tanks).

V.C.2.cc. Thermal oxidizing units, where not otherwise reported in the emissions of another emissions source category.

V.C.2.dd. Well completions (includes flowback).

V.C.2.ee. Well workovers.

V.C.2.ff. Wellhead bradenhead.

VI. (State Only) Oil and Natural Gas Pre-Production and Early Production Operations

VI.A. Definitions

VI.A.1. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

VI.A.2. “Drill-out” means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore clean-up.

VI.A.3. “Drilling” or “drilled” means the process to bore a hole to create a well for oil and/or natural gas production.

VI.A.4. “Flowback” means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

VI.A.5. “Flowback vessel” means a vessel that contains flowback.

VI.A.6. “Hydraulic fracturing” means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

VI.A.7. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

VI.A.8. “Pre-production operations” means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

VI.A.9. “Tank measurement system” means equipment and methods used to determine the quantity of the liquids inside a flowback vessel without requiring direct access through the flowback vessel thief hatch or other opening.

VI.A.10. “Well” means a hole drilled for the purpose of producing oil and/or natural gas.

VI.A.11. “Well completion” means the process that allows for the flow of petroleum and/or natural gas from newly drilled wells, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic fracturing, drill-out, flowback).

VI.A.12. “Well re-completion” means the process that allows for the flow of petroleum and/or natural gas from an existing well from any geological interval not currently producing in the existing well, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic re-fracturing, drill-out, flowback).

VI.B. General provisions

VI.B.1. At all times the facility and equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions.

VI.B.2. Air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable and consistent with technological limitations and good engineering and maintenance practices.

VI.C. Air quality monitoring

VI.C.1. Owners or operators of drilling operations that begin on or after May 1, 2021, must monitor air quality at and/or around the pre-production and early production operations.

VI.C.1.a. Owners or operators must monitor air quality for at least ten (10) days prior to beginning pre-production operations, during all pre-production operations, and for at least six months after the well is capable of consistently producing either separable gas or salable liquid hydrocarbons (i.e., early production).

VI.C.1.b. Owners or operators must submit an air quality monitoring plan to the Division and the local government with jurisdiction over the location of the operations and any other local government unit, where applicable, within 2,000 feet of the proposed operations at least sixty (60) days prior to beginning air quality monitoring. Upon the request of any of these local government units within 14 days of receiving the plan, the Division will consult with them as part of its review process. Owners or operators must receive approval from the Division of the air quality monitoring plan prior to beginning air quality monitoring. Owners or operators must comply with the plan once approved. The air quality monitoring plan must include, at a minimum:

VI.C.1.b.(i) The owner or operator name and the contact information of the owner or operator representative for monitoring purposes.

VI.C.1.b.(ii) The planned schedule for drilling and pre-production operations.

VI.C.1.b.(iii) The operations to be monitored including the API number of the well(s), location of the operations including latitude and longitude coordinates, and any associated facility or equipment AIRS number(s).

VI.C.1.b.(iv) Whether the local government with jurisdiction over the location of the operations has air quality monitoring requirements applicable to pre-production and/or early production operations, a description of those requirements, and a local government contact for air quality monitoring purposes.

VI.C.1.b.(v) The monitoring objective(s), which must include one or more of the following (and may include additional objectives such as field-testing new air quality monitoring technologies or improving emissions inventories):

VI.C.1.b.(v)(A) Detect, evaluate, and reduce as necessary hazardous air pollutant emissions;

VI.C.1.b.(v)(B) Detect, evaluate, and reduce as necessary ozone precursor emissions;

VI.C.1.b.(v)(C) Detect, evaluate, and reduce as necessary methane emissions.

VI.C.1.b.(vi) The air pollutant(s) and other parameters to be monitored. Pollutants must include at least one of the following: total VOCs, methane, benzene or BTEX (benzene, toluene, ethyl benzene and xylenes) or other indicator of hydrocarbon emissions from pre-production and early production operations, as appropriate to meeting the specified monitoring objectives.

VI.C.1.b.(vii) A description of the monitoring equipment to be deployed, including the manufacturer and model information and any manufacturer specifications for the monitoring equipment and data systems. The description of pollutant monitoring equipment should explain why it was chosen and document or provide references describing relevant prior use and evaluations that are known to the owner or operator.

VI.C.1.b.(viii) A description of the meteorological monitoring equipment to be deployed. If meteorological data will not be collected on-site, the plan must provide reasoning and justification, and identify the meteorological station from which data will be obtained and demonstrate that the station represents conditions at the oil and gas development site.

VI.C.1.b.(ix) A monitor siting plan, which must include but is not limited to:

VI.C.1.b.(ix)(A) The number of monitors and/or sensors to be deployed.

VI.C.1.b.(ix)(B) The location and height of the monitoring equipment, including for each phase of operations if location and height of the equipment will change (e.g., monitoring placement impacted by sound walls).

VI.C.1.b.(ix)(C) A topographic map and plan of the site, showing the expected equipment layout, including air quality and meteorological monitor locations and their distance from pre-production and production operations. The map must indicate any obstructions to air flow to the monitor(s) and also show all roads and access ways within a half-mile of the facility and any contiguous structures, whether or not they are part of the production operations.

VI.C.1.b.(ix)(D) A description of how the placement of monitoring equipment minimizes surface disturbances, in alignment with the Colorado Oil and Gas Conservation Commission’s site preparation requirements.

VI.C.1.b.(ix)(E) An explanation of how the number and placement of monitoring equipment will be adequate to achieve the desired air quality monitoring objectives, considering the monitoring equipment’s detection limit and other limitations.

VI.C.1.b.(x) The standard operating procedures that will be employed, to include at minimum:

VI.C.1.b.(x)(A) The sampling and/or measurement interval, averaging times, minimum detection concentration or level, expected precision, and confidence level at which pollutant data will be reported.

VI.C.1.b.(x)(B) The response level for each pollutant or indicator monitored and/or sampled and the response procedures or actions that will be taken if elevated levels are observed.

VI.C.1.b.(x)(C) The data quality indicators for precision and bias of the monitoring equipment.

VI.C.1.b.(x)(D) The quality control and quality assurance procedures, including calibration intervals and frequency, which will be used to ensure proper operation of the monitoring equipment. Owners or operators may reference and attach an existing methodology.

VI.C.1.b.(x)(E) A discussion of known limitations of the pollutant monitoring equipment and, if applicable, how they will be addressed.

VI.C.1.b.(x)(F) The protocol that will be used for acquiring, processing, and recording relevant meteorological data.

VI.C.1.b.(x)(G) The data system and operating protocol to be used for data collection, including, but not limited to, data logging, data processing, recording, downloading, backup and storage, and reporting.

VI.C.1.b.(x)(H) The methods for collecting and analyzing speciated or other samples of chemical constituents identified by the Division when indicated necessary based on site-specific concentration thresholds, if applicable.

VI.C.1.b.(xi) A description of how the monitoring equipment, pollutant(s) monitored, and siting plan are expected to detect elevated emissions and achieve at least one of the monitoring objectives listed in Section VI.C.1.b.(v).

VI.C.1.c. Within ten (10) days of approving a monitoring plan, the Division will notify all local government units identified in Section VI.C.1.b. of the plan approval.

VI.C.2. Recordkeeping and reporting

VI.C.2.a. Owners or operators must keep the following records for a minimum of three (3) years, unless otherwise specified, and upon request make records available to the Division. Local governments identified in Section VI.C.1.b may request those records from the Division. If the Division has not requested the records and a local government(s) identified in Section VI.C.1.b requests the records from the Division, the Division shall request the records from the owner or operator.

VI.C.2.a.(i) The air quality monitoring plan.

VI.C.2.a.(ii) Monthly reports and the data necessary to inform the monthly reports, as provided in Section VI.C.2.b.

VI.C.2.a.(iii) Activity logs to inform Section VI.C.2.b.(iii)(A) of the monthly report.

VI.C.2.a.(iv) For a period of one year after the monthly report, the underlying raw data associated with each monitor.

VI.C.2.a.(v) For a period of one year after the monthly report, the meteorological data in the time intervals as close to the sampling and/or measurement intervals as possible.

VI.C.2.b. Owners or operators must submit monthly reports of monitoring conducted to the Division by the last day of the month following the previous month of monitoring (e.g., by June 30 for the previous May 1-31), including

VI.C.2.b.(i) The month and year of the monitoring period.

VI.C.2.b.(ii) A description of the monitoring equipment and the pollutant(s) monitored.

VI.C.2.b.(iii) A description of the monitored operations including

VI.C.2.b.(iii)(A) The phase of operation (e.g., prior to pre-production, during pre-production operations, early production) and activities occurring during the monitored period.

VI.C.2.b.(iii)(B) API number of the well(s).

VI.C.2.b.(iii)(C) Location of the operations, including latitude and longitude coordinates.

VI.C.2.b.(iii)(D) Any associated facility or equipment AIRS number(s).

VI.C.2.b.(iii)(E) The date, time, and duration of any monitoring equipment downtime.

VI.c.2.b.(iii)(F) The date, time, and duration of operations malfunctions and shut-in periods or other events investigated for influence on monitoring.

VI.C.2.b.(iv) For the first monthly report after beginning monitoring during pre-production operations, a summary of air quality condition results monitored prior to beginning pre-production operations, including time series of the results at hourly or higher time resolution and a statistical summary of the air quality results monitored prior to beginning pre-production operations, including number of observations, maximum concentrations or levels, periodic averages, and data distributions including 5^{th}, 25^{th}, median, 75^{th} and 95^{th} percentile values.

VI.C.2.b.(v) A summary of monitored air quality results, including time series plots as hourly or higher time resolution and a statistical summary including number of observations, maximum concentrations or levels, periodic averages, and date distributions including 5th, 25th, median, 75th and 95 percentile values.

VI.C.2.b.(vi) A description of responsive action(s) taken as a result of monitoring results, including the date; concentration or level measured; correlations with specific events, activities, and/or monitoring thresholds; and any additional steps taken as a result of the responsive action.

VI.C.2.b.(vii) The results of any speciated or other samples of chemical constituents identified by the Division and collected when site-specific concentrations indicate such samples are necessary.

VI.C.2.b.(viii) A summary of meteorological data, including in the time intervals identified for concentration readings in the air quality monitoring plan during the time period of responsive action(s). If meteorological data is collected on-site, the meteorological data assessed in as close to the sampling and/or measurement intervals as possible.

VI.C.2.b.(ix) A description of how data will be processed, if available from the manufacturer, and summarized for purposes of fulfilling monthly reporting requirements, including whether and how data will be corrected, and how missing data and values that are below detection limits will be treated in statistical summaries.

VI.C.2.b.(x) In the last monthly report, a certification by the company representative that supervised the development and submission of the monitoring reports that, based on information and belief formed after reasonable inquiry, the statements and information in the monthly reports are true, accurate, and complete.

VI.C.3. Owners or operators must notify the Division and the local government with jurisdiction over the location of the operations, using the contact provided in Section VI.C.1.b.(iv), within forty-eight (48) hours of responsive action(s) taken as a result of recorded values in excess of the response level.

VI.D. Emission reduction from pre-production flowback vessels

VI.D.1. Control

VI.D.1.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of at least 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

VI.D.1.a.(i) Owners or operators must use enclosed, vapor-tight flowback vessels.

VI.D.1.a.(ii) Flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.

VI.D.1.a.(iii) Owners or operators must use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section VI.D.1.a.(ii)(A).

VI.D.1.a.(iv) Combustion devices used during pre-production operations must be enclosed, have no visible emissions during normal operation, and be designed so that an observer, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

VI.D.1.a.(iv)(A) Combustion devices must be equipped with an operational auto-igniter upon installation of the combustion device.

VI.D.2. Monitoring

VI.D.2.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must conduct daily visual inspections of the flowback vessel and any associated equipment.

VI.D.2.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

VI.D.2.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating.

VI.D.2.a.(iii) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the flowback vessel to the air pollution control equipment are open.

VI.D.2.a.(iv) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

VI.D.2.a.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

VI.D.3. Recordkeeping

VI.D.3.a. The owner or operator of each flowback vessel subject to Section VI.D.1. must maintain records for a period of two (2) years and make them available to the Division upon request, including

VI.D.3.a.(i) The API number of the well and the associated facility location, including latitude and longitude coordinates.

VI.D.3.a.(ii) The date and time of the onset of flowback.

VI.D.3.a.(iii) The date and time the flowback vessels were permanently disconnected, if applicable.

VI.D.3.a.(iii) The date and duration of any period where the air pollution control equipment is not operating.

VI.D.3.a.(iv) Records of the inspections required in Section VI.D.2. including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

VI.D.3.a.(v) Where a combustion device is used, the date and result of any EPA Method 22 test or investigation pursuant to Section VI.D.2.a.(v).

PART E Combustion Equipment and Major Source RACT

I. Control of Emissions from Engines

I.A Requirements for new and existing engines.

I.A.1. The owner or operator of any natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower commencing operations in the 8-hour Ozone Control Area on or after June 1, 2004 shall employ air pollution control technology to control emissions, as provided in Section I.B.

I.A.2. Any existing natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower, which existing engine was operating in the 8-hour Ozone Control Area prior to June 1, 2004, shall employ air pollution control technology on and after May 1, 2005, as provided in Section I.B.

I.A.3. Stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower are subject to Section I.D.5.

I.B. Air pollution control technology requirements

I.B.1. For rich burn reciprocating internal combustion engines, a non-selective catalyst reduction and an air fuel controller shall be required. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

I.B.2. For lean burn reciprocating internal combustion engines, an oxidation catalyst shall be required. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

I.B.3. The emission control equipment required by this Section I.B shall be appropriately sized for the engine and shall be operated and maintained according to manufacturer specifications.

I.C. The air pollution control technology requirements in Sections I.A. and I.B. do not apply to:

I.C.1. Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31.

I.C.2. Reciprocating internal combustion engines that the Division has determined will be permanently removed from service or replaced by electric units on or before May 1, 2007. The owner or operator of such an engine shall provide notice to the Division of such intent by May 1, 2005 and shall not operate the engine identified for removal or replacement in the 8-hour Ozone Control Area after May 1, 2007.

I.C.3. Any emergency power generator exempt from APEN requirements pursuant to Regulation Number 3, Part A.

I.C.4. Any lean burn reciprocating internal combustion engine operating in the 8-hour Ozone Control Area prior to June 1, 2004, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $5,000 per ton of VOC emission reduction. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by May 1, 2005. Any reciprocating internal combustion engine qualifying for this exemption shall not be moved to any other location within the 8-hour Ozone Control Area.

I.D. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

I.D.1. (State Only) Exemptions

I.D.1.a. The requirements of this Section I.D. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.1.b. Internal combustion engines that are subject to an emissions control requirement in a federally maximum achievable control technology (MACT) standard under 40 CFR Part 63, a Best Available Control Technology (BACT) limit, or a New Source Performance Standard (NSPS) under 40 CFR Part 60 are not subject to Section I.D.3.

I.D.2. (State Only) General Provisions

I.D.2.a. At all times, including periods of start-up and shutdown, engines and their associated equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

I.D.2.b. All engines and their associated equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file.

I.D.2.c. Any of the effective dates for installation of controls on internal combustion engines as required in Section I.D.3. may be extended at the Division's discretion for good cause shown.

I.D.3. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.3.a. Except as provided in Section I.D.3.b., the owner or operator of any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in Table 1 shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section I.D.3.b. Table 1.

I.D.3.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥ 100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥ 500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

**These engines may also be subject to emission standards under Section I.D.5.*

I.D.4. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.4.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

I.D.4.a.(i) Except as provided in Sections I.D.4.a.(i)(B) and (C) and I.E.4.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

I.D.4.a.(i)(A) All control equipment required by this Section I.D.4.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

I.D.4.a.(i)(B) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology (“MACT”) standard under 40 CFR Part 63 (January 1, 2011), a Best Available Control Technology (“BACT”) limit, or a New Source Performance Standard under 40 CFR Part 60 (January 1, 2011) are not subject to this Section I.D.4.a.

I.D.4.a.(i)(C) The requirements of this Section I.D.4.a. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.4.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.4.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

I.D.4.b.(i) Except as provided in Section I.D.4.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

I.D.4.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.5. (State Only) Additional Requirements for Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.5.a. Applicability

I.D.5.a.(i) This Section I.D.5. applies to stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower.

I.D.5.a.(i)(A) For purposes of this Section I.D.5., modified means any physical change to the engine or change in method of operation that results in an increase in the emission rate of any air pollutant, and does not include any physical or operational changes excluded by 40 C.F.R. 60.14(e).

I.D.5.a.(i)(B) For purposes of this Section I.D.5., placed in service means the bringing of an engine on-site for use. The placed in service date is the date the engine begins to operate. The following is not considered placed in service: (1) moving an engine subject to an Alternative Company-Wide Compliance Plan to another site with the same owner or operator; (2) for engines in service on or before November 14, 2020, replacement under an authorized alternative operating scenario.

I.D.5.a.(i)(C) For purposes of this Section I.D.5., relocated means the bringing of an engine into the 8-Hour Ozone Control Area from outside the 8-Hour Ozone Control Area or the bringing of an engine into the State of Colorado from outside the State of Colorado. The relocation date is the date the subject engine begins to operate.

I.D.5.a.(ii) Exemptions.

I.D.5.a.(ii)(A) Engines that burn less than 100 MMBtu per year of natural gas on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.

I.D.5.a.(ii)(B) Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31 are not subject to this Section I.D.5.

I.D.5.a.(ii)(C) Any emergency power generator exempt from APEN or construction permit requirements pursuant to Regulation Number 3, Parts A or B are not subject to this Section I.D.5.

I.D.5.a.(ii)(D) Emergency power generators that operate less than 250 hours per year on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.

I.D.5.b. Emission Standards for Engines Subject to Section I.D.5.a.

I.D.5.b.(i) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine that is placed in service, modified, or relocated after November 14, 2020, must comply with the emission standards in Table 2 upon placement in service, modification, or relocation.

I.D.5.b.(ii) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine not subject to Section I.D.5.b.(i) must comply with the emission standards in Table 2 in accordance with the timing set forth Section I.D.5.b.(v).

TABLE 2

Engine Type	Emission Standards (g/hp-hr)		
	NOx	CO	VOC
4-Stroke Lean Burn engines in service on or before November 14, 2020, (unless subject to a more stringent emission standard under Section I.D.3.b, above)	1.2	2.0	0.7
Rich Burn engines in service on or before November 14, 2020	0.8	2.0	0.7
4-Stroke Lean Burn engines placed in service, modified, or relocated after November 14, 2020	0.7	2.0	0.7
Rich Burn engines placed in service, modified, or relocated after November 14, 2020	0.5	2.0	0.7
2-Stroke Lean Burn engines	3.0	2.0	0.7

I.D.5.b.(iii) By May 1, 2021, owners and operators of an engine placed in service on or before November 14, 2020, that is subject to an emission standard in Table 2 must submit a notification to the Division containing the following information:

I.D.5.b.(iii)(A) The list of engines subject to an emission standard in Table 2, including AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), historical annual hours of operation averaged over calendar years 2017, 2018, and 2019, manufacturer model, serial number, horsepower, and engine configuration. The notification must also identify or calculate the g/hp-hr limit in an existing permit and the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the permitted rate. Engine configuration (e.g. rich burn or lean burn) for purposes of the emission standards in Table 2 is determined by the characterization on the engine's permit or APEN as of May 1, 2021. If the engine configuration is not identified in a permit or APEN, the owner or operator must submit an APEN with the current configuration information as determined by the owner or operator by May 1, 2021 to the Division.

I.D.5.b.(iii)(B) An identification of the applicable standard and a declaration as to whether each subject engine meets the applicable standard as of May 1, 2021. If an engine will meet the applicable standard through a permit modification only, as described in Section I.D.5.b.(iv)(A), below, the declaration should note the date of permit modification submittal.

I.D.5.b.(iii)(C) For all engines that do not meet the applicable emission standard as of May 1, 2021 or that cannot comply through a permit modification described in Section I.D.5.b.(iv)(A), below, a declaration of what action the owner or operator will take to meet the standard (e.g., control equipment installation, retrofit, replacement, electrification, shut-down). This declaration can be amended at any time prior to the applicable compliance date for that engine.

I.D.5.b.(iii)(D) The compliance deadline for each engine under Sections I.D.5.b.(i) or I.D.5.b.(v). An owner or operator may change a proposed compliance deadline for an engine subject to Section I.D.5.b.(v)(B) prior to that engine's compliance deadline, only after submittal of an updated notification to the Division that includes the updated compliance date and a demonstration that the requirements of Table 3 are met.

I.D.5.b.(iii)(E) Owners or operators that submit an Alternative Company-Wide Compliance Plan under Section I.D.5.c. are not subject to this Section I.D.5.b.(iii) for the emission standards in Table 2 for the engines covered by the Alternative Company-Wide Compliance Plan.

I.D.5.b.(iv) Permit Modification.

I.D.5.b.(iv)(A) An engine in service on or before November 14, 2020 that requires only a modification of an existing permit to meet the emission standards in this Section I.D.5.b. must submit a complete permit application containing the necessary limitations no later than May 1, 2021.

I.D.5.b.(iv)(B) For any engine not subject to Section I.D.5.b.(iv)(A), owners and operators must modify existing permits to reflect the emission standards or other operating conditions necessary to achieve compliance with Table 2. Complete permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.b.(iii)(D) above for that engine.

I.D.5.b.(v) Compliance Deadlines for engines subject to Section I.D.5.b.(ii).

I.D.5.b.(v)(A) Engines that comply with the emission standards on or before November 14, 2020, or are subject to Section I.D.5.b.(iv)(A) must meet the emission standards in Table 2 by May 1, 2022.

I.D.5.b.(v)(B) Engines not subject to Section I.D.5.b.(v)(A) must meet the emission standards in Table 2 in accordance with the timing set forth in Table 3.

TABLE 3

Location of Subject Engines by Owner or Operator	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of engines that must comply with Table 2 limits				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 34% of engines inside the 8-Hour Ozone Control Area	At least 67% of engines inside the 8-Hour Ozone Control Area; and at least 25% of engines outside the 8-Hour Ozone Control Area	100% of engines in the 8-Hour Ozone Control Area; and at least 50% of engines outside the 8-Hour Ozone Control Area	At least 75% of engines outside the 8-Hour Ozone Control Area	100% of all engines
Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.b.(vi) If an owner or operator replaces an engine subject to an emission standard under this Section I.D.5.b. with a different stationary natural gas fired reciprocating internal combustion engine, the replacement engine must:

I.D.5.b.(vi)(A) if being placed under an alternative operating scenario pursuant to an existing Division issued permit, meet the same emission standard as the engine being replaced; or

I.D.5.b.(vi)(B) if the owner or operator of an engine chooses to comply via an Alternative Company-Wide Compliance Plan under Section I.D.5.c., meet an emission standard at least as stringent as the engine being replaced as provided for in the applicable Alternative Company-Wide Compliance Plan.

I.D.5.c. Alternative Company-Wide Compliance Plan.

I.D.5.c.(i) Owners and operators with five or more engines that are subject to Section I.D.5.b.(v)(B) may comply with the NOx requirements of Section I.D.5.b. through an Alternative Company-Wide Compliance Plan. Any owner or operator electing to develop an Alternative Company-Wide Compliance Plan must submit a Compliance Plan that meets the requirements of Section I.D.5.c.(ii) on or before May 1, 2021.

I.D.5.c.(i)(A) Only engines subject to an emission standard in Table 2 and that were placed in service on or before the November 14, 2020, can be included in an Alternative Company-Wide Compliance Plan submitted pursuant to this Section I.D.5.c.

I.D.5.c.(i)(B) Engines in an Alternative Company-Wide Compliance Plan must still meet the VOC and CO standards in Table 2 by the deadline established for that engine pursuant to Table 4.

I.D.5.c.(i)(C) Owners and operators owned by the same parent company may collectively submit a Compliance Plan in accordance with this Section I.D.5.c. However, the Compliance Plan must be signed and certified by a responsible official from each owner or operator with engines subject to the Compliance Plan acknowledging that each owner and operator is jointly and severally liable for compliance with the Compliance Plan and the provisions of this Section I.D.5.c. No engine may be included in multiple Alternative Company-Wide Compliance Plans.

I.D.5.c.(ii) The Compliance Plan must be submitted on the Division-approved form and include all of the following elements:

I.D.5.c.(ii)(A) A list of all of the engines that will rely on this Section I.D.5.c. to comply with the standards established in Section I.D.5.b. Each engine must be identified by AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), horsepower, manufacturer, model and serial number, historical annual operating hours (averaged over 2017, 2018, and 2019), and engine configuration.

I.D.5.c.(ii)(B) For each engine included in the Alternative Company-Wide Compliance Plan:

I.D.5.c.(ii)(B)(1) Identification of the most stringent NOx emission standard (in g/hp-hr or converted to g/hp-hr, if not expressed as such in the applicable permit) and operating conditions applicable to the engine under any rule or permit condition in effect on or before November 14, 2020.

I.D.5.c.(ii)(B)(2) Identification of the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the rate identified in Section I.D.5.c.(ii)(B)(1), above.

I.D.5.c.(ii)(B)(3) The emission standards (in g/hp-hr) and any operating conditions with which each engine will comply under the Alternate Company-Wide Compliance Plan, including any intended shut-downs, including any modifications or changes made to comply with the VOC or CO standards in Table 2.

I.D.5.c.(ii)(B)(4) The date by which each engine will meet the emission standards or other operating conditions identified in Section I.D.5.c.(ii)(B)(3) above, consistent with Table 4.

I.D.5.c.(ii)(B)(5) The maximum allowable NOx emissions (in tons/year) based on limits applicable on or before November 14, 2020, as identified in Section I.D.5.c.(ii)(B)(1).

I.D.5.c.(ii)(B)(6) The historic NOx emissions (in tons/year) averaged over calendar years 2017, 2018 and 2019, based on actual operating hours and permitted emission standards.

I.D.5.c.(ii)(B)(7) The NOx emissions that would be allowed on an annual basis (in tons/year) assuming the engine was complying with the emission standards established in Table 2.

I.D.5.c.(ii)(B)(8) Each engine's allowable NOx emissions (in tons/year) when operated in accordance with limitations identified in Section I.D.5.c.(ii)(B)(3), above, including any increase in NOx emissions that result from modifications or changes made to comply with the VOC or CO standards in Table 2.

I.D.5.c.(ii)(C) The total allowable NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(5).

I.D.5.c.(ii)(D) The total NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(6).

I.D.5.c.(ii)(E) The total NOx emissions calculated for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with the emission standards established in Table 2, as specified in Section I.D.5.c.(ii)(B)(7).

I.D.5.c.(ii)(F) The total allowable NOx emissions (in tons/year) calculated for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(8) above.

I.D.5.c.(ii)(G) A calculation of:

I.D.5.c.(ii)(G)(1) The difference between Section I.D.5.c.(ii)(C) and Section I.D.5.c.(ii)(F). This difference is called the “Plan Emission Reductions”.

I.D.5.c.(ii)(G)(2) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with Table 2, as specified in Section I.D.5.c.(ii)(E).

I.D.5.c.(ii)(G)(3) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(F).

I.D.5.c.(ii)(H) A demonstration that:

I.D.5.c.(ii)(H)(1) The total NOx emissions allowed under the Alternative Company-Wide Compliance Plan (Section I.D.5.c.(ii)(F)) are less than or equal to the total NOx emissions that would be allowed under Table 2 (Section I.D.5.c.(ii)(E)).

I.D.5.c.(ii)(H)(2) The reductions from emissions achieved by the Alternative Company-Wide Compliance Plan are greater than or equal to the reductions from actual emissions achieved by Table 2 (i.e. that the figure calculated in Section I.D.5.c.(ii)(G)(3) is greater than or equal to the figure calculated in Section I.D.5.c.(ii)(G)(2)).

I.D.5.c.(ii)(I) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the Compliance Plan are true, accurate, and complete.

I.D.5.c.(iii) Any owner or operator utilizing this Alternative Company-Wide Compliance Plan must meet the emission standards for NOx, CO and VOC as identified in I.D.5.c.(ii)(B)(3) by the compliance deadlines listed in Table 4, below.

I.D.5.c.(iv) Owners and operators must modify existing permits to reflect the emission standards or other operating conditions identified in the Compliance Plan (Section I.D.5.c.(ii)(B)(3)) for that engine. Permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.c.(ii)(B)(4) above for that engine.

I.D.5.c.(v) Compliance Plan Updates. By May 1st of each year (beginning in 2022) and continuing through and including the final year of a Compliance Plan, an owner or operator must submit an update to the Compliance Plan with the following information:

I.D.5.c.(v)(A) For each engine, any change in location and any action taken under the Compliance Plan (e.g., permit modification applied for, engine retrofit completed, engine taken offline) and the date;

I.D.5.c.(v)(B) A calculation of the percentage of Plan Emission Reductions achieved as of the date of submittal of the update (in each compliance period and cumulatively);

I.D.5.c.(v)(C) Any changes made to the Compliance Plan (e.g. change in compliance date for an engine). No change to the compliance date for an engine can be made after the date established in the Compliance Plan for that engine.;

I.D.5.c.(v)(D) If ownership or operation of an engine in the Compliance Plan for which emission reductions were included in the calculation of Plan Emission Reductions was sold or transferred in the previous year, an identification of how the owner or operator will achieve the portion of Plan Emission Reductions attributed to that engine under the Compliance Plan (the difference between Section I.D.5.c.(ii)(B)(5) and (8)).

I.D.5.c.(v)(E) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the update are true, accurate, and complete.

I.D.5.c.(vi) Nothing in this section I.D.5.c exempts an engine that is part of an Alternative Company-Wide Compliance Plan from compliance with the performance testing, monitoring, recordkeeping or reporting requirements of this Section I.D.5.

TABLE 4					
Location of Subject Engines covered by the Alternative Company-Wide Compliance Plan	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of Plan Emission Reductions Achieved				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 50% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 25% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 50% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100%of Plan Emission Reductions
Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.d. Performance Testing

I.D.5.d.(i) Engines subject to this Section I.D.5. must conduct a performance test consistent with the requirements of this Section I.D.5.d.

I.D.5.d.(i)(A) The owner or operator of an engine subject to Section I.D.5.b.(ii) must conduct a performance test for NOx, CO, and O2 by May 1, 2021.

I.D.5.d.(i)(B) The owner or operator of an engine placed in service, modified, relocated or replaced after May 1, 2021 must conduct a performance test within 12 months of the date the engine is placed in service, modified, relocated or replaced.

I.D.5.d.(i)(C) The following engines are exempt from the requirements of this Section I.D.5.d.

I.D.5.d.(i)(C)(1) Engines subject to the performance testing requirements of 40 C.F.R. Part 60, Subpart JJJJ (July 1, 2019).

I.D.5.d.(i)(C)(2) Engines subject to at least semi-annual portable analyzer testing or ongoing performance testing in a permit issued on or before November 14, 2020.

I.D.5.d.(i)(D) A performance test conducted in accordance with 40 C.F.R. §60.4244 (July 1, 2019) between January 1, 2020 and May 1, 2021 will satisfy the initial performance testing requirements in Section I.D.5.d.(i)(A).

I.D.5.d.(ii) Performance tests must be conducted in accordance with the applicable reference test methods of 40 C.F.R. Part 60, Appendix A (DATE), and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

I.D.5.d.(iii) Tuning of an engine prior to the performance test required by this Section I.D.5.d is not a violation of this rule. However, readjustment of an engine set point following the performance test that would negatively impact the performance of the engine (i.e. result in increased emissions above applicable permit limits) is a violation of this rule.

I.D.5.e. Monitoring. Except as provided in Section I.D.5.a.(ii), owners or operators of an engine subject to Section I.D.5.a must:

I.D.5.e.(i) Beginning on May 1, 2022, conduct semi-annual portable analyzer monitoring for NOx, CO, and O2. At least one calendar month must separate the semi-annual tests.

I.D.5.e.(i)(A) If the engine is operated for less than 200 hrs in any semi-annual period, then the portable analyzer monitoring need not occur during that semi-annual period (i.e. the engine does not need to be started for the sole purpose of portable monitoring).

I.D.5.e.(i)(B) All portable analyzer testing required by this section must be conducted using the Division's Portable Analyzer Monitoring Protocol (version: March 2006).

I.D.5.e.(i)(C) Tuning of an engine prior to semi-annual monitoring events required by this Section I.D.5.e.(i) is not a violation of this rule. However, readjustment of an engine set point following the monitoring event that would negatively impact the performance (i.e. result in increased emissions above applicable permit limits) of the engine is a violation of this rule.

I.D.5.e.(i)(D) A performance test conducted pursuant to Section I.D.5.d., 40 C.F.R. Part 60, JJJJ, or a permit requirement may take the place of the next required semi-annual portable analyzer test required by this section.

I.D.5.e.(i)(E) An engine subject to at least semi-annual portable analyzer testing requirements in an existing permit issued by the Division can comply with this Section I.D.5.e.(i) by complying with the testing requirements in the permit.

I.D.5.e.(ii) Beginning May 1, 2021, if a catalyst is used to reduce emissions:

I.D.5.e.(ii)(A) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within applicable limits.

I.D.5.e.(ii)(B) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop is greater than 2 inches outside the baseline value established after each semi-annual portable analyzer monitoring.

I.D.5.e.(ii)(C) Engines that are subject to catalyst temperatures and catalyst pressure drop monitoring requirements in an existing permit issued by the Division or 40 C.F.R. Part 63, Subpart ZZZZ (July 1, 2019) satisfy the monitoring requirements of this Section I.D.5.e.(ii).

I.D.5.e.(iii) Beginning May 1, 2021 or the date the engine is placed in service, modified, relocated or replaced (if later), install (if not already) and operate an hour meter or Division approved alternate method to continuously track the hours of operation of the subject engine.

I.D.5.e.(iv) Conduct the following inspections and adjustments at least annually, unless otherwise specified below, beginning in 2022

I.D.5.e.(iv)(A) Change oil and filters as necessary; and,

I.D.5.e.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary; and,

I.D.5.e.(iv)(C) Inspect spark plugs and replace as necessary; or,

I.D.5.e.(iv)(D) Conduct a combustion process adjustment according to the manufacturer recommended procedures and schedule. Alternatively, the owner or operator may rely on a combustion process adjustment conducted in accordance with requirements and schedules of a New Source Performance Standard in 40 CFR Part 60 (July 1, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (July 1, 2019) conducted during the same annual period to satisfy the annual combustion process adjustment requirement of this Section I.D.5.c.(iv)(D) for that 12-month period.

I.D.5.f. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request.

I.D.5.f.(i) Records of performance tests conducted pursuant to Section I.D.5.d, including I.D.5.d.(i)(D)., including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

I.D.5.f.(ii) Records of semi-annual portable analyzer monitoring, including the date, engine settings on the date of the monitoring, and documentation of the results of the monitoring. These records must include any demonstration that no semi-annual portable analyzer monitoring was required as provided under Section I.D.5.e.(i)(D) or I.D.5.e.(i)(E), if applicable.

I.D.5.f.(iii) Records of catalyst monitoring required by Section I.D.5.e.(ii) and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.

I.D.5.f.(iv) If claiming an exemption under Section I.D.5.a.(ii), records demonstrating that fuel combustion was less than 100 MMBtu per year or hours of operation are less than 250 hours per year.

I.D.5.f.(v) Hours of operation as recorded by the hour meter or alternative device approved by the Division continuously tracking hours as required by Section I.D.5.e.(iii), at least on a calendar month basis.

I.D.5.f.(vi) Records of tuning, adjustments, or other combustion process adjustments required under Section I.D.5.e.(iv), including:

I.D.5.f.(vi)(A) The date of the adjustment.

I.D.5.f.(vi)(B) A description of any corrective action taken.

I.D.5.f.(vi)(C) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation since the last combustion process adjustment and the procedures followed. The owner or operator must retain documentation of any relied upon manufacturer recommended procedures, specifications, and maintenance schedule for five years after the owner or operator ceases to rely upon it.

I.D.5.f.(vi)(D) If the owner or operator conducts the combustion process adjustment according to a New Source Performance Standard or National Emission Standard for Hazardous Air Pollutants, what standard applied and what procedures were followed.

I.D.5.g. Reporting. Beginning on the date specified below and by May 1 of each year thereafter, the owner or operator of each engine subject to this Section I.D.5. must submit the following information covering the preceding calendar year:

I.D.5.g.(i) Beginning May 1, 2021, a statement of the status of performance testing required under Section I.D.5.d, and the date and results of that testing;

II.D.5.g.(ii) Beginning May 1, 2022, an identification of any engines placed in service, modified, relocated, or replaced, including AIRS number, serial number, location, engine configuration, and a certification as to whether the emission standards in Table 2 are met;

I.D.5.g.(iii) Beginning May 1, 2022, the date on which the monitoring required by Sections I.D.5.e.(iv) was performed;

I.D.5.g.(iv) Beginning May 1, 2023, the date that all required semi-annual portable analyzer testing was performed under Section I.D.5.e.(i), and the results of that testing.

II. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area

II.A. Requirements for major sources of NOx

II.A.1. Applicability.

II.A.1.a. Except as provided in Section II.A.2., the requirements of this Section II. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, located in the 8-Hour Ozone Control Area.

II.A.1.b. Except as provided in Section II.A.2., the requirements of Section II. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, located in the 8-Hour Ozone Control Area, that is not already subject as provided under Section II.A.1.a.

II.A.2. Exemptions. The following stationary combustion equipment are exempt from the emission limitation requirements of Section II.A.4., the compliance demonstration requirements in Section II.A.5., and the related recordkeeping and reporting requirements of Sections II.A.7.a-e. and II.A.8, but these sources must maintain any and all records necessary to demonstrate that an exemption applies. These records must be maintained for a minimum of five years and made available to the Division upon request. Qualifying for an exemption in this section does not preclude the combustion process adjustment requirements of Section II.A.6., when required by II.A.6.a.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of this Section II.A. as expeditiously as practicable but no later than 36 months after any exemption no longer applies. Additionally, once stationary combustion equipment that is not equipped with CEMS or CERMS no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations of Section II.A.4.

II.A.2.a. Any stationary combustion equipment whose utilization is less than:

II.A.2.a.(i) 20% of its capacity factor on an annual average basis over a 3-year rolling period for boilers; or

II.A.2.a.(ii) 10% of its capacity factor on an annual average basis over a 3-year rolling period for stationary combustion turbines and compression ignition reciprocating internal combustion engines.

II.A.2.b. An engine testing operation or process line.

II.A.2.c. Any gaseous fuel fired stationary combustion equipment used to control VOC emissions from a commercial or industrial process.

II.A.2.d. Any stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx on a calendar year basis.

II.A.2.e. Any natural gas-fired reciprocating internal combustion engines subject to a work practice or emission control requirement contained in this Regulation 7, Section I.A. or B.

II.A.2.f. Any stationary combustion equipment subject to a federally enforceable work practice or emission control requirement contained in this Regulation 7, Section III.A.-B. or Regulation 3, Part F.

II.A.3. Definitions

II.A.3.a. "Affected unit" means any stationary combustion equipment that is subject to or becomes subject to an emission limitation in Section II.A.4.

II.A.3.b. "Boiler" means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

II.A.3.c. "Capacity factor" means the ratio of the amount of fuel burned by an emissions unit in a calendar year to the amount of fuel it could have burned if it had operated at the designed heat input rating for 8,760 hours during the calendar year. Alternatively, for electric generating units, capacity factor can mean the ratio of the unit's actual annual electric output (expressed in MWe/hr) to the electric output the unit could have achieved if it operated at its nameplate capacity (or maximum observed hourly gross load (expressed in MWe/hr) if greater than the nameplate capacity) for 8,760 hours during the calendar year.

II.A.3.d. "Ceramic kiln" means equipment used for the curing or firing of ceramic products or glaze on ceramic products. A kiln may operate continuously or by batch process.

II.A.3.e. "Continuous emission monitoring system" ("CEMS") or "Continuous emission rate monitoring system" ("CERMS") means the total equipment required to sample, condition (if applicable), analyze, and provide a written record of such emissions and/or emission rates, expressed on a continuous basis in terms of an applicable emission limitation. Such equipment includes, but is not limited to, sample collection and calibration interfaces, pollutant analyzers, a diluent analyzer (oxygen or carbon dioxide), stack gas volumetric flow monitors (if appropriate for CERMS), and data recording and storage devices.

II.A.3.f. “Compression ignition reciprocating internal combustion engine (RICE)” means a type of stationary RICE that is liquid fuel-fired and not ignited with a spark plug or other sparking device.

II.A.3.g. “Digester gas” means any gaseous byproduct of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide.

II.A.3.h. “Duct burner” means a device that combusts fuel and is placed in the exhaust duct from another source (e.g., stationary combustion turbine, internal combustion engine, or kiln) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

II.A.3.i. “Dryer” means a device that is used to reduce or evaporate moisture content or remove organic contaminants.

II.A.3.j. “Furnace” means an enclosed device that is an integral component of a manufacturing process and that uses thermal treatment to accomplish recovery of materials or energy.

II.A.3.k. “Gaseous fuel” means natural gas, landfill gas, refinery fuel gas, digester gas, methane, ethane, propane, butane, or any gas stored as a liquid at high pressure such as liquefied petroleum gas.

II.A.3.l. “Glass melting furnace” means an emissions unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass.

II.A.3.m. “Kiln” means the equipment used to remove combined (chemically bound) water and/or gases from mineral material through direct or indirect heating.

II.A.3.n. “Lightweight aggregate” means the expanded, porous product from heating shales, clays, slates, slags, or other natural materials in a kiln.

II.A.3.o. “Liquid fuel” means any fuel which is a liquid at standard conditions including but not limited to distillate oils, kerosene and jet fuel. Liquefied gaseous fuels are not liquid fuels.

II.A.3.p. “Process heater” means an enclosed device using controlled flame and a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

II.A.3.q. “Reciprocating internal combustion engine” means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not used to propel a motor vehicle or a vehicle used solely for competition.

II.A.3.r. "Stationary combustion equipment" means an emissions unit that combusts solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use. Stationary combustion equipment includes, but is not limited to, boilers, duct burners, engines, glass melting furnaces, kilns, process heaters, stationary combustion turbines, dryers, furnaces, and ceramic kilns.

II.A.3.s. "Stationary combustion turbine" means a non-mobile, enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine. Stationary combustion turbines can be simple cycle or combined cycle and they may or may not include a duct burner.

II.A.4. Emission limitations.

By October 1, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.a. may cause, allow, or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis, unless otherwise specified.

By July 20, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.b. may cause, allow, or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis, unless otherwise specified.

II.A.4.a. Boilers.

II.A.4.a.(i) For a gaseous fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(ii) For a liquid fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(iii) For a liquid or gaseous fuel-fired boiler at a major source of NOx (greater than or equal to 50 tpy NOx as of January 27, 2020) with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(iv) For a liquid or gaseous fuel-fired boiler at a major source of NOx (greater than or equal to 50 tpy NOx as of January 27, 2020) with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr but less than 100 MMBtu/hr, 0.1 lb/MMBtu of heat input or less than 83 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(v) Boilers subject to the categorical limits in Section II.A.4.a.(i) through (iv) or boilers with a maximum design heat input capacity less than 100 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.

II.A.4.b. Stationary combustion turbines.

II.A.4.b.(i) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction on or before February 18, 2005 must comply with the following NOx emission limits in Table 1.

Table 1 – NOx limits for stationary combustion turbines constructed on or before February 18, 2005

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOx emission standard
Turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O2 or 54 ng/J of useful output (0.43 lb/MWh)
Turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O2 or 160 ng/J of useful output (1.3 lb/MWh).
Turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O2 or 250 ng/J of useful output (2.0 lb/MWh).
Turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines operating at less than 75 percent of peak load, turbines operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines operating at less than 75 percent of peak load, turbines operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

II.A.4.b.(i)(A) For units with heat recovery and CEMS, determine compliance on a 30-day rolling average.

II.A.4.b.(i)(B) For simple cycle turbines with CEMS, determine compliance on a 4-hour rolling average.

II.A.4.b.(i)(C) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

II.A.4.b.(i)(D) Emissions exceeding the NOx emission limits in Section II.A.4.b.(i) at any time, including during times of startup, shutdown, malfunction, fuel switching, tuning, and testing must be reported as specified in Section II.A.8.a.(i).

II.A.4.b.(ii) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction, modification or reconstruction after February 18, 2005 must comply with the applicable NOx emission limits in 40 CFR Part 60, Subpart KKKK (July 1, 2017).

II.A.4.b.(iii) Stationary combustion turbines subject to the categorical limits in Section II.A.4.b.(i) or (ii) above and stationary combustion turbines with a maximum design heat input capacity less than 10 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.

II.A.4.b.(iv) Stationary combustion turbines, air pollution control equipment, and monitoring equipment must be operated in a manner consistent with good air pollution control practices for minimizing emissions at all times.

II.A.4.c. Lightweight aggregate kilns.

II.A.4.c.(i) For lightweight aggregate kilns with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr, 56.6 pounds of NOx per hour.

II.A.4.d. Glass melting furnaces.

II.A.4.d.(i) For, glass melting furnaces, 1.2 pounds of NOx per ton of glass pulled. However, days in which a glass melting furnace is operated at less than 35% of maximum designed production may be excluded from the 30-day rolling average for purposes of demonstrating compliance with this Section II.A.4.d.(i). During each day excluded from the 30-day rolling average, NOx emissions must be measured continuously in accordance with the applicable monitoring requirements of Section II.A.5, and the furnace must be operated in accordance with good air pollution control practices.

II.A.4.e. Compression ignition RICE.

II.A.4.e.(i) For a compression ignition RICE with a maximum design power output equal to or greater than 500 horsepower, 9 grams per brake horsepower-hour.

II.A.4.e.(ii) Compression ignition RICE subject to the emission limit in Section II.A.4.e.(i) above and compression ignition RICE with a maximum design power output less than 500 horsepower must comply with the combustion process adjustment requirements contained in Section II.A.6.

II.A.4.f. Landfill gas or biogas gas fired RICE.

II.A.4.f.(i) For landfill gas or biogas fired RICE with a maximum design power output equal to or greater than 500 horsepower, 2 grams per brake horsepower-hour

II.A.5. Compliance demonstration.

II.A.5.a. By October 1, 2021, for stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in this Section II.A.5.

II.A.5.b. By July 20, 2021, for stationary combustion equipment specified in Section II.A.1.b., the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in Sections II.A.5.

II.A.5.c. Emissions monitoring requirements for major source RACT limits

II.A.5.c.(i) Continuous emission monitoring

II.A.5.c.(i)(A) Owners or operators of an affected unit subject to a NOx emission limit in Section II.A.4.a.(i)-(iii), c. or d. must install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i). Owners or operators of affected units' subject to a NOx emission limit in Section II.A.4.b. or Section II.A.4.e. may install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i) in lieu of performance testing pursuant to Section II.A.5.c.(ii).

II.A.5.c.(i)(A)(1) The owner or operator of an affected unit that is subject to or becomes subject to the monitoring requirements of 40 CFR part 75 and 40 CFR part 75, Appendices A to I (July 19, 2018), must use those monitoring methods and specifications for monitoring NOx emissions for purposes of this Section II.A.5. and for demonstrating compliance with Section II.A.4. The missing data substitution procedures and bias adjustment requirements of 40 CFR Part 75 (July 19, 2018) do not apply for purposes of demonstrating compliance with Section II.A.4. or this Section II.A.5.

II.A.5.c.(i)(A)(2) For an affected unit equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with an applicable subpart of 40 CFR Part 60 (July 19, 2018), the owner or operator must use the definition of operating day, data averaging methodology, and data validation requirements of the applicable subpart of 40 CFR Part 60 for purposes of demonstrating compliance with an applicable emission limit in Section II.A.4. The owner or operator must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable requirements of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018).

II.A.5.c.(i)(A)(3) For an affected unit that is not equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with 40 CFR Part 60 (July 19, 2018) or Part 75 (July 19, 2018), the owner or operator must install, operate, and maintain a NOx CEMS or CERMS that measures emissions in terms of the applicable emission limitation and must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable provisions of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018). The owner or operator must use the following methodology for purposes of demonstrating compliance with an applicable 30-day rolling average emission limit in Section II.A.4.:

II.A.5.c.(i)(A)(3)(a) A unit operating day is a calendar day when any fuel is combusted in the affected unit.

II.A.5.c.(i)(A)(3)(b) 30-day rolling average emission rates must be calculated as the arithmetic average emissions rates determined by the CEMS or CERMS for all hours the affected unit combusted any fuel from the current unit operating day and the prior 29 unit operating days.

II.A.5.c.(i)(A)(4) When an affected unit utilizes a common flue gas stack system with one or more affected units, but no non-affected units, the owner or operator must follow the applicable procedures of 40 CFR Part 75, Appendix F (July 19, 2018) for the determination of all sampling locations and apportionment of emissions to an individual affected unit.

II.A.5.c.(i)(A) Owners or operators of a stationary combustion turbine subject to a NOx emission limit in Section II.A.4.b. must comply with

II.A.5.c.(i)(A)(1) The applicable monitoring requirements in 40 CFR Part 60, Subpart GG (July 1, 2017) for turbines which commenced construction on or before February 18, 2005.

II.A.5.c.(i)(A)(2) The applicable monitoring requirements in 40 CFR Part 60, Subpart KKKK (July 1, 2017) for turbines which commenced construction after February 18, 2005.

II.A.5.c.(ii) Initial and periodic performance testing

II.A.5.c.(ii)(A) An owner or operator of a stationary combustion turbine subject to 40 CFR Part 60, Subparts GG or KKKK (July 19, 2018) that has used and continues to use performance testing to demonstrate compliance with either Subpart GG or KKKK (July 19, 2018), as applicable, may use those performance testing procedures to demonstrate continued compliance with an applicable limitation contained in Section II.A.4.b., thereby satisfying the requirements of this section II.A.5.c.(ii).

II.A.5.c.(ii)(B) Except as otherwise provided for in Section II.A.5.a.(ii)(A), the owner or operator of an affected unit subject to a NOx emission limitation contained in Sections II.A.4.a.(iv), 4.b., or 4.e. that is not equipped with NOx CEMS or CERMS, must conduct an initial performance test and subsequent performance tests every 2 years thereafter, according to the following requirements, as applicable, to determine the affected unit's NOx emission rate for each fuel fired in the affected unit. A performance test is not required for a fuel used only for startup or for a fuel constituting less than 2% of the unit's annual heat input, as determined at the end of each calendar year.

II.A.5.c.(ii)(B)(1) Initial performance test must include a determination of the capacity load point of the unit's maximum NOx emissions rate based on one 30-minute test run at each capacity load point for which the unit is operated, other than for startup and shutdown, in the load ranges of 20 to 30%, 45 to 55%, and 70 to 100%. Subsequent performance tests must be performed within the capacity load range determined to result in the maximum NOx emissions rate.

II.A.5.c.(ii)(B)(2) Performance tests must determine compliance with Section II.A.4. based on the average of three 60-minute test runs performed at the capacity load determined in II.A.5.c.(ii)(B)(1).

II.A.5.c.(ii)(C) All performance tests must be conducted in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

II.A.5.c.(iii) For affected units' subject to a production-based or output based emission limit contained in Section II.A.4. (e.g. lb of NOx/ton of product), the owner or operator must install, operate, and maintain monitoring equipment for measuring and recording the affected unit's production or output, on an hourly basis, in units consistent with the applicable emission limitation.

II.A.5.c.(iv) Where measuring fuel use is necessary to calculate an emission rate in the units of the applicable standard, fuel flowmeters must be installed, calibrated, maintained, and operated according to manufacturer's instructions for measuring and recording heat input in terms of the applicable emission limitation. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of 40 CFR Part 75, Appendix D (July 19, 2018) are acceptable for demonstrating compliance with this section. The installation of fuel-flowmeters is not required where emissions of NOx in terms of the applicable standard can be calculated in accordance with applicable provisions of EPA Method 19 (July 19, 2018) or where the standard is concentration based (e.g. parts per million dry volume corrected for oxygen).

II.A.6. Combustion process adjustment

II.A.6.a. Applicability

II.A.6.a.(i) As of January 1, 2017, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016.

II.A.6.a.(ii) As of May 1, 2020, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, that is not already subject as provided under Section II.A.6.a.(i).

II.A.6.b. Combustion process adjustment

II.A.6.b.(i) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, the owner or operator must conduct the following inspections and adjustments of boilers and process heaters, as applicable:

II.A.6.b.(i)(A) Inspect the burner and combustion controls and clean or replace components as necessary.

II.A.6.b.(i)(B) Inspect the flame pattern and adjust the burner or combustion controls as necessary to optimize the flame pattern.

II.A.6.b.(i)(C) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly.

II.A.6.b.(i)(D) Measure the concentration in the effluent stream of carbon monoxide and nitrogen oxide in ppm, by volume, before and after the adjustments in Sections II.A.6.b.(i)(A) through (C). Measurements may be taken using a portable analyzer.

II.A.6.b.(ii) The owner or operator of a duct burner must inspect duct burner elements, baffles, support structures, and liners and clean, repair, or replace components as necessary.

II.A.6.b.(iii) The owner or operator of a stationary combustion turbine must conduct the following inspections and adjustments, as applicable:

II.A.6.b.(iii)(A) Inspect turbine inlet systems and align, repair, or replace components as necessary.

II.A.6.b.(iii)(B) Inspect the combustion chamber components, combustion liners, transition pieces, and fuel nozzle assemblies and clean, repair, or replace components as necessary.

II.A.6.b.(iii)(C) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, confirm proper setting and calibration of the combustion controls.

II.A.6.b.(iv) The owner or operator of a stationary internal combustion engine must conduct the following inspections and adjustments, as applicable:

II.A.6.b.(iv)(A) Change oil and filters as necessary.

II.A.6.b.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary.

II.A.6.b.(iv)(C) Inspect spark plugs and replace as necessary.

II.A.6.b.(v) The owner or operator of a dryer or furnace must inspect the burner and combustion controls and adjust, clean, and/or replace components as necessary.

II.A.6.b.(vi) The owner or operator of a ceramic kiln must inspect and maintain the combustion controls and adjust the burners as necessary to ensure a proper air-to-fuel ratio. At units where entry into a piece of process equipment is required to complete the combustion process adjustment, in-kiln inspections and adjustments are required only during planned entries.

II.A.6.b.(vii) The owner or operator must operate and maintain the boiler, duct burner, process heater, stationary combustion turbine, stationary internal combustion engine, dryer, furnace, or ceramic kiln consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

II.A.6.b.(viii) Frequency

II.A.6.b.(viii)(A) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, must conduct the initial combustion process adjustment by April 1, 2017. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016) to satisfy the requirement to conduct an initial combustion process adjustment by April 1, 2017.

II.A.6.b.(viii)(B) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, must conduct the initial combustion process adjustment by May 1, 2020. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) to satisfy the requirement to conduct an initial combustion process adjustment by May 1, 2020.

II.A.6.b.(viii)(C) The owner or operator must conduct subsequent combustion process adjustments at least once every twelve (12) months after the initial combustion adjustment, or on the applicable schedule according to Sections II.A.6.c.(1). or II.A.6.c.(ii).

II.A.6.c. As an alternative to the requirements described in Sections II.A.6.b.(i) through II.A.6.b.(viii):

II.A.6.c.(i) The owner or operator may conduct the combustion process adjustment according to the manufacturer recommended procedures and schedule; or

II.A.6.c.(ii) The owner or operator of combustion equipment that is subject to and required to conduct a periodic tune-up or combustion adjustment by the applicable requirements of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) may conduct tune-ups or adjustments according to the schedule and procedures of the applicable requirements of 40 CFR Part 60 (December 19, 2019) or 40 CFR Part 63 (December 19, 2019).

II.A.7. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request:

II.A.7.a. The applicable emission limit and calculated heat input weighted emission limit for stationary combustion equipment demonstrating compliance for multiple fuels.

II.A.7.b. The 30-day rolling average emission rate calculated on a daily basis for sources using CERMS to comply with Section II.A.

II.A.7.c. The type and amount of fuel used.

II.A.7.d. The stationary combustion equipment's annual capacity factor on a calendar year basis.

II.A.7.e. All records generated to comply with the reporting requirements contained in Section II.A.8.

II.A.7.f. For stationary combustion equipment subject to the combustion process adjustment requirements in Section II.A.6., the following recordkeeping requirements apply:

II.A.7.f.(i) The owner or operator must create a record once every calendar year identifying the combustion equipment at the source subject to Section II.A. and including for each combustion equipment:

II.A.7.f.(i)(A) The date of the adjustment;

II.A.7.f.(i)(B) Whether the combustion process adjustment under Sections II.A.6.b.(i) through II.A.6.b.(vi) was followed, and what procedures were performed;

II.A.7.f.(i)(C) Whether a combustion process adjustment under Sections II.A.6.c.(i). and II.A.6.c.(ii). was followed, what procedures were performed, and what New Source Performance or National Emission Standard for Hazardous Air Pollutants applied, if any; and

II.A.7.f.(i)(D) A description of any corrective action taken.

II.A.7.f.(i)(E) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation.

II.A.7.f.(i)(F) If multiple fuels are used, the type of fuel burned and heat input provided by each fuel.

II.A.7.f.(ii) The owner or operator must retain manufacturer recommended procedures, specifications, and maintenance schedule if utilized under Section II.A.6.c.(i). for the life of the equipment.

II.A.7.f.(iii) As an alternative to the requirements described in Section II.A.7.f.(i), the owner or operator may comply with applicable recordkeeping requirements related to combustion process adjustments conducted according to a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016).

II.A.7.g. All sources qualifying for an exemption under Section II.A.2. must maintain all records necessary to demonstrate that an exemption applies.

II.A.8. Reporting

II.A.8.a. For affected units demonstrating compliance with Section II.A.4. using CEMS or CERMS in accordance with Section II.A.5.c.(i)(A), the owner or operator must submit to the Division the following information:

II.A.8.a.(i) Quarterly or semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual or quarterly period, as applicable. Excess emissions means emissions that exceed the applicable limitations contained in Section II.A.4. Excess emission reports must include the information specified in 40 CFR Part 60, Section 60.7(c) (July 1, 2018).

II.A.8.b. For affected units demonstrating compliance with Section II.A.4 using performance testing pursuant to Section II.A.5.c.(ii)(C), the owner or operator must submit to the Division the following information:

II.A.8.b.(i) Performance test reports within 60 days after completion of the performance test program. All performance test reports must determine compliance with the applicable emission limitations set by Section II.A.4.

III. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-hour Ozone Control Area

III.A. Specific major sources of VOC and/or NOx (greater than or equal to 100 tpy) as of June 3, 2016, located in the 8-hour Ozone Control Area.

III.A.1. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017:

III.A.1.a. National Reconnaissance Office (NRO) – Aerospace Data Facility (005-0028) – engines (pt 128, 139, 144).

III.A.1.b. Colorado State University (069-0011) – engines (pt 024, 035, 036, 037, 038, 040, 043, 052).

III.A.1.c. DCP Midstream, Greeley (123-0099) – engine (pt 102).

III.A.1.d. DCP Midstream, Kersey/Mewbourn (123-0090) – engine (pt 101).

III.A.1.e. DCP Midstream, Spindle (123-0015) – engines (pt 059, 075).

III.A.1.f. IBM (013-0006) – engines (pt 092, 094).

III.A.1.g. Owens-Brockway (123-4406) – engine (pt 024).

III.A.1.h. Plains End (059-0864) – engine (pt 005).

III.A.1.i. PSCo Cherokee (001-0001) – engine (pt 031).

III.A.1.j. Spindle Hill (123-5468) – engine (pt 005).

III.A.1.k. Suncor (001-0003) – engines (pt 150, 151).

III.A.1.l. Timberline Energy (123-0079) – engines (pt 010, 011).

III.A.2. Cemex Construction Materials (013-0003) must comply with applicable THC requirements and associated monitoring, recordkeeping, and reporting in 40 CFR Part 63, Subpart LLL (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.A.3. Denver Regional Landfill and Front Range Landfill (123-0079) (pt 007, 013) must comply with applicable flare requirements in 40 CFR Part 60, Subpart WWW (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.B. Specific major sources of VOC and/or NOx (greater than or equal to 50 tpy) as of January 27, 2020, located in the 8-hour Ozone Control Area.

III.B.1. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (January 30, 2013) as expeditiously as practicable, but no later than July 1, 2021:

III.B.1.a. University of Colorado Denver, Anschutz Medical Campus (001-0106) – engines (pts 011, 012, 013, 014, 015, 016, 017, 018, 020, 021).

III.B.1.b. Centura Health St. Anthony (059-1511) – engines (pts 002, 003).

III.B.2. Flares at the following major sources must comply with applicable flare requirements in 40 CFR Part 60, Section 60.18 (December 22, 2008) as expeditiously as practicable, but no later than July 1, 2021.

III.B.2.a. Waste Management of Colorado Denver Arapahoe Disposal Site (005-1291) (pt 003).

III.B.3. Front Range Energy (123-5097) must comply with applicable monitoring, recordkeeping, and reporting in 40 CFR Part 60, Subpart VV (July 1, 2019) as expeditiously as practicable, but no later than July 1, 2021.

IV. Control of Emissions from Breweries in the 8-hour Ozone Control Area

IV.A. Requirements for Brewing Operations

IV.A.1. Applicability

Except as provided in Section IV.A.2., the requirements of Section IV. apply to owners or operators of breweries that existed at a major source of VOC (greater than or equal to 100 tpy VOC) as of June 3, 2016, located in the 8-hour Ozone Control Area.

IV.A.2. Exemptions

The following emissions units are exempt from Sections IV.A.4. through IV.A.7. but must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Owners or operators must also maintain records necessary to demonstrate than an exemption applies and make such records available to the Division upon request.

Once an emissions unit at a brewery no longer qualifies for an exemption, the owner or operator must comply with the applicable requirements of Sections IV.A.4. through IV.A.7. as expeditiously as practicable but no later than twelve (12) months after the exemption no longer applies, except as specified in Sections IV.A.2.c. and IV.A.2.d.

IV.A.2.a. An emissions unit subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7.

IV.A.2.b. An emissions unit with total uncontrolled actual emissions less than two (2) tons per year VOC on a calendar year basis.

IV.A.2.c. Equipment or activities related to research and development. Research and development ends when the product is sold or offered for sale.

IV.A.2.d. Newly installed, upgraded, or replaced packaging operations for a duration of six months after startup.

IV.A.3. Definitions

IV.A.3.a. "Brewery" means a source that produces malt beverage and is comprised of emissions units related to brewhouse operations, fermentation, aging or secondary fermentation, and/or packaging operations.

IV.A.3.b. "Packaging operation" means the canning, bottling, or filling of malt beverages into a container. Packaging operations include keg filling. Packaging operations do not include the railcar loading and unloading of beer concentrate shipped off-site for packing.

IV.A.3.c. "Pilot brewery operation" means an operation where total packaging operations are less than 50,000 barrels per year.

IV.A.3.d. "Process loss" means the difference between the quantity of malt beverage sent to packaging and the quantity of malt beverage packaged into a container. Process loss does not include malt beverage in filled containers if the malt beverage is processed after filling to remove or recover ethanol.

IV.A.4. Emission limitations. By May 1, 2019, no owner or operator of a brewery may exceed an average of 6 percent process loss across all packaging operations in a calendar month and 4 percent process loss on a 12-month rolling average during packaging operations.

IV.A.5. Packaging operation work practices

IV.A.5.a. The owner or operator must develop performance objectives and metrics for each packaging operation to reduce spillage and process loss. Process loss records must be summarized annually and compared to performance objectives established by the owner or operator. Process loss records and summaries must be made available to the Division upon request.

IV.A.5.b. The owner or operator must develop and implement an operator training program for employees engaged in packaging operations to understand the operation of the filling lines and minimize breakdowns, spillage, and process loss. The operator training materials must be made available to the Division upon request. At a minimum, the training program must include:

IV.A.5.b.(i) A brewery training manager, coordinator, or equivalent;

IV.A.5.b.(ii) Written standard operating procedures for packaging operations;

IV.A.5.b.(iii) A requirement that initial training be conducted for employees performing packaging operations and more frequently for the following:

IV.A.5.b.(iii)(A) Employees changing packaging operation responsibilities; and

IV.A.5.b.(iii)(B) Startup of new, upgraded, or replaced packaging operations.

IV.A.5.c. The owner or operator must use and maintain packaging operation equipment to reduce container breakage and process loss. For packaging operations, except at pilot brewery operations, this includes, but is not limited to:

IV.A.5.c.(i) Using and maintaining automated filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.c.(ii) Installing and operating fill level detectors to monitor the liquid fill levels in containers;

IV.A.5.c.(ii) Installing and operating crown inspectors to monitor the condition of crowns and/or caps applied to bottles, if applicable; and

IV.A.5.c.(iv) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.5.d. The owner or operator of pilot brewery operations must use and maintain packaging operation equipment to reduce container breakage and process loss. This includes, but is not limited to:

IV.A.5.d.(i) Maintaining filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.d.(ii) Monitoring the liquid fill levels in containers; and

IV.A.5.d.(iii) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.6. Wastewater management and treatment. Owners or operators employing microbial and vegetative destruction of VOCs through the land application of wastewater must ensure that the areas where wastewater is applied are areas covered with vegetation at all times when wastewater is applied, except as required following tilling and seeding for crop rotation and field work per standard agricultural practices.

IV.A.7. Recordkeeping

The following records must be kept for a period of five (5) years and made available to the Division upon request:

IV.A.7.a. Monthly records of the percent process loss for packaging operations;

IV.A.7.b. Records necessary to demonstrate compliance with the packaging operation work practice requirements in Section IV.A.5.; and

IV.A.7.c. If applicable, pursuant to Section IV.A.6., monthly and annual records of the amount of wastewater (gallons) sent to the land application site.

V. Control of Emissions from Foam Manufacturing in the 8-hour Ozone Control Area

V.A. Requirements for Foam Product Manufacturing

V.A.1. Applicability

Except as provided in Section V.A.2., the requirements of Section V. apply to owners or operators of foam manufacturing operations that existed at a major source of VOC (greater than or equal to 50 tpy VOC) as of January 27, 2020, located in the 8-hour Ozone Control Area.

V.A.2. Exemptions

Any foam manufacturing operation that uses only non-VOC blowing agents is exempt from this Section V.A.

V.A.3. Definitions

V.A.3.a. "Blowing agent" means any liquid, gaseous or solid substance that alone or in conjunction with other substances is capable of producing a cellular (foam) structure in a polymeric material.

V.A.3.b. "Expandable polystyrene (EPS) beads" means polystyrene beads, particles, or granules, usually less than one-twelfth inch in diameter, that are formulated with a blowing agent (typically 3.5% to 7% of bead weight). When subjected to prescribed heating in an expansion system, the beads puff up, expanding many times their original volume into low density foam globules (called "prepuff" or "puff") from which a variety of EPS foam products are molded.

V.A.3.c. "Expanded polystyrene (EPS) foam" means a lightweight, foam material, made of polystyrene, from which a variety of common items are made, such as ice-chests, insulation board, protective packaging, and single-use cups.

V.A.3.d. "Foam" means a solid material in a lightweight cellular form (having internal voids or cavities called cells that contain air or a gas) resulting from the introduction or generation of gas bubbles throughout its mass during processing.

V.A.3.e. "Foam manufacturing operation" means any EPS production line, or portion of a production line, which processes raw EPS bead into final molded EPS product. Production line processes include, but are not limited to: pre-expansion, aging (pre-puff), and molding. The manufacturing process ends after the product exits the EPS mold. "Foam manufacturing operation" also means any production line processing methylene diphenyl diisocyanate (MDI), resins, and various hardeners and thickeners into foam products and which results in VOC emissions into the atmosphere. The manufacturing process ends after the product exits the drying tunnel.

V.A.3.f. "Non-VOC blowing agent" means a blowing agent which does not contain VOCs.

V.A.3.g. "Polystyrene" means any grade, class, or type of thermoplastic polymer, alloy, or blend that is composed of at least 80% polymerized styrene by weight.

V.A.3.h. "Raw material" means all polystyrene, polyethylene and polypropylene, and blowing agent used in the manufacture of foam products.

V.A.4. Emission Limitations

V.A.4.a. By May 1, 2022, owners and operators of foam manufacturing operations must either

V.A.4.a.(i) Limit VOC emissions from foam manufacturing to 3.0 lbs. per 100 lbs. of total material process, averaged monthly, or

V.A.4.a.(ii) Control VOC emissions from foam manufacturing by 90%. The control device must have a control efficiency of at least 95%.

V.A.5. Work Practices

The owner or operator of any foam manufacturing operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources

V.A.5.a. Store raw materials in closed, leak-free, labeled containers when not in use.

V.A.5.b. Cover open containers in a manner that minimizes evaporation into the atmosphere.

V.A.6. Monitoring

V.A.6.a. The owner or operator of foam manufacturing operations must operate and maintain the control device consistent with the manufacturer's specifications.

V.A.6.b. By November 1, 2022, and every three (3) years afterward, owners or operator of foam manufacturing operations must conduct a performance test during representative operations using EPA Method 24 to determine VOC content and EPA Method 18, 25, or 25A to determine control efficiency of the emission control equipment.

V.A.7. Recordkeeping

The following records must be kept for a period of five (5) years and made available to the Division upon request

V.A.7.a. Any records necessary to demonstrate that an exemption in Section V.A.2. applies.

V.A.7.b. The amount of raw material processed on a daily basis.

V.A.7.c. The type of blowing agent used.

V.A.7.d. The amount of blowing agent used on a monthly basis.

V.A.7.e. The total monthly VOC emissions.

V.A.7.f. For operators complying with the emission limitation in Section V.A.4.a.(i), the total monthly VOC emissions calculated on a pounds per 100 lbs. of material processed basis.

V.A.7.g. For operators that use a control device to comply with the emission limitations in Section V.A.4.a.

V.A.7.g.(i) A manufacturer guarantee of the control equipment's emission control efficiency to demonstrate compliance with Section V.A.4.

V.A.7.g.(ii) The amount of supplementary natural gas combusted in the control device on a monthly basis.

V.A.7.g.(iii) Records of performance tests conducted pursuant to Section V.A.6.

V.A.7.h. Records of calendar year VOC emission estimates demonstrating whether the foam manufacturing operation meets or exceeds the applicability threshold in Section V.A.1.

V.A.8. Reporting

V.A.8.a. Performance test protocols required for performance tests under Section V.A.6.b. must be submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

PART F Statements of Basis, Specific Statutory Authority and Purpose

A. December 21, 1995 (Section II.B.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted consolidate the list of NRVOCs into the Common Provisions, assuring that the same list of NRVOCs apply to all the Colorado regulations. This provides more consistency in those chemicals regulated as VOCs.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to Organic solvents and photochemical substances. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulations Numbers 3, 7, and the Common Provision are intended to clarify substances that are negligibly reactive VOCs, which are reflected in the EPA list of non-photochemically reactive VOCs. By consolidating the list (which consists of the EPA list of non-photochemically VOCs), and adopting the EPA definition by reference, a single list of negligibly reactive VOCs will apply uniformly to all Colorado Air Quality Control Commission regulations.

This revision will also include EPA's recent addition of acetone to the negligibly reactive VOC list. The addition of acetone to the list of negligibly reactive VOC's provides additional flexibility to sources looking for an alternative to more photochemically reactive VOCs. Because the EPA has added acetone to their list of non-photochemically reactive VOCs many industries, which make and supply products to Colorado industries, are planning to substitute acetone for more reactive VOCs. This change in the content of products purchased by industry for use in Colorado would adversely affect industries in Colorado if acetone remains a regulated VOC in Colorado. By adopting acetone as a negligibly-reactive VOC, industry's will be able to take advantage of and benefit from this possible shift in product contents.

B. March 21, 1996 (Sections I.A.1. through I.A.4.; II.D.; II.E.)

The changes to Regulation Number 7 were adopted as part of the Commission's decision to redesignate the Denver metro area as an attainment and maintenance area for ozone, together with the relevant amendments to the Ambient Air Quality Standards regulation and Regulation Number 3. The Ozone Maintenance Plan, also adopted by the Commission on March 21, 1996 as part of the redesignation, based part of its demonstration of maintenance on the continued existence of rules regulating VOC emissions. Such rules include the application of the permit requirements of Regulation Number 3 to gasoline stations, and the continued application of Regulation Number 7 for the control of VOC in nonattainment areas. The VOC controls in Regulation Number 7 were adopted into the SIP in May 1995, after Denver attained the ozone standard. The maintenance demonstration was based on future inventories that assumed the continuance of existing VOC controls in the Denver Metro area.

Pursuant to Section 25-7-107(2.5), C.R.S., the Commission is required to take expeditious action to redesignate the area as an attainment area for ozone. The CAA requires the submittal of a maintenance plan demonstrating maintenance of the ozone standard for any such redesignation request. The changes to Regulation Number 7 are consistent with continued maintenance of the ozone standard and are not otherwise more stringent than the relevant federal requirements.

The purpose of the revisions to Regulation Number 7, Section I.A is to provide a de minimis source with an opportunity to obtain an exemption from the requirements of Regulation Number 7 through rule-making. This revision will be submitted to the EPA for inclusion in the State Implementation Plan (SIP). Upon inclusion of this revision in the SIP, exemptions from Regulation Number 7 adopted by the Commission shall apply for purposes of both federal and state law, pending review by the state legislature pursuant to § 25-7-133(2), C.R.S. The rule revision includes several limitations on the scope of such exemptions:

1. The aggregate of all emissions from de minimis sources may not exceed five tons of emissions per day. The purpose of this limitation is to protect the projections contained in the emissions inventory, and to prevent growth in such emissions from exceeding the National Ambient Air Quality Standard (NAAQS) for ozone.

2. An exemption may not be granted if the Division demonstrates that such exemption will cause or contribute to air pollution levels that exceed the NAAQS, even if the total aggregate emissions from such sources is less than five tons per day.

3. The Commission rule prohibits more than one rulemaking hearing per year to consider potential de minimis exemptions in the aggregate. The purpose of this provision is to prevent the granting of case-by-case exemptions, and to conserve agency resources. The granting of exemptions on a case-by-case basis would grant an unfair advantage for those sources that are able to have their case heard by the Commission before other, similarly situated sources, submit a request for a de minimis exemption. However, upon a showing of an emergency, and at the discretion of the Commission, the Commission may always grant an exemption on a case-by-case basis.

4. The Commission rule provides that the growth in emissions due to such de minimis exemptions may not exceed the growth that was included in the emissions inventory in the SIP.

5. The Commission rule requires the de minimis exemptions to be included in a permit that is subject to review and comment by the public and by EPA.

The rule revision proposed by the Regional Air Quality Council (RAQC) did not include these limitations. However, the Commission may not have used the rule as proposed by RAQC to grant unlimited exemptions from the requirements of Regulation Number 7 because such an action would undermine the regulation and the maintenance demonstration contained in the SIP. The limitations adopted by the Commission were the subject of an alternative proposal submitted by the Division. The purpose of the limit is to ensure that the de minimis exemption provision cannot be used to jeopardize attainment of the NAAQs. Such a limit is necessary in order to obtain EPA approval of this SIP revision. The alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity. Even without an express provision limiting the de minimis exemptions to five tons per day, the Commission generally would not have granted de minimis exemptions in excess of that amount because such emissions are not accounted for in the emissions inventory and would undermine the maintenance demonstration. Furthermore, the alternative proposed by the Division does not, by itself, create an exemption from any regulatory requirement. The alternative simply limits the scope of the exemptions that may become fully effective without a SIP revision. However, the rule does not in any way limit the Commission's authority to amend the SIP.

The emissions inventory submitted to EPA anticipated growth in emissions in both the area source and minor source categories, as well as the major source category. In order to ensure that any growth in emissions due to the granting of de minimis exemptions will not cause total emissions to exceed the growth projections for these categories, the Division will keep track of the permitted allowable emissions that may result from sources and source categories entitled to such exemptions. In addition, the growth in emissions from area, major and minor source categories will be tracked when the Division performs the periodic inventories described in the SIP for the years 1999, 2002 and 2003. Any permitted growth in emissions due to de minimis exemptions will be added to the emissions for the source categories as reflected in the most recent periodic inventory. No further de minimis exemptions will be granted if the total growth in emissions exceeds the growth projections contained in the SIP. In addition, if the total growth exceeds the growth projections contained in the SIP, one or more of the contingency measures will be implemented to offset such growth, or the SIP will be revised as necessary to ensure continued maintenance of the standard.

The purpose of the addition of Regulation Number 7, Section II.E. is to provide sources with a process to obtain approval of an alternative emission control plan, compliance method, test method, or test procedure without waiting for EPA to approve of a site-specific SIP revision. The rule provides that any such alternative must be just as effective as the relevant regulatory provision, and that such effectiveness must be demonstrated using equally effective test methods and procedures. The changes to this section delegate the authority to the Division to approve of such alternatives. Since rulemaking is not required under Section II.E., the language allowing a source to assert that the relevant regulatory provision does not represent RACT has been omitted from this section. Such a change to the substantive requirements of Regulation Number 7 would require a rule change.

The rule revision proposed by the RAQC provided that alternative emissions control plans and compliance methods must be just as effective as those contained in the rule, but did not describe the test methods to be used to demonstrate such effectiveness. The Division proposed an alternative rule requiring such effectiveness to be demonstrated using test methods and procedures that are just as effective as those set out in the rule, or that have otherwise been approved by EPA. Such criteria for test methods and procedures are necessary in order to obtain EPA approval of this SIP revision. However, even without this language in the rule the Division would have required approved test methods and procedures in order to approve of proposed alternatives. The Division's alternative proposal provides the needed certainty in the most flexible manner possible.

Furthermore, the alternative proposed by the Division does not impose any new regulatory requirement. Instead, it merely establishes criteria for allowing persons' subject to the regulation to propose, in their discretion, an alternative means of complying with the existing regulatory requirements. Therefore, the alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity.

The rule revisions provide that no permit may be issued based on the provisions allowing for the creation of de minimis exemptions and the approval of alternative compliance plans without first revising the SIP unless EPA first approves of such regulatory revisions as part of the State Implementation Plan. The purpose of this condition is to address the possible disapproval of these revisions by EPA. In the event these changes are not approved by EPA, the remaining regulatory provisions of Regulation Number 7 will remain in full force and effect, and therefore, the EPA may approve of the maintenance plan and the redesignation request.

The revisions to Regulation Number 7 are procedural changes that are not intended to reduce air pollution.

For clarification, the Commission adopted these regulation revisions as follows:

REGULATION REVISION	OZONE SIP AND MAINTENANCE PLAN
Section I.A.1	Exists in Appendix C of the Ozone Maintenance Plan to become a part of that document approved March 21, 1996
Sections I.A.2., 3., 4.; Section II.D., II.E.	Adopted as subsequent regulation revisions to be submitted to the Governor and EPA separately and concurrently as a revision to the Ozone SIP (and Maintenance Plan)

The specific statutory authority to promulgate the rules necessary for redesignation is set out in §§ 25-7-105(1)(a)(I) and (2); -106(1)(a); -107 (1) and (2.5); and -301. The authority to adopt such rules includes the authority to adopt exceptions to the rules, and the process for applying for any such exemptions.

C. November 21, 1996 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted update the list of NRVOCs so that the state list remains consistent with the federal list. Additionally, because perchloroethylene will no longer be listed as a VOC in Regulation Number 7, Section XII, Control of VOC Emissions from Dry Cleaning Facilities using Perchloroethylene as a Solvent, is being deleted.

Regulation Numbers 8 and 3 list the federal Hazardous Air Pollutants (HAPs). In the June 8, 1996 Federal Register the EPA removed Caprolactam (CAS 105-60-2) from the federal list of Hazardous Air Pollutants. The conforming changes in Regulation Number 3, Appendices B, C and D have been made to keep the list of federal HAPs in Regulation Number 3 consistent with the federal list. The list of HAPs in Regulation Number 8 has been removed and a reference to the list in Regulation Number 3 has been added.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to organic solvents and photochemical substances. Sections 25-7-105(1)(l)(b) and 25-7-109(2)(h) provide authority to adopt emission control regulations and emission control regulations relating to HAPs respectively. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulation Numbers 3, 7, 8 and the Common Provisions are intended to update the state lists of NRVOCs, the Ozone SIP, and HAPs for consistency with the federal lists.

D. October 15, 1998 (Section II.F.)

The Gates Rubber Co. Site-specific Revision

The Gates Rubber Co. (Gates), by and through its attorney, submitted this Statement of Basis, Specific Statutory Authority and Purpose for amendments to Regulation Number 7, Control of Emissions of Volatile Organic Compounds.

Basis

Regulation Number 3 contains a certification and trading of emission reduction credits section (Section V), which sets forth the definitions and process for obtaining emission credits and using those credits. This section was amended to permit the use of emission reduction credits (ERC) to satisfy reasonably available control technology (RACT) requirements. The criteria for approval of ERC transactions specifies that they must involve like pollutants (for volatile organic compounds, the same degree of toxicity and photochemical reactivity), must be within the same nonattainment area, may not be used to satisfy Federal technology control requirements and may not be inconsistent with standards or regulations or to circumvent new source performance standards, best available control technology, lowest available emission rate technology controls or NESHAPs.

Regulation Number 7 sets forth CTG and RACT emission limitations, equipment requirements and work practices intended to control emission of volatile organic compounds (VOC) from new and existing stationary sources. The control measures specified in Regulation Number 7 are designed to reduce the ambient concentrations of ozone in ozone nonattainment areas and to maintain adequate air quality in other areas.

Specific Statutory Authority

The provisions of C.R.S. §§ 25-7-105 and 25-7-109 to 110 provide the specific statutory authority for the amendments to this regulation adopted by the Commission. The Commission has also adopted in compliance with C.R.S. § 24-4-103(4), this Statement of Basis, Specific Statutory Authority and Purpose.

Purpose

The purpose of this amendment to Regulation Number 7 is to establish a source specific rule for Gates to allow the use of emission reduction credits to satisfy the RACT requirements for VOC emissions pursuant to Regulation Number 7 for surface coatings operations not specifically listed in Section IX of Regulation Number 7. Regulation Number 3 provides specific authorization to use emission reduction credit transactions as an alternative compliance method to satisfy CTG and RACT requirements.

Specifically, the VOC certified emissions reduction credits to be used in this emission credit transaction in an amount up to 12 tons per year are from Coors Brewing Company pursuant to their emissions reduction credit Permit. The emission reduction credits will be used to satisfy the general requirements that all sources apply RACT. These emission reduction credits will be used by Gates so that Gates can use solvent-based surface coatings which contain VOCs periodically in lieu of the water-based coatings normally used on its 10 Cord coating line (S033, S034, and S035). These credits will allow Gates to meet RACT requirements without applying control technology to the 10 Cord line, other than the currently installed catalytic incinerator on the emissions from the drying oven from the fourth dip, which reduces those emissions by at least 90%. The relevant portion of Regulation Number 3, which applies to the Gates credit transaction is Section V.F., entitled “Criteria for Approval of all Transactions.” The first requirement is that the transaction involve like pollutants. In the present case, the emission credit transaction involves the exchange of VOC pollutants. Coors credits for methanol will be exchanged for m-pyrol. Exhaust from the catalytic incinerator, which contains unconverted toluene and xylene, is routed to the curing ovens of the other zones of the 10 Cord line, including the first zone. The Division has previously found that, excluding the emissions from the non-compliant coatings addressed in this rule, the 10 Cord line has met RACT standards. The use of the non-compliant coatings adds no HAPs to the Gates emissions. Other non-criteria reportable pollutants are present at well below APEN de minimis quantities under scenario 2, which is applicable to the 10 Cord line. Regulation Number 3 further requires that toxic or VOC pollutants involve the same degree of toxicity and photochemical reactivity or else a greater reduction may be required. Since these pollutants are both toxics and VOCs (except that m-pyrol is not a toxic), both have been addressed.

All of these compounds are commonly used in the surface coating industry with appropriate safeguards during their use. With respect to toxicity of the Gates compounds, m-pyrol is not listed as a toxic compound on either the federal or state lists. Methanol, the VOC in the Coors credit, is a Bin C HAP. Because the m-pyrol in the non-compliant coatings is not a HAP, the Gates VOCs have equal or lower toxicity than those being purchased from Coors. Therefore, HAP emissions will be reduced in the airshed.

The photochemical reactivities of VOCs are important because of their impact on the ozone formation process in an airshed. The Air Pollution Control Division relied upon the work of Dr. William P.L. Carter, Professor at the University of California, whose article entitled “Development of Ozone Reactivity Scales for Volatile Organic Compounds” describes relative photochemical reactivity scales and comparisons. Dr. Carter notes that there are a number of ways to quantify VOC reactivities, but the most relevant measure of VOC effects on ozone is the actual change in ozone formation in an airshed. This results from changing the emissions of the VOC in that airshed which depends not only on how rapidly the VOC reacts and the nature of its atmospheric reaction mechanism, but also the nature of the airshed where it is emitted, including the effects of other pollutants which are present.

Dr. Carter further states that the VOC effect on ozone in the atmosphere can only be estimated using computer airshed models. The effect of changing the emissions of a given VOC on ozone formation in a particular episode will, in general, depend on the magnitude of the emissions change and on whether the VOC is being added to, subtracted from, or replacing a portion of the base case emissions.

Dr. Carter's derived relative reactivity scale includes reactive organic gases whose indices for maximum incremental reactivity (MIR) range from 0.004 to 6.5. The MIR values were updated in 1997. The VOCs and their respective MIR involved with this exchange are as follows:

Methanol	0.16
m-Pyrol	0.57

The pending emission credits of VOCs being used in the proposed emissions credit transaction are for methanol. The VOCs emitted from uncontrolled use of solvent-based coatings at Gates are from m-pyrol. Regulation Number 3 provides that if the VOCs are not of the same photochemical reactivity, a greater offset may be required. The Commission required that, based on a past ERC trade for Pioneer Metal Finishing, that methanol credits in a 1.1:1 offset ratio be exchanged for toluene and xylenes. Here, however, the Commission finds that m-pyrol and methanol have similar photochemical reactivities, so no offset will be required.

The second requirement states that the transaction must not result in an increased concentration, at the point of maximum impact of hazardous air pollutants. This provision was derived from the EPA Emissions Trading Policy Statement and referred to NESHAP requirements involved in bubble transactions. If this provision is interpreted to apply generally to a facility which is limited by an existing permit to some level of VOC emissions on a twenty-four-hour basis, any additional VOCs allowed pursuant to an emission transaction would by its application increase the concentration of VOCs at the maximum point of impact. Since it appears to have been intended to limit NESHAP offsets in bubble transactions, and no NESHAPs are applicable in the Gates transaction, and recognizing the earlier action of the Commission in approving the use of ERC transactions to satisfy CTG requirements and in approving a previous ERC transaction for Pioneer Metal Finishing, the Commission determined that this requirement should not apply to this transaction.

The next requirement states that no transaction may be approved which is inconsistent with any standard established by the Federal Act, the state Air Quality Control Act or the regulations promulgated under either, or to circumvent NSPS requirements or BACT or LAER, although the Commission may approve a transaction using a certified emission reduction credit in lieu of a specified CTG method or RACT. The emissions involved in this transaction at Gates are not subject to NSPS, BACT, or LAER. Regulation Number 7 applies only RACT to the Gates operations involved. Regulation Number 3 clearly permits the use of emission reduction credits to satisfy RACT.

The emission must involve sources which are located within the same nonattainment area. In the present case, both Gates, whose operations are located at 900 S. Broadway, Denver, Colorado, who is proposing to use the credits, and the source of the credits, Verticel, whose operations were located at 4607 South Windermere Street, Englewood, Colorado, are located in the Denver nonattainment area, less than five miles apart.

The next requirement prohibits the use of emission reduction credits to meet applicable technology-based requirements for new sources, such as NSPS, BACT, or LAER. As stated, the Gates operations involved in this transaction are not subject to NSPS, BACT, or LAER or any other technology-based requirement except for RACT requirements for which an ERC transaction may be used to satisfy such requirements.

The next requirement states that VOC trades will be considered equal in ambient effect where the trade is a pound for pound trade in the same control strategy demonstration area. It appears that this requirement, which was taken from the EPA Emissions Trading Policy Statement, made the assumption that the "pound for pound" trend would have an equal impact on the ambient environment, with respect to ozone. Since there was no independent photochemical reactivity equivalency requirement in the 1986 Policy Statement, this requirement appears to be redundant with the requirement for insuring the same degree of photochemical reactivity among traded pollutants.

For VOC trades involving surface coating, the requirements state that emissions must be calculated on a solids-applied basis and must specify the maximum time period over which the emissions may be averaged, not to exceed 24 hours. The proposed emissions credit transaction is based on a 24-hour period. With respect to the solids-applied basis calculation, this transaction will be calculated on the basis of the pounds of VOCs from uncontrolled solvent-based coatings.

The emissions credit transaction will require a SIP revision. The source specific rule for Gates will be forwarded to EPA for approval. The state emissions permit for Gates pursuant to the emissions credit transaction will be state effective (but not federally effective) until the SIP revision is approved by EPA.

Gates proposed the following VOC emissions limitation in its state permit taking into consideration the pounds per year VOC emissions allowed by this emissions credit transaction:

1. A daily maximum limitation of 400 lbs. of VOC emissions from uncontrolled solvent-based surface coatings, calculated on a monthly basis for compliance purposes. Calculations will be performed by the 30th of the following month.

2. An annual limitation of no more than 24,000 lbs. (12 tons) of VOC emissions from uncontrolled solvent-based surface coatings.

Gates proposes to calculate the annual total VOC limitation on a rolling 12-month basis. Gates further proposes to keep monthly totals of non-compliant surface coatings used and to calculate daily usage based on monthly usage divided by the number of days' non-compliant surface coatings were used. Records of usages and calculations will be kept and produced at the Division's request.

This source-specific rule has a negligible or no effect upon the other provisions of the ozone SIP.

It is contemplated that a State construction permit will be issued to Gates upon final approval by the Commission. Should the approval come after the issuance of Gates' Title V operating permit, the terms of the construction permit will be added to the operating permit.

E. January 11, 2001 (Sections III.C., IX.L.2.c.(1), and X.D.2. through XI.A.3.)

Readoption of Changes to Regulation Number 7 that were not printed in the regulation or the Colorado Code of Regulations.

Background

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, C.R.S. (1988), Sections 24-4-103(4) and (12.5) for adopted or modified regulations.

Basis

During a review of the version of Regulation Number 7 adopted by the Air Quality Control Commission and the version of Regulation Number 7 published in the Colorado Code of Regulations, several significant discrepancies have been identified. This rule making will clarify the Commission's intent to adopt the following revisions to Regulation Number 7:

1. Section III.C regarding General Requirements for Storage of Volatile Organic Compounds omits the following revision:

   "Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 PSIA at actual conditions are exempt from the provisions of Section III.B."

2. Section IX.L.2.c.(i) contains discrepancies in reference to the permit number of Coors Brewing Company Emissions Reduction Credit Permit issued on July 25, 1994.

3. Section X.D.2. through Section XI.A.3. was omitted from the CCR as published in the current version of Regulation Number 7.

Authority

Sections 25-7-109, C.R.S. (1997) authorize the Commission to adopt emission control regulations.

Purpose

Re-adoption of the proposed rule will eliminate the discrepancies between the Commission's adopted provisions within Regulation Number 7 and those contained within the Colorado Code of Regulations. Adoption of the amendments will benefit the regulated community by providing sources with consistent information.

F. November 20, 2003 (Sections I.A.2. through I.A.4., II.D. and II.E.)

The Commission repealed the provisions establishing a procedure for granting exemptions for de minimis sources, and the procedure for approving alternative compliance plans without source-specific SIP revisions. The Commission had adopted the repealed provisions in March 1996, but had delayed the effective date pending EPA approval through the SIP revision process. Earlier this year, EPA informed the Commission of its intent to disapprove the provisions unless they were withdrawn. Thus, the provisions that are the subject of this rulemaking action never took effect. The Commission hereby repeals such provisions in order to avoid disapproval of the earlier SIP submittal, and to remove extraneous provisions from Regulation Number 7. Such repeal is required in order to comply with federal requirements, and is not otherwise more stringent than the requirements of the federal act.

Sections 25-7-105(1)(a)(I) and 25-7-301 authorize the Commission to adopt and revise a comprehensive SIP, and to regulate emissions from stationary sources, as necessary to maintain the national ambient air quality standard for ozone in accordance with the federal act.

G. (March 2004, Sections I.A, I.B., XII., and XVI.

The March 2004 revisions were adopted in conjunction with the Early Action Compact Ozone Action Plan, which is a SIP revision for attainment of the 8-hour ozone standard by December 31, 2007. The Commission adopted four new control measures in Regulation Number 7 to reduce emissions of volatile organic compounds (VOC). The control measures require the installation of air pollution control technology to control: (1) VOC emissions from condensate operation at oil and gas (E&P) facilities; (2) emissions from stationary and portable reciprocating internal combustion engines; (3) certain VOC emissions from gas-processing plants; and, (4) emissions from dehydrators at oil and gas operations.

The new requirements in Sections XII., and XVI. apply to a larger geographic area than the pre-existing requirements of Regulation Number 7, as set out in Section I.A. of the rule. The reference to the "Denver Metro Attainment Maintenance Area", which is not a defined term, in Section I.A was changed to refer to the "Denver 1-hour ozone attainment/maintenance area", which is defined in the Ambient Air Quality Standards Rule. Similarly, the reference to the "Denver Metropolitan Nonattainment Area Ozone Maintenance State Implementation Plan" was changed to the "Ozone Redesignation Request and Maintenance Plan for the Denver Metropolitan Area," which is the correct name of the document submitted to EPA in May 2001.

Regarding VOC emissions from condensate operations, the Commission has determined that an overall reduction of 47.5% VOCs is required of each E&P operation so as to meet the requirements of the SIP. Further the Commission decided not to take a unit-by-unit approach, but rather, the amendments take a more flexible approach to regulating such emissions by requiring sources that have filed, or were required to file, APENs to choose emission controls and locations for applying those controls. This approach also minimizes the risk that sources may reconfigure tanks to avoid implementing the regulation.

Section XII.A.6. provides an exemption for owners and operators with less than 30 tpy of flash emissions subject to APEN reporting requirements. Regulation Number 7 previously included more general exemptions for emissions from condensate operations, but such pre-existing exemptions should have been repealed as part of this revision to Regulation Number 7. To the extent any pre-existing exemption for condensate operations remains, such pre-existing exemption shall not be construed to supersede the requirements of Section XII.

The rule also requires annual reports describing how E&P sources will achieve the requisite emission reductions. Such reports are necessary so that the Division can determine whether or not the emission reductions are being achieved.

Section XII.B. of Regulation Number 7 is required to ensure that existing and new natural gas processing plants employ air pollution control technology to control emissions from leaking equipment, and atmospheric condensate storage tanks (and tank batteries). The Commission is specifically requiring a leak detection and repair (LDAR) program for all gas plants, according to the provisions of 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the affected facility. This is necessary to ensure these large facilities are well controlled and VOC emissions minimized.

Section XII. C. pertains to control of VOC emissions from natural gas dehydration operations. The Commission determined that, in order to meet the requirements of the SIP, emissions must be reduced from all dehydration operations located in the 8-hour Ozone Control Area if such operations produce emissions above the minimum threshold specified in the rule. Further the Commission decided that flexibility should be allowed in how emissions are reduced, so several options are listed from which a source owner or operator may choose. If other equally effective measures or control devices are available, the Division may, on a case-by-case basis, approve the use of such alternatives.

Similarly, Section XVI. establishes controls for reciprocating internal combustion engines. Both "lean" and "rich" burn engines are addressed and though the Commission has specified the default control technology to be applied to each engine type, the Division is allowed to approve alternative technology if a demonstration can be made that the alternative is at least as effective as the listed device in reducing VOC emissions. Parties to the rulemaking hearing provided evidence that suitable, cost-effective control equipment may not be available for some existing engines. The rule adopted by the Commission includes an exemption for lean burn engines if the owner demonstrates that such emissions controls would cost $5,000 or more per ton of VOC removed. In calculating such costs, the Division shall use an appropriate amortization period and current discount rate. The Commission directs the Division to further investigate the question of whether controls are available and suitable for lean burn engines, and to recommend any revisions necessary for the regulation applicable to such engines. New engines locating in the control area must comply with the requirements effective June 1, 2004, but existing engines have until May 1, 2005 to come into compliance. Since the rule provides an exemption for existing engines that cannot be controlled for less than $5,000 per ton, the rule must make the distinction between new and existing engines so that engines will not be moved into the area during prior to May 2005 and subsequently apply for such an exemption.

The Commission recognizes that, at this point in time, the controls required by the rule amendments constitute Reasonably Available Control Technology (RACT), at a minimum, and in some cases, the controls mandated by this regulation may, in fact, constitute Best Available Control Technology (BACT). This means that this regulation shall not be used: (a) to preclude a source from asserting that one of the controls mandated herein constitutes BACT or Lowest Achievable Emissions Rate (LAER) for a new source or major modification, (b) require the Division or Commission to mandate different control technologies as BACT, or (c) preclude the Division or Commission from requiring additional or more stringent air pollution control technologies as necessary or appropriate to comply with applicable BACT or LAER requirements for new sources and major modifications.

By its terms, the New Source Performance Standard (NSPS) applicable to leaking equipment at onshore natural gas processing plants (40 CFR Part 60, Subpart KKK) applies to “affected facilities” and “process units” at such facilities as those terms are defined in the standard. In general, plants that were constructed prior to January 20, 1984 are exempt from the standard, unless subsequently modified or reconstructed, or newly constructed after that date. Since process units at a single gas plant can be distinct, certain gas plants may contain equipment that is not presently subject to the NSPS because of its date of construction. The control requirement in Section XII.B. would extend leak detection and repair program requirements to such equipment.

The statutory authority for the revisions to regulation Number 7 is set out in Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The March 2004 revisions to Regulation Number 7 are based on reasonably available, validated, reviewed, and sound scientific methodologies. All validated, reviewed and sound scientific methodologies and information made available by interested parties has been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution. The Commission chose the most cost-effective mix of control strategies available to comply with the 8-hour ozone NAAQS. Where possible, the regulations provide the regulated community with flexibility to achieve the necessary reductions. The Commission chose the regulatory alternative that will maximize the air quality benefits in the most cost-effective manner.

H. (December 2004, SECTIONS I.A., II.A., XII. and XVI.)

The December 2004 revisions were adopted to respond to U.S. EPA comments on the Ozone Action Plan the Commission adopted in March 2004. EPA required the rule revision in order to make the control measures incorporated into the State Implementation Plan practically enforceable as required by the federal Clean Air Act. The Federal Act requires all of the regulatory provisions adopted in this rulemaking action, and none of the provisions are more stringent than the requirements of the federal act.

The revised rule includes a process for obtaining emission reduction credit for pollution prevention measures. In order to qualify for an emission reduction credit, a pollution prevention measures must, among other things, be included in a permit even if it does not involve the construction of an air pollution source and would not otherwise trigger a requirement for a permit. The revisions to the regulation do not, however, create a requirement for sources to obtain a permit for pollution prevention measures for which the source will not take emissions reduction credit.

The Commission has the statutory authority to adopt the revisions pursuant to Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The control measures necessary to achieve the 8-hour ozone standard were adopted in March 2004. The December 2004 rule changes do not impose new emission control requirements or emission reduction requirements on industry. Instead, the December 2004 rule revisions are intended to make the previously adopted requirements more enforceable, and to make sure that the requisite emission reductions occur during the ozone season when they are needed. Thus, the December 2004 are administrative in nature in that they are intended to assist with the administration and enforcement of the previously adopted controls. The Commission recognizes that the December 2004 rule amendments impose additional recordkeeping and reporting requirements, and therefore costs, on the regulated community. The changes, however, are not intended to achieve further reduction in emissions of volatile organic compounds beyond the reduction requirements adopted in March 2004. They are instead intended to make the March 2004 revisions fully enforceable and acceptable to EPA. Since the December 2004 rule changes are administrative in nature, the requirements of Section 25-7-110.8 C.R.S. do not apply.

I. December 17, 2006 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

Regulation Number 7, Section XII imposes emission control requirements on oil and gas condensate tanks located in Adams, Arapahoe, Boulder, Douglas and Jefferson Counties, the Cities and Counties of Broomfield and Denver and parts of Larimer and Weld Counties (“8-Hour Ozone Control Area”). The condensate tank requirements, along with other requirements applicable to oil and gas operations and natural gas fired reciprocating internal combustion engines, were initially promulgated in March 2004, and later revised in December 2004, in connection with an Early Action Compact Ozone Action Plan (“EAC”) entered into between the State of Colorado and the United States Environmental Protection Agency. The purpose of the EAC is to prevent exceedances of the 8-Hour Ozone Standard and avoid a nonattainment designation for the area. Pursuant to the EAC, Colorado committed to limiting Volatile Organic Compound (“VOC”) emissions from condensate tanks located in the 8-Hour Ozone Control Area to 91.3 tons per day (“TPD”) as of May 1, 2007 and 100.9 TPD as of May 1, 2012. Because of unanticipated growth of condensate tank emissions since 2004, the control requirements for condensate tanks adopted during the 2004 rulemaking are insufficient to meet these daily emission numbers. The current revisions require a greater level of control of condensate tank emissions in the 8-Hour Ozone Control Area in order to meet the commitments set forth in the EAC and to prevent future exceedances of the 8-Hour Ozone Standard.

These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Section, 25-7-105(1)(a), C.R.S., which gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of a comprehensive state implementation plan that will assure attainment of national ambient air quality standards. Additional authority for these revisions is set forth in Sections, 25-7-106 and 25-7-109, which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to specified areas within the state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XII. were adopted in order to meet the commitments with respect to condensate tank emissions set forth in the Early Action Compact Ozone Action Plan entered into between the State of Colorado and U.S. EPA, prevent exceedances of the 8-Hour Ozone Standard, and simplify recordkeeping and reporting requirements. To accomplish these goals, the revised regulation raises the system-wide control requirements for the ozone season from the current 47.5% to 75% commencing in 2007 and 78% in 2012. While the rule establishes a higher percentage reduction in 2012 the Commission recognizes that given the uncertainty of emissions growth over the next 6 years, this reduction requirement may be too high and may need to be revisited as the 2012 deadline approaches. For the non-ozone season the required reduction has been raised from 38% to 60% commencing October 2007, and 70% commencing January 1, 2008. Determination of compliance during the ozone season under the revisions will be on a weekly basis instead of a daily basis, in recognition of the fact that condensate production is not typically measured on a daily basis. Under the previous version of the Rule, production could be tracked on something greater than a daily basis and the total divided by the number of days to obtain a daily number. As such, the prior rule did not truly give a daily average and thus the move to a weekly average is of little substance. Apart from this change, calculation of emissions for compliance purposes will remain the same as under the previous version of the rule.

In addition to raising the system-wide reduction requirements, the current rule adds significant new monitoring, record-keeping and reporting requirements, and a “backstop” threshold requirement to have emission controls on all condensate storage tanks with uncontrolled actual emissions of 20 tpy or more of VOC flash emission, as a state-only requirement within the EAC area pursuant to Section XVII.C.1. of Regulation Number 7. Owners and operators will continue to keep a spreadsheet that tracks emission reductions and submit an Annual Report as required under the previous version of the rule. Owners and operators are now also required to submit a semi-annual report on November 30 of each year detailing their emissions during the preceding ozone season. Additional record keeping has been added so as to require that a weekly checklist be maintained detailing inspections of control devices. This checklist will assist operators in the inspection and maintenance practice and provide a record that proper inspections have been done. If the inspections show a problem with the control device, the owner or operator will be required to notify the Division of problems on a monthly basis. This requirement will allow the Division to track problems on a timelier basis and ensure compliance with the rule. Finally, a provision has been added to require owners or operators to submit a list of all their controlled tanks on April 30 of each year and notify the Division monthly during ozone season if the control status of any tank changes.

J. December 17, 2006 (Sections I.A.1.b. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted these state-only provisions as a means of reducing air emissions from oil and gas operations throughout Colorado. Due to the large growth in oil and gas production in a number of regions of the state emissions from oil and gas operations have rapidly increased over the past few years and are expected to increase further in the foreseeable future. These revisions are a proactive measure designed to eliminate air emissions that could threaten attainment of ambient air quality standards and adversely affect visibility in Class I Areas. These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-106 and 25-7-109 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Additional authority is set forth in Section 25-7-105.1, which allows the Commission to adopt state-only standards. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to the entire state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XVII. were adopted in order to reduce air emissions from oil and gas operations and natural gas fired reciprocating internal combustion engines in Colorado. These revisions constitute a forward-looking approach to deal with a rapidly growing source of air emissions, and are designed to reduce the possibility of future problems with respect to the attainment of National Ambient Air Quality Standards and state and federal Class I Area visibility goals. Since the requirements are not mandated under federal law and are not currently necessary to meet National Ambient Air Quality Standards they are being adopted as a state-only requirement in accordance with the Act and as provided for under the Federal Clean Air Act.

These revisions establish emission control requirements for condensate storage tanks, glycol dehydrators and natural gas fired reciprocating internal combustion engines in Colorado. These provisions require that condensate tank and dehydrator controls meet a 95% percent control efficiency. As in the EAC Area, this requirement does not contemplate stack testing in order to verify the control efficiency. The insertion of the word average allows operators some downtime without a violation occurring so long as the downtime does not result in an average control efficiency of less than 95% considering the actual engineered control efficiency. For the purposes of XVII.C.4.b. observed operation of flare auto-igniters can include telemetric monitoring systems, physical on-site function tests or auditory confirmation of the auto-igniter function.

The requirements applicable to glycol dehydrators mirror the requirements applicable in the 8-Hour Ozone Control Area set forth in Section XII, and should be interpreted consistently with those provisions notwithstanding the addition of clarifying language. For example, language has been added clarifying that grouping of dehydrators is limited to dehydrators at a single site. Similarly, the word "production" has been added to the definition of condensate tank to clarify that the requirements, as within the EAC, do not apply to produced water tanks.

Determination of whether a condensate tank's emissions are at or above the threshold is based on the emissions from the tank during the preceding twelve-month period. If a tank has been in service for less than twelve months, applicability shall be based on uncontrolled actual emissions over the service period of the tank multiplied out to twelve months. Accordingly, if a tank has been in service for three months, applicability of the control requirements will be based on the uncontrolled actual emissions from the tank for those three months multiplied by four. If emissions from a controlled tank decrease, operators may remove the controls when emissions from the previous twelve-month period falls below the applicable threshold. Operators will remain responsible, however, for controlling a tank if a subsequent emission increase results in emissions being over the applicable threshold during the preceding twelve months. For tanks serving newly drilled, recompleted or restimulated wells (including refrac'd wells) the owner or operator will have 90 days to determine anticipated production and, if necessary install a control device. In determining anticipated production, the owner or operator may use an appropriate decline factor to determine expected emissions over the first 12 months after the new drilling, recompletion or re-stimulation. If the owner or operator determines that emissions will be below the 20 tpy threshold following the new drilling, recompletion or restimulation, the owner or operator shall notify the Division of this determination.

Certain differences with the requirements applicable to the 8-Hour Ozone Control Area have been included in order to provide greater flexibility to operators in other areas of the state and in light of the fact that the regulation represents a proactive attempt to avoid future impacts from oil and gas emissions. Specifically, the standards for obtaining approval of an alternative pollution control device have been relaxed to promote innovative control strategies. Additionally, a provision has been added to allow an extension of the control requirement deadlines at the Division's discretion for good cause shown. This provision allows the Division to extend a deadline where shortages of control equipment, and crews may prevent an operator from meeting the deadlines, particularly in areas where access is limited by the weather or other issues. With respect to Section VII.B.1.c. of the General Provisions, the Commission has determined that as a general rule during normal operations no emissions should be visible from the air pollution control equipment.

Normal operations include reasonably foreseeable fluctuations in emissions from the condensate tank, including the fluctuations that occur during a separator dump. However, a transient (lasting less than 10 seconds) "puff" of smoke when the main burner ignites or shuts down would not be considered a violation of the "no visible emission" standard. Finally, a provision has been included that exempts units' subject to the rule if such units are also subject to a control standard under the MACT, BACT or NSPS Programs. This exception is of most importance for new and newly relocated engines that may become subject to a currently pending NSPS Standard under Subpart JJJJ.

The engine provisions only apply to engines that are constructed or relocated into Colorado after the applicability date and do not impose requirements on units that are currently located in the state.

The Commission recognizes that the adopted emission control requirements represent a first step in addressing rapidly growing emissions from oil and gas operations throughout the state. Accordingly, the Commission directs the Division to provide an annual update on emission growth trends, environmental impacts, modeling and monitoring efforts, the adequacy of emission controls to protect the NAAQS and the health impacts of emissions from the oil and gas sector.

K. December 12, 2008 (Title, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions throughout Regulation Number 7 to address ozone formation in the 8-Hour Ozone Nonattainment Area (NAA), including the 9-county Denver Metropolitan Area and North Front Range (DMA/NFR) NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions are necessary to ensure attainment with the current 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) set at 0.08 parts per million (ppm), and to achieve additional ozone reductions in light of both the new ozone NAAQS set at 0.075 ppm and the Governor's July 27, 2007 directive to proactively and pragmatically reduce ozone levels.

As of November 20, 2007, the EPA's deferral of a nonattainment designation for the area in question expired, signifying that the area is now considered nonattainment, or in violation of the 1997 8-hour Ozone NAAQS of 0.08 ppm for ground level ozone. The DMA/NFR includes all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson Counties as well as portions of Larimer and Weld Counties. This area is now known as the DMA/NFR NAA.

Pursuant to the Federal Clean Air Act, Colorado must prepare and submit a revision to the State Implementation Plan (SIP) to the EPA no later than June 30, 2009 that demonstrates attainment of the 8-Hour Ozone NAAQS no later than 2010. The Commission has adopted an Attainment Plan that satisfies this requirement. The Attainment Plan demonstrates attainment with no additional control measures.

Photochemical grid dispersion modeling indicates that without further emission controls, Colorado will attain the 8-hour standard by 2010. The dispersion modeling reflects that Colorado would attain the standard by a narrow margin. Photochemical dispersion modeling analysis is the primary tool used to assess present and future air quality trends, and is required for EPA to approve the state attainment demonstration in the SIP.

In addition, pursuant to EPA guidance, if modeling results indicate that the highest ozone levels will fall between 0.082 and 0.087 ppm, Colorado must conduct a "weight of evidence" analysis and other supplemental analyses in order to corroborate the modeling results. Colorado's model results are within this range, and thus the state has conducted this analysis. The analysis supports the conclusion that Colorado will attain the standard by 2010.

The Commission is also adopting State-only revisions to Regulation Number 7 to further address ozone formation in the DMA/NFR NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions help Colorado make progress toward eventual compliance with the new ozone NAAQS set at 0.075 ppm as well as the Governor's directive to proactively and pragmatically reduce ozone levels.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act ("Act"), C.R.S. § 25-7-101, et seq., specifically, C.R.S. §25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and § 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

These revisions to Regulation Number 7 are part of an overall ozone reduction strategy. The Commission intends that this overall ozone reduction strategy accomplishes six objectives: A) reduce VOC and nitrogen oxides' (NOx) emissions from oil and gas operations in the Ozone NAA and across the state, B) revise the control requirements for condensate tanks by a refined system-wide control strategy in the Ozone NAA, C) expand VOC RACT requirements for listed source categories for 100 tpy sources such that all Ozone NAAs are subject to Regulation Number 7's RACT requirements, D) clarify how the RACT requirements in Regulation Numbers 3 and 7 interact in the Ozone NAA, E) improve the Division's inventory of condensate emissions and other relevant sources in the NAA; and F) make typographical, grammatical and formatting changes for greater clarity and readability.

In support of objectives A-D and F, the Commission adopts these revisions to Regulation Number 7 to revise condensate tank regulations, set pneumatic controller regulations, expand RACT applicability and make associated corrections (Regulation Number 7, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F).

In the course of this proceeding, the Division and certain parties supported a compromise proposal regarding the control of condensate tanks. The Commission finds this proposal to be appropriate with certain changes noted herein. The Commission is requiring an increase from 75% to 81% control on a system-wide basis in 2009; to 85% control on a system-wide basis in 2010; and to 90% control on a system-wide basis in 2011 in the 8-Hour Ozone NAA. The Commission is adopting new VOC controls for pneumatic controllers in the 8-Hour Ozone NAA in Regulation Number 7, Section XVIII.

These system-wide control percentages achieve significant ozone precursor reductions in 2009, 2010 and 2011, with emphasis on significant VOC emissions reductions in 2010, during the monitoring period for the attainment demonstration. These revisions will help to ensure that the non-attainment area realizes the necessary reductions during the 2010 attainment year. Further, these revisions are an important step in putting the State on a path towards attaining the 2008 8-Hour ozone standard. A number of parties including the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization supported this proposal to secure VOC reductions from this source at these levels and according to this schedule. The system-wide approach has been approved by the Commission in the past, as well as by EPA in revisions to the State Implementation Plan. The Commission decided to defer decision making on the implementation of a 95% system-wide level of control, given concerns regarding the notable incremental cost associated with control to the equivalent of 2 tpy tanks as well as concerns regarding the flexibility intended to be afforded by a system-wide approach. Tank operators also expressed concern about the loss of incentive to over-control their systems to meet the standard, and the difficulty for small operators to control at the 95% system-wide level at this time.

The proposed control percentages continue to afford flexibility in operations to condensate tank operators, while ensuring attainment of the standard by 2010. Therefore, the Commission is deferring further control for future modeling, air quality analysis, and/or administrative review, whether to control this source in the future at the 95% system-wide control level or through some other approach for purposes of the 2008 8-Hour standard.

The provisions of the compromise proposal, including the commensurate emissions reductions, support the State Implementation Plan's ability to assure attainment and maintenance of the 1997 8-Hour Ozone NAAQS. Inclusion of these provisions enhances the Weight of Evidence demonstration supporting attainment by 2010 pursuant to this State Implementation Plan. The Commission recognizes parties subject to the compromise Regulation Number 7 provisions for condensate tank system-wide emissions reductions concur that these provisions are appropriate for inclusion in the State Implementation Plan.

Further the Commission intends to expand the applicability of RACT requirements to existing, new and modified sources in Ozone NAAs outside of the historic one-hour Ozone NAA or attainment/maintenance area (Regulation Number 7, Sections I and II). The Commission further intends to clarify how the control technology requirements of Regulation Number 7 interact with Regulation 3, Part B, Section II.D.2.

Finally, the Commission intends to make grammatical, typographical, formatting revisions, and other editing revisions throughout Regulation Number 7.

Condensate Tank Emissions Control

Condensate storage tank control requirements in Regulation Number 7, Section XII. are revised by reorganizing the rule, adding/revising definitions, adding monitoring requirements, revising recordkeeping and reporting requirements, and setting additional control requirements for tanks. The current requirements are reorganized by specifying applicability, definitions, general provisions, emissions controls, monitoring, and recordkeeping and reporting sections. The terms new, existing, modified/modification, auto-igniter, and surveillance system were defined.

Tanks serving newly drilled, recompleted or stimulated wells are required to employ air pollution control equipment during the first 90 days of production. After the first 90 calendar days, the control device may be removed. This requirement is designed to address the fact that production, and thus emissions, is at their greatest during the period immediately after drilling, recompletion or stimulation, and the fact that the actual production/emission level is not known prior to drilling, recompletion or stimulation. By requiring controls on all tanks serving newly drilled, recompleted or stimulated wells, the proposed rule significantly reduces emissions during the initial period, while allowing owners and operators to remove control devices afterward, as part of the overall system-wide control regime. All tanks over 2 tpy must participate in the overall system-wide program. Furthermore, since Regulation Number 7's system-wide program is essentially RACT for condensate tanks in the NAA, new and modified 2 tpy or greater condensate tanks (affected by Regulation Number 3 RACT) may also move their control devices after the first 90 days when participating in the overall system-wide control regime, as long as the overall system-wide requirements are being met. Such flexibility is provided as to avoid two regulatory programs: one for tanks that might never be allowed to move their control devices under Regulation Number 3 RACT and one for tanks that would be allowed the flexibility under a system-wide program. Finally, it is the intent of this rule that sources may use their 2 tpy or greater "modified" tanks emissions (i.e., during those tanks' first 90 days of production) in the source's overall system wide calculation. After 90 days, sources must include – whether controlled or otherwise - the 2 tpy or greater "modified" tanks in the overall system-wide calculation. In the case of modified tanks that fall below 2 tpy, it is not the intent of the commission for sources to include these less than 2 tpy tanks in any system-wide calculation. However, sources may use the less than 2 tpy controlled tanks, if necessary to demonstrate system-wide compliance.

The Commission is requiring the installation and operation of auto-igniters for each combustion device. In many cases, condensate tanks are remotely located and unmanned. Auto-igniters will provide greater assurance that the control devices are functioning, under these circumstances. Auto-igniters may be relied on to identify when the pilot is not lit and attempt to relight it, and ensure control operation. The Commission is also requiring surveillance on batteries with uncontrolled emissions greater than 100 tpy. Operators must use surveillance to document the duration of time when the pilot is not lit, and to discover if repairs are necessary to ensure proper control operation. The Commission is targeting this size of battery in order to strike a balance between the need to more carefully monitor performance among the largest batteries, the cost associated with surveillance and the division's capacity to manage the information. The Commission acknowledges that three well operators, Encana, Anadarko and Noble Energy, have agreed to participate with the Division in a pilot program regarding the implementation of electronic surveillance systems.

With regard to recordkeeping and reporting requirements, operators will still record estimated emissions each week (as part of the current Regulation Number 7 requirements) and will report this information to the Division semi-annually. In addition, the Division has revised these requirements so that sources now must keep monthly records throughout the year and provide any of those records within 5 business days of a division request. Further, operators may only use a Division-approved spreadsheet to submit emissions records. Further, a responsible official must now certify the accuracy of the data in the semi-annual reports. This level of recordkeeping and reporting will allow the Division greater capacity to verify compliance and additional availability to work with sources (especially smaller operators). The Commission intends that record-keeping and reporting requirements for surveillance apply only to tanks with uncontrolled emissions greater than 100 tpy.

Controls on 2 Tons Per Year Tanks and Lower

The Commission intends that substantial emissions reductions be achieved from condensate storage tanks and that industry retain the flexibility to decide which tanks to control in order to achieve those reductions. The rule has been revised to subject any condensate storage tank to this rule in the Applicability Section, but stipulates in the Emission Control Section that in order to determine the appropriate system-wide emissions reductions, only two tons per year tanks be considered. In doing this, the Commission intends that tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year or more be considered in determining compliance with the system-wide emissions reductions for the specific ozone non-attainment or attainment maintenance area, and that industry have the flexibility to control smaller tanks in those specific ozone non-attainment or attainment maintenance areas if needed in order to meet the applicable system-wide emissions reductions. For example, if a company owns 20 tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year in a specific ozone non-attainment area, and 15 tanks that emit less than two tons per year, the company would determine its required emission reductions of the production through the 20 two tpy tanks, but be able to control any of the 15 additional less than 2 tpy tanks in order to comply with the system-wide emissions reduction or maintain the desired over control as buffer. However, all tanks controlled in order to comply with the system-wide emissions reduction standard must have filed an APEN and obtained a valid permit in order to be considered as part of the compliance demonstration.

Calendar Weekly and Calendar Monthly Records and Reports

The Commission intends that records and associated reports demonstrating compliance with the weekly emission reduction requirement shall start with the calendar week containing May 1st and end with the calendar week containing September 30th, or other specified dates in the rule. A calendar week begins midnight Sunday morning and ends the following Saturday evening at midnight. Thus, where May 1st falls on any day other than Sunday, the calendar week of May 1st begins on midnight of the preceding Sunday morning. Similarly, the weekly emission reduction requirement applies to the full calendar week that includes September 30th.

So, if September 30th falls somewhere in the middle of a calendar week, the emissions reduction requirement applies to that calendar week in full, beginning midnight Sunday morning and ending the following Saturday evening at midnight.

Consequently, calendar monthly records and associated reports demonstrating compliance with the monthly emission reduction requirement shall apply to midnight the morning of day 1 through midnight the evening of the last day of each specific calendar month.

The Commission intentionally broadened the definition of surveillance to provide that: 1) electronic surveillance is not specifically required, and other means to gather information from remote locations is allowed; and 2) data only had to be gathered on a daily basis. The Commission intends that currently required surveillance need only monitor combustion device flame presence or temperature once every day, in order to balance the need to gather adequate data on combustion device operation with the amount of data to be gathered, handled and processed. The Commission believes this is a fair approach considering that only the largest atmospheric condensate storage tanks (those with actual uncontrolled volatile organic compound emissions equal to or greater than 100 tons per year) are subject to this surveillance requirement.

Finally, the Commission intends that the monitoring be completed to ensure compliance, and has determined that failing to monitor as required, losing monitoring data, and failing to maintain monitoring data should be treated similarly to recordkeeping requirements. Thus, these actions "may be treated by the Division as if the data were not collected."

The Commission intends that system-wide emissions control requirements apply to each specific ozone non-attainment or attainment maintenance area and not collectively to all ozone non-attainment or attainment maintenance areas state-wide. This means that the system-wide emissions control requirements apply specifically to the Ozone Control Area (a.k.a. the Denver Metropolitan Area/North Front Range Ozone Control Area), separately from any future designated ozone non-attainment area. Each new ozone non-attainment area designated in the future shall be subject to the system-wide control requirements by themselves. This is needed to ensure that necessary controls are achieved and maintained in each ozone non-attainment or attainment maintenance area, and that these controls are not removed and offset by system-wide controls in some other ozone non-attainment area.

Pneumatics Emissions Control

This revision establishes new VOC controls for pneumatic controllers in the 8-hour Ozone NAA in Regulation Number 7, Section XVIII. Pneumatic controllers are widely used in the oil and gas industry to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature. Pneumatic controllers of interest are instruments that are actuated using natural gas pressure (of which some natural gas may be bled to the atmosphere from the pneumatic controller and some may be vented from the associated valve). Natural gas-actuated pressure relief devices are not intended to be covered by this rule. There are high-bleed controllers designed to emit more than six standard cubic feet of gas per hour (scfh) to the atmosphere, and low-bleed controllers that emit six scfh or less. Historically, high-bleed controllers have been used.

A 2003 EPA study reported that emissions from pneumatic controllers are collectively one of the largest sources of methane emissions in the natural gas industry. Estimated annual nationwide methane emissions are approximately 31 billion cubic feet (Bcf) from the production sector, 16 Bcf from the processing sector, and 14 Bcf from the transmission sector. As stated, by definition, high-bleed pneumatic controllers emit more than six scfh of natural gas to the atmosphere. The highest bleed rate listed in one source, a table published by the EPA, is 42 cubic feet per hour (cfh). The average bleed rate for high-bleed pneumatic controllers in the NAA is 21 cfh. Natural gas is primarily composed of methane, but also contains other compounds including VOCs and hazardous air pollutants (HAPs).

VOC emissions from pneumatic controllers within the NAA were 24.8 tons per day (tpd) for the 2006 baseline and have been projected to be 31.1 tpd for the 2010 baseline. These emissions represent 14.0

and 15.1 percent of the total VOC emissions from oil and gas sources in the NAA in 2006 and 2010, respectively. Therefore, emission reductions related to this source category have the potential to be significant.

These rules require that most high-bleed controllers must be replaced with the equivalent of low-bleed or better pneumatic controllers by May 1, 2009. There is an exception that allows high-bleed controllers that the Division agrees are necessary for safety purposes. Operators must inspect and maintain in-use high-bleed controllers on a monthly basis. Operators must also keep logs of the number of in-use high-bleed controllers, as well as the reasoning that high-bleed controller remains in place, and the inspection and maintenance of the in-use high-bleed controllers. These revisions further require operators to physically tag the in-use high-bleed controllers to enable the Division to track compliance.

The oil and gas industry has already begun replacing high-bleed controllers with low-bleed controllers, understanding the financial gain of minimizing the bleed rate of pneumatic controllers.

RICE Controls

Reciprocating internal combustion engine (RICE) requirements of Regulation Number 7, Section XVI. applies in what was the early action compact area (now the Ozone NAA). These revisions extend the RICE requirements' applicability to a state-wide basis.

Expand and Clarify RACT Requirements

Regulation Number 7 is revised to expand its application to all subject sources in any Ozone NAA and Attainment/Maintenance Areas. This previously applied to the one-hour attainment/maintenance area nonattainment area. Accordingly, this regulation will apply to some sources that were previously outside of its geographic scope. It is intended that existing sources become subject to previously adopted Control Technique Guidelines (CTGS) or general RACT requirements, and are given time to comply to implement the general RACT requirements. Specifically, existing sources that have not been modified are allowed three years from the date of ozone non-attainment designation to implement general RACT requirements. All new or modified sources become subject to these general RACT requirements upon commencing operation after the new ozone non-attainment designation date. This revision is considered a measured approach to ensuring the consistent use of best practices across the NAA as well as reductions in ozone precursors considered necessary to attaining the 8-hour ozone standard.

This revision expands Regulation Number 7's applicability to any Ozone NAA or attainment/maintenance area. This is done intentionally to apply Regulation Number 7 requirements to current as well as any future Ozone NAA or attainment maintenance areas in Colorado.

Additionally, this revision clarifies how the Regulation Number 3 RACT requirements interact with Regulation Number 7. This revision specifies that pursuant to Regulation Number 7, Section II.C. all existing sources that emit 100 tons per year of VOC emissions and that are located in the 8-hour Ozone NAA become subject to RACT.

Further, Regulation Number 7 is currently unclear on whether or not existing sources that are modified become subject to new source requirements. This revision clarifies that existing sources that are modified are subject to the Regulation Number 3, Part B, Section II.D. requirements and are considered to be a new source for the purposes of Regulation Number 7.

This revision also clarifies that the both case-by-case and general RACT requirements of Regulation Number 7, Section II.C. only apply to existing, new and modified sources. For sources at which all air pollution generating activities at that source are already subject to RACT or BACT, the RACT analysis would show that all activities are already subject to RACT or BACT. For any other air pollution generating activities not covered by RACT or BACT, the source would only have to complete a RACT analysis specific to those activities.

Typographical, Grammatical, Formatting and Other Changes

The commission changed the title of Regulation Number 7 to include NOx. An outline of the sections is provided to better understand the contents of Regulation Number 7. Outdated sections are removed (i.e. Section II.F.1. specific to Gates Rubber Company, which is now out of business). Section XII., specific to condensate tanks in the Ozone NAA is reorganized for clarity. One appendix (new Appendix A) is added to provide maps of Ozone NAAs and chronologies of attainment designations, of which certain requirements key off. Finally, sections and appendices are renumbered and formatted as necessary.

Section 110.5 and 110.8 Analysis

Some of these revisions are not intended to be incorporated into Colorado's SIP. To the extent these revisions could be construed to exceed the requirements of federal law, the Commission provides the following additional statement, consistent with C.R.S. § 25-7-110.5(5)(a):

(I) These rules are intended to reduce uncontrolled emissions of ozone precursor pollutants. The rules thereby serve to attain and maintain compliance with the National Ambient Air Quality Standard (NAAQS) for Ozone. However, there are no comparable federal requirements that apply to the sources in question.

(II) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. There is considerable flexibility in meeting the NAAQS. However, there are very limited sources of uncontrolled anthropogenic ozone precursor emissions to target in order to reduce ozone. Consequently, the sources in question, as a significant source of uncontrolled VOCs and NOx, must be targeted in order to attain the standard.

(III) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. The ozone NAAQS was not determined taking into account concerns that are unique to Colorado.

(IV) These rules may prevent or reduce the need for costly retrofit to meet more stringent requirements at a later date. The DMA/NFR non-attainment area has violated the 0.08 ppm ozone NAAQS. Colorado will soon be required to comply with the new ozone NAAQS of 0.075 ppm. Colorado Governor Ritter has directed that Colorado air quality planning agencies implement measures to reduce ozone to a level below the NAAQS. If these rules are not adopted now, it may be necessary to require costlier retrofitting in order to meet the Governor's directive as well as the new NAAQS.

(V) Since there are no applicable federal requirements, there is no timing issue with regard to implementing federal requirements. However, these controls are intended to help the DMA/NFR attain the NAAQS. If the standard is not attained by the 2010 ozone season, the area may face a "moderate" non-attainment designation.

(VI) The adopted rules will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rules establish reasonable equity for sources subject to the rules by providing the same standards for similarly situated sources.

(VIII) If the state rules were not adopted, other sectors may face a disproportionate share of the burden of reducing precursor pollutants.

(IX) There are no corresponding federal requirements.

(X) Demonstrated technology is available to comply. Sources are already using the control devices intended to be used to comply with these rules. However, sources face an additional burden of implementing auto-igniters and surveillance. The Commission anticipates a reasonable degree of delay in securing and installing the technology in question and has accommodated the sources by providing for a reasonable delay for the application of these requirements.

(XI) The adopted rules will reduce VOC and NOx emissions, thereby contributing to the prevention of the formation of ozone through the most cost-effective means available.

(XII) Alternative rules requiring additional controls for other sources would also provide gains toward attaining the ozone NAAQS. However, oil and gas industry members are the largest anthropogenic stationary source of precursor pollutants in the State. A disproportionate benefit to this industry would accrue if their uncontrolled emissions remain at current levels compared to other stationary sources.

(XIII) A no-action alternative may address the ozone NAAQS. Modeling and other analysis suggests that the NAA would attain the standard by 2010 without these rules. However, this analysis suggests that ambient levels of ozone would be very close to the NAAQS. These rules provide more assurance of attaining the ozone NAAQS while also providing for reductions that are necessary to make progress toward the new ozone NAAQS. No action would only delay the necessary reductions.

Further, pursuant to C.R.S. § 25-7-110.8(1), the Commission makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of ground-level ozone.

(III) Evidence in this record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost effective, provide the regulated community flexibility, and achieve any necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

L. January 7, 2011 (Outline and Sections I. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

Specific Statutory Authority

The Colorado Air Quality Control Commission (Commission) promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); and 25-7-114.4(1) (authority to adopt rules for the administration of permits).

Basis and Purpose

The Commission intends that the current Regulation Number 7, Section XVII.E.3.a. identifying technology-based control requirements for existing rich burn reciprocating internal combustion engines (RICE), or rich burn RICE that were constructed or modified prior to February 1, 2009, become a NOx emission control measure that is included as part of the Regional Haze SIP and become federally enforceable upon EPA approval.

The technology-based control requirements of Section XVII.E.3.a. reduce NOx. This proposal only changes the enforceability of these currently state-only requirements such that they become federally enforceable. This proposal does not change emission control, monitoring, recordkeeping or reporting requirements.

The Commission also intends that the following provisions, added in Sections XVII.E.3.a.(i)(a) through (c), will continue to be effective under the Regional Haze SIP. Specifically, these provisions require good air pollution control practices and allow for exemptions from the requirements for existing rich burn RICE. The exemptions apply to any existing rich burn RICE either with uncontrolled actual emissions below permitting thresholds or that is subject to a New Source Performance Standard (NSPS), National Emission Standard for Hazardous Air Pollutants (NESHAP), or Best Available Control Technology (BACT) limit.

Existing lean burn RICE requirements are not incorporated into the Regional Haze SIP, as the associated controls do not reduce NOx or SO2.

Colorado has determined that it is reasonable and appropriate to make these RICE requirements federally enforceable in this first planning period, as part of the state's strategy for addressing reasonable progress towards achieving natural visibility conditions in federal Class I areas.

M. December 20, 2012 (Sections II., XII., and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), Colorado Revised Statutes (C.R.S.) for new and revised regulations.

Basis

Regulation Number 7 is designed to implement substantive regulatory programs authorized under the Colorado Air Pollution Prevention and Control Act (Act) including provisions of the State Implementation Plan (SIP) addressed in C.R.S. Section 25-7-105(1)(a), emission control regulations addressed in C.R.S. Section 25-7-105(1)(b) and authorization of the development of a program for the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS) in C.R.S. Section 25-7-301, as well as other authorized programs under the Act. The current revisions have been promulgated in order to facilitate this goal. The revisions were made to address the U.S. Environmental Protection Agency's ("EPA") partial disapproval of Colorado's ozone SIP.

On August 5, 2011, EPA published the "Approval and Promulgation of State Implementation Plans; State of Colorado; Attainment Demonstration for the 1997 8-Hour Ozone Standard, and Approval of Related Revisions" (76 Fed. Reg. 47443, August 5, 2011). EPA partially approved and partially disapproved revisions to Colorado's SIP adopted by the Air Quality Control Commission (Commission) in December 2008 and submitted to the EPA in June 2009.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act, C.R.S. Section 25-7-101, et seq., specifically, C.R.S. Section 25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and Section 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

The Commission revised Regulation Number 7 to address the EPA's partial disapproval of Colorado's Ozone State Implementation Plan ("SIP'). On August 5, 2011, the EPA issued a final action on Colorado's June 2009, Ozone SIP submittal, both approving Colorado's attainment demonstration for the 1997 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) and disapproving specific revisions to Regulation Number 7. 76 Fed. Reg. 47443, August 5, 2011. Specifically, the EPA disapproved both the repeal of Regulation Number 7, Section II.D. and all revisions to Section XII. as adopted by the Commission in December 2008. As a basis for its action, the EPA stated that Colorado demonstrated attainment with the 1997 8-Hour Ozone NAAQS, however Colorado did not adequately provide an anti-backsliding demonstration for the revisions to Regulation Number 7 that were adopted by the AQCC in December 2008, and submitted to the EPA in June 2009.

The Commission intends that these 2012 revisions include both SIP and state-only revisions that address EPA's partial disapproval of SIP provisions in Sections II.D and XII., and make related state-only revisions to Section XVII. for consistency.

The Commission does not intend that these 2012 revisions add or strengthen emissions control measures of Section II.D., XII. or XVII. at this time. All SIP revisions are intended to specifically address those provisions that EPA included as part of its basis for disapproving revisions to Regulation Number 7.

While the EPA indicated general approval of the concept of the June 2009 SIP submittal, the EPA took exception to some of the details in the SIP revisions, characterized as "deficiencies," that formed the basis of EPA's disapproval during the SIP review process. EPA's objections to the 2009 SIP revisions and the Commission's responses are summarized as follows:

1. Section II.D. – Alternative Control Plans and Test Methods

   EPA Objection: The EPA objected to the deletion of SIP approved language, allowing for alternative control plans and testing methods.

   Commission Response: The Commission reinstated the SIP approved language.

2. Section XII.C.2. – Emission Factor Calculation Methodology for Condensate Tanks

EPA Objection: The EPA objected to the deletion of the term "gas-condensate-glycol separators" from the emission factor requirements for atmospheric condensate tanks.

Commission Response: The Commission made no revision to the rule text, and instead explained to EPA that this term was used in error as such a separator does not exist. The term used here is a misnomer, which the Commission believes refers to a flash tank located on a glycol dehydration unit, covered by Section XII.H. It is inappropriate to apply emission factor calculation methodology for atmospheric condensate tanks to glycol dehydrators because their emissions vary greatly.

3. Section XII.D.2.a. – System-wide Control Requirements for Condensate Tanks

EPA Objection: The EPA objected to the sunset of the system-wide control requirement in Section XII.D.2.a.(x), which ended the control requirement as of April 30, 2013.

Commission Response: The Commission revised the system-wide control requirements so that the system-wide control requirements do not sunset. Neither the Commission nor the parties to the December 2008 rulemaking intended for the system-wide control to end. The sunset was unintentionally caused when making other revisions to the rule text.

4. Section XII.E.3. – Monitoring Combustion Devices as Control for Condensate Tanks

EPA Objection: The EPA objected to providing a state-only monitoring option (electronic surveillance) as a substitution for the SIP required monitoring of combustion devices being used to control emissions from condensate tanks in accordance with Section XII.

Commission Response: The Commission removed the option of conducting state-only electronic monitoring in lieu of the SIP approved monitoring requirement. This allowance to substitute a SIP required monitoring provision for a state-only monitoring provision was unintentional. None of the sources employing electronic surveillance may use it in place of the SIP approved requirement. If conducted, the electronic surveillance monitoring option must occur in addition to the SIP approved monitoring requirement.

5. Section XII.F.3. – Recordkeeping for Condensate Tanks

EPA Objection: The EPA objected to the lack of SIP required recordkeeping for the control requirement in Section XII.D.1., which requires all condensate tanks at exploration and production sites to be controlled during the first 90 days of well production.

Commission Response: The Commission revised Section XII.D.1. to specify it is state-only. The Commission and parties to the December 2008 rulemaking intended for this first 90-day control requirement to be state-only, which corresponds to the state-only designation on the recordkeeping requirements under Section XII.F.3. Therefore, the Commission made no revision to Section XII.F.3., and instead revised Section XII.D.1. to alleviate this discrepancy.

6. Section XII.F.5. – Recordkeeping and Reporting Exemption for Compressor Stations and Drip Stations

   EPA Objection: The EPA objected to the removal of a SIP approved provision that exempted natural gas compressors or drip stations from recordkeeping and reporting requirements, where total emissions from such facilities are less than 30 tons per year.

   Commission Response: The Commission reinstated the SIP approved 30 tons per year provision.

7. Section XII.G.2. – Control Equipment Requirement for Natural Gas Processing Plants

   EPA Objection: The EPA objected to two aspects of the revisions to this section. The first objection was replacement of the term "APEN de minimus levels" with "greater than or equal to two tons per year." The second objection was inclusion of a rolling 12-month averaging period for the 95% control requirement.

   Commission Response: The Commission made no revision to the replacement of the term "APEN de minimus levels." The Commission explained to the EPA that the associated modeling relied on evaluating condensate tanks with emissions greater than or equal to two tons of volatile organic compounds per year. Therefore, the change in reference does not constitute a lessening of the stringency of the rule. In addition, the Commission removed the rolling 12-month averaging period.

8. Section XII.G.5. Recordkeeping and Reporting for Alternative Compliance Option

   EPA Objection: The EPA objected to the reliance on Title V or construction permits as the location for recordkeeping and reporting requirements for condensate tanks at natural gas compressor or drip stations.

   Commission Response: The Commission revised this section to specify recordkeeping and reporting requirements for condensate tanks at natural gas compressor and drip stations.

9. Section XII.H. Control Requirements for Glycol Dehydrators

   EPA Objection: The EPA stated this entire section lacked clarity and contained redundant language.

   Commission Response: The Commission revised the section in its entirety, while maintaining the intent and applicability of the requirements. Along with this revision, the Commission specified that this control requirement is applicable only to glycol dehydrators with emissions equal to or greater than one ton per year, but that all glycol dehydrators at a stationary source must be included for comparison to the 15 ton per year threshold. The term stationary source is defined in the Common Provisions. Further, the Commission revised the provision to include emission calculation methodology requirements in Section XII. H.

Items 1-9 are all SIP revisions.

In addition, the Commission is also revising the state-only Section XVII.D. for consistency with the 2012 SIP revisions. The Commission does not intend that this state-only revision change the applicability of the control requirements for glycol natural gas dehydrators. Finally, the Commission made typographical, grammatical, and formatting revisions, as necessary.

N. February 23, 2014 (Sections II., XVII., and XVIII.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 CFR Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result and further addresses the volatile organic compound ("VOC"), an ozone precursor, and other hydrocarbon emissions, such as methane, from the oil and gas sector.

The Commission supports the EPA's development of NSPS OOOO and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. First, the Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"); it is likely that EPA will lower the ozone NAAQS in the near future, potentially expanding Colorado's nonattainment area; and Division air monitors and other sampling indicate elevated levels of oil and gas related air emissions in oil and gas development areas. Second, Colorado has seen substantial growth of oil and gas development in recent years, which is a significant source of VOC emissions, and expects that growth to continue in the foreseeable future. In particular, oil and gas storage tanks contribute significantly to the VOC emissions from oil and gas development. Further, oil and gas operations also emit methane, a negligibly reactive ozone precursor and potent greenhouse gas. Third, oil and gas operators have had difficulty meeting the current 95% control requirements in Regulation Number 7 established for condensate tanks in 2004 and 2006 due to "flash" emissions. Fourth, improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs and methane in a cost-effective manner. These technologies and practices include, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras).

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both SIP and state-only requirements. During the rulemaking process, various parties provided extensive evidence concerning whether the proposed revisions, in particular the STEM and LDAR requirements, should apply either statewide or only in the ozone nonattainment area. Based upon careful consideration of all the evidence provided during the rulemaking, the Commission determined it was appropriate to apply the proposed requirements statewide. Further, in addition to the extensive evidence concerning the benefits of statewide hydrocarbon emission reductions, the Commission believes that the tiered and phased nature of many of the requirements properly focuses on emissions. Under this tiered approach, lower emitting sources such as marginal, stripper, and coal bed methane wells will appropriately be subject to less rigorous and costly requirements. In addition, evidence in the rulemaking record and testimony of industry members supports the conclusion that the rules can be effectively implemented. Accordingly, the Commission concludes that the proposed rules are technologically feasible and cost-effective. Moreover, because these revisions apply on a state-wide, state-only basis, and are not a part of Colorado's SIP, the Commission, the Division, and stakeholders have the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes the technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and natural gas compressor stations. The Commission expands existing oil and gas control requirements and establishes additional monitoring, recordkeeping, and reporting requirements. For example, the revisions increase control requirements and improve capture efficiency requirements for oil and gas storage tanks. The Commission also seeks to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells and wells undergoing maintenance and during liquids unloading events. The Commission also expands control requirements for pneumatic devices and glycol natural gas dehydrators. The Commission believes that this combination of revisions is appropriate to complement the full adoption of NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;
- Amend definitions in Section XVII.A. and XVIII.B.;
- Strengthen good air pollution control practices, require use of auto-igniters, remove the off-ramp for condensate tanks if subject to a NSPS, MACT, or BACT, and remove the leak detection and repair requirements off-ramp for glycol natural gas dehydrators and internal combustion engines if subject to a NSPS, MACT, or BACT in Section XVII.B.;
- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;
- Limit venting and establish a storage tank emissions monitoring system ("STEM"), and associated recordkeeping and reporting requirements in Section XVII.C.;
- Expand glycol natural gas dehydrator control requirements in Section XVII.D.;
- Establish a leak detection and repair program for natural gas compressor stations and well production facilities in Section XVII.F.;

- Establish control measures for oil and gas wells in Section XVII.G.;
- Limit venting during well maintenance and liquids unloading in Section XVII.H.; and
- Expand pneumatic device requirements in Section XVIII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Joint Applicability of NSPS OOOO and Regulation Number 7, Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates some overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with six (6) tons per year ("tpy") of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado's SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. It is the Commission's intent that compliance with Regulation Number 7, Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions from storage vessels under NSPS OOOO. In those limited cases where storage tanks are subject to both NSPS OOOO and Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring. However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy, the equivalent of the NSPS OOOO six (6) tpy VOC on a controlled actual basis. While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary and intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT control requirement to avoid having to comply with Section XVII.

It is also possible for glycol natural gas dehydrators and internal combustion engines to be subject to both federal and Regulation Number 7, Section XVII. leak detection and repair requirements. NESHAP HH and HHH require glycol natural gas dehydrators at major sources of hazardous air pollutants ("HAP") that utilize a closed-vent system to conduct annual visual inspections for leaks and defects that could result in air emissions. NESHAP HH and HHH also require detected leaks and defects be repaired within fifteen days, as long as it is technically feasible to do so without a shutdown. NESHAP HH also requires triethylene glycol ("TEG") natural gas dehydrators located at area sources of HAPs that utilize a closed-vent system to conduct annual visual inspections. However, the revisions to Regulation Number 7 require more frequent inspections of all types of glycol natural gas dehydrators at all facilities, resulting in more emissions reductions than NESHAP HH and HHH. Therefore, the Commission believes joint applicability concerning leak detection and repair requirements is necessary.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC and other hydrocarbon emissions, such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of greater than or equal to one (1) minute during a fifteen (15) minute time period, pursuant to EPA Method 22. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. The regulated community may, alternatively, immediately shut-in the equipment to investigate the cause for smoke and perform repairs. While the presence of visible emissions constitutes a violation of the rules, the Commission recognizes that there may be instances where visible emissions occur notwithstanding the owner or operator's best efforts, such as when an upset or malfunction occurs. Accordingly, the Division should consider the owner or operator's efforts and whether the visible emissions resulted from factors outside the owner or operator's control in determining how to best enforce this requirement.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth below.

"Approved instrument monitoring method" ("AIMM") means the methods and technologies utilized for monitoring storage tanks and components at well production facilities and natural gas compressor stations. The instrument being used for AIMM inspections must be capable of measuring hydrocarbon compounds at the applicable leak definition concentration specified in the revisions, and calibrated as appropriate. See EPA Method 21 at 6.0. In addition, while the definition lists EPA Method 21 and IR cameras, the Commission does not intend to limit industry to only EPA Method 21 and IR cameras as the Division may approve the use of additional monitoring devices and methods.

"Component" excludes compressor seals and open-ended valves and lines, which are defined separately, because they are designed to leak and are better addressed with equipment specific work practices, also included separately. Based on concerns that the requirements for small reciprocating compressors at well production facilities may not be cost-effective, the adopted work practices for reciprocating compressors are limited to reciprocating compressors located at natural gas compressor stations. Nevertheless, there is an issue as to whether compressors at well production facilities are a significant source of emissions. The Commission, therefore, directs the Division to investigate whether reciprocating compressors at well production facilities are a significant source of emissions, and if so, whether there may be appropriate, cost-effective work practices to reduce fugitive emissions from reciprocating compressors at well production facilities. The Commission further directs the Division to brief the Commission on this investigation in March, 2015.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both COGCC and Commission requirements.

“Natural gas compressor stations” are subject to leak detection and repair requirements. This definition is meant to exclude compressors at well production facilities and gas processing plants. This definition is also meant to exclude natural gas compressor stations that are downstream of the natural gas processing plant at this time.

“Normal operation” is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of “malfunction” as set forth in the Common Provision regulations.

“Storage tank,” means a single storage tank or a storage tank battery if the storage tanks are manifolded together. In recent years, it has become more common for multiple storage tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of “storage tank,” the Commission revises the definition of storage tank to specify that a storage tank battery must be manifolded by liquid line, and not just by gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small storage tanks in a battery. The Commission’s definition, and Colorado’s approach to emissions reporting and permitting for storage tanks, differs from EPA’s definition of “storage vessel” and the description of an affected storage vessel facility in NSPS OOOO because EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. The Commission intends to maintain this distinction and, therefore, deletes the previously used definition of “atmospheric condensate storage tank” and creates a new definition of “storage tank” which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

“Well production facilities” are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting). The “owned, operated, or leased” qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. This definition is meant to exclude natural gas compressor stations from “well production facility” and avoid overlapping LDAR requirements. This definition is also meant to exclude natural gas storage wells.

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas operations, including those below control thresholds or even below Regulation Number 3 APEN and permitting thresholds, adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;

- Inspecting and repairing seals on thief hatches, access points, or other openings of storage tanks;

- Initiating timely action to address leaks or unpermitted emissions; and

- Maintaining equipment and the facility in good operating condition.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. The Commission intends these revisions to address venting emissions from storage tank thief hatches, pressure relief valves, or other access points during normal operations. Access points are not limited to points of entry of liquids or gas into the storage tank but include any route from which emissions can escape. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices and that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. The Commission does not intend to increase risk or compromise safety of personnel and equipment. However, inadequate design of a storage tank emissions capture system is not a legitimate reason for venting.

Therefore, the Commission intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to owners or operators, provided that the owners or operators demonstrate that the elements of the malfunction defense have been met. The Commission intends that the burden remain on the owner or operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2. The Commission further recognizes that meeting the no venting requirement may be challenging in some cases, and accordingly has adopted additional provisions requiring owners and operators to develop a STEM plan to help ensure compliance. In some cases, development and implementation of the STEM plan may be an iterative process involving ongoing improvements before continuous compliance with the no venting standard is achieved. With this in the mind, the Division should consider the efforts of owners and operators in developing and implementing their STEM plan as part of the Division's assessment about how best to enforce the no venting requirement.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and natural gas compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered by the owner or operator or the Division inspector pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if a leak is identified and the owner or operator is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the owner or operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners or operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tanks Controls (Section XVII.C.)

EPA established a six (6) tpy VOC threshold on a controlled actual emissions basis for applying storage vessel controls. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for applying reporting, permitting, and control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control equipment may be removed if: (1) the storage tank (including manifolded tanks) emissions fall below the uncontrolled actual six (6) tpy threshold, on a rolling twelve-month basis; and (2) those controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the uncontrolled actual six (6) tpy threshold on a rolling twelve-month basis, air pollution control equipment must be installed within sixty (60) days of discovery of the increase.

The Commission does not intend for the storage tank control, or related, requirements to apply to frac tanks that are located at a well production facility for less than 180 consecutive days.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead be significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used the device must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Audio, Visual, Olfactory ("AVO") and Visual Inspections (Section XVII.C.)

The Commission intends that owners and operators of subject storage tanks (including storage tanks during the first ninety (90) days of production and storage tanks containing only stabilized liquids) conduct applicable AVO and visual inspections for venting or leaking. Visual inspections are in addition to AVO monitoring and require further inspections of the storage tank and associated equipment, such as thief hatches and air pollution control equipment. These inspections are not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO and visual inspection, and indicates the frequency at which inspection is required.

Storage Tank Emission Management System ("STEM") Plan, Monitoring, and Recordkeeping (Section XVII.C.)

Owners and operators of storage tanks with uncontrolled actual emissions equal to or greater than six (6) tpy must develop, certify, and implement a STEM plan designed to ensure compliance with the "without venting" requirement of Section XVII.C.2., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies, monitoring, maintenance, and operational practices to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility to develop STEM plans on an individual basis for each storage tank or for multiple storage tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review. Owners and operators of storage tanks controlled during the first ninety (90) days of production or containing only stabilized liquids are not required to develop and implement a STEM plan. However, owners or operators of such storage tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include, but is not limited to, the following elements:

- A monitoring strategy including, at a minimum, the applicable inspection frequencies and methodologies;

- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training be documented to permit the owner or operator to demonstrate the quality and achievements of the STEM plan;

- The calibration methodology and schedule for emission detection equipment used in the monitoring;

- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;

- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;

- A procedure to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and

- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

In addition to AVO and visual inspections for storage tanks, STEM plans must include AIMM inspections on a frequency schedule that is tied to the uncontrolled actual VOC emissions from the storage tank. The Commission intends that the AIMM inspection satisfy any simultaneous AVO and visual inspection requirement.

The STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of applicable monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Unsafe, Difficult, or Inaccessible to Monitor (Sections XVII.C. and XVII.F.)

The Commission does not intend to require owners or operators to conduct either AVO or AIMM inspections of unsafe, difficult, or inaccessible components or storage tanks and associated equipment. The Commission acknowledges that, in limited circumstances, unsafe to monitor may include unsafe weather or travel conditions. However, in those limited circumstances, the Commission expects the owner or operator to resume monitoring once the weather or travel conditions cease to be unsafe. Importantly, the Commission does not intend to allow owners or operators to delay required monitoring for the entire winter season.

Glycol Natural Gas Dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. This revision requires that all existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of six (6) tpy or greater be controlled with air pollution control equipment achieving at least a 95% reduction. This revision also requires that existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled if the dehydrator is located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations.

The Commission does not intend to apply this proximity requirement to the glycol natural gas dehydrator owner or operator's buildings, where public access to the building is also restricted. Further, because glycol natural gas dehydrators are different and unique sources, a similar proximity requirement for storage tanks is not appropriate at this time as storage tanks are more appropriately addressed based on emission thresholds.

This revision also requires that all new glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled with air pollution control equipment achieving at least 95% reduction. If a combustion device is used, it must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. The leak detection and repair program more broadly targets leaks from components at natural gas compressor stations and well production facilities, even if such facilities do not include storage tanks. In contrast, STEM targets venting from storage tanks. The use of an AIMM as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may have lower emissions and may need additional time to comply. Owners or operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor. Owners or operators also have flexibility in timing the AVO and AIMM inspections to coordinate overlapping AVO and AIMM inspections, as well as inspections of facilities in the same area or on the same inspection frequency. The Commission intends that the AIMM inspection satisfy any simultaneous AVO inspection requirement. However, the Commission expects that owners and operators will also utilize this flexibility to ensure that inspections are appropriately spaced on the frequency schedule (e.g. quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Commission distinguished between new and existing well production facilities by utilizing an October 1, 2014, commenced construction date and created an inspection phase-in schedule for existing facilities.

The Commission also distinguished the emissions thresholds for determining inspection frequencies for well production facilities with storage tanks and well production facilities without storage tanks. For well production facilities with storage tanks, the threshold determining inspection frequency is based on the uncontrolled actual VOC emissions from the highest emitting storage tank. For well production facilities without storage tanks, the threshold determining inspection frequency is based on "facility emissions." The Commission has determined that "facility emissions" means the controlled actual VOC emissions from all permanent equipment, including fugitive emissions calculated using the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates.

The Commission has defined a leak requiring repair in a manner that is dependent on the monitoring methodology. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identify the emission rate. Similarly, while IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in selecting a leak detection methodology.

If EPA Method 21 is utilized, the Commission set the threshold at which component leaks must be repaired at 2,000 parts per million ("ppm") hydrocarbons for existing natural gas compressor stations and

500 ppm for new (constructed after May 1, 2014) natural gas compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is utilized, a leak is any detectable emission not associated with normal equipment operation (e.g. the acceptable level of leaks from a component designed to leak). These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources.

Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO identifies leaks at natural gas processing plants at 500 ppm. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices. Further, the Commission finds that the repair deadlines set forth in Section XVII.F.7. provide flexibility for operational differences, including the potential range of leaks and degrees of repair difficulty that may be encountered.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country.

The Commission expects that owners and operators will remonitor leaks requiring repair with either the approved instrument monitoring method the owner or operator used to identify the leak or any method approved for remonitoring of leaks under EPA Method 21.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in permits existing as of the promulgation date of the revisions. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and owners and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

During the rulemaking, several parties requested more stringent requirements for all oil and gas operations located within 1,320 feet of a building unit or designated outside activity area. Residents living within close proximity to oil and gas operations, particularly those living within 1,320 feet of oil and gas operations, may understandably have heightened concerns regarding potential impacts of emissions from such facilities. It is the Commission’s understanding that some oil and gas owners and operators implement practices beyond what is currently required under state law in order to minimize emissions and otherwise be good neighbors, including conducting increased site inspections. The Commission supports such practices.

Also during the rulemaking, various parties provided extensive evidence concerning the frequency of instrument monitoring method inspections, the timing of leak repair, and the costs and benefits associated with more or less frequent monitoring and repair. The Commission recognizes that additional information would benefit the Commission, Division, industry, and other stakeholders and therefore encourages the Division to work with energy companies, to evaluate the comparative effectiveness of various kinds of instrument based monitoring methods and program designs at a range of types, sizes, and frequencies at well production facilities and natural gas compressor stations.

The Commission also encourages the Division to work with industry and other stakeholders to evaluate emissions from and potential control strategies for downstream natural gas compressor stations and intermittent pneumatic controllers.

Lastly, several parties to the rulemaking requested greater transparency and public access to air quality information associated with oil and gas development. In particular, a coalition of local community organizations requested that owner and operators' annual reports as required by these rules be posted on the Division's website. The Commission believes these reports will provide important information when reviewing the efficacy of the inspection and maintenance program, as well as valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make this information available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. In addition, the Commission requests an annual briefing on these regulations. Such briefing will assist the Commission and interested stakeholders to understand the data and implementation issues relating to this new program, as well as other initiatives covered in this rulemaking. The Commission believes that this information would also be valuable to all parties.

Well Maintenance and Liquids Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well maintenance and well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading emissions are estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008, rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. However, the Commission does not intend to expand the pneumatic device requirements to intermittent pneumatic controllers at this time. Further, while the use of low-bleed pneumatic controllers will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources.

However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying a facility, the Commission is only requiring the use of no-bleed pneumatic controllers at facilities that are connected to the electric grid, using electricity to power equipment, and where technically and economically feasible.

Additional Considerations

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Sections XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) The revisions to Regulation Number 7 address VOC and other hydrocarbon emissions from oil and gas facilities, including storage tanks, glycol natural gas dehydrators, pneumatic controllers, well production facilities, and natural gas compressor stations. In addition to NSPS OOOO, NSPS Kb, and NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks, glycol natural gas dehydrators, leaking components, and pneumatic controllers, and address more hydrocarbon emissions. For example, the Regulation Number 7 revisions address more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to TEG dehydrators. Similarly, the Regulation Number 7 revisions address more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. In addition, the Regulation Number 7 revisions address more component leaks than the major source provisions of NESHAP HH, as well as NSPS KKK, which has a 10,000 ppm leak threshold and only applies at natural gas processing plants.

Compared to NSPS OOOO, the revisions to Regulation Number 7 will apply a low- or no-bleed control requirement to more pneumatic controllers because NSPS OOOO only requires zero bleed pneumatic controllers at natural gas processing plants, while the Regulation Number 7 revisions no-bleed provision applies to all facilities. The revisions to Regulation Number 7 will also require a leak detection and repair program for more oil and gas operations because NSPS OOOO only requires leak detection and repair for natural gas processing plants, AVO inspections for storage vessels with controlled actual emissions greater than six (6) tpy, and annual visual inspections for leaks for subject centrifugal compressors. In contrast, the revisions to Regulation Number 7 require a leak detection and repair program for all components at all well production facilities and natural gas compressor stations. Further, the revisions to Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to further address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.

(II) NSPS OOOO, and the other federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, which may be used to avoid NSPS OOOO applicability.

(III) Other federal requirements do not specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. Specifically, during the development of NSPS OOOO, Colorado submitted comments regarding, among other things, concerns with the storage vessel definition, storage vessel control requirements, and lack of leak detection and repair requirements. Colorado's concerns were not fully addressed in NSPS OOOO, therefore, the Commission believes the revisions to Regulation Number 7 are necessary to: (a) address hydrocarbon emissions in a more comprehensive manner; (b) address oil and gas operations and equipment at lower thresholds than NSPS OOOO thresholds, yet that collectively have significant VOC and other hydrocarbon emissions in Colorado; (c) address venting of emissions from storage tanks at oil and gas facilities caused primarily by over pressurization; and (d) address leaks of fugitive hydrocarbon emissions, particularly from well production facilities and natural gas compressor stations.

(IV) Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for costlier retrofits at a later date. Colorado may be required to comply with a lower ozone NAAQS in the near future and the Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS, while other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. The revised rules are proactive and intended to reduce ozone levels now by utilizing controls and techniques already being used by some Colorado oil and gas operators, or that are readily available.

(V) Adoption of these revisions at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.

(VI) The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while utilizing many of the technologies and practices set forth in these revisions.

(VII) The revisions to Regulation Number 7 establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector. Furthermore, the application of the Regulation Number 7 revisions to oil and gas owners and operators regardless of location in the ozone nonattainment or attainment areas is equitable because the nonattainment area is not the only area in Colorado with ozone issues. For example, the Rangely monitor in western Colorado shows violations of the 2008 ozone standard and existing modeling shows that either the nonattainment area has increased its contribution to background ozone or ozone concentrations in the attainment area flowing into the nonattainment area have increased. Notably, the Division's inventory shows that the oil and gas industry contributes more than 50% of the VOC emissions outside the nonattainment area. This monitoring, modeling, and inventory data, considered with the likelihood of a lower ozone NAAQS and the expected growth of the oil and gas sector state-wide, supports the application of the Regulation Number 7 revisions to oil and gas sources in both the nonattainment and attainment areas.

(VIII) The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions. In reductions must come from other operations or sectors at this time, the cost effectiveness would decrease because these revisions reduce emissions from the most significant contributors to VOC emissions and costs will be higher for less emissions reductions from less significant contributors.

(IX) The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO (e.g. storage vessels emitting 120 tpy uncontrolled actual VOC emissions) or NESHAP HH and HHH (e.g. glycol natural gas dehydrators at major sources of HAPs and TEG glycol natural gas dehydrators at area sources of HAPs) and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to ensure compliance with and document the effectiveness of the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the requirements for auto-igniters and pneumatic controllers. In addition, oil and gas owners and operators are already using many of the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides owners and operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the revisions provide for Division approved extensions to compliance.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The reductions of other hydrocarbon emissions, such as methane, add to the already cost-effective and appropriate emission reduction requirements.

(XII) Alternative rules, such as the alternative proposals provided by several parties during the rulemaking process, requiring differing or additional controls for oil and gas facilities could

also provide reductions in hydrocarbon emissions. The Commission could have adopted some or all of the proposed revisions or proposed alternatives. However, the proposed revisions to Regulation Number 7 were developed during a lengthy stakeholder process and provided a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado's economy and the nation's energy independence. The alternative proposals provided during the rulemaking process were primarily either more or less stringent versions of the proposed revisions, further illustrating the balanced approach of the proposed revisions. Furthermore, a no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursor pollutants, necessary for reducing ozone in Colorado.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of hydrocarbon emissions.

(III) Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(VI) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

O. November 17, 2016 (Sections I., X., XII., XIII., XVI., XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data. Due to the reclassification, additional planning requirements were triggered, including the requirement to submit revisions to the State Implementation Plan ("SIP") that address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA Section 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)).

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive state implementation plan that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 25-7-109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions. Separately, EPA had expressed concerns with approving previous Regulation Number 7 revisions related to oil and gas control requirements and submitted in 2009 and 2013 for inclusion in Colorado's ozone SIP.

In response to these related but separate issues, the Commission revised Regulation Number 7 to strengthen Colorado's ozone SIP; and include reasonably available control technology ("RACT") requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of volatile organic compounds ("VOC") or nitrogen oxides ("NOx"). More specifically, the Commission revised the applicability of Regulation Number 7 in Section I.A.1.; included the existing combustion device auto-igniter requirements in Section XII.C.1.e. and XII.E.2. in Colorado's ozone SIP; included existing audio, visual, olfactory ("AVO") storage tank inspection requirements for condensate storage tanks in Colorado's ozone SIP in Section XII.E.4.e.; added requirements for lithographic and letterpress printing in Section XIII.B.; added requirements for industrial cleaning solvents in Section X.E.; and added requirements for major sources in Sections XVI. and XIX.

Apart from the Moderate nonattainment area ozone SIP, the Commission revised Regulation Number 7 to address EPA's monitoring, recordkeeping, reporting, and other concerns with previously submitted Regulation Number 7 revisions. The Commission updated federal rule references for natural gas processing plants in Section XII.G.1.; renumbered the current Sections XII.G.5. and XII.G.6. under Section XII.I.; added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in Sections XII.H.5. and XII.H.6.; and addressed other EPA concerns in Sections XII.C.1.c., XII.C.1.d., XII.C.2.a.(ii)(B), XII.E.3., and XII.H.4.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Ozone reclassification SIP revisions

8-hour ozone control area

All provisions of Regulation Number 7 currently apply to the Denver 1-hour ozone nonattainment and attainment/maintenance area. The 1-hour ozone area does not include all of Adams and Arapahoe counties or the portions of Larimer and Weld counties included in the 8-hour ozone control hour. Therefore, to ensure that all sources in the 8-hour ozone nonattainment area are subject to applicable RACT requirements in Regulation Number 7 on a federally enforceable basis, the Commission revised Regulation Number 7, Section I.A.1.a. to state that all provisions apply to both the 1-hour and 8-hour ozone areas. The Commission intends that provisions clearly marked "state-only" continue to be enforceable only on a state-only basis, and are not included in the SIP.

Auto-igniter and storage tank AVO

Regulation Number 7, Section XII.C.1.e. includes auto-igniter requirements for combustion devices used to control emissions of VOCs. Pursuant to Section XII.E., the auto-igniter must be inspected weekly to ensure it is properly functioning. Prior to the revision, these requirements were "state-only". The Commission revised these provisions to include the auto-igniter installation, operation, and monitoring requirements in the SIP.

Regulation Number 7, Section XII.E. includes requirements for owners or operators of condensate storage tanks subject to Section XII.D. to inspect combustion devices, vapor recovery units, control devices, and thief hatches. These are SIP requirements. Regulation Number 7, Section XVII.C.1.d. also requires of owners or operators of storage tanks subject to Section XVII. to conduct AVO and additional visual inspection at the same frequency as liquids load-out. The requirements of Section XVI.C.1.d. are enforceable on a "state-only" basis. The Commission revised Section XII. to include in the SIP, the requirement that owners and operators conduct AVO inspections of condensate storage tanks with uncontrolled actual VOC emissions of 6 tons per year ("tpy") or greater, making them federally enforceable.

Lithographic and letterpress printing RACT

Pursuant to CAA Section 182(b), Colorado's ozone SIP must provide for implementation of RACT at sources of VOC for which EPA has issued a Control Technique Guideline ("CTG"). EPA's Offset Lithographic Printing and Letterpress Printing CTG ("Printing CTG") addresses VOC emissions from the use of fountain solutions, cleaning materials, and inks at lithographic and letterpress printing operations. The Printing CTG recommends controlling VOC emissions from heatset printing with dryer emissions of at least 25 tpy of VOC from heatset inks with add-on control technology. The Printing CTG recommends controlling VOC emissions from cleaning materials and fountain solutions at printing operations with facility emissions equal to or greater than 15 lb/day by limiting the VOC content of cleaning materials and fountain solutions. The Printing CTG also recommends work practices for printing operations with facility emissions equal to or greater than 15 lb/day.

Colorado has sources in the ozone nonattainment area in this CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included these requirements in Section XIII.B. as RACT for these sources. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy. This is roughly equivalent to the 15lbs/day threshold recommended in the Printing CTG. Based on the Printing CTG, the Commission added language to Section XIII.B.1.b. clarifying that fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses are considered part of the printing process and are not subject to the surface coating or industrial cleaning solvent requirements in Regulation Number 7. With respect to the compliance threshold for Section XIII.B., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. Only emissions from the printing operation and cleaning thereof should be considered in determining if emissions exceed 3 tpy.

The Commission included additional work practices, a VOC content limit for inks and monitoring, recordkeeping and performance testing requirements that are not specified in the Printing CTG but are intended to correspond to current permit requirements and ensure the enforceability of the requirements. With respect to the work practice requirements contained in Section XIII.B.1.c., the Commission applied these requirements to all lithographic and letterpress printing operations, regardless of potential or actual VOC emissions, because they are minimally burdensome, good housekeeping requirements that reduce emissions and correspond to current permit requirements. With respect to the VOC content limit for inks, the Commission included a 40% limit for heatset web offset and heatset web letterpress printing operations that require higher VOC content ink, and a 30% limit for all other lithographic and letterpress printing operations that are commonly already using low VOC inks. Compliance with the VOC content requirement for inks is demonstrated using a weighted average which takes into account the amount of the different inks used and their respective VOC contents.

For consistency with the Printing CTG, cleaning solutions are subject to VOC content or vapor pressure requirements, except that sources using less than 110 gallons of non-compliant cleaning materials per calendar year are exempt from the VOC content or vapor pressure requirements. Larger heatset printing operations, whose maximum allowable emissions before controls from petroleum inks are 25 tpy VOC or more, are subject to a control requirement (not capture and control). Printing operations' emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Industrial cleaning solvents RACT

EPA's CTG for Industrial Cleaning Solvent ("Cleaning Solvent CTG") addresses solvent use in cleaning operations such as spray gun cleaning, spray booth cleaning, large manufactured components cleaning, parts cleaning, equipment cleaning, line cleaning, floor cleaning, tank cleaning, and small manufactured components cleaning. The Cleaning Solvent CTG applies to facilities with VOC emissions from the use of industrial cleaning solvents equal to or greater than 15 lb/day of VOC. The Cleaning Solvent CTG recommends a cleaning solvent VOC content limit and work practices.

Colorado has sources in the ozone nonattainment area in this Cleaning Solvent CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included requirements in Section X.E. as RACT. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy on a calendar basis. This is roughly equivalent to the 15lbs/day threshold recommended in the CTG. The Commission intended for the term "industrial cleaning solvent operation" to be broad and apply to a wide range of work areas where manufacturing or repair activities are performed, but not to residential or janitorial cleaning.

The Commission included language to clarify that VOC emissions that are exempt from the industrial cleaning solvent rule do not count toward this 3 tpy threshold. Therefore, when determining whether a facility meets the applicability threshold of 3 tpy, a source should include facility-wide emissions from all industrial cleaning solvent operations and subtract those emissions that are exempt under Section X.E.4. In adopting the VOC content limit in Section X.E.1.a. and the vapor pressure limit in Section X.E.1.b., the Commission intended for these to be straight, as-applied limits for all industrial cleaning solvents used and not a weighted average. Additionally, in adopting the 90% control efficiency compliance option in Section X.E.1.c., the Commission did not intend for this control efficiency to include capture efficiency. The Commission acknowledged that capture efficiency may be lower than the control efficiency because industrial cleaning solvents are often used over large industrial complexes and result in relatively small VOC emissions.

With respect to the compliance threshold for Section X., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. The Commission also included monitoring, recordkeeping and reporting requirements that are not specified in the Cleaning Solvent CTG but are intended to align with current permit recordkeeping requirements and ensure the enforceability of the requirements.

The Commission included language in Section X.E.4.a.(ii) providing that industrial cleaning solvent operations subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT are exempt from the requirements of Section X. This provision was included so as not to subject sources to overlapping, duplicative, or contradictory RACT requirements. Therefore, if an industrial cleaning solvent operation is subject to a work practice or emission control requirement contained in another, federally approved section of Regulation Number 7, including but not limited to Sections IX. (surface coating operations), X.B. through X.D. (solvent cold-cleaners, non-conveyorized degreasers, and conveyorized degreasers), and XIII. (graphic arts and printing), then that operation would not also be subject to the requirements of Section X.E.4. However, this provision is not intended to exempt an industrial cleaning solvent operation from Section X. when the operation is subject to the restriction on disposal of VOCs by evaporation or spillage contained in to Section V.A. (and RACT is determined to be nothing). Therefore, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be nothing, the operator must comply with Section X. Conversely, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be a work practice or emission control requirement, then the operation is exempt from Section X. Lastly, the Commission adopted additional exemptions recommended in the Cleaning Solvent CTG in Section X.E.4.b. as well as an alternative compliance option for area source aerospace facilities in Section X.E.4.c. due to the unique solvent cleaning needs of those source categories.

Control requirements do not account for capture and control. General industrial solvent use emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Major VOC and NOx source RACT

Colorado has major sources of VOC or NOx (sources that emit or have the potential to emit greater than 100 tpy) in the DMNFR. While many of these sources are currently subject to regulatory RACT requirements in Colorado's SIP, some of the sources or emissions points are subject to RACT requirements in federally enforceable permits or New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado is submitting a SIP revision to include provisions requiring the implementation of RACT for major sources of NOx or VOC in the DMNFR. Therefore, the Commission included a work practice for combustion equipment at major sources of NOx emissions in Section XVI., a requirement for specific major sources to provide RACT analyses to the Division in Section XIX.B., and incorporated by reference applicable requirements of a NSPS or NESHAP in Sections XIX.C-G.

Specifically, the Commission adopted a combustion process adjustment requirement for individual pieces of combustion equipment at major sources of NOx in Section XVI.D., expanding on work practices currently required in federal NESHAP. The combustion process adjustment was modeled after NESHAP DDDDD, which applies to boilers and process heaters at major HAP sources, and NESHAP ZZZZ, which establishes various requirements for stationary reciprocating internal combustion engines. Section XVI.D. is intended to apply to some equipment that is not subject to work practices under the NESHAPs (e.g., natural gas fired boilers at area sources of HAPs) that have uncontrolled actual NOx emissions (annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice without consideration of any emission control equipment or procedures) equal to or greater than 5 tpy. The Commission intended major NOx sources to use the most recent APEN submitted to the Division as of January 1, 2017, to determine whether the combustion equipment is subject to the requirement to conduct an initial combustion process adjustment by April 1, 2017, or alternatively document reliance on an allowed, alternative adjustment. Subsequent determinations will be based on the most recent APEN submitted to the Division as of the year the combustion equipment may be subject to the combustion process adjustment requirements (e.g., most recent APEN submitted to the Division as of January 1, 2018, to determine whether a combustion process adjustment is required in 2018). In addition to the specific adjustment requirements, the Commission intended owners and operators to operate and maintain subject equipment consistent with manufacturer specifications or best combustion engineering practices.

The Commission also established RACT requirements for emission points at major sources of VOC or NOx in the DMNFR area in Section XIX. In Section XIX.A., the Commission listed all major sources of VOC or NOx at the time of adoption of the Moderate nonattainment area RACT SIP. The Commission determined that not all emission points above permitting thresholds at major sources were necessarily subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Colorado's Regional Haze SIP. Therefore, in Sections XIX.C. through XIX.G., the Commission incorporated federal NSPS or NESHAP requirements, including monitoring, recordkeeping, and reporting requirements, for some sources to further satisfy Colorado's RACT obligation for Colorado's major VOC and NOx sources. The Commission acknowledges concerns over potential EPA revisions to NSPS and NESHAP incorporated by reference in Sections XIX.C. through XIX.G., and intended that sources comply with applicable requirements in the most up-to-date version of the federal rule, or alternative requirements approved by EPA in accordance with the NSPS or NESHAP. The Commission also directs the Division to initiate efforts to update the incorporation by reference in the SIP, as necessary and with all due diligence. Sources identified in Section XIX.A. but not specifically included in Sections XIX.B. through XIX.G., were determined to be subject to other, existing regulatory RACT requirements in Colorado's SIP (see the Moderate ozone SIP revision, RACT Chapter 6 and the Technical Support Document for Reasonably Available Control Technology for Major Sources for additional detail). Concerning major sources or source emission points not subject to other, existing regulatory RACT requirements in Colorado's SIP or specified in Sections XIX.C. through XIX.G., the Commission required owners or operators to submit RACT analyses for the facility or specific emission points to the Division by December 31, 2017. The RACT analyses should identify potential options to reduce NOx and/or VOC emissions from the facility or emission point(s), propose RACT for that facility or point, propose associated monitoring, propose a schedule for implementation, and include economic and technical information showing why the RACT proposal is RACT for the particular facility or point. These RACT analyses are not to be limited by a January 1, 2017, implementation date.

CoorsTek submitted a permit application to limit permitted emissions of VOC below 100 tpy. Metro Wastewater Reclamation District submitted an application for minor modification to its Title V permit to correct inconsistencies and remove obsolete limits, which lowered the combined Metro Wastewater/Suez Denver Metro permitted NOx emission limit below 100 tpy. Consequently, the Commission determined that the facilities no longer met the definition of a major source, and therefore were not included in Section XIX. Should either source fail to obtain such federally enforceable permits by July 1, 2018, the Commission directs the Division, with all due diligence, to initiate efforts to establish RACT requirements for that source in Colorado's ozone SIP.

Current SIP review

In 2009, the Commission submitted revisions to Regulation Number 7, Section XII. to EPA related to the 1997 ozone NAAQS attainment plan. In 2011, EPA approved the attainment demonstration but disapproved portions of the Regulation Number 7 revisions. In 2013, the Commission submitted revisions to Regulation 7, Section XII. to EPA to address EPA's disapproval. During the review of the 2013 submittal, EPA noted additional concerns with the monitoring, recordkeeping, and reporting requirements for natural gas processing plants and glycol natural gas dehydrators, as well as other concerns unrelated to the attainment demonstration for the SIP revision required following the reclassification of the DMNFR area to Moderate.

Natural gas processing plants

Regulation Number 7, Section XII.G.1. identifies a leak detection and repair ("LDAR") program applicable to natural gas processing plants. This "LDAR program" includes all applicable requirements in NSPS KKK. EPA has promulgated new LDAR programs for natural gas processing plants in NSPS OOOO and NSPS OOOOa. Therefore, the Commission updated references to applicable federal NSPS (i.e., NSPS OOOO and NSPS OOOOa) monitoring, recordkeeping, and reporting requirements for natural gas processing plants in the SIP.

Glycol natural gas dehydrators

Regulation Number 7, Section XII.H. already includes a 90% control requirement for glycol natural gas dehydrators. This is a SIP requirement. During the review of the 2013 submittal, EPA noted practical enforceability concerns with the monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators. Therefore, the Commission added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in the SIP to address EPA's concerns with ensuring compliance with the control requirement. The Commission based these requirements off of the Division's glycol natural gas dehydrator Operation and Maintenance Plan template to align the Section XII.H. monitoring, recordkeeping, and reporting requirements with the Operation and Maintenance Plan template, where possible. For any glycol dehydration system monitoring, recordkeeping and reporting requirement adopted for inclusion in the SIP during this hearing that conflicts with a similar provision in a Division approved Operation and Maintenance Plan, the Commission intends that sources only have to comply with the provision adopted for inclusion in the SIP and not the competing requirement in the approved Operation and Maintenance Plan. Further, the Commission directs the Division to work with industry to revise the Division's glycol dehydration systems Operating and Maintenance Plan template to remove requirements that are duplicative of the Section XII.H. monitoring, recordkeeping, and reporting requirements, to alleviate competing requirements with Section XII.H., as necessary.

EPA requested revisions

EPA also noted concerns with other previously submitted provisions in Section XII. EPA requested minor changes to Section XII.C.1.c., and a reversion to previously approved SIP language in Sections XII.C.1.d. and XIII.E.3.a. to address concerns with discretionary language. In response, the Commission revised Section XII.C.1.c. and reverted to previously approved SIP language in Sections XII.C.1.d. and XII.E.3.a., as requested by EPA.

Incorporation by Reference in Section XIX

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Section XIX.C through H by reference.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. The Commission also adopted revisions to Regulation Number 7 to address EPA concerns that are unrelated to the reclassification to Moderate. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address combustion device auto-igniters, condensate storage tank inspections, and glycol natural gas dehydrators at oil and gas facilities and equipment leaks at natural gas processing plants. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks and glycol natural gas dehydrators. For example, Regulation Number 7 addresses more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to tri ethylene glycol ("TEG") dehydrators. The Commission revised Regulation Number 7 to include glycol natural gas dehydrator monitoring, recordkeeping, and reporting requirements to ensure compliance with the current 90% system-wide control requirement in Section XII.D. Similarly, Regulation Number 7 addresses more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. Regulation Number 7 also addresses a broader set of storage tanks than NSPS OOOO and NSPS OOOOa, which address only those storage tanks with emissions greater than 6 tpy controlled actual emissions (i.e., 120 tpy uncontrolled actual emissions) and do not require auto-igniters on combustion devices. The Commission revised Regulation Number 7 to include the auto-igniter and condensate storage tank AVO inspections in Colorado's SIP to strengthen Colorado's SIP and support Colorado's 2017 emissions inventory. In addition, Regulation Number 7 addresses more equipment leaks at natural gas processing plants than NSPS KKK, which only applies to natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. The Commission revised Regulation Number 7 to reference the more recent equipment leak detection and repair requirements in NSPS OOOO and NSPS OOOOa.

The revisions to Regulation Number 7 also address RACT requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of VOC and NOx in Colorado's ozone nonattainment area. EPA published CTGs for lithographic and letterpress printing and industrial cleaning solvents in 2006. The Commission revised Regulation Number 7 to include regulatory RACT requirements for these VOC source categories. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission revised Regulation Number 7, Sections XVI. and XIX. to include source specific regulatory RACT requirements and a combustion process adjustment for combustion equipment at major sources of NOx. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with a lower ozone NAAQS in the near future. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Section XII. strengthen Colorado's SIP, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7 Sections X. and XIII. recognize products and practices currently utilized by printing and industrial cleaning solvent operations. The revisions to Regulation Number 7 Sections XVI. and XIX. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Section XII. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7 Sections X., XIII., and XVI. similarly establish the categorical RACT requirements for similarly situated and sized sources. Where a source is not subject to a categorical RACT requirement, RACT is, by its nature, determined on a case-by-case basis.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for auto-igniters, condensate storage tank inspections, and equipment leaks at natural gas processing plants. Other revisions reflect changes in industry practice and market forces, such as the VOC content of printing materials and cleaning solvents. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate Nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

(III) Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

P. November 16, 2017 Revisions to Section II., XII., Section XVII., and Section XVIII.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

Basis

On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate nonattainment area, Colorado must revise its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guideline ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a nonattainment area's attainment date. EPA finalized the Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado must further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado has similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions are not currently in Colorado's Ozone SIP. Therefore, the Commission is adopting RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP (Sections XII. and XVIII.). In order to make additional progress towards attainment of the NAAQS, the Commission is also adopting State Only revisions to require owners or operators of natural gas-driven pneumatic controllers in the DMNFR area to inspect and maintain pneumatic controllers.

Further, the Commission is making clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

Specific Statutory Authority

Section 25-7-105(1) of the Act directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of the Act. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program.

Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides the Commission broad authority to regulate hydrocarbons.

Purpose

As discussed above, Colorado must adopt RACT into its Ozone SIP for sources covered by the Oil and Gas CTG. While the Oil and Gas CTG recommends presumptive RACT, it does allow states the flexibility to determine what constitutes RACT for the state's covered sources. Further, while EPA's Oil and Gas CTG implementation memorandum provides guidance that the emission controls determined by the state to be RACT for the sources covered by the Oil and Gas CTG must be implemented as soon as practicable but in no case later than January 1, 2021, states also have the flexibility to determine the appropriate implementation timeframe for the sources within the state's ozone nonattainment area. The Commission determined that some of Colorado's existing regulations (*i.e.,* the "system-wide" control program for condensate tanks in Section XII.D.2.) achieve greater emission reductions than the RACT recommended by the Oil and Gas CTG. The Commission determined that some sources covered by the Oil and Gas CTG were not addressed in existing regulations (*i.e.,* pneumatic pumps).

The Commission also determined that some sources addressed in the Oil and Gas CTG (*i.e.,* components at well production facilities and natural gas compressor stations, compressors, pneumatic controllers) are already subject to existing regulations that were not yet part of Colorado's Ozone SIP. The Commission adopted many of these rules in 2014, and intends to preserve the substance of these rules, where possible, in moving them into the Ozone SIP, while making a few adjustments and improvements in response to recommendations in the Oil and Gas CTG. The Commission also adopted correlating revisions to the applicability provisions of Sections II. and XII.

The Commission relied on existing regulations in the Ozone SIP for RACT for condensate storage tank controls to satisfy Colorado's obligation to address storage vessels under the Oil and Gas CTG. The Commission adopted requirements for pneumatic pumps in Section XII. to address recommendations in the Oil and Gas CTG. The Commission revised the existing SIP requirements in Section XII.G. for equipment leaks at natural gas processing plants to address recommendations in the Oil and Gas CTG. The Commission duplicated into the Ozone SIP from Section XVII. provisions for compressors and leak detection and repair ("LDAR") for components at well production facilities and natural gas compressor stations. The Commission adjusted these LDAR requirements to address recommendations in the Oil and Gas CTG, along with updates to the recordkeeping and reporting requirements. Corresponding revisions to the LDAR program in Section XVII. are made on a State Only basis. The Commission also revised Section XVIII. to include existing State Only requirements for continuous bleed, natural gas-driven pneumatic controllers in the Ozone SIP and specify that continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants maintain a natural gas bleed rate of zero scfh.

The Commission adopted State Only provisions for the inspection and maintenance of natural gas-driven pneumatic controllers in Section XVIII.

The Commission also made clarifying revisions and corrected typographical, grammatical, and formatting errors found within the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Oil and Gas CTG, generally

The Oil and Gas CTG provides recommendations for states to consider in determining RACT for certain oil and natural gas industry emission sources. EPA included storage vessels, pneumatic controllers, pneumatic pumps, compressors, equipment leaks, and fugitive emissions in the Oil and Gas CTG because EPA determined that these sources are significant sources of VOC emissions. EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." States may implement approaches that differ from the recommendations in the Oil and Gas CTG so long as they are consistent with the CAA, EPA's implementing regulations, and policies on interpreting RACT.

Applicability to hydrocarbons (Section II.B.)

Section II.B. currently exempts negligibly reactive volatile organic compounds, such as methane and ethane, from requirements of the SIP, while making hydrocarbon emissions, including methane and ethane, subject to State Only regulation under Sections XVII. and XVIII. Section XVII. sets a threshold for leaks requiring repair that is based on the concentration of hydrocarbons, as determined using EPA Method 21. Section XII.L. applies the same EPA Method 21 hydrocarbon threshold for leaks requiring repair. The Commission revised Section II.B. to clarify that the Section XII.L. hydrocarbon threshold and Section XVIII. natural gas emission standards serve only as VOC indicators and the SIP does not regulate hydrocarbon emissions.

The continuous bleed, natural gas-driven pneumatic controller requirements in Section XVIII. reduce natural gas emissions, which consists of other pollutants in addition to VOCs. Despite the presence of other constituents, natural gas is principally methane and the Commission intends to regulate emissions of natural gas as hydrocarbons, including methane and ethane, on a State Only basis as described in Sections II.B. and XVIII. The Oil and Gas CTG also utilizes a natural gas bleed rate standard for continuous bleed pneumatic controllers and the Oil and Gas CTG LDAR program employs a methane-based threshold for EPA Method 21 leak detection. Therefore, these revisions are consistent with the Oil and Gas CTG and the CAA.

While the revisions to Sections XII. and XVIII. to include provisions in Colorado's Ozone SIP are limited to the DMNFR, the Commission acknowledges the importance of reducing hydrocarbon emissions from the oil and gas sector (*i.e.*, upstream, midstream, and transmission) statewide. Therefore, without prescribing any particular outcome, the Commission directs the Division to initiate and lead a stakeholder process over the 2018-2019 timeframe to evaluate potential areas for cost-effective hydrocarbon emission reductions. Stakeholders will nominate topics for evaluation, which may include, but are not limited to, the frequency of LDAR inspections, transmission segment compressor emissions, natural gas-driven and zero emission pneumatic controllers outside the DMNFR (to be informed by the pneumatic study and inspection program), and potential expansion of the requirements adopted in the DMNFR as part of this rulemaking. The Division will brief the Commission on the stakeholder process in January 2019 and present recommendations for any new proposals for emission reductions by no later than January 2020. The Commission intends that one representative of industry, local government, and the environmental community each will have the opportunity to speak during the briefings.

Applicability of Section XII. (Section XII.A.)

The Commission is clarifying the applicability of Section XII. Historically, Section XII. has applied to operations that involve the collection, storage, or handling of condensate in the DMNFR. While this remains the case, the requirements in Section XII.J. for compressors, Section XII.K. for pneumatic pumps, and Section XII.L. for components at well production facilities and natural gas compressor stations also apply to those facilities and equipment collecting, storing, or handling other hydrocarbon liquids.

Section XII.A.5. further provides that subject well production facilities are those with uncontrolled actual VOC emissions greater than or equal to one ton per year ("tpy"). This applicability threshold addresses the Oil and Gas CTG's recommended barrels of oil equivalent ("BOE") exemption. EPA crafted the BOE exemption believing that well production facilities with an average production less than 15 BOE per well per day were inherently low emitting facilities. EPA later determined that information submitted on the draft CTG and proposed NSPS OOOOa did not support this conclusion. Therefore, in addition to the complications concerning tracking BOE, the Commission chose to rely upon an uncontrolled actual VOC tpy threshold for well production facility applicability. The use of a tpy threshold is also consistent with Colorado's current air pollutant reporting and permitting thresholds.

Further, Section XII.A. historically exempted from the requirements of Section XII. those operations reflecting a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the DMNFR area. That exemption continues to apply to Sections XII.B. through XII.I., but is not extended to Sections XII.J., XII.K., and XII.L.

Definitions (Sections XII.B. and XVII.A.)

The Commission is adopting definitions into Section XII.B., most of which are consistent with the existing definitions of Section XVII.

In the definition of "component", the Commission is clarifying both in Section XII.B. and in Section XVII.A., that thief hatches and other openings on storage tanks are included in the definition as a pressure relief device. This revision clarifies that leaks can occur from the thief hatch (*e.g.*, faulty or dirty seals) that are different than vented emissions under the standard in Section XVII.C.2.a., and that such leaks are subject to the LDAR program. The Commission anticipates that emissions from storage tanks identified as leaks requiring repair through the LDAR inspections under Sections XII.L. or XVIII.F. will be recorded and reported as leaks starting in 2018 for the 2019 annual report.

The Commission is adding a definition of "custody transfer" that applies to custody transfers of both natural gas and oil products. The Commission is also adding definitions for "natural gas driven diaphragm pump" and "natural gas processing plant" that correspond to federal definitions.

Operate without venting clarification (Section XVII.C.2.a.)

The Commission is providing additional detail concerning provisions adopted in 2014 that established an "operate without venting" standard for storage tanks. In response to industry concern that Section XVII. does not sufficiently define "venting" or delineate "venting" from "leaking," the Commission is adopting provisions clarifying which emissions from storage tanks are considered "venting". Section XVII.F. defines "leaking" in terms of infra-red camera or EPA Method 21 inspections of components. While storage tanks may also have leaks, as the Commission recognizes by including thief hatches or other openings on storage tanks in the definition of component, the Commission now further clarifies the "venting" standard by specifying that "venting" is emissions that are primarily the result of over-pressurization or that are from an open or visibly unseated pressure relief device (*e.g.*, thief hatch). The Commission intends that "visibly unseated" means visible from the outside of the pressure relief device and does not require an owner or operator to open a pressure relief device to determine if the seal is proper. The Commission also authorizes the Division to request a demonstration from the owner or operator that "venting" emissions observed by the Division were not primarily the result of over-pressurization. The Commission intends that such demonstration request allow an owner or operator to provide case specific information or other sufficient details that the design, operation, and maintenance of the facility is adequate to prevent over-pressurization. In clarifying a difference between "leaking" and "venting," the Commission does not prohibit component leaks, per se, so long as leaks are repaired under the applicable repair time frames but does continue to prohibit "venting" from storage tanks.

Ozone season clarification (Sections XII.F.4. and XII.H.6.)

In October 2015, the EPA finalized a revision to the ozone NAAQS. (80 Fed. Reg. 65292 (Oct. 26, 2015)). In publishing its final rule, the EPA revised the length of Colorado's ozone season. Colorado's ozone season is now year-round, rather than the months of May through September. The Commission therefore revised references to "ozone season" in Sections XII.F.4. and XII.H.6. to reflect that the requirements now apply during the months of May to September. There are no substantive changes to the underlying requirements resulting from this revision.

Equipment leaks at natural gas processing plants (Section XII.G.)

The Commission is updating the LDAR program applicable to equipment leaks at natural gas processing plants in the DMNFR by requiring owners or operators to comply with 40 C.F.R. Part 60 (NSPS), Subparts OOOO or OOOOa instead of complying with NSPS Subpart KKK, which is an earlier NSPS and less stringent. Subpart KKK requires sources to implement a NSPS Subpart VV level LDAR program, while Subpart OOOO requires sources to implement a NSPS Subpart VVa level LDAR program. A Subpart VVa level LDAR program is recommended for equipment at natural gas processing plants in the Oil and Gas CTG. The Commission determined that a 2019 implementation date would provide owners and operators of existing natural gas processing plants a reasonable period of time to establish and obtain the necessary resources to transition from Subpart KKK to Subpart OOOO LDAR requirements.

Compressors (Section XII.J.)

The Commission is adopting the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. into new Section XII.J. in order to include the requirements in Colorado's Ozone SIP. The Commission is expanding the existing reciprocating compressor requirements to reciprocating compressors located at natural gas processing plants to address recommendations in the Oil and Gas CTG. Owners or operators of existing reciprocating compressors at natural gas processing plants must begin monitoring the reciprocating compressor hours of operation on January 1, 2018, starting at zero, in relation to the rod packing replacement requirement, conduct the first rod packing replacement prior to January 1, 2021, or route emissions to a process beginning May 1, 2018.

The Commission intends to allow owners or operators the option to reduce VOC emissions by routing centrifugal compressor emissions to a process or control and reciprocating compressor emissions to a process, consistent with the recommendations in the Oil and Gas CTG. With respect to centrifugal compressors, the Oil and Gas CTG and related federal requirements reveal that "process" generally refers to routing emissions via a closed vent system to any enclosed portion of a process unit (*e.g.*, compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Similarly, with respect to reciprocating compressors, routing to a process includes using a rod packing emissions collection system that operates under negative pressure and meets cover and closed vent system requirements. The negative pressure requirement ensures that all emissions are conveyed to the process and avoids inducing back pressure on the rod packing and resultant safety concerns. The Commission recognizes that there may a distinction between air pollution control equipment and process equipment (see e.g., U.S. EPA Letter to Timothy J. Mohin RE: Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment (Nov. 27, 1995)). For example, as noted in the Oil and Gas CTG, vapor recovery units and flow lines that "route emissions to a process" may be considered part of the process and not a control device, however, a related cover and closed vent system, if present, are still subject to applicable requirements. Further, components (as defined in these rules) located within a process or that are part of process equipment are subject to the Section XII.L. LDAR requirements. The Commission intends that owners or operators will follow similar procedures when complying with centrifugal and reciprocating compressor requirements in Section XII.J.

The Commission has adopted an inspection program for compressors, but also intends to provide owners or operators with the alternative of complying with other requirements, including the LDAR program adopted into Section XII.L. While the requirements of the LDAR program would replace the annual visual inspections and EPA Method 21 inspections of the cover and closed vent systems for defects and leaks, owners or operators would still need to conduct monthly inspections of their combustion devices. Compliance with the LDAR program is not limited to the inspection frequency and methods specified therein; owners or operators will also need to maintain records of the inspections and submit reports to the Division, consistent with the requirements of the LDAR program.

The Commission has specified an inspection and repair schedule for compressors, but has recognized that there may be reasons that a system is unsafe or difficult to inspect, or where a repair may not be feasible. Owners or operators will need to maintain records of each cover or closed vent system that is unsafe or difficult to inspect and schedule for inspection when circumstances allow. Similarly, when a repair is infeasible, insofar as it would require a shutdown of the equipment, repair can be delayed until the next scheduled shutdown but must be completed within two years after discovery. The Commission expects owners or operators to attempt to confirm repair before starting up operation after shutdown, to the extent practicable. The Commission also expects that if the repair attempt can be made during an unplanned shutdown, it will be.

The Commission adopts the monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

As an alternative to complying with the control, monitoring, and recordkeeping requirements in Section XII.J., owners or operators may instead comply with centrifugal or reciprocating compressor control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

Natural gas driven diaphragm pumps (Section XII.K.)

The Oil and Gas CTG contains recommendations for RACT for natural gas-driven diaphragm pumps. The Commission has not previously adopted regulations specifically directed at this type of equipment, and does so in Section XII.K.

The Oil and Gas CTG recommends that the pumps located at a natural gas processing plant have zero VOC emissions. The Oil and Gas CTG also recommends that owners or operators of pumps located at well sites route VOC emissions from the pneumatic pump to an onsite control device or process, unless the pneumatic pump operates on fewer than 90 days or an engineering assessment shows that routing the pneumatic pump emissions to a control device or process is technically infeasible. The assessment of technical feasibility may include safety considerations, distance from the control device, pressure losses and differentials in the closed vent system, gas pressure, and the capacity of the control device, among other things. The Commission acknowledges that RACT, by EPA definition, includes both technological and economic feasibility elements. The Commission determined that the cost of routing pneumatic pump emissions to an existing control device or process is reasonable and is, therefore, only providing an exemption from the emission control requirement based on technical infeasibility. However, the Commission does not intend to limit future RACT determinations due to limiting the pneumatic pump infeasibility analysis to technical ability. In addition, the 90-day exemption for pumps was included to address intermittently used or portable pumps. Consistent with the Oil and Gas CTG, the Commission intends that if a pump operates on any period of a calendar day, that day would be included in the calculation for applicability of the 90-day exemption.

The Commission does not expect an owner or operator to install new equipment specifically to route pneumatic pump emissions to a control or process but intends that when an owner or operator subsequently otherwise installs a control device or it becomes technically feasible to route pump emissions to a process, then the owner or operator will capture the emissions from the pneumatic pump and route the emissions to the newly installed control device or feasible process. Routing to a control or process generally refers to routing the emissions through a closed vent system to a vapor recovery unit, combustion device, or enclosed portion of a process where emissions are recycled and/or consumed.

The Commission has applied the same flexibility for pneumatic pumps as it has for compressors; owners or operators may comply with the inspection requirements in Section XII.K. or may follow the LDAR program in Section XII.L. Also similar to compressors, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak or equipment requiring repair so long as repair is completed within two years after discovery. As with compressors, the Commission expects owners or operators to attempt to confirm repair before starting up operation after a shutdown and make an attempt to repair during unscheduled shutdowns, to the extent practicable.

As an alternative to complying with the control, monitoring, recordkeeping, and reporting requirements in Section XII.K., owners or operators may instead comply with pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)

The Oil and Gas CTG recommends LDAR programs at well sites *(i.e.*, well production facilities) and gathering and boosting stations (*i.e.*, natural gas compressor stations), including inspection frequencies, recordkeeping, and reporting. The Commission established Colorado's well production facility and natural gas compressor station LDAR program in 2014 in Section XVII.F., which is not part of the Ozone SIP. In creating a LDAR program in the Ozone SIP, the Commission intends to maintain as much of the current program as feasible. Where the Commission adopted revisions in Section XII.L. that differ from language currently found in the State Only LDAR program, the Commission in most cases made the same or similar revisions to the corresponding provisions in Section XVII.F.

Inspection, repair, and remonitoring

The Oil and Gas CTG recommends LDAR inspections at a minimum quarterly frequency for gathering and boosting stations and a minimum semi-annual frequency for well sites. The Commission is adopting inspection frequencies to address those recommendations in Section XII.L. The Commission is not modifying the LDAR schedules in Section XVII.F. The Commission intends that for those sources required by Section XVII.F. to conduct more frequent LDAR monitoring than specified in Section XII.L., the owner or operator may comply with Sections XII L.1. and XII.L.2. by complying with Sections XVII.F.3. and XVII.F.4. As with the LDAR inspection frequency in Section XVII.F., the Commission expects that owners or operators will ensure that inspections are appropriately spaced on the frequency schedules (*e.g.,* quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Oil and Gas CTG does not recommend a semi-annual LDAR inspection frequency at well sites with a gas to oil ratio less than 300 and which produce, on average, less than or equal to 15 BOE per well per day. The Commission recognizes that a component of RACT is balancing the emission reductions with the cost of the controls, and agrees that there should be a floor below which the recommended minimum frequency does not apply. The Commission determined a threshold of one tpy VOC emissions addresses this balance and the recommendation in the Oil and Gas CTG. Adopting an emissions based threshold maintains consistency with the current Regulation Number 7 applicability program and promotes the clarity and effectiveness of the regulation.

The Commission determined that annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy and semi-annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than six tpy address the Oil and Gas CTG's recommendations.

The Commission understands that the revised inspection frequencies will result in a significant number of new inspections. However, annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy will be less burdensome than semi-annual inspections. The Commission has determined that the emission reductions achieved by this program will improve the ability of the DMNFR area to attain the ozone standard and are cost-effective. While the rule specifies that the new inspection frequencies begin to apply as of June 30, 2018, the rule does not require that the first periodic inspection be completed by June 30, 2018. The Commission also does not require that monitoring be conducted in advance of this date; however, inspections done after January 1, 2018, that are in addition to current required LDAR monitoring frequencies may count towards the first annual or semi-annual inspection, or inspections done in the previous quarter at natural gas compressor stations. The Commission encourages owners or operators to conduct inspections prior to the 2018 summer ozone months to more effectively take advantage of the resulting emission reductions.

To ensure that the Ozone SIP LDAR program in Section XII.L. works with the existing State Only LDAR program in Section XVII.F., the Commission has maintained the same thresholds for identifying leaks that require repair. While the Oil and Gas CTG employs a methane concentration threshold when detected with EPA Method 21, Colorado's LDAR program uses a hydrocarbon concentration threshold. The Commission has also revised Section II. to clarify that Section XII.L. includes the use of hydrocarbons as an indicator of VOC emission reductions.

Concerning the use of non-quantitative instrument monitoring methods, the Commission adopted a quality assurance requirement that owners or operators maintain and operate such devices according to manufacturer recommendations. This requirement corresponds to recommendations in the Oil and Gas CTG concerning the maintenance and operation of OGI uses to detect fugitive emission components. The Commission intends for the Division to work with owners or operator to address any concerns that arise from manufacturer specifications for the maintenance of non-quantitative instrument monitoring methods.

Consistent with the current LDAR program in Section XVII.F., the Commission adopted a requirement to make a first attempt to repair an identified leak within five working (*i.e.,* business) days of discovery. In both Section XII.L. and in Section XVII.F., the Commission has included a requirement that repairs be completed within 30 days unless one of the existing justifications for delay of repair applies. As with compressors and pneumatic pumps, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak requiring repair so long as repair is completed within two years of discovery. The Commission has also maintained the flexibility of the State Only LDAR program in the SIP by giving owners or operators detecting leaks with a non-quantitative method (*e.g.,* IR camera) the ability to quantify the leaks within five working days. If the quantification shows that the leak must be repaired under Section XII.L.5., the deadline to repair runs from the date of discovery, not from the date of quantification.

As it did for Section XVII.F.7.c. in 2014, the Commission has also memorialized its intent, in Section XII.L.5.c., that operators not be subject to enforcement for leaks so long as operators are complying with the LDAR program requirements. However, as it also explained in 2014, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Section XII.C. For example, closing an open thief hatch within five days of an LDAR inspection does not shield an owner or operator from a possible violation of the requirement to minimize emissions to the maximum extent practicable.

Similarly, the Commission does not intend to relieve owners or operators of the obligation, on a State Only basis, to comply with the requirements of Section XVII., including the requirements in Sections XVII.B. and XVII.C.2. to minimize leakage to the extent reasonably practicable and operate without venting, respectively. However, the Commission does not intend these State Only provisions be enforceable under the Ozone SIP.

Recordkeeping and reporting

The Commission has determined that the current requirements did not adequately incentivize owners or operators to make all reasonable good faith efforts to obtain parts necessary to complete repairs. As a result, some leaks continued on delay of repair lists for an unreasonable length of time. Therefore, the Commission has determined that a review and record of such delays by a representative of the owner or operator is necessary for those occasions where unavailable parts have resulted in a delay of repair beyond 30 days.

The Commission expanded the recordkeeping for repair dates to include records of the type of repair method applied. The Commission determined this recordkeeping element aligns with recommendations in the Oil and Gas CTG and will more accurately inform repair activities. The Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of repair to ensure that owners and operators are consistently recording the information required.

The Commission also expanded the requirements for the annual LDAR report to ensure that the data submitted to the Division more accurately represents and summarizes the activities and effectiveness of the LDAR program. The Commission intends that the LDAR reports include the number of inspections, leaks requiring repair, leaking component type, and monitoring method by which the leaks were found – broken out by facility type (*i.e.,* inspection frequency tier of well production facility or natural gas compressor station).

The Commission intends that both the SIP and State Only LDAR reporting requirement can be satisfied by one report. The Commission expects that the first annual report containing the information required by these revisions will be submitted by May 31, 2019 (*i.e.,* no changes are expected to current requirements for the May 31, 2018, annual report representing leak detection and repair activities conducted during 2017).

Alternative approved instrument monitoring method ("AIMM")

The Commission has adopted a process for the review and approval of alternative instrument monitoring methods. The CAA prohibits a state from modifying SIP requirements except through specified CAA processes. EPA interprets this CAA provision to allow EPA approval of SIP provisions that include state authority to approve alternative requirements when the SIP provisions are sufficiently specific, provide for sufficient public process, and are adequately bounded such that EPA can determine, when approving the SIP provision, how the provision will actually be applied and whether there are adverse impacts. (State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction, 80 Fed. Reg. 33917-33918, 33927 (June 12, 2015)) Therefore, the Commission includes an application and review process in the SIP for the potential approval of instrument monitoring methods as alternatives to an infra-red camera or EPA's Method 21. The approval may also include modified recordkeeping and reporting requirements based on the capabilities of the potential alternative instrument monitoring method. This proposed process does not alter the stringency of Colorado's well production facility and natural gas compressor station LDAR program because an alternative AIMM must be capable of reducing emissions through the detection and repair of leaks comparable to the leaks detected and repaired as specified in the SIP to be potentially approvable.

The Commission received comments from stakeholders requesting that the Commission explicitly provide for the ability to employ certain alternatives not equipped with the leak detection capabilities of infra-red cameras or Method 21. These stakeholders emphasized that monitoring technologies are evolving rapidly and new technologies and monitoring programs are being developed that, when used on their own or in conjunction with other methods, may provide the same or better leak detection and repair results, at potentially lower costs. The process outlined in Section XII.L.8. requires an applicant to demonstrate that the proposed alternative monitoring achieves emission reductions that are at least as effective as the leak detection and repair program in Section XII.L. The Commission intends that the rule be flexible enough to allow the Division to consider such alternative monitoring methods or programs, as long as the applicant can demonstrate that the proposed method or program achieves emission reductions that are as effective as other approved technologies or methods. To make this demonstration, an applicant may consider demonstrating that a program of alternative inspection frequencies, pollutants detected, or leak thresholds for repair achieves emission reductions comparable to the inspection frequencies and leaks requiring repair thresholds in Section XII.L., thus the consideration of an alternative leak detection program. The Commission recognizes that current, established approaches or methodologies to evaluate the performance of alternative monitoring technologies and programs as compared to baseline monitoring technologies (infra-red camera, EPA Method 21) do not yet exist. However, such methodologies are being developed.

For example, the Interstate Technology and Regulatory Council (ITRC), in which Colorado participates, is developing, but has not yet published, a guidance document to establish, if possible, a consensus for evaluating and comparing the effectiveness of leak detection technologies. While the criteria for evaluating the effectiveness of an alternative program as compared to the base program is being developed, alternative monitoring method applicants may submit an application for approval of an alternative monitoring method but must be prepared to present a robust and complete evaluation of the technology or program's performance that allows for comparison to the base technologies in the SIP. It is possible the Division may delay consideration and final determination regarding an alternative monitoring method or program application until established comparison criteria are developed or submitted. Taking into account the deliberations of the ITRC process, the Commission expects that the Division will consider complete applications in a timely manner.

The Commission also received comments from stakeholders requesting that the Commission clarify EPA's participation regarding potential alternative monitoring methods. As discussed above, the Commission believes that the process to review and potentially approve alternative monitoring methods is sufficiently constrained such that EPA, when approving the process, can be assured as to what emission reductions any such alternative monitoring will achieve in the context of the Section XII.L. LDAR program. However, the Commission also recognizes EPA's technical knowledge and is requiring the Division to continue to engage with EPA concerning alternative monitoring methods. Specifically, the Division must provide complete applications to EPA early in the review process, which has previously ranged from three to nine months. The Division must also provide EPA six (6) months after approval of an alternative for further EPA review. The Commission believes this process provides sufficient time for meaningful engagement with EPA.

Clarifications

The Commission is clarifying, both in Section XII.L. and Section XVII.F., that all detected emissions are leaks, but that only those leaks above specified thresholds require repair. The Commission did not intend that leaks falling below the specified thresholds would not be considered "leaks," only that those leaks did not require repair in accordance with the prescribed schedules. The Commission has further clarified that only records of leaks requiring repair need to be maintained.

Regulation Number 7 already requires that owners or operators remonitor repaired leaks with an AIMM. AIMM includes EPA Method 21, which includes the soapy water method, and the Commission further clarifies that an owner or operator may use the soapy water method in EPA Method 21 to remonitor a repaired leak.

Some stakeholders asked the Commission to "clarify" that the LDAR repair, remonitoring, recordkeeping, and reporting requirements applied only to those leaks discovered by the owner or operator, and not those discovered by the Division. The Commission believes that would not be a clarification, but a change to the current program, and does not make that requested revision at this time. Therefore, the repair, remonitoring, recordkeeping, and reporting requirements continue to apply to leaks discovered by the Division.

Pneumatic controllers (Section XVIII.)

The Commission is adopting both Ozone SIP and State Only revisions to Section XVIII.

The Commission added definitions of continuous bleed and intermittent pneumatic controller. The Commission also added "continuous bleed" to several provisions throughout Sections XVIII.C. through XVIII.E. to clarify that the provisions adopted in 2014 primarily applied to continuous bleed pneumatic controllers (which emit continuously) as opposed to intermittent pneumatic controllers (which emit only when actuating).

Pneumatic controllers at or upstream of natural gas processing plants

Section XVIII. already requires that owners or operators install low-bleed pneumatic controllers at or upstream of natural gas processing plants, unless a high-bleed pneumatic controller is required for safety or process purposes. This requirement is consistent with the Oil and Gas CTG and the Commission intends that these provisions be included in Colorado's Ozone SIP.

The Commission adopts additional requirements, consistent with the Oil and Gas CTG, related to pneumatic controllers at natural gas processing plants. The Commission is requiring that all continuous bleed, natural gas-driven pneumatic controllers at a natural gas processing plant have a bleed rate of zero (*i.e.,* no VOC emissions), unless a pneumatic controller with a bleed rate greater than zero is necessary due to safety and process reasons. To satisfy this requirement, owners or operators of natural gas processing plants could, for example, drive pneumatic controllers with instrument air, use mechanical or electrically powered pneumatic controllers, or use self-contained pneumatic controllers that release natural gas to a downstream pipeline instead of to the atmosphere. The requirements to submit a justification for a pneumatic controller exceeding the emission standard to the Division, as well as the requirements for tagging and records, duplicate and are intended to be consistent with existing requirements related to high-bleed pneumatic controllers. The requirement to maintain pneumatic controllers exceeding the applicable emission standard are also duplicated from the existing high-bleed maintenance requirement, but revised to include the suggested maintenance actions specifically in the applicable provisions, instead of referring to an "enhanced maintenance" definition. The Commission revised the maintenance requirement in this manner to separate the actions taken to maintain a pneumatic controller exceeding the applicable emission standard from the, potentially very similar, actions taken to return a pneumatic controller to proper operation. For example, the owner or operator of a high-bleed pneumatic controller or a pneumatic controller with a bleed rate greater than zero at a natural gas processing plant is required to perform specified maintenance on the pneumatic controller regardless of whether or not the pneumatic controller is determined to be properly operating. In contrast, the owner or operator of a pneumatic controller inspected under Section XVIII.F. must conduct enhanced response to return that pneumatic controller to proper operation.

Additionally, the Commission is requiring owners or operators to maintain records demonstrating their continuous bleed, natural gas-driven pneumatic controllers meet the applicable low-bleed or bleed rate of zero standards. These records are also intended to inform the extent to which continuous bleed pneumatic controllers are used in the DMNFR. The Commission understands that the number of continuous bleed, natural gas-driven pneumatic controllers in use by an operator can change frequently, and is not requiring a running log or count of each individual pneumatic controller.

The Commission adopted these recordkeeping requirements with the expectation that owners or operators can keep records including, but not limited to, site-specific documentation of continuous bleed, natural gas-driven pneumatic controllers such as manufacturer specifications, engineering calculations, field test data, or documentation of a company's continuous bleed, natural gas-driven pneumatic controller purchase and installation program ensuring that any such pneumatic controller meets the applicable bleed rate standard.

Clarification

The Commission is also clarifying the intent behind provisions adopted in 2014 regarding the use of pneumatic controllers powered by instrument air (as opposed to natural gas) when grid power is being used. In 2014, the Commission intended that when a pneumatic controller was proposed for installation, owners or operators would power the pneumatic controller via electrical power instead of natural gas when electrical grid power was being used on-site. The provisions adopted in 2014 allowed owners or operators to install a pneumatic controller with VOC emissions equal to or less than a low-bleed pneumatic controller in some situations. The Commission has learned that some owners or operators interpret the rule as providing the option of installing either no-bleed or low-bleed pneumatic controllers in all situations.

Even though the Commission believes its intent was clear, the Commission recognizes that the rule could fairly be described as ambiguous and that there is a good faith legal argument for the alternative interpretation. The Commission is revising the rule to clarify that where electric grid power is being used on site and it is technically and economically feasible to install no-bleed pneumatic controllers, any newly installed pneumatic controllers must be no-bleed. Where the owner or operator determines it is not technically and economically feasible to install a no-bleed pneumatic controller, the owner or operator may install a low-bleed or intermittent pneumatic controller.

The Commission recognizes that the installation of an electrically-powered controller may have been feasible in 2014, but may not be feasible to retrofit at this time. The Commission nonetheless encourages owners or operators statewide who, based on a misreading of the regulation, did not install a no-bleed pneumatic controller to evaluate whether retrofitting controllers – with no-bleed or self-contained pneumatic controllers – at this time is technically and economically feasible. The Commission also encourages owners and operators statewide to install, or retrofit with, no-bleed or self-contained pneumatic controllers at locations across the state, even where on site electrical grid power is not available to the extent there is no significant air quality disbenefit in doing so.

Natural gas driven pneumatic controller inspection and enhanced response (State Only)

Following the 2014 rulemaking, the Commission requested that the Division continue its investigation into potential regulations for intermittent pneumatic controllers. During the recent 2016 ozone rulemaking, stakeholders again asked the Commission to address intermittent pneumatic controllers. In response, the Commission again directed the Division to evaluate potential emission reduction measures for intermittent pneumatic controllers.

The Commission is adopting an inspection and enhanced response (*e.g.*, maintenance) program for natural gas-driven pneumatic controllers. While the Oil and Gas CTG notes the value of pneumatic controller inspection and maintenance, the Oil and Gas CTG does not specify a pneumatic controller inspection and maintenance as presumptive RACT. Therefore, while the Commission determined that these revisions are technically and economically feasible, the revisions are proposed as State Only in the DMNFR and are not made part of the Ozone SIP at this time. Natural gas-driven pneumatic controllers include continuous bleed, intermittent, and self-contained pneumatic controllers. Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere.

The Oil and Gas CTG suggests that maintenance of pneumatic controllers, including cleaning and tuning, can eliminate excess emissions from the devices. While the Oil and Gas CTG's recommended RACT (low-bleed or zero emissions) applies to continuous bleed, natural gas-driven pneumatic controllers, the discussion concerning enhanced maintenance of pneumatic controllers builds on earlier EPA discussions, such as EPA's 2014 Pneumatic Controller White Paper, and is not limited to continuous bleed pneumatic controllers. The Commission recognizes that continuous bleed and intermittent pneumatic controllers are designed to have emissions, however these pneumatic controllers can also have excess emissions when not operating properly. As a result, the Commission believes that a pneumatic controller inspection and response program will reduce the excess emissions from such pneumatic controllers.

The Commission intends to apply the same find and fix approach used in the LDAR requirements in Sections XII.L. and XVII.F. to all natural gas-driven pneumatic controllers in the DMNFR. The Commission is requiring that natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the pneumatic controller is operating properly, in contrast to quantitatively comparing pneumatic controller emissions to a regulatory threshold. The Commission is requiring that owners or operators inspect pneumatic controllers at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

The Commission expects that owners or operators will inspect their pneumatic controllers during the same LDAR inspections, and using the same AIMM, conducted for compliance with Sections XII.L. or XVII.F. The pneumatic controller inspection and enhanced response process is intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven pneumatic controller using AIMM to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those pneumatic controllers with detected emissions. Second, the owner or operator must determine whether the pneumatic controllers with detected emissions are operating properly. Use of an AIMM is not required during this second step; the Commission does not at this time intend to mandate to owners or operators how to determine if their pneumatic controllers are operating properly. During this second step, if an owner or operator determines that the pneumatic controller is operating properly, no further action is necessary. Third, where an owner or operator determines the pneumatic controller is not operating properly, the owner or operator must take actions to return an improperly operating pneumatic controller to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those pneumatic controllers that the owner or operator determined not to be operating properly.

Similar to the LDAR records, owners or operators must keep records of the date the pneumatic controller was returned to proper operation and a description of the types of actions taken. As with well production facility and natural gas compressor station LDAR records, the Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of response actions to ensure that owners and operators are consistently recording the information required. The Commission expects that owners or operators will include the pneumatic controller information as State Only information in their LDAR annual reports. In returning a pneumatic controller to proper operation, the Commission relies upon the previously defined term, now enhanced response, found in Section XVIII.B. related to maintaining high-bleed pneumatic controllers. The Commission has expanded this definition to guide responsive activities concerning all natural gas-driven pneumatic controllers. Recognizing that the function and potential maintenance or repair of pneumatic controllers can be variable, owners or operators are not restricted to using an AIMM to determine proper operation or verify the return to proper operation.

The Commission has adopted a "reassessment" provision for this inspection and enhanced response program following a Division led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The Commission also recognizes that owners and operators may currently have limited information on "good engineering and maintenance practices" for pneumatic controllers and intends that more information on these practices will be gathered during the pneumatic study and implementation of Section XVIII.F. to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry's proposal, a task force will be convened by January 30, 2018, consisting of representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection will begin no later than by May 1, 2018. The task force will brief the Commission annually and make any recommendations on its findings in a report to the Commission, due May 1, 2020. The Commission intends that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the Commission. The Commission intends that this information be used to reassess the natural gas-driven pneumatic controller requirements of Section XVIII.F. Section XVIII.F. will remain in effect until rescinded, superseded, or revised.

The Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers, which highlights the need for the reassessment of Section XVIII.F. as well as enforcement discretion. The Commission intends that while the task force is actively working on data collection and the 2020 report to the Commission, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator. Any information gathered through the task force, including on preventative, good engineering, and maintenance practices, will be used to reassess Section XVIII.F. and will not be used for enforcement purpose through 2020.

Additional Considerations

Colorado must revise Colorado's Ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. The Commission carefully considered what provisions to include in Colorado's Ozone SIP, especially given Colorado's pre-existing emission control requirements that address most of the same sources addressed by the Oil and Gas CTG, yet do so differently. Some of these pre-existing requirements were adopted into Colorado's SIP and some will remain as State Only requirements. In determining what existing provisions would be included in Colorado's Ozone SIP, the Commission considered: 1) whether or not Colorado had existing emission control measures for the same sources covered by the Oil and Gas CTG; 2) whether these existing requirements were already adopted for inclusion in the Ozone SIP; and 3) the degree of emissions reductions achieved by any existing Colorado emission control measures in comparison to the Oil and Gas CTG. In resolving differences between existing Colorado provisions and the Oil and Gas CTG, preference was given to existing Colorado provisions, especially those already incorporated into Colorado's Ozone SIP and Colorado's existing regulatory framework. For example, the Commission relied upon existing storage tank requirements already adopted into Colorado's Ozone SIP. In the case of well production facility LDAR, the Commission adopted a tpy applicability threshold in place of the Oil and Gas CTG's BOE threshold, which applies to more sources than the Oil and Gas CTG, yet adopted a less frequent inspection frequency into the Ozone SIP for the smaller facilities than the Oil and Gas CTG.

In determining whether or not any additional requirements would be relied upon in establishing RACT in Colorado's Ozone SIP for the oil and gas sector, the Commission determined whether or not the emission control measures were necessary for the ozone attainment demonstration. In the case of LDAR for pneumatic controllers at well production facilities and natural gas compressor stations, the Commission adopted emission control measures as State Only measures given the need to obtain emission reductions as well as more information on this source type. These examples illustrate the Commission's careful consideration of what provisions to include in Colorado's Ozone SIP.

The CAA requires that Colorado's Ozone SIP include RACT for all sources covered by a CTG, such as the emission sources addressed in the Oil and Gas CTG. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs.

The Commission is also revising certain State Only regulations to reduce emissions and promote attainment of current federal ozone standards. Specifically, the Commission is adopting requirements related to the inspection of natural gas-driven pneumatic controllers at oil and gas facilities. As discussed above, malfunctioning pneumatic controllers can result in significant hydrocarbon emissions. The DMNFR ozone nonattainment area is currently classified as a Moderate nonattainment area under the 2008 ozone NAAQS. The deadline for the DMNFR to attain the 2008 ozone NAAQS is July 2, 2018. If the DMNFR does not attain the standard or does not receive an extension, EPA may reclassify the DMNFR as a Serious nonattainment area under the 2008 ozone NAAQS. In addition, the Commission approved a designation recommendation for the DMNFR under the 2015 ozone NAAQS in September 2016.

While EPA has not yet acted on this recommendation, the Commission expects the DMNFR will be designated as nonattainment under the 2015 ozone NAAQS and is taking action to promote attainment of the more stringent standard. Given both the potential for a reclassification to Serious under the 2008 ozone NAAQS and the need to reduce ozone to meet the more stringent 2015 ozone NAAQS, the Commission is adopting the State Only pneumatic controller inspection requirements that further reduce ozone precursors emissions, notwithstanding the fact that a pneumatic controller inspection program is not specified as presumptive RACT in the Oil and Gas CTG.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) CAA Sections 172(c) and 182(b) require that Colorado submit a SIP that includes provisions requiring the implementation of RACT at sources covered by a CTG. The EPA issued the final Oil and Gas CTG in October 2016, leading to the revisions to the Ozone SIP adopted by the Commission. The EPA revised the ozone NAAQS in 2015 and the DMNFR must attain the new standard or face additional requirements. The revisions to Regulation Number 7 address RACT for compressors, pneumatic pumps, pneumatic controllers, natural gas processing plants, natural gas compressor stations, and well production facilities. The revisions apply to equipment already regulated by Colorado on a State Only basis and apply to equipment not previously subject to regulation. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to the regulated equipment. The Commission determined that the adopted RACT SIP requirements are comparable to the Oil and Gas CTG's recommendations. The Commission also determined that there are not comparable federal rules requiring the inspection and maintenance of natural gas-driven pneumatic controllers.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa to allow an owner or operator to request EPA approve compliance with an alternate emission limitation (e.g., alternative monitoring, state program) instead of related requirements in NSPS OOOOa.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure timely attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here. Further, the State Only pneumatic controller inspection requirements address the lack of federal requirements concerning emissions from malfunctioning pneumatic controllers.

(IV) Unless federal law changes, Colorado will be required to comply with the more stringent 2015 ozone NAAQS in the near future and may be required to comply with the more stringent requirements for a Serious nonattainment area. These current SIP and State Only revisions may improve the ability of the regulated community to comply with new, more stringent, future requirements. In addition, these revisions build upon the existing regulatory programs being implemented by Colorado's oil and gas industry, which is more efficient and cost-effective than a wholesale adoption of EPA's recommended oil and gas RACT provisions.

(V) EPA has established October 27, 2018, deadline for this SIP submission. EPA has not yet established deadlines for the DMNFR to attain the 2015 ozone NAAQS. However, given the potential reclassification of the DMNFR to Serious under the 2008 ozone NAAQS, the Commission determined that taking action to reduce ozone precursor emissions as soon as practicable, either as part of the SIP or on a State Only basis, is warranted.

(VI) The revisions to Regulation Number 7 Sections XII. and XVIII. strengthen Colorado's SIP and State Only provisions, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(VII) The revisions to Regulation Number 7 Sections XII. and XVIII., including the State Only provisions, establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, or qualify for an extension of the attainment deadline, EPA will likely reclassify Colorado as a Serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs. The State Only rule revisions are expected to reduce future costs by achieving emissions reductions that will assist the DMNFR in attaining both the 2008 and 2015 ozone NAAQS thus avoiding additional ozone nonattainment area CAA requirements.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The State Only pneumatic controller inspection program is tailored to be consistent with the SIP required LDAR program, thereby reducing costs related to pneumatic controller inspections.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for compressors, pneumatic controllers, leak detection and repair at well production facilities and natural gas compressor stations, and equipment leaks at natural gas processing plants. Further, pneumatic controller inspections will be conducted using accepted technologies and some owners or operators already repair and maintain pneumatic controllers.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP. The Commission determined that the Division's proposal was reasonable and cost-effective. The Commission further determined the State Only natural gas-driven pneumatic controller inspection program is reasonable and cost-effective, given the potential for reducing emissions from malfunctioning pneumatic controllers and the absence of federal requirements addressing pneumatic controller emissions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's Ozone SIP to address the Moderate nonattainment area requirements. Colorado must also continue to reduce ozone concentrations to address both the possibility of reclassification under the 2008 ozone NAAQS and the 2015 ozone NAAQS. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, including regulatory changes made on a State Only basis, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

Q. July 19, 2018 (Sections XVI. and XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate, effective June 3, 2016, and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e. sources that emit or have the potential to emit 100 tons per year ("tpy") or more). The CAA does not define RACT. However, EPA has defined RACT as the "lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53762 (Sept. 17, 1979). RACT can be adopted in the form of emissions limitations or work practice standards or other operation and maintenance requirements as appropriate.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions.

In response to the reclassification, the Commission revised Regulation Number 7 to satisfy RACT SIP requirements for Moderate nonattainment areas by establishing categorical RACT requirements for major sources of VOC and/or NOx in the DMNFR. Specifically, the Commission adopted RACT requirements in Section XVI.D. for existing boilers, stationary combustion turbines, lightweight aggregate kilns, glass melting furnaces, and compression ignition reciprocating internal combustion engines ("RICE") (collectively referred to as "stationary combustion equipment") located at major sources of NOx in the DMNFR as of June 3, 2016.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Major VOC and NOx source RACT

Colorado has major sources of VOC and/or NOx in the ozone nonattainment area. The following sources were known by the Commission to be major sources of VOC and/or NOx as of June 3, 2016 and were analyzed in Colorado's Moderate Area SIP for the 2008 8-Hour Ozone NAAQS:

Anheuser-Busch, Fort Collins Brewery (069-0060) and Nutri-Turf (123-0497) (major for VOC and NOx)

Ball Metal Beverage Container Corporation (059-0010 major for VOC)

Buckley Air Force Base (005-0028 major for NOx)

Carestream Health (123-6350 major for NOx)

Cemex Construction Materials (013-0003 major for VOC and NOx)

Colorado Interstate Gas, Latigo (005-0055 major for NOx)

Colorado Interstate Gas, Watkins (001-0036 major for VOC and NOx)

Colorado State University (069-0011 major for NOx)

CoorsTek (059-0066 major for VOC)

Corden Pharma Colorado (013-0025 major for VOC)

DCP Midstream, Enterprise (123-0277 major for VOC and NOx)

DCP Midstream, Greeley (123-0099 major for VOC and NOx)

DCP Midstream, Kersey/Mewbourn (123-0090 major for VOC and NOx)

DCP Midstream, Lucerne (123-0107 major for VOC and NOx)

DCP Midstream, Marla (123-0243 major for VOC and NOx)

DCP Midstream, Platteville (123-0595 major for VOC and NOx)

DCP Midstream, Roggen (123-0049 major for VOC and NOx)

DCP Midstream, Spindle (123-0015 major for VOC and NOx)

Denver Regional Landfill, Front Range Landfill, Timberline Energy (123-0079 major for NOx)

Elkay Wood Products (001-1602 major for VOC)

IBM Corporation (013-0006 major for NOx)

Kerr-McGee Gathering, Frederick (123-0184 major for VOC and NOx)

Kerr-McGee Gathering, Hudson (123-0048 major for VOC and NOx)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057 major for VOC and NOx)

Kodak Alaris (123-0003 major for VOC)

Metal Container Corporation (123-0134 major for VOC)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery, Rocky Mountain Metal Container (059-0006), MMI/EtOH (059- 0828), and Colorado Energy Nations Company, LLC (059-0820) (major for VOC and NOx)

Owens-Brockway Glass (123-4406 major for NOx)

Phillips 66 Pipeline, Denver Terminal (001-0015 major for VOC)

Plains End (059-0864 major for VOC and NOx)

Public Service Company, Cherokee (001-0001 major for NOx)

Public Service Company, Denver Steam Plant (031-0041 major for NOx)

Public Service Company, Fort Lupton (123-0014 major for NOx)

Public Service Company, Fort Saint Vrain (123-0023 major for NOx)

Public Service Company, Rocky Mountain Energy Center (123-1342 major for NOx)

Public Service Company, Valmont (013-0001 major for NOx)

Public Service Company, Yosemite (123-0141 major for NOx)

Public Service Company, Zuni (031-0007 major for NOx)

Rocky Mountain Bottle Company (059-0008 major for NOx)

Sinclair Transportation Company, Denver Terminal (001-0019 major for VOC)

Spindle Hill Energy (123-5468 major for NOx)

Suncor Energy, Commerce City Refinery Plants 1, 2, and 3 (001-0003 major for VOC and NOx)

Thermo Cogeneration, JM Shafer (123-0250 major for NOx)

Tri-State Generation, Frank Knutson (001-1349 major for NOx)

TRNLWB, LLC (Trinity Construction Materials, Inc.) (059-0409 major for NOx)

University of Colorado Boulder (013-0553 major for NOx)

WGR Asset Holding, Wattenberg (001-0025 major for VOC and NOx)

Many of the major sources listed above are subject to regulatory RACT requirements. Some of the sources or source emissions points are subject to regulatory RACT requirements in Colorado's SIP; other sources or source emissions points are subject to individual RACT requirements established in federally enforceable permits as a minor source RACT requirement of inclusion of an applicable federal New Source Performance Standards ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado must include in the SIP, provisions to implement RACT for Colorado's major sources. During the November 17, 2016 rulemaking, the Commission adopted source specific RACT for a number of major sources of VOC and/or NOx (again greater than or equal to 100 tons per year) in the DMNFR. These were originally adopted as Sections XIX.C.-XIX.G. for stationary combustion turbines, stationary internal combustion engines, wood furniture manufacturing, and municipal landfills, respectively, during the November 17, 2016 rulemaking. These sections have changed to Sections XVI.D.4.b. and XIX.A.-D. during this July 19, 2018 rulemaking, where requirements for stationary combustion turbines were removed and consolidated into Section XVI.D.4.b. The original Section XIX.C.-XIX.G. RACT requirements became effective on January 1, 2017. However, during the November 17, 2016 rulemaking, the Commission determined that little, if any, additional controls could be implemented by certain major sources by January 1, 2017. The Commission also determined that not all major sources or major source emission points were subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Regulation 3, Part F. Therefore, the Commission opted to adopt RACT for Colorado's existing major sources of NOx on a categorical basis in this July 19, 2018 rulemaking.

Establishing RACT on a categorical basis is a distinctly different process from Colorado's minor source RACT permitting requirement found in Regulation 3, Part B, Section III.D.2. Minor source RACT permitting is specific to new or modified sources (i.e. sources that have already committed to a capital expenditure to construct or modify a process), and the designs of which can more easily accommodate changes prior to construction. Categorical RACT applies much more broadly to source category, including both existing sources/equipment and new/modified sources/equipment. This inclusion of existing equipment significantly impacts costs, as those sources are not already committed to a capital expenditure and any associated shut down to add controls. This ultimately impacts the decision on what controls are determined to be reasonably available, technologically and economically feasible for the source category as a whole. Thus, categorical RACT may in some cases be different from any RACT established for a specific source or piece of equipment under the minor source permitting RACT requirement.

To determine RACT on a categorical basis, the Commission required specific owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017. In these RACT analyses, sources were required to identify potential options to reduce VOC and/or NOx emissions from the facility or emission point(s), propose RACT for that facility or point(s), propose associated monitoring, propose a schedule for implementation, and include economic and technical information demonstrating why the proposal established RACT for the particular facility or emission point(s). The following major sources were required to submit RACT analyses:

Anheuser-Busch (069-0060) – emission points equal to or greater than 2 tpy VOC or 5 tpy NOx

Buckley Air Force (005-0028) – engines and engine test cell (pt 102, 103, 104, 105, 101)

Carestream Health (123-6350) – boilers (pt 004)

Colorado Energy Nations Company, LLC (059-0820) – boilers (pt 001, 002)

Colorado Interstate Gas, Latigo (005-0055) – engines (001, 011)

Colorado Interstate Gas, Watkins (001-0036) – engines (001, 002)

Colorado State University (069-0011) – boilers (pt 003, 005, 007, 013)

IBM (013-0006) – engines and boilers (pt 088, 090, 001, 011, 095)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057) – turbine (pt 052) and engines (pt 038 through 044, and 047 through 049)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery (059-0006) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

MMI/EtOH (059-0828) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Nutri-Turf (123-0497) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Owens-Brockway (123-4406) – emission points with emissions equal to or greater than 5 tpy NOx (pt 001-023, 025)

Public Service Company, Cherokee (001-0001) – turbines (pt 028, 029)

Public Service Company, Fort Saint Vrain (123-0023) – turbines (pt 010, 011, 001)

Public Service Company, Denver Steam Plant (031-0041) – boilers (pt 001, 002)

Public Service Company, Zuni (031-0007) – boilers (pt 001, 002, 003)

Public Service Company, Fort Lupton (123-0014) – turbines (pt 001, 002)

Public Service Company, Valmont (013-0001) – turbine (pt 002)

Rocky Mountain Bottle (059-0008) – glass melt furnaces (pt 001)

Suncor (001-0003) – boilers (pt 309, 019, 021, 023)

Tri-State Generation and Transmission, Frank Knutson (001-1349) – turbines (pt 001, 003)

TRNLWB, LLC (Trinity Construction Materials) (059-0409) – shale kiln (pt 001)

University of Colorado (013-0553) – Power House and East District – boilers (pt 001, 002, 012, 013) and Williams Village– boilers (pt 016, 017)

WGR Asset Holding, Wattenberg (001-0025) – boiler (pt 012), turbine and duct burner (pt 021) and engines (pt 004 and 018)

Based on the information provided in these RACT analyses as well as the Division's own in-depth review of rules adopted by Moderate nonattainment areas in other states and EPA guidance such as the RACT/BACT/LAER Clearinghouse, the Commission adopted RACT requirements in Section XVI.D. for stationary combustion equipment located at existing major sources of NOx in the DMNFR. The requirements of Section XVI.D. only apply to existing stationary combustion equipment located at sources in the DMNFR that were major for NOx as of June 3, 2016 (i.e. the effective date of the DMNFR's reclassification to Moderate nonattainment).

Definitions

The definition for "stationary combustion equipment" refers to individual emission points and not grouped emission points.

Emission limitations and operational requirements

The Commission adopted categorical emission limitations (Section XVI.D.4.), which vary based on fuel type and size of the stationary combustion equipment, where applicable. Affected stationary combustion equipment is required to comply with these exemptions by October 1, 2021. This compliance period is necessary in order to allow affected sources sufficient time to complete any capital expenditures, install any control or monitoring equipment, and/or satisfy any permitting requirements necessary to comply with the applicable emission limitation. The heat input size threshold for determining whether an emission limitation applies refers to the maximum design value of the stationary combustion equipment. De-rated heat input is not the equivalent of maximum design value heat input. Therefore, stationary combustion equipment cannot simply de-rate to fall below the size threshold. For certain categories of stationary combustion equipment, if the equipment's heat input is below the applicability threshold for the emission limitations, then the equipment would still be required to comply with the combustion process adjustment requirements originally adopted by the Commission during the November 17, 2016 rulemaking (now in Section XVI.D.6.) The compliance date for the categorical emission limits (i.e. XVI.D.4 and XVI.D.5) is independent of the compliance date for the combustion process adjustment (i.e. XVI.D.6(b)(vi)(A)).

The combustion process adjustment requirements shall apply as RACT to a particular piece of equipment in accordance with the applicability provision, Section XVI.D.6.a., regardless of whether or not that piece of equipment is subject to a categorical emission limit in Section XVI.D.4. As described in Section XVI.D.6.a., the combustion process adjustment requirements only apply to stationary combustion equipment with uncontrolled actual emissions of NOx equal to or greater than 5 tons per year located at major sources of NOx. For stationary combustion turbines, the heat input capacity threshold for the emission limitations takes into account to the heat input capacity of the stationary combustion turbine only and not the heat input capacity of the stationary combustion turbine and any duct burner that may be used.

For glass melting furnaces at major sources of NOx, the Commission adopted a production-based categorical emission limitation (Section XVI.D.4.d.). Emissions from some glass melting furnaces are routed through a common stack, where total emissions from multiple furnaces are monitored on a continuous basis. Where this is the case, the total emissions, as monitored from the common stack, shall be divided by the total glass production from all glass melting furnaces associated with the common stack to demonstrate compliance with the categorical RACT limit.

Exemptions

The Commission determined several exemptions from compliance with the categorical RACT standards to be appropriate for Colorado's source mix. In Section XVI.D.2.a., the Commission adopted a 20% capacity factor exemption for boilers and a 10% capacity factor exemption for stationary combustion turbines and compression ignition reciprocating internal combustion engines. The Commission established the 20% and 10% capacity factor exemptions, in part, as a consolidation of a number of limited-use exemptions that were analyzed and considered by the Division to limit the complexity of the categorical rules and adequately accommodate technical and cost concerns for limited-use equipment. A number of stakeholders requested reasonable exemptions for specific equipment types involving seasonal operation, limited-use, natural gas curtailment, emergency electric generation, provision of replacement capacity during periods of extended primary unit outage for major maintenance, and the lack of manufacturer emission rate guarantees for low capacity units. The Commission determined that the capacity factor exemptions addressed each of these concerns, and thus that additional individual exemptions were not necessary beyond the capacity factor exemption.

At low capacities, controls are often cost prohibitive or technologically infeasible. The Commission determined that there are multiple facilities with excess steam capacity that have the ability to shift capacity (and therefore emissions) away from older higher emitting boilers that are not currently configured to comply with the categorical standard or monitoring requirements. Many of the older boilers are not equipped with continuous emission monitoring systems ("CEMS") and may require add-on controls to comply with the categorical standard. The shift in capacity to newer, lower emitting boilers which are already equipped with NOx controls and CEMS will result in a net emissions reduction. The 20% capacity factor exemption for boilers provides a secondary compliance option and incentive to facilities that have this ability, and the resulting shift in emissions from high emitting units to low emitting units will result in an overall environmental benefit.

Some stakeholders expressed concerns that a few boilers with low historical use (e.g. heat input below 25%) may need to install controls that cannot meet the RACT standard because manufacturer emission rate guarantees usually apply only when the units operate between 25-100% of the boiler maximum continuous rating ("MCR"). Generally, the boiler burners have a limited range of heat input where the manufacturer can guarantee compliance with a specific emission rate. Emissions from boilers operating at heat inputs below 25% MCR are generally classified as startup/shutdown emissions. Thus, if the Division proposed a RACT standard that a particular low utilization boiler was unable to meet and the Division did not offer an adequate capacity factor exemption, the operator would need to install controls and operate the boiler at higher capacity factors to ensure the installed controls meet manufacturer guaranteed emission rates in order to comply with the RACT standard.

The installation of boiler controls coupled with increasing boiler heat input in order to ensure compliance with a categorical RACT standard runs contrary to the original intent of reducing emissions, thus the Commission concludes that it is reasonable to allow exclusion of limited-use boilers from the categorical standard and associated CEMS requirements, particularly regarding boilers with historically low heat inputs that could not rely on the manufacturer emission rate guarantees if the installation of emission controls are needed in order to comply with the categorical standard. Consequently, the Commission determined that a 20% capacity factor averaged over a 3-year period is reasonable for these limited-use boilers.

For stationary combustion turbines and compression ignition RICE, a 10% capacity factor exemption from the proposed categorical emission standards and monitoring requirements is appropriate because combustion turbines and compression ignition RICE are more likely to operate during the summer months. Moreover, for turbines and compression ignition RICE that are used primarily for emergency power generation or peak demand, historic capacity factors are extremely low (0%-5%), and a 10% capacity factor exemption will provide enough operational flexibility to respond to emergency and peak demand events.

Separately, the categorical RACT for glass melting furnaces provides a 35% low usage allowance similar to capacity factor.

The capacity factor is determined based on the rolling 3-year average of the actual heat input for each calendar year divided by maximum allowable heat input. Alternatively, for electric generating units, the proposal allows for capacity factor to be determined based on electric output, which is consistent with the federal Acid Rain Program.

The Commission intended that the exemption for stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx was based on the permitting threshold in Regulation 3. Similarly, this equipment was not exempted from having to undergo a RACT analysis. The owner or operator must use the most recent air pollution emission notice ("APEN") submitted to the Division to determine total uncontrolled actual emissions.

Stationary combustion equipment that meets one of the exemptions contained in Section XVI.D.2. is not required to comply with the emission limitations, the compliance demonstration requirements and the related recordkeeping and reporting requirements contained in Sections XVI.D.4., XVI.D.5., XVI.D.7., and XVI.D.8., except for XVI.D.7.g, which requires a source that qualifies for an exemption under Section XVI.D.2., to maintain records demonstrating an exemption applies. All stationary combustion equipment is subject to some level of recordkeeping and may also be subject to combustion process adjustment requirements.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of Section XVI.D. as expeditiously as practicable but no later than 36 months after the equipment is no longer exempt. Therefore, if any stationary combustion equipment has to undertake a capital expenditure, such as installing a CEMS, in order to comply with Section XVI.D., then they have up to a maximum of three years to come into compliance. However, if no such capital expenditure or change in operational practice is required, then the stationary combustion equipment should comply sooner than three years (i.e. as expeditiously as practicable.) Additionally, once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations. This means that a source can fall into and out of having to comply with the emission limitation, monitoring, recordkeeping and reporting requirements of the rule if they satisfy the performance test requirements (i.e. the Division will not follow a "once in/always in" approach with respect to emission control requirements of exemptions.) Similarly, this 180-day period starts once the equipment is no longer exempt.

Monitoring, recordkeeping and reporting requirements

The Commission determined that affected stationary combustion equipment comply with certain monitoring, recordkeeping and reporting requirements by October 1, 2021. In order to provide clarity and regulatory certainty, many of the monitoring requirements adopted by the Commission incorporate by reference existing federal requirements and are consistent with rules in Moderate nonattainment areas in other states establishing RACT for these source categories.

The Commission is requiring CEMS or continuous emissions rate monitoring systems ("CERMS") for boilers with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, lightweight aggregate kilns with a maximum heat input design capacity equal to or greater than 50 MMBtu/hr, and glass melting. CERMS may require a stack gas flow rate monitor, where necessary, in order to measure volumetric flow rate and mass emissions. Where stack gas velocity is extremely low, as may be the case for a glass melting furnace, flow can be measured using a Division approved calculation methodology if flow cannot be accurately measured using traditional differential pressure or ultrasonic flow measuring devices. Moreover, where measuring emission rates in terms of emissions per unit of heat input (i.e. lb/MMBtu), EPA Method 19 calculations may be used using the appropriate F factor (i.e. the ratio of combustion gas volumes to heat inputs).

Further, it is the Commission's intent to allow electric utility boilers and stationary combustion turbines subject to the Acid Rain Program to use the quality assurance/quality control and data validation procedures in 40 CFR Part 75 for monitoring emissions to satisfy monitoring, recordkeeping and reporting requirements in this rule. Affected units that are subject to a NOx emission limitation in an NSPS and use CEMS or CERMS to monitor compliance with that limit can use those monitoring, recordkeeping and reporting requirements to demonstrate compliance with this rule.

Similarly, owners or operators of stationary combustion turbines using performance testing to demonstrate compliance with NOx emission limitations of NSPS GG or KKKK may utilize those procedures for demonstrating compliance with the emission limitation in this rule. Where an initial performance test has already been conducted to determine compliance with NSPS GG or KKKK, it is not expected that another initial performance test must be performed for purposes of demonstrating compliance with Section XVI.D. Where an initial performance test has not been previously conducted, it must be completed by October 1, 2021 to demonstrate compliance.

For each initial or periodic test, sources should calculate the backup fuel's heat input for the calendar year prior to the year in which the performance test is required to determine if a test is required for each fuel or only for the primary fuel. Moreover, periodic performance tests must be conducted no more than 24 months apart.

With respect to the fuel flowmeter requirements, the Division reserves the right to audit quality assurance procedures with respect to manufacturer's instructions. The heat input measured and recorded by the fuel flowmeter is to be in the same unit of measurement as the applicable emission limitation. With respect to the quarterly or semi-annual reporting requirement, the Commission intended to only require that reports be submitted no less than semi-annually, but a source may submit quarterly reports in order to be consistent with existing reporting frequencies established in a permit and/or applicable NSPS or NESHAP.

With respect to the performance test reports, all performance test reports must compare average emissions determined by the performance test with the applicable emission limitation using the same number of significant figures as the emission limitation.

Incorporation by Reference in Sections XIX. and XVI.

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Sections XVI.D.5. and XIX.A. through D. by reference.

Additional Considerations

Colorado must revise its ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC and NOx in Colorado's ozone nonattainment area. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission adopted RACT requirements in Section XVI.D. for combustion equipment located at major sources of NOx in the DMNFR. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS Db, NSPS GG, NSPS KKKK, NSPS IIII, NSPS JJJJ, NSPS OOOO, NSPS OOOOa, and the compliance demonstration requirements in 40 CFR Parts 60 and 75 may apply to such stationary combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to specific existing stationary combustion equipment in the DMNFR.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in certain NSPS and MACT. Certain stationary combustion equipment with a lower heat input may trigger the combustion process adjustment work practice requirements of this rule.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7, Sections XVI. and XIX. establish categorical RACT for major sources of VOC and/or NOx, and thus are necessary to satisfy RACT SIP requirements for Moderate nonattainment areas and are specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The Revisions to Regulation Number 7, Sections XVI., and XIX. establish reasonable equity for major sources of VOC and/or NOx by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a 1-year clean data extension), EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal additional monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC and/or NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

R. November 15, 2018 (Sections I., II., VI., VIII., IX., X., XII., XIII., XVI., XVII., XIX., XX., and XXI.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable marginal attainment deadline and therefore reclassified the DMNFR area to moderate, effective June 3, 2016.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 100 tons per year ("tpy") or more) and VOC source categories addressed by an EPA Control Techniques Guideline ("CTG").

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

In November 2016, the Commission determined that some major sources and CTG VOC source categories were adequately addressed under existing SIP requirements. The Commission also adopted new requirements for some major sources and CTG VOC source categories. In November 2017, the Commission adopted categorical RACT requirements for the oil and gas industry in response to EPA's Oil and Gas CTG. In July 2018, the Commission adopted categorical RACT requirements for combustion equipment at major sources that the Commission determined in 2016 were not addressed by SIP RACT requirements.

In this rulemaking, the Commission adopts SIP requirements that further support and complete Colorado's obligation as a moderate ozone nonattainment area to revise Colorado's SIP to include provisions that implement RACT for all major sources of VOC and/or NOx and for all CTG VOC source categories in the DMNFR ozone nonattainment area. Specifically, the Commission adopts categorical RACT requirements for major source breweries, wood furniture manufacturing, and addresses EPA concerns with the industrial cleaning solvent, metal furniture surface coating, and miscellaneous metal surface coating requirements. The Commission also revises specific rule or reference methods incorporated by reference to add applicable citation dates. Last, the Commission adopts specific revisions in a SIP clean-up effort.

Further, the Commission corrects typographical, grammatical, and formatting errors found throughout Regulation Number 7.

Major source RACT

Colorado has major sources of VOC and/or NOx in the DMNFR. Under marginal and moderate ozone nonattainment classifications, major sources are sources with the potential to emit greater than or equal to 100 tpy of NOx or VOC. Many of the major sources analyzed in 2016 were already subject to regulatory RACT requirements in Colorado's SIP, individual RACT requirements established in federally enforceable permits as a minor source RACT requirements, or an applicable federal New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutant ("NESHAP"). However, as a moderate nonattainment area, Colorado must include provisions in the SIP to implement RACT for Colorado's major sources. In November 2016, the Commission directed some major sources to submit RACT analyses to the Division, including two major source breweries. The Commission adopts in this November 2018, rulemaking categorical RACT requirements for major source brewing activities.

Major source breweries

The Commission adopts RACT requirements for owners and operators of breweries producing malt beverages and their brewery related operations at a major source VOC as of June 3, 2016, located in the DMNFR. In a moderate ozone nonattainment area, a major VOC source is one that emits or has the potential to emit greater than 100 tpy VOC. A brewery includes brewhouse, fermentation, aging, and/or packaging operations. Brewery related operations include operations that support the production of malt beverages such as wastewater management, container manufacturing, and ethanol distillation. The Commission established RACT for combustion equipment, including at breweries, in July 2018, in Regulation Number 7, Section XVI. The Commission now adopts a process loss limit and pollution prevention requirements for brewery packaging operations. These pollution prevention provisions include performance metrics to reduce product loss, operator training, and packaging equipment to reduce container breakage and product loss. The Commission also adopts wastewater management and treatment requirements for land application of wastewater. Lastly, the Commission adopts requirements for owners or operators to keep records of production, pollution prevention activities, and wastewater to demonstrate compliance with the operational requirements.

The largest VOC emissions sources inside a brewery are associated with packaging operations, including can, bottle, and other container fillers. Breweries can reduce VOC emissions by optimizing packaging operations. The process loss limitation is representative of packaging and filling optimization and, therefore, is an indicator, and potential driver, of the resulting VOC emission reductions. The process loss limitation does not include the railcar loading of beer concentrate that is shipped off-site for packaging. In this process, empty railcars are filled with beer concentrate held in beer concentrate receiving tanks after the aging process. The process loss from the automated loading of the beer concentrate from tanks into railcars is minimal and emissions from the filling of cans, bottles, kegs, or other containers are included with the emissions of the off-site packaging facility.

The process loss is calculated on calendar month and rolling 12-month bases across all packaging operations (i.e., filling lines), which aligns with existing product tracking programs. Process loss equates to the difference in the quantity of malt beverage metered at the filler and the quantity in containers as tracked for the Alcohol and Tobacco Tax and Trade Bureau ("TTB"). Operators determine the average calendar month process loss by comparing the total volumes metered at the fillers to the total volume counted by the TTB case counters. Owners or operators will then determine monthly average process loss percentage by dividing the difference in meter and case counter values by the total volume metered at the fillers. Utilizing an average process loss limit also allows for variations in individual line or brand product loss due to specialty brands or innovative containers. The brewing industry is seeing decreased sales of high-volume brands and increased consumer demand for small-volume unique or complex brands. This market change impacts process loss as the high-volume brands have low process loss values whereas specialty brands often result in higher process loss values due to brand recipe complexity, brand mix complexity, and production schedule complexity. The packaging of more types of brands and more complex brands result in higher process loss values because of differences in recipes that require more time for the filler to adjust to the appropriate fill level, more frequent product change-overs of the filling lines, and more unique packaging. The requirement to completely flush a filling line between brands also increases process loss values when the specialty brands are produced in lesser quantities than high-volume brands. Further, bottle filling lines often have different process loss values than can filling lines, therefore the change in container demand can impact the overall process loss. The average process loss limit of 6 percent on a calendar month and 4 percent on a 12-month rolling average leaves the necessary margin for variability and innovation, while still providing an indicator of RACT-level control of brewery packaging operations VOC emissions.

The Commission exempts from the process loss, pollution prevention, and recordkeeping requirements emissions units' subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 and emission units with total uncontrolled actual VOC emissions less than two tons per year. The first exemption was adopted to avoid subjecting sources to overlapping, duplicative, or contradictory RACT requirements. The second exemption was adopted for consistency with other major source RACT provisions and the use of Colorado's permitting thresholds for NOx and VOC to identify the emission points at major sources for which Colorado evaluated RACT.

The Commission also exempts equipment or activities related to research and development and newly installed, upgraded, or replaced packaging operations. Research and development activities include testing different recipes and packaging types before a product is distributed into commerce. The six-month startup exemption for newly installed, upgraded, or replaced packaging operations allows for the testing and adjustment of the new equipment to meet performance requirements. Examples of newly installed, upgraded, or replaced packaging operations include a new filling line or an upgraded or replaced man-to-machine-interface. Startup of newly installed, upgraded, or replaced packing operations does not include the startup or changeover of malt beverages or new recipes. Quality assurance teams follow a statistical process to verify that equipment is meeting quality standards prior to releasing salable product. These processes may include additional container testing, product sampling, or additional filler flushes while packaging operations are fine-tuned to meet key performance indicators. The volume of the product metered at the filler during the research and development and startup processes is excluded from the monthly process loss calculations. However, new, upgraded, or replaced packaging operations are not exempt from employees training requirements to ensure that employees understand the new packaging operations after startup.

Pollution prevention provisions also include the use and operation of packaging equipment to reduce container breakage and product loss. The Commission exempts from the automated filling equipment requirements packaging operations at pilot brewery operations. Automated filling equipment may be mechanical with a set fill quantity or electric with a flow meter and adjusting fill quantity. Both processes improve consistency, reduce spillage and product loss, and reduce the variation that may occur from human error.

The automated filling lines also include fill level detectors that will reject inadequately filled containers for recovery and recycling. A pilot brewery operation may serve the purposes of research and development but can also be utilized to produce very small quantities of product that is distributed into commerce. Pilot brewery operations can include different filling operations (e.g., bottles, kegs) but may use some manual filling related processes instead of automated processes. The use of manual processes is consistent with industry practices for operations of this small size, less than 50,000 barrels per year, and provides flexibility to account for production variations that may occur during research and development or small batch production.

Wood furniture manufacturing

In 2016, the Commission determined that only one source in the DMNFR exceeded the Wood Furniture CTG applicability threshold, and that source was a major source of VOC. Therefore, the Commission incorporated by reference requirements in 40 CFR Part 63, Subpart JJ (National Emission Standards for Wood Furniture Manufacturing Operations) into the SIP for wood furniture surface coating operations. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could streamline their RACT analysis by relating MACT controls to VOC RACT considerations. However, EPA has since expressed concerns that the NESHAP JJ volatile hazardous air pollutant ("VHAP") coating content limits may not adequately address coating VOC emissions. The Commission therefore removes the incorporation by reference of NESHAP JJ for wood furniture manufacturing operations in Section XIX. and is instead including the CTG recommended coating VOC content limits and work practices in Section IX.O.

The coating VOC content limits apply to sealers, topcoats, acid-cured alkyd amino vinyl sealers, or acid-cured alkyd amino conversion varnish topcoats. EPA's Wood Furniture CTG does not define acid-cured topcoats or sealers but does describe acid-catalyzed finishes as the most common catalyzed finishes. The Wood Furniture CTG further states that the film-forming resins in these finishes are usually a urea-formaldehyde or melamine-formaldehyde prepolymer mixed with an alkyd resin that serves as a plasticizer. Common catalysts contained in the acid-catalyzed finishes include sulfuric acid and p-toluenesulponic acid and film formation occurs through curing (polymerization) of the resins rather than drying.

SIP Clean-up

Industrial Cleaning Solvent

In 2016, the Commission adopted provisions in Regulation Number 7, Section X. to include RACT requirements related to the use of industrial cleaning solvents. The Commission adopted several exemptions recommended by EPA's Industrial Cleaning Solvents CTG as well as exemption for sources complying with cleaning solvent requirements in a federally enforceable NSPS, NESHAP, Best Available Control Technology requirement, or Lowest Achievable Emissions Rate requirement, which was similar to an EPA approved exemption in Colorado's Regional Haze SIP. EPA has since indicated concerns with approving this broad exemption due to a perceived lack of specificity. The Commission therefore removes the broad exemption in Section X.E.4.a.(i).

Metal furniture and miscellaneous metal surface coating

EPA published Metal Furniture CTGs in 1977 and 2007 and Miscellaneous Metal Parts and Products CTGs in 1978 and in 2008. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could conclude that sources already addressed by RACT determinations for a previous ozone NAAQS do not need to implement additional controls because a new RACT determination would result in the same or similar control technology as the initial RACT determination and any incremental emissions reduction from the application of a second round of controls would be small and the cost unreasonable.

Therefore, in 2016 the Commission relied on the RACT provisions relating to the 1977 and 1978 CTGs adopted into Regulation Number 7, Sections IX.H. and IX.L. in 1978 and 1980 to continue to establish RACT for metal furniture and miscellaneous metal coating operations. EPA has since indicated concerns with the existing provisions due to a lack of specified application technique. The Commission therefore revises Section IX. to specify the use of good air pollution control practices, including efficient application methods.

1990 and 1991 RACT Reports

In 1990, the Commission adopted one of several requirements in Regulation Number 7, specifically Sections I.B.2.f. and I.B.2.g., for existing sources to address EPA concerns with the design, implementation, and enforceability of Colorado's previously submitted and approved Ozone SIP. The provisions included one-time reporting requirements concerning source emissions and RACT for sources existing as of 1989. The provisions were not an ongoing reporting requirement potentially necessary for monitoring compliance with applicable emissions limits. EPA approved these provisions into Colorado's SIP in 1995, without discussion. Due to these one-time requirements having passed and Colorado's major stationary sources being subject to RACT requirements in Regulation Number 7, as adopted by the Commission through 2018, the Commission removed these historic provisions. Removal of these provisions does not remove or modify any control measures, therefore does not affect emissions nor interfere with attainment or reasonable further progress. Where information in the Sections I.B.2.f. and I.B.2.g. reports informed RACT requirements under Section II.C., sources remain subject to applicable RACT requirements and any emission reporting requirements as addressed by the emission statement rule last approved by EPA in 2015 (See 80 Fed. Reg. 50205 (August 19, 2015)).

Incorporation by Reference

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Sections II., VI., VIII., IX., X., XII., XIII., XVI., and XVII.

Additional Considerations

Colorado must revise its Ozone SIP to address the moderate ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC in Colorado's ozone nonattainment area. Colorado's major sources of VOC are subject to various and numerous NSPS or NESHAP, Regulation Number 7 requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC in the SIP. Specifically, the Commission adopted RACT requirements in Section XX. for brewing activities located at major sources of VOC in the DMNFR. The Commission also adopted RACT requirements from EPA's Wood Furniture CTG for wood furniture surface coating in Section IX. MACT JJ may apply to wood furniture surface coating operations.

(II) The federal rule discussed in (I) is primarily technology-based in that it largely prescribes the use of specific coating VHAP contents in order to comply. The federal rule provides flexibility by allowing subject facilities to select any coating meeting the specified VHAP content limits.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP. There is no timing issue that might justify changing this time frame.

(VI) The revisions to Regulation Number 7, Sections IX., X., and XX. establish categorical RACT for major sources of VOC and CTG VOC source categories, and thus are necessary to satisfy RACT SIP requirements for moderate nonattainment areas. The provisions are specific to emission points at sources of VOC, allowing for continued growth at Colorado's sources.

(VII) The Revisions to Regulation Number 7, Sections IX., X., and XX. establish reasonable equity for sources of VOC by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a one-year clean data extension) EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

S. December 19, 2019 (Sections I. through XX. and Appendices A through F – reorganized into Parts A through F)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) Sections 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the Air Quality Control Commission (Commission). This proposed rulemaking focuses on the Air Quality Control Commission directives in Section 25-7-109, CRS, SB19-181 directs the Commission to adopt regulations to "minimize emissions of methane and other hydrocarbons, volatile organic compounds (VOC), and oxides of nitrogen (NOx)" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the Commission should consider including semi-annual leak detection and repair (LDAR) inspection requirements at all well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This rulemaking addressed many of the specific provisions for consideration, except continuous methane monitoring, but is only the first of many rulemakings to come in addressing SB 19-181.

Further, on August 15, 2019, the Environmental Protection Agency (EPA) proposed to reclassify the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 75 parts per billion (ppb). See 84 Fed. Reg. 41,674 (Aug. 15, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy and the DMNFR's attainment date becomes July 20, 2021. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021.

Therefore, as a first step to addressing the new statutory directives, and ensuring progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to minimize emissions from the oil and gas sector and to include reasonably available control technology (RACT) requirements for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy. The oil and gas industry is a significant source of VOC, NOx, ethane, and methane emissions, and the Commission expects the industry's growth to continue in the foreseeable future. Improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs, ethane, and methane in a cost-effective manner. These technologies and practices include, without limitation, frequent LDAR inspections, reducing emissions from pneumatic controllers, reducing emissions from the transmission segment, storage tank measurement systems, and vapor collection and return equipment.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO (and NSPS OOOOa) are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both State Implementation Plan (SIP) requirements that apply in the DMNFR and state-only requirements that apply state-wide. In addition, evidence in the rulemaking record supports the conclusion that the rules can be implemented effectively. Accordingly, the Commission concludes that the rules are technologically feasible and cost-effective.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, *et seq.* (Act), specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas operations, including well production facilities and natural gas compressor stations. The Commission expands the inspection and enhanced response program for pneumatic controllers it adopted in 2017 for pneumatic controllers in the DMNFR to a state-wide applicability. The Commission adopts a new, innovative performance based program to reduce emissions from the downstream transmission segment.

The Commission is replacing the system-wide condensate storage tank control strategy in the SIP with a more straight-forward storage tank control threshold. The Commission is also seeking to reduce emissions from storage tank measurement and sampling and loadout activities, and to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission is expanding the requirement to employ best management practices to minimize emissions at oil and gas wells during well plugging activities. The Commission is also establishing an annual emissions inventory report that oil and gas operators will submit to the Division, which will ensure accountability and assist the Commission in understanding the emissions of methane, ethane, VOC, CO, and NOx associated with different activities and equipment in oil and gas operations. The Commission believes that this combination of revisions is appropriate as a first step in minimizing emissions from oil and gas operations and continuing to make progress towards attainment of the ozone NAAQS.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources ($\geq$ 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, including categorical RACT requirements, and requiring the submission of RACT analyses.

The Commission is also updating requirements for gasoline transport trucks, bulk terminals, and service stations to align with current federal requirements in a SIP clean-up effort.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Reorganization

Over the years, Regulation Number 7 has grown. In an effort to facilitate readability, and to better allow the regulated community to identify and understand the provisions governing their activities, the Division is proposing a full reorganization of Regulation Number 7 into parts. A table identifying the new section(s) along with the prior section/location is below. This Statement of Basis and Purpose will refer to the reorganized section numbers in the discussion of revisions and new provisions.

Reorganized Regulation Number 7 Section	Regulation Number 7 Section (as of 11/15/2018)
Part A	
Part A, Section I.	I. Applicability
Part A, Section II.	II. General Provisions
Part A, Appendix A	Appendix A. Colorado Ozone Nonattainment or Attainment Maintenance Areas

Part B	
Part B, Section I.	III. General Requirements for Storage and Transfer of Volatile Organic Compounds
Part B, Section II.	IV. Storage of Highly Volatile Organic Compounds
Part B, Section III.	V. Disposal of Volatile Organic Compounds
Part B, Section IV.	VI. Storage and Transfer of Petroleum Liquids
Part B, Section V.	VII. Crude Oil
Part B, Section VI.	VIII. Petroleum Processing and Refining
Part B, Section VII.	XV. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities
Part B, Appendix B	Appendix B. Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks
Part B, Appendix C	Appendix C. Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants (Vapor Balance System)
	Appendix E – deleted, paragraphs B and E moved into section, and references replaced with EPA Method 27

Part C	
Part C, Section I.	IX. Surface Coating Operations
Part C, Section II.	X. Use of Cleaning Solvents
Part C, Section III.	XI. Use of Cutback Asphalt
Part C, Section IV.	XIII. Graphic Arts and Printing
Part C, Section V.	XIV. Pharmaceutical Synthesis
Part C, Appendix D	Appendix D. Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers
Part C, Appendix E	Appendix F. Emission Limit Conversion Procedure

Part D	
Part D, Section I.	XII. Volatile Organic Compound Emissions from Oil and Gas Operations
Part D, Section II.	XVII. (State Only, except Section XVII.E.3.a., which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines
Part D, Section III.	XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations
Part D, Section IV. (State Only) Control of emissions from the transmission and storage segment	NEW
Part D, Section V. (State Only) Oil and Natural Gas Operations Emissions Inventory	NEW

Part E	
Part E, Section I.	XVI.A.-C. (natural gas fired reciprocating internal combustion engines in the 8-hour ozone control area) and XVII.E. (new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines)
Part E, Section II.	XVI.D. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area
Part E, Section III.	XIX. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-Hour Ozone Control Area
Part E, Section IV.	XX. Control of Emissions from Breweries in the 8-Hour Ozone Control Area

Part F	
	XXI. Statements of Basis, Specific Statutory Authority and Purpose

State Implementation Plan Revisions (Part D, Section I. (formerly Section XII.))

The Commission adopted several revisions to the SIP provisions that were previously found in Section XII. While not strictly necessary to comply with a particular CAA requirement pertaining to ozone, the revisions implement the mandate of SB 19-181, strengthen Colorado's Ozone SIP, and will achieve further reductions in ozone precursors and other hydrocarbons.

Applicability (Section I.A)

The Commission revised the applicability language of Part D, Section I. to clarify that all oil and gas operations at and upstream of the natural gas processing plant are subject to the provisions of Section I., as more specifically set forth in Sections I.A through L. The Commission also revised the applicability to ensure that storage tanks containing hydrocarbon liquids (*e.g.*, condensate, crude oil) and produced water are subject to the provisions of Section I., which previously applied only to condensate storage tanks.

Further, under previous provisions, owners and operators of condensate storage tanks for which the APENs reflecting emissions from all operations were 30 tpy VOC or less were exempted from Section I. Given the challenges with attaining the ozone NAAQS, the number of tanks that were exempt under this provision, and the need for further reducing emissions from those tanks, the Commission removed this exemption.

However, the Commission retained the exemption from the system-wide control strategy in Section I.I. (formerly Section XII.I.) for owners or operators of natural gas compressor stations that do not also own or operator exploration and production facilities and the exemption in Section I.G. (formerly XII.G.) for owners or operators of natural gas processing plants. Owners or operators of these facilities must continue to control condensate storage tanks as specified in Sections I.I. and I.G. By retaining these exemptions, the Commission does not intend to exempt these facilities from any applicable requirements in Part D, Section II.

Storage Tank Controls (Section I.D)

In 2004, the Commission adopted the initial system-wide control strategy, which required operators to reduce emissions from their system of condensate tanks. The “system” was comprised of condensate tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy, and allowed operators to decide which tanks to control so long as emissions from the “system” were reduced by specified percentages. The system-wide control strategy involved complicated and often times confusing recordkeeping and reporting. Further, the system-wide control strategy had the unintended impact of disincentivizing operators to build new facilities without storage tanks (a real emissions benefit), because operators could not take credit for the production at tankless facilities in their “system.” As a result, the Commission replaced the system-wide control strategy with a straightforward control threshold. Operators in the 8-hour Ozone Control Area will have until May 1, 2020, (prior to summer ozone season 2020) to install controls on storage tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy. Only the requirements for storage tanks with uncontrolled actual VOC emissions equal to or greater than 4 tpy are included in the SIP, while the requirements for the storage tanks between 2 and 4 tpy will remain state-only. This provision expands the control requirements to crude oil and produced water tanks, and will result in several hundred more tanks being controlled. The Commission has reviewed the evidence and has determined that the 4 tpy SIP threshold and implementation timetable is cost-effective, technically feasible, and will ensure no backsliding as provided for in the Clean Air Act, Section 110(l). In Sections I.D.3.b.(v) and I.D.3.b.(vi)., the Commission has required that storage tanks below the 2 tpy threshold that increase emissions above the threshold must be in compliance with 60 days of the first date of the month after which the threshold was exceeded. As a result, if a storage tank exceeds the 2 tpy threshold in September 2020, based on a rolling twelve-month total (*i.e.*, October 2019-September 2020), the tank must have controls installed and operating within 60 days of October 1, 2020. These provisions will not only minimize emissions from storage tanks but will ensure clarity in the applicability of control requirements and will assist Colorado in making additional progress towards attainment of the ozone NAAQS.

The Commission has also determined that storage tanks that cannot install controls by the applicable compliance date may shut-in all wells producing to the applicable storage tanks, so long as production from any well producing into the storage tank is not resumed until controls are installed. It is the Commission's intent that this allowance not apply unless the operator shuts in all wells feeding in to the storage tank/battery requiring controls. This will avoid the need for operators to install control equipment when wells are shut-in and where the operator may determine not to return those wells to production. Further, the Commission intends that the Division will work with operators in the DMNFR to allow for appropriate time to conduct design analyses to comply with Sections I.C.1.b. and II.C.2.a., as long as operators install required controls by May 1, 2020, and are pursuing compliance with reasonable diligence.

The Commission has also included in the SIP in Sections I.D.2.a. and II.C.1.b.(ii) the existing requirements (formerly Sections XII.D.1. and XVII.C.1.c.) that operators of newly constructed tanks employ controls during the first 90 days after the date of first production (this provision was previously designated state-only). However, these revisions to Regulation Number 7, in conjunction with revisions to Regulation Number 3, use the term "commencement of operation" instead of "date of first production." This SIP revision is not part of Colorado's ozone attainment requirements but is directed at making this requirement enforceable by the EPA and members of the public under the CAA. While the Commission does not believe inclusion of this provision in the SIP was required for compliance with Colorado's permitting program in Regulation Number 3 with CAA requirements, including ozone nonattainment area requirements, pursuant to Section 25-7-105.1(1), CRS, including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purpose of permitting.

Storage Tank Monitoring (Section I.E)

The Commission revised Section I.E. to apply the monitoring requirements to all storage tanks controlled pursuant to Section I.D., which will ensure monitoring not only of condensate tanks, but also of crude oil and produced water tanks on a weekly basis. The required inspections have also been updated to include common-sense elements that can have a real impact on performance of well production facility equipment and can reduce emissions. For example, checking that burner trays are not visibly clogged can improve the performance of air pollution control equipment. The Commission does not intend that operators should shut-in the combustor for the sole purpose of performing this inspection to observe the burner tray, and need only inspect those portions of burner trays that are visible without shutting in. The Commission also adopted into Section I.E. requirements that previously existed in Section II. (formerly Section XVII.) to check that pressure relief valves are properly seated and that vent lines are closed. Similarly, to the inspection in Section II.C.1.d.(i), operators are not expected to disassemble or otherwise manipulate the pressure relief valve to complete the inspection, unless the visual observation of the valve reveals it is unseated and corrective action needs to be taken. Further, the Commission does not expect operators to climb on top of a tank to observe the pressure relief valve. However, operators are expected to use an available catwalk or similar permanent access to ensure the best opportunity for inspection, except when a catwalk is not accessible due to a safety hazard.

The Commission has removed references to recordkeeping from Section I.E. and has attempted to condense all recordkeeping requirements in Section I.F. For example, Section I.E.2.c.(iv) no longer provides that operators must "check for and document" the inspection; instead, Section I.E.2.c. requires operators to "check", and the requirement to "document" the inspection is found in Section I.F.2.c.

Recordkeeping and Reporting (Section I.F)

As a result of replacing the system-wide control strategy with the fixed control threshold, the Commission revised the recordkeeping and reporting requirements for demonstrating compliance with Section I.D. Operators subject to the system-wide control strategy will still be required to submit an annual report for calendar year 2019 by the same deadline of April 30, 2020, and are given until August 31, 2020, to submit the report for the time period in 2020 during which the system-wide control strategy remains effective (*i.e.* January 1 – April 30, 2020). In Sections I.F.2. and I.F.3., the Commission has created a new recordkeeping and reporting scheme for the tanks subject to the new control threshold provisions. The Commission has largely maintained the same recordkeeping and reporting requirements for the monitoring provisions in Section I.E. However, the Commission streamlined the new storage tank recordkeeping and reporting requirements, which are included in the SIP for storage tanks at or above the 4 tpy threshold, but are included on a state-only basis for the storage tanks between 2 and 4 tpy.

Miscellaneous

The Commission adopted revisions to definitions (Section I.B.) and the general provisions (Section I.C.). A new definition for "commencement of operation" was added for consistency with Regulation Number 3 and for clarity as to the applicability of other control requirements (previous versions of Regulation Number 7 were tied to the "date of first production," which was not implemented consistently amongst operators). The Commission adopted the term "date of first production" in 2014 with the intent that it coincides with the date reported to the Colorado Oil and Gas Conservation Commission (COGCC) on COGCC Form 5A. Through implementation of the 2014 revisions, differences between the Commission's and the COGCC's use of the term were realized. Therefore, the Commission has replaced "date of first production" with the more clearly defined "commencement of operation" term.

The Commission also adopted new definitions for "hydrocarbon liquid," "produced water," "storage tank," and "storage vessel" to ensure consistency with the state-only program in Part D, Section II. The definition of "storage tank" referred to the federal definition of "storage vessel" and, therefore, captured crude oil and produced water tanks, in addition to condensate tanks. The federal definition has now been included as a standalone definition of "storage vessel."

The Commission also revised Section I.C.1.b. to reflect that Section I. now applies to oil and gas operations collecting, storing, processing, and handling hydrocarbon liquids and produced water, not just condensate. The Commission replaced the term "leakage" with the term "emission" in order to be consistent with the Common Provisions definition of "emission." The Commission does not intend this latter revision to reflect a change in the meaning or applicability of Section I.C.1.b. (or Section II.B.1.a., where this revision is also made), but only to improve clarity.

The Commission revised Section I.C.2., which specifies how operators must calculate emissions and emission reductions for purposes of demonstrating compliance with the control requirements. These revisions expand the current provisions to storage tanks storing hydrocarbon liquids other than condensate and to storage tanks storing produced water. For crude oil tanks and produced water tanks, operators will need to refer to default emission factors as established and updated by the Division. *See, e.g.* PS Memo 14-03, *Oil & Gas Industry Crude Oil, Condensate and Produced Water Atmospheric Condensate Storage Tanks, Regulatory Definitions and Permitting Guidance for General Permit GP08.*

The Commission has not substantively revised the LDAR SIP provisions of Section I.L. but clarified that applicability is based on emissions on a rolling twelve-month basis, not a calendar year basis. Such was the Commission's intention in adopting the program in 2017.

The Commission has also determined to incorporate Section II.F. (formerly Section XVII.G.) into the SIP. This provision requires control of emissions coming off a separator after a well is newly constructed, hydraulically fractured, or recompleted. These emissions must be routed to a gas gathering line or controlled by air pollution control equipment. This SIP revision is not part of Colorado's ozone attainment compliance requirements, but is directed at clarifying that this requirement is enforceable by the EPA and members of the public under the CAA. Including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purposes of permitting. *See* Section 25-7-105.1(1), CRS.

State-wide, State-Only Revisions (Part D, Section II. (formerly Section XVII.))

In Part D, Section II., the Commission adopted several revisions to begin its implementation of SB 19-181. These revisions further support existing control requirements and also seek reductions from previously unregulated emissions activities (*e.g.,* gauging and loadout).

Storage Tank Controls, Monitoring, Recordkeeping, and Reporting (Sections II.C.1.c., II.C.1.d., II.C.2.b. and II.C.3.)

Since 2011, Colorado has made significant progress in reducing emissions from storage tanks. However, storage tanks remain the largest source not only of oil and gas VOC emissions, but of all anthropogenic VOC emission sources in the state (per the 2017 nonattainment area emissions inventory in the Moderate area ozone nonattainment SIP). The Commission has determined that it is cost effective and technically feasible to lower the control threshold from 6 tpy VOC (as established in 2014) to 2 tpy VOC. However, the Commission does not want to facilitate or encourage the use of supplemental fuel to operate control equipment, and understands that this can occasionally be an issue on the West Slope, in particular, where the facilities have lower pressure. The Commission has therefore adopted a provision that allows operators to seek from the Division an exception to controlling tanks between 2 and 6 tpy VOC under these circumstances. Exceptions should be sought prior to compliance deadlines, and will be effective upon submittal unless and until the Division determines an exception is not appropriate. Storage tanks constructed on or after March 1, 2020, must have controls upon commencement of operation, ensuring reductions during the 2020 summer ozone season. Storage tanks outside the nonattainment area constructed prior to March 1, 2020, must be in compliance by May 1, 2021. The Commission determined it was appropriate to give tanks outside the nonattainment area between 2 and 6 tpy VOC extra time to install controls. The Commission does not intend to give extra time to storage tanks with air pollution control equipment already installed, even where controls are not currently required by Regulation Number 7 (e.g., where an operator has submitted an APEN claiming controls).

The Commission revised the approved instrument monitoring method (AIMM) schedule for inspections of controlled storage tanks to align with the Commission's revision of the LDAR inspection frequencies in response to SB 19-181, discussed further below. The Commission adopted a semi-annual frequency for storage tanks with emissions greater than or equal to 2 tpy and less than or equal to 12 tpy. For storage tanks with emissions greater than or equal to 6 tpy and less than or equal to 12 tpy, this is an increase in inspection frequency from annual to semi-annual. Where the Commission specifies that semi-annual monitoring must "begin" in a certain year, the Commission intends that there be at least two AIMM inspections during that year. The Commission also removed the phase-in schedule for storage tanks inspections (within 90 days of January 1, 2016 for storage tanks $\geq$ 6 and within 30 days for storage tanks > 50 tpy) as those schedules have passed. The Commission updated the recordkeeping requirements for AIMM inspections to be consistent with the LDAR recordkeeping in Section II.E. Records of AIMM inspections under Sections II.C. and II.E. may be maintained together, and need not be kept separately.

The Commission has also strengthened monitoring requirements for storage tanks and associated equipment. In Section II.C.1.d., the Commission has determined that it is cost effective and feasible, while already on-site for visual inspection, to check the dump valve on the separator to ensure that it is not stuck open or visibly clogged. The Commission does not intend that operators will need to manipulate equipment or stay on-site for the purpose of observing actuation of the dump valve for purposes of this inspection requirement. The Commission has also determined that excess liquids in the vapor lines can cause a multitude of problems, including over pressurization of the tanks or smoking flares. Therefore, the Commission is directing operators to check liquid knockout vessels, when present, unless the vessel is set up to drain automatically, and to drain liquids if above the low-level indication point. If the knockout vessel is not equipped with a liquid level indicator, operators can comply with this requirement by draining the knockout vessel during the inspection. Further, for underground lines and above-ground lines where no knockout vessel is used, operators should establish a procedure by which they evaluate for the presence of liquids in the vapor lines, and drain as necessary. Appropriate operating and maintenance program documents should set forth this procedure so as to provide clarity on how an operator determines draining is necessary. These actions can be taken while the operator is already on-site for the inspections previously required, are consistent with actions the Commission generally understands operators are already taking in the field and therefore, the Commission does not expect these actions to create additional burden.

The LDAR program in Section II.E. (formerly Section XVII.F.) has required remonitoring following repair of a leak (as has Section I.L.). However, Section II.C. did not include an explicit remonitoring requirement following actions taken to address venting from storage tanks. Operators must now confirm that actions taken to address venting were effective through remonitoring. This confirmation must be made within 24 hours of the action taken to address the venting. This requirement does not reflect a timeframe in which the operator may address the venting without incurring liability for the violation. There is currently no regulatory period in which venting will not be considered a violation of Section II.C.2.a., unless the venting is reasonably necessary for one of the reasons expressly contemplated by Section II.C.2.a. Only where the initial emissions observation was observed through AIMM does the success of the response action need to be verified through AIMM. However, the Commission believes that if the venting was found with an IR camera and was addressed while the IR camera operator was on-site, then there is little to no burden to use the IR camera to confirm, for example, an effective seating of the thief hatch upon closure. In Section II.C.3.f., the Commission has established supplemental recordkeeping requirements when venting is observed and addressed.

In Section II.C.3.d., the Commission has strengthened recordkeeping requirements of inspections under Section II.C.1. These recordkeeping requirements are consistent with the recordkeeping required in Section I.F. (formerly Section XII.F.). The Commission has maintained the exemption from recordkeeping under Section II.C.3.b., for instances where venting is reasonably necessary for maintenance, gauging (unless a storage tank measurement system is required under and the operator complies with Section II.C.4.), or safety of personnel and equipment. However, the Commission expects that the emissions associated with these venting events will be reported in the annual emissions inventory.

Storage Tank Measurement Systems (Section II.C.4.)

Historically, operators have needed – for operational purposes – to open the thief hatch on storage tanks in order to sample and measure the level of the liquid to be sold (i.e., to determine quality and quantity). Technology has advanced over the past few years, including, without limitation, the use of Lease Automatic Custody Transfer (LACT) units, automated tank gauges, and the development of API 18.2 (Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods), which allow for the sampling and measurement of liquids without opening the thief hatch. It is the Commission's intention that owners and operators of facilities and tanks constructed after the deadlines in new Section II.C.4. must measure the level of the liquid (e.g., use tank level sensors) and sample the liquids (e.g., check for temperature, BS&W, and other indicia of merchantability) without opening the thief hatch. These storage tank measurement systems can be employed at facilities with and without automation.

Further, a significant number of operators have already deployed such systems at large and small facilities in the DJ Basin, in some cases voluntarily and in some cases as required pursuant to a Consent Decree or Compliance Order on Consent. The Commission notes that a storage tank management system may be different for tanks where liquids are both sampled and measured than for tanks where liquids are not sampled. For example, Commission understands that some produced water tanks are not sampled for quality, and therefore do not need to have equipment to allow for the sampling of the liquids without opening of the thief hatch.

Therefore, the Commission adopted a requirement to employ storage tank measurement systems to determine the quantity of the liquid at well production facilities, natural gas compressor stations, and natural gas processing plants constructed on or after May 1, 2020. Any such facilities that are constructed after January 1, 2021, must have storage tank management systems in place that determine both the quality and the quantity of the liquid. This requirement also applies to storage tanks at existing well production facilities, natural gas compressor stations, and natural gas processing plants that are modified by adding storage tanks. When operators add new storage vessels to existing facilities (e.g., to add capacity because production or throughput is expected to increase), they must outfit the new storage vessels and retrofit the existing vessels in the same battery with a storage tank management system. However, the ability to retrofit an existing battery may not exist, and is therefore not required, where a single storage tank is replaced due to maintenance concerns or where a tank is installed to provide extra head space in the vapor control system, but no production increase is associated with the installation.

The Commission has adopted minimal recordkeeping provisions for this requirement, including a description of the storage tank measurement system and records of the annual training program. The description must be sufficiently detailed to enable the Division to determine whether the operator is in compliance (e.g., sampling the liquids without opening the thief hatch). If an operator relies on a third party (e.g., hauler) to perform the gauging activities, those operators will need to work with the haulers to facilitate the training that will familiarize haulers with this new requirement.

The Commission has also adopted a requirement to allow for periodic calibration and testing of the storage tank measurement system. The Commission recognizes that while the Bureau of Land Management expressly allows for automatic tank gauging (*see e.g.* 42 C.F.R. Section 3174.3(33), incorporating by reference API 18.2), it can be necessary to test and calibrate the automatic tank gauging system. *See* 42 C.F.R. Section 3174.6(b)(5)(ii)(B). It is not the Commission's intent to adopt requirements at odds with the Bureau of Land Management. Further, some manufacturers may recommend inspection, testing, or calibration more frequently than specified by the Commission; the Commission intends to allow for those maintenance procedures, as reasonably necessary (i.e., the exception should not render ineffective the Commission's intent that thief hatches remain closed during the sampling and measurement process). Operators that perform maintenance procedures more frequently than semi-annually need to document the manufacturer's recommendation for the increased frequency and provide those materials to the Division upon request.

Hydrocarbon Liquids Loadout (Section II.C.5)

In Section II.C.5., the Commission has adopted new requirements to control or avoid emissions associated with the unloading of hydrocarbon liquids into transport vehicles (e.g., trucks). These requirements do not apply to produced water loadout. The Commission has determined to prohibit the venting of hydrocarbons during loadout activities, because the venting is not reasonably necessary within the meaning of Section II.C.2.a.; however, the Commission notes that some thief hatches may be "open" during loadout but are not emitting and are instead operating only as vacuum relief for the storage tank. An "open" pressure relief device that does not emit, but instead creates a vacuum, would not be a violation of the prohibition on venting during loadout, though the burden will remain on operators to demonstrate that any open pressure relief devices are not venting.

These requirements will apply to well production facilities, natural gas compressor stations, and natural gas processing plants constructed before and after May 1, 2020, with annual hydrocarbon liquid loadout throughput equal to or greater than 5,000 barrels per year, on a 12-month rolling basis. Throughput is based on the throughput of liquids loaded out to transport vehicles and does not include liquids loaded out to pipeline. Facilities constructed after May 1, 2020, must control emissions from loadout upon commencement of operation if they anticipate having a loadout throughput over 5,000 barrels per year. Facilities that are modified (e.g., new well drilled, well re-fracked or recompleted) that expect to have throughput over 5,000 barrels per year must also control loadout operations upon commencement of operation following the modification. Facilities that increase throughput such that loadout throughput reaches 5,000 barrels must control the emissions from loadout upon reaching 5,000 barrels. The Commission does not intend that operators may loadout more than 4,999 barrels of hydrocarbon liquids without controls. Thus, if an operator currently loads out to pipeline, and is not subject to this requirement, but the pipeline becomes unavailable (e.g., due to maintenance, whether scheduled or unscheduled) and the operator has 6,000 barrels stored in tanks, the operator must control the emissions from the loadout to transport vehicles or wait to loadout to transport vehicles until it can arrange for controls.

The Commission recognizes that compliance may be more cost effective at newly constructed facilities for several reasons. Operators may account for the vapors associated with loadout in the initial evaluation of air pollution control equipment required. Operators may also design the facility to make compliance easier, with both these requirements and Section II.C.4. However, the Commission has determined that it is also cost-effective and technically feasible to retrofit existing facilities to control loadout emissions. Operators using air pollution control equipment to control loadout emissions must also comply with other Regulation Number 7 requirements applicable to air pollution control equipment (e.g., inspections, recordkeeping). Further, if operators employ vapor collection and return systems, operators should include this vapor source in the engineering evaluation of their storage tanks and vapor control systems to avoid over-pressurizing the tanks.

The Commission has also established additional requirements to ensure the effective control of loadout emissions, including many requirements that the Division has previously established as permit RACT (under Regulation Number 3 and not as categorical RACT used for ozone SIP purposes) in loadout permits. The Commission determined that observation of and/or training and signage related to the loadout process by operators will help ensure that new staff and third parties are effectively implementing these requirements. The Commission directed the Division to develop a template and/or guidance regarding expectations for signage. However, if tanks are loaded out less frequently than monthly, the observation needs to take place during loadout when it does occur, unless observation is not feasible. If observation is not feasible (e.g., the operator did not receive notice of the loadout, which occurred during the middle of the night when no operator personnel was on site), the operator must inspect the facility within 24 hours to ensure that loadout equipment was properly stored and that thief hatches were closed. The Commission encourages the Division to work with operators to better understand when observation is, or is not, feasible.

Leak Detection and Repair (Section II.E)

In SB 19-181, the Legislature directed the Commission to minimize emissions from the oil and gas sector, including the gathering and boosting segment (i.e., compression). In conjunction with this directive, SB 19-181 further instructed the Commission to consider semi-annual monitoring for leaks at well production facilities. Therefore, the Commission has revised the LDAR program of Section II.E. (formerly Section XVII.F.) to increase the frequency of approved instrument monitoring method (AIMM) inspections to semi-annual at compressor stations with emissions between 0 and 12 tpy VOC and at well production facilities with emissions between 2 and 12 tpy VOC. Phase-in of these new inspections begins in 2020, and the Commission expects that operators will conduct the first semi-annual inspection prior to the start of the summer ozone season (i.e., May 1, 2020). Current requirements in place for larger facilities to inspect on a more frequent basis remain unchanged.

The Commission adopted a proposal to require enhanced leak detection and repair requirements for facilities within 1,000 feet of an occupied structure. The commission also directed the Division to work on a proposal that would speed up repair times in these areas and bring forward for the Commission's consideration in a future rulemaking hearing as soon as possible.

There are no other substantive changes to the existing LDAR program.

Emissions Associated with Well Maintenance, Unloading, and Plugging Activities (Section II.G)

In 2014, the Commission adopted a requirement that operators use best management practices (BMPs) to minimize hydrocarbon emissions and the need for well venting associated with well liquids unloading and well maintenance. The Commission is replacing the term "venting" with "emissions" or "emitting" to ensure consistency with the Common Provisions definition of "emission" and to avoid any confusion with the new definition of "venting" that was added to Section II.C.2.a.(i) (formerly Section XVII.C.2.a.(i)) in 2017, though no change in meaning or applicability is intended. The Commission has determined that BMPs should also be employed to reduce emissions from the well associated with well plugging activities. These activities have been increasing in frequency in the DMNFR in recent years, and the Commission finds that BMPs are a cost-effective and flexible proactive strategy to address this emerging emissions source. BMPs include both practices that reduce the need for well liquids unloading or well maintenance activities and practices that reduce or control emissions resulting from the well maintenance, well liquids unloading, and well plugging activities.

The Commission has also clarified and strengthened the recordkeeping and reporting requirements associated with the well emissions and BMPs. The inventories that will be required to demonstrate attainment with the ozone NAAQS in future SIPs necessitate detailed information on the emissions associated with these activities. Further, understanding BMPs employed to reduce or eliminate these emissions will assist the Commission in developing both voluntary and regulatory strategies to make further progress towards attainment. In an effort to minimize duplication with the new emissions inventory in Section V., the Commission intends that all information associated with activities covered by this Section II.G. will be reported on a separate form and not as part of the Section V. inventory. While recordkeeping is to begin in July 2020, the Commission understands that current methods of reporting emissions from these activities may need to be updated or improved in the future, and the Commission directs the Division to work with stakeholders to update emission factors and/or calculation methods as necessary.

Miscellaneous

Section II.C.2.a. prohibits the venting of hydrocarbons, unless reasonably required for maintenance, gauging, or safety. The Commission now clarifies that venting during gauging is expressly prohibited under this requirement where a storage tank measurement system is required under Section II.C.4. If Section II.C.4. allows for the opening of the thief hatch, that activity will not be considered venting within the meaning of Section II.C.2.a.

The Commission has revised Section II.C.2.b.(i), to reflect its intention in adopting the STEM provisions in 2014. The Commission intended in 2014, and specifically noted in the Statement of Basis and Purpose at that time, that STEM plans should include an analysis of the engineering design of the storage tank and associated air pollution control equipment (i.e., the vapor control system) to ensure that storage tanks are not over pressurized, causing excess emissions. The Commission believes that operators now largely understand and comply with this requirement, but has clarified the language in the rule itself principally to aid operators that may be new to the control program as a result of the new, lower control threshold. The Commission notes that this requirement does not require that operators maintain a site-specific design analysis for each facility. Worst-case design analyses or like-kind design analyses for similarly configured facilities may be utilized; however, the burden remains with the operator to show that the design analysis provided for the facility demonstrates adequacy of design.

Further, the Commission acknowledges that closed-loop tank pressure control systems designed to maintain tank pressures below a specified point can be, if designed and operated property, indicative of adequate design. The Commission also acknowledges that design analyses do not need to be maintained within the STEM plan itself, so long as the STEM plan contains a description of the design analysis method employed and specifies the name and location of the design analysis for each facility covered by that STEM plan.

Pneumatic Controllers (Part D, Section III.)

SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.

The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.

The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings.

Downstream transmission (Part D, Section IV.)

SB 19-181 also directed the Commission to consider adopting a requirement that owners and operators of oil and gas transmission pipeline and compressor stations inspect and maintain all equipment and pipelines. The Commission's Regulation Number 7 has not historically regulated the transmission and storage segment, which includes pipeline, compressor stations, and other equipment transporting and storing natural gas downstream of the natural gas processing plant and prior to the distribution segment. Transmission pipelines, however, have been subject to federal and state pipeline safety regulations.

To address the new directive to minimize emissions from the transmission segment, the Commission adopted an innovative program that directs the setting of a methane intensity target and associated programmatic framework. This approach is the second recommendation from the SHER team, and again comes before the January 2020 deadline established by the Commission in November 2017. SHER team stakeholders involved in developing this program include trade associations, transmission segment operators, environmental and citizen groups, local governments, and the Division. The Division will approve a steering committee charter that will detail the purpose, responsibilities, and deliverables of the steering committee. The steering committee will develop an emissions protocol detailing the calculation and reporting of VOC, CO, NOx, ethane, and methane emissions and any associated program guidance documents or templates by September 30, 2020, determine a segment methane emissions intensity target by October 1, 2023, and certify initial target compliance based on the 2024 data. Each owner or operator in the segment will develop a company-specific best management practice (BMP) plan, the elements of which are enforceable by the Division. A goal of this program is continual improvement over time through review of BMPs, assessment of reported emissions and emissions intensity, and analysis of other data and best practices. In furtherance of this goal, the steering committee will periodically reassess the emissions intensity target and may consider, among other factors, the potential to reduce emissions from events beyond the control of the owner or operator.

The Division will provide an update on the development of the program to the Commission in 2021 as well as periodic updates regarding the progress of the program. The program will include a reporting element to demonstrate compliance and continual improvement. The steering committee will develop the criteria by which the industry participants will select a third-party contractor to collect and aggregate the company-wide reports into the segment-wide report prior to the first report due date of September 30, 2022. The third-party contractor, with involvement from the transmission segment owners or operators, may also provide VOC, NOx, and CO emissions data from the annual company-wide reports to the Division related to ozone modeling as needed and requested. Each year after the segment-wide emissions intensity target is established, the steering committee will submit a compliance certification to the Division that the transmission segment achieved the target. If such certification cannot be made, the steering committee will develop a plan for the segment to achieve compliance with the target. This plan, if needed, may include amendments to the program guidance documents, prescriptive control requirements, or other strategies to reduce methane emissions such that the transmission segment achieves the segment-wide emissions intensity target.

The inventory protocol may be based on existing EPA estimation and reporting mechanisms, specifically the EPA's Greenhouse Gas Reporting Program (GHGRP) and the Greenhouse Gas Inventory (GHGI). The emission estimation mechanisms may be updated as emission factors or calculation methods are revised. The inventory protocol will include the method(s) by which the transmission segment owners or operators will quantify and report emissions. The findings of the Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems (MAC) report (May 2016), among other data sources, may be used to develop the segment-specific methane emission reduction goals that, when combined, will achieve the transmission segment's emission intensity target in a cost-effective manner.

Annual inventory (Part D, Section V)

The Commission established an annual emissions reporting requirement to regularly update the Division's emissions inventory for equipment and activities in oil and gas operations. This inventory is intended to assist Colorado in ozone planning and the creation of emission inventories for use in ozone attainment modeling, as well as to comply with the directives in SB 19-181 to minimize emissions from the oil and gas sector. This inventory will provide missing information about oil and gas operations and will supplement the limited information provided on other aspects of those operations to assist the Commission in identifying emission sources appropriate for further emission reduction strategies.

Additionally, this inventory will also help Colorado move forward in beginning to address the broad greenhouse gas directives in SB 19-096 (Concerning the collection of greenhouse gas emissions data to facilitate the implementation of measures that would most cost-effectively allow the state to meet its greenhouse gas emissions reductions goals) and HB 19-1261 (Concerning the reduction of greenhouse gas pollution, and, in connection therewith stablishing statewide greenhouse gas pollution reduction goals). This inventory is separate and apart from the APEN reporting and fee structure in Regulation Number 3, though the Commission expects that the Division, in consultation with stakeholders, will consider ways to align the reporting programs in the future to minimize duplication.

Operators will be required to submit a company-wide report on June 30 of each year for the preceding year. The first report will be due on June 30, 2021, covering emissions from July 1, 2020, through December 31, 2020. Operators are required to use the Division-approved form. The Commission expects that the Division will consult with stakeholders in the development of this form (or forms). The Commission understands that some of the emissions source category activities and equipment are not currently well defined, nor is there necessarily a well understood method of calculation for emissions (e.g., downhole well maintenance). The Commission therefore directs the Division to work with stakeholders from the adoption of this regulation throughout 2020 to, among other things: (1) appropriately define each emissions source category, activity, and equipment; and (2) identify reasonable methods of calculation for each emissions source category activity and equipment. For some emissions source category activities and equipment, achieving both goals may not be realistic before recordkeeping must begin in July 2020. Therefore, for those limited categories, the Commission expects that the Division will identify parameters that may be reported (e.g., frequency and duration) until such time as the category can be well defined and an appropriate calculation method can be identified. The Commission's intent here applies also to the well emissions reported under Section II.G.

Operators will need to include actual emissions information for various air pollutants, specifically methane, ethane, VOC, CO and NOx, for each emissions source category activity and equipment, as well as company-wide. The Commission has determined that monthly emissions information should be submitted for the summer months (May through September), while emissions for the remaining months can be aggregated into the annual figures. The Commission recognizes that, over time, these emissions inventories are likely to reflect ongoing emission reductions from the industry resulting from both the continued implementation of emission reduction strategies and the refinement of emissions estimation techniques. The Commission also recognizes that the emission estimation techniques used for inventory purposes may differ from regulatory methods for calculating, recording, and reporting emissions under the APEN and permitting program, and intends that such differences will be considered in any enforcement matter. It is critical that these inventories be as accurate and complete as possible, and operators are expected to perform quality assurance on the data prior to submittal. However, these inventories will require the submittal of a large amount of information, so operators are provided with timeframes for correcting information found to contain substantive errors.

The Commission directed the Division to report back to the Commission in 2020 regarding the inventory and progress made.

Ozone State Implementation Plan Revisions for Serious Reclassification (Part C, Section II.F. (new section in former Section X.; Part E, Sections II. and III. (formerly Sections XVI.D. and XIX.)

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the CAA's Serious ozone nonattainment area requirements, as set forth in CAA Sections 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., major stationary sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, to address the CAA Serious RACT SIP requirements, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx (which became major sources as of the effective date of the reclassification to Serious). The revisions include expanding the applicability of the combustion equipment requirements, including the combustion process adjustment requirements, in Section II. to equipment located at facilities with NOx emissions greater than or equal to 50 tons per year; incorporating by reference NSPS and/or NESHAP requirements for specific points at some 50 tpy major sources in Section III.; requiring some sources submit RACT analyses to the Division in Section III.; and a new categorical rule regarding general solvent use in Part C, Section II.F.

Consistent with Senate Bill 19-181, House Bill 19-1261 and Senate Bill 19-096, the Commission directs the Division to propose regulatory recommendations to the Commission in 2020 regarding: pneumatic devices that do not vent gas; continuous emission monitoring; alternatives to combustion for emissions control; enhanced LDAR, especially near occupied dwellings; and other options to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen from oil and natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmissions segments of the natural gas supply chain," Colo. Rev. Stat. Section 25-7-109(10)(a), including "pre-production activities, drilling, and completion," id. Section 25-7-109(10)(c).

To increase transparency and accountability, the Commission further directs that in 2020 the Division explore options for developing a publicly accessible and searchable oil and gas complaint filing and tracking tool, and to accept public input on the development of this tool. The Division will report back to the Commission on its progress in 2020.

SIP streamlining (Part B, Sections IV. and VII. (formerly Sections VI. and XV.) and Appendices B, C, and E)

As a SIP clean-up effort, the Commission adopted revisions to Regulation Number 7, Part B, Sections IV. and VII. and removed Appendix E so the requirements align with current EPA methods and requirements.

In 1980, the Commission adopted requirements in Regulation Number 7, Section IV. requiring an annual pressure test for gasoline transport trucks. Those requirements were based on EPA's Control Techniques Guidelines (CTG) Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (December 1978) and included the test procedures for annual pressure and vacuum testing of gasoline transport trucks, as outlined in Appendix E. In 1980, The Commission also adopted Appendix B which specifies the criteria for controlling vapors from gasoline transfer to storage tanks. Those requirements are based on EPA's CTG Design Criteria for Stage I Vapor Control Systems Gasoline Service Stations (November 1975). EPA approved these provisions into Colorado's SIP in 1995.

Since the publication of EPA's CTGs, EPA has published similar requirements for gasoline transport trucks in EPA's NSPS Subpart XX Standards of Performance for Bulk Gasoline Terminals (40 CFR Part 60, Subpart XX (August 18, 1983, last revised December 19, 2003)); NESHAP R National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) (40 CFR Part 63 Subpart R (December 14, 1994, last revised April 6, 2006)); NESHAP Subpart BBBBBB National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (40 CFR Part 63, Subpart BBBBBB (January 10, 2008, last revised January 24, 2011)); and NESHAP Subpart CCCCCC National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities (40 CFR Part 63, Subpart CCCCCC (January 10, 2008, last revised January 24, 2011)). These federal standards reference EPA's Method 27, Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test, in contrast to the CTG's pressure-vacuum test.

The Commission adopted provisions to replace the outdated vacuum-pressure test in Regulation Number 7 with the more current EPA Method 27. The Commission also updated the test values in Regulation Number 7, which are based on EPA's CTG but also correspond to the EPA Method 27 test values in EPA's NSPS XX, NESHAP R, NESHAP BBBBBB, and NESHAP CCCCCC. The Commission also revised the recordkeeping and certification requirements in Section IV. to correspond to EPA's Method 27 and federal standards. Lastly, the Commission clarified the requirements for owners or operators using vapor collection systems that such systems must be leak-tight and properly maintained and operated.

These revisions will update Colorado's SIP and align the gasoline transport truck, terminal, and service station control and testing requirements with current EPA NSPS and NESHAP standards.

Miscellaneous

The Commission has also adopted revisions to provisions not discussed in detail above in order to facilitate and align the substantive revisions identified, including revisions to the Applicability in Part A, Section I.A., and exemptions in Part A, Section II.B.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone serious nonattainment area requirements. The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 that are unrelated to the reclassification to serious to update and streamline requirements for gasoline transport trucks, terminals, and service stations to align with current federal requirements; therefore, these revisions do not exceed or differ from the federal act or rules thereunder. Further, the Commission adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Sections II. (except II.C.1.b.(ii) and II.F.), III.F., IV., and V. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including storage tanks, storage tank loadout, fugitive emissions from components, pneumatic controllers, and downstream transmission operations. The proposed revisions also include an annual oil and gas sector emissions inventory report. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, the Greenhouse Gas Reporting Program (GHGRP), and Pipeline and Hazardous Materials Safety Administration (PHMSA) may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks and fugitive emissions components then the NSPS and NESHAP and more facilities and operations than the GHGRP and PHMSA.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx (> 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part E, Sections II. and III. to include categorical RACT requirements for combustion equipment at major sources of NOx and incorporate by reference federal standards for specific sources or points. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment. The Commission also revised Regulation Number 7 to include categorical RACT requirements for general solvent use and is not aware of federal rules applicable to general solvent use.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits.

(V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Part D, Sections I. through IV. strengthen Colorado's SIP state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections II.F. recognize practices currently utilized by solvent operations. The revisions to Regulation Number 7, Part E, Sections II. and III. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Part D, Sections I. through V. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C, Sections II. and Part E, Section II. similarly establish the categorical RACT requirements for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, or if Colorado continues to fail to achieve the NAAQS, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing an annual oil and gas inventory report are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for storage tanks and component leaks. Other revisions reflect changes in industry practice, such as for solvent use. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) The revisions adopted will reduce significant amounts of VOC and methane, addressing both Colorado's ozone problems and making strides to reduce the impact of climate change. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements related to LDAR, pneumatic devices, monitoring, and the transmission segment. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

Hundreds of people from across the state submitted written comments on the proposed changes to Regulations 3 and 7. Most of these written comments called for additional regulation of oil and gas operations, to fulfill the directives of SB 19-181, protect public health, and reduce greenhouse gas emissions. Prior to the rulemaking hearing, the Commission held public comment sessions in Rifle, Durango, and Loveland, on December 10, 11 and 16, respectively. Dozens of members of the public spoke at each of these sessions. Many commenters expressed support for the proposed changes to Regulations 3 and 7, citing concerns about risks to health and to the climate from oil and gas emissions. Many commenters at the Rifle and Durango meetings emphasized the need for rules to be applied statewide. Commenters also called on the Commission to develop requirements for continuous monitoring of oil and gas emissions. Some speakers at each comment session expressed concern that the industry was being overregulated, with some on the Western Slope emphasizing that their part of the state was in attainment with ozone standards and expressing concerns with the impact more stringent rules might have on the industry.

T. September 17-18 & 23, 2020 (Part D, Sections II., IV., V., VI. and Part E, Section I.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act § 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

Basis

The Commission revised Part E, Section I. to reduce emissions from natural gas fired reciprocating internal combustion engines (RICE) greater than or equal to 1,000 horsepower (hp) on a state-wide basis. The revisions are in response to four distinct directives to secure reductions: Senate Bill 19-181 (SB 19-181); the second implementation period of the Regional Haze Rule pursuant to Clean Air Act Section 169A; progress towards the 2008 ozone National Ambient Air Quality Standard (NAAQS) of 75 ppb and 2015 ozone NAAQS of 70 pp; and to address nitrogen deposition at Rocky Mountain National Park (RMNP).

The Commission also revised Part D, Sections II.G., IV., and V. to include annual reporting of carbon dioxide (CO2) and nitrous oxide (N2O) and Section V. to include additional emissions reporting from class II disposal well facilities. The Commission adopted a new Part D, Section VI. requiring owners and operators of pre-production oil and gas operations to monitor pollution during pre-production (i.e., drilling through flowback) and early-production and to control emissions from pre-production tanks and vessels (i.e., flowback vessels). Lastly, the Commission expanded the requirements in Part D, Section II. to control emissions from hydrocarbon liquids loadout at class II disposal well facilities. These proposed revisions are a next step in addressing the directives of SB 19-181, SB 19-096, and HB 19-1261, building upon revisions adopted by the Commission in December 2019.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, et seq. (Act), specifically § 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations. Sections 25-7-109(1)(a), (2), and (3) authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources; emission control regulations pertaining to NOx, hydrocarbons, and hazardous air pollutants; and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Section 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane, and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Purpose

To address SB 19-181, SB 19-096, HB 19-1261, ozone, visibility, and nitrogen deposition, the Commission adopted revisions to Regulation Number 7 that limit emissions from engines, limit emissions from pre-production tanks, reduce emissions from hydrocarbon liquids loadout at class II disposal well facilities, require reporting of emissions from class II disposal well facilities, expand annual reporting to include additional greenhouse gases, and require monitoring at pre-production and early production oil and gas operations. These revisions are all adopted on a state-wide and state-only basis.

Engines (Part E)

The Commission adopted requirements in Part E, Section I. to minimize emissions from natural gas fired RICE. The requirements apply to natural gas fired RICE greater than or equal to 1,000 HP. The requirements are responsive to SB 19-181 as it applies to engines used in the oil and gas sector, as well as securing NOx reductions that will also reduce ozone, visibility, and nitrogen deposition at RMNP.

Except for the combustion process adjustment requirements for engines at major sources, the Commission has not revised the requirements pertaining to engines since 2010, and emissions from engines associated with oil and gas production in Colorado have continued to increase. While the Commission recognizes the twin challenges currently faced by the oil and gas industry in Colorado - the COVID-19 pandemic and low oil prices - this regulation's provisions for phasing in compliance over time and, particularly, the unique characteristics of the Alternative Company-Wide Compliance Plan (Company-Wide Plan, affords the industry the flexibility necessary to achieve emission reductions necessary to protect public health and the environment in a cost effective manner.

Applicability (Section I.D.5.a.)

The Commission adopted a new subpart, Section I.D.5., to establish state-only standards to reduce emissions from a subset of existing stationary engines operating over or equal to 1,000 HP and those placed in service, modified, or relocated after November 14, 2020. As defined in the rule, "placed in service" addresses when an engine is brought to a site for utilization. "Placed in service" is a new term that deviates from the Division and industry's traditional reliance on the defined term "commence construction" or NSPS JJJJ's reliance upon manufacture date.

The Commission is clarifying when replacement of an engine under an authorized alternative operating scenario (AOS) would not trigger the engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. Subsequent replacements under an authorized AOS also would not trigger the replacement engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. If an engine is replaced under an AOS, while it may not trigger the lower standards based on "placed in service," it may nonetheless trigger the lower standards if it is "relocated" – i.e. if the replacement engine is brought into Colorado from outside Colorado, or brought into the nonattainment area from outside the nonattainment area. The return of an engine to the same site from which it was removed for the sole purpose of repair or maintenance is not considered "placed in service" or "relocated" for purposes of this Section I.D.5.

The Commission also adopted a different framework for "relocated" engines in Regulation Number 7, Part E, then in Regulation Number 6, Part B, which provides that engines brought to a site from another location in Colorado are not considered "new" and are not subject to the more stringent standards of the applicable NSPS. Under Regulation Number 7, there are only two exceptions to when an engine is considered new: when an engine is replaced under an alternative operating scenario (AOS) in an existing permit, which requires the engine to meet the same standards as the engine replaced, or when an engine subject to a Company-Wide Plan is moved from one site to another site with the same owner or operator. When an engine is subject to a Company-Wide Plan, the operator will have more flexibility to move an engine as long as it achieves at least the same emission reductions under the plan. However, an engine brought into the 8-Hour Ozone Control Area is considered "relocated" and must meet or exceed the standards as of the date it begins operation, whether or not it is subject to a Company-Wide Plan.

Emission Standards (Section I.D.5.b.)

The Commission adopted different emission standards based on engine configuration and the date that the engine was placed in service, modified, or relocated. The Commission intends that the applicable engine configuration is determined by the most current Division-issued permit or APEN filed prior to November 14, 2020. If the engine configuration is not identified in a Division-issued permit or APEN, the owner or operator is required to submit an APEN with this information to the Division by May 1, 2021. After November 14, 2020, any change to the identified configuration that results in an emissions increase is considered a modification.

The Commission adopted, generally, more stringent NOx standards applicable to engines placed in service, modified, or relocated after November 14, 2020. However, for 2-stroke lean burn engines, the NOx standard is the same whether the engine is currently in use at a site or brought on at a later date. The Commission also intends that any engines subject to a more stringent standard under a permit or other rule, such as Section I.D.2.b. of Regulation Number 7, must still comply with that more stringent limit. The Commission adopted varying timing requirements for owners or operators to meet the emission standards, based on the location of subject engines inside and outside of the 8-Hour Ozone Control Area. Owners or operators with any engines in the 8-Hour Ozone Control Area are subject to a more aggressive timeline, which requires 100% of engines inside the 8-Hour Ozone Control Area to meet the emission standards by May 1, 2024, and 100% of engines outside the 8-Hour Ozone Control Area meet the emission standards by May 1, 2026. Operators with no engines inside the 8-Hour Ozone Control Area must follow the second timeline and meet the standards of at least 20% of engines each year from 2022 to 2026.

The Commission intends that the emission standards in Table 2 are a gram per horsepower-hour limit based on appropriate averaging times. The Commission also intends that operators demonstrate compliance with the certification and recordkeeping requirements through the performance testing results required by Section I.D.5.d and the portable analyzer results obtained in accordance with Section I.D.5.e., using the appropriate averaging times.

The Commission requests that the Division consider evaluating strategies to increase the electrification of engines, lower emissions standards for engines, and possible controls applicable to smaller engines.

Notification to Division (Section I.D.5.b.(iii))

If an owner or operator has subject engines, the owner or operator must submit a notice to the Division no later than May 1, 2021. However, the owner or operator of engines covered by a Company-Wide Plan will not need to submit the information required by Section I.D.5.b.(iii) for all engines.

Permit Modification (Section I.D.5.b.(iv))

The Commission adopted two deadlines for when a permit modification application is required. If the engine can meet the standards through only a permit modification, the application is due May 1, 2021. If the engine cannot meet the standards through only a permit modification, the application is due 365 days prior to that engine's compliance deadline. An example of the first scenario is where an engine currently permitted with a high emission rate can meet the standards if operated at a lower emission rate and it is, in fact, already operating as of November 14, 2020, at that lower emission rate. In contrast, an example of the second scenario is where an engine is permitted at an emission rate above the applicable standard and operates at its permitted level, which would require the operator to change the operation of the engine in order to comply. This engine, therefore, would have a compliance date in accordance with Section I.D.5.b.(v)(B), and the permit application would be due 365 days prior to that engine's compliance deadline. Stakeholders expressed concerns that the Division may not be able to timely process all of the permit modifications. Therefore, the Commission determined that the flexibility outlined in the rule was necessary for both industry and the Division. In the case of a pending permit modification, the Commission intends that the most current APEN requested limits will be used to determine compliance with the rule.

Industry stakeholders have expressed that the rules need to be more accommodating for Division delays in permit issuance for those situations where owners and operators cannot take action to comply with the emission standards without a permit in hand. Industry notes that without a revised permit, owners and operators would be out of compliance with federal and state permit requirements, leaving the operator with the choice of what standards to comply with. Based on information provided by these stakeholders, the Division believes that there are only 15 such permits. Additionally, the vast majority of engine upgrades do not necessitate a permit modification prior to completing the upgrade.

The Division has indicated that it has enough dedicated staff to complete the required permit modifications in a timely fashion so long as the operator submits the permit application at least one year in advance of the compliance deadline. To address stakeholder concerns, the Commission expects the Division to work with operators that require a permit prior to commencing upgrades and create a process to give these permit applications priority. Should any permits push up against the one-year issuance deadline, the Division, in its discretion, will evaluate any potential operator compliance deadline extensions on a case-by-case basis.

Alternative Company-Wide Compliance Plan (Company-Wide Plan) *(Section I.D.5.c)*

The Commission adopted a Company-Wide Plan option to allow flexibility for each owner or operator to develop a technologically and economically feasible timeline tailored to its individual operations to achieve the same or better emission reductions than would be achieved through compliance with the emission standards on an individual engine basis.

The Company-Wide Plan requires an overall emissions percentage reduction based on company-wide engine operations. Owners or operators using this option must demonstrate that the total NOx emissions allowed under the Company-Wide Plan are less than or equal to the total NOx emissions allowed through compliance with the emission standards on an individual engine basis. Engines included in a Company-Wide Plan remain subject to the performance testing, monitoring, recordkeeping, and reporting requirements.

This Company-Wide Plan option is available only to owners or operators with five or more engines that are subject to Section I.D.5.b(v)(B). For purpose of the Company-Wide Plan only, the term owner/operator refers to owners or operators that are participating in a Company-Wide Plan and are owned or operated by the same parent company. Engines that already meet the emission standards of Table 2 but only need a permit modification to reflect compliance may not be part of a Company Wide Plan for which credit is claimed by the operator. However, if the operator makes a further retrofit to the engine, the operator may include that engine in the Company Wide Plan and claim credit for the reductions achieved by the further retrofit. For example, if Engine A, a 4-stroke lean burn engine, has a permit limit of 1.8 g/hp-hr, but currently operates at 1.2 g/hp-hr, Engine A would not be included in the Company Wide Plan. However, if the operator installs additional control technology such that Engine A can now operate at 1.0 g/hp-hr, the emission reductions associated with the drop in emissions from 1.2 g/hp-hr to 1.0 g/hp-hr can be included in the Company-Wide Plan. Only physical retrofits, and not operational changes, can be accounted for in this manner.

Owners or operators will submit a notification (referred to as a compliance plan) using a Division-approved form that will be developed with stakeholder input. Recognizing that the Company-Wide Plan is intended to afford flexibility only where it will achieve the same or better reductions, the Commission has provided for detailed information to be submitted to the Division for review. The information submitted will allow the Division to compare the emission standards and operating conditions that an engine is meeting before and after the Company-Wide plan as well as the maximum emissions permissible if all Company-Wide Plan engines complied individually with the standards versus the permissible emissions under the Company-Wide Plan.

Owners or operators must calculate “Plan Emission Reductions” - i.e. a summation of NOx emission reductions from all engines in the Company-Wide Plan. This figure is calculated by looking at the maximum amount of NOx emissions from the engines before November 14, 2020 (using the current permitted emission rate) and subtracting the maximum amount of NOx emissions that will be allowed from those engines under the Company-Wide Plan.

Owners or operators must also demonstrate that the Company-Wide Plan will result in real emission reductions, and the Division is directed to disapprove any Company-Wide Plan that the Division determines does not achieve those reductions. Owners or operators will calculate the estimated historic emissions from the plan's engines in tons per year as a baseline, using the most stringent regulatory or permitted emission standards and operating conditions in conjunction with actual operating hours (averaged over 2017-2019). That baseline figure is then compared to the maximum amount of emissions permissible from the Company-Wide Plan engines to ensure that the Company-Wide Plan will result in emission reductions. The demonstration also includes a comparison of the emission reductions that would be achieved from the actual baseline figure if each engine complied with the emission standards on an individual basis to the reductions that will be achieved under the Company-Wide Plan. In this way, the Commission seeks to ensure that a Company-Wide Plan achieves demonstrable reductions in NOx emissions.

Owners or operators will not be allowed to utilize reductions in permitted operating hours to offset emission reductions that would otherwise be achieved where permitted hours are higher than actual hours of operation (on average over 2017, 2018, and 2019). For example, an operator with a permit to operate at 8,760 hours per year but that operated only at 5,000 hours per year (on average over 2017, 2018, and 2019) cannot modify its permit to lower the permitted hours of operation to 5,000 and thereby create NOx emissions for which it can take credit in its Company-Wide Plan.

Some stakeholders have expressed concerns over how engines that began operation during or after the averaging years will calculate "historic" emissions. For these types of engines, the Commission expects that the most recent year(s) of operation should be used to calculate "historic" emissions. If there is less than one year of operation during this time frame, the Commission expects that the operator should extrapolate the available operation emission data to one year to estimate "historic" emissions.

Owners or operators must also submit notice of relocated engines in the annual update to the Company-Wide Plan, beginning in 2022. A relocated engine will be categorized by its new location (inside or outside of the 8-Hour Ozone Control Area) for purposes of the engine's compliance deadline.

To assist with implementation, the Commission directs the Division to provide timely guidance to the regulated community as to how to develop a Company-Wide Plan. The Commission recognizes that the Company-Wide Plan provisions are complicated, and believes providing the following examples of how the Commission intends the program to work will be helpful.

Example 1:

An engine in a Company-Wide Plan is located inside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), also within the 8-Hour Ozone Control Area. The engine was not "placed in service" or "relocated" within the meaning of this rule, and compliance deadlines would not change. The owner/operator just submits the new location in its annual update.

Example 2:

An engine in a Company-Wide Plan is located outside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), except that site B is located inside the 8-Hour Ozone Control Area. The engine is not "placed in service" within the meaning of this rule but it is "relocated." The engine's relocation into the 8-Hour Ozone Control impacts both the standard with which it must comply and the timing of when the new standard must be achieved.

If the engine was not proposed for retrofit or if it was proposed for retrofit but under the Company-Wide Plan it would not meet the standard, the engine will need to meet the emission standards as of its date of operation following relocation. If the engine was proposed for retrofit to achieve performance below the emission standards (retrofit/shut-down, etc.), the engine must meet the more stringent of either the applicable standard or the proposed Company-Wide Plan standard as of the date of operation following the relocation date.

Conversely, if an engine subject to a Company-Wide Plan located in the 8-Hour Ozone Control Area is moved to a different site (same owner/operator) outside of the 8-Hour Ozone Control Area, the engine is not "placed in service" or "relocated" within the meaning of this rule. The engine must meet the standard specified in the Company-Wide Plan consistent with the applicable compliance date.

Example 3:

Operator A has 20 engines and submits a Company-Wide Plan that includes modifying five engines (in 2022 and 2023) and shutting down two engines (in 2024). Operator A then transfers ownership of one of the engines (either the engine or the entire facility) to be shut down to Operator B; that shutdown would have achieved 20 tons per year (tpy) NOx reduction. Operator A must find an additional 20 tpy NOx reduction from the 19 engines remaining in its Company-Wide Plan.

Example 4:

A Company-Wide Plan includes shutting down an engine. The operator then realizes it needs a replacement engine at that same site. The operator has a few options. First, the operator can amend its Company-Wide Plan to no longer shut down the engine (assuming the engine's compliance deadline has not yet passed) and can identify other actions to be taken to achieve the emission reductions that would have otherwise been realized from the shutdown of the engine. Second, the operator can shut down the engine as originally intended and bring on a new engine. The new engine will be subject to the emission standards as an engine "placed in service" after November 14, 2020, and cannot be a part of the operator's Company-Wide Plan because an engine scheduled for shut down under a Company-Wide Plan cannot be replaced with a different engine subject to the Company-Wide Plan. Because the operator must comply with the Company-Wide Plan, the operator will still need to cancel the APEN and permit for the existing engine and permit the new engine as a new source.

Example 5:

An operator has ten engines subject to a Company-Wide Plan and intends to modify five of those engines to achieve the required Plan Emission Reductions. However, in order to meet the CO standards for one of the engines that will not be modified to achieve Plan Emission Reductions, the operator must make an adjustment that has the effect of increasing NOx emissions from that engine. In calculating the maximum allowable NOx emissions from engines in the compliance plan and Plan Emission Reductions required, the operator must account for the increase in NOx emissions from the engine.

Performance Testing, Monitoring, Recordkeeping, and Reporting (Sections I.D.5.d., I.D.5.e., I.D.5.f., and I.D.5.g.)

The Commission adopted performance testing requirements to establish a baseline for evaluating an engine's performance – i.e. to enable an operator to know whether the engine was meeting the standards already or how much action might be required to meet the standards. To conserve the resources of both the Division and the operators, the Commission has allowed for operators to rely on existing ongoing semi-annual portable analyzer testing requirements, as well as performance testing conducted under NSPS JJJJ, a permit, or testing conducted voluntarily after January 1, 2020.

The Commission also adopted semi-annual portable analyzer testing requirements. The portable analyzer monitoring must commence within twelve (12) months of the initial performance test. The Commission intends that operators will conduct two portable analyzer tests in 2022, the first of which must be completed by June 30, 2022.

The Commission has also adopted new monitoring, recordkeeping and reporting requirements. With respect to oil and filter changes under Section I.D.5.e.(iv)(A), the Commission acknowledges that the development of an oil analysis program that tests to ensure that oil does not need to be changed meets the requirements of that section.

In the recordkeeping section, the Commission requires that for both performance tests and portable analyzer tests, the owner or operator retains records regarding the date, engine settings on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission acknowledges that maintaining the test reports (for performance tests) and maintaining records consistent with the Division's Portable Analyzer Monitoring Protocol (for portable analyzer test), is sufficient to demonstrate compliance with the requirements to maintain the date, engine setting on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission has required the reporting of the results of performance tests (Section I.D.5.g.(i)) and semi-annual portable tests (Section I.D.5.g.(iv)). By "results," the Commission means that the owner/operator shall indicate whether the tests were passed or failed. Other, more detailed results are required to be maintained as part of the recordkeeping requirements and will be available to the Division upon request.

General provisions (Section I.D.2.)

In 2019, the Commission adopted a reorganization of Regulation Number 7 moving like-sections together, including engines. The Commission now completes the reorganization of the engine sections by duplicating the applicable general provisions that applied to engines in Part D, Section II. (formerly numbered Section XVII.) in Part E, Section I.D.2. These provisions will continue to apply to engines addressed in Part E, Sections I.D.3. and I.D.4. (formerly Sections XVII.E.) and will also apply to engines addressed under the new Part E, Section I.D.5.

Oil and gas operations (Part D)

The Commission expanded or adopted additional requirements in Part D to further minimize emissions of greenhouse gases, ozone precursors, and other hydrocarbons from the oil and gas sector.

Pre-production and early production monitoring

The Commission adopted a new Section IV. that requires owners or operators to monitor air quality at and/or around pre-production operations (i.e., drilling, fracturing, drill-out, flowback) and early production operations (i.e., six months). The purpose of this air quality monitoring is multi-faceted in that the Commission anticipates the monitoring program will gather information about the evolving oil and gas monitoring technologies, data about potential emissions during pre-production and early production operations (e.g., ozone precursor emissions, greenhouse gas emissions, hazardous air pollutants), and inform future monitoring efforts. Owners or operators will also monitor air quality for ten days prior to beginning pre-production operations. The Commission recognizes that ten days does not provide a comprehensive or long-term baseline but intends that it cover day-of-week variability in surrounding activities and short-term meteorological variability, in order to provide a reference point for interpreting subsequent data.

Owners or operators must submit an air quality monitoring plan to the Division for approval prior to monitoring air quality. The Commission created a flexible air quality monitoring program that allows the operator to specify what pollutant(s) representative of pre-production and early production hydrocarbon emissions will be monitored and by what monitoring technology. The Commission anticipates that the additional elements of the air quality monitoring plan, such as monitor siting, frequency of measurements, monitoring equipment limitations, and ability to trigger or collect speciated samples, will vary based on the monitoring objectives and technology utilized. The Commission also anticipates that the response level(s) will vary based on the monitoring technology, monitor placement, the pollutant(s) monitored, data collection and averaging times, and other factors. The response level may differ from a lower detection level established by the owner or operator that triggers an initial investigation of potential emissions at the facility. The Commission expects that the monitoring technology selected will have a detection ability sufficient to detect the pollutant(s) monitored at an appropriate level above area concentrations such that the monitoring objectives (e.g., detect ozone precursors, detect hazardous air pollutants, detect greenhouse gas emissions, associate elevated monitored values to an emission source within the monitored operations) are achieved. The Commission recognizes that not every elevated measurement constitutes a detection requiring a response but instead may be accompanied by analytics evaluating the measurements in comparison to an emission source or activity. The Commission also expects that placement of the monitors will be designed to be adequate to meet the objectives of the monitoring plan and that operators will select a monitoring technology that collects measurements at short-term intervals (e.g., 1 minute, 15 minutes, 1 hour) and appropriate sensitivity.

For example, concentrations at 2000-4000 feet away from the operations are likely to be low and, therefore, would require high-sensitivity instruments; monitors placed in close distance to the operations may need to be placed at variable heights to detect emissions from equipment of different heights; or monitors may need to be placed in both upwind and downwind locations, depending on the monitoring technology. In addition, the Commission expects the Division to work with operators in approving air quality monitoring plans to make sure that local jurisdiction air quality monitoring requirements and COGCC site preparation requirements are considered. The Commission expects the Division to consult with relevant local governments in reviewing monitoring plans, to obtain their input on local circumstances or concerns that may guide the Division's determinations on plan adequacy.

Owners or operators will also submit monthly reports of air quality monitoring to the Division. These monthly reports will include descriptions of activities that occurred during the monitoring period such that monitoring data can be understood in relation to activity onsite (e.g., accounting for engine emissions). The Commission recognizes that monitoring data often requires additional analysis to interpret the resulting data. Therefore, for this first oil and gas air quality monitoring program, the Commission expects that operators will make the raw data (e.g., monitor/sensor and meteorological readings prior to analysis or processing) available to the Division upon request (and expects the Division to make the raw data available to the relevant local government entities upon request) but submit the analyzed data results in the monthly reports. The Commission believes these reports will provide valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make the reports publicly available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. This flexible monitoring program is intended as an initial step to help inform future oil and gas monitoring efforts.

Recognizing that this pre-production emissions monitoring program represents a first step in understanding both pre-production emissions and the rapidly evolving technologies that may be used to monitor them, the Commission directs the Division to report back to the Commission no later than March 31, 2022 with an initial summary of activities to implement the rule since September, 2020; learnings and insights on monitoring technologies, including technologies for continuous methane monitoring; appropriate data summaries on observed emissions based on the monthly reports received; initial feedback on the adequate length of monitoring time during and possible identification of exemptions from monitoring for certain types of facilities.

Flowback vessels

The Commission also adopted in the new Section VI. a requirement for owners of operators of pre-production operations to control emissions from flowback vessels. After hydraulic fracturing, operators bring the frac fluids and entrained solids to the surface. EPA's NSPS OOOOa Section 60.5375a requires operators to route flowback during the initial flowback stage into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. During the separation flowback stage, NSPS OOOOa requires operators to route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into a well, or route the liquids to a collection system. NSPS OOOOa allows operators to use open vessels to contain flowback fluids and solids and does not consider a well completion vessel a storage vessel, which means operators are not required to control well completion vessel emissions. Therefore, to build on the NSPS reduced emission completion requirements and further reduce pre-production tank emissions, owners or operators of pre-production operations must use enclosed flowback vessels after the drill-out phase, which the Commission recognizes has a high ratio of solids to liquids, and route emissions from flowback vessels to air pollution control equipment.

Class II disposal well facilities

The Commission added a new definition of class II disposal well facilities. This definition is based on EPA's Underground Injection Control Program: Criteria and Standard definition of class II well (see 40 CFR Section 146.5(b)(1)). The Commission did not include the element of EPA's definition concerning enhanced recovery of oil or natural gas as storage tanks related to those activities are considered part of the associated well production facility. The Commission recognizes that some class II disposal well facility operators interpret Part D, Section II.C. such that their storage tanks have not been subject to the storage tank control requirements. Although the Commission understands that the Division intended Part D, Section II.C. to apply to storage tanks serving class II disposal well facilities, the Commission also recognizes that a good faith argument existed under the prior rule language to support the alternative interpretation. The Commission intends for the Division to work with owners or operators to address implementation concerns that may arise including related to the May 1, 2021, state-wide compliance deadline for controlling emissions from storage tanks $\geq$ 2 tpy and associated monitoring requirements as well as concerns related to the need for supplemental fuel to control emissions.

The Commission also expanded the hydrocarbon liquids loadout requirements in Part D, Section II.5. to hydrocarbon liquids loadout at class II disposal well facilities. Operators inject fluids, primarily brines, associated with oil and natural gas production into class II wells. Current regulatory requirements in the Safe Drinking Water Act for class II wells relate to the construction, operation, and monitoring of the well. The Safe Drinking Water Act does not require emissions reporting or storage tank or loadout emissions controls at class II disposal well facilities. Therefore, the Commission expanded the hydrocarbon liquids loadout requirements to class II disposal well facilities to reduce emissions from these operations.

The Commission directs the division to evaluate potential emission issues associated with load ins at class II disposal facilities

Annual emissions reporting

In 2019, the Commission adopted annual emissions reporting requirements for Colorado's oil and gas sector in Part D, Sections II.G., IV., and V. Owners and operators are required to report VOC, NOx, CO, ethane, and methane emissions to the Division on an annual basis. To further address and inform the GHG directives of Senate Bill 19-096 and House Bill 19-1261, the Commission expanded the reporting requirements to include the reporting of CO2 and N2O emissions from Colorado's oil and gas sector.

As described above, the Safe Drinking Water Act does not require emissions reporting. Therefore, the Commission also clarified and expanded the annual emissions reporting requirements for class II disposal well facilities to better understand the emissions from these facilities and activities. Related to the fluids accepted for injection disposal, the Commission is requiring owners or operators to take periodic samples of the liquids to inform emission estimates. Acknowledging that fluid intake and facility designs may differ, the Commission expects the Division will work with owners and operators to develop sampling frequencies and protocols and to ensure accurate and consistent methods are used for emissions estimation and reporting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission includes reference dates to rules and reference methods incorporated in Regulation Number 7.

Community Engagement

Section 25-7-105(e) requires engagement with disproportionately impacted communities, other state agencies, stakeholders, and the public. The Division provided multiple ways for the public, local governments, industry, environmental groups, and other stakeholders to provide comment during the development of the proposed rules, including email and remote stakeholder meeting participation.

Additional Considerations

The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and Regional Haze Rule and requires Colorado to attain the NAAQS and reduce visibility. Therefore, the Commission adopted certain revisions to Regulation Number 7 to reduce VOC and NOx emissions in Colorado.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including engines, pre-production operations, and class II disposal well facilities storage tanks and storage tank loadout. The proposed revisions also revise the annual oil and gas sector emissions inventory report to include GHGs and class II disposal well facilities. NSPS JJJJ, NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, NESHAP ZZZZ, and the Greenhouse Gas Reporting Program (GHGRP) in 40 CFR Part 98 may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks then the NSPS and NESHAP, more engines than NESHAP JJJJ, and more facilities and operations than the GHGRP.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. The Regional Haze Rule was also not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. And, Colorado must improve visibility in accordance with Regional Haze. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits. And, the current revisions will improve visibility across the state, in particular in Colorado's class I areas.

(V) Colorado must attain the 2008 ozone NAAQS by July 20, 2021, and the 2015 ozone NAAQS by August 3, 3021, or risk being reclassified. Colorado must make reasonable progress toward improving visibility or risk EPA establishing a federal regional haze plan for Colorado. EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. EPA has established a Regional Haze SIP submittal deadline of July 1, 2021. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 address emissions from engines and the oil and gas sector in a cost-effective manner, as detailed in the Economic Impact Analysis, allowing for continued growth of Colorado's industry.

(VII) The revisions to Regulation Number 7 establish reasonable equity for owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado continues to fail to achieve the NAAQS or make progress to reduce visibility, EPA may promulgate Federal Implementation Plans; thus potentially determining requirements for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing and revising annual oil and gas inventory reporting are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for hydrocarbon liquid loadout. Other revisions reflect changes in industry practice, such as for controlling emissions from flowback vessels.

(XI) The revisions adopted will reduce NOx, VOC, and methane, addressing both Colorado's ozone problems, making strides to reduce the impact of climate change, and making progress to improve visibility. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in greenhouse gases, ozone, VOC, NOx, other hydrocarbons, impacts to visibility, and nitrogen deposition to address Regional Haze, SB 19-181, and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements for the oil and gas sector. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in the need for much more stringent requirements to reduce nitrogen deposition in RMNP, improve visibility in Colorado's Class I areas, and reduce ozone across the state but particularly in the DMNFR.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

To the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

U. December 17-18, 2020 (Part D, Section II.; Part E, Sections II., IV., and V.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

On December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb.

Therefore, to ensure progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to include reasonably available control requirements (RACT) for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy; specifically, for foam manufacturing, boilers, turbines, landfill gas and biogas fired engines, and wood surface coating.

Statutory Authority

The State Air Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rational for the adoption of the revisions.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources ($\geq$ 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, and including categorical RACT requirements.

The Commission is also clarifying requirements related to leak detection and repair (LDAR) inspections. The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

Major source RACT

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the Clean Air Act's (CAA) Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx including a NOx emission limit for boilers between 50 MMBtu/hr and 100 MMBtu/hr, a NOx emission limit for landfill gas or biogas fired engines, NOx emission limits for combustion turbines, categorical requirements to reduce VOC emissions related to foam manufacturing, and expanded categorical requirements to reduce VOC emissions related to wood surface coating.

Boilers

In 2019, the Commission expanded the combustion equipment requirements adopted in 2016 and 2018 for the 100 tpy major sources to the 50 tpy major sources. Specifically, for boilers, the Commission adopted provisions requiring boilers greater than or equal to 50 MMBtu/hr at 50 tpy major sources to comply with a 0.2 lb/MMBtu NOx emission limit. The Commission now further expands the categorical RACT requirements to require 50-100 MMBtu/hr boilers at 50 tpy major sources to comply with a 0.1 lb/MMBtu NOx emission limits. The owners or operators of these boilers will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Engines

In 2019, the Commission expanded the NOx emission limit requirements for compression ignition reciprocating internal combustion engines (RICE) and combustion process adjustment requirements for stationary RICE. The Commission now further expands the categorical RACT requirements for engines to include landfill gas and biogas fired RICE and require the engines to comply with the NOx emission limit in EPA's NSPS JJJJ for landfill/digester gas fired engines. The owners or operators of these engines will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Turbines

In 2019, the Commission adopted provisions requiring turbines constructed before February 18, 2005, to comply with NSPS GG and turbines construction after February 18, 2005, to comply with NSPS KKKK. During review of the submitted SIP RACT requirements, EPA questioned Colorado's reliance on EPA's NSPS GG as RACT and requested Colorado consider the NOx emission limits in EPA's NSPS KKKK for Colorado's NSPS GG and pre-NSPS GG turbines at major sources. While the Commission does not agree that NSPS GG is inappropriate as SIP RACT for Colorado's NSPS GG and pre-NSPS GG turbines, the Commission revised the requirements for turbines to reference NSPS KKKK NOx emission limits for the turbines constructed before February 18, 2005, but retain the testing and monitoring requirements of NSPS GG. Turbines with CEMS that are capable of operating in both combined and simple cycle modes are to show compliance with a 30-day average. Similar to EPA's discussion in the preamble to NSPS KKKK, the Commission recognizes turbines may have emission spikes during unit startup and that, therefore intends the turbine NOx emission limits to be implemented as under NSPS KKKK. See 71 Fed. Reg. 38,482 at 38,488-38,489 (July 6, 2006) "While continuous compliance is not required, excess emissions during startup, shutdown, and malfunction must be reported." All turbines will continue to comply with good air practices for minimizing emissions, combustion process adjustment, and recordkeeping requirements.

Wood coating

In 2018, the Commission adopted requirements for wood furniture surface coating based on recommendations in EPA's Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations CTG (Wood Furniture CTG) (1996), including topcoat and sealer VOC content limits, work practices, and recordkeeping requirements. Wood furniture is defined to mean "any product made of wood, a wood product such as rattan or wicker, or an engineered wood product such as particleboard," which is not inclusive of all wood products such as doors. However, in EPA's A Guide to the Wood Furniture CTG and NESHAP (1997), EPA states that "States may choose to extend their rules to other operations. For example, some States have developed rules for manufacturers of wood products so they may include limitations for manufacturers of items such as musical instruments or doors." Therefore, the Commission expanded the wood furniture surface coating requirements to the surface coating of other wood products such as doors, door casings, and decorative wood accents.

Foam manufacturing

The Commission adopted new VOC control requirements for foam manufacturing operations. The new provisions affect three foam manufacturing operations, although one of the sources is modifying their permit to more accurately reflect their actual emissions and will, therefore, have VOC emissions below 50 tpy. These new provisions include emission control requirements, work practices, monitoring, and recordkeeping requirements for foam manufacturing operations.

LDAR (Part D, Section II.)

The Commission also adopted clarifying revisions to the leak detection and repair (LDAR) provisions the Commission adopted in December 2019 including clarification to applicability and requirements for recordkeeping and reporting. The clarifications to Sections II.E.4.c. and II.E.4.d. ensure that operators continue to determine applicability in accordance with the storage tank or facility emissions as they have since the LDAR program was adopted in 2014. The inclusion of recordkeeping and reporting elements specific to increased inspections based on location from occupied areas ensure that the Commission can evaluate the efficacy of the LDAR program. The Commission acknowledges that not all operators will need to conduct a precise analysis concerning their location in relation to occupied areas (i.e., proximity analysis) based on their general distance. However, the Commission believes it is important for operators to provide at least general documentation that they considered their location, even if to describe an extreme remote location. The Commission also acknowledges that some operators may elect to comply with the increased frequency inspections for certain facilities without conducting a proximity analysis. Documentation of this decision to comply with the increased inspection frequency satisfies the proximity analysis requirement.

The Local Community Organizations proposed an alternate rule to establish shorter repair deadlines for leaks discovered at well production facilities within 1,000 feet of an occupied area. The Local Community Organizations, industry, and the Division negotiated and agreed to the final language adopted by the Commission. For leaks identified at a well production facility located within 1,000 feet of an occupied area, operators must make a first attempt to repair the leak as soon as practicable, but no later than five working days after discovery of the leak. If repair cannot be completed within five days and the leak is not stopped using other means, the owner or operator must notify the local government with jurisdiction over the location and the Division. Reasons why an operator may be unable to attempt or complete repair within five days include, among other things, inclement weather that prevents a timely repair or repair attempt or delays in procuring necessary heavy equipment and workover rigs. The industry parties also raised the issue about local government or other agency requirements potentially delaying repair. Such impacts to repair schedules should be considered as the program is implemented.

The Commission notes that it will be the operator's responsibility to demonstrate the need for the delay beyond five working days, and the Commission expects that operators will be able to explain the types of reasonable efforts the operator undertakes to avoid the delay (e.g., reasonable efforts in procuring the equipment). If a leak is detected at a facility without a proximity analysis, operators may conduct a proximity analysis and may follow the repair deadlines in Section II.E.7.a. if there are no occupied areas within 1,000 feet.

Consistent with the existing LDAR program, leaks detected are not subject to enforcement by the Division so long as the operator complies with the repair and recordkeeping requirements of Section II.E. However, as the Commission noted in 2014 and again in 2017, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Part D, Sections I.C, II.B, or II.C (as applicable), including the requirements to minimize emissions and to operate without venting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the serious ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), CRS, the Commission determines

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including fugitive emissions from components. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more fugitive emissions components then the NSPS.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx (≥ 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part B, Section I. and Part E, Sections II. and V. to include categorical regulatory RACT requirements. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.

(III) The CAA establishes the 2008 NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 strengthen Colorado's SIP and state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections I. recognize practices currently utilized by wood coating operations. The revisions to Regulation Number 7, Part E, also consider specific existing major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C and Part E similarly establish the categorical RACT requirements for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for component leaks. Other revisions reflect changes in industry practice, such as for wood coating and foam manufacturing. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

V. February 18, 2021 (Part D, Section III.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for the Commission. SB 19-181 revised the Air Quality Control Commission's directives in § 25-7-109, CRS, to consider pneumatic device requirements. Additionally, in HB 19-1261, the legislature mandated a 26% reduction in GHG by 2025, 50% by 2030, and 90% by 2050 (from a 2005 baseline), §§ 25-7-102(2)(g), 25-7-105(1)(e)(II), CRS.

Further, on December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb.

Therefore, to further minimize emissions from the oil and gas sector and ensure progress towards attainment of the 2008 and 2015 ozone NAAQS and necessary greenhouse gas emission reductions, the Commission is adopting revisions to Regulation Number 7 to require non-emitting controllers in certain situations.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution.

Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7- 109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7 and includes the technological and scientific rationale for the adoption of the revisions. The revisions also correct typographical, grammatical, and formatting errors found through the regulation. As discussed, SB 19-181 identifies specific requirements the Air Quality Control Commission should consider, including pneumatic controller requirements.

In December 2019, the Commission expanded the pneumatic controller inspection and maintenance requirements, adopted in 2017, from nonattainment area applicability to statewide applicability. As part of that rulemaking, the Commission directed the Statewide Hydrocarbon Emission Reduction (SHER) team and Pneumatic Controller Task Force (PCTF), stakeholder processes directed by the Commission in 2017, to continue their stakeholder processes and bring to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Both the SHER team and PCTF continued to meet through the spring of 2020. The stakeholder discussions from 2017-2020 informed the Commission's adopted provisions regarding non-emitting controllers. Non-emitting controllers are a broader category than no-bleed pneumatic controllers and can include, but are not limited to, air-driven controllers, mechanical controllers, electric controllers, self-contained controllers and controllers where exhaust gas is routed to a combustion device.

Definitions

The Commission took the opportunity to amend the definitions associated with pneumatic controllers to reflect more accurate and appropriate technical definitions. The definition of "intermittent pneumatic controller" is intended to include controllers that are not designed to have a continuous bleed rate. Although intermittent pneumatic controllers are not designed to emit between actuations, de minimis emissions may occur between actuations. Such de minimis emissions do not alter a controller's classification as "intermittent."

New Facilities and Certain Retrofits

The revisions to Regulation Number 7 adopted in this rulemaking require the use of non-emitting controllers at well production facilities and natural gas compressor stations that commence operations on or after May 1, 2021. The revisions also require retrofits of natural gas emitting pneumatic controllers to non-emitting controllers at well production facilities where a well first begins production or is recompleted or refractured on or after May 1, 2021 and at natural gas compressor stations that increase horsepower on or after May 1, 2021.

Company-wide plans

Additionally, the Commission has required operators with well production facilities or natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert some of such facilities to use non-emitting controllers. For purposes of Section III.C.4, retrofit refers to converting a natural gas emitting pneumatic controller to a non-emitting controller. Plugging and abandoning an existing well production facility constitutes an alternative method of compliance with retrofit requirements as described in Section III.C.4.c.(iii). Specifically, the Commission has adopted a program that requires owners or operators of well production facilities that commenced operations prior to May 1, 2021 to determine the percentage of their total liquids production at facilities with non-emitting controllers. Facilities that commenced operation prior to May 1, 2021 shall be included in the relevant (well production or compressor station) companywide plan, and the companywide plan shall reflect operations as of May 1, 2021. If any of the events described in Sections III.C.4.a.(ii) or (iii) occur on or after May 1, 2021 and before May 1, 2023, then the owner or operator may count, as applicable, the: (1) percentage of production allocated to that facility as of May 1, 2021 as retrofit for purposes of the well production facility companywide plan; or (2) the pneumatic controllers emitting to atmosphere as of May 1, 2021 as retrofit for purposes of the compressor station companywide plan. Where facility production must be estimated pursuant to Section III.C.4.c.(ii)(A)(3), owners or operators will follow the same process that would be used to establish permit limitations on production throughput, such as summation of anticipated production curves. Of note, if a facility operating in 2019 was subsequently acquired by a new operator, then the facility (and its percent of production) is associated with the company-wide plan of the entity owning the facility as of May 1, 2021.

Based upon this percentage, operators will be required to retrofit facilities incrementally by May 1, 2022 and May 1 2023; the required retrofits correspond to an increasing percentage of each operator's total liquids production flowing through facilities with non-emitting controllers. The incremental percentage increases for well production facilities are found in Table 1. Operators that increase their total non-emitting facility percent production up to a specified threshold are not required to achieve the entire incremental percentage increase that would otherwise apply for that year. However, the minimum incremental increases and specified thresholds do not restrict operators from exceeding the requirements.

Each well production facility operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, its total liquids production, facilities with non-emitting controllers, total percentage of liquid production flowing through facilities with non-emitting controllers, and the facilities that the operator intends to retrofit or plug and abandon in order to achieve the incremental increases in total liquids production flowing through facilities with non-emitting controllers. This company-wide plan should be updated in July 2022, with a final company- wide plan reflecting all facilities that were retrofit or plugged and abandoned submitted in July 2023.

The Commission has also required operators of natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert pneumatic controllers at such facilities to non-emitting controllers. Specifically, the Commission has adopted a program that requires operators to determine the percentage of emitting and non-emitting pneumatic controllers and based upon that percentage, operators will be required to increase the percentage of non-emitting controllers incrementally by May 1, 2022 and May 1, 2023. The incremental percentage requirements for natural gas compressor stations are found in Table 2. As for well production facilities, operators that increase their total percentage of non-emitting controllers up to a specified threshold are not required to achieve the entire percentage increase for that year that would otherwise apply. The minimum percentage increases and specified thresholds do not restrict operators from exceeding these requirements.

Each operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, total controllers, percentage of emitting and non-emitting controllers, the required incremental increases in non-emitting controllers, and the pneumatic controllers that the operator intends to retrofit or remove from service to achieve the incremental increases in non-emitting controllers.

For well production facilities and natural gas compressor stations, an owner or operator may elect to combine facilities with other owners or operators that are owned or operated by the same parent company in complying with company-wide compliance plan requirements.

At this time, operators will not be subject to the requirement to retrofit pneumatic controllers if they have facilities that on a company-wide basis, and taking into account only wells that produced oil or gas or both in calendar year 2019, averaged 15 barrels of oil and gas equivalent (“BOE”) or less per day per well. However, in 2021, the Commission plans to consider additional emission reductions for the oil and gas sector that would enable the state to meet its ambitious climate goals as set forth in HB 19-1261. The Commission directs the Division to consider whether additional requirements to reduce emissions at the sites not subject to retrofit pursuant to Section III.C.4.c.(iv), including retrofit of pneumatic controllers, should be included in that rulemaking.

The requirement to submit an acknowledgement or certification under Sections III.C.4.c.(v) and III.C.4.d.(v) (regarding sale or transfer) does not apply to well production facilities or natural gas compressor stations that, at the time of sale or transfer are not intended to and will not be used to achieve the Total Required Non-Emitting Facility Percent Production or Total Required Non-Emitting Percent Controller target, as applicable. The following are each an acceptable means of ensuring compliance with Section III. following transfer through which owners or operators shall satisfy their obligations under Section III.C.4.c.(v) or Section III.C.4.d.(v), as applicable:

Example 1: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61%. Operator A is required to achieve an additional 5% of non-emitting facility percent production by May 1, 2022, and an additional 10% by May 1, 2023, with a Total Required Non-Emitting Facility Percent Production target of 76%. Operator A achieves the additional 5% of non-emitting facility percent production by May 1, 2022. In 2023, prior to May 1, Operator A transfer's ownership to Operator B of two well production facilities that Operator A had intended to retrofit with non-emitting controllers or plug and abandon in order to achieve its Total Required Non-Emitting Facility Percent Production. Retrofitting or plugging and abandoning those two facilities would have comprised half of the additional production required by May 1, 2023 (*i.e.*, 5% of Total Required Non-Emitting Facility Percent Production).

Scenario 1: Notwithstanding the transfer, Operator A may find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non-Emitting Facility Percent Production. In this case, Operator A does not need to submit an acknowledgement or certification upon transfer, but shall include this information in its next update to the Company-Wide Plan. This example would apply equally to transfers of assets subject to a Company-Wide Compressor Station Pneumatic Controller Compliance Plan.

Scenario 2: Operator A submits an acknowledgement, on a Division-approved form, that it will ensure the transferred asset is retrofit by May 1, 2023. Under this scenario, either Operator A or Operator B may undertake any necessary retrofitting (or plugging and abandonment) of the asset to allow Operator A to take credit for retrofit of the 5% of Total Historic Production, provided, however, that Operator A will remain responsible for retrofit of that asset to achieve its Total Required Non-Emitting Facility Percent Production. This means that if retrofit of the asset is not completed for whatever reason, Operator A would have to find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non- Emitting Facility Percent Production by May 1, 2023.

Scenario 3: Operator A submits an acknowledgement, on a Division-approved form, that it plans to use the transferred asset to achieve its Total Required Non-Emitting Facility Percent Production and Operator B certifies, on a Division-approved form, that it will retrofit the transferred asset by May 1, 2023. Upon certification by Operator B, Operator A shall receive credit for the retrofit of the 5% of Total Historic Production towards its applicable targets under Section III.C.4. The Division-approved form must include a statement that Operator B assumes Operator A's Section III.C.4 obligations with respect to the transferred asset and is, therefore, subject to the Division's enforcement authority in the event of noncompliance. Acquisition of the asset does not alter the calculation of Operator B's compliance with the percentage thresholds specified in Table 1 or 2 for its own Company-Wide Plan, if applicable.

Example 2: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61% and a Total Required Non-Emitting Facility Percent Production target of 76%. Operator B has a Total Historic Non-Emitting Facility Percent of 21% and a Total Required Non-Emitting Facility Percent Production target of 56%. Operator A and Operator B merge (or one entity acquires the other) in 2023, prior to May 1. Despite the merger, the resulting ownership of Operators A and B must continue to separately comply with the respective Company-Wide Plans and Total Required Non-Emitting Facility Percent Production targets of Operator A and Operator B that existed prior to merger.

Exemptions for Specific Controllers

The Commission has recognized that there are appropriate circumstances where even non-emitting facilities may need to use pneumatic controllers that emit natural gas to the atmosphere.

Section III.C.4.e.(i)(A) authorizes use of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas. Starting May 1, 2021, new well production facilities or facilities where a well first begins production or is recompleted or refractured, and new compressor stations or stations that increase horsepower, must submit a justification for any safety or process exemption to the Division for approval 45 days prior to installation of the emitting device or retrofit of the facility. Owners or operators that intend to rely on this exemption to maintain emitting controllers at facilities that are retrofit under a company-wide plan must submit a justification to the Division 45 days prior to retrofit of the facility. The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities and natural gas compressor stations commencing operation or taking actions described in Sections III.C.4.a.(ii) or (iii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(A)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Sections III.C.4.a.(ii) or (iii) occur. Section III.C.4.e.(i)(A), the requirement to seek Division approval is not applicable for: (1) well production facilities that qualify as contributing to Historic Non-Emitting Facility Percent Production, as defined in Section III.C.4.c.(ii)(D)(1) to (2), or (2) compressor stations that commenced operation before May 1, 2021.

Section III.C.4.e.(i)(B) authorizes use of pneumatic controllers that emit natural gas for activities that occur prior to the end of flowback and well abandonment activities. In addition, Section III.C.4.e.(i)(C) allows owners or operators, upon notice to the Division, to use temporary and portable equipment with pneumatic controllers that emit natural gas for sixty days for purposes other than increasing the throughput of the facility. The Commission directs the Division to develop a streamlined mechanism for filing these notifications, including evaluating the potential for electronic notification. Owners or operators must request Division approval to extend the sixty-day timeframe and must do so at least fourteen days prior to the end of the exemption period. Owners or operators utilizing temporary or portable equipment with pneumatic controllers that emit natural gas must conduct AVO and AIMM inspections of those controllers on the same schedule as the associated well production facility or compressor station under Section II.E., and must comply with the repair, recordkeeping, and reporting requirements of Sections II.E.6 through 9.

The requirement to use non-emitting pneumatic controllers at sites that commenced operations on or after May 1, 2021, or where one or more wells first begin production or are recompleted or refractured on or after May 1, 2021 does not apply in certain applications at some wellheads located away from the associated production facilities. Additionally, operators that have or retrofit well production facilities to be non-emitting pursuant to the company-wide plan may not be required to use non-emitting controllers in certain applications at some wellheads located away from the associated production facilities.

As set forth in Section III.C.4.e.(i)(D), operators may use natural gas actuated pneumatic controllers that emit to the atmosphere to control emergency shutdown devices or artificial lift control at a wellhead if the wellhead is located more than one quarter of a mile from the associated well production facility for well production facilities commencing operations on or after May 1, 2021, or for wellheads not located on the same surface disturbance for well production facilities commencing operations prior to May 1, 2021. Any other pneumatic controllers (e.g. those not used as emergency shutdown devices or for artificial lift control) located at the wellheads within the specified distance from the associated production facilities must be non-emitting, unless the operator submits a justification for use of an emitting controller to the Division for approval at least 45 days prior to installation of the emitting device or retrofit of the facility or by July 1, 2021 for well production facilities that commenced operations prior to May 1, 2021 and the operator intends to be reflected as non-emitting in the company-wide plan. The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities commencing operation or taking actions described in Section III.C.4.a.(ii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(D)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Section III.C.4.a.(ii) occur. The one quarter mile measurement associated with distance from the wellhead to the well production facility shall be measured from the wellhead to the closest equipment associated with the well production facility.

To qualify for the exemption in Section III.C.4.e.(i)(D), the operator must use an approved instrument monitoring method and AVO to detect leaks at the wellhead at the same frequency as the associated well production facility as set forth in Table 3 of Section II.E.4, which sets forth the frequency of component inspections, or no less than once per year, whichever is greater. For facilities that commenced operations prior to May 1, 2021, this monitoring requirement will begin on May 1, 2022, or the date the facility is converted to a site with only non-emitting controllers, whichever is later. The Commission recognizes that wellheads may sometimes be difficult to inspect due to land access issues or severe weather and has adopted provisions allowing operators to delay inspections until access is restored. Owners or operators also may utilize OGI camera-equipped aerial drones to perform these wellhead inspections to provide frequent leak detection and further promote the advancement of leak detection methodologies - both of which are foundational to Colorado's find and fix approach to leak detection. At the same time, the Commission believes this application of OGI requires rethinking of the methodology generally used for land based OGI applications.

Thus, the provisions of Section III.C.4.e.(i)(D)(3) allowing for the use of OGI camera-equipped aerial drones to inspect wellhead equipment apply on a limited basis, as state-only provisions and do not by themselves authorize the use of drones to inspect other equipment or constitute approval of drones as alternative AIMM. Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request. The methodology must include, at a minimum, procedures for: determining maximum wind speed during which the inspection can be performed; determining the maximum viewing distance from the equipment; how the operator will ensure an adequate thermal background is present to view potential leaks; how the operator will deal with adverse monitoring conditions, such as wind; and how the operator will deal with interferences. At a minimum, any drone inspection must ensure line of sight from the drone to all wellhead equipment and components and take place when the drone-mounted camera is close enough to the wellhead equipment and components to achieve sensitivity for detection of emissions similar to the sensitivity commonly achieved during OGI inspections carried out with hand-carried infrared cameras. Furthermore, the Commission directs the parties to this rulemaking that wish to participate to jointly recommend an OGI camera-equipped aerial drone usage methodology to the Division's Alternative AIMM Team by May 2022, for further review and consideration.

Finally, operators may not use this exemption where equipment with natural gas emitting pneumatic controllers other than the wellhead, such as a separator, is located at the wellhead site. Under those circumstances, emitting pneumatic controllers used for emergency shut down control may still qualify for the safety and process exemption under Section III.C.4.e.(i)(A) where the necessary conditions and approvals for that exemption are met.

Tagging of Controllers

In order to assist in ease of identification of pneumatic controllers that are authorized to emit natural gas to the atmosphere, the Commission has required operators to tag pneumatic controllers that are authorized to emit natural gas to the atmosphere pursuant to the specified exemptions in Section III.C.4.e.(i) at wellhead production facilities which are non-emitting and at natural gas compressor stations that have one or more non-emitting controllers. Natural gas compressor station operators must differentiate between emitting pneumatic controllers that are exempt under Section III.C.4.e.(i) and those that are not identified as non-emitting controllers in the company-wide plan and are, thus, not required to retrofit. The requirement to tag pneumatic controllers that emit natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) does not apply at well production facilities that are not required to be non-emitting or elected to be non-emitting pursuant to the company-wide plan requirements. In each instance where the regulation references a requirement to use non-emitting controllers, such reference is limited by the exemptions allowing the use of pneumatic controllers to emit natural gas to atmosphere as set forth in the regulation.

Recordkeeping

Operators of well production facilities or natural gas compressor stations must keep the following records for five years, and make them available to the Division upon request: (1) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date the natural gas compressor station pneumatic controllers were retrofit or it is taken out of service, (2) If claiming an exemption for an emitting pneumatic controller, records for each controller demonstrating the exemption applies, (3) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans, (4) For any operator utilizing III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies under that provision, and (5) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time, other than those revising definitions currently in the SIP.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7- 110.5(5)(b), CRS, the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including natural gas-driven pneumatic controllers. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more natural gas-driven pneumatic controllers than the NSPS.

(II) The Federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations.

(III) The revisions to Regulation Number 7 strengthen Colorado's state-only provisions. These revisions currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(IV) The revisions to Regulation Number 7, Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(V) Where necessary, the revisions to Regulation Number 7 include monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(VI) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for pneumatic controllers.

(VII) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(VIII) Alternative rules could also provide reductions in ozone, VOC, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19- 181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements related to pneumatic devices. The Commission determined that the alternate proposal was reasonable and cost-effective.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

To the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record support the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of the regulation in the most cost-effective manner.



Oil and Gas Production Facilities
Chapter 6, Section 2 Permitting Guidance

June 1997
Revised November 1998
Revised January 2000
Revised August 2001
Revised July 28, 2004 (specific guidance for Jonah/Pinedale Anticline Area)
Revised August 2007
Revised March 2010
Revised September 2013 (Added specific guidance for UGRB and revisions to JPAD)
Revised May 2016

Under § 35-11-801(e) of the Wyoming Environmental Quality Act, construction or modification of an oil and gas exploration or production well may occur prior to permitting, as long as the facility (1) is not a major source; (2) is permitted within 90 days of the first date of production (FDOP); and (3) applies Best Available Control Technology (BACT). However, any owner or operator may instead apply for a construction or modification permit under Chapter 6, Section 2 of the Wyoming Air Quality Standards and Regulations prior to construction or modification of a facility.

This interpretive guidance discusses the Division's current understanding of BACT for the purpose of assisting owners and operators who choose to construct or modify oil and gas production facilities prior to initiating the permitting process. This interpretive policy is not binding on the agency, the regulated community, or any person; it is for informational purposes and does not create any rights, responsibilities, or liabilities for the Division, members of the regulated community, or any other person.

Owners and operators should be advised that this Guidance represents the agency's current understanding of BACT as of May 12, 2016.

This Guidance applies to surface oil and gas production facilities where hydrocarbon fluids are produced, processed and/or treated prior to custody transfer from the facility.

This Guidance does not apply to sour (H_2S containing) oil production sites. This Guidance also may not be used for sour gas (H_2S) production facilities unless the only emissions of H_2S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc. If there will be H_2S emissions associated with vented gas or tank vapors or if sour gas will be flared the applicant shall contact the Division for permitting guidance prior to construction to determine BACT requirements.

This Guidance does not apply to greenhouse gas emissions (GHGs) or major sources as defined under Wyoming Air Quality Standards and Regulations Chapter 6, Section 3 or Chapter 6, Section 13.

This Guidance does not apply to reciprocating internal combustion engines located at oil and gas production facilities unless the engine is natural gas-fired, used to power a pumping unit, is less than or equal to 50 horsepower, and meets BACT. Reciprocating internal combustion engines larger than 50 horsepower are required to obtain an air quality permit or permit waiver prior to installation.

The Presumptive BACT permitting requirements under this Guidance apply to facilities with associated wells that have a first date of production (FDOP) on/after July 1, 2016 and to facilities with a modification occurring on/after July 1, 2016.

Start up or modification of a facility may occur prior to obtaining an Air Quality Permit or Waiver only when the Presumptive BACT permitting requirements under this Guidance are met. Otherwise, an Air Quality Permit or Waiver shall be obtained prior to start up or modification of a facility.

For the purposes of this Guidance **SWA** (**STATEWIDE AREA**) refers to all facilities not located in the **UGRB** or **JPAD/NPL**.

UGRB refers to facilities located in the **Upper Green River Basin.**

JPAD/NPL refers to facilities located in the **Jonah and Pinedale Anticline Development Area and Normally Pressured Lance**.

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Acronyms and Abbreviations

AQD	Air Quality Division
API	American Petroleum Institute
BACT	Best Available Control Technology
BBL	barrel
BPD	barrels per day
BTEX	Benzene/Toluene/ Ethyl-benzene/Xylenes
Btu	British thermal unit
C6 S2	Chapter 6 Section 2 (of the WAQSR)
CAA	Clean Air Act Amendments of 1990
CO	Carbon Monoxide
EPA	Environmental Protection Agency
FEM	Fugitive Emissions Monitoring
FWKO	Free water knockout
gpm	gallons per minute
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutants
HP	high pressure
Hp	horsepower
IMPACT	Inventory, Monitoring, Permitting, And Compliance Tracking online data system
lb	pound
LP	low pressure
MMBtu	one million BTUs
MMSCF	one million standard cubic feet ($SCF \times 10^6$) (MMSCFD = 1,000,000 SCF per day)
MSCF	one thousand standard cubic feet (SCF×1000) (MSCFD=1000 SCF per day)
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Installation
NOV	Notice of Violation
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O&G	Oil and Gas
P-BACT	Presumptive BACT
pph	pounds per hour
PPMV	parts per million by volume
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
psia	pounds per square inch absolute
SCF	standard cubic foot
SO_2	Sulfur Dioxide
S/W/B	Standing/Working/Breathing losses
TEG	Tri-Ethylene Glycol
TPY	Tons per Year
VOC	Volatile Organic Compounds
WAQSR	Wyoming Air Quality Standards and Regulations
WDEQ	Wyoming Department of Environmental Quality



Introduction

The Oil and Gas Production Facilities Chapter 6 Section 2 Permitting Guidance (C6 S2 Guidance) document is an interpretive policy intended to publicize the Division's current understanding of BACT for certain types of emission sources at certain types of oil and gas production facilities. This interpretive policy is not binding on the agency, the regulated community, or any person; it is for informational purposes and does not create any rights, responsibilities, or liabilities for the Division, members of the regulated community, or any person. Any owners or operators seeking site-specific BACT analyses may choose to follow the standard Chapter 6, Section 2 permitting process prior to the construction or modification of a facility.



Applicability

When is a permit needed?

If **ANY** air pollutant will be released to the atmosphere from a new or modified facility, the facility is subject to the Wyoming Air Quality Standards and Regulations (**WAQSR**) and the Wyoming Environmental Quality Act. This Guidance does not apply to greenhouse gas emissions, sour oil production sites, or reciprocating internal combustion engines greater than 50 horsepower. This Guidance also may not be used for sour gas production facilities unless the only emissions of H_2S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc.

Owners/operators of **ALL** regulated air emission sources constructed or modified after May 29, 1974 shall comply with the WAQSR Chapter 6, Section 2 permitting requirements. To obtain a copy of the WAQSR contact the Wyoming Air Quality Division at (307) 777-7391 or download an electronic version from the Wyoming Secretary of State (http://soswy.state.wy.us/Rules/default.aspx). A link to the Secretary of State's website is available on the WDEQ's Air Quality website at http://deq.wyoming.gov/aqd/.

Under the Wyoming Environmental Quality Act, certain oil and gas production facilities may be constructed or modified prior to obtaining a permit or waiver, as long as they are minor sources, obtain a permit within 90 days of FDOP, and utilize BACT. Wyo. Stat. Ann. § 35-11-801(e).

Failure to comply with the Wyoming Environmental Quality Act and Wyoming Air Quality Regulations may result in an enforcement action undertaken by the State in the form of a "Notice of Violation", a complaint filed in District Court, or any other enforcement action allowed by law. The Wyoming Environmental Quality Act authorizes the assessment of penalties of up to $10,000.00 per violation per day and/or injunctive relief.

Which pollutants are associated with oil and gas (O&G) production facilities?

The following air pollutants are commonly associated with O&G production facilities:

Volatile Organic Compounds (**VOC**): Hydrocarbon compounds excluding methane (C_1) and ethane (C_2). VOCs are also referred to as C_3^+ compounds – propane, butane, pentane, hexane, etc.

Hazardous Air Pollutants (**HAP**): HAPs commonly associated with O&G production are BTEX and n-hexane (benzene, toluene, ethyl-benzene, xylenes and n-C_6). Section 112(b) of the Clean Air Act identified the regulated HAPs.

Nitrogen Oxides (**NO_X**): NO_X emissions are the result of natural gas combustion.

Carbon Monoxide (**CO**): CO emissions are the result of natural gas combustion.

Hydrogen Sulfide (**H_2S**): Contained within fields that produce sour gas.

Sulfur Dioxide (**SO_2**): Created when H_2S is combusted.



Production Facility Emission Sources

O&G production facilities emission sources:

Storage Tanks: Vapors containing regulated air pollutants are released from solution as oil, condensate and water are transferred from separation equipment to atmospheric storage tanks. These vapors are called **flashing losses**. Vapors evaporated or displaced from tanks are called **working and breathing (also called standing) losses (S/W/B)**.

Dehydration Units: Glycol, usually tri-ethylene glycol (TEG), is used in dehydration units to absorb water from wet produced gas. "Lean" TEG contacts the wet gas and absorbs water. The TEG, now considered "rich" is routed through a flash separator and/or reboiler for regeneration. Vapors released from the flash separator and reboiler still vent contain regulated air pollutants.

Pressurized Process Vessels: Vapors vented from gun barrels, separators, treaters, water knockouts, gas boots, flash separators, drip pots, etc. contain regulated air pollutants. The discharge lines and vents from all of these vessels shall be considered when determining emission sources.

Natural Gas-Fired Equipment: Some of the byproducts of natural gas combustion in process heaters, boilers, burners, flares, engines, etc. are regulated air pollutants.

Fugitives: All production facilities contain numerous equipment components such as valves, flanges, threaded connections, tubing connections, open-ended lines, pump seals, etc., which are manufactured and installed in ways intended to contain gases or liquids. Over time some of them begin to leak. Emissions associated with leaks are called fugitive emissions. For purposes of this Guidance, emissions from components that are improperly designed (e.g. enardo valves over pressurizing, failure of thief hatches to reseat after over pressurizing) or equipment not maintained properly (e.g., thief hatch left open) are not considered to be fugitive emissions.

Pneumatic Pumps & Controllers: The discharge vapors from natural gas-operated pneumatic equipment contain regulated air pollutants.

Truck Loading: Vapors displaced from truck tanks during the loading of produced liquids that contain regulated air pollutants.

Venting & Blowdown: Natural gas and liquids contain regulated air pollutants.

Well Completions: Activities that occur after a well is drilled that are undertaken to produce hydrocarbon fluids from the well. These include casing, cementing, perforating, gravel packing and installing a production tree.

I N T E N T I O N A L L Y L E F T B L A N K



BACT and Presumptive BACT

Under WAQSR Chapter 6, Section 2(c), all new or modified sources or facilities, which may generate regulated air emissions shall be permitted prior to construction or modification and **Best Available Control Technology (BACT)** shall be applied to reduce or eliminate emissions, with consideration given for technical feasibility and economical reasonableness. **BACT** is a process, not an emission limit. Regulations do not set a minimum emission threshold below which **BACT** does not need to be considered.

At O&G facilities production rates and associated pollutant emissions are usually unknown prior to start up. The AQD has tailored a permitting program allowing for the start up or modification of O&G facilities prior to permitting provided specific emission control requirements are met.

This is the **Presumptive BACT** permitting process for O&G production facilities.

Presumptive BACT requirements have been established for emissions associated with:

- Flashing & S/W/B losses from atmospheric storage tanks and pressurized vessels
- Dehydration unit process vents
- Natural gas-operated pneumatic equipment
- Natural gas-fired pumping unit engines
- Truck loading
- Produced water tanks
- Well completions
- Well blowdown/venting

If emissions **are known prior to** construction or modification, a permit shall be obtained **PRIOR TO CONSTRUCTION or MODIFICATION** and BACT, including Presumptive BACT requirements, shall be addressed in the application. Examples include:

- Construction of a central tank battery for collecting and processing production from surrounding existing wells with known production rates
- Consolidation of multiple existing facilities for which production rates have been established
- Installation of a dehydration unit for an existing well with an established gas production rate
- Installation of larger capacity equipment to replace undersized equipment
- Replacement of an emission control system or device with a different system or device

Presumptive BACT requirements have been established for three (3) areas:

SWA refers to all facilities not located in the **UGRB** or **JPAD/NPL**.

UGRB refers to facilities located in the **Upper Green River Basin.**

JPAD/NPL refers to facilities located in the **Jonah and Pinedale Anticline Development Area and Normally Pressured Lance**.

The **UGRB** area is defined, in accordance with the public land survey system, as:

Sublette County: (all)

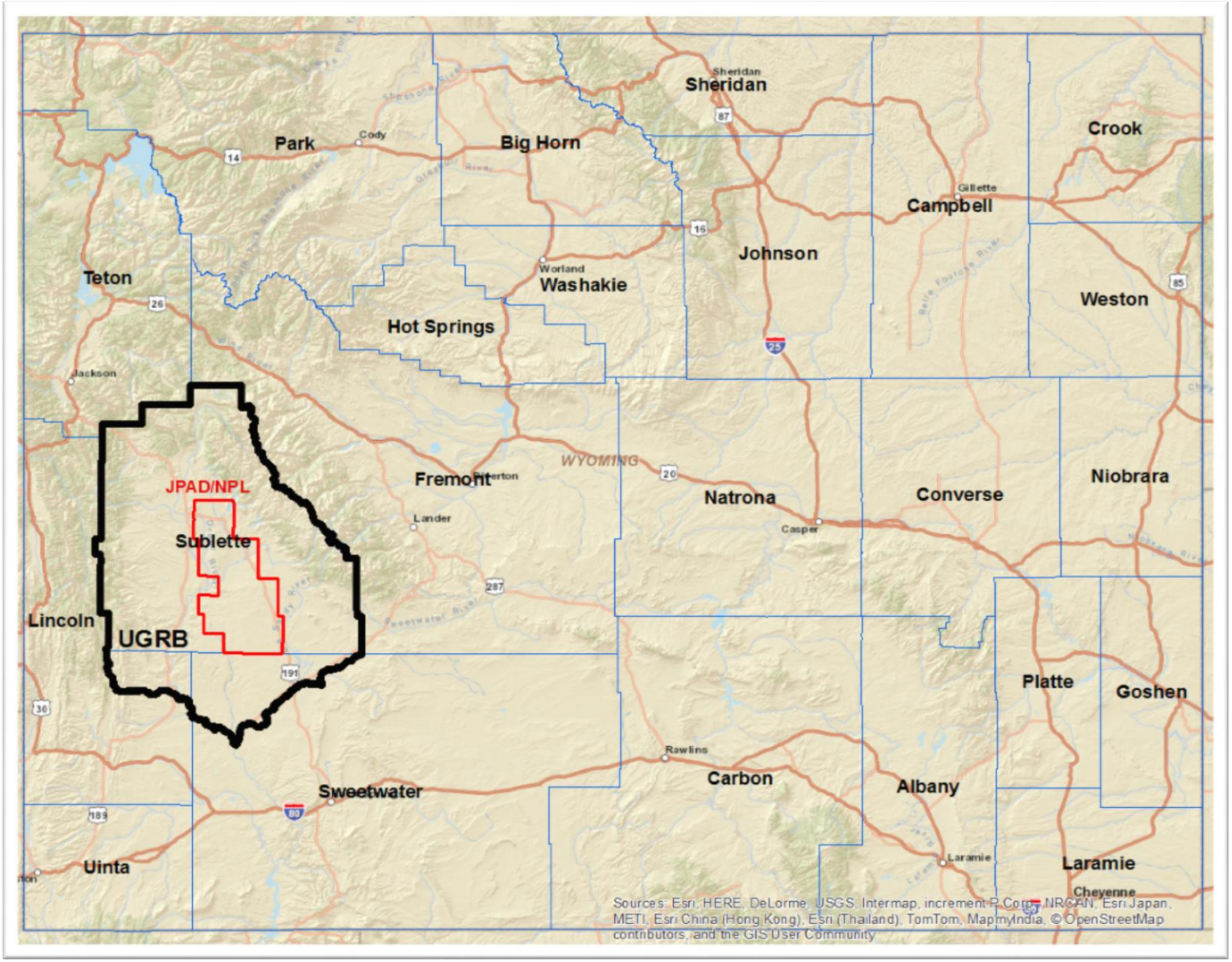
Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range (R) 115 West (R115W) Township (T) 27 North (T27N) and the northwest corner of Section 31 R115W T27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to the Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24N Section 31 crosses into Sweetwater County.

Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W T22N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast long the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T26N. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T26N, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.

The **JPAD/NPL** area is defined as:

Sublette County: R109W & R110W in T34N,
R109W & R110W in T33N,
R108W, R109W & R110W in T32N,
R108W, R109W & R110W in T31N,
R107W, R108W & R109W in T30N,
R107W, R108W, R109W, & R110W in T29N,
R107W, R108W, R109W, & R110W in T28N,
and R107W, R108W & R109W in T27N

The **SWA** refers to all other areas in the State excluding the **UGRB** or **JPAD/NPL**.


Sheridan
Sheridan
Park
Cody
Big Horn
Crook
Gillette
Campbell
Johnson
Teton
Worland
Washakie
Weston
Hot Springs
Jackson
JPAD/NPL
WYOMING
Fremont
Natrona
Converse
Niobrara
Lander
Casper
Sublette
Lincoln
UGRB
Platte
Goshen
Rawlins
Carbon
Albany
Sweetwater
Uinta
Laramie
Laramie
Cheyenne
Sources: Esri, HERE, DeLorme, USGS, Intermap, increment P Corp., NRCAN, Esri Japan, METI, Esri China (Hong Kong), Esri (Thailand), TomTom, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community



Presumptive BACT Requirements for SWA Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC and/or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

PAD Facilities

Upon First Date of Production (FDOP), VOC and HAP flashing emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, flashing emissions containing greater than or equal to 6 Tons per Year (TPY) VOC and HAPs shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, all new and existing VOC and HAP flash emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, all new and existing flashing emissions containing greater than or equal to 6 TPY VOC and HAPs shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site solely for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of a flashing emissions control device(s) may be allowed upon approval if, after at least one year from the date of installation, VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY of VOC and HAPs.



Presumptive BACT Requirements for SWA Facilities (cont.)

Dehydration Units

For the purpose of determining emissions from dehydration units, vapor streams containing VOC or HAP components released from the process vents (reboiler still vents & glycol flash separator vents) of all dehydration units at a facility, which are or may be vented to the atmosphere shall be considered. See page 9 for the definitions of **potential uncontrolled** VOC and HAP emissions and **potential** VOC and HAP emissions.

New Facilities

Upon FDOP, all dehydration units shall be equipped with reboiler still vent condensers. Removal of the condensers will not be allowed.

PAD Facilities

Upon FDOP, all dehydration unit VOC and HAP emissions shall be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Single Well Facilities

Within 60 days of FDOP, if total **potential uncontrolled** VOC and HAP emissions from all units are greater than or equal to 6 TPY, emissions from all units shall be controlled by at least 98%.

After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Modified Facilities

Requirements are the same as those for PADs and single well facilities except use the date of modification in place of FDOP. Control requirements apply to all existing and new dehydration units.

All Facilities

When a combustion unit is required at a facility for control of dehydration unit emissions, all non-condensable still vent vapors shall be collected and routed to a combustion unit for at least 98% control of VOC and HAP emissions. All glycol flash separator vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and/or used as fuel for process equipment burners.



Presumptive BACT Requirements for SWA Facilities (cont.)

All Facilities (cont.)

At facilities where a combustion unit is not required for control of flash or dehydration unit emissions, all glycol flash separator vapors shall be collected for use as fuel in process equipment burners. Excess flash vapors that are not used as fuel may be vented to the atmosphere.

Potential Uncontrolled VOC and HAPs emissions shall be determined using GRI-GLYCalc version 4.0 (V4.0) or higher or other method accepted by the Division and shall be based on the projected, year one, average daily dry gas throughput rate, maximum circulation rate for the glycol circulation pump(s) installed, average expected operating parameters for wet gas temperature and pressure, maximum dry gas water content or number of absorber stages and extended hydrocarbon content of the wet gas from a sample of the wet gas taken upstream of the dehydration unit contact tower. Flash separators, still vent condensers, limited operating hours, and limited glycol circulation rates shall not be considered when determining potential uncontrolled emissions.

Still vent condensers shall consist of equipment engineered and designed to achieve maximum condensation of the condensable components in the still vent vapors by providing adequate temperature differentials between the condenser outlet and still vent stream. Still vent pipes shall not be considered condensers.

Potential emissions for determining combustion device removal after one year shall be calculated using GRI-GLYCalc V4.0 or higher or other method accepted by the Division based on the past twelve calendar months of normal gas production rates, actual average wet gas temperature and pressure, actual water content of the dried gas or number of absorber stages.

Actual operating parameters for glycol flash separators may be used upon approval. Limited operating hours and limited glycol circulation rates shall not be considered for control removal.



Presumptive BACT Requirements for SWA Facilities (cont.)

Pneumatic Pumps

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Single Well Facilities and Tank Batteries

Within 60 days of FDOP,

At sites with controls installed for flashing or dehydration unit emissions:

VOC and HAP emissions associated with the discharge streams from natural gas-operated pneumatic pumps shall be controlled by at least 98% or the discharge streams shall be routed into a closed loop system.

At sites without controls installed for flashing or dehydration unit emissions:

Pneumatic pumps (other than heat trace/heat medium/hot glycol circulation) shall be solar, electric or air-driven pumps in lieu of natural gas-operated pneumatic pumps or the discharge streams shall be routed into a closed loop system. Wherever possible, heat trace/heat medium/hot glycol circulation pumps shall be solar-operated, electric or air-driven.

Modified Facilities

Requirements are the same as above except include all new and existing pneumatic pumps and use the date of modification in place of FDOP.

New and Modified Facilities

At sites where pneumatic pump emissions are controlled by a combustion unit used for the control of flashing or dehydration unit emissions, control of the pneumatic pump emissions will be evaluated upon request for removal of the combustion unit. (See Flashing, Page 7)



Presumptive BACT Requirements for SWA Facilities (cont.)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low bleed or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the discharge streams of existing natural gas-operated pneumatic controllers shall be routed into a closed loop system.

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.



Presumptive BACT Requirements for SWA Facilities (cont.)

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the State. An example of a well completions or "Green Completions" permit is available on the AQD website, http://deq.wyoming.gov/aqd/new-source-review or a copy may be obtained by contacting the Wyoming Air Quality Division at **(307) 777-7391.**

For existing operators, Green Completion permit applications shall be filed with the Division by January 1, 2017. For new operators, a Green Completion permit application shall be filed with the first application for a production site.

Produced Water Tanks

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

New and Modified Facilities

Produced water tanks that are on site solely for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of a emissions control device(s) may be allowed upon approval if, after at least one year from the date of installation, VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY of VOC and HAPs.



Presumptive BACT Requirements for SWA Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements for new and modified facilities.

BMP: During manual and automated blowdown/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blowdown or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

For existing operators, well blowdown and venting permit applications shall be filed with the Division by January 1, 2017. For new operators, a well blowdown and venting permit application shall be filed with the first application for a production site.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 6 TPY VOC and HAP emissions, that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

I N T E N T I O N A L L Y L E F T B L A N K



Presumptive BACT Requirements for UGRB Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP flashing emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, flashing emissions containing greater than or equal to 4 TPY VOC and HAPs shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, all new and existing VOC and HAP flash emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, all new and existing flashing emissions containing greater than or equal to 4 TPY VOC and HAPs shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of flashing emissions control devices may be allowed upon approval after one year if VOC flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Dehydration Units

For the purpose of determining emissions from dehydration units, vapor streams containing VOC or HAP components released from the process vents (reboiler still vents & glycol flash separator vents) of all dehydration units at a facility, which are or may be vented to the atmosphere shall be considered. See page 9 for the definitions of **potential uncontrolled** VOC and HAP emissions and **potential** VOC and HAP emissions.

New Facilities

Upon FDOP, all dehydration units shall be equipped with reboiler still vent condensers. Removal of the condensers will not be allowed.

PAD Facilities

Upon FDOP, all dehydration unit VOC and HAP emissions shall be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Single Well Facilities

Within 60 days of FDOP, if total **potential uncontrolled** VOC and HAP emissions from all units are greater than or equal to 4 TPY, emissions from all units shall be controlled by at least 98%.

After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Modified Facilities

Requirements are the same as those for PADs and single well facilities except use the date of modification in place of FDOP. Control requirements apply to existing and new dehydration units.

All Facilities

When a combustion unit is required at a facility for control of flash or dehydration unit emissions, all non-condensable still vent vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and all glycol flash separator vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and/or used as fuel for process equipment burners.

At facilities where a combustion unit is not required for control of flash or dehydration unit emissions, all glycol flash separator vapors shall be collected for use as fuel in process equipment burners. Excess flash vapors that are not used as fuel may be vented to the atmosphere.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Pneumatic Pumps

New Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Modified Facilities

Upon modification, VOC and HAP emissions associated with the discharge streams of all new and existing natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system.

New and Modified Facilities

At sites where pneumatic pump emissions are controlled by a combustion unit used for the control of flash or dehydration unit emissions, control of the pneumatic pump emissions will be evaluated upon request for removal of the combustion unit. (See Flashing, Page 14)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the discharge streams of existing natural gas-operated pneumatic controllers shall be routed into a closed loop system.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Fugitives

For new and modified facilities where fugitive emissions are greater than or equal to 4 TPY of VOCs, operators shall submit a Fugitive Emissions Monitoring (FEM) Protocol. The fugitive emission monitoring in the FEM Protocol shall be no less frequent than quarterly, and may consist of Method 21, infrared camera, audio-visual-olfactory (AVO) inspections, or some combination thereof and must be approved by the Division. A proposed FEM Protocol consisting of only AVO inspections will not be accepted by the Division.

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the **UGRB**. The permits will be modeled after those issued to operators completing wells in the Jonah and Pinedale Anticline Development Area. An example of a well completions or "Green Completions" permit is available on the AQD website, http://deq.wyoming.gov/aqd/new-source-review or a copy may be obtained by contacting the Wyoming Air Quality Division at **(307) 777-7391.**

Produced Water Tanks

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

New and Modified Facilities

Open-top or blow down tanks shall not be used as active produced water tanks but may be used for blow down or for temporary storage during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, and do not have to be tied into 98% control systems.

Removal of produced water tank emissions control may be allowed upon approval. (See Flashing, Page 14)



Presumptive BACT Requirements for UGRB Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements will be incorporated into permits for new and modified facilities.

BMP: During manual and automated blowdown/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blowdown or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 4 TPY VOC that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

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Presumptive BACT Requirements for JPAD/NPL Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

Upon FDOP, VOC and HAP flashing emissions shall be controlled by at least 98%.

Modified Facilities

Upon modification, all new and existing VOC and HAP flashing emissions shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of flashing emissions control devices may be allowed upon approval after one year if VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY.

Dehydration Units

New Facilities

Upon FDOP, all VOC and HAP emissions from dehydration unit process vents shall be controlled by at least 98%. No control removal will be allowed.

Modified Facilities

Upon modification, all VOC and HAP emissions from new and existing dehydration unit process vents shall be controlled by at least 98%. No control removal will be allowed.



Presumptive BACT Requirements for JPAD/NPL Facilities (cont.)

Pneumatic Pumps

New Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Modified Facilities

Upon modification, VOC and HAP emissions associated with the discharge streams of all new and existing natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system.

New and Modified Facilities

For pneumatic pump emissions controlled by a combustion unit used to control flash emissions which may be removed, the control method for pump emissions will be evaluated upon request for approval to remove the combustion unit. (See Flashing, Page 20)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.



Presumptive BACT Requirements for JPAD/NPL Facilities (cont.)

Produced Water Tanks

New Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

New and Modified Facilities

Open-top or blow down tanks shall not be used as active produced water tanks but may be used for blow down or for temporary storage during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, and do not have to be tied into 98% control systems.

Removal of water tank emissions control may be allowed upon approval. (See Flashing, Page 20)

Fugitives

For new and modified facilities where fugitive emissions are greater than or equal to 4 TPY of VOCs, operators shall submit a FEM Protocol. The fugitive emission monitoring in the FEM Protocol shall be no less frequent than quarterly, and may consist of Method 21, infrared camera, AVO inspections, or some combination thereof and must be approved by the Division. A proposed FEM Protocol consisting of only AVO inspections will not be accepted by the Division.



Presumptive BACT Requirements for JPAD/NPL Facilities (cont.)

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the **JPAD/NPL**. The permits will be modeled after those issued to operators completing wells in the Jonah and Pinedale Anticline Development Area. An example of a well completions or "Green Completions" permit is available on the AQD website, http://deq.wyoming.gov/aqd/new-source-review or a copy may be obtained by contacting the Wyoming Air Quality Division at **(307) 777-7391.**



Presumptive BACT Requirements for JPAD/NPL Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements will be incorporated into permits for new and modified facilities.

BMP: During manual and automated blow down/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blow down or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 4 TPY VOC and HAPs that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

I N T E N T I O N A L L Y L E F T B L A N K



Determining P-BACT Flashing Emissions

Flashing losses occur when produced liquids (crude oil or condensate) are exposed to temperature increases or pressure drops as they are transferred from production vessels to other vessels or to atmospheric storage tanks. For purposes of this guidance, the term "**flash emissions**" refers to VOC and HAP pollutants associated with entrained natural gas vapors released to the atmosphere from hydrocarbon liquids in surface production equipment. This production equipment may include gun barrels, separators, treaters, produced water tanks, gas drips, freewater knockouts, etc. In addition to flash emissions, vessels containing hydrocarbon liquids also have emissions associated with **working** and **breathing** (also called standing) losses. These are vapors displaced from oil or condensate due to evaporation and agitating.

Use the following steps to determine projected potential flashing and working/breathing losses:

STEP 1: 30 days after the First Date of Production calculate the **average daily condensate or oil production**.
Example: Well produced 600 BBL during the first 30 days after the First Date of Production.
***average daily condensate/oil production** = 600 BBL ÷ 30 days = 20 BPD*

STEP 2: Calculate the **projected first year annualized average daily condensate/oil production** rate by multiplying the average 30-day rate times 0.6. This effectively results in a first year, annualized daily production rate, which is 20% of the initial production rate. Additionally, this effectively accounts for an 80% decline in daily production by the end of the first year. (described in more detail on page 36)

Example:
***projected first year, annualized average daily oil/condensate production** = 20 × 0.6 = 12 BPD*

If the expected decline rate is less than 80%, then the expected decline rate should be used. Using an expected decline rate > 80% requires pre-approval from the Division.

STEP 3: Use an approved flash emissions model or direct measurement of tank emissions to determine **projected first year VOC and HAP emissions associated with the projected first year average daily production rate**.

Actual flash emissions are determined the same as projected potential emissions except that the actual average daily condensate or oil production rate is used rather than a projected production rate.



Determining P-BACT Flashing Emissions (cont.)

Several methods are available to calculate or measure flash emissions with some being more accurate than others. Even though working/breathing/flashing losses are almost always mixed together and exit from a common vent at the same time, some methods only calculate working and breathing losses and some only calculate flashing losses. Some methods will calculate all three types of emissions simultaneously. Each method has specific constraints. For whichever method used, all supporting data used to calculate the emissions, including identification of the calculation method, description of sampling methods and copies of lab sampling analyses shall be provided with the emissions estimate.

	Method	Emissions Calculated	Comments
1	Direct measurement	working, breathing, flash	Sampling and lab analysis required. Results are relatively accurate.
2	Process Simulator	flash, working, breathing	i.e. PROMAX, HYSIM, HYSIS Software is expensive but results are accurate when based on site-specific sampling and lab analysis.
3	API E&P TANKS Software V 2.0 and higher	working, breathing, flash	Requires site specific sampling. Not as accurate as more expensive process simulators and no longer supported by the software producer (American Petroleum Institute).
4	Laboratory measurement of the Gas-Oil-Ratio (GOR) from a pressurized liquid sample	flash only	This is a direct laboratory analysis of the flash vapors emitted from a pressurized oil/condensate sample.
5	EPA TANKS 4.0.9d	working, breathing only	Program distributed by the EPA through their website at https://www3.epa.gov/ttn/chief/software/tanks/index.html

Extended hydrocarbon liquids analyses used for model input shall be no older than **three** years. Composite analyses may be used as input. These are averaged extended hydrocarbon compositions based on samples from at least five wells located in the same geographical area, producing from the same formation and under similar conditions (± 25° psig) as the well being permitted. Analyses used as the basis for the average shall be no older than **three** years.



Determining P-BACT Dehydration Unit Emissions

Dehydration units use glycol (TEG, DEG or EG) to absorb water from produced gas before it is introduced into gas sales or collection lines. Upon contact with wet gas, "lean" glycol absorbs water and other liquids. It is then considered "rich". To remove impurities, or regenerate, the rich glycol is routed through a glycol flash separator and/or a reboiler. During flash separation and reboiling, water and hydrocarbon vapors containing VOC and HAP pollutants are released from the rich glycol. These are then discharged to the atmosphere from the dehydration unit process vents.

Use the following steps to determine projected potential dehydration unit emissions:

STEP 1: Once a new well has produced for 30 days after the First Date of Production, determine the average daily gas production rate.
Example:
Well produced 100 MMCF during the first 30 days after the First Date of Production
average daily gas production = 100 MMCF ÷ 30 days = 3.3 MMCFD

STEP 2: Calculate the **projected first year, annualized average daily gas production** rate by multiplying the initial average 30-day rate times 0.6. This effectively results in a first year, annualized daily production rate, which is 20% of the initial production rate. Additionally, this effectively calculates an 80% decline in daily production by the end of the first year. (described in more detail on page 36.)

Example:
projected first year, annualized average daily gas production *= 3.3 × 0.6 = 2.0 MMCFD*

STEP 3: Use GRI-GLYCalc V4.0 or higher or other method approved by the Division with the projected first year, annualized average daily production rate to determine **potential, annualized uncontrolled VOC and HAP emissions** from the dehydration unit **process vents**. **Process vents** include reboiler still vents, glycol flash separators and still vent condensers.

Model input:

1) An extended hydrocarbon analysis of wet gas sampled upstream of the reboiler contact tower. Or, a composite extended hydrocarbon analysis may be used. A composite analysis is the average composition from at least five nearby wells producing from the same formation as the new well and under the same or very similar separator pressure and temperature conditions. Samples shall be no older than three years.
2) The projected first year average daily gas production rate (MMCFD).
3) Average, actual equipment operational parameters, including wet gas temperature and pressure, dry gas water content, glycol flash separator temperature and pressure, stripping gas source and rate and average operating parameters of emission control equipment.
4) The **maximum lean glycol circulation rate** (gpm) for the glycol circulation pump in use. Maximum circulation rates for the most commonly used Kimray Model pumps are listed in **TABLE 1**.



Determining P-BACT Dehydration Unit Emissions (cont.)

TABLE 1

KIMRAY GLYCOL PUMP RATES				
Model #	Capacity (gpm)		Working Pressure (psi)	
	min	max	min	max
3154 PV	0.05	0.22	100	1500
1715 PV	0.13	0.67	300	1500
4015 PV	0.2	0.67	300	1500
9015 PV	0.45	1.5	300	1500
21015 PV	1.1	3.5	400	1500
45015 PV	2.77	7.5	400	1500
4015 LP	0.13	0.33	100	500
2015 SC	0.13	0.33	100	500
5015 SC	0.2	0.83	100	500
10015 SC	0.37	1.67	100	500
20015 SC	1	3.33	100	500

Data from Kimray O&G Equipment and Controls Catalog

Actual dehydration unit emissions are determined the same as projected potential emissions except that the actual average daily gas production rate is used in the GLYCalc model rather than a projected production rate.



BACT for Flashing Emissions

The following control systems or devices are accepted by the Division as meeting BACT for flash emissions:

1) A vapor recovery device that is designed and operated and may be demonstrated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98%.
2) An enclosed, smokeless combustion device or flare that is designed and operated and may be demonstrated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98%.
3) Any other control device or configuration that can be demonstrated to reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 98%.
4) Monitoring and recordkeeping, which will demonstrate continuous and effective emission control are required upon start up of the control system. For a combustion device this may be a thermocouple and continuous recording device or any other equivalent device to detect and record the presence of the pilot flame, or a combustion chamber temperature recorder/monitor. The monitoring/recording requirements become enforceable permit conditions.
5) Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, thief hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device, shall be maintained and operated during any time a well is producing such that the emissions are controlled at all times.

CAUTION: Total emissions from any facility or source shall not exceed major source levels prior to emission control installation. Major source levels are 10 TPY of any single HAP, 25 TPY of any combination of HAP or 100 TPY of any regulated pollutant. Flash emissions prior to control installation will be determined using approved emission models or methods based on actual reported production and operating conditions. Reported production includes that sold during well completion activities, which are reported to the WOGCC. Flash emissions are directly proportional to production rates, provided operational parameters remain consistent, so it is acceptable to prorate emissions based on production.



BACT for Dehydration Unit Emissions

Other emission control systems or devices than those previously discussed may be used upon approval by the Division to meet BACT requirements for emissions from dehydration unit process vents (reboiler still vents and vents from glycol flash separators or glycol flash tanks). In order to be approved, the operator must provide a demonstration certifying the system or device will reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 98%.

Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device, shall be maintained and operated during any time a well is producing such that the emissions are controlled at all times.

Monitoring and recordkeeping, which will demonstrate continuous and effective emission control are required upon start up of the control system. For combustion devices this may be a thermocouple and continuous recording device for the pilot flame or any other equivalent device to detect and record the presence of the pilot flame. A temperature recorder/monitor might be used to demonstrate sufficient heat of combustion or a continuous, wind-up chart recorder might be used to demonstrate continual operation by measuring and recording temperature or pressure parameters.

REMINDER: Dehydration units at oil and gas production facilities may be subject to additional NESHAP requirements under 40 CFR part 63, subpart HH. It is the operator's responsibility to comply with all applicable requirements of the NESHAP regulations.

CAUTION: Total emissions from any facility or source shall not exceed major source levels prior to emission control installation. Major source levels are 10 TPY of any single HAP, 25 TPY of any combination of HAP or 100 TPY of any regulated pollutant. Dehydration unit emissions occurring prior to the installation of required controls will be determined using the GRI-GLYCalc model or other method approved by the Division based on the maximum lean glycol circulation rate and the actual reported gas production rate including any gas, which was routed through the dehydration unit during well completion operations.



BACT for Sources without P-BACT Requirements

For emission sources without PRESUMPTIVE BACT requirements, BACT shall be addressed when the uncontrolled source emits greater than or equal to 6 TPY VOC and HAPs for sources located in the **SWA** or 4 TPY VOC and HAPs for sources located in the **UGRB** or **JPAD/NPL**.

For these sources **EITHER** the emission source will be controlled using previously implemented BACT **OR** a BACT cost analysis will be performed and submitted with the application showing either:

control is not technically feasible (i.e., due to physical constraints the emissions cannot be controlled)

OR

control is not economically reasonable (i.e., based on a control cost analysis the "cost to control per ton of pollutant reduced" is uneconomical).

CAUTION: **BACT** may be required at lower levels and for other emissions and emission sources than those stated in this guidance, but as a minimum, **BACT** shall be considered when equal to or above these guidance emission levels. For example, operators installing pumping unit engines according to Guidance might be asked to submit a BACT analysis for the engine.

Multiple pieces of the same type of equipment are considered one emission source for permitting purposes.

For example, there are five oily rag burners at a facility located in the **SWA**. Uncontrolled emissions from the five burners shall be aggregated for permitting purposes. If total uncontrolled VOC emissions from the five burners are less than the development area specific threshold of 6 TPY, BACT requirements are met with no control. If total uncontrolled emissions from the five burners are greater than or equal to 6 TPY VOC and HAPs, emissions from all five burners shall be reduced to less than 6 TPY VOC and HAPs in order to meet BACT requirements or the applicant shall demonstrate controlling the emissions is not economically reasonable nor technically feasible.



Permit Applications

For **JPAD/NPL**, **UGRB** and **SWA** facilities, unless a permit is issued prior to start up, a C6 S2 Oil & Gas Production Facilities permit application shall be filed within 90 days after the First Date of Production for a new facility or Date of Modification of an existing facility. The application notifies the AQD that the new or modified facility has begun operation. It describes the facility process, equipment and associated emissions/emissions controls and serves as a form of certification by the owner that the Presumptive BACT requirements have been met.

Whether the application is being filed after construction under the Presumptive BACT process or prior to construction, the appropriate application forms, depending upon the facility equipment and operating scenario, need to be filled out. A complete application includes the following

- A cover letter stating the purpose of the application
- Equipment list for the facility
- A written process description and process diagram for the facility, including each air emission source and the operational parameters of each source (examples provided on pages 34 & 35)
- The appropriate IMPACT forms
  - Cover Sheet
  - Emission Unit Form for all new or modified equipment
  - Pollutant Emissions Form for each emission unit
  - Release Point Form for each emission unit
  - Control Equipment Form (where applicable)
- The appropriate additional documentation (examples include)
  - Emission Summary
  - BACT cost analysis
- Explanations or demonstrations of all methods used to calculate or estimate emissions for each emission source, including controlled and uncontrolled sources. Emission calculation methods are described later.
- All applicable and required attachments, including:
  - Input and output for emission models/software/process simulations
  - Equipment manufacturer's emissions information
  - Laboratory analyses used for emission models/software/process simulations or calculations including a description of sampling procedures and handling, sampling locations, sampling location parameters (i.e., pressure and temperature at sampling port)
- Any additional attachments or information necessary for complete review of the application



Permit Applications (cont.)

As of September 2, 2014, the New Source Review program is processing all air quality permit applications electronically through the IMPACT System. There are two acceptable methods to submit an application. Please choose just one of the methods below:

- Applications may be submitted through the IMPACT portal (https://airimpact.wyo.gov). Submittals through the IMPACT portal are sufficient and paper copies are not required.

- Two paper copies (one with an original signature) of each complete permit application.

The preferred method for filing the application is through the IMPACT portal.

For facilities constructed or modified under the **Presumptive BACT** process a complete C6 S2 application shall be submitted within **90 days** of the **First Date of Production**. In the event that the IMPACT portal is not functioning properly and prevents the submittal of the application within 90 days of First Date of Production, the applicant will need to contact the Division prior to the due date of the application to inform NSR of the issue and the applicant will need to provide documentation in the permit application showing the reason for the delayed submittal. Examples of acceptable documentation include a screen shot showing the issue or a copy of email correspondence between the applicant and the Division discussing the problem.

If not submitting through the IMPACT portal, download IMPACT application forms from the AQD website:

http://deq.wyoming.gov/aqd/new-source-review/resources/application-forms/

The oil and gas applications forms are contained in one Microsoft Excel file. The file name for the IMPACT application forms is "01 - AQD - NSR - Application Form".

If you need assistance with the applications forms, contact the Wyoming Air Quality Division at **(307) 777-7391.**

Address written requests to: Wyoming Department of Environmental Quality
Air Quality Division
(see WDEQ website for current mailing address)
attn: O&G NSR Permitting*

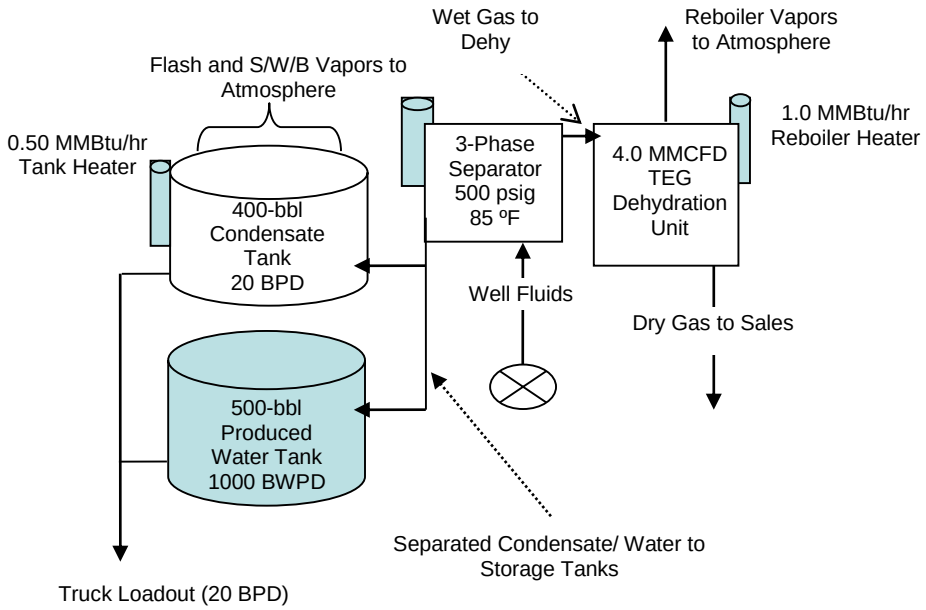
*To assist with the proper routing of the application and application materials, please make sure to address the materials to O&G NSR Permitting.

With the implementation of an electronic permitting system, the NOI process will no longer be utilized for new applications. Minor equipment installations and/or modifications that qualified for a NOI will now submit a complete application with the appropriate information listed on page 32. IMPACT forms and associated information are required for new or modified equipment.



Permit Applications (cont.)

Example Process Diagram & Description

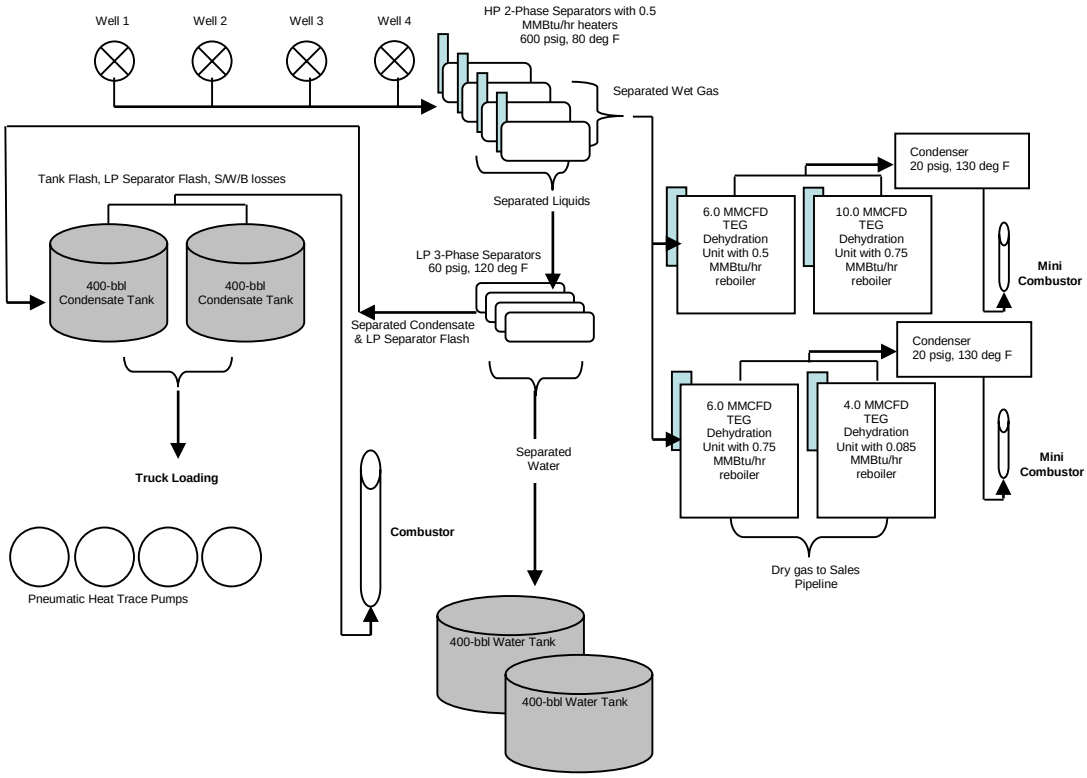


EXAMPLE: Air emission sources in the diagram are the condensate storage tank from which vapors are vented to the atmosphere, the dehydration unit reboiler still vent and the three natural gas-fired process heaters. Produced fluids are directed to the 3-phase separator for separation of condensate/water/gas. Wet gas is directed to the TEG dehydration unit for drying. Separated condensate and water are routed to the appropriate tanks for storage prior to being hauled from location via truck. Produced gas is used as burner fuel. Reboiler vapors and flash emissions are vented to the atmosphere along with S/W/B losses from the condensate tank.



Permit Applications (cont.)

Example Process Diagram & Description



EXAMPLE: Total well fluids from four wells flow to the 2-ph HP separators. Wet gas from the HP separators flows to the four dehydration units. Separated fluids from the 2-ph HP separators flows to the 3-ph LP separators. Separated condensate and water flows from the 3-ph LP separators to the storage tanks. Gas released in the 3-ph separators is routed to the condensate storage tanks. Tank vapors, including tank flash, gas from the 3-ph LP separators and S/W/B vapors are collected and directed to a 30-foot smokeless combustor. The temperature of the combustor is continually monitored and recorded using a SCADA (supervisory control and data acquisition) system. Reboiler still vents vapors flow through condensers. Condensed liquids are pumped to the condensate storage tanks. Non-condensable vapors flow to the 20-foot Mini-Combustors. The temperature of the Mini-combustors is continually monitored and recorded using a SCADA system. Pneumatic heat trace pumps operate 6 months per year using produced gas from the HP separators to operate. Vent lines from the pumps are routed into the condensate dump lines from the LP separators.

The process diagram does not need to be computer generated. A simple hand sketch is sufficient as long as the required information is included. The diagram does not need to be drawn to scale and does not need to represent the exact position of production equipment at the facility as long as the process description and operating scenario are clearly defined.



Permit Applications (cont.)

Upon receipt of a paper application, the Division must input the required application information into an electronic system (IMPACT) for processing. Once the paper application is processed, the Division sends the applicant a receipt letter. For electronic applications received via IMPACT, the Division simply issues a receipt letter after the application is received and a reviewer is assigned. The reviewer has up to 30 days to perform a completeness review to ensure adequate and correct information has been filed. If the application is deemed incomplete the reviewer will notify the applicant and request further information. Upon completeness the reviewer has 60 days to complete a technical review, write an application analysis and make any recommendations. During this process the decision to issue a permit or waiver takes place. If the decision is to issue a permit, the proposed permit, including compliance requirements, is published for a mandatory 30 day public comment period. If no comments are received the permit is issued once the public comment period ends. If comments are received these are addressed by the AQD. It is possible comments will warrant a public hearing. When this is the case, a final permit may be denied or delayed.

A minimum fee ($464, subject to change) will be charged to each application. An hourly fee ($58 per hour, subject to change) will be assessed for the time it takes AQD personnel to process the application. A bill will be sent to the applicant when the process is complete. Billing is handled as follows:

> **Initial billing** (permits only) is assessed when a proposed permit is sent to public notice. The initial billing must be paid before AQD can issue a final permit.
>
> **Final billing** is assessed for waivers and permits after these are issued.

Contact the Division for the current hourly rate.

NOTE: The Presumptive BACT permitting process may not be used for sour gas (H_2S) production facilities unless the only emissions of H_2S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc. If there will be H_2S emissions associated with vented gas or tank vapors or if sour gas will be flared the applicant shall contact the Division for permitting guidance prior to construction.

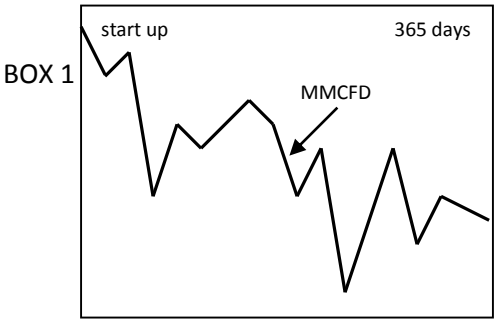
No internal combustion compressor engines or generator engines may be installed under the Presumptive BACT process.

No pumping unit engines greater than 50 Hp may be installed under the Presumptive BACT permitting process. Such engines shall be permitted prior to installation.



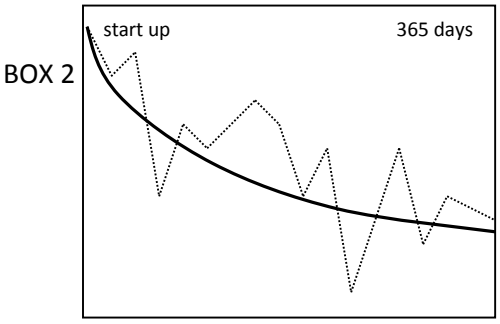
The 0.6 decline factor

The first year daily production rates are represented by the jagged line **BOX 1**. The area under the line represents the total actual production volume for the first year. It is difficult to calculate the total volume under the jagged line so it is smoothed out **BOX 2** using statistical methods.

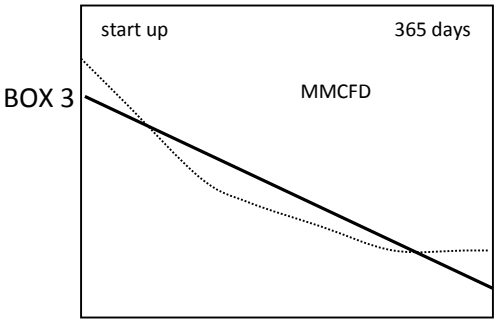


EXAMPLE - actual daily gas production rate vs time

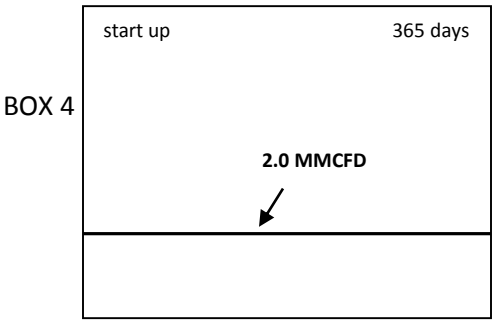
Actual production during the first year is represented by the area under the jagged line which ultimately turns out to be ≈ 730 MMCF.



The jagged line representing daily production is "smoothed" out using statistical methods.



The "smoothed" curve in BOX 2 is "straightened" out using mathematical methods.



"leveled" out, projected daily gas production rate vs time

Total projected production for the first year is represented by the area under the straight line
2 MMCFD × 365 days = 730 MMCF

First year projected emissions are based on 730 MMCF of produced gas.

The smoothed curve is "straightened" out in **BOX 3**, then "leveled" out in **BOX 4**. Now the total production for the first year is represented by the area under the line in **BOX 4,** which is easily calculated. Production curves from a large sampling of Wyoming wells indicate the average well declines by 80% during the first year. That 80% decline is represented by the level line in **BOX 4** after the first 30-day average production rate is multiplied by 0.6. For the first month the well makes an average 3.333 MMCFD. With 80% decline during the first year, the well will make 0.667 MMCFD at the end of the first year (3.333 - 0.8(3.333) = 0.667). Then the average daily production rate over 365 days is (3.333 + 0.667)/2 = 2.0 MMCFD, which is the same as 3.333 × 0.6 = 2.0.



Pumping Unit Engines

A pumping unit engine is an engine used to provide electrical or mechanical energy to a pump in order to produce a well.

This Guidance does not apply to compressor engines, engines used for vapor recovery, or pumping unit engines greater than 50 Hp.

This Guidance replaces the March 9, 2012 Pumping Unit Engine Emissions Policy.

Historically, AQD has allowed the installation of pumping unit engines at oil & gas production facilities as part of the Guidance. Engines were allowed to be installed prior to permit issuance, provided the engine was site rated for less than 50 Hp and emitted less than 5 TPY of NO_x.

The Guidance does not however preclude the Division from asking the applicant to submit a Best Available Control Technology (BACT) analysis to determine if emissions from the engine are technically feasible and economically reasonable to control. As demonstrated in the March 9, 2012 Pumping Unit Engine Emissions Policy, BACT is a moving target and relying on an emissions threshold of 5 TPY NO_x was no longer considered BACT for pumping unit engines less than 50 Hp. AQD will continue to allow installation of pumping unit engines prior to obtaining a permit provided the engine meets BACT and the requirements listed below.

Installation of pumping unit engines site rated for 50 Hp or less is allowed provided the engine meets NO_x emissions of 2.0 g/hp-hr and CO emissions of 3.0 g/hp-hr.

Initial and/or periodic emissions testing and monitoring of the pumping unit engine may be established in the permit or permit waiver.

APPENDIX A

EMISSION CALCULATIONS

Emissions from processes and equipment, which shall be accounted for and reported by applicants FOR ALL O&G PRODUCTION FACILITIES are:

Emission Unit or Process	Associated Emissions
storage tanks (flashing & S/W/B losses)	VOC HAP
pressurized vessels (flashing losses)	VOC HAP
dehydration units (reboiler still vents & glycol flash tanks)	VOC HAP
natural gas fired burners, heaters, flares	VOC NO_X CO
natural gas operated pneumatic controllers/pumps	VOC HAP
fugitives	VOC HAP
natural gas fired engines	NO_X CO VOC
truck load out	VOC HAP

AP-42 EMISSION FACTORS

Throughout this Guidance reference is made to AP-42 emission factors. The complete AP-42 compilation may be downloaded from https://www3.epa.gov/ttn/chief/ap42/index.html.

STORAGE TANK EMISSIONS

Flashing and Standing/Working/Breathing (S/W/B) losses are the terms for emissions which occur when hydrocarbon liquids are exposed to temperature and pressure changes (i.e., from separator pressure and temperature to storage tank pressure and temperature) causing hydrocarbon vapors to be released from the liquids. The vapors may contain VOCs, HAPs and H_2S.

Software is available for modeling these emissions. Models accepted by the Air Quality Division are those using Peng-Robinson or S-R-K methods based on widely accepted principals of behavior for hydrocarbon vapors and liquids. Some common software programs for estimating these emissions are PROMAX, HYSIM, HYSYS, K-FLASH, PROSIM and API E&P TANKS (v2.0 and higher). The models require input detailing chemical properties of the fluids handled and physical operating parameters of the system(s) and production equipment. Output from the models includes volumes, rates and chemical components of the individual process streams from tanks and pressurized vessels.

Emissions from storage tanks may also be physically measured. In order to do so all tank valves, hatches, relief devices, leaks, etc. shall be sealed. Tank vapors shall only be allowed to exit the tank through a metered outlet. Usually this requires a meter capable of measuring low volumes. The measurement period shall last long enough to capture a representative tank vapor volume. An extended hydrocarbon analysis of the vapors shall be obtained along with the vapor volume.

MEASURED TANK FLASH EMISSIONS – EXAMPLE CALCULATION

The tons per year of VOC and HAP emissions associated with tank flashing are calculated as follows:

Given: Condensate tank vapors = 1000 scf/day
VOC weight % = 20
HAP weight % = 5
Condensate vapor molecular weight = 20 lb/lb-mol

TPY total flash emissions = 1000 scf/day × (1 lb-mol/379 scf) × (20 lb/lb-mol) × (ton/2000 lb) × (365 days/year) = 9.6 TPY

TPY total VOC emissions = 9.6 TPY × (20 weight % VOC / 100) = 1.9 TPY VOC
TPY total HAP emissions = 9.6 TPY × (5 weight % HAP / 100) = 0.5 TPY HAP

S/W/B losses
Not all software programs include tools for estimating S/W/B losses. There is free software available from the EPA named EPA TANKS. The most recent available version of EPA TANKS may be downloaded from the EPA website at https://www3.epa.gov/ttn/chief/software/tanks/index.html.

PRESSURIZED VESSELS

Whenever vapors from a pressurized vessel (separator, treater, FWKO, flash separator, gunbarrel, gas boot, etc) are released to the atmosphere, other than during times of emergency or upset conditions, emissions associated with those vapors shall be accounted for.

The same flash emission models mentioned above, for tank flash emissions, are often used to estimate emissions from pressurized vessels. Again, an extended hydrocarbon analysis of the liquids involved and actual operational conditions of the production equipment are necessary as input for the models.

Even when vapors from a pressurized vessel are collected for use as process burner fuel or fuel for an IC engine, for example, emissions associated with the total vapors shall be accounted for when considering potential emissions from a facility. If the volume and rate of vented vapors are known and an extended hydrocarbon analysis is available, associated emissions may be calculated in the same manner as described on Page 39 (calculation of flash emissions). If these are not available, the volumes shall be measured and analyzed in order to perform the calculations and determine associated emissions.

DEHYDRATION UNIT EMISSIONS

Air pollutants, mostly VOCs and HAPs, are associated vapors released from reboiler still vents and glycol flash separators. To estimate these emissions the GRI-GLYCalc v4.0 or higher model or other approved method is used. This relatively inexpensive software was created by the Gas Research Institute (GRI) for determining optimal operating parameters for dehydration units and is available from the Gas Technology Institute (GTI) with a website address of http://sales.gastechnology.org/.

Input for the model includes an extended hydrocarbon analysis of wet gas sampled upstream of the contact tower, actual operating parameters of all associated equipment (i.e., reboiler still vent temp., flash separator temp., dry gas flow rate, glycol recirculation rate, condenser, etc) and physical properties of the dry and wet gas streams. The model provides an estimate of individual emission components and the rates of vapor and liquid streams exiting each process vent of a dehydration unit. When submitting a GRI-GLYCalc

model it is only necessary to submit the INPUT SUMMARY, EMISSIONS SUMMARY, CONDENSER VENT OUTPUT (if applicable) and FLASH TANK OUTPUT (if applicable).

NATURAL GAS FIRED HEATERS (external combustion equipment)

NO_X, CO and VOC emissions from process unit heaters should be calculated using the emission factors (EF) below from EPA AP-42, Tables 1.4-1, 1.4-2 and 1.5-1. The following lists these factors:

Emission Factors for Industrial and Commercial Boilers

Pollutant	Butane Gas[1] (0.3 to 100 MMBtu/hr heat input)	Propane Gas[2] (0.3 to 100 MMBtu/hr heat input)	Natural Gas[3] <100 MMBtu/hr heat input	Natural Gas[3] <100 MMBtu/hr heat input
NO_X[4]	15 lb/1000 gal	13 lb/1000 gal	0.098 lb/MMBtu	100 lb/MMcf
CO[4]	8.4 lb/1000 gal	7.5 lb/1000 gal	0.082 lb/MMBtu	84 lb/MMcf
TOC[4,5]	1.1 lb/1000 gal	1.0 lb/1000 gal	0.010 lb/MMBtu	11 lb/MMcf

1 Based on an average heating value of 102×10^6 Btu/1000 gallons of Butane.

2 Based on an average heating value of 91.5×10^6 Btu/1000 gallons of Propane.

3 Based on an average heating value of 1020 Btu/SCF of natural gas.

4 The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factors by the ratio of the heating value of the actual gas used to the average heating values listed
Converted EF = (EF from table above × (actual heat value/heat value in table)).

5 VOC emissions may be determined by multiplying the calculated TOC (total organic compounds) emission rate by the weight percent of VOC compounds in the actual fuel gas stream.

HEATER EMISSIONS - EXAMPLE CALCULATION

Given: Separator heater rating = 0.5 MMBtu/hr
Gas Heating Value = 1300 Btu/scf
VOC weight % = 20
Annual operating hours = 8760
NO_X EF = 100 lb/MMcf
CO EF = 84 lb/MMcf
TOC EF = 11 lb/MMcf

NO_X emissions = (0.5 MMBtu/hr) × (100 lb/MMcf) × (1300 Btu/1020 Btu) x (1 scf/1020 Btu) × (8760 hr/yr) × (ton/2000 lb) = 0.27 TPY NO_X

For CO emissions, the same calculation is used except the EF is 84 lb/MMcf.

VOC emissions = 0.5 × 11 x (1300/1020) x 1/1020 × 8760/2000 x (20% VOC/100) = 0.006 VOC TPY VOC ← INSIGNIFICANT at less than 0.1 TPY

FLARES

The NO_X and CO emissions for flares should be based on **0.14 lb NO_X/MMBtu and 0.035 lb CO/MMBtu** (Emission factors from Section 4 of EPA Document "Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations") and the reported fuel usage based heat input. VOC and HAP emissions from flaring should be based upon the guaranteed destruction efficiency of the flare. Reported flared gases shall include pilot gas with heat content and flared gas with average estimated heat content. The rational for using these factors as opposed to AP-42 factors for flares is that the flare factors are believed to be only applicable to chemical plant type flares engaged in burning low BTU gases. The gases typically burned in flares in Wyoming contain more than 900 Btu/scf and emissions are expected to be closer to the AP-42 factors for NO_X and CO from gas fired heaters and boilers greater than 10 MMBtu/hr.

FLARE EMISSIONS - EXAMPLE CALCULATIONS – CONDENSATE TANK FLASH

Given: Total waste gas = 125 scf/hr
Gas heating value = 1350 Btu/scf

NO_X emissions = (125 scf/hr) × (1350 Btu/scf) × (0.14 lb NO_X /MMBtu) × (MMBtu/10^6 Btu) × (8760 hr/yr) × (1 ton/2000 lb) = 0.1 TPY NO_X

FLARE PILOT EMISSIONS

Given: Flare pilot gas = 5 scf/min
Gas heating value = 1000 Btu/scf

NO_X emissions = (5 scf/min) × (1000 Btu/scf) × (0.14 lb NO_X/MMBtu) × (MMBtu/10^6 Btu) × (60 min/hr) × (8760 hr/yr) × (1 ton/2000 lb)
= 0.18 TPY NO_X

For CO emissions the same calculations are used except the EF for CO is 0.035 lb/MMBtu.

FLARE EMISSIONS EXAMPLE CALCULATION – DEHYDRATION UNITS

Given: Glycol flash separator vapors = 25 scf/min
Reboiler still vent vapors = 5 scf/min
Total waste gas = 30 scf/min (25 scf/min glycol flash vapors + 5 scf/min reboiler still vent vapors)
Gas Heating Value = 1050 Btu/scf (**assume at least 1000 BTU/SCF if the heat content is unknown**)

NO_X emissions = (30 scf/min) × (1050 Btu/scf) × (0.14 lb NO_X/MMBtu) × (1 MMBtu/10^6 Btu) × (60 min/hr) × (8760 hr/yr) × (1 ton/2000 lb)
= 1.1 TPY NO_X

For CO emissions the same calculations are used except the EF for CO is 0.035 lb/MMBtu.

PNEUMATIC PUMPS

If a pneumatic pump uses natural gas as the motive gas, the pump will release VOC and HAP emissions each time it strokes since all motive gas is vented by the pump. To determine emissions from the pump, manufacturer's information regarding gas usage shall be known as well as the hydrocarbon composition of the motive gas.

PNEUMATIC PUMP EMISSIONS - EXAMPLE CALCULATION

A Texsteam Series MX pump is used to circulate hot glycol in heat trace lines. The pump moves 0.15 gallons per 40 strokes and is currently stroking at 20 strokes per minute (spm). The pump requires 24 scf for each gallon of glycol pumped. The pump motive gas weighs 20 lb/lb-mol and contains 50 wt% VOCs and 30 wt% HAPs.

Pump usage/vent rate = (20 strokes/min) × (0.15 gallons/40 strokes) × (24 scf/gallon) = 1.8 scf/min

VOC emissions = (1.8 scf/min) × (20 lb/lb-mol) × (lb-mol/379 scf) × (ton/2000 lb) × (525600 min/yr) × (50 wt% VOC/100) = 12.5 TPY VOC

PNEUMATIC CONTROLLERS

Emissions from continuous bleed pneumatic controllers shall be based on the manufacturer-certified bleed rates. Emissions from intermittent vent controllers shall be based on the volume of gas required for actuation and the applicant's best engineering estimate of the frequency of actuations.

TRUCK LOADING

VOC emissions from loading oil or condensate into tank trucks should be estimated using the following formula with data from AP-42 tables.

$$L_L - 12.46 \times S \times P \times M/T$$

Where: L_L = loading loss, pound per 1,000 gallons of liquid loaded (lb/1000 gal)
S = a saturation factor (See Table 5.2-1 below)
P = true vapor pressure of liquid loaded (psia)
M = molecular weight of tank vapors (lb/lb-mol)
T = temperature of bulk liquid loaded (°R) (°R = °F + 460)
"S" values are obtained from Table 5.2-1.
"M" and "N" values are obtained from Table 7.1-2.

Table 5.2-1 Saturation (S) Factors for Calculating Petroleum Liquid Loading Losses

Cargo Carrier	Mode of Operation	"S" Factor
tank trucks and rail tank cars	submerged loading of a clean cargo tank	0.50
	submerged loading: dedicated normal service	0.60
	submerged loading: dedicated vapor balance service	1.00
	splash loading of a clean cargo tank	1.45
	splash loading: dedicated normal service	1.45
	splash loading: dedicated vapor balance service	1.00

Table 7.1-2 Properties of Selected Petroleum Liquids
Only crude oil properties are supplied here. The full table of values can be found in AP-42, Table 7.1-2)

petroleum liquid	vapor molecular weight at 60ºF (lb/lb-mol)	condensed vapor density at 60ºF (lb/gal)	liquid density at 60ºF (lb/gal)	true vapor pressure (psi) at various temperatures in ºF						
				40	50	60	70	80	90	100
	"M"			"P"						
Crude Oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7

TRUCK LOADOUT - EXAMPLE CALCULATION

Given: Condensate loaded = 360 bbl crude/month
S = 0.6
P = 2.3 psi
M = 50 lb/lb-mol
T = 50

$$L_L = \frac{(12.46) \times (0.60) \times (2.3 \text{ psi}) \times (50 \text{ lb/lb-mol})}{(50^\circ\text{F} + 460)} = 1.69 \text{ lb/1000 gal}$$

Loading losses (TPY) = (1.69 lb/1000 gal) × (annual sales of 360 bbl/mo) × (12 mo/yr) × (42 gal/bbl) × (ton/2000 lb) = 0.15 TPY

Capture efficiencies are determined on a case-by-case basis for controlled sites.

FUGITIVE EMISSIONS

The easiest way to calculate total hydrocarbon fugitive emissions is to multiply the number of components at a site by the EPA Average Emissions Factors shown in the tables below. The first table lists the average emission rates of **total hydrocarbon** (THC) to be assumed for all components in hydrocarbon service installed at a site. The factors are current as of June 15, 1996 and given in pounds per component - day (lb/component-day). The second table lists speciated rates.

The only information needed for this method is a count or estimate of the number of flanges, connectors (other than flanges), open-ended lines, pumps, valves and "other" components at the site grouped by stream (gas, light oil, heavy oil, water/oil). The number of components can be determined by either counting them in the field or by estimating them.

EPA Average Emission Factors for Total Hydrocarbon (THC) Emissions From O&G Production Operations

(lb/component-day)

equipment type	equipment service category			
	gas	heavy oil (< 20ºAPI)	light oil (> 20ºAPI)	water/light oil [1]
connector	.011	.0004	.011	.0058
flange	.021	.000021	.0058	.00015
open ended line	.11	.0074	.074	.013
other [2]	.47	.0017	.4	.74
pump	.13	not available	.69	.0013
valve	.24	.00044	.13	.0052

SOURCE: US EPA Bulletin Board (Leaks_OG.WP5; 8/9/1995)

[1] The water/light oil emission factors apply to water streams in light oil service with water content between 50% and 99%. For streams with water content > 99% the emission rate is considered negligible.

[2] The "other" equipment type includes compressor, pressure relief valves, diaphragms, drains, dump arms, hatches, instruments, meters, polished rods and vents.

NOTE: The emission factors in the table above are not intended to be used to represent emissions from components that are improperly designed (e.g., enardo valves over pressurizing, failure of thief hatches to reseat after over pressurizing) or equipment not maintained properly (e.g., thief hatch left open). For example, emissions from an enardo valve on a condensate tank vent line, operating in the full or partially open position due to excessive tank vapor pressure that exceeds the pressure setting of the enardo valve, are not considered to be fugitive emissions.

Speciated hydrocarbon emission rates can be estimated by multiplying the total hydrocarbon emission rates obtained from the table above by actual measured weight fractions. If measured data is not available, contact the Division for further guidance.

FUGITIVE EMISSIONS - EXAMPLE CALCULATION

Given: 25 valves in light oil service
THC emission factor = 0.13 lb/component-day
VOC weight fraction = 0.292
HAP weight fractions = 0.02430 + 0.00027 + 0.00075 + 0.00017 + 0.00036 = 0.0259

VOC emissions = 25 valves × 0.13 lb THC/valves-day × 1 ton/2000 lb × 365 day/hr × 0.292 = 0.17 TPY VOC

HAP emissions = 25 valves × 0.13 lb THC/valves-day × 1 ton/2000 lb × 365 day/yr × 0.0259 = 0.015 TPY total HAPs

INTERNAL COMBUSTION PUMPING UNIT ENGINE EMISSIONS

The method for calculating engine emissions is to use emission factors provided by the engine manufacturer, the maximum site-rated horsepower and the annual operating hours.

PUMPING UNIT ENGINE EMISSIONS - EXAMPLE CALCULATION

Given: Manufacturer's NO_X emission factor = 2 g/hp-hr
Maximum site-rated horsepower = 250 hp
Annual operating hours = 8760

NO_X emissions = (2.0 g/hp-hr) × (250 hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 4.8 TPY

For CO and VOC emissions the same calculations are used except the manufacturer's EF for CO and VOC are used.

CONVERTING MOLE PERCENT TO WEIGHT PERCENT

Many emission estimation and calculation methods require weight percent to be used, rather than mole percent. Most lab analyses list gas constituents in mole percent, however you can request the lab provide both mole and weight percent.

You may download the Excel spreadsheet to convert mole percent to weight percent, at http://deq.wyoming.gov/aqd/new-source-revew/.

APPENDIX B

DEFINITIONS

Air Contaminant – Shall mean dust, fumes, mist, smoke, other particulate matter, vapor, gas or any combination of these; but shall not include steam or water vapor.

Air pollutants – Also known as criteria pollutants, Air pollutant emissions which have ambient air standards associated with them. Air pollutants include such emissions as volatile organic compounds (VOC), nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), hazardous air pollutants (HAP) and others.

Average Daily Production – The qualified maximum total production of domestic crude petroleum and petroleum condensates including natural gas liquids produced from a well during a certain period of time (i.e. 1-month, 1-year) divided by the number of calendar days in the certain period during which the well produced. For example, the average 30-daily condensate production rate for well ABC is the qualified maximum total condensate production during the 30-day period x(BBL) ÷ 30(days) = y(BPD). If well ABC only produced 5 days out of the 30-day period, then the average daily condensate production rate for the well is x(BBL) ÷ 5(days) = y(BPD).

Closed System – A vessel (treater, separator), pipeline, sales line, gathering line, collection line, field gas supply or distribution line or any other vessel or line from which no vapors or liquids can exit through open lines, holes, vents or valves unless those lines, holes, vents or valves are connected to another closed system or to a source of continual and complete combustion, unless the vent or valve is a relief device that is designed and intended to open only during emergency situations.

Completion – An oil well shall be considered completed when the first new oil is produced through wellhead equipment into lease tanks from the producing interval after the production string has been run. A gas well shall be considered completed when the well is capable of producing gas through wellhead equipment from the producing zone after the production string has been run.

Condensate – Hydrocarbon liquid separated from natural gas that condenses (becomes liquid) due to changes in temperature, pressure, or both, and remains liquid at standard conditions.

Custody Transfer – The transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Division – The Wyoming Department of Environmental Quality, Air Quality Division.

First Date of Production – The date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to the First Date of Production. If extended periods of time pass between zone completions but production from initially completed zones is consistently flowing to permanent production equipment, the First Date of Production is the date when production from the initial zones began consistently flowing to the permanent production equipment, even though more zones will be completed later.

Fugitive Emissions (Fugitives) – Air emissions which result from gas vapors escaping through and around seals, packing, gaskets, threads, and other such pressure sealing connections.

Gas – All natural gases and all hydrocarbons not defined as oil.

Gas Well – A well, the principal production of which, at the mouth of the well, is gas, as defined by the Wyoming Conservation Law.

Grandfathered – A facility, installation or site which was built or in service before May 29, 1974 and that has not been physically or operationally changed, causing an increase in any pollutant (to which any state standard applies) or causing the emission of a new pollutant. (Modifications which could eliminate grandfather status are increasing production rate by fracturing, acidizing, recompletion of a zone, change in artificial lift methods, bringing new wells into a central battery or a waterflood response. Also such things as installing an engine, increasing horsepower, change in burner ratings. This list is not all inclusive and judgment should be used to determine appropriate status.)

HAP – Pollutants identified in Section 112(b) of the Clean Air Act. Typical hazardous air pollutants include benzene, toluene, ethyl-benzene, xylene, n-hexane, formaldehyde, methanol and others.

Low bleed pneumatic controller – A continuous bleed or intermittent vent device that emits less than 6 scf/hr. The Division considers controllers that are operated in accordance with manufacturer design specifications and have a manufacturer-designed emission rate that satisfies the 6 scf/hr threshold, to meet the definition of low bleed pneumatic controller.

Major Emitting Facility – A facility which either has the potential to emit 250 TPY or more of any one regulated air pollutant or is a named facility and has the potential to emit 100 TPY or more of any one regulated air pollutant. For a facility located in a non-attainment area, the definition of major emitting facility is subject to change based on the area's classification. See WAQSR Chapter 6, Section 13.

Major Source – A source which emits either 100 TPY or more of a regulated air pollutant, 10 TPY or more of a hazardous air pollutant, or 25 TPY or more of the total hazardous air pollutants.

Modified Facility – An existing facility becomes modified once production streams or production equipment associated with another well or wells is added to or tied into it. The date modification occurs to an existing facility is the First Date of Production for the added well or the date the production streams associated with an additional well or wells are tied into equipment at the existing facility.

Examples of facility modifications not involving new wells or added production from other wells are:

- Increasing the production rate above the average daily condensate/oil or gas production rate for the previous twelve (12) calendar months by fracturing, acidizing, recompletion of a current production zone, change in artificial lift methods, or a CO_2 flood/water flood response.
- Completing in additional production zones resulting in an increase in production above the average daily condensate/oil or gas production rate for the previous twelve (12) calendar months and/or emissions at the facility.
- Existing production equipment is replaced with larger equipment, resulting in increased potential or actual emissions.

Note: When equipment with Presumptive BACT requirements is added to a facility but doesn't trigger the definition of a modified facility, the Presumptive BACT requirements only have to be met for the new equipment (i.e., a pneumatic methanol pump is added, this new pump would have to either be controlled or solar, air or electric).

Oil – Crude petroleum oil and any other hydrocarbons, regardless of gravities, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir.

Oil Well – A well, the principal production of which, at the mouth of the well, is oil, as defined by the Wyoming Conservation Law.

PAD – A PAD facility is a location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains located at the same or contiguous and adjacent location. If the production streams or production equipment associated with one or more wells is added to an existing single well facility, that location is then considered to be a PAD facility. A single well becomes a multiple well or PAD facility upon the First Date of Production of an additional well at the location or on the day production streams associated with an additional well or wells from separate locations are routed to the single well facility. A tank battery is not considered a PAD facility.

Potential to Emit – The maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by the EPA and the Division.

Recompletion – Any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geological interval not currently completed or producing in said existing oil or gas well.

Single Well Facility – A single well facility is one where production equipment is associated with only one well. A single well becomes a multiple well or PAD facility upon the First Date of Production of an additional well at the location or on the day production streams associated with an additional well or wells from separate locations are routed to the single well facility.

Spud – The commencement of operations for the first boring of a hole for the drilling of an oil, gas or injection well. This includes setting conductor casing.

Synthetic Minor – "Synthetic Minor" sources are sources that do the following types of things to limit emission rates below 100 TPY: 1) limit operating hours of a source or 2) limit production rates such that source emissions are less than 100 TPY.

Tank Battery – An oil production facility with little to no produced gas that is comprised mainly of separators, heaters, and tanks. The facility does not use dehydration units. The API gravity of the produced oil is no higher than 25°.

VOC – Volatile organic compound means any organic compound which participates in atmospheric photochemical reactions; typically considered C_3^+ or Non-methane/ethane hydrocarbon vapors.

VOC Weight Percent – This is the weight of the volatile organic compounds, expressed as a percent, as compared to the total weight of the compounds in a gas stream. (This should not be confused with the volume or mole percent of a gas stream, which is usually how it is expressed in a lab analysis of a gas.)

Wildcat Well – Any oil or gas well designated as a wildcat well by the Wyoming Oil and Gas Conservation Commission. Wildcat wells are wells outside known fields or new wells which are determined by the Commission to have discovered oil or gas in a pool not previously proven productive.

Workover – Any downhole operation in an existing oil or gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or gas well. Workover includes but is not limited to: acidizing, reperforating, fracture treating, sand/paraffin removal, casing repair, squeeze cementing or setting bridge plugs to isolate water productive zones from oil or gas productive zones or any combination thereof. Workover does not mean the routine maintenance, repair or replacement of downhole equipment such as rods, pumps, tubing, packers or other mechanical devices.

Worst case – A situation allowed in air permitting in the State of Wyoming where a facility, site or source (which is representative of all the facilities, sites or sources within a designated field area) may be used to represent the worst air emissions for the field area sources.

Wyoming Environmental Quality Act – Wyoming Statute, Title 35 "Public Health and Safety", Chapter 11 "Environmental Quality" which provides the authority for the rules and regulations of the Air Quality Division.

Zero bleed controller – Electric, air-driven, or solar powered controller that does not rely on natural gas to actuate.

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part.
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, 2021, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

C. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

D. "Calendar year" means a year beginning January 1 and ending December 31.

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

G. "Commencement of operation" means for an oil and natural gas well site~~head~~, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other

opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol.

I. "Connector" means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

J. "Construction" means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

K. "Custody transfer" means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

L. "Control device" means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, ~~air fuel ratio controllers (AFRs),~~ catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

M. "Department" means the New Mexico environment department.

N. "Downtime" means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

O. "Enclosed combustion device" means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

P. "Existing" means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

Q. "Gathering and boosting station" means a facility, including all equipment and compressors, located downstream of well sites, designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.~~means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage~~.

R. "Glycol dehydrator" means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

S. "Hydrocarbon liquid" means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

T. "Liquid unloading" means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

U. "Liquid transfer" means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

V. "Local distribution company custody transfer station" means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

W. "Natural gas compressor station" means ~~one or more compressors~~a facility, including all equipment and compressors, designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline. Natural gas compressor stations include transmission compressor stations.

X. "Natural gas-fired heater" means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

Y. "Natural gas processing plant" means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Z. "New" means constructed or reconstructed on or after the effective date of this Part.

AA. "Operator" means the person or persons responsible for the overall operation of a stationary source.

BB. "Optical gas imaging (OGI)" means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

CC. "Owner" means the person or persons who own a stationary source or part of a stationary source.

DD. "Permanent pit" means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

EE. "Pneumatic controller" means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.

FF. "Pneumatic diaphragm pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

GG. "Potential to emit (PTE)" means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

HH. "Produced water" means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

II. "Produced water management unit" means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

JJ. "Qualified Professional Engineer" means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

KK. "Reciprocating compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

LL. "Reconstruction" means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

MM. "Recycling facility" means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

NN. "Responsible official" means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

OO. "Small business facility" means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.

PP. "Startup" means the setting into operation of air pollution control equipment or process equipment.

QQ. "Stationary Source" or **"source"** means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

RR. "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well

after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

SS. "Transmission Compressor Station" means a facility, including all equipment and compressors, that moves natural gas at elevated pressure from well sites or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

~~SS.~~**TT.** **"Well workover"** means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

UU~~TT~~. "Well~~head~~ site" means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A well~~head~~ site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.

[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.

[20.2.50.10 NMAC - N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.

[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.

[20.2.50.12 NMAC - N, XX/XX/2021]

[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [RESERVED]

20.2.50.111 APPLICABILITY:

A. This Part applies to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations, up to the point of the local distribution company custody transfer station.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer. The requirements of this part may not be considered in the PTE calculation required in this Section or in determining if any source is subject to this part. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil refinery and transmission pipelines are not subject to this Part.

[20.2.50.111 NMAC - N, XX/XX/2021]

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule sufficient to operate and maintain such units in good working order. The owner or operator shall keep such maintenance schedules on file and make them available to the department upon request.

(2) Sources subject to emission standards or requirements under this Part shall be operated to minimize emissions of air contaminants, including VOC and NO_x.

(3) Within two years of the effective date of this Part, owners and operators of a source requiring an Equipment Monitoring Tag (EMT) shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the source's record of the data required by this Part. The EMT shall be maintained by the owner or operator, and data in the EMT shall provide at a minimum, the following information:

(a) unique unit identification number;

(b) location of the source;

(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);

(d) for each source, the VOC (and NO_x, if applicable) PTE in lbs./hr. and tpy;

(e) for a control device, the controlled VOC and NO_x PTE in lbs./hr. and tpy;

(f) make, model, and serial number; and

(g) a link to the manufacturer's maintenance schedule or repair recommendations.

(4) The EMT shall be installed and maintained by the owner or operator of the facility.

(5) The EMT shall be of a format scannable by an owner or operator's authorized representatives and, upon scanning, shall provide unique identifier that shall index the source's record of the data required by this Part.

(6) The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.

(7) The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.

(8) If read by the owner or operator's authorized representative, the EMT shall access the owner or operator's database record for that source.

(9) The owner or operator shall contemporaneously track each compliance event for each source subject to the EMT requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.

(b) data required by this Part shall be maintained in the database for at least five years.

(10) The department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department.

B. Monitoring requirements:

(1) Sources subject to emission standards and monitoring (e.g. inspection, testing, parametric monitoring) requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(2) An owner or operator may submit for the department's review and approval an equally

effective, enforceable, and equivalent alternative monitoring strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

(3) Each monitoring event (e.g. testing, inspection, parametric monitoring) shall be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:

(a) date and time of the testing, monitoring, or inspection event;

(b) name of the personnel conducting the testing, monitoring, or inspection;

(c) identification number and type of unit;

(d) a description of any maintenance or repair activity conducted; and

(e) results of testing, monitoring, or inspection as required under this Part.

C. Recordkeeping requirements:

(1) Within three business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the following data:

(a) date and time of the testing, monitoring, or inspection event;

(b) name of the personnel conducting the testing, monitoring, or inspection;

(c) identification number and type of unit;

(d) a description of any maintenance or repair activity conducted; and

(e) results of any testing, monitoring, or inspections required under this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years. The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.

(3) Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for for five years.

D. Reporting requirements: Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-

five percent of the company's existing engines meets the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual NOx and VOC emissions are reduced by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, OR INSTALLED BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	>1,000	0.50 g/bhp-hr	47 ppmvd @ 15% O_2 or 93% reduction	0.70 g/bhp-hr
Rich-burn	>1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, OR INSTALLED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	>500 - <1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥1,000	0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than two years from the effective date of this Part:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)

≥1,000 and <5,000	50	50	9
≥5,000 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction
For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <5,000	25	25	9
≥5,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

(10) The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall meet the minimum manufacturer recommended maintenance schedule. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

(a) routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

(b) unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer or supplier recommended maintenance schedules, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for NO_x, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

(a) emissions testing events shall be conducted at ninety percent or greater of the

unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine operated for less than 100 hours per year shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and EMT for the engine or turbine;

(b) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule;

(c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time of an inspection, maintenance or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the personnel conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(v) a description of maintenance or repair activity conducted; and

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine.

The records shall include:

(a) the make, model, serial number, and EMT for the tested engine or turbine;

(b) the date and time of sampling or measurements;

(c) the date analyses were performed;

(d) the name of the personnel and the qualified entity that performed the analyses;

(e) the analytical or test methods used;

(f) the results of analyses or tests;

(g) for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine operated less than 100 hours per year shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission reduction requirement is met.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.113 NM–C - N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:

A. Applicability:

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, or ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at well~~head~~ sites are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, or ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at well~~head~~ sites are not subject to the requirements of 20.2.50.114 NMAC.

B. Emission standards:

(1) The owner or operator of an existing centrifugal compressor shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor shall, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-eight percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, fuel cell or a process stream.

(5) The owner or operator of a centrifugal or reciprocating compressor shall install an EMT on the compressor in accordance with 20.2.50.112 NMAC.

(6) The owner or operator complying with the emission standards in Subsection B of

20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location of the centrifugal compressor;

(b) the date of construction, reconstruction, or modification of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the personnel conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and identification number of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location of the reciprocating compressor;

(b) the date of construction, reconstruction, or modification of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since initial startup or the last rod packing replacement;

(ii) the records of pressure in the rod packing emissions collection system; and

(iii) the time and date of the inspection, the personnel conducting the inspection, a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed, a description of problems observed during the inspection, and a description and date of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.114 NM–C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES:

A. Applicability: These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NO_x.

(3) The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.

(4) The owner or operator shall inspect control devices used to comply with this Part at least monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

(5) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(6) The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic controller or pump, or storage vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate all emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected equipment are routed to the control device or process; and

(c) have the closed vent system certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(7) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include:

(a) manufacturer name, make, and model;

(b) maximum heating value for an open flare, ECD, or TO;

(c) maximum rated capacity for an open flare, ECD/TO, or VRU;

(d) gas flow range for an open flare, ECD, or TO; and

(e) designed destruction or vapor recovery efficiency.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall combust the gas sent to the flare and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (C) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly.

(e) the owner or operator shall repair the flare within three business days of any alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes;

(d) prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the gas analysis for the gas being flared, including VOC content and heating value; and

(e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes.

(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of an alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(b) the result of the U.S. EPA method 22 observation; and

(c) the results of gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

F. Recordkeeping requirements: The owner or operator of a control device shall maintain a record of the following:

(1) the certification of the closed vent system as required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, gas processing plants, natural gas ~~transmission~~ compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. The requirements of this Part may be considered in the facility's PTE and in determining the monitoring frequency requirements of this Section.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, gas processing plants, or ~~transmission~~ natural gas compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

(1) The owner or operator of a facility with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be considered a leak; and

(e) a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

(2) The owner or operator of a facility with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for well~~head~~ sites or tank battery facilities:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(b) for gathering and boosting ~~sites~~stations, gas processing plants, and ~~transmission~~ natural gas compressor stations:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but nor more than, 10,000 ppm methane or n-hexane; and

(c) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

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(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

(2) leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

(3) the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated “Repair delayed,” and must be repaired before the end of the next process unit shutdown.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;

(b) date of inspection;

(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);

(d) name of the personnel performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible flag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:

(a) the date the leak is detected;

(b) the date of attempt to repair;

(c) for a leak with a designation of "repair delayed" the following shall be recorded:

(i) reason for delay if a leak is not repaired within the required number of days after discovery;

(ii) signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;

(d) date of successful leak repair;

(e) date the leak was monitored after repair and the results of the monitoring; and

(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Liquid unloading operations including down-hole well maintenance events at natural gas wells are subject to the requirements of 20.2.50.117 NMAC.

B. Emission standards:

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown;

(b) monitor manual liquid unloading in close proximity to the well or via remote telemetry; and

(c) close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

(3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during an unloading event:

(a) installation and use of a plunger lift;

(b) installation and use of ~~an~~ artificial lift ~~engine~~; or

(c) installation and use of a control device.

(4) The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during liquid unloading:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the storage vessel or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a liquid unloading event.

(3) A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:

(a) identification number and location of the well;

(b) date the liquid unloading was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);

(e) duration of venting to the storage vessel or atmosphere;

(f) a description of the management practice used to minimize release of VOC emissions before and during the liquid unloading;

(g) the type of control device used to control VOC emissions during the liquid unloading; and

(h) a calculation of the VOC emissions vented during the liquid unloading based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.117 NMAC - N, XX/XX/2021]

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.118 NMAC.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank no later than two years after the effective date. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts and a compressor that reinjects the natural gas into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications;

(c) still vent and flash tank emissions shall not be vented to the atmosphere during normal operation; and

(d) the owner or operator of a glycol dehydrator shall install an EMT on the glycol dehydrator in accordance with 20.2.50.112 NMAC.

(4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator,

including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) dehydrator location and identification number;

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) amount of controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and identification number of the control device or process the emissions are being routed;

(f) date and results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(g) a copy of the glycol dehydrator manufacturer operation and maintenance recommendations.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.118 NMAC - N, XX/XX/2021]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO_x (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than one year after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

(4) The owner or operator of a natural gas-fired heater shall install an EMT on the heater in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications and good engineering practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly;

(iv) optimizing total emissions of CO consistent with the NO_x requirement, manufacturer specifications, and good combustion engineering practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_X and CO emissions and O_2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_X or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring, inspection, maintenance, or repair event, the owner or operator shall scan the EMT and the required monitoring data shall be captured in accordance with this Part.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) location of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date the inspection, testing, maintenance, or repair was conducted;

(b) name of the personnel conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O_2 in volume percent; and

(d) the results of the inspections and any the corrective action taken.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.119 NMAC - N, XX/XX/2021]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, or ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance

or~~,~~ vapor recovery to control VOC emissions by 100%, or a control device to control VOC emissions by at least ninety-eight percent, when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

(2) An owner or operator using vapor balance during a liquid transfer operation shall:

(a) transfer the vapor displaced from the vessel being loaded back to the vessel being emptied via a pipe or hose connected before the start of the transfer operation;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ensure that connector pipes, hoses, couplers, valves, and pressure relief devices are maintained in a leak-free condition;

(d) check the liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Bottom loading or submerged filling shall be used for the liquid transfer.

(4) Connector pipes and couplers shall be maintained in a leak-free condition.

(5) Connections of hoses and pipes used during liquid transfer operations shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) Liquid leaks that occur shall be cleaned and disposed of in a manner that ~~prevents~~ minimizes emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(7) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of a liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

~~**(3)** Tanker trucks and tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:~~

~~**(a)** method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H_2O (18 inches H_2O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H_2O (six inches H_2O) gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are shown in table 1 of 20.2.50.120 NMAC.~~

~~Table 1 – ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE~~

~~Cargo tank or compartment capacity, liters (gallons)~~	~~Allowable vacuum change (Δv) in five minutes, mm H_2O (inches H_2O)~~	~~Allowable pressure change (Δp) in five minutes, mm H_2O (inches H_2O)~~
~~< 3,785 (< 1,000)~~	~~64 (2.5)~~	~~102 (4.0)~~
~~3,785 < 5,678 (1,000 < 1,500)~~	~~51 (2.0)~~	~~89 (3.5)~~
~~5,678 < 9,464 (1,500 < 2,500)~~	~~38 (1.5)~~	~~76 (3.0)~~
~~> 9,464 (> 2,500)~~	~~25 (1.0)~~	~~64 (2.5)~~

~~**(b)** pressure test the tanker truck or tanker railcar tank's internal vapor valve as follows:~~

~~**(i)** after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H_2O (18 inches H_2O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.~~

~~**(ii)** relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H_2O (five inches H_2O).~~

(3~~4~~) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120

NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(45) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device.~~:~~

(2) The owner or operator shall maintain a record of the inspections ~~and testing~~ required in Subsection C of 20.2.50.120 NMAC and shall include the following:

(a) the time and date of the inspection ~~and testing~~;

(b) the name of the personnel conducting the inspection ~~and testing~~;

(c) a description of any problem observed during the inspection ~~and testing~~; and

(d) the results of the inspection ~~and testing~~ and a description of any repair or corrective action taken.

(3) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.120 NMAC - N, XX/XX/2021]

20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Pipeline pig launching and receiving operations located within or outside of the property boundary of well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that prevents emissions to the atmosphere; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

(2) The owner or operator of pig launching and receiving operations shall inspect the equipment for a leak using RM 21 or OGI immediately before the commencement and immediately after the conclusion of the pig launching or receiving operation, and according to the requirements in 20.2.50.116 NMAC.

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112

NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its location, make, and model.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, ~~and~~and natural gas compressor stations ~~transmission compressor stations~~ are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An existing natural gas-driven pneumatic controller shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

Table 1 – WELL~~HEAD~~ SITES, TANK BATTERIES, GATHERING AND BOOSTING ~~FACILITIES~~STATIONS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	85%	90%
> 60-75 %	80%	85%	90%
> 40-60 %	65%	70%	80%
> 20-40 %	45%	70%	80%
0-20 %	25%	65%	80%

Table 2 – NATURAL GAS COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	95%	98%
> 60-75 %	80%	95%	98%
> 40-60 %	65%	95%	98%
> 20-40 %	50%	95%	98%
0-20 %	35%	95%	98%

(4) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers with access to commercial line electrical power shall have an emission rate of zero.

(c) existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC,

and shall comply with the following:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator is not subject to ~~has satisfied~~ the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(d) a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional engineer.

(5) Standards for natural gas-driven pneumatic pumps.

(a) pneumatic pumps located at a natural gas processing plants shall have an emission rate of zero.

(b) pneumatic pumps located at a well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, or ~~transmission~~ natural gas compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) owners and operators of pneumatic pumps located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, or ~~transmission~~ natural gas compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device.

(6) The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a pneumatic controller subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject controller at each facility.

(3) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall, on a monthly basis, scan the controller and conduct an AVO inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) The EMT shall be linked to a database that contains the following:

(a) pneumatic controller identification number;

(b) type of controller (continuous or intermittent);
(c) if continuous, design continuous bleed rate in standard cubic feet per hour;
(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and
(e) design annual bleed in standard cubic feet per year.

(5) The owner or operator of a pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(6) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

(5) The owner or operator shall maintain an electronic record for each pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:
(a) pneumatic controller identification number;
(b) inspection dates;
(c) name of the personnel conducting the inspection;
(d) AVO inspection result;
(e) AVO level discrepancy in continuous or intermittent bleed rate;
(f) maintenance date and maintenance activity; and
(g) a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record in the EMT database of the pneumatic controller documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC.

(7) The owner or operator shall maintain a record in the EMT database for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:
(a) for a natural gas-driven pneumatic pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.
(b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.
(c) records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.122 NMAC - N, XX/XX/2021]

20.2.50.123 STORAGE VESSELS

A. Applicability: Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, or ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.123 NMAC.

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent no later than three years after the effective date of this Part.

(2) An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.

(3) A new storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup.

(4) A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent upon startup.

(5) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the uncontrolled actual annual VOC emissions decrease to less than two tpy.

(6) If a control device is not installed by the date specified in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

(7) The owner or operator of a new or existing storage vessel with a thief hatch shall install a control device that allows the thief hatch to open sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.

(8) The owner or operator of a new or existing storage vessel shall install an EMT on the storage vessel in accordance with 20.2.50.112 NMAC.

(9) An owner or operator complying with Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

C. Monitoring requirements: The owner or operator of a storage vessel shall:

(1) monitor on a monthly basis the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig). When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

(b) monthly liquid throughput and the most recent date of measurement;

(c) the average monthly upstream separator pressure;

(d) the data and methodology used to calculate the PTE of VOC (the calculation methodology shall be department approved);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput ~~in~~ shall be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the time and date of the inspection;

(b) the personnel conducting the inspection;

(c) a notation that the required leak check was completed;
(d) a description of any problem observed during the inspection; and
(e) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

20.2.50.124 WELL WORKOVERS

A. Applicability: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. Emission standards: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during a workover:
(a) wellhead pressure;
(b) flow rate of the vented natural gas (to the extent feasible); and
(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following record for a workover:
(a) identification number and location of the well;
(b) date the workover was performed;
(c) wellhead pressure;
(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;
(e) duration of venting to the atmosphere;
(f) description of the management practices used to minimize release of VOC before and during the workover; and
(g) calculation of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

[20.2.50.124 NMAC - N, XX/XX/2021]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (10) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;

(2) calculated VOC and NO_x emissions from each facility and the company-wide VOC and NO_x emissions for all subject facilities;

(3) records as required under Subsection F of 20.2.50.116 NMAC.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.

[20.2.50.125 NMAC - N, XX/XX/2021]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use best management and good engineering practices to minimize emissions of VOC from produced water management units.

(2) The owner or operator shall control VOC emissions from each produced water management unit to less than two tons per year.

C. Monitoring requirements: The owner or operator shall:

(1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit;

(2) monthly, monitor the best management and engineering practices implemented to reduce emissions at each unit to ensure their effectiveness; and

(3) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each produced water management unit:

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and engineering practices used to minimize release of VOC at the unit; and

(c) a record of the monthly rolling 12-month total VOC emissions from each unit.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.126 NMAC - N, XX/XX/2021]

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible information obtained by the department indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.

C. If credible information provided to the department by a member of the public indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.

[20.2.50.127 NMAC - N, XX/XX/2021]

HISTORY OF 20.2.50 NMAC: [**RESERVED**]

DRAFT

While we have taken steps to ensure the accuracy of this Internet version of the document, it is not the official version. To see a complete version including any recent edits, visit: https://www.ecfr.gov/cgi-bin/ECFR?page=browse and search under Title 40, Protection of Environment.

METHOD 21 - DETERMINATION OF VOLATILE ORGANIC COMPOUND LEAKS

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.
Volatile Organic Compounds (VOC)	No CAS number assigned.

1.2 Scope. This method is applicable for the determination of VOC leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 6.0. A leak definition concentration based on a reference compound is specified in each applicable regulation. This method is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.

3.0 Definitions

3.1 *Calibration gas* means the VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.

3.2 *Calibration precision* means the degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

3.3 *Leak definition concentration* means the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

3.4 *No detectable emission* means a local VOC concentration at the surface of a leak source, adjusted for local VOC ambient concentration, that is less than 2.5 percent of the specified leak definition concentration. that indicates that a VOC emission (leak) is not present.

3.5 *Reference compound* means the VOC species selected as the instrument calibration basis for specification of the leak definition concentration. (For example, if a leak definition concentration is 10,000 ppm as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument meter calibrated with methane would be classified as a leak. In this example, the leak definition concentration is 10,000 ppm and the reference compound is methane.)

3.6 *Response factor* means the ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.

3.7 *Response time* means the time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

4.0 Interferences[Reserved]

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Hazardous Pollutants. Several of the compounds, leaks of which may be determined by this method, may be irritating or corrosive to tissues (*e.g.*, heptane) or may be toxic (*e.g.*, benzene, methyl alcohol). Nearly all are fire hazards. Compounds in emissions should be determined through familiarity with the source. Appropriate precautions can be found in reference documents, such as reference No. 4 in Section 16.0.

6.0 Equipment and Supplies

A VOC monitoring instrument meeting the following specifications is required:

6.1 The VOC instrument detector shall respond to the compounds being processed. Detector types that may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

6.2 The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

6.3 The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration.

6.4 The instrument shall be equipped with an electrically driven pump to ensure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.10 to 3.0 l/min (0.004 to 0.1 ft^3 /min) when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument.

6.5 The instrument shall be equipped with a probe or probe extension or sampling not to exceed 6.4 mm (1/4in) in outside diameter, with a single end opening for admission of sample.

6.6 The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code by the National Fire Prevention Association or other applicable regulatory code for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and/or Class 2, Division 1 conditions, as appropriate, as defined by the example code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.

7.0 Reagents and Standards

7.1 Two gas mixtures are required for instrument calibration and performance evaluation:

7.1.1 Zero Gas. Air, less than 10 parts per million by volume (ppmv) VOC.

7.1.2 Calibration Gas. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration approximately equal to the applicable leak definition specified in the regulation.

7.2 Cylinder Gases. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within 2 percent accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life.

7.3 Prepared Gases. Calibration gases may be prepared by the user according to any accepted gaseous preparation procedure that will yield a mixture accurate to within 2 percent. Prepared standards must be replaced each day of use unless it is demonstrated that degradation does not occur during storage.

7.4 Mixtures with non-Reference Compound Gases. Calibrations may be performed using a compound other than the reference compound. In this case, a conversion factor must be determined for the alternative compound such that the resulting meter readings during source surveys can be converted to reference compound results.

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Instrument Performance Evaluation. Assemble and start up the instrument according to the manufacturer's instructions for recommended warm-up period and preliminary adjustments.

8.1.1 Response Factor. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

8.1.1.1 Calibrate the instrument with the reference compound as specified in the applicable regulation. Introduce the calibration gas mixture to the analyzer and record the observed meter reading. Introduce zero gas until a stable reading is obtained. Make a total of three measurements by alternating between the calibration gas and zero gas. Calculate the response factor for each repetition and the average response factor.

8.1.1.2 The instrument response factors for each of the individual VOC to be measured shall be less than 10 unless otherwise specified in the applicable regulation. When no instrument is available that meets this specification when calibrated with the reference VOC specified in the applicable regulation, the available instrument may be calibrated with one of the VOC to be measured, or any other VOC, so long as the instrument then has a response factor of less than 10 for each of the individual VOC to be measured.

8.1.1.3 Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in References 1–3 of Section 17.0.

8.1.2 Calibration Precision. The calibration precision test must be completed prior to placing the analyzer into service and at subsequent 3-month intervals or at the next use, whichever is later.

8.1.2.1 Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and multiply by 100 to express the resulting calibration precision as a percentage.

8.1.2.2 The calibration precision shall be equal to or less than 10 percent of the calibration gas value.

8.1.3 Response Time. The response time test is required before placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required before further use.

8.1.3.1 Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. After switching, measure the time required to attain 90 percent of the final stable reading. Perform this test sequence three times and record the results. Calculate the average response time.

8.1.3.2 The instrument response time shall be equal to or less than 30 seconds. The instrument pump, dilution probe (if any), sample probe, and probe filter that will be used during testing shall all be in place during the response time determination.

8.2 Instrument Calibration. Calibrate the VOC monitoring instrument according to Section 10.0.

8.3 Individual Source Surveys.

8.3.1 Type I—Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

8.3.1.1 Valves. The most common source of leaks from valves is the seal between the stem and housing. Place the probe at the interface where the stem exits the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample

the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where a leak could occur.

8.3.1.2 Flanges and Other Connections. For welded flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

8.3.1.3 Pumps and Compressors. Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

8.3.1.4 Pressure Relief Devices. The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

8.3.1.5 Process Drains. For open drains, place the probe inlet at approximately the center of the area open to the atmosphere. For covered drains, place the probe at the surface of the cover interface and conduct a peripheral traverse.

8.3.1.6 Open-ended Lines or Valves. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.7 Seal System Degassing Vents and Accumulator Vents. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.8 Access door seals. Place the probe inlet at the surface of the door seal interface and conduct a peripheral traverse.

8.3.2 Type II—"No Detectable Emission". Determine the local ambient VOC concentration around the source by moving the probe randomly upwind and downwind at a distance of one to two meters from the source. If an interference exists with this determination due to a nearby emission or leak, the local ambient concentration may be determined at distances closer to the source, but in no case shall the distance be less than 25 centimeters. Then move the probe inlet to the surface of the source and determine the concentration as outlined in Section 8.3.1. The difference between these concentrations determines whether there are no detectable emissions. Record and report the results as specified by the regulation. For those cases where the regulation requires a specific device installation, or that specified vents be ducted or piped to a control device, the existence of these conditions shall be visually confirmed. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are:

8.3.2.1 Pump or Compressor Seals. If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described in Section 8.3.2.

8.3.2.2 Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices. If applicable, observe whether or not the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur upstream of the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere upstream of

the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in Section 8.3.2 shall be used to determine if detectable emissions exist.

8.3.3 Alternative Screening Procedure.

8.3.3.1 A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present must be surveyed using the instrument technique of Section 8.3.1 or 8.3.2.

8.3.3.2 Spray a soap solution over all potential leak sources. The soap solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water. A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of Section 8.3.1 or 8.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

9.0 Quality Control

Section	Quality control measure	Effect
8.1.2	Instrument calibration precision check	Ensure precision and accuracy, respectively, of instrument response to standard.
10.0	Instrument calibration	

10.0 Calibration and Standardization

10.1 Calibrate the VOC monitoring instrument as follows. After the appropriate warm-up period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

Note: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.

11.0 Analytical Procedures[Reserved]

12.0 Data Analyses and Calculations[Reserved]

13.0 Method Performance[Reserved]

14.0 Pollution Prevention[Reserved]

15.0 Waste Management[Reserved]

16.0 References

1. Dubose, D.A., and G.E. Harris. Response Factors of VOC Analyzers at a Meter Reading of 10,000 ppmv for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2–81051. September 1981.

2. Brown, G.E., *et al.* Response Factors of VOC Analyzers Calibrated with Methane for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2–81–022. May 1981.

3. DuBose, D.A. *et al.* Response of Portable VOC Analyzers to Chemical Mixtures. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2–81–110. September 1981.

4. Handbook of Hazardous Materials: Fire, Safety, Health. Alliance of American Insurers. Schaumberg, IL. 1983.

17.0 Tables, Diagrams, Flowcharts, and Validation Data[Reserved]

5.2 Transportation And Marketing Of Petroleum Liquids[1-3]

5.2.1 General

The transportation and marketing of petroleum liquids involve many distinct operations, each of which represents a potential source of evaporation loss. Crude oil is transported from production operations to a refinery by tankers, barges, rail tank cars, tank trucks, and pipelines. Refined petroleum products are conveyed to fuel marketing terminals and petrochemical industries by these same modes. From the fuel marketing terminals, the fuels are delivered by tank trucks to service stations, commercial accounts, and local bulk storage plants. The final destination for gasoline is usually a motor vehicle gasoline tank. Similar distribution paths exist for fuel oils and other petroleum products. A general depiction of these activities is shown in Figure 5.2-1.

5.2.2 Emissions And Controls

Evaporative emissions from the transportation and marketing of petroleum liquids may be considered, by storage equipment and mode of transportation used, in four categories:

1. Rail tank cars, tank trucks, and marine vessels: loading, transit, and ballasting losses.
2. Service stations: bulk fuel drop losses and underground tank breathing losses.
3. Motor vehicle tanks: refueling losses.
4. Large storage tanks: breathing, working, and standing storage losses. (See Chapter 7, "Liquid Storage Tanks".)

Evaporative and exhaust emissions are also associated with motor vehicle operation, and these topics are discussed in AP-42 *Volume II: Mobile Sources*.

5.2.2.1 Rail Tank Cars, Tank Trucks, And Marine Vessels -

Emissions from these sources are from loading losses, ballasting losses, and transit losses.

5.2.2.1.1 Loading Losses -

Loading losses are the primary source of evaporative emissions from rail tank car, tank truck, and marine vessel operations. Loading losses occur as organic vapors in "empty" cargo tanks are displaced to the atmosphere by the liquid being loaded into the tanks. These vapors are a composite of (1) vapors formed in the empty tank by evaporation of residual product from previous loads, (2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and (3) vapors generated in the tank as the new product is being loaded. The quantity of evaporative losses from loading operations is, therefore, a function of the following parameters:

- Physical and chemical characteristics of the previous cargo;
- Method of unloading the previous cargo;
- Operations to transport the empty carrier to a loading terminal;
- Method of loading the new cargo; and
- Physical and chemical characteristics of the new cargo.

The principal methods of cargo carrier loading are illustrated in Figure 5.2-2, Figure 5.2-3, and Figure 5.2-4. In the splash loading method, the fill pipe dispensing the cargo is lowered only part way into the cargo tank. Significant turbulence and vapor/liquid contact occur during the splash

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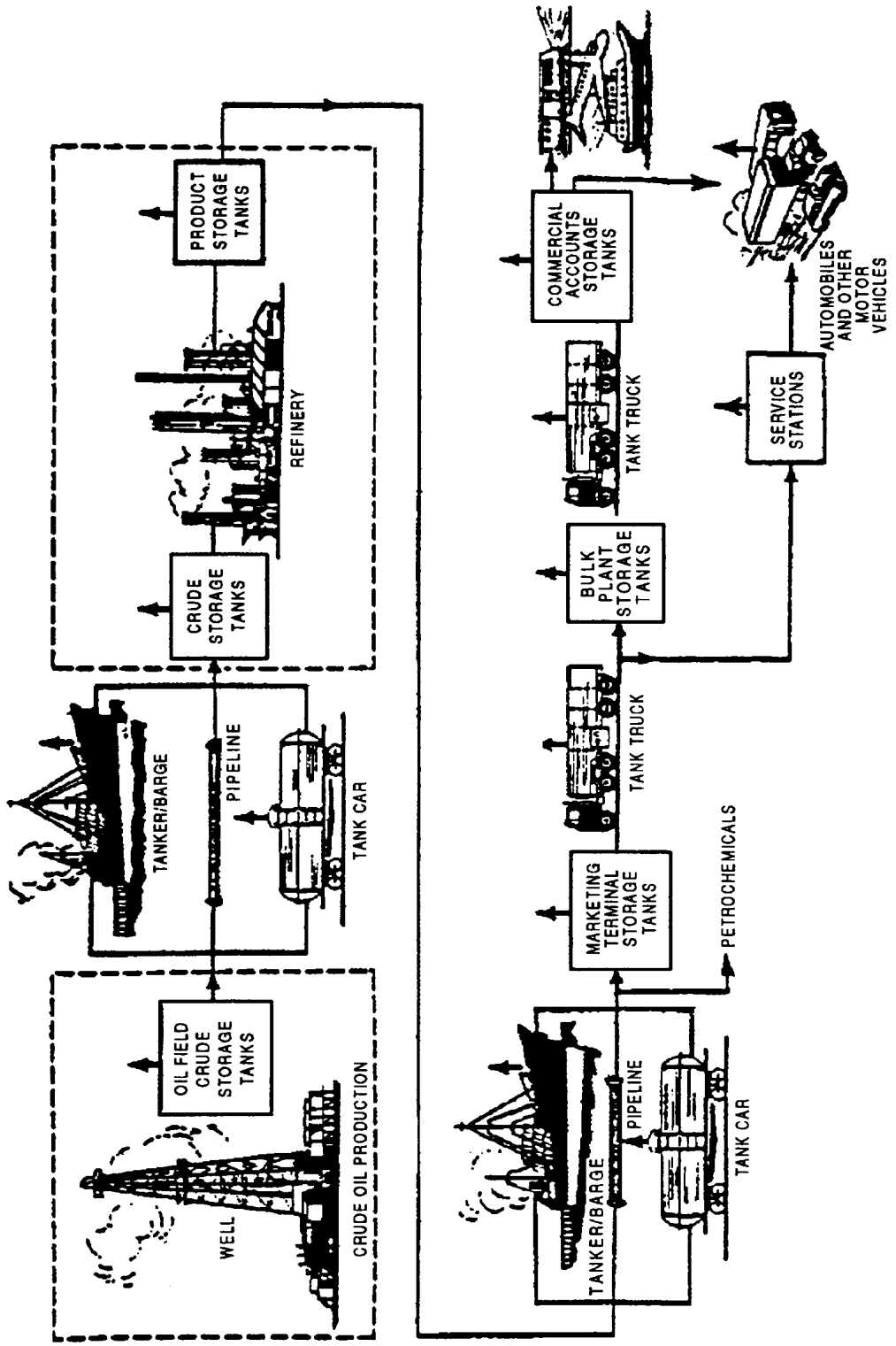


Figure 5.2-1. Flow sheet of petroleum production, refining, and distribution systems. (Points of organic emissions are indicated by vertical arrows.)

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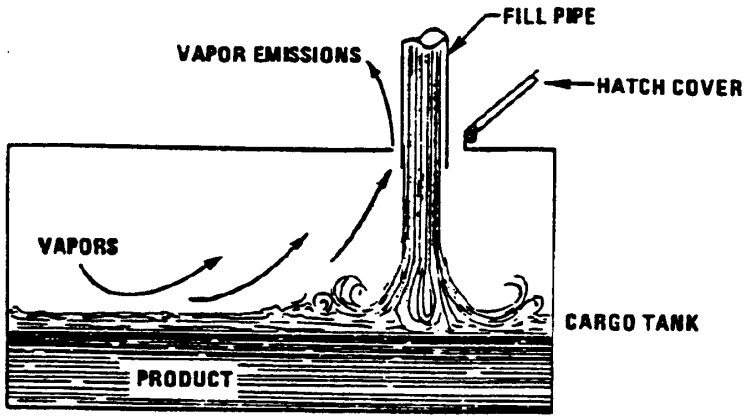


Figure 5.2-2. Splash loading method.

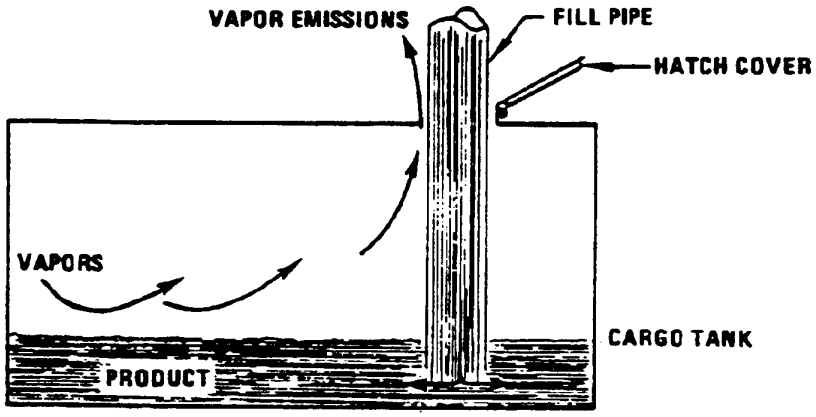


Figure 5.2-3. Submerged fill pipe.

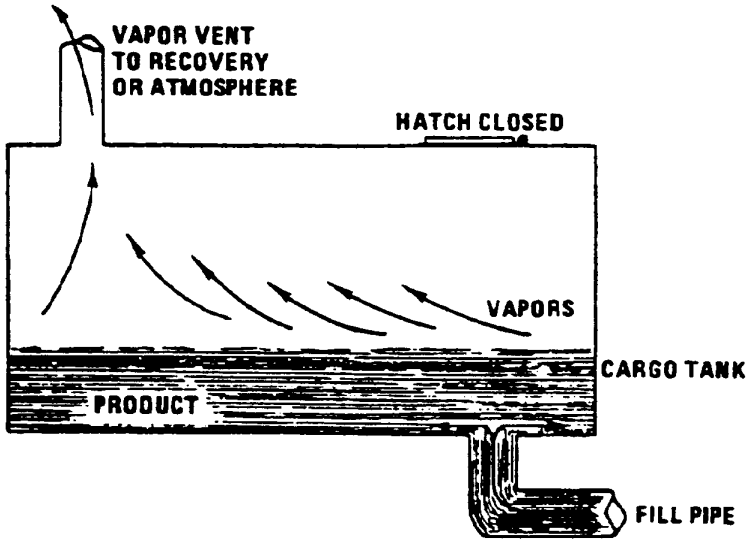


Figure 5.2-4. Bottom loading.

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loading operation, resulting in high levels of vapor generation and loss. If the turbulence is great enough, liquid droplets will be entrained in the vented vapors.

A second method of loading is submerged loading. Two types are the submerged fill pipe method and the bottom loading method. In the submerged fill pipe method, the fill pipe extends almost to the bottom of the cargo tank. In the bottom loading method, a permanent fill pipe is attached to the cargo tank bottom. During most of submerged loading by both methods, the fill pipe opening is below the liquid surface level. Liquid turbulence is controlled significantly during submerged loading, resulting in much lower vapor generation than encountered during splash loading.

The recent loading history of a cargo carrier is just as important a factor in loading losses as the method of loading. If the carrier has carried a nonvolatile liquid such as fuel oil, or has just been cleaned, it will contain vapor-free air. If it has just carried gasoline and has not been vented, the air in the carrier tank will contain volatile organic vapors, which will be expelled during the loading operation along with newly generated vapors.

Cargo carriers are sometimes designated to transport only one product, and in such cases are practicing "dedicated service". Dedicated gasoline cargo tanks return to a loading terminal containing air fully or partially saturated with vapor from the previous load. Cargo tanks may also be "switch loaded" with various products, so that a nonvolatile product being loaded may expel the vapors remaining from a previous load of a volatile product such as gasoline. These circumstances vary with the type of cargo tank and with the ownership of the carrier, the petroleum liquids being transported, geographic location, and season of the year.

One control measure for vapors displaced during liquid loading is called "vapor balance service", in which the cargo tank retrieves the vapors displaced during product unloading at bulk plants or service stations and transports the vapors back to the loading terminal. Figure 5.2-5 shows a tank truck in vapor balance service filling a service station underground tank and taking on displaced gasoline vapors for return to the terminal. A cargo tank returning to a bulk terminal in vapor balance service normally is saturated with organic vapors, and the presence of these vapors at the start of submerged loading of the tanker truck results in greater loading losses than encountered during nonvapor balance, or "normal", service. Vapor balance service is usually not practiced with marine vessels, although some vessels practice emission control by means of vapor transfer within their own cargo tanks during ballasting operations, discussed below.

Emissions from loading petroleum liquid can be estimated (with a probable error of ±30 percent)[4] using the following expression:

$$L_L = 12.46 \frac{SPM}{T} \quad (1)$$

where:

L_L = loading loss, pounds per 1000 gallons ($lb/10^3$ gal) of liquid loaded

S = a saturation factor (see Table 5.2-1)
P = true vapor pressure of liquid loaded, pounds per square inch absolute (psia) (see Section 7.1, "Organic Liquid Storage Tanks")
M = molecular weight of vapors, pounds per pound-mole (lb/lb-mole) (see Section 7.1, "Organic Liquid Storage Tanks")
T = temperature of bulk liquid loaded, °R (°F + 460)

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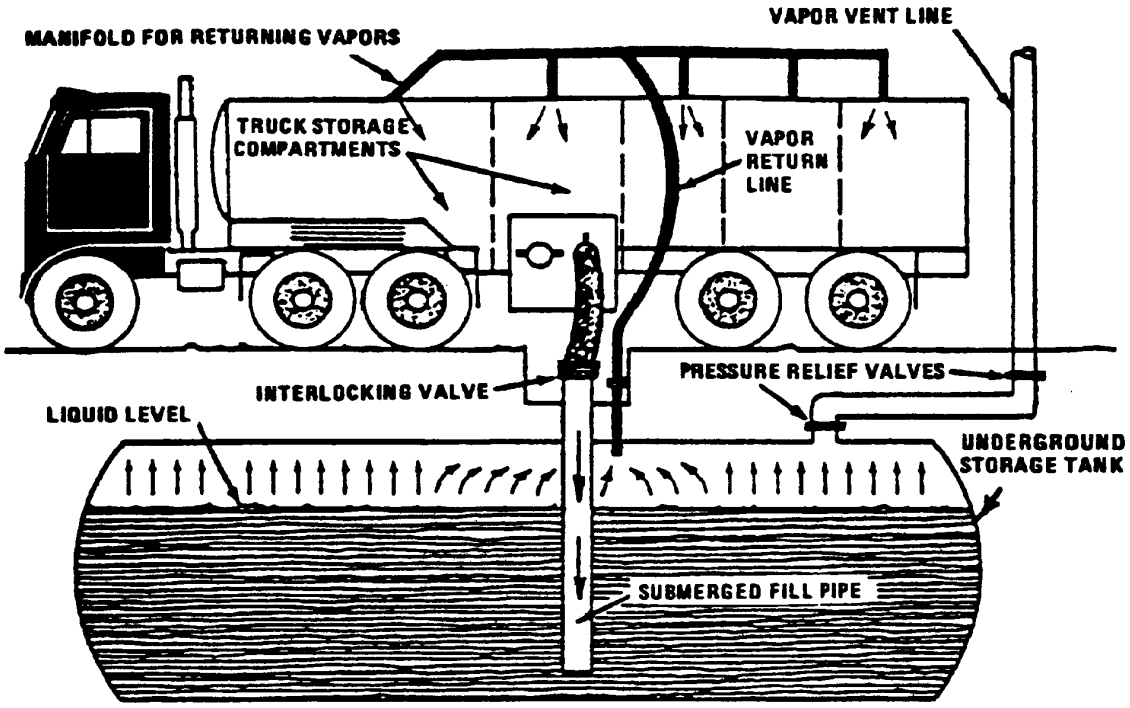


Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

Table 5.2-1. SATURATION (S) FACTORS FOR CALCULATING PETROLEUM LIQUID LOADING LOSSES

Cargo Carrier	Mode Of Operation	S Factor
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapor balance service	1.00
Marine vessels[a]	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

[a] For products other than gasoline and crude oil. For marine loading of gasoline, use factors from Table 5.2-2. For marine loading of crude oil, use Equations 2 and 3 and Table 5.2-3.

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The saturation factor, S, represents the expelled vapor's fractional approach to saturation, and it accounts for the variations observed in emission rates from the different unloading and loading methods. Table 5.2-1 lists suggested saturation factors.

Emissions from controlled loading operations can be calculated by multiplying the uncontrolled emission rate calculated in Equation 1 by an overall reduction efficiency term:

$$\left(1 - \frac{\text{eff}}{100}\right)$$

The overall reduction efficiency should account for the capture efficiency of the collection system as well as both the control efficiency and any downtime of the control device. Measures to reduce loading emissions include selection of alternate loading methods and application of vapor recovery equipment. The latter captures organic vapors displaced during loading operations and recovers the vapors by the use of refrigeration, absorption, adsorption, and/or compression. The recovered product is piped back to storage. Vapors can also be controlled through combustion in a thermal oxidation unit, with no product recovery. Figure 5.2-6 demonstrates the recovery of gasoline vapors from tank trucks during loading operations at bulk terminals. Control efficiencies for the recovery units range from 90 to over 99 percent, depending on both the nature of the vapors and the type of control equipment used.[5-6] However, not all of the displaced vapors reach the control device, because of leakage from both the tank truck and collection system. The collection efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water).[7] A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS-level annual test (3 inches pressure change) A collection efficiency of 70 percent should be assumed for trucks not passing one of these annual leak tests[6].

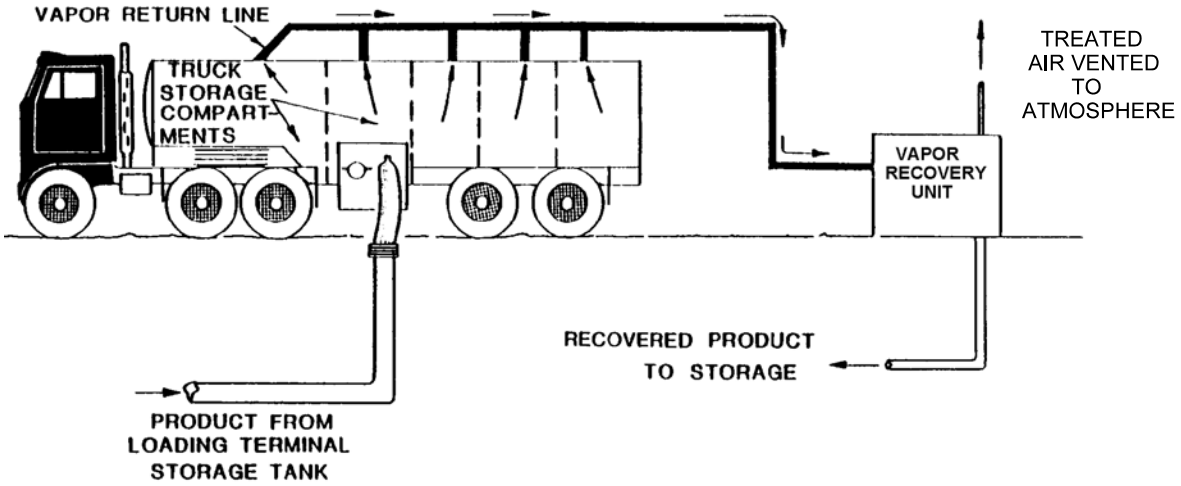


Figure 5.2-6. Tank truck loading with vapor recovery.

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Sample Calculation -

Loading losses (L_L) from a gasoline tank truck in dedicated vapor balance service and practicing vapor recovery would be calculated as follows, using Equation 1:

Design basis -

Cargo tank volume is 8000 gal
Gasoline Reid vapor pressure (RVP) is 9 psia
Product temperature is 80°F
Vapor recovery efficiency is 95 percent
Vapor collection efficiency is 98.7 percent (NSPS-level annual leak test)

Loading loss equation -

$$L_L = 12.46 \frac{SPM}{T}\left(1 - \frac{eff}{100}\right)$$

where:

S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of gasoline = 6.6 psia
M = molecular weight of gasoline vapors = 66
T = temperature of gasoline = 540°R
eff = overall reduction efficiency (95 percent control x 98.7 percent collection) = 94 percent

$$L_L = 12.46 \frac{(1.00)(6.6)(66)}{540}\left(1 - \frac{94}{100}\right)$$

$$= 0.60 \text{ lb}/10^3 \text{ gal}$$

Total loading losses are:

$$(0.60 \text{ lb}/10^3 \text{ gal})(8.0 \times 10^3 \text{ gal}) = 4.8 \text{ pounds (lb)}$$

Measurements of gasoline loading losses from ships and barges have led to the development of emission factors for these specific loading operations.[8] These factors are presented in Table 5.2-2 and should be used instead of Equation 1 for gasoline loading operations at marine terminals. Factors are expressed in units of milligrams per liter (mg/L) and pounds per 1000 gallons (lb/10^3 gal).

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Table 5.2-2 (Metric And English Units). VOLATILE ORGANIC COMPOUND (VOC) EMISSION FACTORS FOR GASOLINE LOADING OPERATIONS AT MARINE TERMINALS[a]

Vessel Tank Condition	Previous Cargo	Ships/Ocean Barges[b]		Barges[b]	
		mg/L Transferred	lb/10^3 gal Transferred	mg/L Transferred	lb/10^3 gal Transferred
Uncleaned	Volatile[c]	315	2.6	465	3.9
Ballasted	Volatile	205	1.7	—[d]	—[d]
Cleaned	Volatile	180	1.5	ND	ND
Gas-freed	Volatile	85	0.7	ND	ND
Any condition	Nonvolatile	85	0.7	ND	ND
Gas-freed	Any cargo	ND	ND	245	2.0
Typical overall situation[e]	Any cargo	215	1.8	410	3.4

[a] References 2,9. Factors are for both VOC emissions (which excludes methane and ethane) and total organic emissions, because methane and ethane have been found to constitute a negligible weight fraction of the evaporative emissions from gasoline. ND = no data.
[b] Ocean barges (tank compartment depth about 12.2 m [40 ft]) exhibit emission levels similar to tank ships. Shallow draft barges (compartment depth 3.0 to 3.7 m [10 to 12 ft]) exhibit higher emission levels.
[c] Volatile cargoes are those with a true vapor pressure greater than 10 kilopascals (kPa) (1.5 psia).
[d] Barges are usually not ballasted.
[e] Based on observation that 41% of tested ship compartments were uncleaned, 11% ballasted, 24% cleaned, and 24% gas-freed. For barges, 76% were uncleaned.

In addition to Equation 1, which estimates emissions from the loading of petroleum liquids, Equation 2 has been developed specifically for estimating emissions from the loading of crude oil into ships and ocean barges:

$$C_L = C_A + C_G \quad (2)$$

where:

C_L = total loading loss, lb/10^3 gal of crude oil loaded
C_A = arrival emission factor, contributed by vapors in the empty tank compartment before loading, lb/10^3 gal loaded (see Note below)
C_G = generated emission factor, contributed by evaporation during loading, lb/10^3 gal loaded

Note: Values of C_A for various cargo tank conditions are listed in Table 5.2-3.

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5.2-3 (English Units). AVERAGE ARRIVAL EMISSION FACTORS, C_A, FOR CRUDE OIL LOADING EMISSION EQUATION[a]

Ship/Ocean Barge Tank Condition	Previous Cargo	Arrival Emission Factor, lb/10^3 gal
Uncleaned	Volatile[b]	0.86
Ballasted	Volatile	0.46
Cleaned or gas-freed	Volatile	0.33
Any condition	Nonvolatile	0.33

[a] Arrival emission factors (C_A) to be added to generated emission factors (C_G) calculated in Equation 3 to produce total crude oil loading loss (C_L). Factors are for total organic compounds; VOC emission factors average about 15% lower, because VOC does not include methane or ethane.
[b] Volatile cargoes are those with a true vapor pressure greater than 10 kPa (1.5 psia).

This equation was developed empirically from test measurements of several vessel compartments.[8] The quantity C_G can be calculated using Equation 3:

$$C_G = 1.84\ (0.44\ P - 0.42)\ \frac{M\ G}{T} \qquad (3)$$

where:

P = true vapor pressure of loaded crude oil, psia
M = molecular weight of vapors, lb/lb-mole
G = vapor growth factor = 1.02 (dimensionless)
T = temperature of vapors, °R (°F + 460)

Emission factors derived from Equation 3 and Table 5.2-3 represent total organic compounds. Volatile organic compound (VOC) emission factors (which exclude methane and ethane because they are exempted from the regulatory definition of "VOC") for crude oil vapors have been found to range from approximately 55 to 100 weight percent of these total organic factors. When specific vapor composition information is not available, the VOC emission factor can be estimated by taking 85 percent of the total organic factor.[3]

5.2.2.1.2 Ballasting Losses -

Ballasting operations are a major source of evaporative emissions associated with the unloading of petroleum liquids at marine terminals. It is common practice to load several cargo tank compartments with sea water after the cargo has been unloaded. This water, termed "ballast", improves the stability of the empty tanker during the subsequent voyage. Although ballasting practices vary, individual cargo tanks are ballasted typically about 80 percent, and the total vessel 15 to 40 percent, of capacity. Ballasting emissions occur as vapor-laden air in the "empty" cargo tank is displaced to the atmosphere by ballast water being pumped into the tank. Upon arrival at a loading port, the ballast water is pumped from the cargo tanks before the new cargo is loaded. The ballasting of cargo tanks reduces the quantity of vapors returning in the empty tank, thereby reducing the quantity of vapors emitted during subsequent tanker loading. Regulations administered by the U. S. Coast Guard require that, at marine terminals located in ozone nonattainment areas, large tankers with crude oil washing systems contain the organic vapors from ballasting.[10] This is accomplished principally by displacing the vapors during ballasting into a cargo tank being simultaneously unloaded. In other areas, marine vessels emit organic vapors directly to the atmosphere.

Equation 4 has been developed from test data to calculate the ballasting emissions from crude oil ships and ocean barges[8]:

$$L_B = 0.31 + 0.20\ P + 0.01\ PU_A \qquad (4)$$

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where:

L_B = ballasting emission factor, lb/10^3 gal of ballast water
P = true vapor pressure of discharged crude oil, psia
U_A = arrival cargo true ullage, before dockside discharge, measured from the deck, feet; (the term "ullage" here refers to the distance between the cargo surface level and the deck level)

Table 5.2-4 lists average total organic emission factors for ballasting into uncleaned crude oil cargo compartments. The first category applies to "full" compartments wherein the crude oil true ullage just before cargo discharge is less than 1.5 meters (m) (5 ft). The second category applies to lightered, or short-loaded, compartments (part of cargo previously discharged, or original load a partial fill), with an arrival true ullage greater than 1.5 m (5 ft). It should be remembered that these tabulated emission factors are examples only, based on average conditions, to be used when crude oil vapor pressure is unknown. Equation 4 should be used when information about crude oil vapor pressure and cargo compartment condition is available. The following sample calculation illustrates the use of Equation 4.

5.2-4 (Metric And English Units). TOTAL ORGANIC EMISSION FACTORS FOR CRUDE OIL BALLASTING[a]

Compartment Condition Before Cargo Discharge	Average Emission Factors			
	By Category		Typical Overall[b]	
	mg/L Ballast Water	lb/10^3 gal Ballast Water	mg/L Ballast Water	lb/10^3 gal Ballast Water
Fully loaded[c]	111	0.9	129	1.1
Lightered or previously short loaded[d]	171	1.4		

[a] Assumes crude oil temperature of 16°C (60°F) and RVP of 34 kPa (5 psia). VOC emission factors average about 85% of these total organic factors, because VOCs do not include methane or ethane.
[b] Based on observation that 70% of tested compartments had been fully loaded before ballasting. May not represent average vessel practices.
[c] Assumed typical arrival ullage of 0.6 m (2 ft).
[d] Assumed typical arrival ullage of 6.1 m (20 ft).

NMED Exhibit 43 - 0010

Sample Calculation -

Ballasting emissions from a crude oil cargo ship would be calculated as follows, using Equation 4:

Design basis -

Vessel and cargo description: 80,000 dead-weight-ton tanker, crude oil capacity 500,000 barrels (bbl); 20 percent of the cargo capacity is filled with ballast water after cargo discharge. The crude oil has an RVP of 6 psia and is discharged at 75°F.

Compartment conditions: 70 percent of the ballast water is loaded into compartments that had been fully loaded to 2 ft ullage, and 30 percent is loaded into compartments that had been lightered to 15 ft ullage before arrival at dockside.

Ballasting emission equation -

$$L_B = 0.31 + 0.20\ P + 0.01\ PU_A$$

where:

P = true vapor pressure of crude oil
= 4.6 psia
U_A = true cargo ullage for the full compartments = 2 ft, and true cargo ullage for the lightered compartments = 15 ft

$$L_B = 0.70\ [0.31 + (0.20)\ (4.6) + (0.01)\ (4.6)\ (2)] + 0.30\ [0.31 + (0.20)\ (4.6) + (0.01)\ (4.6)\ (15)]$$

$$= 1.5\ lb/10^3\ gal$$

Total ballasting emissions are:

$$(1.5\ lb/10^3\ gal)\ (0.20)\ (500{,}000\ bbl)\ (42\ gal/bbl) = 6{,}300\ lb$$

Since VOC emissions average about 85 percent of these total organic emissions, emissions of VOCs are about: (0.85)(6,300 lb) = 5,360 lb

5.2.2.1.3 Transit Losses -

In addition to loading and ballasting losses, losses occur while the cargo is in transit. Transit losses are similar in many ways to breathing losses associated with petroleum storage (see Section 7.1, "Organic Liquid Storage Tanks"). Experimental tests on ships and barges[4] have indicated that transit losses can be calculated using Equation 5:

$$L_T = 0.1\ PW \qquad (5)$$

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where:

L_T = transit loss from ships and barges, lb/week-10^3 gal transported
P = true vapor pressure of the transported liquid, psia
W = density of the condensed vapors, lb/gal

Emissions from gasoline truck cargo tanks during transit have been studied by a combination of theoretical and experimental techniques, and typical emission values are presented in Table 5.2-5.[11-12] Emissions depend on the extent of venting from the cargo tank during transit, which in turn depends on the vapor tightness of the tank, the pressure relief valve settings, the pressure in the tank at the start of the trip, the vapor pressure of the fuel being transported, and the degree of fuel vapor saturation of the space in the tank. The emissions are not directly proportional to the time spent in transit. If the vapor leakage rate of the tank increases, emissions increase up to a point, and then the rate changes as other determining factors take over. Truck tanks in dedicated vapor balance service usually contain saturated vapors, and this leads to lower emissions during transit because no additional fuel evaporates to raise the pressure in the tank to cause venting. Table 5.2-5 lists "typical" values for transit emissions and "extreme" values that could occur in the unlikely event that all determining factors combined to cause maximum emissions.

Table 5.2-5 (Metric And English Units). TOTAL UNCONTROLLED ORGANIC EMISSION FACTORS FOR PETROLEUM LIQUID RAIL TANK CARS AND TANK TRUCKS

Emission Source	Gasoline[a]	Crude Oil[b]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Loading operations[c]						
Submerged loading - Dedicated normal service[d]						
mg/L transferred	590	240	180	1.9	1.7	0.01
lb/10^3 gal transferred	5	2	1.5	0.016	0.014	0.0001
Submerged loading - Vapor balance service[d]						
mg/L transferred	980	400	300	—[e]	—[e]	—[e]
lb/10^3 gal transferred	8	3	2.5	—[e]	—[e]	—[e]
Splash loading - Dedicated normal service						
mg/L transferred	1,430	580	430	5	4	0.03
lb/10^3 gal transferred	12	5	4	0.04	0.03	0.0003
Splash loading - Vapor balance service						
mg/L transferred	980	400	300	—[e]	—[e]	—[e]
lb/10^3 gal transferred	8	3	2.5	—[e]	—[e]	—[e]

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Table 5.2-5 (cont.).

Emission Source	Gasoline[a]	Crude Oil[b]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Transit losses						
Loaded with product						
mg/L transported						
Typical	0 - 1.0	ND	ND	ND	ND	ND
Extreme	0 - 9.0	ND	ND	ND	ND	ND
lb/10^3 gal transported						
Typical	0 - 0.01	ND	ND	ND	ND	ND
Extreme	0 - 0.08	ND	ND	ND	ND	ND
Return with vapor						
mg/L transported						
Typical	0 - 13.0	ND	ND	ND	ND	ND
Extreme	0 - 44.0	ND	ND	ND	ND	ND
lb/10^3 gal transported						
Typical	0 - 0.11	ND	ND	ND	ND	ND
Extreme	0 - 0.37	ND	ND	ND	ND	ND

[a] Reference 2. Gasoline factors represent emissions of VOC as well as total organics, because methane and ethane constitute a negligible weight fraction of the evaporative emissions from gasoline. VOC factors for crude oil can be assumed to be 15% lower than the total organic factors, to account for the methane and ethane content of crude oil evaporative emissions. All other products should be assumed to have VOC factors equal to total organics. The example gasoline has an RVP of 69 kPa (10 psia). ND = no data.
[b] The example crude oil has an RVP of 34 kPa (5 psia).
[c] Loading emission factors are calculated using Equation 1 for a dispensed product temperature of 16°C (60°F).
[d] Reference 2.
[e] Not normally used.

In the absence of specific inputs for Equations 1 through 5, the typical evaporative emission factors presented in Tables 5.2-5 and 5.2-6 should be used. It should be noted that, although the crude oil used to calculate the emission values presented in these tables has an RVP of 5, the RVP of crude oils can range from less than 1 up to 10. Similarly, the RVP of gasolines ranges from 7 to 13. In areas where loading and transportation sources are major factors affecting air quality, it is advisable to obtain the necessary parameters and to calculate emission estimates using Equations 1 through 5.

5.2.2.2 Service Stations -

Another major source of evaporative emissions is the filling of underground gasoline storage tanks at service stations. Gasoline is usually delivered to service stations in 30,000-liter (8,000-gal) tank trucks or smaller account trucks. Emissions are generated when gasoline vapors in the underground storage tank are displaced to the atmosphere by the gasoline being loaded into the tank. As with other loading losses, the quantity of loss in service station tank filling depends on several variables, including the method and rate of filling, the tank configuration, and the gasoline temperature, vapor pressure and composition. An average emission rate for submerged filling is 880 mg/L (7.3 lb/1000 gal) of transferred gasoline, and the rate for splash filling is 1380 mg/L (11.5 lb/1000 gal) transferred gasoline (see Table 5.2-7).[5]

NMED Exhibit 43 - 0013

Table 5.2-6 (Metric And English Units). TOTAL ORGANIC EMISSION FACTORS FOR PETROLEUM MARINE VESSEL SOURCES[a]

Emission Source	Gasoline[b]	Crude Oil[c]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Loading operations						
Ships/ocean barges						
mg/L transferred	—[d]	73	60	0.63	0.55	0.004
lb/10^3 gal transferred	—[d]	0.61	0.50	0.005	0.005	0.00004
Barges						
mg/L transferred	—[d]	120	150	1.60	1.40	0.011
lb/10^3 gal transferred	—[d]	1.0	1.2	0.013	0.012	0.00009
Tanker ballasting						
mg/L ballast water	100	—[e]	ND	ND	ND	ND
lb/10^3 gal ballast water	0.8	—[e]	ND	ND	ND	ND
Transit						
mg/week-L transported	320	150	84	0.60	0.54	0.003
lb/week-10^3 gal transported	2.7	1.3	0.7	0.005	0.005	0.00003

[a] Factors are for a dispensed product of 16°C (60°F). ND = no data.
[b] Factors represent VOC as well as total organic emissions, because methane and ethane constitute a negligible fraction of gasoline evaporative emissions. All products other than crude oil can be assumed to have VOC factors equal to total organic factors. The example gasoline has an RVP of 69 kPa (10 psia).
[c] VOC emission factors for a typical crude oil are 15% lower than the total organic factors shown, in order to account for methane and ethane. The example crude oil has an RVP of 34 kPa (5 psia).
[d] See Table 5.2-2 for these factors.
[e] See Table 5.2-4 for these factors.

Emissions from underground tank filling operations at service stations can be reduced by the use of a vapor balance system such as in Figure 5.2-5 (termed Stage I vapor control). The vapor balance system employs a hose that returns gasoline vapors displaced from the underground tank to the tank truck cargo compartments being emptied. The control efficiency of the balance system ranges from 93 to 100 percent. Organic emissions from underground tank filling operations at a service station employing a vapor balance system and submerged filling are not expected to exceed 40 mg/L (0.3 lb/1000 gal) of transferred gasoline.

NMED Exhibit 43 - 0014

Table 5.2-7 (Metric And English Units). EVAPORATIVE EMISSIONS FROM GASOLINE SERVICE STATION OPERATIONS[a]

Emission Source	Emission Rate	
	mg/L Throughput	lb/10^3 gal Throughput
Filling underground tank (Stage I)		
Submerged filling	880	7.3
Splash filling	1,380	11.5
Balanced submerged filling	40	0.3
Underground tank breathing and emptying[b]	120	1.0
Vehicle refueling operations (Stage II)		
Displacement losses (uncontrolled)[c]	1,320	11.0
Displacement losses (controlled)	132	1.1
Spillage	80	0.7

[a] Factors are for VOC as well as total organic emissions, because of the methane and ethane content of gasoline evaporative emissions is negligible.
[b] Includes any vapor loss between underground tank and gas pump.
[c] Based on Equation 6, using average conditions.

A second source of vapor emissions from service stations is underground tank breathing. Breathing losses occur daily and are attributable to gasoline evaporation and barometric pressure changes. The frequency with which gasoline is withdrawn from the tank, allowing fresh air to enter to enhance evaporation, also has a major effect on the quantity of these emissions. An average breathing emission rate is 120 mg/L (1.0 lb/1000 gal) of throughput.

5.2.2.3 Motor Vehicle Refueling -

Service station vehicle refueling activity also produces evaporative emissions. Vehicle refueling emissions come from vapors displaced from the automobile tank by dispensed gasoline and from spillage. The quantity of displaced vapors depends on gasoline temperature, auto tank temperature, gasoline RVP, and dispensing rate. Equation 6 can be used to estimate uncontrolled displacement losses from vehicle refueling for a particular set of conditions.[14]

$$E_R = 264.2\ [(-5.909) - 0.0949\ (\Delta T) + 0.0884\ (T_D) + 0.485\ (RVP)] \quad (6)$$

where:

E_R = refueling emissions, mg/L
ΔT = difference between temperature of fuel in vehicle tank and temperature of dispensed fuel, °F
T_D = temperature of dispensed fuel, °F
RVP = Reid vapor pressure, psia

Note that this equation and the spillage loss factor are incorporated into the *MOBILE* model. The *MOBILE* model allows for disabling of this calculation if it is desired to include these emissions in the stationary area source portion of an inventory rather than in the mobile source portion. It is estimated that the uncontrolled emissions from vapors displaced during vehicle refueling average 1320 mg/L (11.0 lb/1000 gal) of dispensed gasoline.[5,13]

Spillage loss is made up of contributions from prefill and postfill nozzle drip and from spit-back and

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overflow from the vehicles's fuel tank filler pipe during filling. The amount of spillage loss can depend on several variables, including service station business characteristics, tank configuration, and operator techniques. An average spillage loss is 80 mg/L (0.7 lb/1000 gal) of dispensed gasoline.[5,13]

Control methods for vehicle refueling emissions are based on conveying the vapors displaced from the vehicle fuel tank to the underground storage tank vapor space through the use of a special hose and nozzle, as depicted in Figure 5.2-7 (termed Stage II vapor control). In "balance" vapor control systems, the vapors are conveyed by natural pressure differentials established during refueling. In "vacuum assist" systems, the conveyance of vapors from the auto fuel tank to the underground storage tank is assisted by a vacuum pump. Tests on a few systems have indicated overall systems control efficiencies in the range of 88 to 92 percent.[5,13] When inventorying these emissions as an area source, rule penetration and rule effectiveness should also be taken into account. *Procedures For Emission Inventory Preparation, Volume IV: Mobile Sources*, EPA-450/4-81-026d, provides more detail on this.

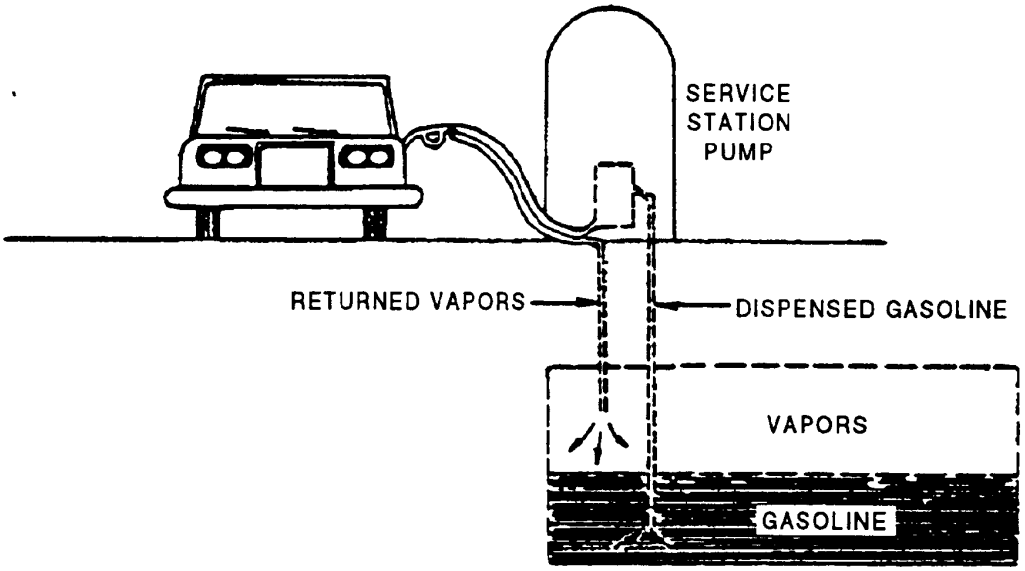


Figure 5.2-7. Automobile refueling vapor recovery system.

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NMED Exhibit 43 - 0017

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells



Executive Summary

When first completed, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and liquid hydrocarbon) to the surface along with the produced gas. As gas production continues, the reservoir pressure declines, and as pressure declines, the velocity of the fluid in the well tubing decreases. Eventually, the gas velocity up the production tubing is no longer sufficient to lift liquid droplets to the surface. Liquids accumulate in the tubing, creating additional pressure drop, slowing gas velocity, and raising pressure in the reservoir surrounding the well perforations and inside the casing. As the bottom well pressure approaches reservoir shut-in pressure, gas flow stops and all liquids accumulate at the bottom of the tubing. A common approach to temporarily restore flow is to vent the well to the atmosphere (well "blowdown"), which produces substantial methane emissions. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990—2008* estimates 9.6 billion cubic feet (Bcf) of annual methane emissions from venting of low pressure gas wells.

At different stages in the life of a gas well, various alternatives to repeated well venting can be deployed to move accumulated liquids to the surface. These options include:

- ★ Foaming agents or surfactants
- ★ Velocity tubing
- ★ Plunger lift, operated manually or with 'smart' well automation
- ★ Downhole pumps, which include reciprocating (beam) pumps and rotating (progressive cavity) pumps.

Natural Gas STAR Partners report significant methane emission reductions and economic benefits from implementing one or more lift options to remove accumulated liquids in gas wells. Not only are vented methane emissions reduced or eliminated, but these lift techniques can provide the additional benefit of increased gas production.

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings and Incremental Production[1] (Mcf/well/year)	Value of Natural Gas Savings and Additional Production (Mcf/well/year)			Implementation Cost[1] (2010 $/Well)	Project Payback (years)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Use Foaming Agents	500 – 9,360	$1,500 - $28,080	$2,500 - $46,800	$3,500 - $65,520	$500 - $9,880	0 to 7	0 to 4	0 to 3
Install Velocity Tubing	9,285 – 27,610	$27,855 - $82,830	$46,425 - $138,050	$64,995 - $193,270	$7,000 - $64,000	0 to 3	0 to 2	0 to 1
"Smart" Well Automated Controls for Plunger Lift[2]	800 – 1,463[2]	$2,400 - $4,389	$4,000 - $7,315	$5,600 - $10,241	$5,700 - $18,000	1 to 8	1 to 5	1 to 4
Install Rod Pumps and Pumping Units[2]	973 – 2,040[2]	$2,919 - $6,120	$4,865 - $10,200	$6,811 - $14,280	$41,000 - $62,000	6 to 22	4 to 13	3 to 10

[1]Based on results reported by Natural Gas STAR Partners
[2]Does not include incremental gas production. Includes only potential gas savings from avoided well venting.

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By avoiding or reducing well blowdowns, Partners report annual methane emissions savings that range from 500 thousand cubic feet (Mcf) per well to more than 27,000 Mcf/well. The benefit of increased gas production will vary considerably among individual wells and reservoirs, but can be substantial. For example, Partners report that increased gas production following plunger lift installation yielded as much as 18,250 Mcf per well.

Technology Background

Most gas wells will have liquid loading occur at some point during the productive life of the well. When this occurs, a common course of action to improve gas flow includes:

- ★ Shutting–in the well to allow bottom hole pressure to increase,
- ★ Swabbing the well to remove accumulated fluids,
- ★ Venting the well to the atmosphere (well blowdown),
- ★ Installing an artificial lift system.

'No-Emissions' Solutions for Liquid Loading in Gas Wells:

- ★ Foaming Agents/ Surfactants
  - – Low cost/ low volume lift method
  - – Applied early in production decline, when the bottom hole pressure still generates sufficient velocity to lift liquid droplets
- ★ Velocity Tubing
  - – Low maintenance, effective for low volumes lifted
  - – Somewhat expensive to acquire and install
  - – Often deployed in combination with foaming agents
- ★ Plunger Lift
  - – Long lasting
  - – Less expense to install and operate than a pumping unit
  - – Often, plunger lift cannot produce a well to its economic limit (abandonment).
  - – Challenging to operate effectively; requires more time and expertise to manage.
- ★ Rod Pumping Units
  - – Can be deployed in applications to remove greater liquid volumes than plunger lift.

Swabbing and "blowing down" a well to temporarily restore production can vent significant methane emissions, from 80 to 1600 Mcf/year per well. The process must be repeated as fluids reaccumulate, resulting in additional methane emissions. Operators may wait until well blowdown becomes increasingly ineffective before implementing some type of artificial lift. At this point, the cumulative methane emissions from a well could be substantial.

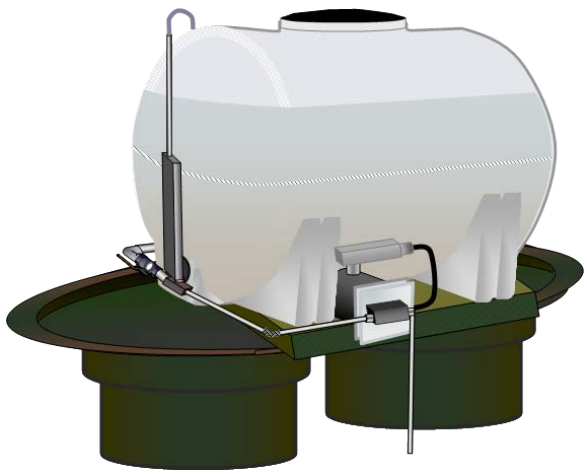
Natural Gas STAR Partners have found that applying artificial lift options early in the life of a well offers significant emissions savings and economic benefits. Each method for lifting liquid in a well has advantages and disadvantages for prolonging the economic life of a well. Total gas savings and methane emission reductions that result from reducing or eliminating well venting will vary for each well depending on flow line operating pressure, reservoir pressure, liquid volume, specific gravity and the number of blowdowns eliminated.

Fluid Removal Options for Gas Wells

Foaming Agents

The use of foam produced by surfactants can be effective for gas wells that accumulate liquid at low rates (Exhibit 1). Foam reduces the density and surface tension of the fluid column, which reduces the critical gas velocity needed to lift fluids to surface and aids liquid removal from the well. Compared to other artificial lift methods, foaming agents are one of the least costly applications for unloading gas wells. Foaming agents work best if the fluid in the well is at least 50 percent water. Surfactants are not

Exhibit 1: Liquid Foaming Agent

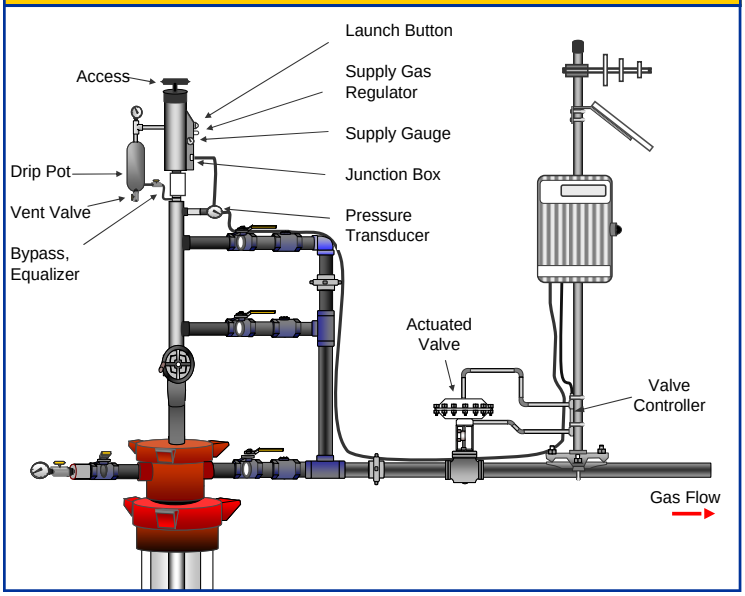


Source: S. Bumgardner, Advanced Resources International, inc.

effective for natural gas liquids or liquid hydrocarbons.

Surfactants are delivered to the well as soap sticks or as a liquid injected directly into the casing-tubing annulus or down a capillary tubing string. For shallow wells, the surfactant delivery can be as simple as the operator periodically pouring surfactant down the annulus of the well through an open valve. For deep wells, a surfactant injection system requires the installation of surface equipment, as well as regular monitoring. The surface equipment includes a surfactant or 'soap' reservoir, an injection pump, a motor valve with a timer (depending on the installation design), and a power source for the pump (Exhibit 2). No equipment is required in the well, although foaming agents and velocity tubing may be more effective when used in combination.

Exhibit 2: Soap Stick Launcher with Automatic Controller



Source: S. Bumgardner, Advanced Resources International, inc.

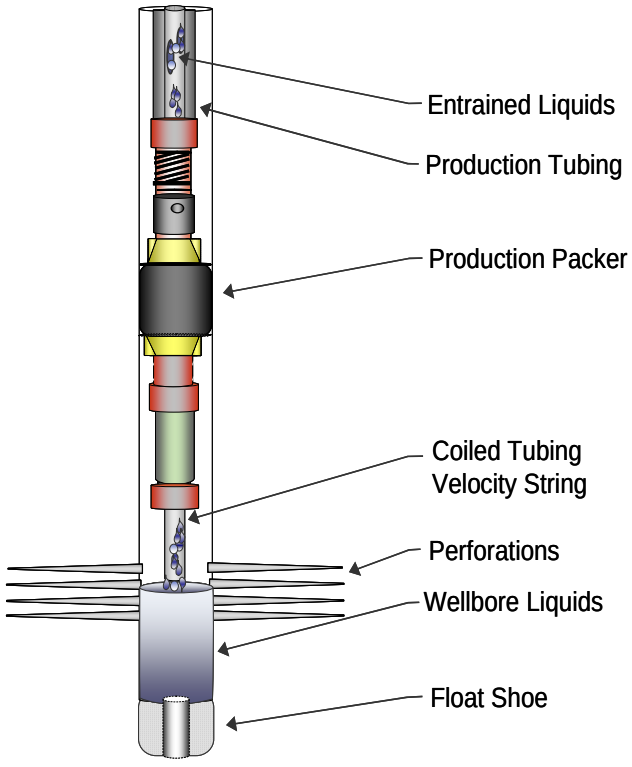
Electric pumps can be powered by AC power where available or by solar power to charge batteries. Other pump choices include mechanical pumps that are actuated by the movement of another piece of equipment or pneumatic pumps actuated by gas pressure. Different pump types have different advantages with respect to reliability, precision, remote operation, simplicity, maintenance frequency, efficiency, and equipment compatibility.

Velocity Tubing

The velocity at which gas flows through pipe determines the capacity to lift liquids. When the gas flow velocity in a well is not sufficient to move reservoir fluids, the liquids will build up in the well tubing and eventually block gas flow from the reservoir. One option to overcome liquid loading is to install smaller diameter production tubing or 'velocity tubing'. The cross-sectional area of the conduit through which gas is produced determines the velocity of flow and can be critical for controlling liquid loading. A velocity string reduces the cross-sectional area of flow and increases the flow velocity, achieving liquid removal while limiting blowdowns to the atmosphere.

Exhibit 3 shows that the conduit for gas flow up a wellbore can be either production tubing, the casing-tubing annulus or simultaneous flow through both the tubing and the annulus. In any case, a 2004 study estimated that gas velocity must be at least 5 to 10 ft/sec (300 to 600 ft/min) to effectively remove hydrocarbon liquids from a well, and at least 10 to 20 ft/ sec (600 to 1200 ft/min) to move produced water. As a rule of thumb, gas flow velocity of 1,000 feet per minute is needed to remove liquid. These figures assume used pipe in good condition with low relative roughness of the pipe wall.

Exhibit 3: Velocity Tubing



Source: S. Bumgardner, Advanced Resources International, inc.

The installation of a velocity string is relatively simple and requires calculation of the proper tubing diameter to achieve the required velocity at the inlet and outlet pressures of the tubing. Velocity tubing to facilitate liquid removal can be successfully deployed in low volume gas wells upon initial completion or near the end of their productive lives. Candidate wells include marginal gas wells producing less than 60 Mfcd. Installation of velocity tubing requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well.

Coiled tubing may also be used, allowing for easier installation and the application of a greater range of tubing diameters as small as 0.25 inches. Coiled tubing can be applied in wells with lower velocity gas production due to better relative roughness characteristics of the tubing and the absence of pipe joint connections. Studies indicate that seamed coiled tubing provides better lift characteristics due to the elimination of turbulence in the flow stream because the seam acts as a "straightening vane".

Plunger Lift with 'Smart' Well Automation

Plunger lifts are commonly used to lift fluids from gas wells. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger and a column of fluid above the plunger up the well tubing to the surface. Exhibit 4 shows a conventional plunger lift installation on a gas well.

Exhibit 4: Plunger Lift



Source: Chesapeake Energy

The operation of a plunger lift system relies on pressure buildup in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must significantly exceed the sales line pressure in order to lift the plunger and load of accumulated fluid to the surface against the sales line backpressure. A companion Lessons Learned paper, *Installing Plunger Lift Systems in Gas Wells,* discusses the installation, gas savings and economics of plunger lift systems. The focus of the present Lessons Learned paper are the incremental gas savings obtained from installing 'smart' automation systems to better manage the operation of plunger lift installations on a field-wide or basin-wide scale.

Most plunger systems operate on a fixed time cycle or on a preset differential pressure. Regardless of activation system (manual, fixed time cycle, or preset pressure differential), a valve mechanism and controller at the surface cause gas volume and pressure to build up in the wellbore initiating the plunger release cycle. At this point, the surface valve closes and the plunger drops to the bottom of the well. Once adequate pressure is reached, the surface valve opens and the plunger rises to the surface with the liquid load. Insufficient reservoir energy, or too much fluid buildup can overload a plunger lift. When that occurs, venting the well to the atmosphere (well blowdown) instantaneously reduces the backpressure on the plunger and usually allows the plunger to return to the surface.

Automated control systems optimize plunger lift and well unloading operations to prevent overloading (plunger cannot overcome backpressure and rise to the surface) and underloading (plunger rises to quickly, possibly damaging equipment) therefore reducing or eliminating well venting. "Smart" automated control systems combine customized control software with standard well control hardware such as remote terminal units (RTUs) and programmable logic controllers (PLCs) to cycle the plunger system and lift fluids out of the tubing. The artificial intelligence component of a smart automation system monitors the tubing and sales line pressures and allows the PLC to "learn" a well's performance characteristics (such as flow rate and plunger velocity) and to build an inflow performance relationship (IPR) curve for the well. The frequency and duration of the plunger cycle is then modified to optimize well performance.

Data analysis combined with wellhead control technology is the key to an effective gas well "smart" automation system. A smart automation system stores historical well production data allowing the program to learn from experience by monitoring and analyzing wellhead instrument data. The control system relays wellhead

instrument data to a central computer, tracks venting times, and reports well problems and high-venting wells, all of which allow custom management of field production.

The components of a smart well automation system that must be installed on each gas well include:

- ★ remote terminal unit with PLC,
- ★ tubing and casing transmitters,
- ★ gas measurement equipment,
- ★ control valve, and
- ★ plunger detector.

Automated controllers at the wellhead monitor well parameters and adjust plunger cycling. These typically operate on low-voltage, solar batteries. Exhibit 5 illustrates typical wellhead equipment and telemetry for plunger lift automated control systems. A host system capable of retrieving and presenting data is also required for continuous data logging and remote data transition. Operators configure all controls and send them to the RTU from the host system. Engineering time is needed to customize the control software and optimize the system. Field operating practices and protocols must be flexible to quickly address well performance deficiencies and operating problems.

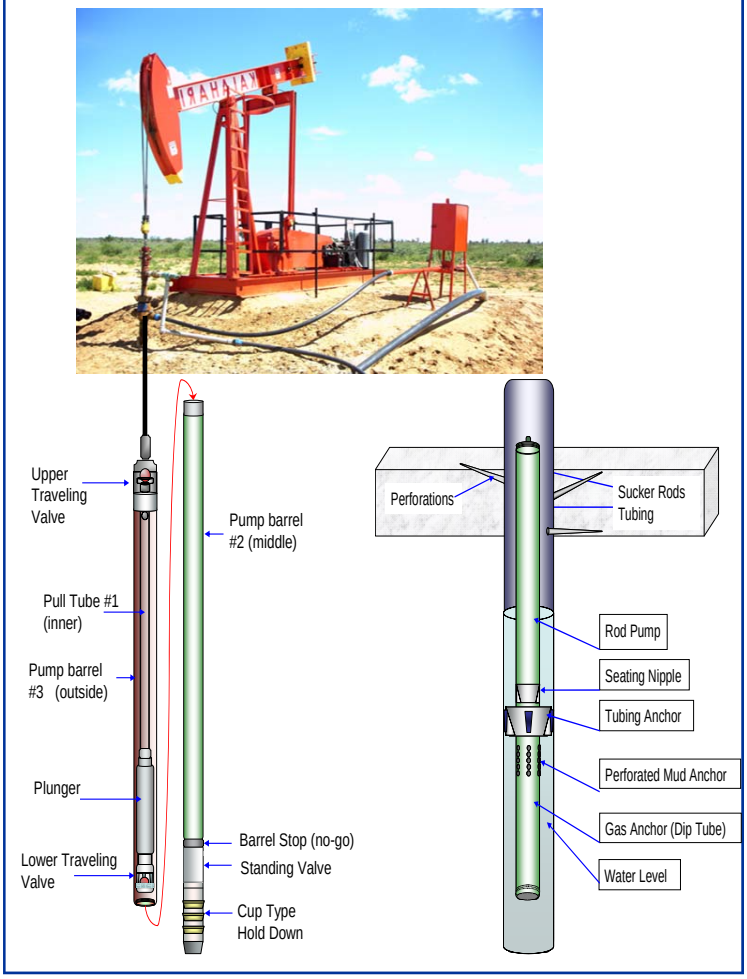
Partners have found that optimized plunger lift cycling to remove liquids can decrease the amount of gas vented by up to 90+ percent. Methane emission savings from reduced well venting is a significant benefit that can add up to huge volumes when applied on a field or basin scale.

Exhibit 5: Typical Wellhead Equipment and Telemetry for Automated Control Systems for Plunger Lift



Source: BP

Exhibit 6: Diagram of a Sucker Rod Pump and Pump Jack



Source: S. Bumgardner, Advanced Resources International, inc.

Rod Pumps and Pumping Units

A downhole positive displacement, reciprocating rod pump with surface pump unit can be deployed in the later stages of a well's life to remove liquids from the wellbore and maximize production until the well is depleted (Exhibit 6). Pumping units can be installed when there is insufficient reservoir pressure to operate a plunger lift. The units can be manually controlled by the field pumper, or very low volume wells may be operated with a timer.

Pumping units not only eliminate the need to vent the well to unload fluids but also extend the productive life of a well. Methane emissions can be further reduced by operating pumping units with electric motors, rather than natural gas-fueled engines. The annual fuel requirement for a typical pumping unit is approximately 1,500 Mcf per unit, of which 0.5 percent is emitted as unburned methane (8 Mcf per unit per year).

A well workover rig is required to install the downhole rod pump, rods, and tubing in the well. Field personnel must be trained for rod pump operations and proper maintenance of the surface equipment. Excessive wear of the rods and tubing can be a major expense for rod pump applications where solids are produced or down hole corrosion is a problem.

A common problem with reciprocating pumps in gas wells is gas locking of the rod pump valves, which prevents the pump from delivering fluid to the surface at the design rate. The presence of free gas in the subsurface sucker rod pump decreases the volumetric pump efficiency and can prevent the pump from lifting fluid. This is not a problem found in progressive cavity pumps as there are no valves to gas lock.

Economic and Environmental Benefits

Implementation of fluid removal options and artificial lift provide economic and environmentally beneficial alternatives to well blowdown. The major benefit of the various fluid removal options is extending the productive life of a well. The full scope of environmental and economic benefits depend on the type of artificial lift system and the remaining productive capacity of the well. Several benefits described below, are realized with the progressive application of fluid removal options in gas wells.

★ **Improved gas production rates and extended well life.** Fluid removal and artificial lift systems conserve reservoir energy and boost gas production. Regular fluid removal generally extends the economic life of declining wells resulting in more continuous gas production, improved gas production rates, and incremental ultimate recovery.

★ **Reclaims vented gas to sales.** Avoiding well blowdown reclaims the value of gas that would otherwise be vented to the atmosphere.

★ **Reduced pollution.** Eliminating well blowdown and gas venting eliminates a significant source of methane and other air pollutant emissions.

★ **Lower well maintenance costs and fewer remedial treatments.** Overall well maintenance costs can be reduced by eliminating the cost of a workover rig for swabbing wells. Other savings occur when well blowdowns are significantly reduced or eliminated.

Four Steps for Evaluating Artificial Lift Options:

1. **Determine the technical feasibility of various artificial lift options.**
2. **Determine the cost of various options.**
3. **Estimate the natural gas savings and production increase.**
4. **Evaluate and compare the economics of artificial lift options.**

Decision Process

The decision to implement any type of liquid removal option during the life-cycle of a gas well should be made when the value of the estimated incremental gas production exceeds the cost of the fluid removal option. When one fluid removal approach becomes ineffective and uneconomic, another can be deployed. If venting a well is the current fluid removal approach, the application of foaming agents, velocity tubing or plunger lift should be evaluated before well blowdowns become too frequent, less effective and costly. Natural Gas STAR Partners can use the following decision process as a guide to evaluate the application, safety, and cost effectiveness of fluid removal and artificial lift installations.

Step 1: Determine the technical feasibility of a fluid removal option or artificial lift installation.

Various data and criteria should be evaluated to select a fluid removal approach that is both technically feasible and cost effective. These data include IPR (inflow

performance relationship) curves; reservoir pressure; gas and fluid production flow rates; fluid levels in the well; the desired flowing bottom hole pressure and casing pressure; production tubing size, the downhole condition of the well; other mechanical limitations of the well and production site; and the capabilities and training of field personnel.

Appendix A (Exhibit A1 and A2) shows the Turner relationship and Lee relationship between critical flow rate (critical gas velocity), and flowing pressure for various sizes of production tubing. If the relationship between flow rate and pressure falls below a line specifying a size of production tubing, a well will not flow liquids to the surface for the indicated tubing size. If flow rate vs pressure falls on or above the line for a specified tubing size, a well meets or exceeds the critical flow rate for the specified tubing size and the well is able to unload fluid to the surface. Exhibits A1 and A2 can be used as starting points to estimate whether a fluid removal or artificial lift option is likely to be effective. Following are some technical considerations that enter into the decision process for each fluid removal option:

- ★ **Foaming Agents.** Partners typically use foaming agents early in the life of gas wells when the wells begin to load with formation water and the liquid production rate is comparatively low. Foaming works best if the liquid in the wellbore is mainly water, and condensate content is less than 50 percent. Foaming agents may also be used in combination with other well treatments that reduce salt and scale build up, or may be applied in combination with velocity tubing.

- ★ **Velocity Tubing**. Velocity tubing strings are appropriate for natural gas wells with relatively small liquid production and higher reservoir pressure. Low surface pipeline pressure relative to the reservoir pressure is also necessary to create the pressure drop that will achieve an adequate flow rate. The depth of the well affects the overall cost of the installation, but is usually offset by the higher pressure and gas volume in deeper wells. Velocity tubing can also be a good option for deviated wells and crooked well bores. Rod pumped wells with deviation and or dog legs that become uneconomic due to high failure rates and servicing costs may also be candidates for velocity strings.

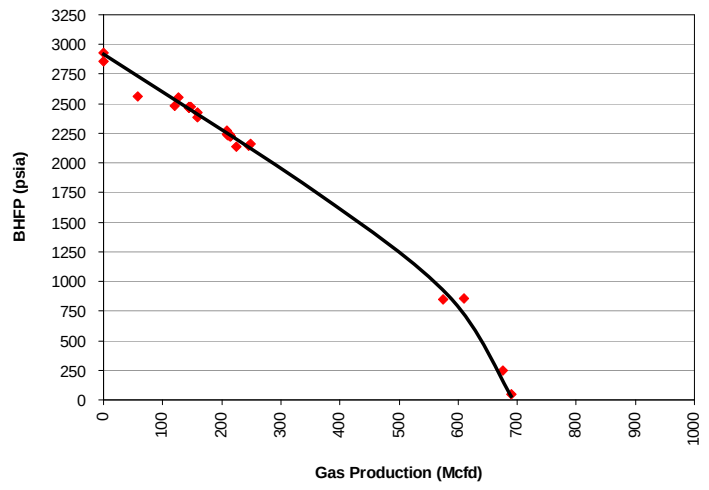
Determining the feasibility of installing a velocity tubing string is relatively straightforward. An inflow performance relationship (IPR curve) is calculated to establish the flow regime in the well tubing, as shown in Exhibit 7. The diagram shown in Exhibit 7 illustrates the relationship between gas production and the bottom hole flowing pressure (BHFP). Gas flow is evaluated and the velocity relationships for various sizes of tubing are developed to determine the appropriate diameter for use in each well. As a rule of thumb, a gas flow velocity of approximately 1,000 feet per minute is the minimum necessary to remove fresh water. Condensate requires less velocity due to its lower density while more dense brine requires a higher velocity.

Once the velocity string is installed, no other artificial lift equipment is required until the reservoir pressure declines to the point that

Indicators of Liquid Loading in Gas Wells:

1. Construct an IPR curve and evaluate the production efficiency of the well.
2. Monitor production curves for each well on a regular basis. Liquid loading is indicated if the curve for a normally declining well becomes erratic and the production rate drops.
3. Compute the critical gas velocity (flow rate) at which liquid can no longer be lifted in the tubing (see Appendix)
4. Critical velocity vs. flowing tubing pressure can be constructed for various tubing diameters.

Exhibit 7: Example of Inflow Performance Relationship Curve for Evaluating Fluid Removal Options



Source: S. Bumgardner, Advanced Resources International, inc.

velocities of 1,000 feet per minute are no longer possible in the tubing. The introduction of a foaming agent to the bottom of a tubing string will extend the effective life of a velocity string below the 1,000 feet per minute velocity required to lift water by reducing the density of the column that is lifted. This only applies to water lifted from the well tubing since condensate is not affected by a surfactant.

★ **"Smart" Well Automation of Plunger Lift.** Candidate wells for plunger lift generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system. Like pumping units, plunger lifts are used to extend the productive life of a well. Installation is less expensive than rod pumps, but plunger lifts may be difficult to operate.

Conventional plunger lift operations rely upon manual, on-site adjustments to tune a plunger cycle time. When a plunger lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. A "smart" well automation system enhances plunger performance by monitoring parameters such as tubing and casing pressure, well flow rate and plunger cycle frequency (travel time). Data for each well are relayed to a host computer where operators review the data and address any performance deficiencies or operating problems. This helps to optimize plunger lift performance, improve gas production, and reduce well venting.

Optimum plunger lift performance generally occurs when the plunger cycle is frequent and set to lift the smallest liquid loads. Small liquid loads require lower operating bottom hole pressure, which allows for better inflow performance. As with velocity tubing, a desirable velocity for a plunger to ascend in tubing is in the range of 500 to 1,000 ft per minute.

★ **Pumping Units.** Rod pump installations for gas wells can be costly to install and operate, but can extend well life, increase ultimate recovery, increase profits and reduce methane emissions. A rod pumping application for gas wells must be carefully designed to ensure trouble-free installation of the pumping units, minimize installation costs, and maximize operating cost savings by reducing mechanical wear and the need for well servicing.

Technical considerations for a rod pump application include the amount of pump capacity required, the pump setting depth in the well, and the type and gravity of the fluid in the hole (brine, fresh water, hydrocarbon, hydrogen sulfide, carbon dioxide, etc.). These factors influence the components of a rod pump installation, including rod pump materials, rod string size and grade, pumping unit design, size of the prime mover (motor), pump speed and stroke length. Resources available for evaluating and designing rod pump applications for gas wells include American Petroleum Institute and various Society of Petroleum Engineers publications; commercial pumping unit vendors; and computer design models. In general, rod pump installations for gas wells have lower fluid volumes than for oil wells. Operating costs can be minimized by correctly sizing the artificial lift and pumping as slow as possible while maintaining a pumped-off condition. The use of pump-off controllers are also effective by matching the pump displacement to the volume of fluid entering the well bore.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

Step 2. Determine the cost of fluid removal options.

Costs associated with the various fluid removal options include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the systems.

★ **Foaming Agents.** Partners report upfront capital and start-up costs to install soap launchers ranging from $500 to $3,880 per well. Monthly cost for the foaming agent is $500 per well, or approximately $6,000 per year. As such, typical costs can vary between $500 and $9,880.

★ **Velocity Tubing.** One Partner reports total capital and installation costs of at least $25,000 per well, which includes the workover rig time, downhole tools, tubing connections and supervision. Another Partner has deployed velocity tubing in more than 100 wells and reports total installation costs ranging from $8,100 per well to $30,000 per well. Based on Partner experiences, typical costs will vary between $7,000 and $64,000 per well.

- ★ **"Smart" Well Automation of Plunger Lift.** Two Partners report implementing "smart" automation systems to control plunger lift operations. One operation is fairly small, consisting of 21 wells. The second is a basin-wide deployment on more than 2,150 wells. Reported upfront costs for the smaller installation is $6,300 per well. Total cost over 5 years reported for the larger automation project is $12,200,000 or approximately $5,700 per well. Typical costs will vary between $5,700 and $18,000 depending on the complexity of the "smart" automation system. These costs would be incremental over the cost of installing a plunger lift system.

- ★ **Pumping Units.** Capital and installation costs include the use of a workover rig and crew, for approximately one day, sucker rods, rod guides and pump costs, and the cost of the pumping unit and motor. Other start-up costs can include miscellaneous clean out operations to prepare the well to receive a down hole pump and sucker rods.

  Partners report that location preparation, well clean out, artificial lift equipment, and a pumping unit can be installed for approximately $41,000 to $62,000 per well. The reported average cost of the pumping unit alone appears to range from approximately $17,000 to $27,000. Most companies have surplus units in stock that can be deployed at the expense of transportation and repair, or may purchase used units.

Step 3. Estimate the savings from various fluid removal options.

The total savings associated with any of the fluid removal and artificial lift options include:

- ★ Revenue from incremental increased gas production;
- ★ Revenue from avoided emissions;
- ★ Additional avoided costs such as well treatment and workover costs, and reduced fuel and electricity;
- ★ Salvage value.

Revenue from Increased Production

The most significant benefit of deploying foaming agents, velocity tubing or a pumping unit is to extend the productive life of the well by decreasing the abandonment pressure of the reservoir and increasing the cumulative gas production. The benefit of automating a plunger lift system is to optimize the plunger cycle. Most of the increase in gas production is realized by the initial decision to install plunger lifts. Installing a 'smart' automated control system provides some incremental increase in gas production over a plunger lift system operated manually or by a timer, but the most significant benefit is the emissions avoided from repeated well blowdowns and the reduction in personnel time required at the well.

The fluid removal options are evaluated based on the incremental gas production predicted by well blowdowns. For wells that are not on production decline, the incremental gas production from installing velocity tubing or artificial lift can be estimated by assuming the average peak production after a well blowdown event represents the incremental peak production that will be achieved after the fluid removal option is implemented in the well.

The more common evaluation is for a well already experiencing production decline. In such a case, estimating incremental gas production from implementing a fluid removal/ artificial lift method is more complex and requires generating a new "expected" production and decline curve that would result from reducing the back pressure at the well perforations. This requires well-specific reservoir engineering analyses, a basic example of which is provided in Appendix B.

Once the incremental gas production from implementing a fluid removal approach is estimated, operators can

Exhibit 8: Gas Production Increase from Application of Foaming Agents — One Partner's Experience

- One Gas STAR Partner reports injecting foaming agent into 15 wells using soap sticks.
- Incremental gas production of individual wells increased an average of 513 Mcf per well per year.
- Annual incremental gas production for the entire project was 7,700 Mcf.
- Total cost for the project was $8,871 in 2010 dollars.
- At nominal gas prices ranging from $3.00/ Mcf to $5.00/ Mcf, the value incremental gas production ranges from approximately $23,100 to $38,500/ year and project payback occurs in 3 to 5 months.

calculate the value of the incremental gas and estimate the economics of the application. Exhibit 8 is an example of the potential revenue from increased gas production using foaming agents. Note that Exhibit 8 does not include other benefits such as avoided blowdown emissions and operations cost savings.

Revenue from Avoided Emissions

Emissions from venting gas to the atmosphere vary in both frequency and flow rates, and are entirely well and reservoir specific. The volume of natural gas emissions avoided by reducing or eliminating well blow-downs will vary due to individual characteristics such as sales line pressure, well shut-in pressure, fluid accumulation rate, and well dimensions (such as depth and casing and tubing diameters). Another key variable is an operator's normal practice for venting wells. Some operators put wells on automatic vent timers. Some wells are vented manually with personnel standing by monitoring the blow-down. In some cases, wells are open to vent and unattended for hours or days, depending upon the time it typically takes the well to clear liquids. The economic benefits of avoided emissions will vary considerably, and some projects will have significantly shorter payback periods than others.

Partner-reported annual emissions attributable to well blowdowns vary from 1 Mcf per well to several thousand Mcf per well, so methane emissions savings attributable to avoided emissions will also vary according to the characteristics and available data for the particular wells being vented. Exhibit 9 illustrates the range of avoided emissions reported by various Partners after applying specific fluid removal and artificial lift strategies in their operations.

Revenue from avoided emissions can be calculated by multiplying the sales price of the gas by the volume of vented gas. If well emissions have not been measured, they can be estimated. The volume of emissions from well venting can be estimated by constructing an IPR curve to predict the open flow potential of the well based on reservoir pressure, depth, tubular sizes, and fluid constituents. Other operator methods are discussed in Appendix C. The volume of gas released during well blow-down is dependent on the duration of the event, wellhead temperature and pressure, size of the vent line, the properties of the gas, and the quantity of water produced.

Four approaches to estimating well blow-down emissions are provided in Appendix C. None of the estimations discussed in Appendix C provide the "exact" result in an absolute sense, but they are accurate enough for effective management of producing gas wells. One emission estimation approach calculates well blow-down volume as a function of venting time, normal production rate, well volume and gas properties. Another approach uses

Exhibit 9: Comparison of Partner-Reported Costs and Emissions Savings for Fluid Removal / Artificial Lift Options

Fluid Removal Approach	Installation Costs ($/well)	Incremental Gas Production (Mcf/well/year)	Avoided Methane Emissions from Swabbing/ Blowdown[2] (Mcf/Well/Year)	Other Potential Cost Savings ($/well)
Use Foaming Agents	$500 - $9,880 *(installation of soap launcher);* $500/month *(surfactant)*	365 – 1,095	178 – 7,394	$2,000 *(eliminate well swabbing)*
Install Velocity Tubing	$7,000 - $64,000	9,125 – 18,250	146 – 7,394	$2,000 - $13,200 *(eliminate well swabbing & blowdown)*
"Smart" Well Automated Controls for Plunger Lift[1]	Partner reported average cost = $5,700 - $18,000	Not reported by Partners (*5,000 Mcf estimated for average U.S. gas well by assuming a 10-20% increase in production)*	Partner reported = 630 – 900 (500 Mcf estimated *for average U.S. well by assuming 1 % of annual production)*	$7,500 *(reduces labor cost to monitor plunger lift installations in the field)*
Install Rod Pumps and Pumping Units	$41,000 - $62,000	Not reported	769 – 1,612	$22,994 *(salvage value at end of well life)*

[1]Incremental cost, gas production and methane emissions savings for installation of automated plunger lift control system.
[2]Assumes methane content of natural gas at wellhead is 79 percent, unless reported otherwise.

pressure transient analysis to extrapolate gas flow rate from wellhead pressure. A final approach installs an orifice meter on a vent line and measures specific vent volume over time. The resulting vent rates expressed in Mcf/minute are averaged by producing formation and extrapolated from the initial subset of wells measured to the larger well population.

Avoided Costs and Other Benefits

Avoided costs and additional benefits depend on the type of fluid removal/ artificial lift system currently applied in the well and the new system to be deployed. These can include avoided chemical treatments, fewer well workovers, lower fuel costs and lower daily operations and maintenance costs. Partners report using foaming agents to replace well swabbing for a savings of approximately $2,000 annually per well. EPA's Natural Gas STAR Partners report that "smart" well automated control systems for plunger lifts have reduced the labor cost for field monitoring by approximately $7,500 per well. Velocity tubing eliminates well swabbing, well blowdowns and chemical treatments, the cost of which are reported to range from a few thousand to more than $13,000 per treatment.

Step 4. Evaluate the economics of fluid removal options.

Basic cash flow analysis can be used to compare the costs and benefits of the various fluid removal options. Exhibit 9 is a summary of the installation costs, gas savings and reduced methane losses associated with each fluid removal approach that have been reported by Natural Gas STAR Partners. Cash flow analyses based on Partner-reported experience and data are provided in Exhibit 10 for installing velocity tubing strings and in Exhibit 11 for "smart" well automated control systems for plunger lift.

Partner Experience

This section highlights specific experiences reported by Gas STAR Partners with the selected fluid removal options for gas wells.

Install Velocity Tubing Strings.

One Partner reported installation of velocity tubing in two Gulf Coast wells during 2008. Total installation cost in 2008 was $25,000 per well, which included a workover rig to remove and replace tubing, downhole tools, connections and supervision. Due to low inflation between years 2008 and 2010, the installation cost in 2010 dollars is only slightly higher than 2008.

The velocity tubing installation in these wells improved gas production by 25 Mcfd to 50 Mcfd, which equates to annual incremental gas production of approximately 9,125 Mcf to 18,250 Mcf per well. In addition, gas savings from eliminating well swabbing is 160 Mcf per year per well. Methane content of gas at the well head is 91 percent, so the estimated reduction in methane losses are 146 Mcf per well. Velocity tubing also eliminated annual swabbing costs of approximately $2000 per well per year. Exhibit 10

Exhibit 10: Economic Analysis of Velocity Tubing Installation Replacing Periodic Swabbing

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production[1]		$36,500	$36,500	$36,500	$36,500	$36,500
Value of Gas from Avoided Emissions[2]		$640	$640	$640	$640	$640
Velocity Tubing Installation Cost	($25,000)					
Avoided Swabbing Cost		$2,000	$2,000	$2,000	$2,000	$2,000
Net Annual Cash Flow	**($25,000)**	**$39,140**	**$39,140**	**$39,140**	**$39,140**	**$39,140**

Internal Rate of Return = 155%
NPV (Net Present Value)[3] = $112,156
Payback Period = 8 months

[1] Gas valued at $4.00/ Mcf for 9,125 Mcf/well (25 Mcfd) due to increased gas production
[2] Gas valued at $4.00/Mcf for 160 Mcf /well of avoided gas emissions due to elimination of well swabbing
[3] Net present value based on 10 percent discount rate over 5 years

provides a cash flow analysis of this Partner's velocity tubing installation replacing well swabbing.

Install "Smart" Automated Control Systems on Plunger Lifts

Two Partners have applied "smart" well automated control systems at plunger lift installations. One Partner—BP—initiated an automation project in 2000, and in 2001 began installing automated plunger lift control systems across their San Juan Basin operations. BP justified the project based on gas and methane emissions savings resulting from a 50 percent reduction in well venting between 2000 and 2004. By 2007, BP implemented automated control systems for more than 2,150 wells equipped with plunger lift which resulted in average methane emissions savings of 900 Mcf per well. Total cost for the "smart" automation systems was $12.2 million. Total gas venting was reduced from approximately 4 billion cubic feet of gas per year (Bcf) to approximately 0.8 Bcf.

Another Natural Gas STAR Partner found that a substantially smaller application of "smart" automated controls for plunger lift can be similarly effective. An automated control system was implemented for 21 wells equipped with plunger lifts. Total gas savings are 16,800 Mcf per year, or 800 Mcf per well. Assuming a methane content of 79 percent, estimated annual methane emissions savings are 632 Mcf per well.

The wide range in upfront capital and installation costs for components of plunger lift automated control systems are indicated in Exhibit 9. The host computer and communication system can be quite costly ($50,000 to $750,000) depending upon the size of the project, but as more plunger lift-equipped wells are added, the unit cost for the automated control system is significantly reduced. The two Natural Gas STAR Partners report approximate unit costs for plunger lift automated control systems of $6,800 and $5,950 per well, respectively. Exhibit 11 provides a basic cash flow analysis of "smart" well automated control systems for plunger lift based on

Exhibit 11: Economic Analysis of "Smart" Well Automated Control Systems for Plunger Lift for Hypothetical Onshore Gas Field[1]

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production[2]		$220,000	$220,000	$220,000	$220,000	$220,000
Value of Gas from Avoided Emissions[3]		$40,000	$40,000	$40,000	$40,000	$40,000
Install RTUs at Wells, $ ($11,000/well x 20 wells)	($220,000)					
Install Host Computer/ Communication ($50K - - $750K)	($200,000)					
Avoided Labor Cost for Field Monitoring ($7500/well x 20 wells)		$150,000	$150,000	$150,000	$150,000	$150,000
Net Cash Inflow	**($420,000)**	**$410,000**	**$410,000**	**$410,000**	**$410,000**	**$410,000**

Internal Rate of Return = 94%
NPV (Net Present Value)[4] = $1,031,111
Payback Period = 12.3months

[1] Assumes production from average US gas well is 50,000 Mcf/Year
[2] Gas valued at $4.00/Mcf for 5,000 Mcf /well of increased gas production due to optimized plunger lift operation; equivalent to 10% of production for average US onshore gas well. Assumes 20 wells in project.
[3] Gas valued at $4.00/Mcf for 500 Mcf of gas savings due to reduced well blowdown/venting; equivalent to 1% of production for average US onshore gas well. Assumes 20 wells in project.
[4] Net present value based on 10 percent discount rate over 5 years

generic assumptions about potential increased gas production and methane emissions savings for the average onshore natural gas well in the United States.

Install Pumping Units on Wells Lifting Low Water Volumes

ConocoPhillips installed pumping units on 45 low-pressure gas wells in 2003 to remove low water volumes from the wells and prevent them from loading up. This installation eliminated routine venting of the wells for up to one hour per day. The primary benefit of installing pumping units on these wells is the incremental gas production gained by extending the productive life of the wells. The Partner reported gas savings of 973 Mcf per well from the elimination of well blowdowns as a secondary, but not insignificant, benefit. The pump jacks at this installation are powered by electric motors rather than natural gas engines, which contributes to fewer methane emissions and lower maintenance costs.

ConocoPhillips reported total gas savings of 43,780 Mcf for the project or approximately 973 Mcf per well per year. At a nominal gas price of $4.00 to $5.00/Mcf, this corresponds to savings of approximately $3,892 to $4,865 per unit, or $175,140 to $218,900 per year for the entire project consisting of 45 wells. Assuming a methane content of 79 percent, this project has reduced methane losses by 34,586 Mcf per year.

Total capital and installation costs for the downhole pumps and surface pumping units were estimated to be $62,000 per well in 2003 or the equivalent of $73,332 in 2010 dollars. The total cost in 2003 included $45,000 for site preparation, downhole equipment, and installation plus an average cost of $17,000 per pumping unit. The project was expanded in subsequent years. ConocoPhillips reported a total of 100 pumping units installed from 2005 through 2007. During this time, the average reported upfront installation cost declined to approximately $38,000 per unit in 2010 dollars. Assuming a nominal gas price of $4, the vented gas savings alone pays back the typical pumping unit installation for this project in less than 10 years.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Lessons Learned

- ★ For natural gas wells, a progression of fluid removal options are available to unload accumulated fluid, boost gas production, extend well life and reduce or eliminate the need for well venting.
- ★ Options for removing accumulated wellbore fluids from gas wells range from relatively low cost application of surfactants, appropriate for wells with low fluid production and significant remaining reservoir energy, to installing pumping units and downhole rod pumps on wells with depleted reservoir pressure and significant water production.
- ★ The best approach will depend on the where a well is performing along the continuum of its productive life.
- ★ Well blowdown and swabbing can release large volumes of natural gas to the atmosphere, producing significant methane emissions and gas losses.
- ★ Fluid removal approaches presented in this paper can reduce the amount of remedial work needed during the lifetime of a well, eliminate well blowdowns, and increase the ultimate recovery of the well while minimizing methane emissions to the atmosphere.
- ★ If a well is in production decline, the fluid removal alternatives discussed here will increase gas production in most cases or at least arrest the decline.
- ★ This increased gas production should be captured in analyses of cash flow and future economic benefit when evaluating fluid removal options for gas wells. In most cases, increased gas production is the primary benefit from implementing any or all of the fluid removal options.

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★ Methane emissions and gas savings from the elimination of well venting is generally a secondary, but significant, benefit, which may cover all or most of the upfront installation costs for a fluid removal technology.

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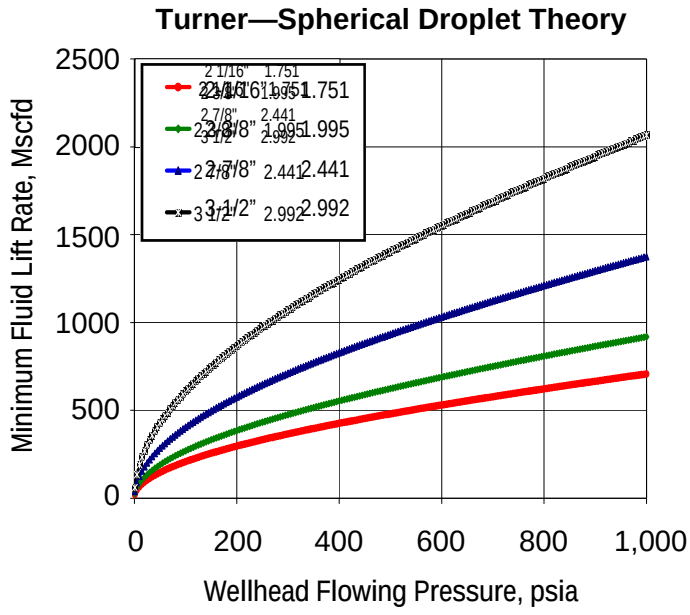
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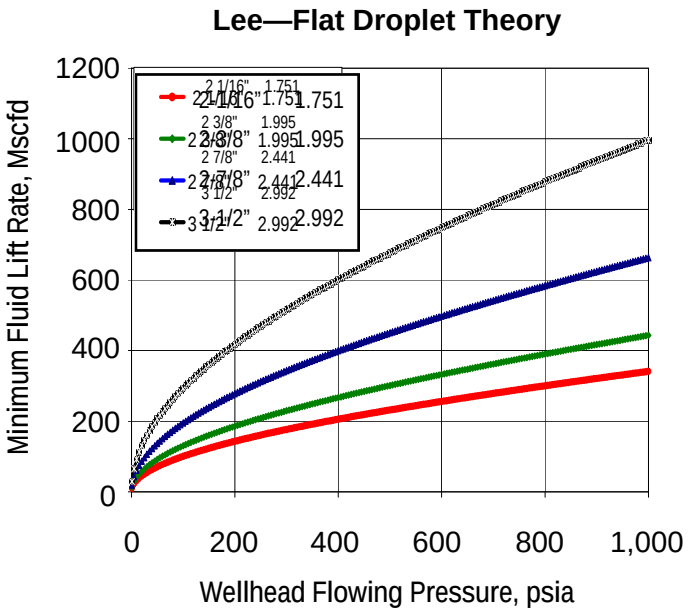
APPENDIX A: Estimating the Critical Flow Rate to Remove Liquids from Production Tubing

Exhibit A1: Turner Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

Exhibit A2: Lee Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

APPENDIX B: Estimating Incremental Production for Declining Wells

From Dake's Fundamentals of Reservoir Engineering (1978) the following analytical model can be used to estimate increased gas flow into a well in response to reducing back pressure on the perforations by removing accumulated liquids. The semi-steady state inflow equation is:

$$m(p_{avg})-m(p_{wf})=[(1422 \times Q \times T)/(k \times h)] \times [\ln(r_e/r_w)-3/4+S)] \times (8.15)$$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

Incremental production achieved by implementing various artificial lift options can be estimated by solving this equation for `Q' calculated for retarded flow with fluids in the hole (current conditions and current decline curve), and comparing to `Q' calculated for the condition of no fluids in the hole (artificial lift active and improved decline curve). This discussion is intended as a guide for estimating the potential impact of fluid removal alternatives, and is not a substitute for thorough reservoir engineering analyses of specific wells.

APPENDIX C: Alternate Techniques for Estimating Avoided Emissions When Replacing Blowdowns

Simple Vent Volume Calculation

A conservative estimate of well venting volumes can be made using the following equation:

Annual Vent Volume, Mscf/yr = (0.37×10^{-6})*(Casing Diameter^2)*(Well Depth)*(Shut-in Pressure)*# of Annual Vents)

Where, casing diameter is in inches, well depth is in feet and shut-in pressure is in psia. If the shut-in pressure is not known, a suitable surrogate is the casing pressure at the surface.

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure.

If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to sales line pressure.

Partners can estimate the minimum time needed to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If a Partner's practice is to open and vent the wells for a longer time than calculated by these methods, the Annual Vent Volume calculated by this equation can be scaled up according to the ratio of the actual vent time versus the minimum vent time calculated using the Weymouth equation.

Natural Gas STAR Partner, BP, has reported three approaches to estimating well venting and completion emissions, which include: 1) a more detailed version of the vent volume calculation method above, 2) pressure transient analysis, and 3) installing an orifice meter on the vent line.

Detailed Vent Volume Calculation

The detailed vent volume calculation is a function of venting time, normal production rate, and "well blowdown value" that represents the volume of gas in a well under an assumption of line pressure.

Vent Volume(Mcf) =
((Vent Time – 30 min)*(1/1440)* Production Rate) + (Well Blowdown Volume)

Well Blowdown Volume (Mcf) =
(well depth*3.1416*(casing diameter/2)^2) * ((tubing press + atmospheric press)/14.7) * (520/(Temp+460))/ Z/ 1000

Variables:

- production rate, Mcf per day
- well depth, ft
- atmospheric pressure, psia
- shut-in tubing pressure, psig
- temperature of gas in pipeline, ^{o}F
- diameter of production casing, ft
- compressibility, Z

A limitation of the vent volume calculation method is that it does not account for either the volume or weight of a column of fluid in the wellbore at the time of venting.

Pressure Transient Analysis

This method is based on observations of wellhead pressure versus flow rate for a specific set of wells which are used to develop a linear expression of gas flow rate versus wellhead pressure. This relationship is then applied to pressure transient data during blowdown to extrapolate Mcf versus time for the venting period. All data are evaluated using pressure data analysis software to extrapolate total vented volumes based on the blowdown time, pipe diameter and the decline in well head pressure during the process. An advantage of this approach is that it accounts for choke flow and is tailored to specific wells. Limitations of the approach are that it fails to account for very large influx into the reservoir and the observations data set may not be representative of the formation. To make the data set more representative, it is recommended that the data include at least one point within the following 5 ranges:

- ★ $P \leq 25$ psia
- ★ 25 psia $< P \leq 60$ psia

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- ★ 60 psia < P ≤ 110 psia
- ★ 110 psia < P ≤ 200 psia
- ★ 200 psia < P

Orifice Metering of Blow Down

For this approach, an orifice meter is installed on a vent line and flow rates are measured directly during blowdown. An advantage of this approach is the precision of the data that are obtained, potentially offering meaningful comparisons of vent volumes between well types, well completions or producing formations.

A limitation of the approach is that results obtained from a 'study population' or small subset of producing wells will likely be extrapolated to a larger field or producing area, and the original study wells may not be representative of field operations as a whole.

United States
Environmental Protection Agency
Air and Radiation (6202J)
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Washington, DC 20460

2011

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

Technical Information
Oil and Gas Sector
Significant Stationary Sources of NOx Emissions

Final
October 17, 2012

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1.0 Introduction

The oil and gas exploration and production sector is a large, complex industry with a diverse array of equipment and many sources of NOx emissions. Larger sources within the sector, such as refineries and natural gas processing facilities, are reasonably well documented and are generally treated as point sources with the appropriate applicable NOx emissions limitations. However, the oil and gas sector includes many smaller, diffuse NOx emission sources that support the equipment used for the exploration for oil and gas and the subsequent transport of the oil and gas from the source in the ground to the marketplace. Many of these NOx emission sources are well distributed throughout the country, including those used to support oil or gas pipeline transportation. However, in areas where there are concentrations of oil or gas in underground reservoirs, there tends to also be a concentration of drilling operations, pumps, compressors, etc that collectively emit NOx emissions at levels that may impact air quality. These oil and gas industry NOx emissions sources are the subject of this review.

Some equipment within the oil and gas sectors **emits** NOx that may contribute to air quality problems locally and in downwind states. While much of the equipment, such as drilling rigs and well pumps and compressors, ~~are~~ **is** concentrated in areas with abundant in-situ supply of oil and/or natural gas, other sources such as refineries, gas processing plants, fuel-fired pipeline gas compressors and pipeline oil pumps are located throughout the country. This equipment operates in a wide variety of modes, with some only operating during initial phases of extracting the product from the ground, some operating almost continuously as long as the source well is productive, and some operating in a variable capacity to meet the demand for the product.

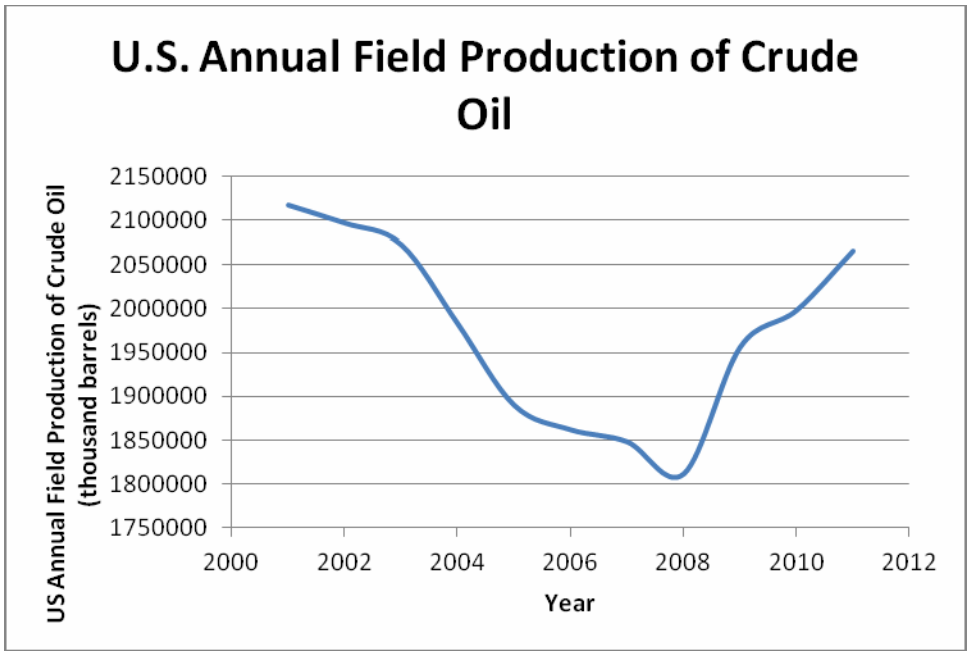
This review attempted to assemble relevant information and technical documentation regarding the combustion devices utilized in the gas and oil sector in the Northeast and Mid-Atlantic states, excluding those sources located in refineries and gas processing facilities, and to present relevant information regarding the possibility of controlling NOx emissions from those sources. The twelve states and District of Columbia that constitute the Ozone Transport Commission (OTC) are developing this document to understand the potential for reductions in emissions of nitrogen oxides (NOx) that may be available from the oil and gas sector. Reductions in NOx emissions may assist the OTC states to attain and maintain the ozone national ambient air quality standards.

The production and consumption of natural gas have both increased dramatically in recent years, and the rate of both natural gas production and natural gas consumption is projected to continue to increase. As a result, many new sources of NOx emissions have been added to the existing inventory within the OTR (as well as surrounding states), primarily in Pennsylvania and New York. While many of these engines are small, the emissions from these small sources as a group may become an air quality problem if the existing and new equipment is not properly controlled. This document addresses the equipment used in drilling of exploratory wells and production wells for crude oil and natural gas, pumps and compressors to take the product from the well heads to the gathering system, oil and gas heaters near the well head, and pipeline pumps and compressors to transport the product to processing facilities, storage facilities, and to distribution systems. Potential emissions controls for internal combustion engines and combustion turbines that are used in the above listed applications are detailed in Section 4 of this document. The document also provides a sample of state and federal air quality laws and regulations that apply to this portion of the oil and natural gas sector.

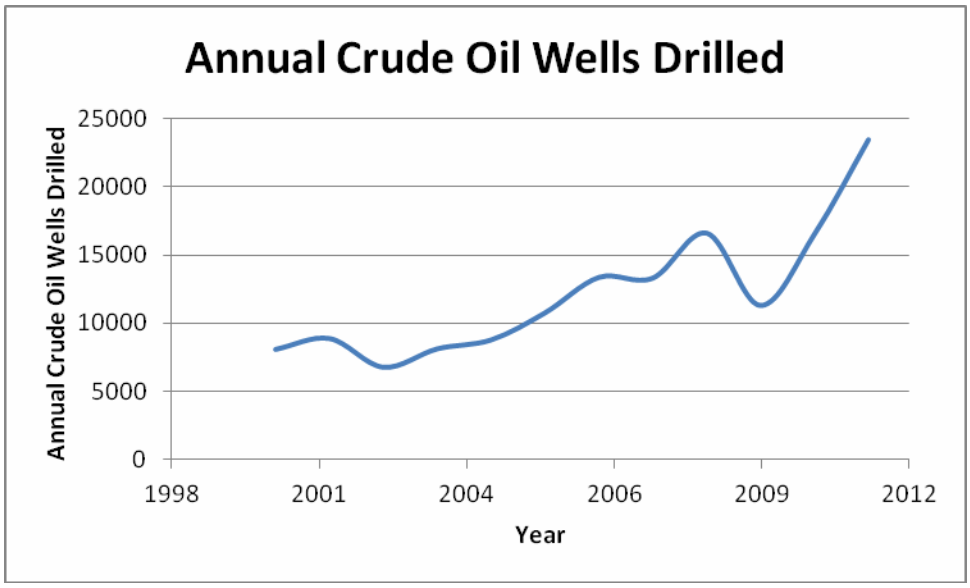
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2.0 US Annual Crude Oil and Natural Gas Production

Crude oil production in the lower 48 states has been in a general decline for a long period of time, including a portion of the last decade. However, the crude oil production has demonstrated an increase in the last few years. In the lower 48 states, the states of Texas, California, and North Dakota have been the largest crude oil producers. Within the Ozone Transport Region (OTR), the states of Pennsylvania and New York are crude oil producers. The following graph shows the US crude oil production over the last decade:

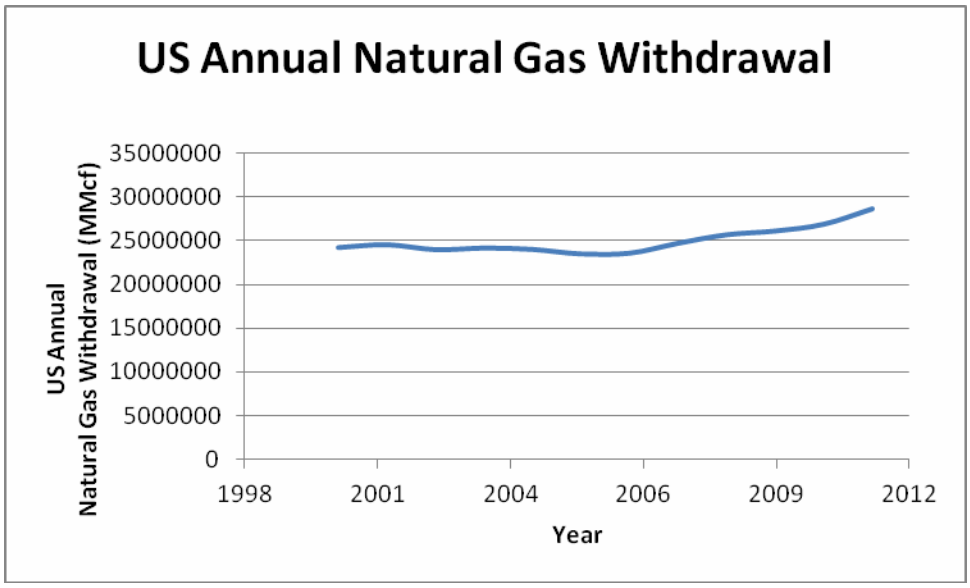


In order to maintain and increase the crude oil production across the US, new crude oil wells have been, and continue to be, drilled in many locations throughout the US. The following graph shows the general increase in crude oil well drilling over the last decade:

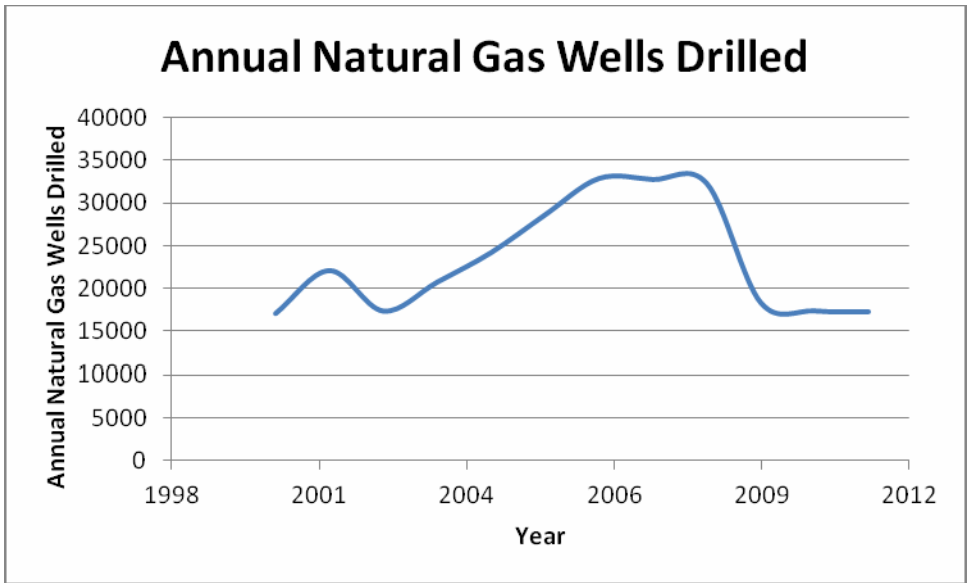


Based on the available data, the U.S. Department of Energy's Energy Information Agency (EIA) noted that in 2009 there were in excess of 960,000 producing oil wells in the US.

Natural gas is produced in 30 of the lower 48 states. Within the OTR, the states of Pennsylvania, New York, and Maryland produce natural gas. Natural gas production has shown an overall increase over the last decade, with an accelerated rate of increase in the last few years. It is interesting to note that during the last few years gas production from conventional (wells drilled vertically into conventional geological formations) gas wells and oil wells has actually decreased. However, that reduction in natural gas production from conventional gas wells and oil wells has been compensated for and surpassed by gas production from shale gas wells and coal bed methane wells. Annual US natural gas production for the last decade is shown in the following graph:

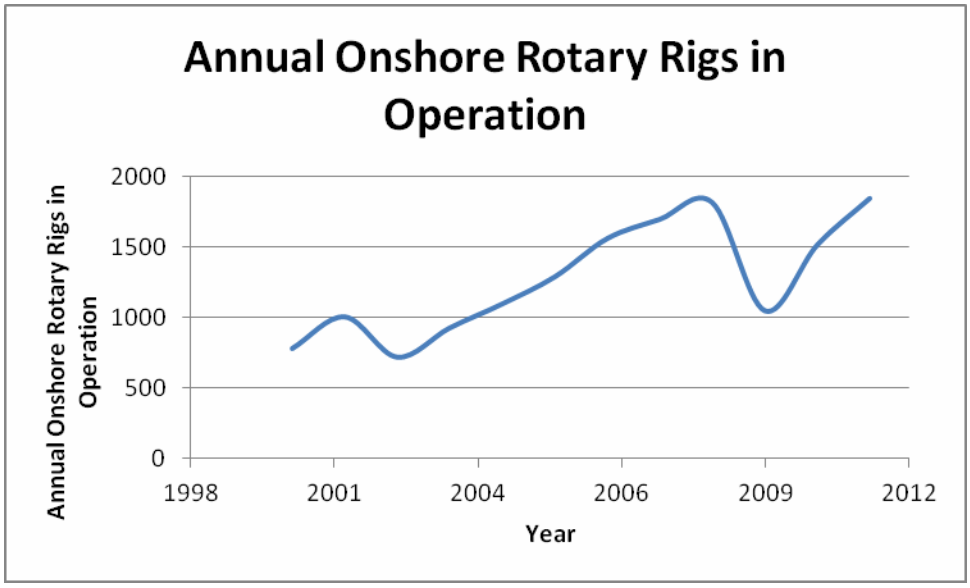


As shown in the following graph, the annual number of natural gas wells being drilled has decreased in the last few years. However, the graph also shows that a significant number of new natural gas wells are continuing to be drilled on an annual basis. While it may seem strange that the natural gas withdrawal has increased but the rate of well drilling has decreased, it should be noted that much of the increase in natural gas production is from shale gas and coal bed methane wells. Shale gas wells and coal bed methane wells are typically deeper and/or longer than conventional gas wells, requiring longer drilling periods, and have, to date, been highly productive.

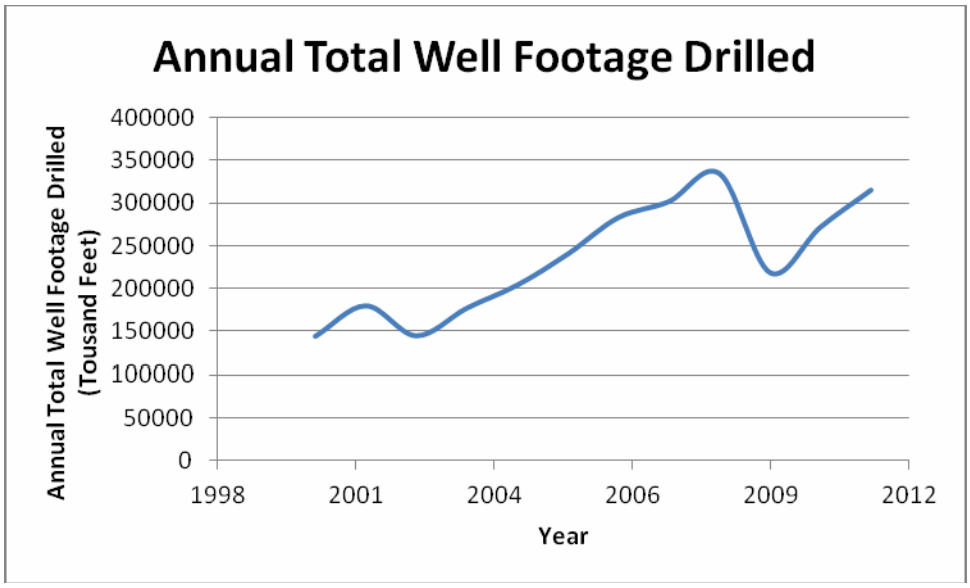


Based on the available data, the EIA noted that in 2009 there were in excess of 1,097,000 producing gas wells in the US.

The combination of increased demand for crude oil and natural gas has caused a general increase in drilling operations. As shown in the following graph, the annual number of well drilling rigs in on-shore operation has generally increased over the last decade.



As would be expected, the general increase in the annual number of well drilling rigs in operation is accompanied by a general increase in the annual total well footage drilled. The following graph shows the total annual well footage drilled over the last decade:



3.0 Oil and Gas Sector NOx Emissions Sources

Within the oil and gas sector, there are many significant NOx emitting sources. Excluding NOx emissions from sources at refineries and gas processing facilities, oil and gas sector NOx emissions sources include the following:

- Diesel and spark ignition reciprocating engines in drilling rig operations (gas and oil sectors).
- Diesel reciprocating engines, spark ignition reciprocating engines, and combustion turbines driving electric generators for power in remote locations and for supporting operation of electric motors (gas and oil sectors).
- Diesel and spark ignition reciprocating engines engine driving hydraulic fracturing pumps, recovery pumps, and water recirculating pumps (oil and gas sectors).
- Gas heating units in well fields working with "wet" gas.
- Oil well heating units.
- Diesel reciprocating engines, spark ignition reciprocating engines, and combustion turbines for well field gas compressors, gas field gathering compressors, and gas pipeline compressors
- Diesel reciprocating engines, spark ignition reciprocating engines, and combustion turbines for wellhead oil pumps, oil field gathering pumps, and oil transportation pipeline pumps.
- Well flairs (oil and gas sectors)

The oil and gas sector NOx emitting processes noted above are further discussed in the following sections.

3.1 Well Drilling and Completion

A well is created by drilling a hole (diameter dependent upon product and expected flow rate) into the earth with a drilling rig that rotates a drill pipe with a drill bit attached. This drilling process is facilitated by the use of a drill rig which contains all the necessary equipment to pump and circulate the drilling fluid, hoist and turn the drill pipe, control down-hole movement, remove cuttings from the drilling fluid, and generate on-site power for these operations.

After drilling and casing the well, it must be 'completed'. Completion is the process in which the well is enabled to produce oil or gas. Often well completion is performed utilizing a specialized rig or platform, enabling the drilling rig to be moved to a new location to drill another well. Well completion may include preparing the last section of the pipe casing in the reservoir to create a flow path from the reservoir into the piping. After a flow path is made, acids and fracturing fluids may be pumped into the well to fracture, clean, or otherwise prepare and stimulate the reservoir rock to optimally produce hydrocarbons into the wellbore.

In some wells, the natural pressure of the subsurface reservoir is high enough for the oil or gas to flow to the surface. However, this is not always the case, especially in depleted fields where the pressures have been lowered by other producing wells, or in low permeability oil reservoirs. Installing smaller diameter tubing may be enough to help the production, but artificial lift methods, such as downhole pumps or surface pumps or compressors, may also be needed. Many new systems have been introduced for improving well completion in recent years that have cut completion costs and improved production, especially in the case of horizontal wells. Some of these well completion activities have also reduced the

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amount of gas that is flared by capturing the gas that might otherwise have been flared off and treating and utilizing it as a product.

Sources of NOx emissions from the drilling and completion processes include, but are not limited to, engines driving electric generators that provide electric power supporting the drilling process, engines used to directly power the drilling drive and related pumps and compressors, and flaring of relatively small amount of natural gas as part of well completion. The majority of the engines utilized in this service are diesel reciprocating engines.

Shell operates drilling rigs to support their oil and natural gas development activities. In a presentation, Shell indicated that they have installed SCR on diesel engines that they utilize in drilling rig operations. They indicated that they had been able to achieve greater than 90% reduction in NOx emissions while encountering minimal operational issues.

EIA data indicates that in 2011 there were 1844 on-shore oil and gas drilling rigs in operation in the US, an increase of 330 over 2010 and an increase of 798 over 2009.

EIA data also indicates that there were a combined total of 45,529 oil and gas exploratory and development wells drilled in 2011, an increase of 7,207 wells from those drilled in 2010 and an increase of 12,390 wells from those drilled in 2009. The data indicates that a combined 314,840 thousand feet were drilled in 2011, compared to 271,912 thousand combined feet drilled in 2010 and 218,693 thousand combined feet drilled in 2009.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics (material being drilled through, well depth, etc), it is difficult to estimate the magnitude of those NOx emissions from well drilling and well completion activities. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), "An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region" (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the gas industry, and investigated regional data to estimate NOx emissions factors primarily for natural gas industry operations, with some additional effort to assess oil and methane bed NOx emission factors. The regional data presented in the report indicated a relatively wide range in estimated emission factors, likely due to the site and equipment variability. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region specific data is not available for other locations. The emissions factors presented in the WRAP report were as follows:

- Drilling: Range of 2.26 tons NOx/well to 9.78 tons NOx/well
- Well Completion: Range of 0.85 tons NOx/well to 1.5 tons NOx/well

While there is no certainty that the above range of emission factors are representative of the range of emission factors on a national basis, the drilling of 45,529 oil and gas wells in 2011 and the use of the

above emissions factors results in a range of NOx emissions of from 141,596 tons to 513,567 tons (drilling and completion related activities only).

An emissions inventory of oil and gas sector emissions for 2005 in Texas (for additional detail see http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784003FY0701-20090831-ergi-ei_from_old_gas_facilities.pdf) indicated that oil and gas drilling operations accounted for approximately 56.4% of the onshore oil and gas sector NOx emissions. In that same 2005 Texas emissions inventory, oil and gas well completions accounted for approximately 0.2% of the total oil and gas sector NOx emissions.

A more detailed discussion of the engines used to support well drilling and completion activities, and control of NOx emissions from those engines, is provided in later sections of this document.

3.2 Oil Well Pumps

Pumps are often required to raise oil in an oil well from the oil's underground location to the surface. There are several types of pumping devices that are used to provide artificial lift in an oil field. These include: mechanical lift powered by a motor or engine on the surface; hydraulic lift, where oil or water is pumped down into the well to operate a hydraulic pump; electric submersible pump, where a electric motor driven pump at the bottom of the well is driven is supplied electricity from the surface; and gas lift, where natural gas injected into the piping at intervals lightens the weight of the fluid, helping it rise to the surface. All four of these systems offer advantages and disadvantages for specific situations. Mechanical lift is one of the more commonly used oil well pumping devices.

When located near sources of grid supplied electric power, the oil pumps are generally powered by electric motors. In some more remote areas, the oil pumps may still be powered by electric motors, but utilize electricity generated locally using natural gas engine or diesel engine powered electric generators. In other instances, the oil pumps may be driven directly by natural gas fueled engines or diesel engines. The required output rating of the engines would vary depending on the depth of the well, pumping capacity, etc. However, these engines tend to have a relatively small output rating, generally less than 200 hp.

Once the oil is extracted from the well, it is pumped to a storage tank(s) that may be common to multiple supply wells. The oil is then typically transported from the storage tank by truck or pumped out through a pipeline.

Little data was located that could be used to estimate the NOx emissions from oil well pumps. Documentation of previous estimation efforts were equally absent in the data searches. Variables such as well depth and type of prime mover (reciprocating engine, combustion turbine, electric motor) make it very difficult to make any sort of reasonable estimate of the NOx emissions without some detailed inventory and operational information. Because of the lack of data and/or guidance information, no estimates were made of the potential NOx emissions from oil well pumping activities. However, the NOx emissions from engines used to power the oil pumps are generically addressed in later sections of this document.

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3.3 Oil Pipeline Pumps

Crude oil is often transported from field gathering locations to downstream locations through pipelines. Industry data indicated that in 2008, pipelines accounted for 71% of all petroleum transportation, up from 67% in 2007. The data indicates that it is estimated that in the US there is in excess of 55,000 miles of crude oil trunk lines connecting regional markets, and estimated that there is from 30,000 miles to 40,000 miles of small crude oil gathering pipelines. Pipelines are also utilized for transportation of refined petroleum products, and industry data estimates indicate that there are approximately 95,000 miles of refined products pipelines in the US.

Pumps are generally required to pump the oil through the pipelines, with pumps generally located at the originating field gathering location and at 20 to 100 mile intervals along the pipeline, depending upon pipeline design, pipeline path geography, and flow requirements. These oil pumps are often driven by electric motors, but some may utilize diesel engines, natural gas fueled reciprocating engines, or combustion turbines to power the pumps when warranted. Little data could be found documenting the size and makeup of the population of oil pipeline pump prime movers.

Little data was located that could be used to estimate the NOx emissions from oil pipeline pumps. Documentation of previous estimation efforts were equally absent in the data searches. Because of the lack of data and/or guidance information, no estimates were made of the potential NOx emissions from oil pipeline pumping activities. However, the NOx emissions from engines used to power the oil pumps are generically addressed in later sections of this document.

3.4 Coal Bed Methane Pumps

In order to facilitate gas extraction from coal bed methane wells, it is often necessary to pump out large amounts of water to reduce the pressure in the coal bed and thereby facilitate methane desorption from the coal. Desorption from the coal allows the methane to be extracted and transported to gathering pipelines. Industry information indicates that the water pumping may occur throughout the useful life of the coal bed methane well, but will tend to experience a reduction with "age" of the well or well field. Coal bed methane pumps are sometimes powered by electric motors, but are typically powered by diesel engines or spark ignited reciprocating engines.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics, it is difficult to estimate the magnitude of NOx emissions from coal bed methane pumping. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), "An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region" (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the gas industry, and investigated regional data to estimate NOx emissions factors that included coal bed methane pumping NOx emission factors. The regional data presented in the report indicated a relatively wide range in estimated emission factors, likely due to the site and equipment variability. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region

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specific data is not available for other locations. The emissions factors presented in the WRAP report for coal bed methane pumps ranged from 0.06 ton/year/well to 0.60 ton/year/well.

NOx emissions from engines used to power the coal bed methane pumps are generically addressed in later sections of this document.

3.5 Oil Well Heaters

Some oil wells require heating of the crude oil, as the crude oil reaching the surface of a well may contain varying amounts of impurities. The well heaters are used to heat crude oil to separate water, solids such as paraffin, and natural gas from the crude oil. Heat from combustion in the heater's firebox heats the crude oil and helps water droplets and solids settle out so that they can be drained out of the bottom of the heater. The heating of the crude oil also facilitates the separation of natural gas from the crude oil, allowing the gas to rise and be piped off from the top of the heater. The oil is then drawn off for pumping to a pipeline or storage tanks.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics, it is difficult to estimate the magnitude of NOx emissions from oil well heaters. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), "An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region" (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the oil and gas industry, and investigated regional data to estimate NOx emissions factors that included oil well heater NOx emission factors. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region specific data is not available for other locations. The average NOx emissions factor presented in the WRAP report for oil well heaters is 0.005 lb NOx/barrel produced.

Because of the small size of most oil well heater burners, there may be few commercially available combustion or post-combustion technologies commercially available for NOx reduction.

3.6 Gas Well Heaters

Due to varying amounts of condensates and moisture in the gas coming to the surface, some natural gas wells require treatment near the well head. Heating is often part of this "cleanup" process, generally utilizing natural gas fired heating units. The heating of the natural gas is sometimes required to ensure that the temperature of the natural gas does not drop too low where it could facilitate the formation of a hydrate with any water vapor in the gas stream. Natural gas hydrates are crystalline ice-like solids or semi-solids that can impede the passage of natural gas through valves and pipes.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics, it is difficult to estimate the magnitude of NOx

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emissions from gas well heaters. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), "An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region" (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the oil and gas industry, and investigated regional data to estimate NOx emissions factors that included gas well heater NOx emission factors. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region specific data is not available for other locations. The average NOx emissions factor presented in the WRAP report for gas well heaters is 1,752 lb NOx/well/year.

An emissions inventory of oil and gas sector emissions for 2005 in Texas indicated that gas well heaters accounted for approximately 0.5% of the onshore oil and gas sector NOx emissions.

Because of the small size of most gas well heater burners, there may be few commercially available combustion or post-combustion technologies commercially available for NOx reduction from these devices.

3.7 Natural Gas Compressors

The natural gas system in the continental United States is a complex network consisting of equipment and pipelines to gather natural gas from wellheads, transport the raw natural gas to processing facilities as required, transporting the natural gas from processing facilities across potentially large distances to storage facilities and distribution systems, and supplying natural gas to distribution systems that provide the natural gas to the end users.

Compressors are utilized in natural gas fields to boost natural gas wellhead pressure so that the natural gas may be injected into the gathering pipelines to transport it to processing facilities and/or inject the natural gas into the transport pipelines. Compressors are utilized in the transportation network to keep the pipelines pressurized and achieve the desired flow of natural gas. Compressors are also utilized at storage facilities to inject the natural gas into storage and to extract the natural gas from storage and re-inject it back into the transportation or distribution pipelines. Compressors are also sometimes utilized in distribution systems to ensure adequate flow and pressure to the natural gas end users. Most natural gas compressor facilities are normally unmanned, and many are operated from remote facilities to start/stop/modulate output to meet the demands of the associated pipeline systems.

Many natural gas wells require the use of compressors to facilitate extracting the natural gas from the well, boosting the pressure for injecting the natural gas into the field gathering pipeline system, and transporting the natural gas to and from any required field processing facility. Typically, reciprocating engines fueled by raw natural gas are utilized in this service, but other prime movers such as natural gas fueled combustion turbines or electric motors may be utilized in some circumstances. Industry information indicates that compressors utilized in this service tend to run with a relatively constant capacity factor throughout any given calendar year.

Industry literature indicates that the number and size of the compressors utilized in wellhead/gathering systems varies greatly as a result of differences in needed flow capability and pressure boost

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requirements. The industry information indicates that utilized compressors can range from portable compressor units with 5 HP prime movers to units that have prime mover ratings in excess of 1500 HP. Natural gas fueled reciprocating engines and combustion turbines, along with electric motors, are commonly utilized in this service. Some locations may be remote relative to sources of off-site electric power, prohibiting the use of electric motors for driving gas compressors unless local electric generation is also provided.

Some natural gas gathering systems include a well field processing facility, which performs such functions as removing impurities like water, carbon dioxide or sulfur that might corrode a pipeline, or inert gases, such as helium, that would reduce the energy value of the gas. These well field processing plants also can remove small quantities of propane and butane. These gases may used for chemical feedstocks and other applications. Compressors in this service may be utilized to transport natural gas from the wellheads to the well field processing facility, and then from the ell field processing facility to the main pipeline network.

Because of the relatively small size of some (but certainly not all)of the combustion engines utilized in natural gas field gathering applications, the available data concerning these units is more limited than that available for the generally higher output mainline compressor prime movers. Industry information indicates that some gas compressor engines used in this service are part of a skid mounted assembly, allowing the compressor to be moved with relative ease and thereby providing additional flexibility in meeting the changing demand associated with removing natural gas from any given well or well field. Industry information also indicates that many of the natural gas compressor prime movers used in this service are leased units.

An emissions inventory of oil and gas sector emissions for 2005 in Texas indicated that natural gas compressors of all kinds collectively accounted for approximately 42.9% of the onshore oil and gas sector NOx emissions.

There was a study performed in 2005 to support an investigation of natural gas field gathering engines in Eastern Texas that might provide some more insight into the potential diversity of engines utilized in the natural gas field gathering service. One of the goals of the Texas study was to get a more firm estimate of the inventory of compressors in use in the area in question. That study indicated that there were a number of engine manufacturers represented in the investigation area, along with a significant number of different engine models among the manufactures. The study was able to determine the age for only a very small portion of the engines in the study, but for that group the engine age ranged from 2 years to 25 years old. The output ratings of the engines in the study ranged from 26 HP to 1478 HP, with the majority rated between 50 HP and 200 HP. Some engines were owned by the gas/collection company, but the majority of the engines were leased units. The Texas report indicates that for this particular group of engines, there was little “seasonality” to their operating schedule, but that they seldom ran at full load (generally between 10% and 70% capacity). In the portion of the region covered in the Texas study that were non-attainment areas, the majority of the engines were found to be rich burn engines, with most required to have NSCR NOx emissions controls installed. The report indicates that the engines in the non-attainment areas not requiring NOx emissions controls were primarily 2-stroke engines, engines under 50 HP, and 4-stroke lean burn engines.

Mainline natural gas transmissions pipeline systems utilize compressors at gas compressor stations to maintain system flow and overcome pressure losses due to the movement of the natural gas through the natural gas pipeline system. These compressor stations are typically located at 40 mile to 100 mile

intervals along the transmission pipeline, as required by the particular pipeline section duty, to maintain the required flow and pressure. These mainline natural gas compressor facilities will often include multiple gas compressors to add flexibility and reliability in meeting the variable natural gas flow demand. Prime movers for these mainline compressors are typically natural gas fired reciprocating engines and combustion turbines, although there are also a number of electric motor driven gas compressors. In some instances, combustion compressor prime movers and electric motor compressor prime movers are located in the same compressor facilities. The horsepower ratings of the individual combustion compressor prime movers range from less than 300 hp to 15,000 hp and more.

For many mainline natural gas compressor stations, industry data indicated that the gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity. The industry data indicates that on average a compressor unit will tend to experience an annual average capacity factor of approximately 40%. For many mainline natural gas compressor facilities, reciprocating engines are preferred for their ability to adjust their output to meet the pipeline demand. Compressor loading will tend to increase during periods of high natural gas demand, such as cold periods with high heating fuel demand or high electric demand days in the Northeast when natural gas fired electric generation is a significant consumer of natural gas.

EIA data indicates that in 2006 there were 1201 natural gas mainline compressor stations in the US, with a combined installed horsepower combined rating in excess of 16.8 million horsepower. The Federal Energy Regulatory Commission (FERC), the approval authority for interstate pipelines projects (including compressor facilities), has records that show that between 2007 through 2010, FERC had approved new compressor facilities or upgrades to existing compressor facilities that are expected to result in the addition of approximately 2.6 million horsepower of compression capability.

Many of the installed reciprocating engines driving mainline natural gas compressors are in excess of 40 years old and therefore pre-date any applicable modern original equipment manufacturer (OEM) installed NOx emissions controls and any otherwise applicable NSPS NOx controls. Little information was readily identifiable regarding the number of these units that may have undergone any NOx emissions reduction modifications as a result of federal or state NOx reduction retrofit requirements and regulations subsequent to the initial unit installation.

In a document titled “ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NOx”, dated 5/21/2009, prepared by a technical group for the Pipeline Research Council International, it was stated that a gas industry database of compressor engines identified that there were approximately 5,600 engines on the natural gas pipeline system with a collective rating of approximately 9,150,000 horsepower. The document further indicates that of the engine population, approximately 80% of the rated output was represented by purpose designed low speed two stroke and four stroke integral engines and diesel-derived medium speed engines converted to spark ignition by the engine’s original manufacturer. Of the engines represented in the 80% figure, approximately 78% of the engines were two stroke lean burn engines, approximately 14% were four stroke lean burn engines, and 8% of the engines were four stroke rich burn engines. That same population, on a rated horsepower basis, was made up of approximately 80% two stroke lean burn, approximately 15% four stroke lean burn, and approximately 5% four stroke rich burn.

4.0 Oil and Gas Sector Fuel Fired Prime Movers

Data indicates that with the exception of refineries and central natural gas processing plants, the largest collective sources of NOx emissions from the oil and gas sector are reciprocating engines and combustion turbines. These reciprocating engines and combustion turbines are used to power drilling operations, drive various pumping operations, drive oil well pumps and pipeline pumps, and drive well head and pipeline natural gas compressors. Further discussion of these NOx emissions sources and potential NOx controls follow.

4.1 Reciprocating Engines - Two Stroke Lean Burn Spark Ignition Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Spark ignition engines use a spark (across a spark plug) to ignite the compressed fuel-air mixture to create the motive force.

Two-stroke engines complete the power cycle in a single engine revolution compared to 2 revolutions for 4-stroke engines. With the 2-stroke engine, the air/fuel charge is injected with the piston near the bottom of the power stroke. The ports or valves are all covered or closed, and the piston moves to the top of the cylinder compressing the charge. Following ignition and combustion, the power stroke starts with the downward movement of the piston. Exhaust ports or valves are then uncovered to remove the combustion products, and a new air/fuel charge is ingested. Two-stroke engines may be turbocharged using an exhaust-powered turbine to pressurize the charge for injection into the cylinder. Non-turbocharged engines may be either blower scavenged or piston scavenged to improve removal of combustion products. The air and fuel are mixed inside the power cylinder and fired by either a spark plug or pre-combustion chamber.

Two stroke engines generally are set to operate with a lean mixture to minimize combustion temperatures, and the fuel lean combustion mixtures tend to produce lower combustion temperatures and therefore lower NOx emissions. Some lean burn engines can be modified to operate with very fuel lean mixtures, further reducing NOx emissions, up to the point where engine miss-fire becomes a problem. Some of the combustion improvements discussed below (high energy ignition, pre-chamber combustion, and improved fuel mixing) facilitate the use of very fuel lean mixtures before engine miss-fires are encountered.

There are many 2-stroke spark ignition reciprocating engines utilized in the oil and gas sector, representing a number of different manufacturers, model numbers, and a wide range of engine output ratings.

4.1.1 Two Stroke Lean Burn Spark Ignition Reciprocating Engine NOx Controls

Industry literature indicates that there are a number of methodologies that are commercially available to help control NOx emissions from two-stroke lean burn spark ignition reciprocating engines (2SLB), most of which are related to efforts to acceptably operate with very lean air/fuel mixtures. While most of the technologies are generically applicable to most of the existing two-stroke lean burn engines,

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application on any specific make/model of engine may present unique circumstances that may affect the effectiveness of the control and the cost of installation on that particular engine.

When an engine's air/fuel mixture is leaned to achieve NOx emissions reductions, the amount of spark required from the ignition system to start combustion is increased. High energy ignition systems are applicable to most lean burn engines that are not already equipped with such a system. The high energy ignition system is generally a conventional open-chamber system with the spark plug (or plugs) generally located with the spark plug protruding from the bottom of the combustion cylinder head into the combustion chamber. High energy ignition systems allow more energy to be delivered to the spark plug(s) with a larger gap, thereby increasing the spark energy delivered to the air/fuel mixture and ensuring proper ignition. High energy ignition systems may be digitally controlled systems that use crankshaft referenced angle encoders to deliver precise, high energy ignition sparks. These high energy ignition systems may have the capability to generate multiple, successive sparks during combustion to ensure proper air/fuel light- off. Modern high energy ignition systems tend to reduce miss-fires and engine detonation, and provide a more stable combustion over an engine's entire operating range. Industry information indicates that a slight NOx emissions reduction, approximately 10%, can be achieved through application of a high energy ignition system on an engine that does not have an existing high energy ignition system.

Another methodology for controlling NOx emissions is by improving the combustion air flow characteristics of the engine. Increasing the air flow tends to produce a leaner air/fuel mixture, reducing the peak combustion temperature which tends to reduce NOx emissions. For some engine designs, this may be accomplished by varying the engine load or increasing the engine speed (if within the manufacturer's limits). The air flow of many engines can be increased by converting non-turbocharged engines to incorporate a turbocharger system, modifying or upgrading existing turbocharger systems on engines already incorporating turbochargers, or other unit-specific means to supply combustion air or scavenge the cylinder of combustion products. Turbocharger additions or upgrades often also require upgrades to the rest of the air intake and exhaust systems to accommodate and optimize the new or upgraded turbochargers. Additionally, a turbocharger installation or upgrade may be optimized through the use of intake/combustion air cooling systems. Industry information indicates that, depending upon the degree of upgrade, NOx emissions reductions of up to 75% may be expected for the addition of properly engineered turbocharger systems with intake /combustion air cooling.

Enhanced air fuel mixing technologies are another method of achieving NOx emissions reductions. The design of some two-stroke engines exhibit problems with the ability to thoroughly mix combustion air and fuel. For these engines, the combustion air and fuel may not be introduced for mixing until each has entered the combustion cylinder. The combustion air and fuel mix as the fuel is "sprayed" into the combustion air already in the cylinder. For some engine designs, the air and fuel mixing results in a non-homogeneous mixture that can cause a sporadic and unstable burning process as the flame burns through the cylinder filled with different regions of differing air/fuel mixtures. To improve the mixing process, the fuel supply system and components can be converted to utilize higher fuel injection pressures that force a more rapid and turbulent interaction between the combustion air and fuel and result in a more homogeneous mixture. Industry information indicates that increasing the pressure at which the fuel is injected, and directing the dispersion of the fuel during injection, can significantly reduce emissions and fuel consumption. Industry information indicates that relative to an older low pressure fuel injection system, a well engineered high pressure fuel injection system may be able to facilitate NOx emissions reductions of up to 90% in some engines.

As mentioned above, leaner air/fuel ratios have a tendency to help reduce NOx emissions. However, as the air/fuel ratio is further leaned to attain lower NOx emission rates, the extremely lean air/fuel mixtures become more difficult, if not impossible, to ignite using a standard open-chamber spark plug ignition system. In these cases, a combustion pre-chamber (typically less than 10 percent of the volume of the main chamber) may be installed in the power cylinder head and fitted with a conventional spark plug in the pre-chamber. The fuel supply system is modified to inject fuel into the pre-chamber as well as the main power chamber. During the intake process, the pre-chamber is charged with a richer air/fuel mixture than the main combustion chamber. This richer pre-chamber combustion mixture is more easily ignited by the sparkplug. As the pre-chamber combustion mixture burns, the pressure of the combustion pushes the burning mixture into the main combustion chamber, igniting the main combustion chamber's lean air/fuel mixture. Industry information indicates that the use of ignition pre-chambers may facilitate NOx reductions capabilities of up to 90% in some engines.

Modern electronic engine controls also may be utilized to facilitate the NOx reduction benefits of the above modifications. This is especially true for varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. Some of these devices are air/fuel ratio controllers. Some of these air/fuel ratio controllers utilize mathematical models to monitor certain engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating conditions. By tracking and maintaining the "optimal" air/fuel mixture, the engine runs clean and more efficiently. In this way, the engine is more capable of maintaining NOx emissions compliance even with changing operating conditions and ambient condition changes.

Selective catalytic reduction (SCR) is a post-combustion NOx control that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the engine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) that passes over a catalyst to help convert the NOx, hydrocarbons, and CO into water, nitrogen and CO_2. Catalyst selection is somewhat based on the expected temperature range of the engine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control may facilitate NOx reductions of up to 95%.

2-Stroke Lean Burn Spark Ignition Engine

NOx Control Retrofit Technology	**Potential NOx Reduction**
High Energy Ignition System	10%
Intake Air Upgrade (turbocharger, etc)	75%
Improved Mixing (high pressure fuel injection)	90%
Pre-Combustion Chamber Ignition System	90%
SCR Catalyst	50% - 95%

4.1.2 Example Existing Rules and Regulations – 2SLB

California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from http://aqmd.gov/rules/download.html)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp≥500	36 ppmvd NOx (*approximately 0.5 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2010	
Nameplate - Bhp≥500	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for lean burn engines with nameplate ratings of greater than 50 hp and not used for agricultural operations include:

Two-stroke lean burn, gas fueled, < 100hp	75 ppmvd NOx
Lean burn limited use	65 ppmvd NOx
Lean burn used for gas compression	65 ppmvd NOx
Lean burn – all others	11 ppmvd NOx

(Note that the San Joaquin Valley Air Pollution Control District's Rule 4702 definition of limited use requires the engine have a permit restricting the engine's operation to no more than 4000 hrs/yr.)

The state of Colorado's Air Quality Control Commission has established NOx emissions limitations for stationary internal combustion reciprocating engines in its Regulation 7, Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides).
Colorado's Regulation 7 has no NOx emissions limitations applicable to lean burn engines.

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However, Colorado's Regulation 7 does include NOx emissions limitations applicable to lean burn engines that are new, modified, or relocated stationary natural gas fueled reciprocating internal combustion engines, as follows:

Engine Nameplate	Manufacture Date	NOx Emissions Limit
Nameplate-100≤Bhp<500	Effective January 1, 2008	2 g/bhp-hr
	Effective January 1, 2011	1 g/bhp-hr
Nameplate Bhp≥500	Effective July 1, 2007	2 g/bhp-hr
	Effective July 1, 2010	1 g/bhp-hr

(This Colorado rule may be viewed at http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf)

The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for 2-stroke lean burn spark ignition engines. The relevant emissions limitations in the rule include the following:

Engine Type	Manufacture Date	NOx Emissions Limit
Two stroke, lean burn SI– BHP≥ 500	Mfg before 9/23/1982	8g/bhp-hr
	Mfg before 6/18/92 & BHP<825	8g/bhp-hr
	9/23/1982≤Mfg<6/18/1992&BHP>825	5g/bhp-hr
	6/18/1992≤Mfg<6/1/2010	2g/bhp-hr
		(exc 5 g/bhp-hr at reduced speed and torque 80%<>100%)
	Mfg on or after 6/1/2010	1/g/bhp-hr

(This Texas rule can be reviewed at:
http://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf).

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone Non Attainment Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for natural gas fueled lean burn spark ignition reciprocating engines as follows:

Gas Fueled Lean Burn SI Engine ≥ 300 bhp	3.0 g/bhp-hr

Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to all spark ignition internal combustion engines and other air contamination sources at natural gas production and processing facilities. In the proposed GP-5, existing rich and lean burn engines with a nameplate rating of less than or equal to 100

horsepower, but less than 1500 horsepower, will be required to continue to meet the existing GP-5 NOx emissions limit of 2 g/bhp-hr. When the currently proposed GP-5 becomes effective, new and reconstructed engines will be required to meet the following NOx emissions limits:

Configuration	**NOx Limit**
New and reconfigured Lean Burn Engine ≤ 100hp	2 g/bhp-hr
New and reconfigured Lean Burn Engine 100< hp ≤ 637	1 g/bhp-hr
New and reconfigured Lean Burn Engine > 637hp	0.5 g/bhp-hr

The USEPA established NOx emissions limitations for natural gas fueled lean burn spark ignition engines in 40 CFR Part 60, Subpart JJJJ (NSPS) (1/18/08 73 FR 3567). The applicable NOx emissions limits for lean burn natural gas-fueled, spark ignition engines are as follows:

Engine Type	**Output Rating**	**Manufacture Date**	**NOx Emissions Limit**
SI Nat. Gas Lean Burn	500≥HP<1350	mfg after 7/1/2008	2.0 g/HP-hr
SI Nat. Gas Lean Burn	500≥HP<1350	mfg after 7/1/2010	1.0 g/HP-hr

4.1.3 Discussion of NOx Reduction Capability – Combustion Modifications

With regard to combustion related NOx reduction retrofits for 2-stroke lean natural gas fueled spark ignition engines, the literature suggests that there are often significant differences in design characteristics between 2SLB engine manufacturers' designs such that applicability and effectiveness of generic NOx combustion controls is highly variable. The literature suggests that this is sometimes due to the air/fuel mixing characteristics and patterns in the engine cylinders that were employed by the manufacturer in the design of the particular engine model. This would indicate that there is also the likelihood of differences between a given manufacturer's engine models and vintage that could affect the applicability and effectiveness of a given NOx control combustion control technology. For some of the more popular or numerous makes and models, the original manufacturer or an aftermarket vendor may offer effective "off-the-shelf" NOx reduction retrofit packages that help reduce the cost of NOx reduction for those makes and model engines. For other engines, only limited support may be available which could require custom design, installation, and tuning of NOx controls that would tend to increase the cost of the NOx emissions reduction project and possibly impact the overall effectiveness of the project.

Other characteristics may also affect the reduction effectiveness, and the cost effectiveness, of a NOx emissions reduction project on any particular engine, such as frequency of startups and shutdowns, operational loading characteristics, location, (altitude, seasonal variations), etc. Variability also potentially exists from installation to installation due to equipment clearances, etc.

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The industry literature suggests that in some cases combustion related modifications/upgrades may also offer the possibility of improving the 2-stroke lean burn reciprocating engine's efficiency and range of operation.

There are a number of manufacturers and suppliers that provide components, systems, and services to support combustion related NOx emission reductions from two stroke lean burn engines. Some of these organizations include the following:

- Windrock offers an autobalance system that automatically balances the cylinder-to-cylinder combustion in multi-cylinder slow speed integral engines such as Cooper-Bessemer, Clark/Dresser, Ingersoll-Rand, Worthington, and other two- or four-stroke engines with individual cylinder fuel adjustment valves. The system constantly adjusts fuel flow to each power cylinder in order to maintain peak firing pressures to ± 5% of engine average during differing ambient conditions, varying speeds and changing loads. Eliminating unbalanced operation across all operating conditions enables the engine to run with the minimum possible NOx and facilitates the positive results of other NOx reduction modifications. For additional information see: http://www.cookcompression.com/files/comm_id_68/GMJournal_Q32009_AutoBalance.pdf

- Dresser-Rand, a reciprocating engine OEM, offers a retrofit NOx emission technology system for a number of engine models. While somewhat dependent upon the specific model, the retrofit NOx emission reduction system may include a screw-in combustion pre-chamber high energy ignition system, earlier fuel injection timing and directional fuel injection for improved air/fuel mixing, improved controls for more precise fuel injection and engine timing, and improved air flow to further lean the mixture when applicable. Dresser-Rand also offers more extensive NOx reduction systems for retrofit, which depending upon engine model may include new cylinder heads with pre-combustion chambers, new main fuel gas injection valves, high efficiency turbochargers, larger turbocharger combustion air intercooler with plenums, new fuel management system, air/fuel ratio controller, new spark controller, new cams and/or camshaft on four-stroke engines, and a high-energy ignition system. Industry literature indicates that Dresser-Rand offers related retrofit NOx reduction controls for TVC, TCVA, TCVD, TLA, TLAD, LA, HLA, HLA/T, BA, HBA, HBA/T, RA, HRA, and HRA/T two stroke engines (Clark, Dresser-Clark). The literature also indicates that NOx emission guarantees of between 2.5 g/bhp-hr and 3.0 g/bhp-hr have been provided with these NOx reduction technologies, and that those guarantees have been consistently met or improved upon. For additional information see: http://dresser-rand.com/service/engineeredsolutions/revamps/recip.php , http://www.dresser-rand.com/techpapers/tp014.pdf

- Cameron offers a NOx reduction system for Ajax two stroke lean burn engines. Cameron's exhaust expansion chamber for the Ajax engine features diverging and converging sections of pipe using exhaust pulsations to optimize the scavenging of the power cylinders while providing a substantial increase in fresh air trapped in the cylinder. The results are improved performance and cooler combustion, which reduce the NOx levels up to 60%. For additional information see: (http://cameronscompressionsystems.blogspot.com/2009/10/ajax-integral-engine-compressors.html) (http://www.coopercameron.com/images/File/AJAX_brochure-vf2.pdf)

Cameron also offers retrofit NOx reduction systems for many Cooper Bessemer engines. Depending upon the model, the retrofits may include electronic fuel injection, pre-chambers with electronic check valves, and improved intake and exhaust systems. For certain models Cameron may also redesign the cylinder head to allow for leaner combustion and improving combustion stability. For additional information see: http://cameronscompressionsystems.blogspot.com/2009/10/cooper-bessemer.html

An internet search identified a couple of documents discussing the results of NOx reduction combustion control projects or studies for two stroke lean burn engines, including some limited cost estimates. The information from this search is discussed below:

- In a 2011 presentation, Available Emission Reduction Technology for Existing Large Bore Slow Speed Two Stroke Engines, Cameron discussed its ability and experience in retrofitting low-NOx combustion modifications for large bore 2-stroke lean burn engines. In the document Cameron discussed a recent (2010) retrofit project that incorporated the use of high pressure fuel injection, turbocharging, pre-combustion chambers, and cylinder head modifications to attain a NOx emissions rate of 0.5 g/bhp-hr with an operating range of 80% for both engine speed and torque output. In this presentation Cameron further provided estimates for the cost of achieving similar NOx emission rates for several makes, models and output ratings of two stroke lean burn engines. The engines identified by Cameron in this estimation ranged from 200hp 6-cylinder engines to 11,000hp 20-cylinder engines. The estimated project costs ranged, depending upon make/model/output, from $4.3 million per engine to $1.9 million per engine, or from a low of $162,500 per cylinder to a high of $466,667 per cylinder, or from a low of $245 per rated hp to a high of $1400 per rated hp. This information shows the variability associated with NOx reduction efforts required for the various makes/models/outputs of the large bore two stroke engines.

- In a document titled "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NOx", dated 5/21/2009, prepared by a technical group for the Pipeline Research Council International, the results were discussed of an evaluation of the costs to attain NOx emission rates of 0.5 g/bhp-hr for legacy natural gas fueled 2-stroke lean burn engines used in pipeline compressor service. For the evaluation, three of the most representative make/models of 2-stroke lean burn integral compressor engines (2250 hp Cooper GMVH-10, 2000 hp Clark TLA-6, 2500hp Cooper GMW-10) were selected for evaluation. The evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring. The document also provided an estimate of the cost range to achieve the 0.5 g/bhp-hr NOx emission rate for each of the subject engines, as follows:

Engine	Output	First Unit Upgrade Cost	Follow On Unit Upgrade Cost
Cooper GMVH-10	2250 hp	$2,050,000 - $2,150,000	$1,850,000 - $1,950,000
Clark TLA-6	2000 hp	$2,850,000 - $2,950,000	$2,550,000 - $2,650,000
Cooper GMW-10	2500 hp	$3,250,000 - $3,350,000	$2,950,000 - $3,050,000

(Source: http://www.coresymposium.com/2010Core/EngineCostStudy.pdf)

The information suggests that most 2-stroke lean burn engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). All of the mentioned retrofit combustion related NOx controls may not be commercially available for all manufacturers and models of 2-stroke lean burn engines. It appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may be greatly problematic or not cost effective. These engine and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects. These types of issues can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The available information suggests that combustion related modifications have the potential to achieve from 60% to 90% reduction in NOx emissions from two stroke lean burn spark ignited reciprocating engines, depending upon the make/model configuration of the engine. This suggests an approximate range of NOx emissions rate of 3.0 g/bhp-hr to 0.5 b/bhp-hr, depending upon the make/model configuration of the engine. The higher rates of NOx emissions reductions, and lower g/bhp-hr rate NOx emissions, are potentially achievable on some of the larger two stroke lean burn engines where NOx reduction systems are available that include layered combustion controls such as improved airflow, improved fuel-air mixing, improved ignition, and upgraded controls. The higher emission rates would tend to be more representative of the two stroke lean burn spark ignited reciprocating engine design and some larger units where layered NOx reduction packages have not been commercialized.

The same information indicates that there is a wide range of estimated costs for installation of combustion related controls with a target NOx emissions rate of 0.5 g/bhp-hr. The estimated range of cost is from $245 per rated horsepower to $1475 per rated horsepower. The range in cost appears to be affected both by the make/model/configuration of the engine and the output rating of the engine.

4.1.4 Discussion of NOx Reduction Capability – Post Combustion Modifications

With regards to post-combustion related NOx reduction retrofits for 2-stroke lean burn natural gas fueled spark ignition engines, the literature suggests that selective catalytic reduction (SCR) is technically feasible to achieve significant NOx emission rate reductions from 2SLB engines, but that there are problems that make SCR installation questionable. The first issue is that the 2SLB engine operation is very sensitive to changes in exhaust pressure, which could be problematic with the retrofit of SCR on existing engines. However, this issue can be alleviated for most units through proper design and sizing of airflow and exhaust components.

Some industry information suggests that the two stroke lean burn spark ignition engine's range of exhaust temperature may be too low for proper SCR operation. In a presentation titled "Challenges in Retrofitting Selective Catalytic Reduction (SCR) Systems to Existing Stationary Natural Gas Fired Engines" that was presented at the October 5, 2011 Gas Machinery Conference, it was stated that applying SCR to pipeline engines is not feasible because the exhaust temperatures are below the operating window for SCR or at a level where the SCR effectiveness is reduced, that the exhaust temperature is below the temperature for reliable decomposition of urea into ammonia, and the effectiveness of SCR has not been demonstrated on the slow speed, large bore, low exhaust temperatures typical of gas pipeline engines. For additional information see:

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http://www.gmrc.org/ckfinder/userfiles/files/GMC%20Conf/Final%20Papers/Challenges%20in%20Retrofitting%20SCR%20Systems.pdf

However, there are a number of organizations that market SCR systems that indicate that their catalysts are capable of effectively operating over a wide range of exhaust gas temperature. Such catalysts would serve to offer considerable flexibility for application to varying makes/models of two stroke lean burn engines, as well as providing flexibility for effective NOx reduction over a range of operating conditions for those engines.

Another stated issue is that many compressor facilities are unmanned and that SCR installations have not been demonstrated in unmanned facilities. Other industry information indicates that while it may be true that there are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location.

Another industry concern that has been stated is that SCRs have not been demonstrated on combustion devices with variable loads. However, SCR manufactures indicate that they offer catalysts that are effective over wide temperature ranges characteristic of a range in engine operating load. Modern controls also have the ability to closely regulate fuel and air flows to ensure combustion gas oxygen and temperature levels at expected levels and to regulate reagent flow, all serving to ensure proper SCR function over a broad range of load.

In a document titled "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NOx", dated 5/21/2009, prepared by a technical group for the Pipeline Research Council International, the results were discussed of an evaluation of the costs to attain NOx emission rates of 0.5 g/bhp-hr for legacy natural gas fueled 2-stroke lean burn engines used in pipeline compressor service. For the evaluation, three of the most representative make/models of 2-stroke lean burn integral compressor engines (2250 hp Cooper GMVH-10, 2000 hp Clark TLA-6, 2500hp Cooper GMW-10) were selected for evaluation. The evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring. The document also briefly discusses using SCR as an alternative to the layered combustion related improvements/retrofits. The document discussed that SCR is a high cost alternative to the combustion related improvements/retrofits, primarily due to the high cost of ongoing reagent consumption. For additional information see:
(http://www.coresymposium.com/2010Core/EngineCostStudy.pdf)

Even though some industry sources indicate that SCR is not a practical or proven NOx reduction technology for two stroke lean burn engines, there are a number of manufacturer's and suppliers that offer SCR systems that may be used on two stroke lean burn engines. Some of the manufacturer and supplier information is provided below:

- Johnson Matthey markets urea based SCR systems that reduce NOx emissions from lean burn natural gas fueled engines by 90% or more. Johnson Matthey offers catalysts with a broad effective operating temperature range to achieve NOx reductions earlier in an engine operating cycle and across a wide engine operating range. For additional information see:
  (http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946)

- Miratech Corporation offers a SCR based NOx reduction system that is advertised to be applicable to lean burn engines used in natural gas compression applications. Miratech indicates that NOx reductions of up to 99% are achievable with their SCR system. For additional information see: http://www.miratechcorp.com/images/data/attachments/0000/0019/SCR_Systems.pdf

- CleanAir Systems offers a SCR system that they advertise as being applicable to lean burn natural gas fired engines, including those utilized for gas compression. CleanAir indicates that their SCR catalyst allows NOx reduction operation in a wide range of temperatures, from approximately 300 degF to approximately 1000 degF. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) Their lean burn engine SCR product is now being referred to as E-Pod SCR. CleanAir indicates that their lean burn engine capable SCR achieves up to 95% reduction in NOx emissions across a wide range of exhaust temperatures. For additional information see: http://www.cleanairsys.com/products/hybrids/index.htm

Information from the Manufacturers of Emission Controls Association (MECA) indicated that there have been some limited examples of SCR being retrofit on two stroke lean burn engines as part of demonstration test programs, but that the results of these test programs have never been published. MECA indicated that there have been several demonstrations conducted by independent laboratories where SCR was retrofitted on such two-stroke, lean-burn natural gas spark ignited reciprocating engines that achieved >90% reduction in NOx. It was indicated that SCR retrofits were a challenge on some two stroke lean burn engines because of the relatively low exhaust temperatures on some of the older 2-stroke engines. However, MECA indicated that more modern SCR systems operate over a much broader operating range, and some of MECA's members have formulated catalysts specifically for these large two-stroke engines and demonstrated their effectiveness down to exhaust temperatures as low as 250^{o}C and as high as 550^{o}C. MECA stated that a NOx emissions rate of around 0.5 g/bhp-hr would more closely represent the capability of SCR achieving a 90% reduction in NOx emissions from two stroke lean burn spark ignited reciprocating engines.

It also appears that installation of SCR may be a beneficial NOx control technology on two stroke lean burn spark ignition reciprocating engines that have previously been modified with combustion related controls to moderately reduce the engine's NOx emission rate. The "reduced engine out" NOx emission rate, combined with the NOx control capability of SCR, may achieve NOx emission rates of 0.5 g/bhp-hr or less.

From the available information it appears that SCR systems potentially applicable to two stroke lean burn reciprocating engines are available from several suppliers. It also appears that one of the main drawbacks at this time is that there are no public demonstration projects or completed projects in commercial operation to prove the viability of SCR in this service. As of the preparation of this document, we are unaware of installations of SCR controls in this application.

From the available information it appears that the use of SCR for NOx control does not appear to be technically infeasible generically, but that individual two stroke lean burn reciprocating engine characteristics and installations may be greatly problematic or not cost effective. This "site specific" issue is not altogether any different than other types of emission reduction technologies, and can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

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Without the benefit of information from actual installations or comprehensive engineering evaluations, it is difficult to definitively identify a range of NOx emissions reduction possible from installation of SCR on two stroke lean burn spark ignition reciprocating engines. The information from SCR suppliers and MECA suggests that, for two stroke lean burn reciprocating engines, SCR may be capable of achieving approximately 90% reduction in NOx emissions, giving a potential range of NOx emissions rates of 0.5 g/bhp-hr to 1.0 g/bhp-hr.

Likewise, without the benefit of information from actual installations or comprehensive engineering evaluations, it is difficult to provide any range of costs regarding installation of SCR on the variety of two stroke lean burn spark ignited reciprocating engines. However, the "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NOx" document provided some capital cost information related to the installation of SCR on two stroke lean burn engines with the intent of approaching a NOx emissions rate of 0.5 g/bhp-hr. (The document points out that some combustion related NOx emission reductions may be required to help the primary SCR NOx control to achieve an overall 0.5 g/bhp-hr NOx emission rate.) For the nominal 2000 hp to 2500 hp two stroke lean burn reciprocating engines evaluated in the ERLE document, the document indicates that capital cost estimates for SCR would be in the range of $740,000 to $890,000. The document also estimated annual reagent costs in excess of $120,000 for these SCR systems.

4.1.5 Two Stroke Lean Burn Spark Ignition Reciprocating Engine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available NOx reduction technologies applicable to natural gas fueled, spark ignited, lean burn reciprocating engines. The information suggests that most of these engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). The industry information also indicates that there are technically feasible, commercially available post-combustion (SCR) NOx reduction systems available for use on these same engines. However, some of the combustion related and post combustion NOx controls may not be commercially available for all manufacturers and models of two stroke lean burn spark ignited reciprocating engines.

From the industry information it appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may impact controls installation such that the installations are operationally problematic or not cost effective. These engine design and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects, and can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The information therefore seems to support NOx emission rate limits of as low as 0.5 g/bhp-hr for many two-stroke lean burn spark ignition reciprocating engines with a nameplate rating of 250 hp or above, providing that there is consideration of individual engine design and site specific flexibility provisions. For two stoke lean burn engines with nameplate ratings below 250 hp, the available industry information indicates NOx emission rate limits of around 3 g/bhp-hr for some of the existing popular

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make/model combinations. Again, this could be addressed with appropriate rule or regulation consideration of individual engine design and site specific flexibility provisions.

Very little information was found regarding the cost of purchase and installation of combustion related and post-combustion NOx controls for two stroke lean burn engines. The following summarizes the limited information:

Type of NOx Control	Engine Size Range (hp)	Estimated Range of NOx Reduction (%)	Estimated Range of NOx Emissions Rate (g/bhp-hr)	NOx Control Estimated Costs ($)
Layered Combustion	100 - 250	60 - 90	3 - 0.5	182,000 - 456,000
Layered Combustion	2000 - 2500	90	0.5	2,175,000 - 3,554,000
SCR	2000 - 2500	90	0.5	1,050,000 - 1,210,000

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on information from "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NOx" document, adjusted for CPI.)

It should be noted that the range of costs, especially for the combustion related NOx control modifications, is more representative of the diversity of the modifications that might be required to attain the NOx emission rate limits rather than a function of the nameplate rating of the engine. This is due to the fact that some engines may require complete new turbocharger systems with related auxiliaries, while some may require relatively modest modifications to existing induction systems, some may require new precombustion chamber (PCC) combustion ignition systems while others may require only minor improvements, etc. These differences can exist across the range of four stroke lean burn engine nameplate ratings. As discussed earlier, applicability and effectiveness of a given NOx control technology to a particular engine may vary by engine make, model, vintage, location, and operating characteristics.

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4.2 Reciprocating Engines - Four Stroke Lean Burn Spark Ignition Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Spark ignition engines use a spark (across a spark plug) to ignite the compressed fuel-air mixture to create the motive force.

Four-stroke spark ignition reciprocating engines use a separate engine revolution for the intake/compression stroke and the power/exhaust stroke. Four-stroke engines complete the combustion cycle in two revolutions of the crankshaft. Each of the piston's four strokes has an important function in the engine cycle (intake, compression, power and exhaust). These engines have intake and exhaust valves to introduce combustion air into the cylinder and exhaust combustion gases from the cylinder. Most four-stroke spark ignition reciprocating engines use open-chamber spark plugs to ignite the air/fuel mixture, and can be configured to operate as rich- or lean burn, depending on the air/fuel mixture. These reciprocating engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or utilize a supercharger or turbocharger to pressurize the inlet air/fuel charge.

Lean-burn four-stroke spark ignition engines usually have a fuel injection system that injects the fuel near the intake valves or in the power head. They use either open-chambered spark plugs or pre-combustion chamber ignition systems to assure ignition of the lean mixture. Lean burn spark ignited reciprocating engines are often fitted with a mechanically driven blower or turbocharger to supply the required combustion air. Lean burn engines have higher oxygen levels in the combustion chamber (and exhaust), which decreases the combustion temperature and thereby reducing the amount of NOx that is formed during combustion. Because the air-to-fuel ratio is lean with fuel, less fuel is used, which results in decreased combustion temperatures, decreased engine power, and increased engine efficiency relative to a rich burn engine.

Some lean burn four-stroke spark ignited reciprocating engines can be modified to operate with very fuel lean mixtures, further reducing NOx emissions, up to the point where engine misfire becomes a problem. Combustion improvements such as high energy ignition, pre-chamber combustion, and improved fuel mixing may be incorporated on four-stroke engines to facilitate the use of very fuel lean mixtures before engine misfires are encountered.

There are many four stroke lean burn (4SLB) spark ignition reciprocating engines in service, representing a number of different manufacturers, model numbers, and a range of output ratings.

4.2.1 Four Stroke Lean Burn Spark Ignition Engine NOx Controls

Industry literature indicates that there are a number of methodologies that are commercially available to help control NOx emissions from four-stroke lean burn spark ignition reciprocating engines, most of which are related to efforts to acceptably operate with very lean air/fuel mixtures. While most of the technologies are generically applicable to most of the existing four-stroke lean burn reciprocating engines, application on any specific make/model of engine may present unique circumstances that may affect the effectiveness of the control and the cost of installation on that particular engine.

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When an engine's air/fuel mixture is leaned to achieve NOx emissions reductions, the amount of spark energy required from the ignition system to start combustion is increased. High energy ignition systems are applicable to most lean burn engines that are not already equipped with such a system. The high energy ignition system is generally a conventional open-chamber system with the spark plug (or plugs) generally located with the spark plug protruding from the bottom of the combustion cylinder head into the combustion chamber. High energy ignition systems allow more energy to be delivered to the spark plug(s) with a larger gap, thereby increasing the spark energy delivered to the air/fuel mixture and ensuring proper ignition. High energy ignition systems may be digitally controlled systems that use crankshaft referenced angle encoders to deliver precise, high energy ignition sparks. These high energy ignition systems may have the capability to generate multiple, successive sparks during combustion to ensure proper air/fuel light- off. Modern high energy ignition systems tend to reduce misfires and engine detonation, and provide a more stable combustion over an engine's entire operating range. Industry information indicates that a slight NOx emissions reduction, approximately 10%, can be achieved through application of a high energy ignition system on an engine that does not have an existing high energy ignition system.

Another methodology for controlling NOx emissions is by improving the combustion air flow characteristics of the engine. Increasing the air flow tends to produce a leaner air/fuel mixture, reducing the peak combustion temperature which tends to reduce NOx emissions. For some engine designs, this may be accomplished by varying the engine load or increasing the engine speed (if within the manufacturer's limits). The air flow of many engines can be increased by converting non-turbocharged engines to incorporate a turbocharger system, modifying or upgrading existing turbocharger systems on engines already incorporating turbochargers, or other unit-specific means to supply combustion air or scavenge the cylinder of combustion products. Turbocharger additions or upgrades often also require upgrades to the rest of the air intake and exhaust systems to accommodate and optimize the new or upgraded turbochargers. Additionally, a turbocharger installation or upgrade may be optimized through the use of intake/combustion air cooling systems. Industry information indicates that, depending upon the degree of upgrade, NOx emissions reductions of up to 75% may be expected for the addition of properly engineered turbocharger systems with intake /combustion air cooling.

Enhanced air-fuel mixing technologies are another method of achieving NOx emissions reductions. The design of some four-stroke engines exhibit problems with the ability to thoroughly mix combustion air and fuel. For these engines, the combustion air and fuel may not be introduced for mixing until each has entered the combustion cylinder. The combustion air and fuel mix as the fuel is "sprayed" into the combustion air already in the cylinder. For some engine designs, the air and fuel mixing results in a non-homogeneous mixture that can cause a sporadic and unstable burning process as the flame burns through the cylinder filled with different regions of differing air/fuel mixtures. To improve the mixing process, the fuel supply system and components can be converted to utilize higher fuel injection pressures that force a more rapid and turbulent interaction between the combustion air and fuel and result in a more homogeneous mixture. Industry information indicates that increasing the pressure at which the fuel is injected, and directing the dispersion of the fuel during injection, can significantly reduce emissions and fuel consumption. Industry information indicates that relative to an older low pressure fuel injection system, a well engineered high pressure fuel injection system may be able to facilitate NOx emissions reductions of up to 90% in some engines.

As mentioned above, leaner air/fuel ratios have a tendency to help reduce NOx emissions. However, as the air/fuel ratio is further leaned to attain lower NOx emission rates, the extremely lean air/fuel

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mixtures become more difficult, if not impossible, to ignite using a standard open-chamber spark plug ignition system. In these cases, a combustion pre-chamber (typically less than 10 percent of the volume of the main chamber) may be installed in the power cylinder head and fitted with a conventional spark plug in the pre-chamber. The fuel supply system is modified to inject fuel into the pre-chamber as well as the main power chamber. During the intake process, the pre-chamber is charged with a richer air/fuel mixture than the main chamber. This richer pre-chamber combustion mixture is more easily ignited by the sparkplug. As the pre-chamber combustion mixture burns, the pressure of the combustion pushes the burning mixture into the main power chamber, igniting the main power chamber's lean air/fuel mixture. Industry information indicates that the use of ignition pre-chambers may facilitate NOx reductions capabilities of up to 90% in some four stroke spark ignited reciprocating engines.

Modern electronic engine controls also may be utilized to facilitate the NOx reduction benefits of the above modifications. This is especially true for varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. One type of control device is referred to as an air/fuel ratio controller. Some of these air/fuel ratio controllers utilize mathematical models to monitor certain engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating conditions. By tracking and maintaining the "correct" air/fuel mixture, the engine runs clean and more efficiently. In this way, the engine is more capable of maintaining NOx emissions compliance even with changing operating conditions and changes in ambient conditions.

Another potential NOx reduction technology for four-stroke lean burn spark ignited reciprocating engines is the use of exhaust gas recirculation (EGR). EGR systems utilize hardware changes to recirculate engine exhaust gases into the combustion chamber of the engine as an inert substitute for the excess air normally supplied in lean burn reciprocating engine operation. EGR allows the combustion chamber to operate as if it were a rich burn engine and, since no excess oxygen is present in the exhaust, a much less expensive nonselective reduction catalyst (NSCR) can be used when post-combustion NOx controls are needed to meet the most stringent NOx emissions standards. NOx emissions rates from an EGR and NSCR equipped engine can be as low as, or lower than, a lean burn engine equipped with a selective catalytic reduction (SCR) system. Several independent companies have installed retrofit systems on existing natural gas engines and have reported some success in meeting very low emissions requirements during initial and limited field testing. Engine performance and fuel efficiency are reported to be the equivalent of standard lean burn engines yet are still able to utilize NSCR for meeting stringent NOx emissions limitations. This NOx control strategy has yet to achieve widespread acceptance in a retrofit application.

Selective catalytic reduction (SCR) is a post-combustion NOx control that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the engine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) passes over a catalyst to help convert the NOx, hydrocarbons, and CO into water, nitrogen and CO_2. Catalyst selection is somewhat based on the expected temperature range of the engine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control may facilitate NOx reductions of up to 95%.

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4-Stroke Lean Burn Spark Ignition Engine NOx Control Retrofit Technology	**Potential NOx Reduction**
High Energy Ignition System	10%
Intake Air Upgrade (turbocharger, etc)	60% - 70%
Improved Mixing (high pressure fuel injection)	90%
Pre-Combustion Chamber Ignition System	90%
SCR Catalyst	50% - 95%

4.2.2 Example Existing Rules and Regulations – 4SLB

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from http://aqmd.gov/rules/download.html)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp≥500	36 ppmvd NOx (*approximately 0.5 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2010	
Nameplate - Bhp≥500	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California – California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for lean burn engines with nameplate ratings greater than 50 hp and not used for agricultural operations include:

Two-stroke lean burn, gas fueled, < 100hp	75 ppmvd NOx
Lean burn limited use	65 ppmvd NOx
Lean burn used for gas compression	65 ppmvd NOx
Lean burn – all others	11 ppmvd NOx

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(Note that the San Joaquin Valley Air Pollution Control District's Rule 4702 definition of limited use requires the engine have a permit restricting the engine's operation to no more than 4000 hrs/yr.)

Colorado - The state of Colorado's Air Quality Control Commission has established NOx emissions limitations for stationary internal combustion reciprocating engines in its Regulation 7, Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides). Colorado's Regulation 7 has no NOx emissions limitations applicable to existing lean burn engines.

However, Colorado's Regulation 7 does include NOx emissions limitations applicable to lean burn engines that are new, modified, or relocated stationary natural gas fueled reciprocating internal combustion engines, as follows:

Engine Nameplate	**Manufacture Date**	**NOx Emissions Limit**
Nameplate-100≤Bhp<500	Effective January 1, 2008	2 g/bhp-hr
	Effective January 1, 2011	1 g/bhp-hr
Nameplate Bhp≥500	Effective July 1, 2007	2 g/bhp-hr
	Effective July 1, 2010	1 g/bhp-hr

(This Colorado rule may be viewed at http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf)

Texas - The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for 4-stroke lean burn spark ignition engines. The relevant emissions limitations in the rule include the following:

Engine Type	**Manufacture Date**	**NOx Emissions Limit**
Four stroke, lean burn SI-BHP<500	Mfg before 7/1/2008 (After 1/1/2030, no 4SLB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.)	2g/bhp-hr
Four stroke, lean burn SI-BHP≥500	Mfg before 9/23/1982	5g/bhp-hr (exc 8 g/bhp-hr at reduced speed and torque 80%<>100%)
	Mfg before 6/18/92 & BHP<825	5g/bhp-hr (exc 8 g/bhp-hr at reduced speed and torque 80%<>100%)
	9/23/1982≤Mfg<6/18/1992&BHP>825	5g/bhp-hr
	6/18/1992≤Mfg<6/1/2010	2g/bhp-hr (exc 5 g/bhp-hr at reduced speed and torque 80%<>100%)
	Mfg on or after 6/1/2010	1/g/bhp-hr

(After 1/1/2030, no 4SLB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.)

(This Texas rule can be reviewed at: http://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf).

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone Non Attainment Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for natural gas fueled lean burn spark ignition reciprocating engines as follows:

Gas Fueled Lean Burn SI Engine ≥ 300 bhp	3.0 g/bhp-hr

Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to all spark ignition internal combustion engines and other air contamination sources at natural gas production and processing facilities. In the proposed GP-5, existing rich and lean burn engines with a nameplate rating of less than or equal to 100 horsepower, but less than 1500 horsepower, will be required to continue to meet the existing GP-5 NOx emissions limit of 2 g/bhp-hr. When the currently proposed GP-5 becomes effective, new and reconstructed engines will be required to meet the following NOx emissions limits:

Configuration	**NOx Limit**
New and reconfigured Lean Burn Engine ≤ 100hp	2 g/bhp-hr
New and reconfigured Lean Burn Engine 100< hp ≤ 637	1 g/bhp-hr
New and reconfigured Lean Burn Engine > 637hp	0.5 g/bhp-hr

The USEPA established NOx emissions limitations for natural gas fueled lean burn spark ignition engines in 40 CFR Part 60, Subpart JJJJ (NSPS) (1/18/08 73 FR 3567). The applicable NOx emissions limits for lean burn natural gas-fueled, spark ignition engines are as follows:

Engine Type	**Output Rating**	**Manufacture Date**	**NOx Emissions Limit**
SI Nat. Gas Lean Burn	500≥HP<1350	mfg after 7/1/2008	2.0 g/HP-hr
SI Nat. Gas Lean Burn	500≥HP<1350	mfg after 7/1/2010	1.0 g/HP-hr

4.2.3 Discussion of 4-Stroke Lean Burn NOx Reduction Capability – Combustion Controls

With regards to the NOx reduction capabilities of combustion modifications for four stroke lean burn spark ignited reciprocating engines, the literature suggests that there are often significant differences in design characteristics between four stroke lean burn reciprocating engine manufacturers' designs such that applicability and effectiveness of generic NOx combustion controls is highly variable. The literature

suggests that this is sometimes due to the air/fuel mixing characteristics and patterns in the engine cylinders that were employed by the manufacturer in the design of the particular engine model. This would indicate that there is also the likelihood of differences between a given manufacturer's engine models and vintage that could affect the applicability and effectiveness of a given NOx control combustion control technology. For some of the more popular or numerous makes and models, the original manufacturer or an aftermarket vendor may offer effective "off-the-shelf" NOx reduction retrofit packages that help reduce the cost of NOx reduction for those makes and model engines. For other engines, only limited support may be available which could require custom design, installation, and tuning of NOx controls that would tend to increase the cost of the NOx emissions reduction project and possibly impact the overall effectiveness of the project.

Other characteristics may also affect the reduction effectiveness, and the cost effectiveness, of a NOx emissions reduction project on any particular engine, such as frequency of startups and shutdowns, operational loading characteristics, location, (altitude, seasonal variations), etc. Variability also potentially exists from installation to installation due to equipment clearances, etc.

The information suggests that most four stroke lean burn spark ignited reciprocating engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). These (or some of these) modifications/upgrades may represent a generic NOx reduction strategy with the potential of reducing NOx emission rates by up to 90% from uncontrolled by facilitating operation with very lean fuel air mixtures. All of the mentioned retrofit NOx controls may not be commercially available for all manufacturers and models of gas compressor four stroke lean burn engines. The actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. These modifications/upgrades also offer the possibility of improving the four stroke lean burn spark ignited reciprocating engine's efficiency.

There are a number of manufacturers and suppliers that provide components, systems, and services to support combustion related NOx emission reductions from four stroke lean burn engines. Some of these organizations include the following:

- Windrock offers an autobalance system that automatically balances the cylinder-to-cylinder combustion in multi-cylinder slow speed integral engines such as Cooper-Bessemer, Clark/Dresser, Ingersoll-Rand, Worthington, and other two- or four-stroke engines with individual cylinder fuel adjustment valves. The system constantly adjusts fuel flow to each power cylinder in order to maintain peak firing pressures to ± 5% of engine average during differing ambient conditions, varying speeds and changing loads. Eliminating unbalanced operation across all operating conditions enables the engine to run with the minimum possible NOx and facilitates the positive results of other NOx reduction modifications. For additional information see: http://www.cookcompression.com/files/comm_id_68/GMJournal_Q32009_AutoBalance.pdf

- Attainment Technologies company markets gas recirculation systems for NOx control for lean burn spark ignited reciprocating engines. (Gas recirculation as a NOx control for these engines is also being offered by some original equipment manufacturers (OEMs).) With this process, instead of high levels of excess air, re-circulated and cooled exhaust gas is used as a heat sink in the combustion process. High, lean burn reciprocating engine compression ratios can be used without

engine knock complications. Engine performance and fuel efficiency is equivalent to a standard lean burn engine. The advantage compared to traditional lean burn reciprocating engines is the availability of NSCR as an emission after-treatment. This is possible, since there is no excess oxygen in the exhaust stream. Attainment Technologies' literature indicates that retrofitted lean burn engines have achieved NOx emission rates of 0.1 g/bhp-hr in testing using the Attainment Technologies NOx reduction systems. For additional information see: http://www.attainmenttech.com/solutions.html

- Dresser-Rand, a reciprocating engine OEM, offers a retrofit NOx emission technology system for many engine models, including four stroke lean burn spark ignited reciprocating engines. While somewhat dependent upon the specific model, the retrofit NOx emission reduction system may include a screw-in combustion pre-chamber high energy ignition system, earlier fuel injection timing and directional fuel injection for improved air/fuel mixing, improved controls for more precise fuel injection and engine timing, and improved air flow to further lean the mixture when applicable. Dresser-Rand also offers more extensive (and expensive) NOx reduction systems for retrofit, which depending upon engine model may include new cylinder heads with pre-combustion chambers, new main fuel gas injection valves, high efficiency turbochargers, a larger turbocharger combustion air intercooler with plenums, a new fuel management system, an air/fuel ratio controller, a new spark controller, new cams and/or camshaft on four-stroke engines, and a high-energy ignition system. Industry literature indicates that Dresser-Rand offers related NOx controls for KVS, KVSR, KVR, KVT, SVS, TVS, and TVR four stroke engines (Dresser-Rand, Ingersoll-Rand). The literature also indicates that NOx emission guarantees of between 2.5 g/bhp-hr and 3.0 g/bhp-hr have been provided with these NOx reduction technologies, and that those guarantees have been consistently met or improved upon. For additional information see: http://dresser-rand.com/service/engineeredsolutions/revamps/recip.php, http://www.dresser-rand.com/techpapers/tp014.pdf

- Dresser Rand also indicates that they have considerable experience in the retrofit of NOx emissions controls across a broad range of existing legacy natural gas compression lean burn reciprocating engines. Their products and systems include a high-pressure fuel injection system, a real-time engine and compressor monitoring platform, high delivery ratio turbochargers designed for the performance requirements of emission reduction packages, a low emissions reduction (LEC) kit and a variety of products designed to reduce emissions while expanding the operating envelope, model-based control strategies that provide operational flexibility, adaptive air/fuel ratio controllers, and catalytic exhaust emissions control systems. Dresser Rand indicates that they have experience in working with a number of engine makes and models, including Caterpillar (3500 Series and 3600 Series), Cooper Bessemer (GMW, GMWA, GMV, GMVH, V-250, W-330, LSV, Quad 12), Clark (BA, HBA, TLA, TCV, TCVA, TCVC, TCVD), Ingersoll Rand (KVG,KVS Series, KVTR, KVGR, LVG, PVG, PSVG, SVG), Nordberg (FSE), White Superior (825, 2416), Wartsilla (18V34SG), Waukesha (3521, 5790, 7042), and Worthington (UTC, UTC-T, Mainliner (ML), Mainliner (MLV)). For additional information see: http://www.dresser-rand.com/service/engineeredsolutions/enginuity/solutions/emissions.php

- Compression Components Texas (CCT) advertises a retrofit kit for Caterpillar G3516 natural gas fueled four stoke lean burn spark ignited reciprocating engines that enable the engine to meet a 0.15 g/hp-hr NOx emission rate limit with little or no loss in engine power. The CCT kit is comprised of a group of combustion related improvements/upgrades and does not incorporate any post-

combustion controls. For additional information see: http://www.compressioncomponentstx.com/-/Low_NOx.html

- Caterpillar offers new lean burn spark ignited reciprocating engines with a wide range of output ratings up to approximately 5000 HP with a broad operating speed range. Caterpillar advertises that many of these engines are capable of achieving NOx emissions limits of 0.5 g/bhp-hr without post-combustion NOx emission controls. For additional information see: http://catoilandgas.cat.com/products/engines

- Dresser Waukesha offers new 12 cylinder and 16 cylinder versions of its 275GL lean burn engine for the gas compression market. The engines are reported to be able to achieve NOx emission rates of less than 0.5 g/bhp-hr, and are rated at 3,625 hp for the 12 cylinder version and 4,835 hp for the 16 cylinder version. For additional information see: http://www.pipelineandgasjournal.com/12-16-cylinder-versions-low-emission-compressor-engine-unveiled

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for lean burn reciprocating engines. Included in this evaluation for lean burn spark ignited reciprocating engines is the installation of a low emissions control (LEC), layered NOx control system. The document indicates that LEC has the capability of reducing NOx emissions from lean burn engines by approximately 80% to 93%. The following summarizes the lean burn spark ignited reciprocating engine evaluation:

Type of Control	Nameplate Rating (HP)	Total Capital Cost (2004 $)
Low Speed LB Layered Comb	500 – 11,000	751,600 – 4,249,700
Med Speed LB Layered Comb	500 – 11,000	130,300 – 2,149,300

For additional information see: http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf

The industry information suggests that most four stroke lean burn spark ignited reciprocating engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). All of the combustion related NOx controls may not be commercially available for all manufacturers and models of four stroke lean burn spark ignited reciprocating engines. It appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may be greatly problematic or not cost effective. These engine and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects. These types of issues can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The available information suggests that retrofit combustion related modifications have the potential to achieve an approximate 90% reduction in NOx emissions from most four stroke lean burn spark ignited engines, given potential variability between engine designs. This suggests an approximate range of NOx emissions rate of 0.5 g/bhp-hr to 2.0 g/bhp-hr from otherwise uncontrolled lean burn spark ignited reciprocating engines, depending upon the make/model configuration of the engine.

The industry information also indicates that there is a wide range of estimated costs for installation of combustion related controls with a target NOx emissions rate of 0.5 g/bhp-hr. One source of information estimated a range of cost is from $245 per rated horsepower to $1475 per rated horsepower. The range in cost appears to be affected more by the make/model/configuration of the engine rather than strictly by the size of the engine. Some reasons for this include that some engines will require the installation of new turbocharger and auxiliaries, some engines will require relatively easy upgrades to existing turbochargers and auxiliaries, some engines will require head modifications to accept pre-combustion chamber ignitions while others can utilize screw in pre-combustion chamber ignition systems, etc.

4.2.4 Discussion of 4-Stroke Lean Burn NOx Reduction Capability – Post Combustion Controls

With regards to the NOx reduction capabilities of post combustion modifications for four stroke lean burn spark ignited reciprocating engines, the literature suggests that SCR is technically feasible to achieve significant NOx emission rate reductions from four stroke lean burn engines. However, some industry trade organizations indicate that there are problems that make the installation and successful operation of SCR questionable.

In a presentation titled "Challenges in Retrofitting Selective Catalytic Reduction (SCR) Systems to Existing Stationary Natural Gas Fired Engines" that was presented at the October 5, 2011 Gas Machinery Conference, it was stated that applying SCR to pipeline engines is not feasible because the exhaust temperatures are below the operating window for SCR or at a level where the SCR effectiveness is reduced, that the exhaust temperature is below the temperature range for reliable decomposition of urea into ammonia, and the effectiveness of SCR has not been demonstrated on the slow speed, large bore, low exhaust temperatures typical of gas pipeline reciprocating engines. For additional information see:
http://www.gmrc.org/ckfinder/userfiles/files/GMC%20Conf/Final%20Papers/Challenges%20in%20Retrofitting%20SCR%20Systems.pdf

However, there are a number of organizations that market SCR systems that indicate that their catalysts are capable of effectively operating over a wide range of exhaust gas temperature. Such catalysts would serve to offer considerable flexibility for application to varying makes/models of four stroke lean burn engines, as well as providing flexibility for effective NOx reduction over a range of operating conditions for those engines.

Another stated issue with the use of SCR for four stroke lean burn spark ignition reciprocating engines is that many compressor facilities are unmanned and that SCR installations have not been demonstrated in unmanned facilities. Other industry information indicates that while it may be true that there are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location.

It has also been stated by the gas industry that SCRs have not been demonstrated on combustion devices with variable loads. SCR manufacturers offer catalysts that are effective over wide temperature

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ranges characteristic of a range in engine operating load. Modern controls also have the ability to closely regulate fuel and air flows to ensure combustion gas oxygen and temperature levels at expected levels and to regulate reagent flow, all serving to ensure proper SCR function over a broad range of load.

The industry trade organizations have also pointed out that many compressor locations are remote and do not include immediate access to an electric supply capable of handling the pumps, etc that are necessary for an SCR system. While this may be a true statement, not all compressor facilities are without access to electric supply resources. Further, any rules or regulations that support NOx emissions limits based on SCR NOx removal capabilities could be configured to offer alternatives for sites with acceptable justification for being unable to attain those limits.

The Manufacturers of Emission Controls Association (MECA) has stated that the commercial use of SCR systems for the control of NOx emissions from lean-burn stationary engines has been in place since the mid-1980s in Europe and since the early 1990s in the US. According to MECA, since 1995, one MECA member company has installed over 400 SCR systems worldwide for stationary engines with varying fuel combinations, including dozens of natural gas powered compressor engines at sites in the US. MECA indicated that these four stroke lean burn gas compressor engines equipped with urea-SCR achieved in excess of 90% reduction in NOx emissions. Comments from MECA indicate that their member experience is that NOx emission rates of 0.2 g/hp-hr to 0.5 g/hp-hr are representative of modern SCR technology on these engines.

Even though some industry sources indicate that SCR is not a practical or proven NOx reduction technology for four stroke lean burn spark ignition reciprocating engines, the information suggests that SCR is not technically infeasible from a generic standpoint. There are a number of manufacturers and suppliers that offer SCR systems that may be used on four stroke lean burn spark ignited reciprocating engines. Some of the manufacturer and supplier information is provided below:

- EF&EE (Engines, Fuel & Emissions Engineering Incorporated) announced on November 10, 2010, that it had received an order from Clean Air Power, Inc. for six SCR reductant metering and control systems. These systems were due to be delivered by the end of 2010, to be installed on large, lean-burn natural gas compressor engines at gas storage sites in Texas and Mississippi. For additional information see: http://www.efee.com/news.html

- EF&EE, on November 22, 2010, also announced Compact SCR(tm) system that enables conventional lean-burn natural gas and biogas engines to meet the California ARB Distributed Generation standard of 0.07 pounds of NOx per megawatt-hour. For additional information see: http://www.efee.com/news.html

- Caterpillar literature indicates that they offer SCR systems for many of their lean burn spark ignition reciprocating engine models, for both new engine installations and existing engine retrofits. Caterpillar indicates that NOx reductions of up to 95% are possible utilizing SCR.

- Johnson Matthey markets urea based SCR systems that reduce NOx emissions from lean burn natural gas fueled engines by 90% or more. Johnson Matthey offers catalysts with a broad effective operating temperature range to achieve NOx reductions earlier in an engine operating cycle and across a wide engine operating range. For additional information see: (http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946)

- CleanAir Systems offers a SCR system that they advertise as being applicable to lean burn natural gas fired engines, including those utilized for gas compression. CleanAir indicates that their SCR catalyst allows NOx reduction operation in a wide range of temperatures, from approximately 300 degF to approximately 1000 degF. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) Their lean burn engine SCR product is now being referred to as E-Pod SCR. CleanAir indicates that their lean burn engine capable SCR achieves up to 95% reduction in NOx emissions across a wide range of exhaust temperatures. For additional information see: http://www.cleanairsys.com/products/hybrids/index.htm

- Clean Air Power has a case study, dated 3/4/2009, indicating that they had supplied four SCR units (in 2006, with an additional 2 ordered for 2009 delivery) for emissions control of natural gas fueled spark ignition reciprocating engines at the Pine Prairie Energy Center, a salt cavern natural gas storage facility in Louisiana. FERC information indicates that the Pine Prairie Energy Center was incorporating six Caterpillar G16CM34 reciprocating engines, each rated 8,100 HP. For additional information see: http://www.cleanairpower.com/emissionCasestudies.php?mode=details&libraryId=2&start=0&caseId=TXpVPQ

- Clean Air Power has a case study, dated 3/4/2009, indicating that they had supplied an SCR unit for a Caterpillar G3616 natural gas engine located at the salt cavern natural gas storage/hub services facility EXTERRAN/TRESPALACIOS in Texas. For additional information see: http://www.cleanairpower.com/emissionCasestudies.php?mode=details&libraryId=2&start=0&caseId=TXpZPQ==

- Clean Air Power has a case study, dated 3/4/2009, indicating that they were involved in a project that would include supplying four SCR units for natural gas fueled Caterpillar G3616 engines at the EXTERRAN / LEAF RIVER facility in Mississippi. This facility is a salt cavern natural gas storage and delivery site. For additional information see: http://www.cleanairpower.com/emissionCasestudies.php?mode=details&libraryId=2&start=0&caseId=TXpnPQ==

- Miratech Corporation offers a SCR based NOx reduction system that is advertised to be applicable to lean burn engines used in natural gas compression applications. Miratech indicates that NOx reductions of up to 99% are achievable with their SCR system. For additional information see: http://www.miratechcorp.com/images/data/attachments/0000/0019/SCR_Systems.pdf

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for lean burn reciprocating engines. Included in this evaluation for lean burn engines is the application of SCR for NOx control. The document indicates that SCR has the capability of reducing NOx emissions from lean burn engines by approximately 90%. The following summarizes the lean burn engine SCR evaluation:

Type of Control	Nameplate Rating (HP)	Total Capital Cost (2004 $)
Lean Burn SCR	550 – 11,000	457,500 – 1,451,000

For additional information see: http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf

In support of its development of Rule 4702, Internal Combustion Engines Phase 2, in 2003 the San Joaquin Valley Air Pollution Control District prepared a cost effectiveness analysis for the retrofit installation of SCR on natural gas fueled lean burn spark ignited internal combustion engines. The analysis was performed for a range of engine output ratings. The analysis assumed the installation would achieve compliance with a proposed NOx emissions rate limit of 65 ppmvd @15% O2 (approximately 0.89 g/bhp-hr). The results of the analysis for lean burn spark ignition engines is summarized below:

Lean Burn Engine SCR NOx Reduction Control Installation Cost Estimation

Nameplate Rating (hp)	SCR Installed Cost ($)	Annual O&M Cost ($)	Annualized Cost ($)	25% Cap Fact Cost Effectiveness ($/ton)	75% Cap Fact Cost Effectiveness ($/ton)
50	45000	20102	27424	24593	8198
200	45000	26102	33424	7493	2498
500	60000	35102	44864	4023	1341
1000	149000	78102	102344	4589	1530
1500	185000	117102	147202	4400	1467

Note: Annualized cost based on 10 year life and 10% interest.
NOx reductions based on 9.55 g/bhp-hr pre-installation and 0.37 g/bhp-hr post-installation.
For a additional information see:
http://www.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf

4.2.5 Four Stroke Lean Burn Spark Ignition Reciprocating Engine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available NOx reduction technologies applicable to natural gas fueled, spark ignited, lean burn reciprocating engines. The information suggests that most of these engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). The industry information also indicates that there are technically feasible, commercially available post-combustion (SCR) NOx reduction systems available for use on these same engines, with MECA indicating that NOx emission rates in the range of 0.2 g/hp-hr to 0.5 g/hp-hr being achievable utilizing SCR on these engines. However, some of the combustion related and post combustion NOx controls may not be commercially available for all manufacturers and models of four stroke lean burn spark ignited reciprocating engines.

From the industry information it appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may impact controls installation such that the installations are operationally problematic or not cost effective. These engine design and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects, and can usually be

addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The information therefore seems to support NOx emission rate limits of as low as 0.5 g/bhp-hr for many four-stroke lean burn spark ignition reciprocating engines with a nameplate rating of 250 hp or above, providing that there is consideration of individual engine design and site specific flexibility provisions. For four stoke lean burn spark ignited reciprocating engines with nameplate ratings below 250 hp, the available industry information indicates NOx emission rate limits of around 3 g/bhp-hr for some of the existing popular make/model combinations. Again, this could be addressed with appropriate rule or regulation consideration of individual engine design and site specific flexibility provisions.

Very little information was found regarding the cost of purchase and installation of combustion related and post-combustion NOx controls for four stroke lean burn engines. The following summarizes the limited information:

Type of NOx Control	Engine Size Range (hp)	Estimated Range of NOx Reduction (%)	Estimated Range of NOx Emissions Rate (g/bhp-hr)	NOx Control Estimated Costs ($)
Layered Combustion	100 - 250	60 - 90	0.5 - 3	182,000 - 456,000
Layered Combustion	500 - 11000	90	0.5	143,000 – 4,666,000
SCR	2000 - 2500	90	0.2 - 0.5	502,000 – 1,593,000

Note: Estimated control costs are initial capital cost estimates only. Costs are based on Illinois' "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines", adjusted for CPI.

It should be noted that the range of costs, especially for the combustion related NOx control modifications, is more representative of the diversity of the modifications that might be required to attain the NOx emission rate limits rather than a function of the nameplate rating of the engine. This is due to the fact that some engines may require complete new turbocharger systems with related auxiliaries, while some may require relatively modest modifications to existing systems, some may require new PCC combustion ignition systems while others may require only minor improvements, etc. These differences can exist across the range of four stroke lean burn spark ignited reciprocating engine nameplate ratings. As discussed earlier, applicability and effectiveness of a given NOx control technology to a particular engine may vary by engine make, model, vintage, location, and operating characteristics.

4.3 Reciprocating Engines - Four Stroke Rich Burn Spark Ignition Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Spark ignition engines use a spark (across a spark plug) to ignite the compressed fuel-air mixture to create the motive force.

Four-stroke spark ignition reciprocating engines use a separate engine revolution for the intake/compression stroke and the power/exhaust stroke. Four-stroke reciprocating engines complete the combustion cycle in two revolutions of the crankshaft. Each of the piston's four strokes has an important function in the engine cycle (intake, compression, power and exhaust). These engines have intake and exhaust valves to introduce combustion air into the cylinder and exhaust combustion gases from the cylinder. Most four-stroke spark ignition reciprocating engines use open-chamber spark plugs to ignite the air/fuel mixture. These engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or utilize a supercharger or turbocharger to pressurize the inlet air/fuel charge.

Rich-burn four-stroke spark ignited reciprocating engines are configured to operate at or near a stoichiometric air/fuel ratio with little or no excess air. The engines can be carbureted or fuel injected, and they use the intake stroke of the piston to draw air into the cylinder (naturally aspirated). Manufacturers have added superchargers and turbochargers to increase the delivery of combustion air, which increases horsepower output capability. Because the air-to-fuel ratio is rich with fuel, more fuel is used, which results in increased combustion temperatures, increased engine power, and decreased engine efficiency relative to a lean burn engine.

There are a number of four stroke rich burn (4SRB) spark ignition reciprocating engines in service in the oil and gas sector, representing several manufacturers and model numbers.

4.3.1 Four Stroke Rich Burn Spark Ignition Engine NOx Controls

Industry literature indicates that application of high energy ignition systems on rich burn spark ignited reciprocating engines has the potential of resulting in modest NOx emissions by providing a more stable combustion over an engine's entire operating range. The high energy ignition system is generally a conventional open-chamber system with the spark plug (or plugs) generally located with the spark plug protruding from the bottom of the combustion cylinder head into the combustion chamber. High energy ignition systems allow more energy to be delivered to the spark plug(s) with a larger gap, thereby increasing the spark energy delivered to the air/fuel mixture and ensuring proper ignition. High energy ignition systems may be digitally controlled systems that use crankshaft referenced angle encoders to deliver precise, high energy ignition sparks. These high energy ignition systems may have the capability to generate multiple, successive sparks during combustion to ensure proper air/fuel light- off. Modern high energy ignition systems tend to reduce misfires and engine detonation, and provide a more stable combustion over an engine's entire operating range. Industry information indicates that a slight NOx emissions reduction, approximately 10%, can be achieved through application of a high energy ignition system on an engine that does not have an existing high energy ignition system.

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Non Selective Catalytic Reduction (NSCR) is an effective NOx reduction technology for rich burn spark ignited reciprocating engines that exhibit low levels of excess oxygen in the exhaust. A NSCR, or three way catalyst, is similar to the catalyst controls installed on most modern automobiles. Exhaust from the engine is passed through a metallic or ceramic honeycomb covered with a platinum group metal catalyst. The catalyst promotes the low temperature (approximately 850 degF) reduction of NOx into N_2, the oxidation of CO into CO_2, and the oxidation of VOCs into H_2O and CO_2. NSCR catalyst efficiency is directly related to the air /fuel mixture and temperature of the exhaust. Efficient operation of the catalyst requires the engine exhaust gasses contain no more than 0.5% O_2. In order to obtain the proper exhaust gas O_2 across the operating range, an air/fuel ratio controller is installed that measures the oxygen concentration in the exhaust and adjusts the inlet air fuel ratio to meet the proper 0.5% O_2 exhaust requirement for varying engine load and engine speed conditions and varying ambient conditions. Industry literature indicates that the proper use of NSCR on four-stroke rich burn spark ignition reciprocating engines has NOx reduction capabilities of up to 99%, with NOx emission rates below 0.5 g/bhp-hr. Industry information indicates that, across the US, there are thousands of existing NSCR installations. [Retrofit installation of NSCR on five Caterpillar rich burn engines in Texas achieved a NOx reduction of 96% or greater on all of the engines. On two of those engines, testing conducted after more than 4000 hours of operation with the NSCR indicated the NSCR controls were still achieving 95% NOx reduction.]

As indicated above, proper control of the air/fuel ratio is important for optimizing the emissions performance of NSCR equipped engines, as industry information indicates that post-catalyst emissions are dependent upon pre-catalyst oxygen concentration. Industry information indicates that there is a trade off between NOx emissions and CO, ammonia, and hydrocarbon emissions, generally requiring air/fuel ratio control within a tight band to attain simultaneous low levels of NOx and CO emissions. If the engine's air/fuel ratio drifts to a fuel rich operation, NOx emissions tend to decrease while CO, ammonia, and hydrocarbon emissions tend to decrease. If the engine's air/fuel ratio drifts to a fuel lean operation, NOx emissions tend to increase while CO, ammonia, and hydrocarbon emissions tend to decrease. For this reason, accurate control of the engine air/fuel ratio is considered to be an integral requirement for the successful application of NSCR for NOx emissions reduction.

Some industry literature suggests that some particular 4-stroke rich burn spark ignition reciprocating engines can be converted to lean burn configurations with the accompanying lean burn engine NOx reduction capabilities. One vendor indicates that conversion to a lean burn configuration and the use of exhaust gas recirculation delivers the advantages of a lean burn engine's efficiency and the rich burn engine's capability of utilizing NSCR for NOx control. The ability to convert a rich burn engine to a lean burn configuration is highly unit specific and does appear to have had widespread application in industry.

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4-Stroke Rich Burn Spark Ignition Engine	
NOx Control Retrofit Technology	**Potential NOx Reduction**
High Energy Ignition System	10%
NSCR Catalyst (with air/fuel ratio controller)	90% - 99%

4.3.2 Example Existing Rules and Regulations – 4SRB

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from http://aqmd.gov/rules/download.html)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp≥500	36 ppmvd NOx (*approximately 0.5 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2010	
Nameplate - Bhp≥500	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California – California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for rich burn engines with nameplate ratings of greater than 50 hp and not used for agricultural operations include:

Rich burn, waste gas fueled	50 ppmvd NOx
Rich burn, cyclic loaded, field gas fueled	50 ppmvd NOx
Rich burn, limited Use	25 ppmvd NOx
Rich burn, all others	11 ppmvd NOx

(Note that the San Joaquin Valley Air Pollution Control District's Rule 4702 definition of limited use requires the engine have a permit restricting the engine's operation to no more than 4000 hrs/yr.)

Colorado - The state of Colorado's Air Quality Control Commission has established NOx emissions limitation for stationary spark ignited internal combustion reciprocating engines in its Regulation 7, Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides). (This rule may be viewed at http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf) NOx emissions limits noted in Colorado's Regulation 7 applicable to existing stationary natural gas fueled rich burn reciprocating internal combustion engines include:

Rich Burn Engine Nameplate – BHP>500	Install NSCR and AFR by July 1, 2010

(Note: The rule includes a $5000/ton cost effectiveness exemption for combined NOx and VOC reductions from rich burn engines.)

NOx emissions limits noted in Colorado's Regulation 7 applicable to new, modified, or relocated stationary natural gas fueled reciprocating internal combustion engines include:

Nameplate-100≤Bhp<500	
Effective January 1, 2008	2 g/bhp-hr
Effective January 1, 2011	1 g/bhp-hr
Nameplate Bhp≥500	
Effective July 1, 2007	2 g/bhp-hr
Effective July 1, 2010	1 g/bhp-hr

Texas - The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for 4-stroke lean burn spark ignition engines. The relevant emissions limitations in the rule include the following:

Rich Burn SI Engines – BHP ≥ 500	Mfg before 1/1/2011	2g/bhp-hr
	Mfg on or after 1/1/2011	1g/bhp-hr
	After 1/1/2020, regardless of mfg date	1g/bhp-hr

(This rule can be reviewed at:
http://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf).

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone NonAttainment Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for rich burn spark ignited engines as follows:

Gas Fueled Rich Burn SI Engine ≥ 300 bhp	2.0 g/bhp-hr

Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to all spark ignition internal combustion engines and other air contamination sources at natural gas production and processing facilities. In the

proposed GP-5, existing rich and lean burn engines with a nameplate rating of less than or equal to 100 horsepower, but less than 1500 horsepower, will be required to continue to meet the existing GP-5 NOx emissions limit of 2 g/bhp-hr. When the currently proposed GP-5 becomes effective, new and reconstructed rich burn engines will be required to meet the following NOx emissions limits:

Configuration	**NOx Limit**
New and reconfigured Rich Burn Engine - All	0.2 g/bhp-hr

The USEPA established NOx emissions limitations for natural gas fueled rich burn spark ignition engines in 40 CFR Part 60, Subpart JJJJ (NSPS) (1/18/08 73 FR 3567). The applicable NOx emissions limits for rich burn natural gas-fueled, spark ignition engines are as follows:

Engine Type	**Output Rating**	**Manufacture Date**	**NOx Emissions Limit**
SI Nat. Gas	100≤HP<500	mfg after 7/1/2008	2.0 g/HP-hr
SI Nat. Gas	100≤HP<500	mfg after 1/1/2011	1.0 g/HP-hr
SI Nat. Gas	HP≥500	mfg after 7/1/2007	2.0 g/HP-hr
SI Nat. Gas	HP>500	mfg after 7/1/2010	1.0 g/HP-hr

4.3.3 Discussion of Four Stroke Spark Ignition Engine NOx Reduction Capability – Combustion Modifications

Industry literature indicates that there are relatively few highly effective combustion related NOx emission controls utilized for four stroke rich burn spark ignition engines, other than ignition related controls that would be expected to have only minor NOx reduction benefits. Industry literature suggests that some individual model four stroke rich burn spark ignition engines can be converted to a lean burn configuration with the potential of achieving NOx reductions similar to those of other lean burn engines. However, the literature suggests that such conversion capabilities appear to be very limited and expensive.

Some information that was found regarding combustion controls for NOx reduction from rich burn engines is summarized below:

- A 1999 paper by Enginuity (now part of Dresser-Rand) discusses a project to install NOx reduction combustion controls on five 1950's vintage Ingersoll Rand KVG-103 four stroke rich burn carbureted engines rated at 1000hp each. The project included the installation of a turbocharger and related auxiliaries, removal of the carburetor and installation of single point fuel injection and related controls, installation of a screw-in pre-combustion chamber to improve ignition, and improved engine controls. NOx emissions were reduced 80% to 90% to below 2 g/bhp-hr across the engines' load range, with improvements in fuel consumption. For additional information see: http://www.dresser-rand.com/techpapers/tp149.pdf

- Attainment Technologies company markets gas recirculation systems for NOx control for four stroke rich burn spark ignition engines. (Exhaust gas recirculation as a NOx control for these engines is also being offered by some original equipment manufacturers (OEMs).) Attainment Technologies' literature indicates that the use of their rich burn engine NOx reduction process can lower the engine out NOx emissions by up to 80%. The NOx reduction is accompanied by a higher power output and better fuel efficiency when a higher compression ratio can be used. Experience with a Caterpillar 3516 turbocharged engine showed an increase in power output by 10**%** and a decrease in fuel consumption of 7**%** when this principal is applied. Attainment Technologies' literature indicates that retrofitted rich burn spark ignition reciprocating engines have achieved NOx emission rates of 0.1 g/bhp-hr in testing using the Attainment Technologies NOx reduction systems. For additional information see: http://www.attainmenttech.com/solutions.html

- Caterpillar literature indicates that they offer emissions upgrade groups for retrofit for certain of its engine models, including many 3306 and 3406 models. These emissions upgrade groups may include an upgraded turbocharger, fuel pump/governor, nozzles, cylinder pack, after-coolers (if applicable), and installation parts.

4.3.4 Discussion of NOx Reduction Capability – Post Combustion Modifications

Industry literature suggests that the use of non-selective catalytic reduction NOx controls (both in new and retrofit application), in conjunction with a modern air/fuel controller, on four stroke rich burn engines is a highly effective NOx control for these engines and has been installed in relatively high numbers. NSCR controls are available from a number of suppliers including some engine OEMs. With modern air/fuel controllers, the NSCR is an effective NOx control over a broad range of engine operation. The data suggests that there are many NSCRs in successful service on four stroke rich burn spark ignition reciprocating engines, and the controls have been installed on four stroke rich burn reciprocating engines representative of a wide range of engine nameplate ratings. Industry literature suggests that NOx control in excess of 90% can be expected through utilization of NSCR and air/fuel ratio controller on an otherwise uncontrolled four stroke rich burn engine. Information from MECA indicated that the experience of their members indicates that modern NSCR and air fuel ratio controller installations on these engines can support 99% reductions in NOx emissions and can achieve NOx emission rates in the range of 0.2 g/hp-hr to 0.5 g/hp-hr.

While NSCR is considered a post-combustion control, successful application of the NSCR usually also requires the installation of a modern air fuel ratio controller (AFRC). The AFRC is necessary to properly manipulate the engine combustion parameters across the rich burn engine's operating range in order to maintain the exhaust gas excess oxygen in the range required for proper, efficient operation of the NSCR. Because successful, efficient operation of the NSCR is dependent upon proper control of an AFRC, the further discussion of NSCR below implies the simultaneous installation of an appropriate AFRC. There are a number of manufacturers of air fuel ratio controllers, including the following:

- Altronic Inc. offers a variety of air fuel ratio controllers to support operation of a wide range of engines, for both new installation and retrofit applications. For additional information see: http://altronicinc.com/index.html

- Continental Controls offers air fuel ratio control for a range of gas fueled engines for both new and retrofit applications. For additional information: http://www.continentalcontrols.com/index.php

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- Woodward Governor Company offers air fuel ratio control for a range of gas fueled engines for both new and retrofit applications. For additional information see: http://www.woodward.com/airfuelratiocontrol.aspx

There are a number of manufacturer's and suppliers that offer NSCR systems that may be used on four stroke rich burn spark ignition reciprocating engines. Some of the manufacturer and supplier information reviewed is summarized below:

- A presentation by Environ, Demonstration of NOx Emission Controls for Gas Compressor Engines, A Study for Northeast Texas Presented by ENVIRON, dated December 6, 2005, discussed a study where NSCR NOx controls were installed on existing Caterpillar rich burn engines with output rating from 145 hp to 265 hp. After installation of the NSCR controls, NOx emissions were reduced to a range of 0.3 g/bhp-hr to 0.5 g/bhp-hr. The document indicated that the average cost was $10,622 per engine, including the NSCR module, an AFR controller, a solar power unit, and installation labor. For additional information see: http://www.epa.gov/glo/SIPToolkit/documents/12-20-05_rich-burn_engine_control_briefing.pdf (The above project was more completely documented in "A Pilot Project to Assess the Effectiveness of an Emission Control System for Gas Compressor Engines in Northeast Texas", Final Report, November 4, 2005, http://www.scribd.com/doc/1597001/Environmental-Protection-Agency-NETAC-Compressor-Retrofit-Final-Report-110405)

- DCL International Inc. offers NSCR catalyst systems for a wide range of sizes of rich burn stationary engines. For additional information see: http://www.dcl-inc.com/home

- Dresser-Rand markets NSCR systems for NOx reduction from rich burn engines, as both new unit installations and for retrofit to existing engines. For additional information see: http://dresser-rand.com/literature/enginuity/2187_Enginuity-Compi_catsys.pdf

- Caterpillar literature indicates that they offer NSCR systems for many of their rich burn engine models, for both new engine installations and existing engine retrofits. Caterpillar indicates that NOx reductions of up to 95% are possible utilizing NSCR.

- CleanAir Systems offers a NSCR NOx reduction catalyst for rich burn engines, including those utilized for gas compression. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) CleanAir Systems' NSCR is now referred to as ASURE TWC (three way converter). The use of an air fuel ratio controller is also recommended in these applications, and they are also offered by CleanAir Systems. CleanAir Systems indicates that their ASSURE TWC NSCR can achieve NOx emission reductions up to 99%. For additional information see: http://www.cleanairsys.com/products/converters/ASSURE-OC-TWC.htm

- Miratech Corporation offers a NSCR catalyst system for NOx reduction from rich burn engines used in natural gas compression applications. For additional information see: http://www.miratechcorp.com/site/miratech/section/17

- Johnson Matthey markets 3-way catalyst systems that reduce NOx emissions from rich burn natural gas fueled engines by 95% or more, and able to achieve NOx emission rates down to approximately

0.07 g/bhp-hr. For additional information see : (http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946)

- A 2009 brochure from Dresser Waukesha indicates that new Waukesha rich burn engines are commercially available with horsepower ratings up to 1,980 hp and, equipped with NSCR, achieve NOx emissions levels below 0.15 g/bhp-hr. For additional information see: http://www.dresserwaukesha.com/documents/1256_0309.pdf

In an April 28, 2006 memo from Alpha-Gama Technologies to the USEPA, Control Costs for Reciprocating Internal Combustion Engines at Major and Area Sources, cost estimates were prepared for the installation of NSCR on four stroke rich burn engines. For capital cost estimates, the following equation was determined: NSCR Capital Cost = 19.7 * HP + 1799, where HP is the engine's horsepower output rating. For annual operating costs, the following equation was determined: NSCR Annual Cost = 2.65 * HP + 657, where HP is the engine's horsepower output rating. For additional information see: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2005-0030-0005

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for rich burn reciprocating engines. Included in this evaluation for rich burn engines is the application of NSCR for NOx control. The document indicates that NSCR has the capability of reducing NOx emissions from rich burn engines by approximately 90% to 98%. The following summarizes the rich burn engine NSCR evaluation:

Type of Control	Nameplate Rating (HP)	Total Capital Cost (2004 $)	Cost Effectiveness (2004 $/ton)
Rich Burn NSCR	500 – 8,000	35,400 – 330,700	319 – 1,647

For additional information see: http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf

In support of its development of Rule 4702, Internal Combustion Engines Phase 2, in 2003 the San Joaquin Valley Air Pollution Control District prepared a cost effectiveness analysis for the retrofit installation of NSCR on rich burn spark ignited internal combustion engines. The analysis was performed for a range of engine output ratings. The analysis assumed the installation would achieve compliance with a proposed NOx emissions rate limit of 25 ppmvd @15% O2 (approximately 0.37 g/bhp-hr). The results of the analysis for rich burn spark ignition engines is summarized below:

Rich Burn Engine NSCR NOx Reduction Control Installation Cost Estimation

Nameplate Rating (hp)	NSCR Installed Cost ($)	Annual O&M Cost ($)	Annualized Cost ($)	25% Cap Fact Cost Effectiveness ($/ton)	75% Cap Fact Cost Effectiveness ($/ton)
50	13500	7199	9395	8415	2829
200	18500	7819	10829	2446	815
500	20500	8819	12154	1098	366
1000	30500	11319	16281	735	245
1500	47000	18919	26566	800	267

Note: Annualized cost based on 10 year life and 10% interest.

NOx reductions based on 9.55 g/bhp-hr pre-installation and 0.37 g/bhp-hr post-installation.
For additional information see:
http://www.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf

4.3.5 Four Stroke Rich Burn Spark Ignition Engine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available NOx reduction technologies applicable to natural gas fired, spark ignited, rich burn engines. The information suggests that there are a few combustion related NOx emissions control applicable to these rich burn engines, such as installation of EGR, improved induction and fuel delivery, modification for lean burn operation, etc. However, such modifications may not be feasible for retrofit for all subject rich burn engines due unavailability of the required components or extraordinarily high costs to make the conversions. The industry information also indicates that there are technically feasible, commercially available post-combustion (NSCR) NOx reduction systems available for use on virtually the entire range of nameplate ratings and make/model variability of the four stroke rich burn spark ignition reciprocating engines.

From the industry information it appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, achievable from installation of NSCR tends to be engine design specific. However, it appears that commercially proven NSCR NOx reduction technologies are widely available from engine original equipment manufacturer (OEM) companies as well as aftermarket suppliers that can be expected to achieve NOx reductions of 90% or greater. While there may be a few engine specific or site specific installation or operational problems that could impact NSCR performance, there appears to be little industry information that documents such issues. Any potential engine design or site specific issues could generally be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The information therefore seems to support NOx emission rate limits of 0.2-0.5 g/bhp-hr for many four-stroke rich burn spark ignition reciprocating engines with a nameplate rating of 50 hp or above, providing that there is consideration of individual engine design and site specific flexibility provisions. Engine specific and site specific issues could be addressed with appropriate rule or regulation flexibility of consideration of individual engine design and site specific flexibility provisions.

The installation of NSCR on both a new and retrofit basis for rich burn engines has been a widespread practice for a considerable time, and should be considered a relatively mature process. While capital costs would be somewhat site specific, industry literature indicates that for the majority of installations the capital costs are primarily a function of the rich burn engine's nameplate rating.

Type of NOx Control	Engine Size Range (hp)	Estimated Range of NOx Reduction (%)	Estimated Range of NOx Emissions Rate (g/bhp-hr)	NOx Control Estimated Costs ($)
Retrofit NSCR	50 - 2000	99	0.2 - 0.5	16,700 - 363,000
New Unit w/NSCR	50 - 2000	N/A	0.15	N/A

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on Illinois' "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines", adjusted for CPI.)

It should be noted that the range of costs for installation of NSCR on four stroke rich burn spark ignition reciprocating engines is primarily a function of the nameplate rating of the engine. However, variability may exist due to site specific conditions and complexity of installation of an air/fuel ratio controller. Also, the cost effectiveness (in terms of $/tons of NOx reduced) will depend upon the operational characteristics (capacity factor) of the affected engine.

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4.4 Reciprocating Engines - Diesel Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Compression ignition engines utilize the heat generated during relatively high levels of compression of the combustion air in the combustion chamber to cause ignition of the fuel air mixture when the fuel is introduced into the combustion chamber. Diesel engines may be either two-stroke or four-stroke.

In a diesel engine, combustion air is drawn into the cylinder and compressed in the combustion chamber with a relatively high compression ratio compared to most spark ignition engines. As a result of the compression, the combustion air temperature is raised to a high level, often 1300 degF to 1650 degF. With the piston at or near the top of the compression stroke, diesel fuel is injected into the combustion chamber through an atomizing fuel nozzle, mixing the fuel with the hot combustion air. The fuel air mixture ignites as a result of the high temperature in the combustion chamber. The expanding combustion products push down on the piston and connecting rod, which transfers this motion to the crankshaft, resulting in rotary motion and engine output power. The inlet of combustion air and exhaust of spent combustion products occurs through ports or valves in the cylinder heads. To further improve the output and efficiency of a diesel engine, turbochargers are often utilized to compress the combustion air prior to entry into the cylinder and attaining a high level of cylinder filling and pressure. The use of air coolers between the air outlet of the turbocharger and the cylinder inlet cools the combustion air and helps further improve the engine efficiency.

Diesel engines may be either 2 stroke or 4 stroke configurations, with the majority being 4 stroke and some large units being 2 stroke. Diesel engines are lean burn engines.

There are various diesel engine manufacturers, with most manufacturing multiple models with a range of rated outputs.

4.4.1 Diesel Engine NOx Controls

One potential method to achieve modest NOx emissions reductions from diesel engines is the appropriate setting of the fuel injection timing. Control of the start of fuel injection timing, relative to the crankshaft angle of top-dead-center for the specific cylinder, can affect the diesel engine's efficiency and NOx emissions, depending upon engine design and load. Advancing the fuel injection timing, relative to the cylinder's compression top dead center, will tend to improve the engines efficiency and result in higher NOx emissions. Retarding the injection timing, relative to the cylinder's compression top dead center, will tend to reduce NOx emissions but also reduced the engine's efficiency, possibly increasing the engine's particulate emissions. The amount of effective control is highly dependent upon the engine design and operating characteristics. While this NOx reduction technology is applicable to nearly any diesel engine, its effectiveness is likely greatest on older, otherwise uncontrolled, diesel engines. Industry literature suggests that NOx reductions of up to 20% to 25% may be possible utilizing diesel injection timing retard, with a 10% reduction being more common.

Another potential method to achieve modest diesel engine NOx emissions reductions is the use of emulsified fuels. Emulsified diesel fuel is a blended mixture of diesel fuel, water and other additives.

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The water is suspended in droplets within the fuel, creating a cooling effect in the combustion chamber that decreases NOx emissions. A fuel-water emulsion creates a leaner fuel environment in the engine, lowering NOx and PM emissions. Emulsified diesel can be used in any diesel engine, but there is a decrease in power and fuel economy due to the fact that the addition of water reduces fuel energy content. Emulsified fuel can achieve emission reduction of NOx by about 10 to 20 percent and PM by about 50 to 60 percent.

The use of exhaust gas recirculation (EGR) is an effective NOx control for diesel engines in new and retrofit applications. Both low-pressure and high-pressure EGR systems exist but low-pressure EGR is used for retrofit applications because it does not require engine modifications. EGR involves recirculating a portion of the engine's exhaust gas back to the turbocharger inlet or intake manifold, in the case of a naturally aspirated engines. In most systems, an intercooler lowers the temperature of the recirculated exhaust gas. The cooled recirculated exhaust gas mixed in with the combustion air tends to result in an overall lower combustion temperature in the engine, thus inhibiting NOx formation. Diesel particulate filters are always used with a low-pressure EGR system to ensure that large amounts of particulate matter are not recirculated to the engine. EGR systems are capable of achieving NOx reductions of more than 40 percent in both new and retrofit applications.

Selective catalytic reduction (SCR) is a post-combustion NOx control applicable to diesel engines that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the engine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) passes over a catalyst to help convert the NOx, hydrocarbons and CO into water, nitrogen and CO_2. Catalyst selection is somewhat based on the expected temperature range of the engine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control may facilitate NOx reductions of up to 95%, although 75% to 90% reduction is more typical. Industry information indicates that there are a number of suppliers of SCR systems for diesel engines, and many systems have been installed and are successfully in commercial operation. SCR may be utilized in either a new or retrofit application.

Industry information indicates that there are additional NOx reduction technologies applicable to diesel engines. One technology, lean NOx catalyst systems, utilize injection of a small amount of fuel into the exhaust to act as a reductant in conjunction with a zeolite catalyst to attain NOx reductions of 10% to 50%. Another, lean NOx traps, traps NOx in a barium hydroxide or barium carbonate material during normal engine lean operation, and engine controls periodically cause the engine to operate fuel rich mode to regenerate the trap material and release the NOx as N2 or NH3. Industry information indicates that lean NOx traps may be able to reduce NOx emissions by as much as 90%. No information was found regarding commercial operation of either of these technologies in the field, so they are not considered to be commercially available diesel engine NOx reduction technologies for the purposes of this review.

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Compression Ignition Engine NOx Control Retrofit Technology	**Potential NOx Reduction**
Fuel Injection Timing	10%
Emulsified Fuel	10% - 20%
Exhaust Gas Recirculation	40% - 50%
Selective Catalytic Reduction	75% - 90%

4.4.2 Example Existing Rules and Regulations – Diesel Engines

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from http://aqmd.gov/rules/download.html)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp≥500	36 ppmvd NOx (*approximately 0.5 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2010	
Nameplate - Bhp≥500	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)
Nameplate - Bhp<500	45 ppmvd NOx (*approximately 0.6 g/bhp-hr*)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (*approximately 0.15 g/bhp-hr*)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California - California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for non-certified compression ignition engines, installed on or before June 1, 2006,and with nameplate ratings of greater than 50 hp include:

50 < HP ≤ 500	EPA Tier 3 or Tier 4
500 < HP ≤ 750 and less than 1000 hrs/yr operation	EPA Tier 3
HP > 750 and less than 1000 hrs/yr operation	EPA Tier 4
HP > 500 and 1000 hrs/yr or more operation	80 ppmvd NOx

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The USEPA has established NOx emissions limitations for new compression ignition engines, and those limitations vary with the manufacture date of the subject engines. For example 40 CFR Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, requires that the owners and operators of pre-2007 model year non-emergency stationary compression ignition engines with a displacement of less than 10 liters per cylinder comply with the following NOx emission standards:

Maximum Engine Power	Emission standards or stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007 -2010 model year engines > 3000 HP and with a displacement of <10 liters per cylinder (g/HP-hr)
HP<11	
11≤HP<25	
25≤HP<50	
50≤HP<75	6.9
75≤HP<100	6.9
100≤HP<175	6.9
175≤HP<300	6.9
300≤HP<600	6.9
600≤HP≤750	6.9
HP>750	6.9

NOx emissions standards for 2011 and beyond compression ignition engines are identified in 40 CFR Part 1039—Control Of Emissions From New And In-Use Nonroad Compression-Ignition Engines, as shown in the following table:

Maximum engine power	**NO_X**
kW < 19	
19 ≤ kW < 56	
56 ≤ kW < 130	0.4
130 ≤ kW ≤ 560	0.4
kW > 560	3.5

(Note: Nox emissions limits in above table are in g/kw-hr)

4.4.3 Discussion of Diesel Engine NOx Reduction Capability – Combustion Modifications

The use of emulsified fuels is accomplished by using surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture while ensuring that the water does not contact metal engine parts. Firing emulsified fuels in diesel engines tends to reduce peak engine combustion temperatures and increase fuel atomization and combustion efficiency. However, the use of the emulsified fuels also tends to result in an approximate 20% reduction in peak engine output. Emulsified fuels are expected to have an approximate 15% cost penalty compared to traditional diesel fuel costs. The low NOx reduction capability of this technology, along with the relatively large impact on engine output, make the use of emulsified fuels an unlikely standalone technology for use in diesel engine NOx reduction.

Exhaust gas recirculation (EGR) is an available NOx reduction technology applicable to diesel engines. Some original equipment manufacturer (OEM) diesel engines are currently being marketed with EGR as original equipment. There are also some suppliers of retrofit EGR systems for existing diesel engines. There is little information concerning the availability of such retrofits for the wide range of diesel engine makes and models. Any EGR system would likely require a custom design for each make and model, with potential further customization required for site specific conditions. Some of the industry information indicates that low sulfur fuels and particulate traps are required with the retrofit of EGR systems to help maintain system performance and to limit additional wear on engine components and contamination of lube oil. The industry information indicates that the use of EGR can achieve NOx reductions of from 40% to 50%. The information also indicates that the use of EGR can result in an approximate 2% loss in fuel efficiency and a loss of approximately 2% in engine output capability, dependent upon the amount of exhaust gas recirculated. No specific cost estimates were found regarding the retrofit of EGR on existing diesel engines. However, one source suggested a potential retrofit capital cost of $500 to $700 per engine rated horsepower.

4.4.4 Discussion of Diesel Engine NOx Reduction Capability – Post Combustion Modifications

The post-combustion control selective catalytic reduction (SCR) is the process where a reductant (typically ammonia or urea) is added to the flue gas stream and is absorbed onto the catalyst (typically vanadium or zeolite) enabling the chemical reduction of NOx to molecular nitrogen and water. Diesel engines typically have unconsumed oxygen in the exhaust, which inhibits removal of oxygen from the NOx molecules. To remove the unconsumed oxygen, the catalyst decomposes the reductant causing the release of hydrogen, which reacts with the oxygen. This creates local oxygen depletion near the catalyst allowing the hydrogen to also react with the NOx molecules to form nitrogen and water.

A number of information sources discuss diesel engine applicable SCR systems and the performance of some installation examples, including the following:

- A presentation by Shell indicated that Shell has been installing SCR NOx reduction systems on diesel engines used to support drilling rig operations. Shell's information indicated that Shell has observed NOx reductions of greater than 90% in this application with minimal impact on operations. This project is further documented in an application fact sheet from Johnson Matthey Catalysts, "Case No. 801: Controlling NOx From Gas Drilling Rig Engines With Johnson Matthey's

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Urea SCR System" . For the project, Johnson Matthey provided urea SCR systems for three 1476 hp Caterpillar 3512 BDITA diesel engines. Johnson Matthey indicated that the supplied SCR systems were designed to operate in harsh environmental conditions and with the dramatic engine load swings associated with drilling operations. Johnson Matthey indicated that they met the 90% NOx emissions reduction requirements, actually achieving NOx reductions between 91% and 99%. For additional information see: http://ect.jmcatalysts.com/pdfs-library/Application%20Fact%20Sheet%20801%20-%20Shell%20Gas%20Drill%20Rig.pdf

- Johnson Matthey markets urea based SCR systems that reduce NOx emissions from diesel engines by 90% or more. Johnson Matthey offers catalysts with a broad effective operating temperature range to achieve NOx reductions earlier in an engine operating cycle and across a wide engine operating range. For additional information see: http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946

- CleanAir Systems offers a SCR system that they advertise as being applicable to dieselengines. CleanAir indicates that their SCR catalyst allows NOx reduction operation in a wide range of temperatures, from approximately 300 degF to approximately 1000 degF. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) Their diesel engine SCR product is now being referred to as E-Pod SCR. CleanAir indicates that their diesel engine capable SCR achieves up to 95% reduction in NOx emissions across a wide range of exhaust temperatures. For additional information see: http://www.cleanairsys.com/products/hybrids/index.htm

- Miratech Corporation offers a SCR based NOx reduction system that is advertised to be applicable to diesel engines. Miratech indicates that NOx reductions of up to 99% are achievable with their SCR system. For additional information see: http://www.miratechcorp.com/images/data/attachments/0000/0019/SCR_Systems.pdf

- Wartsila offers a retrofit SCR NOx reduction system for diesel engines. Wartsila indicates that their product is scalable to meet the needs of various engine size/needs and may be provided as a skid-based system. Wartsila specifically targets the oil/gas industry for this system, most specifically for drilling rig operations. Wartsila indicates that their SCR system can attain 85% to 95% reduction in NOx emissions. For additional information see: http://wartsila.com/en/environmental-technologies/air-emissions-control/NOR

- A Combustion Components Associates Inc. technical bulletin describes a project involving the installation of SCR systems on four new Caterpillar 3516 2.5MW diesel engines. The SCR systems were designed to eliminate the need for compressed air in atomizing the urea, and achieved NOx reductions of over 90%. The bulletin indicates that the SCR systems allowed the engines to achieve NOx emissions rates below the 0.6 g/bhp-hr across an operating load range of 25% to 100% load. For additional information see: (http://combustioncomponents.com/downloads/Technical_Bulletin_2009-001.pdf)

- A Combustion Components Associates Inc. technical bulletin describes a project involving the installation of SCR systems on four existing General Motors EMD two-stroke V-16 2100kw diesel engines. The SCR systems were designed to achieve a NOx emissions rate limit of 2.3 g/bhp-hr which represented an approximate 73% reduction from the uncontrolled emissions rate.

For additional information see:
(http://combustioncomponents.com/downloads/BL_England_Case_Study.pdf)

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for diesel reciprocating engines. Included in this evaluation for diesel engines is the application of SCR for NOx control. The document indicates that SCR has the capability of reducing NOx emissions from diesel engines by approximately 80% to 90%. The following summarizes the diesel engine SCR evaluation:

Type of Control	Nameplate Rating (HP)	Total Capital Cost (2004 $)	Cost Effectiveness (2004 $/ton)
Diesel SCR	500 - 8000	308,500 – 1,264,100	899 – 4,536

For additional information see: http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf

In its "Alternative Controls Techniques Document: Stationary Diesel Engines", the EPA provided estimated costs for the installation of SCR on diesel engines. In the document, the EPA states that the capital costs for diesel EGR are approximately $98 per rated horsepower, including the catalyst, reactor housing and ductwork, ammonia injection system, controls, engineering, and installation. The following table summarizes the EPA's estimates presented in the document:

Diesel Engine Nameplate Rating (hp)	Estimated Capital Cost (2009$)
75 – 100	7,350
175 – 300	23,324
600 – 750	66,150
>750	98,000

For additional information see: http://www.epa.gov/ttn/atw/rice/diesel_eng_act.pdf

4.4.5 Diesel Engine NOx Control Summary

Industry information indicates that there are several available NOx reduction technologies applicable to diesel engines. Some combustion related NOx reduction technologies offer only low levels of NOx reduction, e.g. injection timing (~ 10% reduction), emulsified fuel (10% to 20% reduction). Another combustion related diesel engine NOx reduction technology, exhaust gas recirculation (EGR), is reported to be capable of moderate levels of NOx reduction (40% to 50%), but has had limited retrofit application to date. Because of the limited NOx reduction capabilities of these technologies and apparent limited commercial availability of the technologies, at this time these combustion related technologies are not considered primary NOx reduction technologies for use in diesel engine retrofit. This could change in the future as the technologies become more developed and more widely commercially available.

The industry information indicates that post-combustion controls are also applicable to diesel engines for NOx reduction. The available information describes NOx traps and NOx absorbers for diesel engine

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applications, but no examples of commercial application of these technologies on diesel engines could be found at the time of preparation of this document. In contrast, SCR is a post combustion NOx reduction technology applicable to diesel engines, it is commercially available from several suppliers, and has been in commercial operation on diesel engines for some time. Some examples of existing installation of SCR on diesel engines include the use of diesel to drive electric generators in base, intermediate, and peak operating modes and for use on diesel generators utilized to power drilling rigs (variable operation). Industry information indicates the SCR can achieve NOx reductions from diesel engines in the range of 75% to 90%.

Based on the available information, it appears that a properly sized and engineered SCR system is the only currently commercially available NOx emission control for diesel engines with the capability of achieving up to 90% control of NOx emissions.

NOx Reduction Technology	Nameplate Rating (hp)	Estimate Range of Controlled NOx (%)	Estimated Cost ($)
SCR	500 - 8000	75 – 90	371,700 – 1,523,200

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on Illinois' "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines", adjusted for CPI.)

It should be noted that the range of costs for installation of SCR on diesel reciprocating engines is primarily a function of the nameplate rating of the engine. However, variability may exist due to site specific conditions and complexity of installation. Also, the cost effectiveness (in terms of $/tons of NOx reduced) will depend upon the operational characteristics (capacity factor) of the affected engine.

4.5 Combustion Turbines

Combustion turbines have three main sections; the compressor, the combustor, and the power turbine. The compressor draws in and pressurizes ambient air. In the combustor, fuel is mixed and combusted with a portion of the compressed air. The resulting combustion gases are diluted with the remainder of the air from the compressor to create a large volume of a hot, compressed combustion gas mixture. The hot, compressed gases then expand in the turbine section, driving the power turbine and creating the turbine's output rotary motion. The rotating turbine shaft is connected to the driven load, sometimes through a gear box.

There are several different manufacturers of combustion turbines, and each manufacturer generally has multiple combustion turbine models that represent a wide range of combustion turbine output ratings.

4.5.1 Combustion Turbine NOx Controls

There are a number of commercially available NOx reduction technologies for combustion turbines, but not all may be applicable or available for any given make/model of combustion turbine.

Water injection is a NOx reduction technology applicable to most combustion turbines. Injecting water into the combustion zone tends to lower peak flame temperatures, thereby lowering the amount of thermal NOx formation during combustion. Water may be injected directly into the turbine combustor, or may be converted to steam using turbine exhaust waste heat with a heat recovery steam generator (HRSG), and then injected into the combustor as steam. More steam than water must be used to achieve a comparable NOx reduction, but the use of steam may result in a lower energy penalty than use of water if the turbine's waste heat would not otherwise be recovered and used. Depending upon the make/model of the applicable combustion turbine, turbine modifications may be as simple as replacement of fuel nozzles with nozzles capable of supplying fuel and water/steam (and associated plumbing), or may be as complex as requiring replacement of the combustors designed to operate with water/steam injection (and associated plumbing). Other required equipment would include appropriate combustion turbine control systems, a source of demineralized water (onsite water plant with storage, or storage tank for demineralized water prepared offsite), a water injection pump, and a water/steam flow metering station. Industry literature indicates that water/steam injection can result in combustion turbine NOx emissions reductions of 40% or more.

The use of dry low NOx burners (DLNB) is a NOx emissions reduction technology available for many makes and models of combustion turbines. DLNB technology utilizes a lean, premixed flame in the combustor as opposed to a turbulent diffusion flame. In a lean, premixed combustor, the fuel and air are premixed prior to entering the combustion zone. With a lean, premixed flame, the contribution of prompt and thermal NOx can be much lower than for a turbulent diffusion flame that is typical for non-DLNB combustion turbine combustors. Many DLNB combustors are capable of achieving NOx emissions reductions across the full load range, but some require more sophistication to allow variable operating modes in order to maintain flame stability across the full load range. Not all turbine designs can accommodate a DLNB, and DNLB combustors may not be available for all makes and models of combustion turbines. In addition to the replacement of the turbine's combustors, installation of DLNB technology may require modifications or replacement of associated piping and turbine combustion control modification or replacement. Industry literature indicates that the retrofit utilization of DLNB

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technology can achieve NOx reductions of 60% or more for those units where the technology is available.

Selective catalytic reduction (SCR) is a NOx reduction technology applicable to combustion turbines. SCR is a post-combustion NOx control that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the combustion turbine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) passes over a catalyst to help convert the NOx, hydrocarbons, and CO into water, nitrogen and CO2. Catalyst selection is somewhat based on the expected temperature range of the combustion turbine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), a reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of combustion turbine load, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control on combustion turbines may facilitate NOx reductions of 95% or more.

Combustion Turbine NOx Control Technology	**Potential NOx Reduction**
Water Injection	40%
Dry Low NOx Burners (DLNB)	60%
SCR	95%

4.5.2 Example Existing Rules and Regulations - Combustion Turbines

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1134, EMISSIONS OF OXIDES OF NITROGEN FROM STATIONARY GAS TURBINES, that provides NOx emissions limitations for combustion turbines. (This rule may be viewed at http://aqmd.gov/rules/reg/reg11/r1134.pdf)

Rule 1134 provides an equation that is used to determine the NOx emissions limitations for various sizes of combustion turbines. The equation is:

Compliance Limit = Reference Limit x (EFF/25%)

Where Compliance Limit = NOx emissions limit (ppmvd@15% O2)
EFF = Thermal efficiency (%)
Reference Limit = NOx rate (ppmvd) from following table

Nameplate Rating	**Ref. NOx Limit (ppmvd)**
0.3 to Less Than 2.9 MW	25
2.9 to Less Than 10.0 MW	9
2.9 to Less Than 10.0 MW No SCR	15
10.0 MW and Over	9
10.0 MW and Over No SCR	12

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Texas - The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for combustion turbines. The relevant emissions limitation in the rule includes the following:

Combustion Turbine 25 ppmvd@15% O2

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone NonAttainment Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for combustion turbines as follows:

Combustion Turbine > 10.0 MW 42 ppmv @ 15% O2

Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to simple cycle combustion turbines and other air contamination sources at natural gas production and processing facilities. When the currently proposed GP-5 becomes effective, new and reconstructed simple cycle combustion turbines with a nameplate rating greater than or equal to 1000 hp will be required to comply with a NOx emissions rate limit of 15 ppm @ 15% O2.

USEPA - The USEPA established NOx emissions limitations for combustion turbines in 40 CFR Part 60, Subpart KKKK (NSPS) (7/6/06 71 FR 38482) applicable to natural gas-fueled combustion turbines are summarized in the following table:

Combustion Turbine Type	Peak Load Heat Input	NOx Limit
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2or 690 ng/J of useful output (5.5 lb/MWh).

New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2or 590 ng/J of useful output (4.7 lb/MWh).

4.5.3 Combustion Turbine NOx Reduction Combustion Controls

The literature suggests that the combustion related NOx reduction technologies of water injection and dry low NOx burners (DLNB) are commercially available NOx reduction technologies for combustion turbines that are capable of achieving NOx reductions of 40% and 60%, or greater, respectively. Although there appears to be both OEM and aftermarket suppliers of these NOx reduction technologies for combustion turbines, the literature indicates that these NOx reduction technologies may not be commercially available for all makes and models of combustion turbines, more so for the relatively small size of combustion turbine representative of industrial utilization.

Some of the combustion turbine manufacturers offer a version of low NOx burners for many of their particular models of combustion turbine, some as original equipment and some as retrofit, as follows:

- Capstone markets a new natural gas fueled combustion microturbine, turbine generator with a 1 MW electrical rating. Capstone indicates that the NOx emissions from this turbine generator are less than 9 ppmvd in standard version and less than 4 ppmvd in CARB version. For additional information see: http://www.microturbine.de/uploads/File/C1000%20HPNG.pdf

- GE offers retrofit dry low NOx emissions systems for many of their combustion turbines. Dependent upon the model of the combustion turbine (technology/product may not be available for all models), GE offers low NOx burner systems that may result in NOx emissions levels in the single digit ppmvd range. For certain models, GE offers dry low NOx emissions systems along with water injection for further NOx emissions reductions. For additional information see: http://www.ge-energy.com/products_and_services/industries/oil_and_gas_upstream.jsp

- Solar Turbines information indicates that Solar offers an extensive line of standard NOx reduction retrofit kits for most of the Solar gas turbine product line, including their low-NOx SoLoNOx gas fuel system upgrade to achieve NOx emissions reductions. Solar also offers its SoLoNOx emissions reduction technology for many of its currently offered gas turbine models. For additional information see: http://mysolar.cat.com/cda/layout?m=35881&x=7

- A paper presented by Alstom described a project to achieve low NOx emissions from an Alstom GT10 combustion turbine, with an approximate 23 MW nameplate rating. The paper indicates that this series of combustion turbine was originally intended to drive compressors, but was being used for cogeneration in this particular application. The NOx control system used a combination of low-NOx combustor design and water injection to meet a 15 ppmvd NOx emissions limit over a wide range of operating and ambient conditions. The paper indicated that the combustion turbine outlet NOx emissions were generally held to 10 ppmvd. For additional information see: http://cogen.mit.edu/files/powergen.pdf

Similarly, the literature suggests that the cost for combustion related and post combustion NOx emissions controls vary greatly with the make and model of the combustion turbine. For example, in a 1999 document, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, the following capital cost estimates were prepared for presentation to the US Department of Energy:

Make/Model	Rating (approximate) (MW)	Water Injection Capital Cost ($)	DLN Capital Cost ($)	Hi-Temp SCR Capital Cost ($)
GE LM2500	23	1,083,175	800,000	1,269,324
GE 7FA	170		4,500,000	5,216,400
Solar Centaur 50	4.2	405,500	190,000	
Allison 501-KB5	4	291,000	20,000	
Solar Taurus 60	5		190,000	652,050

Note: The above costs are in 1999 $.
The DLN capital costs are incremental costs compared to conventional burners.
For additional information see:
http://www1.eere.energy.gov/industry/distributedenergy/pdfs/gas_turbines_nox_cost_analysis.pdf

4.5.4 Combustion Turbine NOx Reduction Post Combustion Controls

The post combustion NOx reduction technology SCR appears to be a technically feasible NOx reduction technology for many combustion turbines, and systems appear to be commercially available for simple cycle combustion turbines. However, industry representatives have raised several issues questioning the applicability of SCR to combustion turbines driving natural gas compressors.

One industry stated issue concerned with the use of SCR for combustion turbines is that many related facilities are unmanned and that SCR installations have not been demonstrated in un-manned facilities. Other industry information indicates that while it may be true that are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location.

Industry sources have also stated that SCRs have not been demonstrated on combustion devices with variable loads. SCR manufactures offer catalysts that are effective over wide temperature ranges characteristic of a range in combustion turbine operating load. Modern controls also have the ability to closely regulate fuel and air flows to ensure combustion gas oxygen and temperature levels at expected levels and to regulate reagent flow, all serving to ensure proper SCR function over a broad range of load.

Several organizations market SCR systems applicable to combustion turbines. A summary of some of the marketed systems are summarized below:

- Johnson Matthey markets SCR systems for combustion turbines, and indicates that they have supplied SCR systems for combustion turbines with output ratings ranging from 3MW to greater than 200MW. Johnson Matthey indicates that they can engineer the systems to work with natural gas fuel, diesel fuel, or co-fired natural gas and diesel. Johnson Matthey states that their SCR systems are designed to have a rapid startup capability, permitting the combustion turbine to come in compliance with NOx emission limits within minutes of startup. The Johnson Matthey SCR

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systems for combustion turbines are capable of achieving NOx reductions in excess of 95%, and attaining NOx emission rates below 2 ppm. For additional information see: http://ect.jmcatalysts.com/emission-control-technologies-gas-turbines

- Nationwide Environmental Solutions offers their CataStak SCR NOx reduction systems for combustion turbines, delivering reliable NOx emissions as low as 2.5 ppm @ 15% O2. Nationwide Environmental Solution's literature indicates that they offer SCR systems for combustion turbines sized down to an output rating of 0.5 MW, and with a combustion gas exhaust temperature of up to 1000 degF. The Nationwide Environmental Solution's information also indicates that their design includes simple controls, requires minimal operator intervention (Auto Start/Stop) and is easy to retrofit on existing equipment (vertical or horizontal arrangements). For additional information see: For additional information see: http://www.catastak.com/catastak_gt/index.html

- Turner EnviroLogic offers SCR systems for simple cycle combustion turbines that are designed to integrate with the combustion turbine controls to provide operation with little to no operator attention. The design is intended to facilitate efficient, reliable operation with the frequent start/stop cycling typical of the operation of many simple cycle combustion turbines. The document also indicates that the SCR systems and components can be custom designed to accommodate site specific installation requirements. For additional information see: http://equipmentsourceco.com/pdf/scr_systems.pdf

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for reciprocating engines and combustion turbines. Included in this evaluation for combustion turbines is the application of SCR for NOx control. The document indicates that SCR has the capability of reducing NOx emissions from combustion turbines by approximately 90%. The following summarizes the combustion turbine SCR evaluation:

Type of Control	Nameplate Rating (MW)	Total Capital Cost (2004 $)	Cost Effectiveness (2004 $/ton)
SCR (gas fuel)	5 – 25	748,000 – 2,018,000	1,606 – 3,203
SCR (oil fuel)	5 – 25	748,000 – 2,018,000	1,072 – 2,039

For additional information see: http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf

The cost effectiveness (in terms of $/ton of NOx reduced) for application of SCR to any given combustion turbine is highly dependent upon the operating capacity factor of that engine.

4.5.5 Combustion Turbine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available combustion and post combustion NOx controls available for combustion turbine. The most common combustion controls are water injection and the installation of low-NOx combustors. These controls are generally able to attain moderate levels of NOx reduction in retrofit application; approximately 40% for water injection and up to approximately 60% for low-NOx combustors. Due to the design differences between makes and models of combustion turbines, not all combustion turbines are able to achieve those levels of NOx reduction. Also because of the design differences between makes and models of combustion

turbines, water injection systems and/or low-NOx combustors must be designed for the specific make and model of combustion turbine. Water injection systems and/or low-NOx combustors are not available for all makes and models of existing combustion turbines. Some organizations market a NOx reduction system that incorporates both low-NOx combustors and water injection to optimize unit efficiency, operability, and emissions control over a wide range of unit load and ambient conditions.

Combustion turbine manufacturers offer multiple models of new combustion turbines with low NOx combustion technology that are capable of operating with NOx emission rates in the single digit ppmvd range.

Industry information also indicates that retrofit SCR is a technically feasible, commercially available post-combustion NOx control for combustion turbines. SCR is applicable and available for both retrofit and new unit installations. SCR is capable of achieving combustion turbine NOx reductions of 90% or more. Based on the available information, SCR appears to be the only commercially available combustion turbine NOx reduction technology capable of attaining those high levels of NOx reduction. While the SCR process is generally applicable to any combustion turbine, site specific conditions or economic considerations may affect the feasibility of a given SCR retrofit project. SCR systems are generally able to attain outlet NOx emission rates in the low single digit ppmvd range.

NOx Control	Nameplate Rating (MW)	Estimated NOx Reduction (%)	Estimated Cost ($)
Water Injection	4 – 23	40	398,000 – 1,481,000
Low NOx Combustors	4 – 23	60	260,000 – 1,094,000
SCR	5 – 25	90	901,000 – 2,432,000

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on “Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines”, adjusted for CPI.)

It should be noted that the range of costs for installation of the combustion related NOx reduction controls on combustion turbines is highly dependent upon the make and model of the combustion turbine, and less dependent upon the combustion turbine’s nameplate rating for this size range. Additionally, cost effectiveness (in terms of $/ton of NOx reduced) of any NOx reduction project would be dependent upon the capacity factor of the affected combustion turbine.

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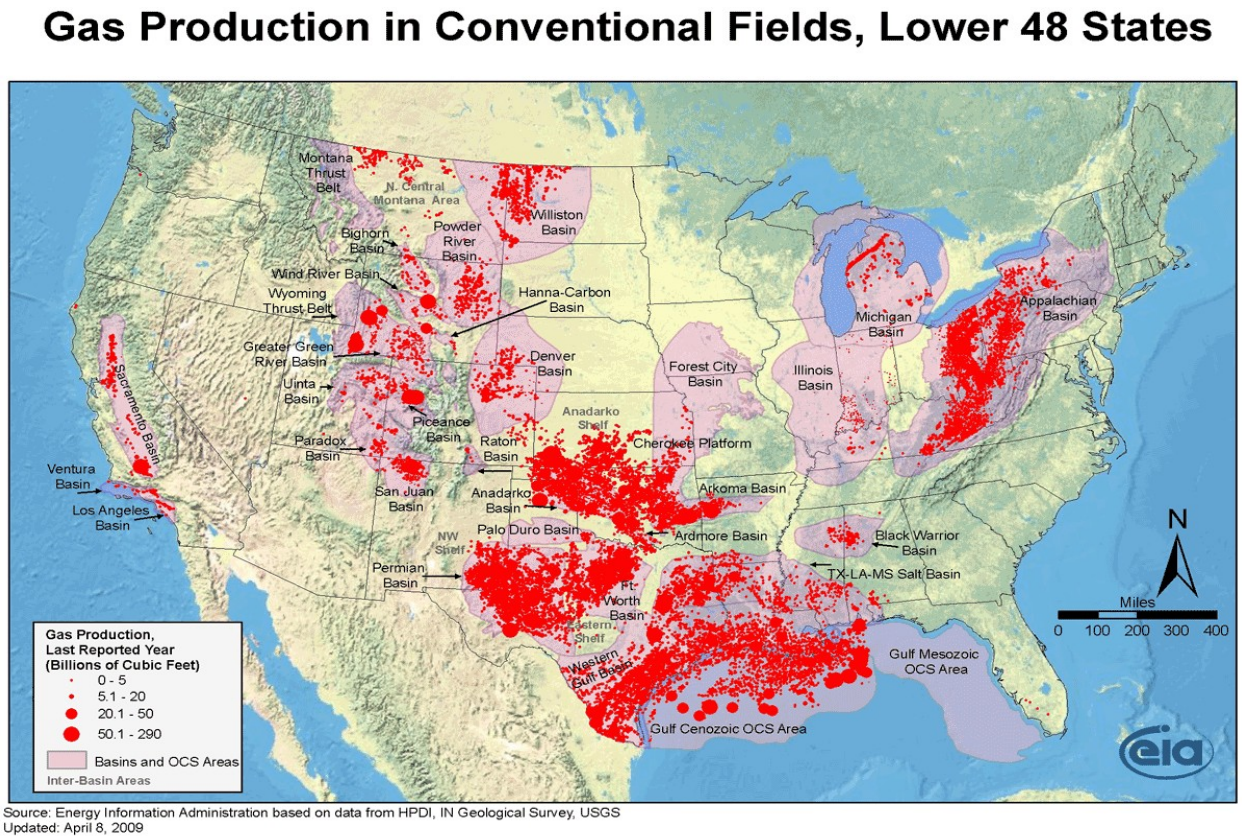
Attachment 1
Upstream Oil and Gas Sector NOx Emitting Equipment
OTR Region

Oil and gas sector activities in the ozone transport region (OTR) that emit NOx closely mimic those of the overall lower 48 states, as discussed in the body of this document. Within the OTR these activities include crude oil and gas well drilling operations, oil well pumps and wellhead heaters, gas well compressors and wellhead gas heating, field gathering activities, mainline pumps and compressors, and underground storage activities.

OTR Oil and Gas Well Drilling

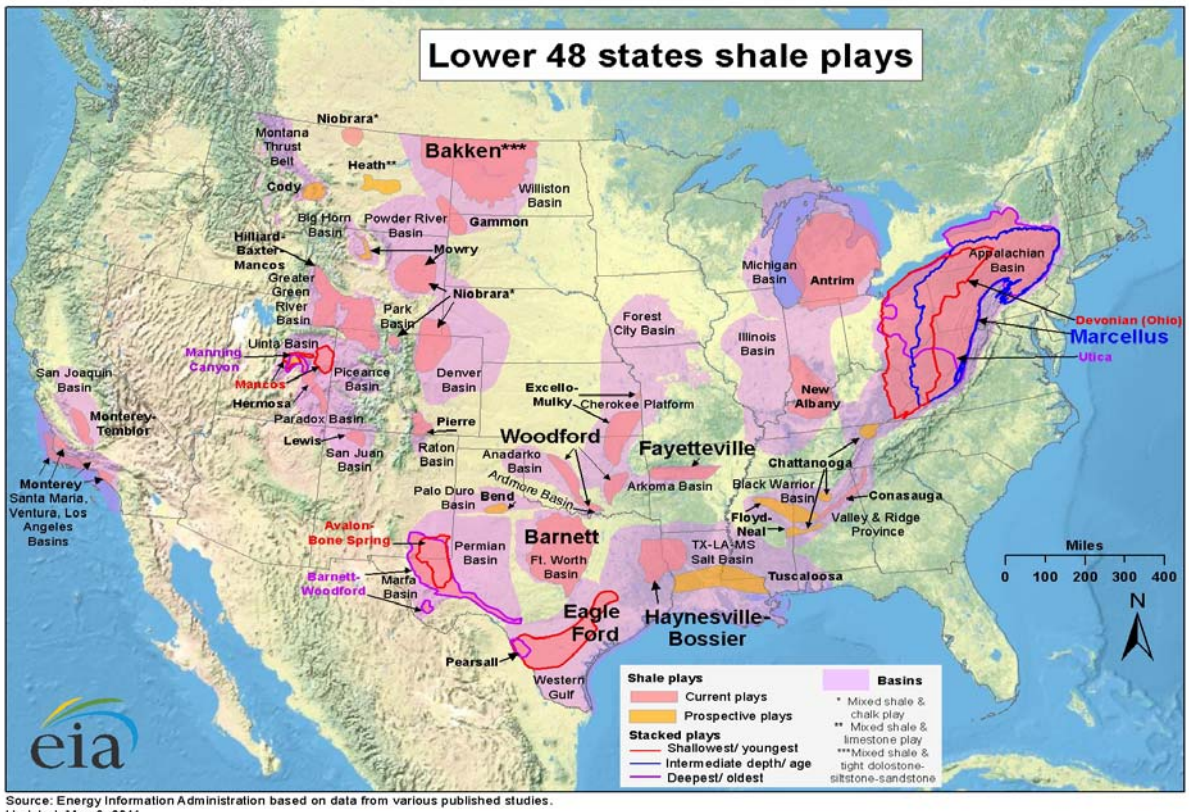
While both crude oil and natural gas are produced in the OTR, from an upstream activities standpoint the gas sector is larger and better documented than the oil sector.

Gas drilling in the OTR includes drilling for conventional gas, shale gas, and coal bed methane. The following illustration from the EIA shows the conventional gas fields in the lower 48 states, including those in the OTR:



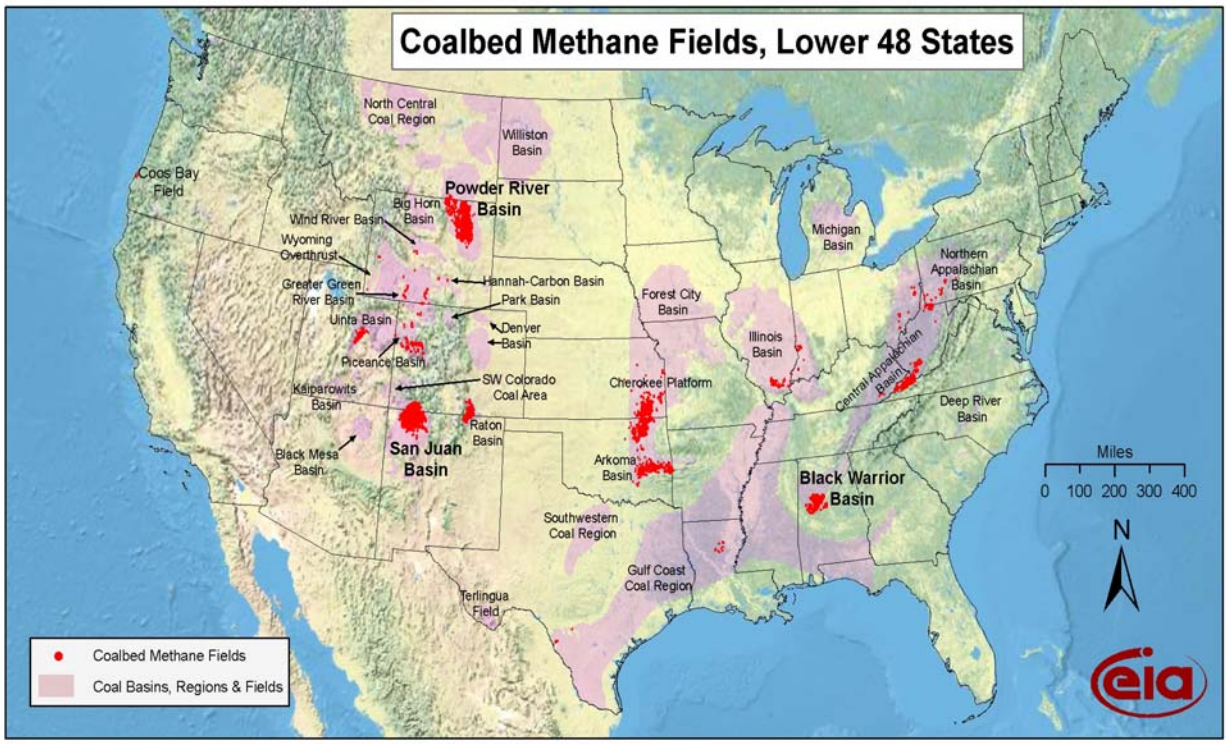
Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009

The following illustration, also taken from the EIA website, shows the shale gas fields in the lower 48 states, including those in the OTR:



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

The following illustration is also from the EIA website, and shows the coal bed methane fields in the lower 48 states, including those in the OTR:



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Rotary drill rigs are utilized for the drilling of oil wells and gas wells. These drill rigs are moved from site to site to support the drilling of exploratory and production wells. Within the last decade, drill rigs have been employed to drill oil and/or gas wells in the OTR states of Maryland, New York, and Pennsylvania. The following table presents data from the EIA website, and shows the annual average number of rotary drill rigs in operation in these OTR states:

Annual Average Count of Rotary Rigs in Operation
(Average of Monthly Averages)

Year	Maryland	New York	Pennsylvania
2002	0	4	11
2003	0	3	10
2004	0	5	9
2005	0	4	13
2006	0	6	16
2007	1	6	16
2008	0	6	23
2009	0	2	42
2010	0	1	85
2011	0	0	110

Data from the RigData website indicates that as of the date the website was accessed, in the OTR only the states of New York and Pennsylvania have had rotary drill rigs in operation so far in 2012. The following table shows the number of drill rigs in operation by month for the OTR states:

Drilling Rigs In Operation 2012
Weekly Average for the Month

	January	February	March	April
New York	2	0	0	2
Pennsylvania	139	124	120	116

The RigData website also provided information concerning the number of wells started for each state by month. As of the date the website was accessed, the following table shows the number of wells started for the OTR states:

Well Starts 2012

	January	February	March
New York	3	0	0
Pennsylvania	196	184	208

For the wells started in 2012, the RigData website provided data regarding the depth range of the wells and the approximate total number of feet drilled for those wells. As of the date the website the accessed, the following table shows the number of wells started for each depth range and the approximate total number of feet drilled for those wells:

Well Starts by Depth Range
January – March 2012

	1 – 2,499 ft depth	2,500 – 4,999 ft depth	5,000 – 9,999 ft depth
New York	1 well, 2000 ft	2 wells, 5,000 ft total	0
Pennsylvania	20 wells, 37,000 ft total	27 wells, 102,000 ft total	535 wells, 3,891,000 ft total

OTR Oil and Natural Gas Production

Within the OTR, New York and Pennsylvania are the two states that produce crude oil. Only a limited amount of data could be located documenting the number of oil wells in the New York and Pennsylvania. The following data is the latest data available from the EIA website, and represents the annual number of oil wells operating in the respective states:

Year	No. of Oil Wells New York	No. of Oil Wells Pennsylvania
2000	NA	6011
2001	NA	6589
2002	916	5243
2003	2884	5480
2004	2968	5167
2005	2789	NA
2006	3121	NA
2007	2979	NA
2008	3271	NA
2009	3011	NA

Collectively, the production of crude oil in Pennsylvania and New York represent less than 0.5% of the crude oil produced in the US. The following table shows the annual crude oil production in Pennsylvania and New York for the last several years:

Year	New York Field Production of Crude Oil (Thousand Barrels)	Pennsylvania Field Production of Crude Oil (Thousand Barrels)
2001	166	1620
2002	165	2233
2003	144	2425
2004	170	2538
2005	197	3947
2006	319	3626
2007	380	3653
2008	386	3611
2009	339	3541
2010	378	3474
2011	390	3656

The above data was extracted from EIA sources, and includes the latest annual data available at the time the data was accessed. It can be seen in the above data that after a step increase in crude oil production around 2005, the crude oil production from New York and Pennsylvania was relatively flat through 2011.

Within the OTR, the states of Pennsylvania and New York are also two of the three natural gas producing states, the third state being Maryland. The following table shows the latest data available from the EIA website, and represents the annual number of gas wells in the respective states:

Year	Maryland Natural Gas Number of Gas and Gas Condensate Wells	New York Natural Gas Number of Gas and Gas Condensate Wells	Pennsylvania Natural Gas Number of Gas and Gas Condensate Wells
2001	7	5913	40100
2002	5	6496	40830
2003	7	5878	42437
2004	7	5781	44227
2005	7	5449	46654
2006	7	5985	49750
2007	7	6680	52700
2008	7	6675	55631
2009	7	6628	57356
2010	7	6736	44500

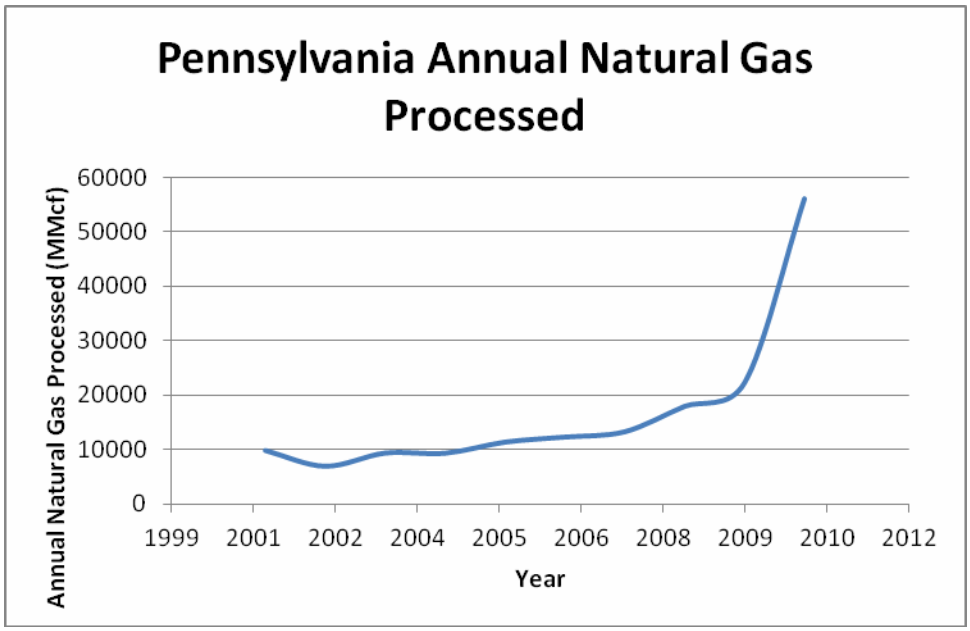
The following table shows the natural gas production in Maryland, New York, and Pennsylvania for the last several years:

Year	Maryland Natural Gas Gross Withdrawals (MMcf)	New York Natural Gas Gross Withdrawals (MMcf)	Pennsylvania Natural Gas Gross Withdrawals (MMcf)	Total OTR Natural Gas Gross Withdrawals (MMcf)
2001	32	27787	130853	158672
2002	22	36816	157800	194638
2003	48	36137	159827	196012
2004	34	46050	197217	243301
2005	46	55180	168501	223727
2006	48	55980	175950	231978
2007	35	54942	182277	237254
2008	28	50320	198295	248643
2009	43	44849	273869	318761
2010	43	35813	572902	608758

The above data was extracted from EIA sources, and includes the latest annual data available at the time the data was accessed. It can be seen in the above data that between 2001 and 2008 there was a slow, steady increase in the collective annual natural gas production from the three states. However, the data also indicates that beginning in 2009 that here was a sharp increase in natural gas production

collectively from the states. In can be seen that this increase is predominately from Pennsylvania, and that increase roughly corresponds to the expansion of shale gas development in Pennsylvania.

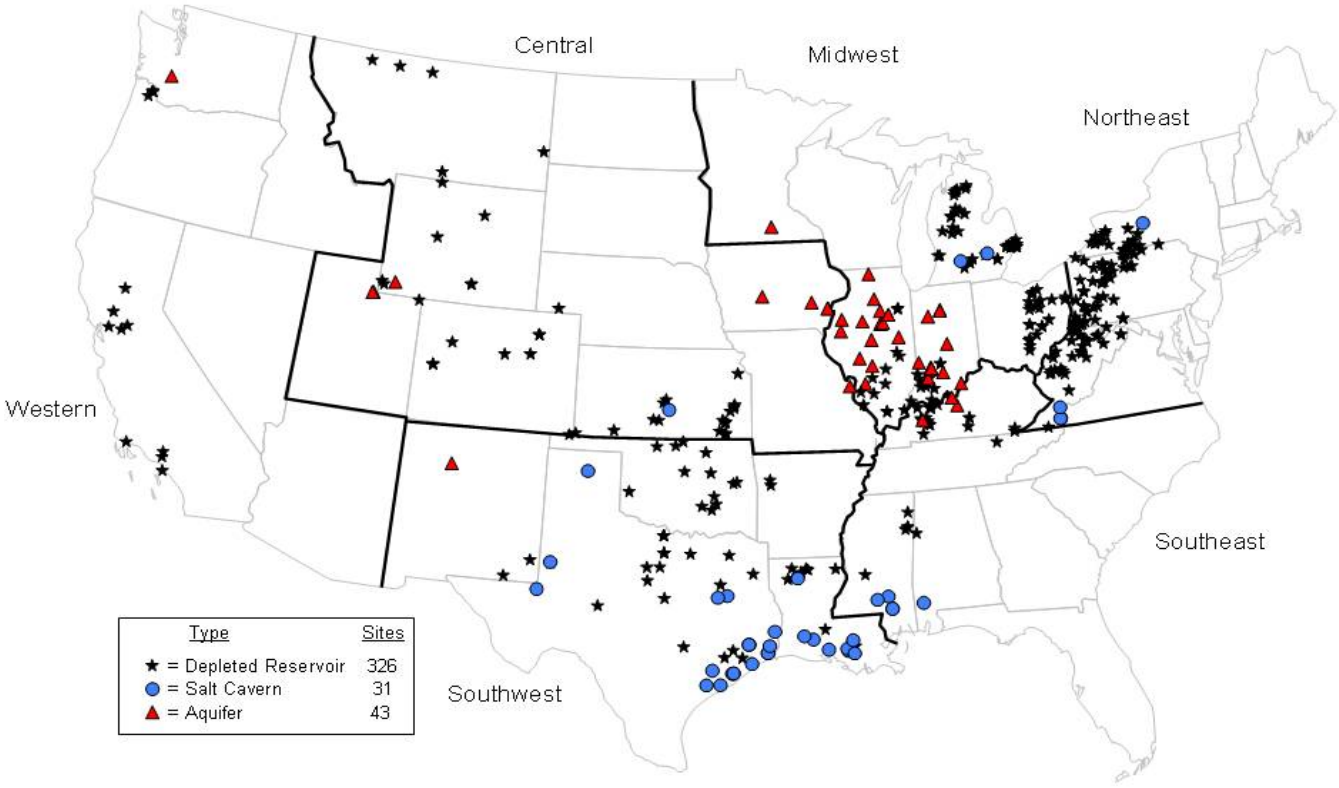
The sharp increase in natural gas production in recent years in Pennsylvania is also evidenced in the output from natural gas processing plants in Pennsylvania. (Pennsylvania is the only state in the OTR with large central natural gas processing plants according to EIA data.) Some natural gas requires processing before it is pipeline quality, and therefore must be appropriately processed before it can be injected into mainline or distribution pipelines. The following chart of EIA data shows the amount of natural gas processed in Pennsylvania's natural gas processing plants over the last several years:



OTR Underground Natural Gas Storage

The following map shows the natural gas storage facilities in the lower 48 states.

U.S. Underground Natural Gas Storage Facilities, 2007



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

It can be seen in the map that within the OTR, New York and Pennsylvania are the primary locations of underground natural gas storage facilities. The natural gas storage facilities in the OTR are important for balancing natural gas demand with supplies during peak demand periods. In New York and Pennsylvania, the majority of the underground storage is depleted natural gas production fields, thereby potentially taking advantage of existing wells, gathering stems, pipeline connections, etc that were installed originally to facilitate natural gas extraction. New York also has a salt cavern natural gas storage facility. Pennsylvania has more underground natural gas storage facilities than any other state.

The compressors at underground storage facilities may be used to inject pipeline natural gas into storage and then re-inject the natural gas back into the pipelines for transportation to the users. EIA data from 2006 indicated that Pennsylvania and New York ranked 5th and 8th highest among states with the largest increase in natural gas underground storage deliverability for the period of 1998 through 2005. (Pennsylvania exhibited a 13% increase (969 MMcuft/day added) and New York exhibited a 44% increase (510 MMcuft/day added)).

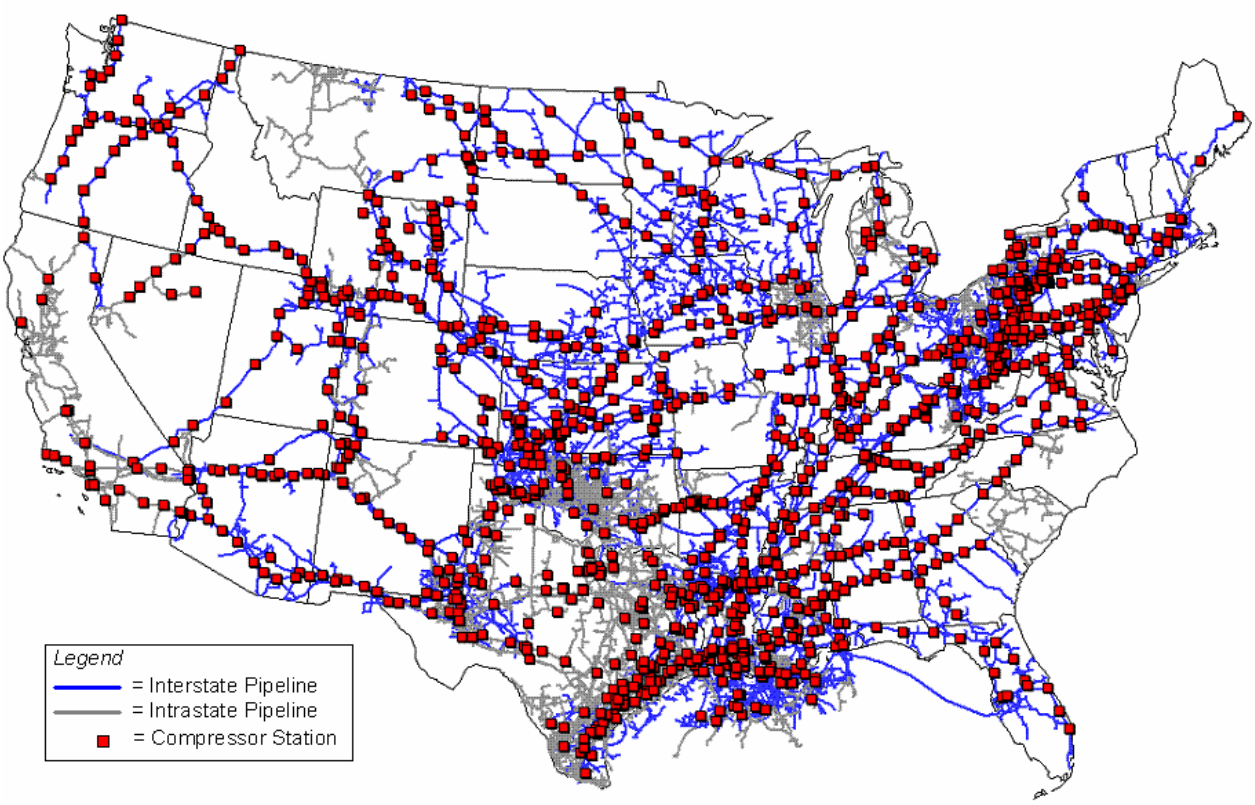
OTR State Natural Gas Underground Storage Capacity

State	Number of Storage Sites	Working Storage Capacity (bcf)
MD	1	17
NY	24	117
PA	50	406

OTR Natural Gas Pipeline Compressors

Mainline natural gas transmissions pipeline systems utilize compressors at gas compressor stations to maintain system flow and overcome pressure losses due to the movement of the natural gas through the natural gas pipeline system. These compressor stations are typically located at 40 mile to 100 mile intervals along the transmission pipeline, as required by the particular pipeline section duty, to maintain the required flow and pressure. These mainline natural gas compressor facilities will often include multiple gas compressors to add flexibility and reliability in meeting the variable natural gas flow demand. Below is a map from the EIA of the US interstate mainline gas system noting the location of the mainline compressor stations as of 2006. EIA and Federal Energy Regulatory Commission (FERC) data indicates that there have been a number of compressors stations (and compression additions to existing compressor stations) that have been put in service subsequent to 2006 to help meet the growing demand for natural gas as a fuel. Some of the new compression stations (and compression additions to existing compressor stations) have been added in the OTR.

U.S. Natural Gas Pipeline Compressor Stations, EIA, 2008



The map shows that there are many mainline compressor stations in the OTR, with a relatively high concentration in New York and Pennsylvania. Prime movers for these mainline compressors are typically natural gas fired reciprocating engines and combustion turbines, although there are also a number of electric motor gas compressor prime movers in the OTR. In some instances, combustion compressor prime movers and electric motor compressor prime movers are located in the same compressor facilities. The horsepower ratings of the individual combustion compressor prime movers range from less than 300 hp to 15,000 hp and more.

Many mainline natural gas compressor stations have multiple compressors operating in parallel to help meet large variations in the natural gas flow, and may also have some redundancy to minimize the impact of maintenance or problems with any given compressor unit. Industry data indicated that many of the mainline natural gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity. Within the OTR, FERC compressor facility specific (not unit specific) data indicated that for 2007 the range of facility operating capacity (in terms of compressor operating hours) ranged from 0% to approximately 95%, with an average of approximately 35%. For many mainline natural gas compressor facilities, reciprocating engines are preferred for their ability to adjust their output to meet the pipeline demand. Compressor loading will tend to increase during periods of high natural gas demand, such as cold periods with high heating fuel demand or high electric demand days in the northeast when natural gas fired electric generation is a significant consumer of natural gas. Within the OTR, FERC compressor facility specific data for 2007 indicated that 24 of 141 compressor facilities saw their peak 2007 day during the ozone season.

A review of 2010 FERC Form 2 and Form 2A data indicated that in 2010 there were 149 compressor stations in the OTR used for natural gas transmission service. The FERC data indicated that these compressor stations collectively had 518 natural gas compressors with a collective total horsepower rating of 2,053,510 hp (an unknown portion of which is likely powered by electric motors). The FERC data indicates that in 2010 these facilities collectively combusted 47,426,022 dth (approximately 47,426,022,000 cf) of natural gas for compression services.

Data from MARAMA's 2007 Point Source Inventory was reviewed to obtain a better understanding of the makeup of the OTR's population of fuel-combustion natural gas compressor prime movers. The review of the data indicated that a number of the units in the database did not give sufficient information to categorize each unit, sometimes not identifying the prime mover configuration (engine, turbine, 2SLB, etc), manufacturer, model number, output capacity, etc. It was possible to supplement some of the MARAMA data with information obtained from internet searches of compressor station operating permits, but there remains a significant number of units in the database with only partial information. Also, it is likely that the 2007 MARAMA data includes compressor units utilized for field gathering and underground storage in addition to the mainline compressors.

NMED Exhibit 45

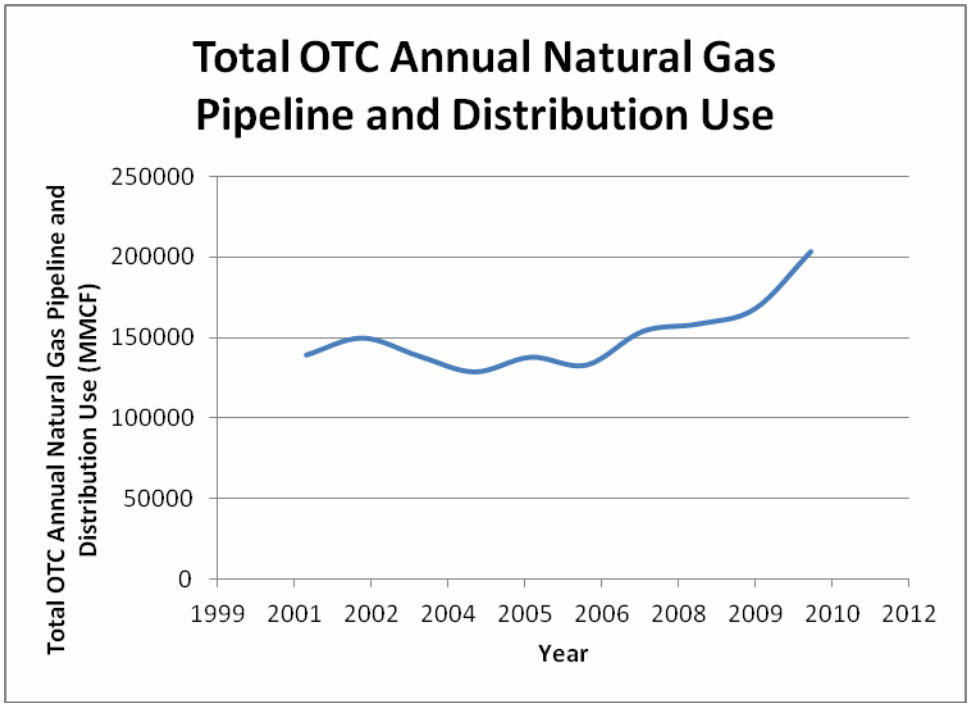
From the available information, it appears that the population of OTR natural gas compressor prime movers is diverse with regards to make, model, and capacity. For the reciprocating engines (2SLB, 4SLB, and 4SRB), the available data indicates that there are at least 60 different engine models spread among 13 different manufacturers. For the turbines, the available data indicates that there are at least 20 different models spread among 6 different manufacturers. [It should be noted that the number of manufacturers represented in the data are sometimes the result of mergers and buyouts. For example, the reciprocating engine manufacturer Superior (existing since the early 1900's) became White-Superior in the mid-1960s, then became Cooper-Superior in the early 1970s, and became Superior (within Cameron) in the mid-1970s. In fact, Cameron is also the current OEM for the Cooper-Bessemer line of engines.]

Within the available OTR compressor inventory data for reciprocating engines, the range of output for 2SLB reciprocating engines is approximately 400 HP to 5500 HP, the range of output rating for 4SLB reciprocating engines is approximately 650 HP to 4,300 HP, and the range of output rating for 4SRB reciprocating engines is approximately 200 HP to approximately 1,300 HP. Also within the available OTR compressor inventory data for combustion turbines, the range of output is approximately 1,000 HP to approximately 20,000 HP.

The data inventory also does not provide an indication of the vintage or age of the prime movers. Of most concern is the vintage of the reciprocating engines, as they have been available as compressor prime movers longer than combustion turbines and have been shown to have long service life. Industry information indicates that nationally there are many natural gas compression reciprocating engines that are in excess of 40 years old. While the data available at this time for the OTR natural gas pipeline compression reciprocating engines does not include an indication of the age of these engines, some inference can be made that many "vintage" reciprocating engine compressor prime movers continue in operation in the OTR by reviewing the manufacturer and model number of the subject engines. For example, industry information indicates that the Cooper-Bessemer family of GMW 2-stroke integral engines was manufactured between 1946 and 1965. The 2007 MARAMA database indicates that there are a number of such engines in the OTR that were still operating in 2007. The database does not contain sufficiently detailed information to determine if any of these vintage engines have undergone NOx RACT or been subject to any other NOx reduction activities.

The 2007 MARAMA point source data indicted that, collectively, the compressor prime movers in the OTR compressor facilities emitted approximately 11,000 tons of NOx in 2007, with the average facility emitting approximately 112 tons of NOx in 2007. The highest NOx emitting facility emitted in excess of 1100 tons of NOx in 2007, those emissions collectively from 12 reciprocating engines. Because portions of the 2007 MARAMA point source data is presented as "per facility" rather than all on a "per unit" basis, it is difficult to get a thorough understanding of the unit-by-unit annual NOx emissions of the OTR gas compressor prime movers. It appears that the range of unit specific 2007 annual NOx emissions ranged from approximately 177 tons of NOx to less than 0.1 ton of NOx. The gas compressor prime movers at the upper end of the range appear to be predominately gas turbines and 2-stroke lean burn reciprocating engines.

The following graph reflects EIA data and shows the annual amount of natural gas consumed in the OTR for use in natural gas pipeline and distribution operations. This natural gas consumption is primarily for compression. The graph shows that there has been a significant increase in the amount of natural gas utilized for gas pipeline and distribution purposes over the last few years. This increase in use follows the increased demand for natural gas from OTR users, and the increased production of natural gas from OTR sources.

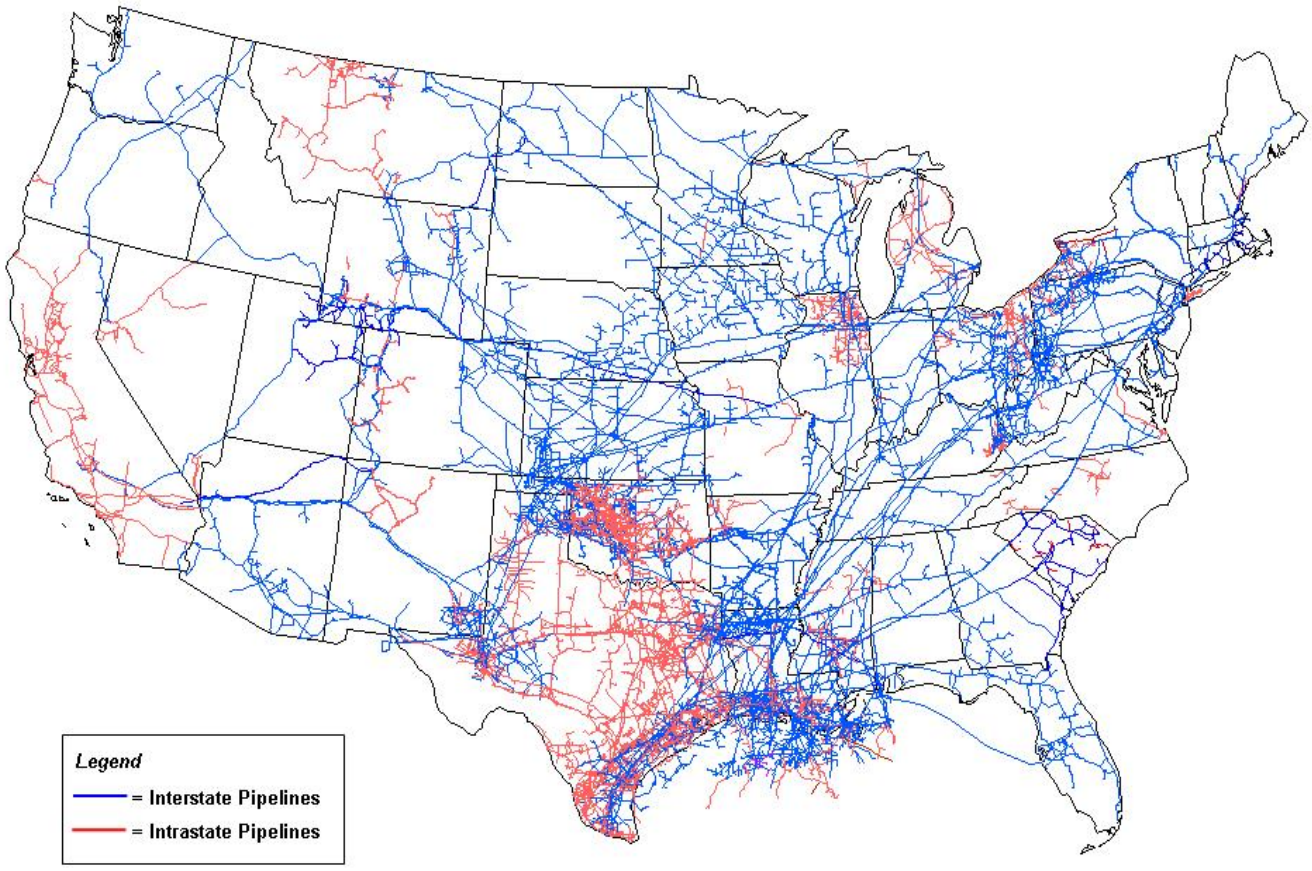


OTR Mainline Natural Gas Pipelines

While natural gas pipelines do not emit NOx themselves, the existence of the complex pipeline system is critical to the function of the natural gas industry in the OTR, and therefore the NOx emitting processes associated with the natural gas industry in the OTR. Interstate pipelines deliver natural gas to the OTR through several intrastate natural gas pipelines and to many local distribution companies in the OTR. In addition, the interstate pipelines also serve many large industrial concerns and natural gas fired electric power generation facilities.

The natural gas pipeline and local distribution companies serving the OTR have access to supplies from several major domestic natural gas producing areas, including those in the OTR, and from Canada. Natural gas from outside the OTR flows into the region from the Southeast through Virginia and West Virginia, and from the Midwest through West Virginia and Pennsylvania. Canadian natural gas imports come into the OTR principally through New York, Maine, and New Hampshire.

Liquefied natural gas (LNG) supplies also enter the region through import terminals located in Massachusetts, Maryland, and New Brunswick, Canada.



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

The interstate natural gas pipeline systems that serve the OTR include the following:

- One of the largest natural gas pipelines transporting natural gas into the OTR is the Transcontinental Gas Pipeline Company system, which extends from South Texas to the New York City area.
- The Tennessee Gas Pipeline Company and the Texas Eastern Transmission Company natural gas pipeline systems bring supplies to the OTR from Texas, Louisiana, and the Gulf of Mexico. The Tennessee Gas Pipeline Company system, unlike the Transcontinental Gas Pipeline Company and Texas Eastern Transmission Company systems, extends its service northward as far as New Hampshire and is a major transporter of natural gas to Connecticut, Massachusetts, and Rhode Island.

- The Tennessee Gas Pipeline Company system is also a significant source of supply for the regional Algonquin Gas Transmission Company system, which is the principal interstate natural gas pipeline serving the Boston, Massachusetts area. The Texas Eastern Transmission Company, an affiliate of the Algonquin Gas Transmission Company, is the primary source of supply for that pipeline, delivering approximately 65 percent of Algonquin's requirements at interconnections in New Jersey. The Algonquin Gas Transmission Company system has the capability to move a significant portion of its system capacity from New Jersey into the New York metropolitan area.

- The Algonquin Gas Transmission Company is also receives natural gas processed at the Northeast Gateway liquefied natural gas (LNG) import terminal located 10 miles offshore of Massachusetts. The Northeast Gateway port's infrastructure features two submerged turret loading buoys for off loading, and is linked to the Algonquin Gas Transmission Company system by a 16-mile submerged pipeline.

- The Columbia Gas Transmission Company has an extensive network of natural gas pipelines that provide service to Maryland, New Jersey, New York, and Pennsylvania. The Columbia pipeline transports natural gas from the Gulf of Mexico as well as natural gas produced in the Appalachian region. The Columbia Gas Transmission Company supplies some of the largest natural gas distribution companies in the OTR.

- The Millennium Pipeline natural gas system begins at an interconnection with the Empire Pipeline system in southwest central New York State and terminates in the New York City metropolitan area. It is part of an overall regional effort involving expansion of the existing Empire, Algonquin and Iroquois Pipelines, which are among its major supply sources.

- The Dominion Transmission Company system serves Maryland, New York, and Pennsylvania. The Dominion Transmission Company also serves some of the largest natural gas distribution companies in the OTR.

In addition to the interstate natural gas pipeline companies that bring natural gas into the OTR, several smaller interstate natural gas pipeline companies operate primarily within the OTR (and OTR-neighboring states). Among these systems are:

- Equitrans Inc. serves western Pennsylvania, and its pipeline system was developed to move local production to regional markets through connections with local natural gas field gathering, distribution, and storage interconnections.

- The Eastern Shore Natural Gas Company is the only natural gas pipeline serving southern Delaware and the lower Delmarva Peninsula. It receives its supplies from Transcontinental Gas Pipeline Company and Columbia Gas Transmission Company at points in southeastern Pennsylvania, with a route that takes it southward through Delaware to Maryland's eastern shore.

- The Granite State Transmission Company receives natural gas from the Tennessee Gas Pipeline Company and/or the PNGTS/Maritimes and Northeast Pipeline system at the southern New

Hampshire/Massachusetts border. From there it transports to customers in New Hampshire and to the Northern Utilities Company system.

- The KeySpan Energy Delivery Company is the principal provider of natural gas service to New York City and Long Island, New York, its intrastate operations also include service in Massachusetts and New Hampshire as well.

Canada is also a significant source of natural gas to the OTR through the pipeline system. Some of the more significant sources include the following:

- The Iroquois Gas Transmission Company system is supplied with natural gas from the TransCanada Pipeline Ltd system in Ontario, Canada.

- The Empire Pipeline Company system, an intrastate affiliate of National Fuel Gas Supply Corporation, brings in Canadian natural gas at Grand Island, New York to north central New York State with interconnections to the Dominion Transmission Company and National Fuel Gas Supply Corporation systems. These latter two companies also access Canadian natural gas supplies from the Tennessee Gas Pipeline, which imports Canadian natural gas through Niagara Falls, New York.

- The Portland Natural Gas Transmission System (PNGTS) merges with the Maritimes and Northwest Pipeline system at Wells, Maine, where they form a joint natural gas pipeline that extends south through southern New Hampshire and terminates in northern Massachusetts (with an interconnection to the Tennessee Gas Pipeline Company system). PNGTS also provides bidirectional service to its customers allowing shippers of Canadian Sable Island natural gas (which use the Maritimes & Northeast Pipeline Company system) the opportunity to redirect some of their natural gas to markets located in Quebec (which previously had access only to western Canadian natural gas supplies).

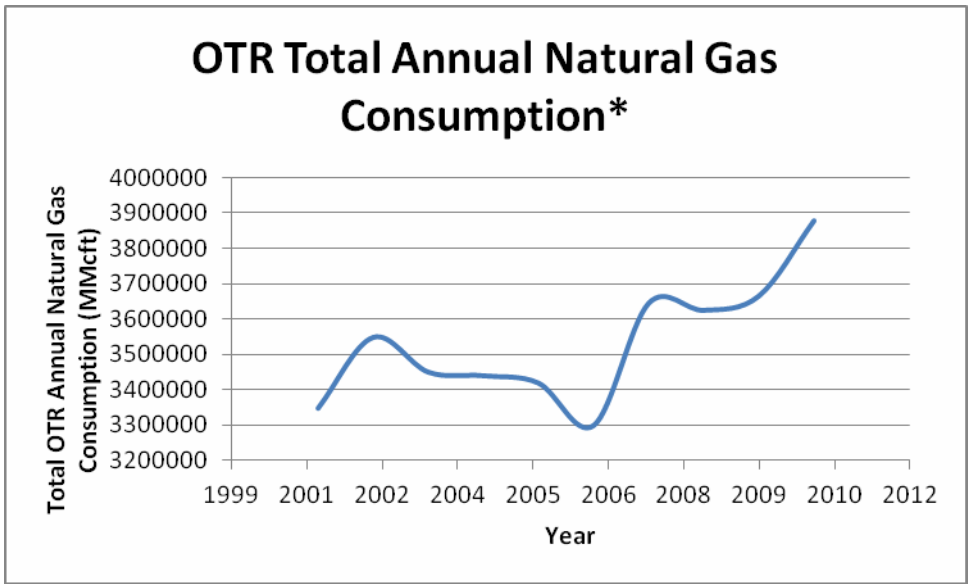
- The U.S. portion of the Maritimes and Northeast Pipeline Company system begins at Calais, Maine, at the Canadian border and extends to Wells, Maine. The Maritimes and Northeast Pipeline system was built to access natural gas production off the eastern coast of Canada (Sable Island) and to transport it to New England. The Maritimes and Northeast Pipeline Company system was extended from Boston, Massachusetts to provide natural gas that area. The system also can transport natural gas processed at the Canaport liquefied natural gas (LNG) import terminal located in New Brunswick, Canada, to New England markets.

- Several smaller regional natural gas importing pipelines, such as North County Pipeline Company and the St. Lawrence Gas Company, both located in upper New York State, and the Vermont Gas Systems Company, the only natural gas pipeline in the State of Vermont, depend upon Canadian natural gas imports completely for their natural gas supplies since they do not interconnect with any other U.S. natural gas pipeline.

The robust natural gas pipeline system supplying and distributing natural gas in the OTR has been instrumental in supporting the widespread use of natural gas for residential, commercial, and industrial

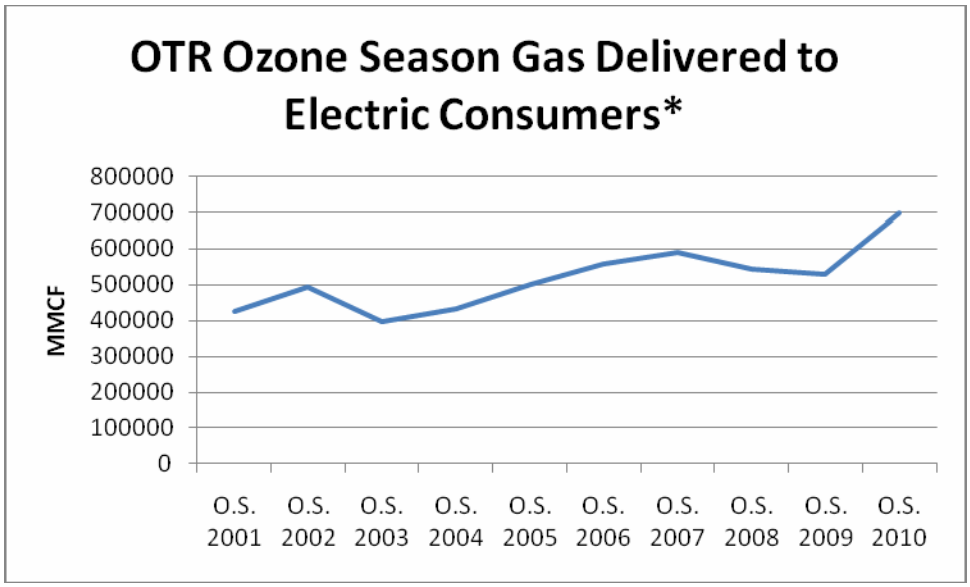
NMED Exhibit 45

purposes. As shown in the following graph, the use of natural gas has been on a general incline in the OTR as a whole over the last decade:

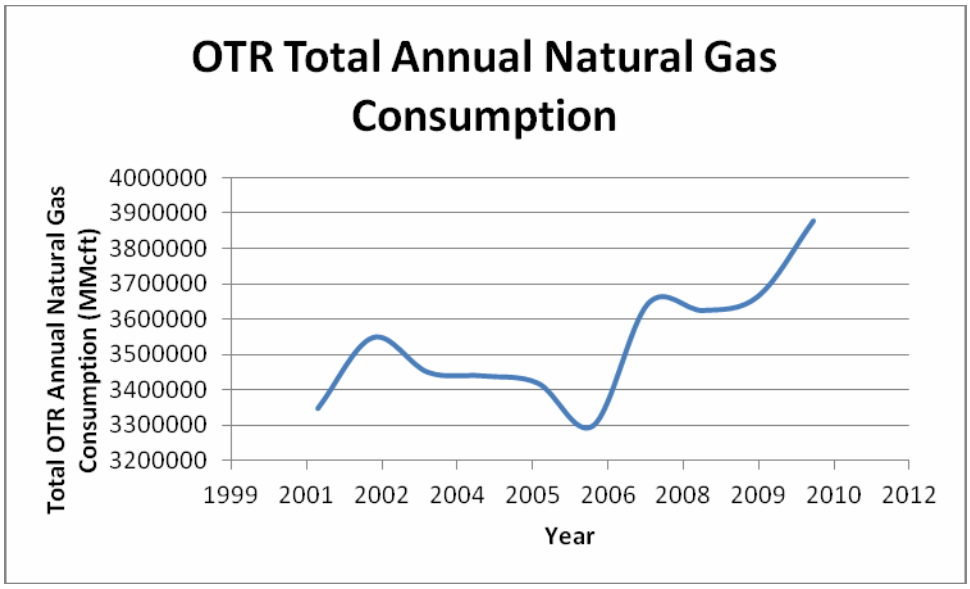


*Excluding Virginia

Some of the growth in the OTR's natural gas consumption has been due to increased use by electric generating units in the OTR. This increase is evdent in both the OTR annual total electric genrating unit natural gas consumption and the OTR ozone season total electric generating unit natural gas consumption, as shown in the following two graphs:



*Excluding VA

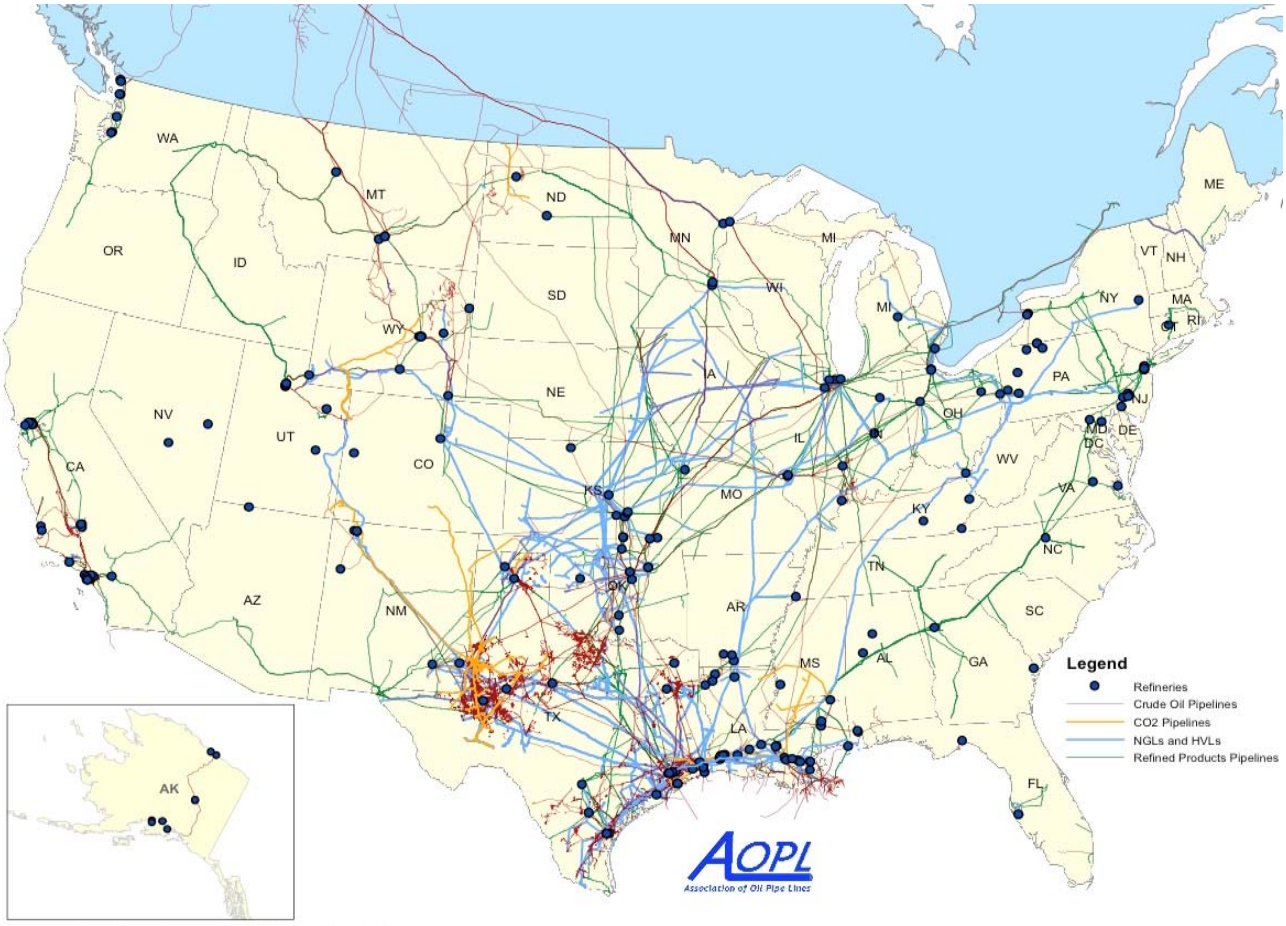


Note: Excluding VA

Crude Oil and Refined Products Pipelines

Within the OTR there are also a number of pipelines for transporting crude oil and refined products. Little information could be located regarding the number and makeup of pumping stations on those pipelines. The following map shows the relate pipeline system for the lower 48 states. It can be seen in the map that, relative to natural gas pipeline network system, the crude oil and refined products pipeline network is far less extensive in the OTR states.

Lower 48 States Crude Oil and Refined Products Pipelines, 2009



Source: Petroleum Geographics Corporation 2012

Attachment 2

2010 FERC Form 2 and Form 2A Data

OTR Natural Gas Compressors

State	Service	Facility Name/Location	No. Compressors	Total HP	Gas Compressor 2010 Fuel Use (MMBTU/yr)	Compressor 2010 Operating Hrs	Electric Compressor 2010 Power Usage (kwhr)
CT	Transmission	Chaplin Compressor Station, Chaplin, CT	2	13900	287115	4417	0
CT	Transmission	Cromwell Compressor Station, Cromwell, CT	8	21400	647985	27190	0
CT	Transmission	Oxford Compressor Station, Oxford, CT	3	37700	285982	3258	0
CT	Transmission	Brookfield Compressor Station, Brookfield, CT	2	18010	754008	11737	829750
CT	Transmission	Milford Compressor Station, Milford, CT	2	20620	260736	3101	509640
MA	Transmission	#261 - Agawam, MA Electric/Gas	5	17110	112038	6598	3199914
MA	Transmission	#264 - Charlton City, MA	2	12552	740495	7674	0
MA	Transmission	#266A - Mendon, MA	3	9170	167252	6769	0
MA	Transmission	#267 - Hopkinton, MA	5	5000	48126	728	0
MD	Transmission	Rutledge, MD	3	12000	0	7984	17053583
MD	Undrgrd Strg	Accident, MD	2	11000	86106	5212	1167552
MD	Transmission	No. 190 Ellicott City, Maryland	12	29250	1980798	96310	0
ME	Transmission	Baileyville Compressor Station,ME	2	16622	258129	3550	0
ME	Transmission	Richmond Compressor Station, ME	2	16622	208448	3108	0
ME	Transmission	Wood Chopping Ridge Compressor Station, ME	1	18085	367363	3323	0
ME	Transmission	Brewer Compressor Station, ME	1	18085	233651	2494	0
ME	Transmission	Searsmont Compressor Staion, ME	1	18085	123360	553	0
ME	Transmission	Westbrook Compressor Station, ME	2	26666	129882	1418	0
ME	Transmission	Eliot Compressor Station, ME	1	8960	20775	256	0
NH	Transmission	#270B1 - Pelham	1	6053	7959	97	0
NJ	Transmission	Hanover Compressor Station, Hanover, NJ	3	22000	193007	6245	0
NJ	Transmission	#325 - Sussex, NJ	2	14991	276720	5675	0
NJ	Transmission	Franklin (Freehold), NJ	1	5000	0	12	356417
NJ	Transmission	Hanover, NJ	1	6500	168087	6	180960
NJ	Transmission	Lambertville, NJ	7	24600	509431	22921	6818612
NJ	Transmission	Linden, NJ	3	6150	228305	13840	363520
NJ	Transmission	No. 205 Lawrenceville, New Jersey	3	30200	0	3333	31162606
NJ	Transmission	No: 207 Sayreville, New Jersey	2	10000	1806	4519	16011555
NJ	Transmission	No. 505 Centerville, New Jersey	8	16000	132840	8776	0
NJ	Other	No. 240 Hackensack Meadows, New Jersey	5	4320	148182	11445	0
NY	Transmission	Southeast Compressor Station, Southeast, NY	5	40010	1299694	14952	0
NY	Transmission	Stony Point Compressor Station, Stony Point, NY	7	38800	870835	13768	0
NY	Transmission	Corning, NY	1	1000	5904	2551	0
NY	Undrgrd Strg	Dundee, NY	3	1880	618	2133	0
NY	Undrgrd Strg	North Greenwood, NY	1	1000	0	0	0
NY	Undrgrd Strg	Quinlan, NY	2	4740	57565	2085	0
NY	Undrgrd Strg	Woodhull, NY	8	14700	260074	14522	0
NY	Transmission	Borger, NY	3	21910	236330	4100	0
NY	Transmission	Brookmans Corner, NY	1	7300	11139	114	0
NY	Transmission	Lockport, NY	0	0	0	0	0
NY	Transmission	Utica, NY	7	9500	34762	3813	0

NY	Transmission	Oakfield NY	2	20620	20134	220	262560
NY	Transmission	Croghan Compressor Station, Croghan, NY	2	17180	333832	4548	702880
NY	Transmission	Wright Compressor Station, Wright, NY	2	14302	436558	7607	513456
NY	Transmission	Athens Compressor Station, Athens, NY	1	10028	228932	2667	442080
NY	Transmission	Boonville Compressor Station, Boonville, NY	1	18371	206107	1533	620320
NY	Transmission	Dover Compressor Station, Dover, NY	1	18371	330391	2510	948538
NY	Transmission	Corning Millenium, NY	1	15000	0	1611	0
NY	Field	Field Compressor St - Appalachian Field	1	450	8262	8112	186221
NY	Undrgrd Strg	Beech Hill	3	8350	12113	8068	388560
NY	Undrgrd Strg	Derby	1	75	400	1832	9183
NY	Undrgrd Strg	Independence	4	5000	104882	10801	324800
NY	Undrgrd Strg	Limestone	1	800	31525	4328	97680
NY	Undrgrd Strg	Nashville	3	3320	20434	4543	292000
NY	Undrgrd Strg	Porterville	4	600	30413	5721	116682
NY	Undrgrd Strg	Tuscarora	2	1440	40840	4876	101496
NY	Undrgrd Strg	Zoar	8	1200	39286	18824	150880
NY	Transmission	#224 - Clymer, NY	4	8000	309015	18570	0
NY	Transmission	#229 - Hamburg, NY	6	8400	529074	46324	0
NY	Transmission	#230C - Lockport, NY	4	18000	8213	327	0
NY	Transmission	#233 - Geneseo, NY	2	7000	148178	3463	0
NY	Transmission	#237 - Clifton Springs, NY	3	8000	346521	13720	0
NY	Transmission	#241 - Lafayette, NY	5	18400	591170	20342	0
NY	Transmission	#245 - West Winfield, NY	12	19700	698051	44411	0
NY	Transmission	#249 - Carlisle, NY	4	16200	616398	18652	0
NY	Transmission	#254 - Nassau, NY	7	18710	410132	9804	0
NY	Transmission	#405A - CONNEXION NEW ENGLAND	1	7700	244347	4404	0
PA	Transmission	Artemas #2, PA	3	3670	0	1270	0
PA	Transmission	Delmont, PA	2	1954	56852	9200	0
PA	Transmission	Downingtown, PA	2	12000	0	7096	25681552
PA	Transmission	Eagle, PA	4	8050	255513	18536	0
PA	Transmission	Easton, PA	3	2890	11615	1225	0
PA	Transmission	Ellwood City, PA	2	1000	10570	1886	0
PA	Transmission	Gettysburg, PA	4	7500	233265	7969	0
PA	Transmission	Greencastle, PA	4	7070	265821	9314	0
PA	Transmission	Hellertown, PA	2	2200	21718	2502	0
PA	Transmission	Marietta, PA	3	4050	0	6281	0
PA	Transmission	McClellandtown, PA	1	225	0	0	0
PA	Transmission	Milford, PA	2	680	0	9	0
PA	Transmission	Renovo, PA	5	3370	30348	16619	0
PA	Transmission	Rimersburg, PA	1	320	13299	4692	0
PA	Transmission	Salisbury, PA	5	5480	458179	31623	0
PA	Transmission	Waynesburg, PA	5	5400	470930	22856	0
PA	Undrgrd Strg	Artemas #1, PA	2	4000	177424	8242	0
PA	Undrgrd Strg	Donegal, PA	2	2000	41653	4975	0
PA	Undrgrd Strg	Holbrook, PA	1	130	0	0	0
PA	Extraction	Hutchinson, PA	2	250	0	3564	130880
PA	Undrgrd Strg	Boom, PA	2	5200	3745	26	0
PA	Undrgrd Strg	Ellisburg, PA	8	18400	298419	24948	0
PA	Undrgrd Strg	Greenlick, PA	4	13600	394904	12019	0
PA	Undrgrd Strg	Harrison, PA	6	11100	84666	11300	0

PA	Undrgrd Strg	Leidy, PA	13	25800	427133	38719	0
PA	Undrgrd Strg	Lincoln Heights, PA	2	510	6367	9330	0
PA	Undrgrd Strg	North Oakford, PA	0	0	0	0	22730086
PA	Undrgrd Strg	North Summit. PA	2	6400	114736	4468	0
PA	Undrgrd Strg	Oakford, PA	15	43800	309724	44620	0
PA	Undrgrd Strg	Sabinsville, PA	8	12870	218612	13035	0
PA	Undrgrd Strg	South Oakford, PA	4	24200	122824	20655	28479000
PA	Undrgrd Strg	State Line, PA	4	4650	63271	5396	0
PA	Undrgrd Strg	Tioga, PA	2	8400	55413	3679	0
PA	Transmission	Ardell, PA	1	15000	304790	1822	0
PA	Transmission	Ardell 2 PA	2	3550	0	8767	0
PA	Transmission	Beaver, PA	4	12800	539427	23243	0
PA	Transmission	Bedford-TE, PA	0	0	0	0	10541707
PA	Transmission	Big Run, PA	1	1775	81786	8637	0
PA	Transmission	Centre,PA	2	12400	17980	298	0
PA	Transmission	Chambersburg, PA	4	24800	91016	5402	15584000
PA	Transmission	Chambersburg-TE, PA	0	0	0	0	5303820
PA	Transmission	Cherry Tree, PA	2	1520	84100	16146	0
PA	Transmission	Connellsville-TE, PA	0	0	0	0	0
PA	Transmission	Crayne, PA	2	15600	604644	10636	0
PA	Transmission	Finnefrock, PA	6	17500	721073	30509	0
PA	Transmission	Helvetia, PA	1	330	14608	5966	0
PA	Transmission	J.B. Tonkin, PA	1	6000	313000	7796	0
PA	Transmission	Little Greenlick, PA	3	11135	202960	8515	0
PA	Transmission	Luthersburg, PA	2	880	34281	8730	0
PA	Transmission	NFG-Ellisburg, PA	0	0	0	0	0
PA	Transmission	Perulak, PA	1	4735	99400	3674	0
PA	Transmission	Punxsutawney, PA	3	13132	397058	13087	0
PA	Transmission	Rochester Mills, PA	3	1320	69928	19079	0
PA	Transmission	Rock Springs, PA	2	4740	127	102	0
PA	Transmission	Rural Valley, PA	2	5325	104902	6433	0
PA	Transmission	Sabinsville, PA	1	5800	0	17	0
PA	Transmission	South Bend, PA	6	12000	262572	14602	0
PA	Transmission	Stoney Run, PA	3	1152	31542	9646	0
PA	Transmission	Uniontown-TE, PA	0	0	0	0	18220824
PA	Undrgrd Strg	Hartson-Washington County, PA	3	3300	114572	12354	0
PA	Transmission	Pratt-Greene County, PA	5	4800	179718	23494	0
PA	Field	Mt. Morris-Greene County, PA	2	220	4007	8826	0
PA	Field	Ryerson-Greene County, PA	1	41	0	0	0
PA	Field	Waynesburg-Greene County, PA	2	3600	203445	15651	0
PA	Undrgrd Strg	Boone Mountain	2	300	10583	318	36313
PA	Undrgrd Strg	Carter Hill	2	765	2270	678	45687
PA	Undrgrd Strg	Ellisburg	4	9445	0	19892	0
PA	Undrgrd Strg	Henderson	2	2700	125012	9575	193240
PA	Undrgrd Strg	Queen	4	450	14507	12611	51636
PA	Undrgrd Strg	Summit	2	880	14606	2324	123250
PA	Undrgrd Strg	Wellendorf	1	325	259	528	0
PA	Transmission	East Fork	5	3060	40543	9332	82669
PA	Transmission	Eldred	2	300	14770	10710	60186
PA	Transmission	Heath	1	1160	1489	7107	385200

PA	Transmission	Island Run	4	615	17527	11507	130386
PA	Transmission	Kaylor	1	145	10879	8091	13776
PA	Transmission	Knox	4	1968	64031	20087	124617
PA	Transmission	Lamont	8	1490	51257	30288	263200
PA	Transmission	Roystone	12	5500	189451	62384	149443
PA	Transmission	Sackett	4	675	28152	25532	125954
PA	Transmission	Van	2	476	5750	9346	7766
PA	Transmission	Concord	5	11250	23546	1276	332000
PA	Transmission	Costello	2	1440	0	14985	28074
PA	Transmission	Ellisburg	5	11450	491390	11450	812700
PA	Transmission	Lockport	4	18000	41925	0	0
PA	Transmission	Boone Mountain	1	280	0	5269	0
PA	Transmission	Nashville	1	225	0	3471	0
PA	Transmission	Reynoldsville	1	150	7720	6891	40903
PA	Transmission	Bowen	1	1340	360	65	23825
PA	Undrgrd Strg	#313 - Coudersport, PA	14	24270	1051775	69136	0
PA	Transmission	#219 - Mercer, PA	14	21550	867950	63824	0
PA	Transmission	#307 - Pigeon, PA (Kane)	6	15500	661587	29745	0
PA	Transmission	#313A Elllisburg, PA	2	4730	131993	8594	0
PA	Transmission	#315 - Wellsboro, PA	1	9300	70305	589	0
PA	Transmission	#317 - Troy, PA Electric	1	13000	4355	1588	7303548
PA	Transmission	#319 - Wyalusing, PA	2	9000	165676	3426	0
PA	Transmission	#321 - West Clifford, PA	3	14100	275679	7815	0
PA	Transmission	#323A - Hawley, PA (Stagecoach) Electric	1	13400	740	3918	32003200
PA	Transmission	Armagh, PA	1	22000	429957	1631	150900
PA	Transmission	Bechtelsville, PA	4	33500	1353738	20510	744902
PA	Transmission	Bedford, PA	11	33880	307777	29591	47453065
PA	Transmission	Bernville, PA	2	41800	953347	4919	591360
PA	Transmission	Heidlersburg, PA	1	16000	0	2325	14020634
PA	Transmission	Chambersburg, PA	2	41300	0	3595	16217920
PA	Transmission	Delmont, PA	12	46400	1901482	55591	2034669
PA	Transmission	Entriken, PA	1	22000	344877	1476	333840
PA	Transmission	Grantville, PA	4	33500	1571988	20018	875712
PA	Transmission	Holbrook, PA	15	58800	1908009	49712	2164622
PA	Transmission	Leidy, PA	4	8100	0	12443	189160
PA	Transmission	Lilly, PA	4	34800	1601960	22505	679680
PA	Transmission	Marietta, PA	7	23960	756327	17906	757200
PA	Transmission	Perulack, PA	4	34800	1594479	25627	1628800
PA	Transmission	Phoenixville,PA/Eagle, Pa	1	4000	0	1497	1605646
PA	Transmission	Shermans Dale, PA	2	41800	1062290	5403	531520
PA	Transmission	Uniontown, PA/Connelsville	8	79200	1293221	16995	72090151
PA	Transmission	Waynesburg, PA	1	5000	169717	4395	111200
PA	Undrgrd Strg	Leidy, PA	13	25800	242377	38719	0
PA	Undrgrd Strg	Oakford, PA (Oakford)	15	43800	358108	44620	0
PA	Undrgrd Strg	Oakford, PA (South Oakford)	4	24200	137830	20655	0
PA	Undrgrd Strg	Oakford, PA (Lincoln Heights)	2	510	9203	9330	0
PA	Undrgrd Strg	No. 530 Leidy-Tamarack Storage Field, PA	0	0	2243866	0	0
PA	Undrgrd Strg	No. 535 Wharton Storage Field, PA	5	8500	121644	20106	0
PA	Transmission	No. 195 Delta, Pennsylvania	5	19460	906501	35626	0
PA	Transmission	No. 200 Malvern, Pennsylvania	13	30860	2044206	100036	0

PA	Transmission	No. 515 Bear Creek, Pennsylvania	6	32000	423899	12281	0
PA	Transmission	No. 517 Benton, Pennsylvania	4	38500	245552	2459	0
PA	Transmission	No. 520 Salladasburg, Pennsylvania	7	35200	483089	10580	0
RI	Transmission	Burrillville Compressor Station, Burriville, RI	5	22000	599629	11360	0
RI	Transmission	#265E - Burrillville, RI (Rise)	1	7170	332999	7550	0
VA*	Transmission	Loudoun, VA	9	15190	185470	10858	0
VA*	Transmission	Loudoun, VA	3	12000	205510	8434	0
VA*	Transmission	Leesburg, VA	3	14200	357748	10089	0
VA*	Transmission	No. 185 Manassas, Virginia	10	20000	1182138	74626	0
		Total	721	2442801	55239677	2393711	414001868

*FERC 2 and 2A compressor stations in OTR area of VA

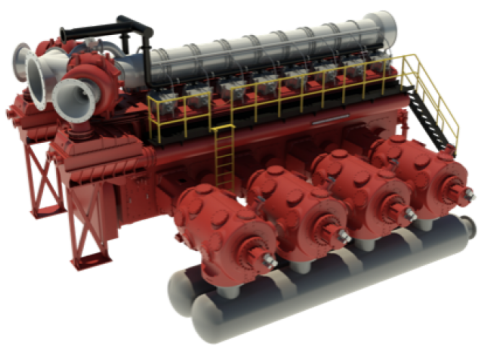
2010 OTR Natural Gas Compressors
FERC Form 2 and Form 2A Data

State	No. Compressors	Total Horsepower
CT	17	111630
MA	15	43832
MD	17	52250
ME	10	123125
NH	1	6053
NJ	35	139761
NY	123	406057
PA	472	1469533
RI	6	29170
VA*	25	61390

*OTR area of VA only

0.5 g/bhp-hr NOx SOLUTION

CONTACT US



OVERVIEW UPGRADES OUR EXPERIENCE

OVERVIEW

WE ARE MARKET LEADERS

Cooper's acquisition of HOERBIGER's Engine Solutions division has allowed us to become the market leader once again in offering upgrades for your engine automation and emissions reduction. Cooper is very proud to offer a complete upgrade solution for 0.5 g/bhp-hr NOx emission that is available for all Clark, Cooper-Bessemer, and Ingersoll Rand slow speed engine models. This solution is fully backed by Cooper's ownership of guarantee.

Our solution is built around two elements:

- Optimally designed forced air delivery system through either a turbocharger or a blower
- Electronic system upgrades for fuel, ignition, air/fuel ratio control, diagnostics, and balancing. These retrofits can be installed and operated independently with seamless ability to be integrated.

Complete Solution

OUR UPGRADES



Turbo Charger Upgrade



High Presure Fuel Injection





Balancing & Diagnostics



ePFI Electronic Port Fuel Injection



SDM Solenoid Driver Module



ePCC Pre-Chamber Control

OUR EXPERIENCE

UNITS OPERATING AT 0.5 g/bhp-hr NOx

Product Brand	Model	# Units	Location	Upgrade Technologies Applied
Clark	TLAD-8	1	Rhode Island	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	16W330	1	Arkansas	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	16W330	1	South Carolina	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMV-10	4	Texas	Blower, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMV-10	6	Texas	Blower, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMVH-8	2	New Jersey	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMWH-10C	2	Indiana	Turbocharger Re-Aero, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Ingersoll-Rand	KVG 410	6	Pennsylvania	ARC I, PLC automation, NSCR Catalyst

UNITS CAPABLE OF OPERATING AT 0.5 g/bhp-hr NOx

Product Brand	Model	# Units	Location	Upgrade Technologies Applied
Clark	HBA-8	3	New Jersey	Turbocharger, EFC, ePCC, HyperBalance
Clark	TCV-10	1	Pennsylvania	Hyperfuel, ePCC
Clark	TCV-10	2	Pennsylvania	Hyperfuel, ePCC

Product Brand	Model	# Units	Location	Upgrade Technologies Applied
Clark	TCV-10	3	Pennsylvania	Hyperfuel, ePCC
Clark	TCV-10	4	Pennsylvania	Hyperfuel, ePCC
Clark	TCVD-16	1	Louisiana	Hyperfuel, ePCC, HyperBalance
Cooper-Bessemer	12W330	1	Pennsylvania	HyperFuel, PCC, PLC automation
Cooper-Bessemer	GMVA-8	1	Pennsylvania	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC automation
Cooper-Bessemer	GMVH-8	2	New York	HyperFuel, PCC, HyperBalance

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(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)(Amended June 3, 2005)
(Amended February 1, 2008)(Amended July 9, 2010)(Amended September 7, 2012)
(Amended December 4, 2015)(Amended June 3, 2016)(Amended November 1, 2019)

RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops of the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.

(3) BREAKDOWN is a physical or mechanical failure or malfunction of an engine, air pollution control equipment, or related operating equipment that is not the result of operator error, neglect, improper operation or improper maintenance procedures, which leads to excess emissions beyond rule related emission limits or equipment permit conditions.

(4) CERTIFIED SPARK-IGNITION ENGINE means engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(5) COMPRESSOR GAS LEAN-BURN ENGINE is a stationary gaseous-fueled two-stroke or four-stroke lean-burn engine used to compress natural gas or pipeline quality natural gas for delivery through a pipeline or into storage.

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(c) (6) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during periods of fuel or energy shortage or while the primary power supply is under repair.

(7) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOC's, but not including engines used for self-propulsion.

(8) ESSENTIAL PUBLIC SERVICE includes any facility or operator as defined in Rule 1302.

(9) EXEMPT COMPOUNDS are defined in South Coast AQMD Rule 102 – Definition of Terms.

(10) FACILITY means any source or group of sources or other air contaminant emitting activities which are located on one or more contiguous properties within the South Coast AQMD, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control), or an outer continental shelf (OCS) source as determined in Section 55.2 of Title 40, Part 55 of the Code of Federal Regulations (40 CFR Part 55). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility. Sources or installations involved in crude oil and gas production in Southern California Coastal or OCS Waters and transport of such crude oil and gas in Southern California Coastal or OCS Waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas production facility on-shore.

(11) FORMER RECLAIM FACILITY means a facility, or any of its successors, that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a final determination notification, and is no longer in the RECLAIM program.

(12) LEAN-BURN ENGINE means an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.

(13) LOCATION means any single site at a building, structure, facility, or installation. For the purpose of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

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(c) (14) NET ELECTRICAL ENERGY means the electrical energy produced by a generator, less the electrical energy consumed by any auxiliary equipment necessary to operate the engine generator and, if applicable, any heat recovery equipment, such as heat exchangers.

(15) NON-RECLAIM FACILITY means a facility, or any of its successors, that was not in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.

(16) NON-ROAD ENGINE is any engine, defined under 40 CFR Part 89, that does not remain or will not remain at a location for more than 12 consecutive months, or a shorter period of time where such period is representative of normal annual source operation at a stationary source that resides at a fixed location for more than 12 months (e.g., seasonal operations such as canning facilities), and meets one of the following:

(A) Is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as a mobile crane); or

(B) Is used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawn mowers and string trimmers); or

(C) By itself, or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Transportability includes, but is not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting.

(17) OPERATING CYCLE means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.

(18) OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide.

(19) PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not

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(c) limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation.

An engine is not portable if:

(A) The engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted toward the consecutive time period; or

(B) The engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or

(C) The engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

(20) RATED BRAKE HORSEPOWER (bhp) is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.

(21) RECLAIM FACILITY means a facility, or any of its successors, that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.

(22) RICH-BURN ENGINE WITH A THREE-WAY CATALYST means an engine designed to operate near stoichiometric conditions with a catalytic control device that simultaneously reduces emissions of NOx, CO and VOC.

(23) STATIONARY ENGINE is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code.

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(c) (24) TIER 2 AND TIER 3 DIESEL ENGINES mean engines certified by CARB to meet Tier 2 or Tier 3 emission standards in accordance with Title 13, Chapter 9, Article 4 of the CCR.

(25) USEFUL HEAT RECOVERED means the waste heat recovered from the engine exhaust and/or cooling system that is put to productive use. The waste heat recovered may by assumed to be 100% useful unless the hot water, steam or other medium is vented to the atmosphere, or sent directly to a cooling tower or other unproductive use.

(26) VOLATILE ORGANIC COMPOUND (VOC) is as defined in Rule 102.

(d) Requirements

(1) Stationary Engines:

(A) Operators of stationary engines with an amended Rule 1110.1 Emission Control Plan submitted by July 1, 1991, or an Approved Emission Control Plan, designating the permanent removal of engines or the replacement of engines with electric motors, in accordance with subparagraph (d)(1)(B), shall do so by December 31, 1999, or not operate the engines on or after December 31, 1999 in a manner that exceeds the emission concentration limits listed in Table I:

TABLE I
ALTERNATIVE TO ELECTRIFICATION
CONCENTRATION LIMITS

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	70

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon**,** corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(B) The operator of any other stationary engine not covered by subparagraph (d)(1)(A) shall:

(i) Remove such engine permanently from service or replace the engine with an electric motor, or alternatively comply

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(d) with the following, if applicable:

(ii) Comply with the applicable emission concentration limits listed in either Table II or Table III-A or B, or technologically achievable case-by-case VOC or CO emission concentration limits approved by the Executive Officer pursuant to clause (d)(1)(B)(vii), averaged over 15 minutes or other averaging time period allowed by clauses (d)(1)(B)(iii) through (d)(1)(B)(v);

(iii) Use an averaging time approved by the Executive Officer for an engine that uses non-pipeline quality natural gas that has demonstrated that due to the varying heating value of the gas a longer averaging time was necessary. The fixed-interval averaging time shall not exceed six hours for any of the concentration limits of Table II, unless an engine is subject to an existing permit condition allowing for an averaging time greater than six hours. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility;

(iv) Use a fixed-interval averaging time of one hour for engines equipped with a Continuous Emissions Monitoring System (CEMS), to demonstrate compliance with the emission concentration limits of Table II or Table III-B;

(v) Use a fixed-interval averaging time of three hours for compressor gas lean-burn engines equipped with selective catalytic reduction pollution control equipment and a CEMS, to demonstrate compliance with the NOx emission concentration limit of Table II;

(vi) Comply with the emission concentration limits listed in Table II for Low-Use Engines. A Low-Use engine is an engine that operates less than 500 hours per year or uses less than 1×10^9 British Thermal Units (Btus) per year (higher heating value) of fuel;

(vii) Comply with any technologically achievable case-by-case CO and VOC limits that were approved by the Executive Officer in lieu of the concentration limits in Table II

(d) effective on and after July 1, 2011 for a two-stroke engine equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing that has demonstrated that the CO and VOC limits effective on and after July 1, 2011 were not achievable. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO, but must comply with the applicable NOx concentration limit in Table II.

TABLE II
CONCENTRATION LIMITS FOR LOW-USE ENGINES

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 bhp < 500: 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis.

[2] Parts per million by volume, measured as carbon**,** corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(C) The operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III-A, provided that the facility monthly average biogas usage by the biogas engine is 90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response

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(d) plan, because of either high influent flows caused by precipitation or a disaster.

TABLE III-A CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED LOW-USE ENGINES		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
TABLE III-B CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES EFFECTIVE JANUARY 1, 2017		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis.

[2] Parts per million by volume, measured as carbon**,** corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

[3] ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

(i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME Performance Test Code PTC 17 -1973, at the average load of the engine; and

(ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

The ECF is as follows:

$$ECF = \frac{9250 \text{ Btus/hp-hr}}{\text{Measured } q_a \text{ in Btus/hp-hr}}$$

Measured q_a shall be based on the lower heating value of the fuel. ECF shall not be less than 1.0.

(d) The Executive Officer may approve the burning of more than 10% natural gas in a landfill or digester gas-fired engine, when it is necessary, if: the only alternative to limiting natural gas to 10% would be shutting down the engine and flaring more landfill or digester gas; or the engine requires more natural gas in order for a waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.

(D) Notwithstanding the provisions of subparagraph (d)(1)(B), the operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III.

(E) Biogas engine operators that establish to the satisfaction of the Executive Officer that they have complied with the emissions limits of Table III-B by January 1, 2015 will have their respective engine permit application fees refunded.

(F) For the City of San Bernardino, Orange County Sanitation District, and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all their biogas engines shall have until January 1, 2018 to comply with the requirements of Table III-B.

(G) Once an engine complies with the concentration limits as specified in Table III-B, there shall be no limit on the percentage of natural gas burned.

(H) The concentration limits effective as specified in Table III-A shall apply to engines that are biogas-fired Low-Use engines. A biogas-fired Low-Use engine is an engine that operates fewer than 500 hours per year or uses less than 1×10^9 Btus per year (higher heating value) of fuel.

(I) An operator of a biogas engine with a CEMS shall meet either:

(i) The NOx and CO limits of Table III-B, averaged pursuant to the specified averaging provisions in subparagraph (d)(1)(B);

(ii) The emission limits at or below 11 ppmvd for NOx and 250 ppmvd for CO (if CO is selected for averaging), each

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(d) corrected to 15% O2 and averaged over a 24-hour fixed interval, with the emission limits and averaging time specified as a condition in the engine's permit to operate on or before November 1, 2019; or

(iii) The emission limits at or below 9.9 ppmvd for NOx and 225 ppmvd for CO (if CO is selected for averaging), each corrected to 15% O2 and averaged over a 48-hour fixed interval, with emission limits and averaging time specified as a condition in the engine's permit to operate.

(J) The operator of any new engine subject to subparagraph (e)(1)(B) shall:

(i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a South Coast AQMD permit; or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table I if the engine does not require a South Coast AQMD permit.

(K) By February 1, 2009, the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and EPA.

(L) New Non-Emergency Electrical Generators

(i) All new non-emergency engines driving electrical-generators shall comply with the following emission standards in lbs/MW-hr:

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(d)

TABLE IV EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION DEVICES		
Pollutant	**Emission Standard (lbs/MW-hr)[1]**	**Concentration Limit[3] (ppmvd)[4]**
NOx	0.070	2.5
CO	0.20	12
VOC	0.10[2]	10

1 The averaging time of the emission standard for VOC is the sampling time required by the test method.

2 Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

3 Concentration limit is calculated using a 40% engine efficiency and no applied thermal credit.

4 Parts per million by volume, corrected to 15% oxygen on a dry basis.

(ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MW_e-hr). The compliance of such engines shall be based on the following equation:

$$\frac{\text{Lbs}}{\text{MW-hr}} = \frac{\text{Lbs}}{\text{MW}_e\text{-hr}} \times \text{Electrical Energy Factor (EEF)}$$

Where:

Lbs/MW-hr = The calculated emissions standard.

Lbs/MW_e-hr = The short-term engine emission limit in pounds per MWe-hr of net electrical energy produced.

EEF = The annual MW_e-hrs of net electrical energy produced divided by the sum of annual MW_e-hrs plus annual MW_{th}-hrs of useful heat recovered.

(iii) For combined heat and power engines, the short-term

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(d) emission limits in lbs/MW_e-hr and the maximum allowed annual EEF must be selected by operator and stated on the operating permit.

(iv) The requirements of this subparagraph shall apply to NOx emissions from new non-emergency engines driving electrical-generators subject to Regulation XX (RECLAIM).

(v) This subparagraph does not apply to: engines installed prior to February 1, 2008; engines issued a permit to construct prior to February 1, 2008 and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digester gas-fired engines that meet the requirements of subparagraph (d)(1)(C).

(vi) For engines driving electrical generators and operating with a CEMS, a fixed-interval averaging time of one hour shall be used to demonstrate compliance with the NOx and CO emission standard requirements of Table IV in lbs/MW-hr. For engines driving electrical generators and operating without a CEMS, the NOx and CO emission standard requirements of Table IV in lbs/MW-hr shall be averaged over 15 minutes.

(vii) Owners and operators of new engines installed prior to January 1, 2024 with no ammonia emissions from add-on control equipment and where NOx emissions meet the concentration limit of Table IV at all times may elect to apply for and comply with the concentration limits of Table IV, expressed in ppmvd, except an alternative VOC concentration limit that is equal to or less than 25 ppmvd may be complied with. The Executive Officer shall accumulate daily VOC emissions in excess of the concentration limit of Table IV based on the permitted VOC

(d) limits from each such engine and shall not approve any additional permit for such engine that will cause the total accumulated daily VOC emissions to exceed 45 lbs per day. Any new installation on or after January 1, 2024 shall comply with the VOC concentration limit in Table IV in ppmvd.

(2) Portable Engines:

(A) The operator of any portable engine generator subject to this rule shall not use the portable generator for:

(i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or

(ii) Primary or supplemental power to a building, facility, stationary source, or stationary equipment, except during unforeseen interruptions of electrical power from the serving utility, maintenance and repair operations, and remote operations where grid power is unavailable. For interruptions of electrical power, the operation of a portable generator shall not exceed the time of the actual interruption of power.

This subparagraph shall not apply to a portable generator that complies with emission concentration limits of Table I and the other requirements in this rule applicable to stationary engines.

(B) The operator of any portable diesel engine shall comply with the applicable requirements of the Subchapter 7.5 Airborne Toxic Control Measures for diesel particulate matter in Chapter 1, Division 3, Title 17 of the California Code of Regulations.

(C) The operator of any portable spark-ignited engine shall comply with the applicable requirements of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

(e) Compliance

(1) Agricultural Stationary Engines:

(A) The operator of any agricultural stationary engine subject to this rule and installed or issued a permit to construct prior to June 3,

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(e) 2005 shall comply with subparagraph (d)(1)(B) and the other applicable provisions of this rule in accordance with the compliance schedules in Table V:

TABLE V
COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES

Action Required	**Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q)**	**Other Engines**
Submit notification of applicability to the Executive Officer	January 1, 2006	January 1, 2006
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2009	September 1, 2007
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2009, or 30 days after the permit to construct is issued, whichever is later	March 30, 2008, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2010, or 60 days after the permit to construct is issued, whichever is later	July 1, 2008, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2010, or 120 days after the permit to construct is issued, whichever is later	September 1, 2008, or 120 days after the permit to construct is issued, whichever is later

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(e) The notification of applicability shall include the following for each engine:

(i) Name and mailing address of the operator

(ii) Address of the engine location

(iii) Manufacturer, model, serial number, and date of manufacture of the engine

(iv) Application number

(v) Engine type (diesel, rich-burn spark-ignition or lean-burn spark-ignition)

(vi) Engine fuel type

(vii) Engine use (pump, compressor, generator, or other)

(viii) Expected means of compliance (engine replacement, control equipment installation, or electrification)

(B) The operator of any new agricultural stationary engine that is not subject to the compliance schedule of subparagraph (e)(1)(A) for existing engines shall comply with the requirements of subparagraph (d)(1)(J) immediately upon installation.

(2) Non-Agricultural Stationary Engines:

(A) The operator of any stationary engine not meeting the requirements of subparagraph (d)(1)(B) or (d)(1)(C) that go into effect in 2010 or later, shall comply with the compliance schedule in Table VI.

(B) The operator of any stationary engine that elects to amend a permit to operate to incorporate ECF-adjusted emission limits shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008, and comply with emission limits of the previous version of this rule until February 1, 2009 when the engine shall be in compliance with the emission limits of this rule.

(C) The operator of any stationary engine that is required to add operating restrictions to a permit to operate to meet the requirements of this rule shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008.

(e)

TABLE VI COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES	
Action Required	**Applicable Compliance Date**
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	Twelve months before the final compliance date
Initiate construction of engine modifications, control equipment, or replacement engines	Three months before the final compliance date, or 60 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	The final compliance date, or 120 days after the permit to construct is issued, whichever is later
Complete initial source testing	60 days after the final compliance date in subparagraph (d)(1)(B) or (d)(1)(C), or 180 days after the permit to construct is issued, whichever is later

(3) Stationary Engine CEMS

(A) The operator of any stationary engine with an existing CEMS shall commence the reporting required by Rule 218 Subdivision (f) on January 1, 2008. The first summary report for the six months ending June 30, 2008 shall be due on July 30, 2008.

(B) The operator of any stationary engine that is required to modify an existing CEMS or install a CEMS on an existing engine shall comply with the compliance schedule in Table VII. Public agencies shall be allowed one year more than the dates in Table VII, except for biogas engines.

(C) The operator of any stationary engine that is located at a RECLAIM or former RECLAIM facility that is required to modify an existing CEMS or install a CEMS on an existing engine that is subject to paragraph (f)(1) shall comply with the compliance schedule in Table VII except that the operator shall submit to the

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(e) Executive Officer applications for a new or modified CEMS within 90 days of becoming a former RECLAIM facility.

(i) For engines at a RECLAIM or former RECLAIM facility, installation of a CEMS is required concurrently with the installation of retrofit control technologies or new engine replacements to meet the requirements of paragraph (d)(1).

TABLE VII
COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS ON EXISTING ENGINES

Action Required	Applicable Compliance Dates For:		
	Non-Biogas Engines Rated at 750 bhp or More	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit to the Executive Officer applications for new or modified CEMS	August 1, 2008	August 1, 2009	January 1, 2011
Complete installation and commence CEMS operation, calibration, and reporting requirements	Within 180 days of initial approval	Within 180 days of initial approval	Within 180 days of initial approval
Complete certification tests	Within 90 days of installation	Within 90 days of installation	Within 90 days of installation
Submit certification reports to Executive Officer	Within 45 days after tests are completed	Within 45 days after tests are completed	Within 45 days after tests are completed
Obtain final approval of CEMS	Within 1 year of initial approval	Within 1 year of initial approval	Within 1 year of initial approval

* A biogas engine is one that is subject to the emission limits of Table III.

(e) (4) Stationary Engine Inspection and Monitoring (I&M) Plans:

The operator of stationary engines subject to the I&M plan provisions of subparagraph (f)(1)(D) shall:

(A) By August 1, 2008, submit an initial I&M plan application to the Executive Officer for approval;

(B) By December 1, 2008, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

Any operator of 15 or more stationary engines subject to the I&M plan provisions shall comply with the above schedule for at least 50% of engines, and for the remaining engines shall:

(C) By February 1, 2009, submit an initial I&M plan application to the Executive Officer for approval;

(D) By June 1, 2009, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

(5) Stationary Engine Air-to-Fuel Ratio Controllers

(A) The operator of any stationary engine that does not have an air-to-fuel ratio controller, as required by subparagraph (d)(1)(K), shall comply with those requirements in accordance with the compliance schedule in Table V, except that the application due date is no later than May 1, 2008 and the initial source testing may be conducted at the time of the testing required by subparagraph (f)(1)(C).

(B) The operator of any stationary engine that has the air-to-fuel ratio controller required by subparagraph (d)(1)(K), but it is not listed on the permit to operate, shall submit to the Executive Officer an application to amend the permit by April 1, 2008.

(C) The operator of more than five engines that do not have air-to-fuel ratio controllers may take an additional three months, to May 1, 2009, to install the equipment on up to 50% of the affected engines.

(6) New Stationary Engines

The operator of any new stationary engine issued a permit to construct after February 1, 2008 shall comply with the applicable I&M or CEMS requirements of this rule when operation commences. If applicable, the operator shall provide the required information in subparagraph (f)(1)(D) to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit. A separate I&M

(e) plan application is not required.

(7) Biogas Engines

For any biogas engine for which the operator applies to the Executive Officer by April 1, 2008 for a change of permit conditions for ECF-corrected emission limits, or the approval to burn more than 10 percent natural gas in accordance with subparagraph (d)(1)(C), the biogas engine shall not be subject to the initial concentration limits of Tables II or III until August 1, 2008, provided the operator continues to comply with all emission limits in effect prior to February 1, 2008.

(8) Compliance Schedule Exception

If an engine operator submits to the Executive Officer an application for an administrative change of permit conditions to add a permit condition that causes the engine permit to expire by the effective date of any requirement of this rule, then the operator is not required to comply with the earlier steps required by this subdivision for that requirement. The effective date for the CEMS requirements shall be one year after the date that a CEMS application is due.

(9) Exceedance of Usage Limits

(A) If an engine was initially exempt from the new concentration limits in subparagraph (d)(1)(B) or subparagraph (d)(1)(C) that take effect on or after July 1, 2011 because of low engine use but later exceeds the low-use criteria, the operator shall bring the engine into compliance with the rule in accordance with the schedule in Table VI with the final compliance date in Table VI being twelve months after the conclusion of the first twelve-month period for which the engine exceeds the low-use criteria.

(B) If engines that were initially exempt from new CEMS by the low-use criterion in subclause (f)(1)(A)(ii)(I) later exceed that criterion, the operator shall install CEMS on those engines in accordance with the schedule in Table VII, except that the date for submitting the CEMS application in Table VII shall be six months after the conclusion of the first twelve-month period for which the engines exceed the criterion.

(10) RECLAIM or Former RECLAIM Facilities

The owner or operator of a RECLAIM or former RECLAIM facility with any unit(s) subject to subdivision (d) shall meet the applicable NOx

(e) emission limit in Table II or III-B in accordance with the schedule specified in Rule 1100 – Implementation Schedule for NOx Facilities.

(f) Monitoring, Testing, Recordkeeping and Reporting

(1) Stationary engines:

The operator of any engine subject to the provisions of paragraph (d)(1) of this rule shall meet the following requirements:

(A) Continuous Emission Monitoring

(i) For engines of 1000 bhp and greater and operating more than two million bhp-hr per calendar year, a NO_x and CO CEMS shall be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of this rule.

(ii) (I) For facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 10^9 Btus per year (higher heating value), CEMS shall be installed, operated and maintained in calibration to demonstrate compliance of those engines with the applicable NO_x and CO emission limits of this rule.

(II) Any engine that as of October 1, 2007 is located within 75 feet of another engine (measured from engine block to engine block) is considered to be at the same location. Operators of new engines shall not install engines farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that operational needs or space limitations require it.

(III) The following engines shall not be counted toward the combined rating or required to have a CEMS by this clause: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1000 hours

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(f) per year or a fuel usage of less than 8×10^9 Btus per year (higher heating value of all fuels used); engines that are used primarily to fuel public natural gas transit vehicles and that are required by a permit condition to be irreversibly removed from service by December 31, 2014; and engines required to have a CEMS by the previous clause. A CEMS shall not be required if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

(IV) For engines rated below 1000 bhp, the CEMS may be time shared by multiple engines.

(V) Operation of engines by the electric utility in the Big Bear Lake area during the failure of a transmission line to the utility may be excluded from an hours-per-year or fuel usage limit that is elected by the operator pursuant to subclause (f)(1)(A)(ii)(III).

(VI) In lieu of complying with subclause (f)(1)(A)(ii)(I), an operator that is a public agency, or is contracted to operate engines solely for a public agency, may comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), except that the operator shall conduct diagnostic emission checks at least weekly or every 150 operating hours, whichever occurs later. If any such engine is found to exceed an applicable NOx or CO limit by a source test required by subparagraph (f)(1)(C) or South Coast AQMD test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of this subparagraph for such engine in accordance with the compliance schedule of Table VII, except that the operator shall submit a CEMS application to

(f) the Executive Officer within six months of the third exceedance.

(iii) All CEMS required by this rule shall:

(I) Comply with the applicable requirements of Rules 218 and 218.1, including equipment specifications and certification, operating, recordkeeping, quality assurance and reporting requirements, except as otherwise authorized by this rule;

(II) Include equipment that measures and records exhaust gas concentrations, both uncorrected and corrected to 15 percent oxygen on a dry basis; and

(III) Have data gathering and retrieval capability approved by the Executive Officer

(iv) The operator of an engine that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to demonstrate compliance with the emission limits of this rule. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine. Upon approval by the Executive Officer, the substitute criteria shall be submitted to EPA as an amendment to the State Implementation Plan (SIP).

If the alternative monitoring device is denied or fails to be recertified, a CEMS shall be required.

(v) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii) may:

(f)

(I) Store data electronically without a strip chart recorder, but there shall be redundant data storage capability for at least 15 days of data. The operator must demonstrate that both sets of data are equivalent.

(II) Conduct relative accuracy testing on the same schedule for source testing in clause (f)(1)(C)(i), instead of annually. The minimum sampling time for each test is 15 minutes.

(vi) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii), and that are to be monitored by a timeshared CEMS, may:

(I) Monitor an engine with the CEMS for 15 consecutive minutes, purge for the minimum required purge time, then monitor the next engine for 15 consecutive minutes. The CEMS shall operate continuously in this manner, except for required calibrations.

(II) Record the corrected and uncorrected NOx, CO and diluent data at least once per minute and calculate and record the 15-minute average corrected concentrations for each sampling period.

(III) Have sample lines to each engine that are not the same length. The purge time will be based on the sample line with the longest response time. Response times shall be checked during cylinder gas audits. Sample lines shall not exceed 100 feet in length.

(IV) Conduct a minimum of five tests for each engine during relative accuracy tests.

(V) Perform a cylinder gas audit every calendar quarter on each engine, except for engines for which relative accuracy testing was conducted that quarter.

(VI) Exclude monitoring of nitrogen dioxide (NO_2) for rich-burn engines, unless source testing

(f) demonstrates that NO_2 is more than 10 percent of total NOx.

(VII) Conduct daily calibration error (CE) tests by injecting calibration gases at the analyzers, except that at least once per week the CE test shall be conducted by injecting calibration gases as close to the probe tip as practical.

(VIII) Stop operating and calibrating the CEMs during any period that the operator has a continuous record that the engine was not in operation.

(vii) A CO CEMS shall not be required for lean-burn engines or an engine that is subject to Regulation XX (RECLAIM), and not required to have a NOx CEMS by that regulation.

(viii) Notwithstanding the requirements of this paragraph and paragraph (c)(2) of Rule 2012, an operator may take an existing NOx CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.

(ix) In lieu of clause (f)(1)(A)(i), an Essential Public Service or a contractor for an Essential Public Service that is operating a biogas engine of 1000 bhp and greater and less than 1200 bhp, may alternatively comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), provided the operator conducts diagnostic emission checks at least weekly or every 150 operating hours, whichever occurs later.

(x) If an Essential Public Service or a contractor for an Essential Public Service has elected to comply with the Inspection and Monitoring Plan provisions pursuant to clause (f)(1)(A)(ix) for biogas engines is found to exceed an applicable NOx or CO limit by a source test required by subparagraph (f)(1)(C) or South Coast AQMD test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of clause (f)(1)(A)(i) for such biogas engine in accordance with the compliance schedule of Table VII

(f) except that the operator shall submit a CEMS application to the Executive Officer within six months of the third exceedance.

(B) Elapsed Time Meter

Maintain an operational non-resettable totalizing time meter to determine the engine elapsed operating time.

(C) Source Testing

(i) Effective August 1, 2008, conduct source testing for NO_x, VOC reported as carbon, and CO concentrations (concentrations in ppm by volume, corrected to 15 percent oxygen on dry basis) at least once every two years from the date of the previous source test, no later than the last day of the calendar month that the test is due, or every 8,760 operating hours, whichever occurs first. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E shall satisfy this requirement for those pollutants monitored by a CEMS. The above source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated before the date a source test is due, the source test shall be conducted by the end of seven consecutive days or 15 cumulative days of resumed operation. The operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

(ii) Conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, conduct source testing for NOx and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test, and; at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, ± 10%. No pre-tests for

(f) compliance are permitted. The emission test shall be conducted at least 40 operating hours, or at least 1 week, after any engine servicing or tuning. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. The operator shall correct the exceedance, and the source test may be immediately resumed. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E shall satisfy this requirement for those pollutants monitored by a CEMS for all applicable operating loads specified in this clause (f)(1)(C)(ii).

(iii) Use a contractor to conduct the source testing that is approved by the Executive Officer under the Laboratory Approval Program for the necessary test methods.

(iv) Submit a source test protocol to the Executive Officer for written approval at least 60 days before the scheduled date of the test. The source test protocol shall include the name, address and phone number of the engine operator and a South Coast AQMD-approved source testing contractor that will conduct the test, the application and permit number(s), emission limits, a description of the engine(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads, the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels, and a description of the parameters to be measured in accordance with the I&M plan required by subparagraph (f)(1)(D). The source test protocol shall be approved by the Executive Officer prior to any testing. The operator is not required to submit a protocol for approval if: there is a previously approved protocol that meets these requirements; the engine has not been altered in a manner that requires a permit alteration; and emission limits have not changed since the previous test. If the operator submits the protocol by the required date, and the Executive Officer takes longer than 60 days to approve the protocol, the

(f) operator shall be allowed the additional time needed to conduct the test.

(v) Provide the Executive Officer at least 30 days prior notice of any source test to afford the Executive Officer the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the engine operator shall notify the Executive Officer as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Executive Officer by mutual agreement.

(vi) Submit all source test reports, including a description of the equipment tested, to the Executive Officer within 60 days of completion of the test.

(vii) By February 1, 2009, provide, or cause to be provided, source testing facilities as follows:

(I) Sampling ports adequate for the applicable test methods. This includes constructing the air pollution control system and stack or duct such that pollutant concentrations can be accurately determined by applicable test methods;

(II) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders. Agricultural stationary engines are excused from this subclause if they are in remote locations without electrical power;

(III) Utilities for sampling and testing equipment. Agricultural stationary engines are exempt from this subclause if they are on wheels and moved to storage during the off season.

(D) Inspection and Monitoring (I&M) Requirements

(i) I&M Plan. The operator shall:

(I) Submit to the Executive Officer for written approval

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(f) an I&M plan. One plan application is required for each facility that does not have a NOx and CO CEMS for each engine. The I&M plan shall include all items listed in Attachment 1. The owner or operator may request an alternative item(s) in Attachment 1 that is determined by the Executive Officer to be equivalent in meeting the same objectives.

(II) Upon written approval by the Executive Officer, implement the I&M plan as approved.

(III) Submit an I&M plan for approval to the Executive Officer for a plan revision before any change in I&M plan operations can be implemented. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.

(ii) Diagnostic emission checks by a portable NOx, CO, and oxygen analyzer shall be conducted at least weekly or every 150 engine operating hours, whichever occurs later.

(I) If an engine is in compliance for three consecutive diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant diagnostic emission check or, for rich-burn engines with three-way catalysts, until the oxygen sensor is replaced. When making adjustments to the oxygen sensor set points that are not within 72 hours prior to the diagnostic emission check, returning to a more frequent diagnostic emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments.

(II) For diesel engines and other lean-burn engines that operate at a RECLAIM or former RECLAIM facility or have a NOx CEMS, and that are subject to a CO limit more stringent than the 2000 ppmvd limit

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(f) of Tables II or III, a CO diagnostic emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.

(III) For diesel engines and other lean-burn engines that operate at a RECLAIM or former RECLAIM facility or have a NOx CEMS, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, diagnostic emission checks are not required.

(IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the diagnostic emission check, unless it is an unscheduled, required repair.

(V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on February 1, 2008, or subsequent protocol approved by EPA and the Executive Officer.

(iii) Requirements for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range.

(I) For any diagnostic emission check or breakdown that results in emissions in excess of those allowed by this rule or a permit condition, the operator shall correct the problem as soon as possible and demonstrate compliance with another diagnostic emission check, or shut down an engine by the end of an operating cycle, or within 24 hours from the time the operator knew of the breakdown or excess emissions, or reasonably should have known,

(f) whichever is sooner.

(II) For excess emissions due to breakdowns that result in NOx or CO emissions greater than the concentrations specified in Table VIII, the operator shall not be considered in violation of this rule if the operator demonstrates the all of the following: (1) compliance with subclause (f)(1)(D)(iii)(I), (2) compliance with the reporting requirements of subparagraph (f)(1)(H), and (3) the engine with excess emissions has no more than three incidences of breakdowns with emissions exceeding Table VIII limits in the calendar quarter.

TABLE VIII
EXCESS EMISSION CONCENTRATION THRESHOLDS FOR BREAKDOWNS

	NO_x (ppmvd)[1]	CO (ppmvd)[1]
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000
Biogas Engines[2]	185	2000

1 Corrected to 15% oxygen.

2 Effective up to the time of compliance with the limits specified in Table III-B, after which the thresholds revert to the applicable lean or rich-burn engine limits.

(III) Any emission check conducted by South Coast AQMD staff that finds excess emissions will be treated as a violation.

(IV) For other problems, such as parameters out-of-range, an operator shall correct the problem and demonstrate compliance with another diagnostic emission check within 48 hours of the operator first knowing of the problem.

(iv) If an engine has a NOx CEMS and does not have a CO CEMS, it is subject to this subparagraph (f)(1)(D) as it

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(f) pertains to CO only.

(E) Operating Log

Maintain a monthly engine operating log that includes:

(i) Total hours of operation;

(ii) Type of liquid and/or type of gaseous fuel;

(iii) Fuel consumption (cubic feet of gas and gallons of liquid); and

(iv) Cumulative hours of operation since the last source test required in subparagraph (f)(1)(C).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit until such time that the facility becomes a former RECLAIM facility. The facility shall maintain a monthly engine log starting in the month that it has become a former RECLAIM facility.

(F) New Non-Emergency Electrical Generating Engines

Operators of engines subject to the requirements of subparagraph (d)(1)(L) shall also meet the following requirements.

(i) The engine generator shall be monitored with a calibrated electric meter that measures the net electrical output of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator.

(ii) For engines monitored with a CEMS, the emissions of the monitored pollutants in ppmvd corrected to 15% O2, lbs/hr, and lbs/MW_e-hr and the net MW_e-hrs produced shall be calculated and recorded for the four 15-minute periods of each hour of operation. The mass emissions of NOx shall be calculated based on the measured fuel flow and one of the F factor methods of 40 CFR Part 60, Appendix A, Method 19, or other method approved by the Executive Officer. Mass emissions of CO shall be calculated in the same manner as NOx, except that the ppmvd CO shall be converted to lb/scf using a conversion factor of 0.727 x 10^{-7}.

(f)

(iii) For NOx and CO emissions from engines not monitored with a CEMS and VOC emissions from all engines, the emissions of NOx, CO and VOC in lbs/MW_e-hr shall be calculated and recorded whenever the pollutant is measured by a source test or diagnostic emission check. Mass emissions of NOx and CO shall be calculated in the same manner as the previous clause. Mass emissions of VOC shall be calculated in the same manner, except that the ppmvd VOC as carbon shall be converted to lb/scf using a conversion factor of 0.415×10^{-7}.

(iv) For engines generating combined heat and power that rely on the EEF to comply with Table IV emission standards, the daily and annual useful heat recovered (MW_{th}-hrs), net electrical energy generated (MW_e-hrs) and EEF shall be monitored and recorded.

(v) Other methods of calculating mass emissions than those specified, such as by direct measurement of exhaust volume, may be used if approved by the Executive Officer. All monitoring, calculation, and recordkeeping procedures must be approved by the Executive Officer.

(vi) Operators of combined heat and power engines shall submit to the Executive Officer the reports of the following information within 15 days of the end of the first year of operation, and thereafter within 15 days of the end of each calendar year: the annual net electrical energy generated (MW_e-hrs); the annual useful heat recovered (MW_{th}-hrs), the annual EEF calculated in accordance with clause (d)(1)(L)(ii); and the maximum annual EEF allowed by the operating permit. If the actual annual EEF exceeds the allowed EEF, the report shall also include the time periods and emissions for all instances where emissions exceeded any emission standard in Table IV.

(G) Portable Analyzer Operator Training

The portable analyzer tests required by the I&M Plan requirements of subparagraph (f)(1)(D) shall only be conducted by a person who

(f) has completed an appropriate South Coast AQMD-approved training program in the operation of portable analyzers and has received a certification issued by the District.

(H) Reporting Requirements

(i) The operator shall report to the Executive Officer, by telephone (1-800-CUT-SMOG or 1-800-288-7664) or other South Coast AQMD-approved method, any breakdown resulting in emissions in excess of rule or permit emission limits within one hour of such noncompliance or within one hour of the time the operator knew or reasonably should have known of its occurrence. Such report shall identify the time, specific location, equipment involved, responsible party to contact for further information, and to the extent known, the causes of the noncompliance, and the estimated time for repairs. In the case of emergencies that prevent a person from reporting all required information within the one-hour limit, the Executive Officer may extend the time for the reporting of required information provided the operator has notified the Executive Officer of the noncompliance within the one-hour limit.

(ii) Within seven calendar days after the reported breakdown has been corrected, but no later than thirty calendar days from the initial date of the breakdown, unless an extension has been approved in writing by the Executive Officer, the operator shall submit a written breakdown report to the Executive Officer which includes:

(I) An identification of the equipment involved in causing, or suspected of having caused, or having been affected by the breakdown;

(II) The duration of the breakdown;

(III) The date of correction and information demonstrating that compliance is achieved;

(IV) An identification of the types of excess emissions, if any, resulting from the breakdown;

(V) A quantification of the excess emissions, if any, resulting from the breakdown and the basis used to

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(f) quantify the emissions;

(VI) Information substantiating whether the breakdown resulted from operator error, neglect or improper operation or maintenance procedures;

(VII) Information substantiating that steps were immediately taken to correct the condition causing the breakdown, and to minimize the emissions, if any, resulting from the breakdown;

(VIII) A description of the corrective measures undertaken and/or to be undertaken to avoid such a breakdown in the future; and

(IX) Pictures of any equipment which failed, if available.

(iii) Within 15 days of the end of each calendar quarter, the operator shall submit to the Executive Officer a report that lists each occurrence of a breakdown, fault, malfunction, alarm, engine or control system operating parameter out of the acceptable range established by an I&M plan or permit condition, or a diagnostic emission check that finds excess emissions. Such report shall be in a South Coast AQMD-approved format, and for each incident shall identify the time of the incident, the time the operator learned of the incident, specific location, equipment involved, responsible party to contact for further information, to the extent known the causes of the event, the time and description of corrective actions, including shutting an engine down, and the results of all portable analyzer NOx and CO emissions checks done before or after the corrective actions. The operator shall also report if no incidents occurred.

(2) Portable engines:

The operator of any portable engine shall maintain a monthly engine operating log that includes:

(i) Total hours of operation; or

(ii) Type of liquid and/or type of gaseous fuel; and

(iii) Fuel consumption (cubic feet of gas and gallons of liquid).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit until

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(f) such time that the facility becomes a former RECLAIM facility. The facility shall maintain a monthly engine log starting in the month that it has become a former RECLAIM facility.

(3) Recordkeeping for All Engines

All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer.

(g) Test Methods

Testing to verify compliance with the applicable requirements shall be conducted in accordance with the test methods specified in Table IX, or any test methods approved by CARB and EPA, and authorized by the Executive Officer.

TABLE IX
TESTING METHODS

Pollutant	Method
NO_x	South Coast Air Quality Management District Method 100.1
CO	South Coast Air Quality Management District Method 100.1
VOC	South Coast Air Quality Management District Method 25.1* or Method 25.3*

* Excluding ethane and methane

A violation of any standard of this rule established by any of the specified test methods, or any test methods approved by the CARB or EPA, and authorized by the Executive Officer, shall constitute a violation of this rule.

(h) Alternate Compliance Option

(1) In lieu of complying with the applicable emission limits by the effective date specified in Table III-B or subparagraph (d)(1)(F), owners or operators of biogas-fired units may elect to defer compliance in quarterly increments up to one additional year, provided the owner or operator:

(A) Submits an alternate compliance plan and pays a Compliance Flexibility Fee, as provided for in paragraph (h)(2), to the Executive Officer at least 60 days prior to the applicable compliance date in either Table III-B or subparagraph (d)(1)(F) for qualified biogas technology demonstration project engines, and

(h) (B) Maintains on-site a copy of verification of Compliance Flexibility Fee payment and South Coast AQMD approval of the alternate compliance plan that shall be made available upon request to South Coast AQMD staff.

(2) Plan Submittal

The alternate compliance plan submitted pursuant to paragraph (h)(1) shall include:

(A) A completed South Coast AQMD Form 400A with company name, South Coast AQMD Facility ID, identification that application is for a compliance plan (Section 7a of form), and identification that request is for Rule 1110.2 Compliance Flexibility Fee option (Section 9 of form);

(B) Attached documentation of unit permit ID, unit rated brake horsepower (bhp), and fee calculation;

(C) Filing Fee payment; and

(D) Compliance Flexibility Fee payment as calculated by the following equation:

CFF = bhp x R x Q

Where,

CFF = Compliance Flexibility Fee, $

bhp = rated brake horsepower of unit

R = Fee Rate = $11.75 per brake horsepower per quarter

Q = Number of quarters (up to four)

(3) Usage of Compliance Flexibility Fee funds

The funds collected from the Compliance Flexibility Fee will be applied to South Coast AQMD NOx reduction programs pursuant to protocols approved under South Coast AQMD rules.

(i) Exemptions

(1) The provisions of subdivision (d) shall not apply to:

(A) All orchard wind machines powered by an internal combustion engine.

(B) Emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines approved by the Executive Officer, which have permit conditions that limit

(i) operation to 200 hours or less per year as determined by an elapsed operating time meter, and agricultural emergency standby engines that are exempt from a South Coast AQMD permit and operate 200 hours or less per year as determined by an elapsed operating time meter.

(C) Laboratory engines used in research and testing purposes.

(D) Engines operated for purposes of performance verification and testing of engines.

(E) Auxiliary engines used to power other engines or gas turbines during start-ups.

(F) Portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR.

(G) Nonroad engines, with the exception that subparagraph (d)(2)(A) shall apply to portable generators.

(H) Engines operating on San Clemente Island.

(I) Agricultural stationary engines provided that:

(i) The operator submits documentation to the Executive Officer by the applicable date in Table V when permit applications are due that the applicable electric utility has rejected an application for an electrical line extension to the location of the engines, or the Executive Officer determines that the operator does not qualify, due to no fault of the operator, for funding authorized by California Health and Safety Code Section 44229; and

(ii) The operator replaces the engines, in accordance with the compliance schedule of Table X, with engines certified by CARB to meet the Tier 4 emission standards of 40 CFR Part 1039 Section 1039.101, Table 1. These Tier 4 replacement engines shall be considered to comply with Best Available Control Technology; and

(iii) The operator does not operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Part 1039 Section 1039.101(e), as determined by the test methods of subdivision (g) of this rule.

(i)

TABLE X
COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES

Action Required	Due Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2013
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2013, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2014, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2014, or 120 days after the permit to construct is issued, whichever is later

(J) An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment or for the tuning of the engine and/or emission control equipment, and an engine shutdown period. The periods shall not exceed 30 minutes, unless the Executive Officer approves in writing a longer period not exceeding two hours for an engine and makes it a condition of the engine permit.

(K) An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head or for the installation or the replacement of catalytic emission control equipment, for a period not to exceed four operating hours.

(L) The initial commissioning of a new engine for a period specified by permit conditions, provided the operator takes measures to reduce emissions and the duration of the commissioning to the extent possible. The commissioning period shall not exceed 150 operating hours.

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(i)

(M) An engine used exclusively for electrical generation at remote two-way radio transmission towers where no utility, electricity, or natural gas is available within a ½ mile radius, has a manufacturer's rating of 100 bhp or less, and is fired exclusively on diesel #2, compressed natural gas, or liquefied petroleum gas.

(N) Any engine at a RECLAIM or former RECLAIM facility that is subject to a NOx emission limit in a different rule for an industry-specific category defined in Rule 1100 – Implementation Schedule for NOx facilities.

(O) An engine operated in either the Southern California Coastal Waters or Outer Continental Shelf Waters provided:

(i) The engine is used to power a crane;

(ii) The engine is certified by CARB to meet the Tier 4 – Final emission standards of 40 CFR Part 1039 Section 1039.101 Table 1;

(iii) The engine is operated per the specifications of the engine manufacturer; and

(iv) The operator submits an I&M Plan to the Executive Officer for approval and implementation, pursuant to the requirements of subparagraph (f)(1)(D).

(2) The facility operator of MM PRIMA DESHECHA ENERGY, LLC, or any of its successors, shall not be required to meet the emissions requirements specified in Table III-B if they submit a detailed retirement plan that is approved by the Executive Officer for the permanent shutdown of all equipment subject to Rule 1110.2 by October 1, 2022. The plan shall describe in detail the steps and schedule that will be taken to remove the equipment or render the equipment permanently inoperable by October 1, 2022 and shall require the surrendering of the permits for the equipment by that date. The plan shall be submitted before July 1, 2016 and include:

(A) South Coast AQMD Form 400A with company name, South Coast AQMD Facility ID, and permit number(s) for the subject equipment; and

(B) Filing Fee payment pursuant to Rule 306.

The Executive Officer shall act on the plan before January 1, 2017.

(i) (3) The provisions of this rule shall not apply to units located at landfills or publicly owned treatment works that are subject to a NOx emission limit in a Regulation XI rule adopted or amended after November 1, 2019.

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ATTACHMENT 1

An I&M Plan submitted to the Executive Officer for approval and implementation, pursuant to the requirements of paragraphs (e)(4) and (e)(6), and subparagraph (f)(1)(D) of the rule, shall include:

A. Identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This shall include, but not be limited to:

1. Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60% and 95% load (or fuel flow rate), ± 5%, or the minimum, midpoint and maximum loads that actually occur during normal operation, ± 5%, or at any one load within the ± 10% range that an engine permit is limited to in accordance with clause (f)(1)(C)(ii) of the rule;
2. Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by subdivision D of this attachment;
3. Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with three way catalysts, between 100 and 150 engine operating hours after an oxygen sensor replacement;
4. For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;
5. For lean-burn engines with selective catalytic control devices, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using a portable NOx and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load.

Parameter monitoring is not required for diesel engines without exhaust gas recirculation and catalytic exhaust control devices.

B. Procedures for alerting the operator to emission control malfunctions. Engine control systems, such as air-to-fuel ratio controllers, shall have a malfunction indicator light and audible alarm.

C. Procedures for diagnostic emission checks conducted by a portable NOx, CO, and oxygen analyzer per the requirements of clause (f)(1)(D)(ii) of the rule.

D. Procedures for at least daily monitoring, inspection and recordkeeping of:

1. engine load or fuel flow rate;
2. the set points, maximums and acceptable ranges of the parameters identified by subdivision A of this attachment, and the actual values of the same parameters;
3. the engine elapsed time meter operating hours;
4. the operating hours since the last diagnostic emission check required by clause (f)(1)(D)(ii) of the rule;
5. for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);
6. engine control system and AFRC system faults or alarms that affect emissions.

The daily monitoring and recordkeeping may be done in person by the operator, or by remote monitoring.

E. Procedures for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range, per the requirements of clause (f)(1)(D)(iii) of the rule.

F. Procedures and schedules for preventive and corrective maintenance.

G. Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H) of the rule.

H. Procedures and format for the recordkeeping of monitoring and other actions required by the plan.



Stationary Reciprocating Internal Combustion Engines

Updated Information on NOx Emissions and Control Techniques

EPA-457/R-00-001
September 2000

Stationary Reciprocating Internal Combustion Engines
Updated Information on NOx Emissions and Control Techniques

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U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Policy Division
Research Triangle Park, NC

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1.0 INTRODUCTION

1.1 PURPOSE OF THIS DOCUMENT

The purpose of this document is to update portions of *Alternative Control Techniques Document–NO_X Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).[1] This update will provide more recent data on emission control technologies and control costs.

This report focuses on the natural gas transmission and storage industry because this is a large segment of stationary reciprocating internal combustion (IC) engine users. In addition, the report focuses on low emission combustion (LEC) control technology because developments in the technology and costs make an update especially necessary.

This document does not replace the 1993 ACT document, but only updates certain portions. The reader should refer to the 1993 ACT document for additional information on the types of IC engines, the mechanisms of the formation of nitrogen oxides (NO_X) in IC engines, the full range of control alternatives and the technical details of each, and the costs and cost effectiveness of controls.

1.2 METHODS

Data were collected for this report primarily through site visits at facilities that operate IC engines equipped with controls for NO_X emissions; contacts with engine manufacturers, control technology vendors, and regulatory agencies; and a literature search. Additional information was obtained through seeking out useful sites on the Internet.

1.3 ORGANIZATION

Chapter 2 presents a summary of the findings of this study. Chapter 3 addresses uncontrolled emissions from selected IC engine types. Chapter 4 presents an update on selected NO_X control technologies. Chapter 5 presents a limited update on control costs and cost effectiveness.

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1.4 REFERENCE FOR CHAPTER 1

1. *Alternative Control Techniques Document–NO_X Emissions from Stationary Reciprocating Internal Combustion Engines*. U. S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA-453/R-93-032. July 1993. 315pp. http://www.epa.gov/ttncatc1/products.html.

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2.0 SUMMARY

This report primarily addresses nitrogen oxides (NO_X) emissions and cost data from lean-burn, spark-ignited (SI) stationary reciprocating internal combustion (IC) engines equipped with low-emission combustion (LEC) technology. This chapter presents a summary of updated information on these engines. This information is presented in greater depth in subsequent chapters, along with less extensive information on other selected types of IC engines and NO_X control technologies. Section 2.1 includes as summary of performance test data on NO_X emissions from lean-burn SI engines controlled with LEC technology. Section 2.2 presents a summary of updated control costs for these engines.

Throughout this document, NO_X emissions are expressed as grams per brake horsepower hour (g/bhp-hr) and/or parts per million by volume (ppmv). Unless otherwise stated, all concentrations given in units of ppmv are on a dry basis and corrected to 15 percent oxygen. The primary unit is g/bhp-hr because it expresses emissions on a comparable basis across all IC engine types and models, and because it is the standard practice.

In preparing this report, the following conversion factors were used as necessary:

- Uncontrolled rich-burn SI engines and rich-burn engines controlled with nonselective catalytic reduction (NSCR): 67 ppmv = 1 g/bhp-hr

- Uncontrolled lean-burn engines, lean-burn engines controlled with selective catalytic reduction (SCR), and rich-burn engines controlled with prestratified charge™ (PSC) technology: 73 ppmv = 1 g/bhp-hr

- Lean-burn engines controlled with low emission combustion technology: 75 ppmv = 1 g/bhp-hr

For example, when emission test results were reported only in ppmv, these factors were used to convert the results to g/bhp-hr. These conversion factors are consistent with those used in *Alternative Control Techniques Document–NO_X Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).[1]

The NO_X emission unit of pounds per million British thermal units input (lb/MMBtu) is not used in this report because it is less frequently used in conjunction with IC engines. As a

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result, a comparison of IC engine NO_X emissions with emission from other types of fuel-burning equipment cannot always be readily made. However, it should be noted that uncontrolled IC engine emissions in terms of heat input can be over an order of magnitude higher than emissions from turbines or boilers. Well controlled IC engines often emit NO_X at higher levels than uncontrolled gas turbines and boilers.

2.1 CONTROLLED NO_X EMISSIONS FROM LEC-EQUIPPED ENGINES

Table 2-1 presents LEC emissions data from several different sources. In a May 2000 memo, the EPA summarized data from 269 emissions tests on a variety of engines makes, models, and sizes. In addition to the data from the EPA memo, Table 2-1 presents data from 476 different NO_X emissions tests for 58 engines with LEC technology. Other sources of data for the table include performance test data bases from the San Diego, Santa Barbara, and Ventura County (California) Air Pollution Control Districts, test data summaries from Southern California Gas Company and Pacific Gas and Electric Company, and a Gas Research Institute (GRI) report prepared by Arthur D. Little, Inc. Note that the EPA memo also includes data from earlier versions of the Ventura and Santa Barbara County data bases.

Table 2-1 shows that the emissions ranged from 0.1 to 4.8 g/bhp-hr. Nearly 97 percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (354) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests found emissions greater than or equal to 4 g/bhp-hr.

Chapter 4 contains a more detailed update on NO_X control technologies, including LEC, selective catalytic reduction (SCR), Prestratified Charge™ (PSC), and nonselective catalytic reduction (NSCR).

2.2 CONTROL COSTS FOR LEC-EQUIPPED ENGINES

The results of the cost analysis in 1990 and 1997 dollars are summarized in Tables 2-2a and 2-2b, respectively. The tables present total capital investment and annual costs of LEC controls for eight engine sizes ranging from 80 to 8,000 bhp. In addition, the tables include the NO_X emission reductions and cost effectiveness on an annual basis and for the ozone season (May through September). The tables show that capital and annual costs increase with engine size. For example, Table 2-2b (1997 dollars) shows that capital and annual costs for an 80 bhp engine would be $231,000 and $59,100, respectively, whereas for an 8,000 bhp engine, these costs would be $760,000 and $175,000. On the other hand, the cost effectiveness per ton of NO_X reduced varies inversely with engine size. Table 2-2b (1997 dollars) shows that cost effectiveness varies from $6,470 annually and $15,500 for the ozone season for an 80 bhp engine, down to $192 annually and $460 for the ozone season for an 8,000 bhp engine.

As explained in greater detail in Chapter 5, we obtained information on LEC costs from several sources. The cost and cost effectiveness projections presented in Tables 2-2a and 2-2b

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TABLE 2-1. NO_X EMISSIONS DATA FROM ENGINES WITH LEC CONTROL TECHNOLOGY

Source	No. of tests	No. of engines	No. of models	Minimum emissions (g/bhp-hr)	Maximum emissions (g/bhp-hr)	Average emissions (g/bhp-hr)	Tests ≤3 g per bhp-hr		Tests ≤2 g per bhp-hr		Tests ≤1 g per bhp-hr		Tests ≤0.5 g per bhp-hr		Tests ≥4 g per bhp-hr	
							No.	%	No.	%	No.	%	No.	%	No.	%
EPA Memo[2]	269	49	≥22	0.1	6.0	NA	266	99%	258	96%	192	71%	NA	NA	1	<1%
Ventura County[3] [a]	320	23	8	0.1	4.0	0.7	319	>99%	318	99%	275	86%	102	32%	1	<1%
Santa Barbara County[4] [a]	12	3	3	0.1	0.7	0.5	12	100%	12	100%	12	100%	8	67%	0	0%
San Diego County[5]	121	13	5	0.3	4.8	1.1	120	99%	108	89%	52	43%	7	6%	1	1%
So. California Gas Company[6]	7	7	1	0.8	1.5	1.1	7	100%	7	100%	5	71%	0	0%	0	0%
So. California Gas Company[7]	3	3	1	0.5	0.6	0.6	3	100%	3	100%	2	67%	1	33%	0	0%
So. California Gas Company[8]	1	1	1			0.6	1	100%	1	100%	1	100%	0	0%	0	0%
So. California Gas Company[9]	7	5	1	0.4	0.7	0.6	7	100%	7	100%	7	100%	2	29%	0	0%
Pacific Gas and Electric[10]	2	2	1	1.0	1.3	1.2	2	100%	2	100%	1	50%	0	0%	0	0%
GRI Report[11]	3	1	1	1.4	2.4	1.9	3	100%	2	67%	1	33%	0	0%	0	0%
Summary[b]	476	58	15	0.1	4.8	0.8	474	>99%	460	97%	356	75%	120	25%	2	<1%

NA = Not Available

[a]Ventura County and Santa Barbara County data are more recent, more extensive versions of emission test data bases included in the EPA memo (see Section 4.1.3.2).

[b]The summary calculation does not include data from the EPA memo in order to avoid double counting Ventura County and Santa Barbara County data that appear in both data sets. Percentages in this row were calculated relative to a total of 476 tests.

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TABLE 2-2a. COSTS AND COST EFFECTIVENESS OF LEC CONTROLS IN 1990 $'s

Engine size, bhp	Total capital investment	Annual cost	NO_X reduction, tons		Cost effectiveness, $/ton NO_X	
			Annual	O_3 season	Annual	O_3 season
80	$214,000	$55,000	9	4	$6,020	$14,400
240	$224,000	$57,000	27	11	$2,080	$4,990
500	$240,000	$60,500	57	24	$1,060	$2,540
1,000	$271,000	$67,100	114	48	$590	$1,410
2,000	$333,000	$80,400	228	95	$350	$840
4,000	$456,000	$107,000	457	190	$240	$560
6,000	$580,000	$134,000	685	285	$170	$470
8,000	$703,000	$161,000	914	381	$180	$420

TABLE 2-2b. COSTS AND COST EFFECTIVENESS OF LEC CONTROLS IN 1997 $'s

Engine size, bhp	Total capital investment	Annual cost	NO_X reduction, tons		Cost effectiveness, $/ton NO_X	
			Annual	O_3 season	Annual	O_3 season
80	$231,000	$59,100	9	4	$6,470	$15,500
240	$242,000	$61,400	27	11	$2,240	$5,380
500	$259,000	$65,200	57	24	$1,140	$2,740
1,000	$293,000	$72,400	114	48	$630	$1,520
2,000	$359,000	$86,900	228	95	$380	$910
4,000	$493,000	$116,000	457	190	$250	$610
6,000	$627,000	$146,000	685	285	$210	$510
8,000	$760,000	$175,000	914	381	$190	$460

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are based on new information on actual costs for several LEC retrofits obtained from one engine manufacturer and one third-party LEC vendor. Other inputs include uncontrolled NO_X emissions of 16.8 g/bhp-hr, controlled emissions of 2.0 g/bhp-hr, and capacity utilization of 7,000 operating hours per year (prorated for the 5 months of the ozone season). In most respects, the analysis was conducted according to the methodology of the 1993 ACT document, which, in turn, was based on the *OAQPS Control Cost Manual*. For additional detail, refer to Section 5.1.

No other cost analyses were carried out for this report. However, some cost information was obtained during this study on modern SCR systems that use urea as the reducing agent for control of NO_X emissions from lean-burn SI engines and diesel engines. See Section 5.2 of Chapter 5 for that information.

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2.3 REFERENCES FOR CHAPTER 2

1. *Alternative Control Techniques Document–NO_X Emissions from Stationary Reciprocating Internal Combustion Engines*. U. S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA-453/R-93-032. July 1993. 315pp. http://www.epa.gov/ttncatc1/products.html.

2. Memo from D. Sanders, EPA, to D. Grano, EPA, and Docket No. A-98-12. Performance of Low Emission Combustion. May 19, 2000.

3. Memo from S. Edgerton, EC/R Inc., to Project File. Analysis of Ventura County APCD Test Data–Low Emission Combustion. July 28, 2000.

4. Memo from S. Edgerton, EC/R Inc., to Project File. Analysis of Santa Barbara County APCD Test Data–Low Emission Combustion. July 28, 2000.

5. Memo from S. Edgerton, EC/R Inc., to Project File. Analysis of San Diego County APCD Test Data–Low Emission Combustion. July 28, 2000.

6. EC/R Incorporated. Final Site Visit Reports for Southern California Gas Company Facilities, Attachment 5. Prepared for Ozone Policy and Strategies Group, U. S. Environmental Protection Agency, Research Triangle Park, NC. June 26, 2000. 12pp.

7. Southern California Gas Company. Facsimile from G. Arney to S. Edgerton, EC/R Incorporated. Information on Aliso Canyon Station. Southern California Gas Company, Aliso Canyon, CA. December 16, 1999. 26pp.

8. Southern California Gas Company. Facsimile from G. Arney to S. Edgerton, EC/R Incorporated. Information on Goleta Station. Southern California Gas Company, Goleta Station, CA. December 16, 1999. 24pp.

9. Southern California Gas Company. Facsimile from G. Arney to S. Edgerton, EC/R Incorporated. Information on Honor Rancho Station. Southern California Gas Company, Honor Rancho Station, CA. December 16, 1999. 16pp.

10. Pacific Gas and Electric Company. Letter and attachments from C. Burke to W. Neuffer, U. S. EPA. Information on Hinkley Compressor Station Units K-11 and K-12. Pacific Gas and Electric Company. February 3, 2000. 8pp.

11. GRI-98/0117. *NO_X Control for Two-Cycle Pipeline Reciprocating Engines*. Prepared by Arthur D. Little, Inc., for the Gas Research Institute. December 1998.

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3.0 UNCONTROLLED NO_X EMISSIONS

This chapter presents information on uncontrolled emissions of nitrogen oxides (NO_X) from stationary reciprocating internal combustion (IC) engines that has been generated since EPA published its *Alternative Control Techniques Document–NO_X Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).[1] This chapter updates the information in the 1993 ACT document, but is not intended to replace it. For example, this chapter does not discuss NO_X formation mechanisms; the reader should refer to the 1993 ACT document for a discussion of NO_X formation.

For purposes of this report, "uncontrolled emissions" are defined as the NO_X emission level prior to any actions taken to reduce emissions, such as adjusting the engine's operating parameters, retrofitting an engine for combustion modification, installing an add-on control device, or redesigning new engines for improved emissions performance. Thus, engines that include low-emission combustion (LEC) technology as original equipment are considered controlled, rather than uncontrolled. To the extent possible, these engines will be excluded from average uncontrolled emissions values. In contrast, engine technologies that have been incorporated for purposes other than emission reduction that, nevertheless, reduce NO_X emissions (notably turbocharging and intercooling) are not necessarily considered control technologies, unless undertaken as part of a project to reduce emissions.

This chapter addresses lean-burn, spark-ignited (SI) engines fired on pipeline-quality natural gas (Section 3.1) and rich-burn SI engines, also fired on pipeline-quality natural gas (Section 3.2). No additional data on diesel-fueled, compression-ignition (CI) engines and dual-fuel CI engines, which use diesel fuel to initiate combustion of natural gas, were collected for this report. The CI engine types are not addressed in this chapter. Section 3.3 provides the references for this entire chapter.

3.1 LEAN-BURN SI ENGINES

This section presents and discusses information on uncontrolled NO_X emissions from lean-burn SI engines. Section 3.1.1 presents the information, and Section 3.1.2 provides a discussion of the information and presents conclusions.

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3.1.1 Information on Uncontrolled NO_X Emissions from Lean-Burn SI Engines

Some information sources reviewed for this report include NO_X emission factors based on aggregated test data or contain actual test results. These information sources are described briefly in the paragraphs that follow.

A 1994 Gas Research Institute (GRI) report includes separate NO_X emission levels for 2-stroke (12.5 grams per brake horsepower-hour [g/bhp-hr]) and 4-stroke (13.2 g/bhp-hr) lean-burn natural gas prime movers. (These are lean-burn SI engines used in natural gas compression, transmission, and storage service, which represents a major segment of the population of this type of engine.) The emission levels included in the report are based on an extensive data base of emission test results, although the number of lean-burn engine tests is not stated. The reported emission levels are weighted averages, weighted based on the natural gas prime mover population (i.e., the number of each engine model in prime mover service according to 1989 data) and on horsepower. Test results for 2-stroke engines ranged from 2 g/bhp-hr to 29 g/bhp-hr. For 4-stroke engines, the results ranged from 1 g/bhp-hr to 25 g/bhp-hr.

This report notes that the higher end of the range (25 to 29 g/bhp-hr) reflects older, uncontrolled engines. Engines equipped with turbochargers and intercoolers as original design features ("pure turbocharged" engines) typically emit NO_X in the 7 to 15 g/bhp-hr range. The lower end of the range often reflects the newer lean-burn engines that are included in the inventory, which achieve very low NO_X emissions (1 to 2 g/bhp-hr) through the use of higher excess air and advanced ignition technology (i.e., engines classified as controlled using LEC technology for purposes of this report–see Section 4.1.1). The GRI report also notes that LEC technology is available for retrofit, although it does not state whether any retrofitted engines are included in the inventory of test results.[2] Thus, the average emission levels presented in this GRI report were calculated including some engines considered controlled for purposes of this report. The number of such engines included and their effect on the reported average is not known.

The EPA's *Compilation of Air Pollutant Emission Factors* (AP-42) current Section 3.2 on natural gas prime movers (dated October 1996) characterizes uncontrolled NO_X emissions as 10.9 g/bhp-hr for 2-stroke engines and as 11.8 g/bhp-hr for 4-stroke engines, based on emission test data. This document includes many of the same test data references as the GRI report discussed above, including compilations of test data prepared for the natural gas industry that contain the bulk of the test results considered.[3] It is not clear why these emission factors are lower than the GRI report's, although it likely relates to the averaging methodology. The AP-42 section indicates that these values represent uncontrolled emissions, and the section also contains NO_X emission factors for controlled lean-burn engines (including factors for two manufacturers' LEC-equipped engines–see Section 4.1.3). However, based on the large overlap with the GRI data, it appears likely that the "uncontrolled" data include test results from newer lean-burn engines that would be considered controlled (i.e., LEC-equipped) for purposes of this report.

The 1997 draft revision for AP-42 Section 3.2 indicates uncontrolled NO_X emissions of 12.2 g/bhp-hr for 2-stroke lean-burn engines and 15.0 g/bhp-hr for 4-stroke lean-burn engines, based on emission test data (38 tests for 2-stroke engines and 18 tests for 4-stroke engines). The

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draft also includes emission factors for 2-stroke and 4-stroke "clean-burn" engines, referring to these engines as separate "engine families," distinct from other lean-burn engines.[4, 5] "CleanBurn" is a registered trademark of Cooper Energy Services, denoting that company's system of precombustion chambers coupled with a high-efficiency turbocharger. This system is included in the definition of LEC technology used in this document.

During comment on the 1997 draft AP-42 section, other companies noted that they also offer similar technology (i.e., LEC), but refer to these engines simply as "lean-burn engines." Thus, some engines equipped with LEC technology were believed to have been included in the uncontrolled, lean-burn engine category. The draft AP-42 section is being revised to eliminate the separate "clean-burn" engine categories. The final section may include both uncontrolled and LEC-equipped engines in the 2-stroke and 4-stroke lean-burn engine categories because of concern that LEC-equipped engines included in the test data cannot be identified conclusively.[6] This discussion indicates that the "uncontrolled" emission factors given above may be based on data that include test results from lean-burn engines that would be considered controlled (i.e., LEC-equipped) for purposes of this report.

A 1996 GRI report includes emission test data for several lean-burn SI engines. These data include six 2-stroke engines representing five different models and three 4-stroke engines representing two different models. Each engine was tested from two to five times. For the 2-stroke engines, the average NO_X emission levels ranged from 4.9 g/bhp-hr to 20.8 g/bhp-hr. The 4-stroke engines averaged from 7.0 g/bhp-hr to 22.0 g/bhp-hr. In both cases, the test data were more concentrated toward the lower end of the range.[7] These test results were among the data used to develop the 1997 draft revision for the AP-42 Section 3.2 discussed immediately above. This report discriminates clearly between engines equipped with LEC and those that are not.

A 1998 GRI report includes some NO_X emissions data generated during a project with Cooper Energy Systems to develop lower-cost CleanBurn™ retrofit technology for some Cooper-Bessemer 2-stroke lean-burn engine models often used in gas transmission applications. The report indicates that emissions of NO_X from a Cooper Z-330 engine that has <u>not</u> been retrofit range from 24 g/bhp-hr down to 2 g/bhp-hr as the air-to-fuel (A/F) ratio is made leaner. However, engine performance when leaned to below 7 g/bhp-hr is unacceptable due to increased fuel consumption, misfire, and elevated carbon monoxide and hydrocarbon emissions. The typical field operation level is not specified in the report, although the greatest fuel economy appears to be achieved at about the 16 g/bhp-hr level. The document also reports baseline (i.e., prior to retrofit) test results for a GMV-6 model (11.5 g/bhp-hr at 100 percent rated speed and torque) and a GMV-10-TF model (6 to 13 g/bhp-hr at rated conditions).[8]

Test data from Pacific Gas and Electric Company for two Cooper-Bessemer W-330 engines tested in 1995 show uncontrolled NO_X emissions of 18.9 and 16.7 g/bhp-hr (based on a typical conversion factor for lean-burn engines of 1 g/bhp-hr per 73 parts per million by volume [ppmv] at 15 percent oxygen).[9] These engines were tested prior to being retrofitted with LEC technology.

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Test data from Southern California Gas Company for two Ingersoll-Rand 412KVS engines tested in 1993 show uncontrolled NO_X emissions of 21.4 and 17.0 g/bhp-hr. These tests were conducted upstream of selective catalytic reduction (SCR) control devices.

Several other documents reviewed for this report include information on uncontrolled NO_X emissions that was not based directly on test data (or, at least, the test data were not included or cited in the document). These are primarily general statements regarding NO_X emissions from knowledgeable sources. This information is described briefly below:

- A 1990 GRI report states that uncontrolled NO_X emissions for natural gas pipeline engines (both lean burn and rich burn) range from about 7 g/bhp-hr to 26 g/bhp-hr.[10] The report reflects the prime mover population prior to widespread use of newer lean-burn engines equipped with LEC technology.

- A 1992 paper prepared for a meeting of the Society of Petroleum Engineers by Cooper Industries personnel states that, prior to regulation, NO_X emissions from natural gas-fired engines ranged from 10 g/bhp-hr to 20 g/bhp-hr.[11] This range would include both lean-burn and rich-burn SI engines.

- A 1997 report prepared by the Manufacturers of Emission Controls Association (MECA) indicates that the typical NO_X emission level for natural gas-fired engines operated slightly lean of the stoichiometric A/F ratio is 18.0 g/bhp-hr.[12]

- A 1994 article in the *Oil & Gas Journal* states that natural gas compressor station engines typically emit NO_X at 15 g/bhp-hr.[13] This would include both lean-burn and rich-burn engines.

- A knowledgeable representative of Southern California Gas Company stated during a site visit that NO_X emissions from the Delaval HVA16C engines at the facility were around 28 g/bhp-hr on hot days, prior to being retrofitted with LEC technology.

- Product literature from the Ajax Superior Division of Cooper Energy Services indicates that uncontrolled NO_X emissions from the Ajax line of relatively small 2-stroke lean-burn engines (110 bhp to 720 bhp) range from 3.0 g/bhp-hr to 9.5 g/bhp-hr. This information indicates that uncontrolled NO_X emissions from the Superior line of 4-stroke lean-burn engines (825 bhp to 2650 bhp) range from 15.0 g/bhp-hr to 22.1 g/bhp-hr.[14]

Another major source of information on uncontrolled NO_X emissions from lean-burn SI engines is the 1993 ACT document. For that document, the EPA collected information from 8 major engine manufacturers on 290 models of IC engines of all types in 1991 and 1992. While most manufacturers provided emissions data only for current (at that time) production engines, some included older engine lines, as well.[15] We were not able to obtain the original information to review for this report. We have assumed that the data comprises guaranteed emission levels for the represented engine models.

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The 1993 ACT document presents an average uncontrolled NO_X emission level for lean-burn SI engines of 16.8 g/bhp-hr. This value was calculated based on manufacturers' information on 122 models.[16] The 1993 ACT document did not provide separate uncontrolled NO_X emission factors for 2-stroke and 4-stroke lean-burn engines.

3.1.2 Discussion and Conclusions on Uncontrolled NO_X Emissions from Lean-Burn SI Engines

The primary sources of data on uncontrolled NO_X emissions are engine manufacturers (in the form of guarantees) and emission tests. As discussed above, general statements regarding uncontrolled emissions may be made by sources familiar with these types of primary data.

In Section 3.1.2.1 below, we present considerations related to information from engine manufacturers. Section 3.1.2.2 presents considerations related to emission test results. In Section 3.1.2.3, the potential division of lean-burn SI engines into 2-stroke and 4-stroke subcategories is discussed. Section 3.1.2.4 presents conclusions regarding the appropriate uncontrolled NO_X emission levels for purposes of this report.

3.1.2.1 Discussion of NO_X Emissions Information from Engine Manufacturers.

Emissions data from engine manufacturers may tend to overstate emissions to some degree because the manufacturer may be liable if the engine fails to meet emissions guarantees. This potential liability motivates the engine manufacturer to elevate the emissions guarantee to a level that ensures that each individual engine in the model line will meet it. The guaranteed level also must account for the range of operating and ambient conditions to which the guarantee applies. On the other hand, the manufacturer is not motivated to inflate guaranteed emissions unnecessarily because this might make the engines less desirable to many potential customers. Based on these factors, we believe that engine manufacturers' guarantees provide a reasonable upper bound on uncontrolled NO_X emissions from well-maintained, well-operated engines.

Although the data were not available for this study, we believe that the engine manufacturers provided this type of information for the 1993 ACT document. As noted above, the value in that document for the average uncontrolled NO_X emission level for lean-burn SI engines was calculated based on manufacturers' information on 122 models of 2-stroke and 4-stroke engines.

The 1993 ACT document tabulated and averaged the uncontrolled NO_X emissions from lean-burn SI engines in five rated horsepower ranges. The overall average uncontrolled NO_X emission level for these engines was calculated as the weighted average of these averages (weighted by the number of engine models for which data were provided in each horsepower range). Thus, in effect, the overall average for lean-burn SI engines was calculated as the straight, unweighted average NO_X emission level of the engine models for which the manufacturers provided uncontrolled NO_X emissions data.

Given available data, this approach is appropriate. In an ideal situation, one might choose to calculate average uncontrolled emissions based on the actual in-use IC engine population, i.e., calculating an average weighted on the number of each model in service and the rated

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horsepower of each. However, complete data are not available on the distribution of IC engines by model and size across the entire engine population. Even if such data were available, it is very likely that manufacturers' guarantees for uncontrolled NO_X emissions would be unavailable for many engine models, particularly older, discontinued models. In addition, manufacturers and operators may modify a model's design over time, so current information on uncontrolled emissions may not apply to older versions of the same engine model.

To examine the potential effect of weighting manufacturers' guaranteed uncontrolled NO_X emission levels by horsepower, we recalculated the average for lean-burn SI engines using the data in the 1993 ACT document. For each horsepower range, we multiplied the number of engine models in the range by the horsepower at the midpoint of the range to compute the total capacity for the range. (For the "greater than 4,000 bhp" range, we used 6,000 bhp.) We then computed the weighted average uncontrolled NO_X emissions based on these range capacities. The result was a weighted average of 17.0 g/bhp-hr, only 1 percent different than the unweighted average. When the exercise was repeated for the two rated horsepower ranges greater than 2,000 bhp (i.e., the engines most likely to be affected by EPA's NO_X SIP call or the related FIP), the resulting weighted average was 16.8 g/bhp-hr, which is the same value originally computed for the 1993 ACT document.

3.1.2.2 Discussion of Emission Test Data on NO_X Emissions. In contrast to the conservatism of manufacturers' guarantees, emission tests give an accurate reading of how a particular IC engine performed during a particular test period. However, owners typically have the opportunity to tune their engines prior to testing because emission tests are nearly always scheduled by the engine owner and conducted by a testing firm hired by the engine owner. This ability may affect the relationship between test results and the long-term emissions achieved by the engine. (This statement is not to imply that engine operators routinely manipulate emission test results in a gross manner. Nevertheless, many operators may adjust operation of emission sources, within the range of normal operations, to achieve the most favorable emission rate for the facility during testing.)

As discussed later in Section 4.1.4, when a controlled engine is tested for compliance purposes, the operator may tune the engine to minimize NO_X emissions prior to the test. In such cases, it is reasonable to conclude that test results represent a floor on the NO_X emission level achieved by the tested engine under the operating and ambient conditions of the test. In the case of uncontrolled IC engines, it is not so clear how the existing test data discussed above in Section 3.1.1 are likely to be related to long-term NO_X emissions. This uncertainty stems from the fact that we do not know why most of these tests were conducted.

Different types of regulatory requirements can exert upward or downward pressure on uncontrolled emission test results. For example, an "uncontrolled" engine might be subject to an emission limit that could be met through certain constraints on its operating parameters. While the owner of such a regulated, uncontrolled engine would adjust and operate the engine to reduce NO_X emissions to the required level, operators of unregulated engines of the same type would not need to make such adjustments. Thus, emission test results from an uncontrolled engine that is subject to emission limits may not be representative of other, unregulated engines of the same

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model. The owner of an uncontrolled engine conducting a test to determine major or minor source status might also have an interest in minimizing the tested NO_X emissions.

In contrast, an emission test on an uncontrolled engine might be carried out prior to installing emission controls to establish the baseline for evaluating percent control and/or emission reduction credits to be generated upon control of the source. In this situation, it would be to the facility's advantage to maximize the tested NO_X emissions.

A third potential situation is the research study. The 1996 GRI document discussed above reports the test results of such a study. In such cases, one would expect the engines to be adjusted to represent typical, well-operated facilities. An unbiased study would not be expected to motivate adjustments either to minimize or to maximize NO_X emissions.

We do not know the circumstances of most of the testing that has been carried out on uncontrolled lean-burn SI engines, particularly that which served as the basis for the 1994 GRI document, the current AP-42 section (1996), and the draft revised AP-42 section (1997) on these engines. Thus, we cannot draw firm conclusions regarding the relationship of these data to typical long-term NO_X emissions.

Another unknown regarding the test data is how representative the data are of the general population of lean-burn SI engines. However, it should be pointed out that the data summary in the 1994 GRI document indicates that test data from a wide variety of engine models and sizes were reviewed for that report. In addition, the current AP-42 section (1996) assigns an A rating (excellent) to the emission factors for 2-stroke and 4-stroke lean-burn SI engines. This rating, while somewhat subjective, generally means that the factors were developed from A-rated test data from many randomly chosen facilities in the industry population.

On the other hand, the authors of 1997 draft revision to the AP-42 section rejected some of the data used for the 1996 AP-42 section on the grounds that the emission tests were not conducted using currently approved test methods and/or the tests did not include sufficient process data to characterize engine operation. The 1997 draft revision assigns an A rating to its NO_X emission factor for 2-stroke lean-burn SI engines, specifically meaning that the factor was developed from A-rated data from eight or more different engine models. This draft section's NO_X emission factor for 4-stroke lean-burn SI engines is assigned a B rating, meaning that the factor was developed from A-rated data from five to seven different engine models.

3.1.2.3 Discussion of Potential Subcategorization of Lean-Burn SI Engines. Some of the sources of information on uncontrolled NO_X emission discussed above in Section 3.1.1 distinguished between 2-stroke and 4-stroke lean-burn SI engines, with uncontrolled NO_X emissions from 2-stroke engines typically lower. These documents include the following:

- The 1994 GRI report includes separate emission factors for 2-stroke (12.5 g/bhp-hr) and 4-stroke (13.2 g/bhp-hr) lean-burn natural gas prime movers, based on emission test data. This represents a difference of about 5 percent. The report uses a

generalized emission factor of 13 g/bhp-hr for all lean-burn engines in the text discussion and in its analysis of the cost effectiveness of controls on these engines.[17]

- The current Section 3.2 of the AP-42 (1996) also addresses natural gas prime movers. This document characterizes uncontrolled NO_X emissions as 10.9 g/bhp-hr for 2-stroke engines and as 11.8 g/bhp-hr for 4-stroke engines, based on emission test data.[18] This represents a difference of about 8 percent.

- The draft revision of the AP-42 section (1997) indicates NO_X emissions of 12.2 g/bhp-hr for 2-stroke engines and 15.0 g/bhp-hr for 4-stroke engines, based on emission test data.[19] This indicates a difference of about 20 percent between average uncontrolled NO_X emissions from 2-stroke and 4-stroke lean-burn SI engines. However, this draft is undergoing significant further revision due to an inability to distinguish reliably between engines with and without LEC control technology. As a result, these emission factors cannot be considered final.

- The 1996 GRI document also differentiates between uncontrolled emissions from 2-stroke and 4-stroke engines. For the engines tested in that study, the average NO_X emission levels ranged from 4.9 g/bhp-hr to 20.8 g/bhp-hr for 2-stroke engines and from 7.0 g/bhp-hr to 22.0 g/bhp-hr for 4-stroke engines.[20] There is a great deal of overlap between these ranges.

These differences between uncontrolled NO_X emission levels for the two subcategories of lean-burn SI engines, while not trivial, certainly are not so great as to invalidate the use of a single emission level to characterize the entire lean-burn engine category. The variation among models within each subcategory is much greater than the differences between subcategories indicated in these documents, and there is a great deal of overlap. As noted, the 1994 GRI document reports separate emission levels for the two subcategories where the analysis of emission levels is detailed, but uses a combined emission level for the entire lean-burn category in other portions of the document, including the cost analysis.

The 1993 ACT document does not differentiate between 2-stroke and 4-stroke engines. The single uncontrolled NO_X emissions value in this document for lean-burn SI engines is based on information provided by major manufacturers of both 2-stroke and 4-stroke engines. Thus, this value is an average of data from both subcategories of lean-burn engines. The original data provided by the engine manufacturers for the 1993 ACT document were not available during preparation of this report. Thus, it was not possible to reevaluate the data to differentiate between 2-stroke and 4-stroke engines.

A number of the general statements regarding uncontrolled NO_X emissions cited previously in Section 3.1.1 do not differentiate among natural-gas fired engines at all. These statements provide an average value or typical range of values that would include rich-burn SI engines as well as 2-stroke and 4-stroke lean-burn engines.

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3.1.2.4 Conclusions on Uncontrolled NO_X Emissions from Lean-Burn SI Engines. A single uncontrolled NO_X emission level of 16.8 g/bhp-hr published in the 1993 ACT document is appropriate and reasonable for the purposes of this report. While this value based on manufacturers' guarantees may represent the upper bound on well-operated and well-maintained lean-burn engines (as discussed previously in Section 3.1.2.1), it is also based on the most complete and most certain data set of the data reviewed for this report. Much of the other data presented above in Section 3.1.1 generally supports this value, including a number of sources of test data on individual engines. However, the information sources based on aggregated emission test data give lower values.

To reiterate, the uncontrolled NO_X emission level from the 1993 ACT document is based on information for 112 models of lean-burn SI engines gathered by the EPA in 1991 and 1992. Some manufacturers included data on older engine lines, as well as current production engines. We believe that these data are the most representative available for the existing stock of uncontrolled lean-burn engines.

With good maintenance, IC engines often have a very long life. For example, the 1994 GRI report indicates that many lean-burn IC engines used for natural gas compression, transmission, and storage have been in operation for several decades, with discontinued models having greater than 50 years of service.[21] Thus, the in-use lean-burn engine population includes many engines manufactured before NO_X emissions were a concern.

Many lean-burn engine models currently in production incorporate low-NO_X technology. In fact, the term "lean burn" is often used today to refer to what we have defined as LEC technology for purposes of this report. This trend toward producing engines with inherently lower NO_X emissions increasingly is blurring the line between controlled and uncontrolled lean-burn engines. In fact, the 1997 draft AP-42 section defined 2-stroke and 4-stroke "clean burn" engines (i.e., engines equipped with LEC precombustion chamber technology) as separate engine families, distinct from other 2-stroke and 4-stroke lean-burn engines. This draft section attempted to provide uncontrolled emission factors for these clean burn engine families, instead of treating them as controlled lean-burn engines. However, the EPA has been unable to differentiate definitively between prechambered engines and other lean-burn engines in its NO_X emissions data. As a result, the next draft of the AP-42 section is expected to address only 2-stroke and 4-stroke lean-burn engines, combining all the test data without differentiating by combustion system technology.

This trend toward manufacturing LEC-equipped lean-burn engines was well underway when the data for the 1993 ACT were collected. However, it is clear from the data summary in that document that EPA did not include such engines in the uncontrolled data set. The NO_X emission level at the lower end of the each rated horsepower range exceeds the levels that are achieved using LEC technology.

The same cannot be said for the emission test data underlying the 1994 GRI report, the current AP-42 section (1996), or the draft revision to the AP-42 section (1997). The 1994 GRI report acknowledges that new, LEC-equipped engines are included in its data set. Although the

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authors of the two AP-42 sections attempted to separate such engines from uncontrolled engines, there is some doubt as to whether they were entirely successful, as discussed previously.

Another factor favoring use of the NO_X emission level developed from manufacturers' data for the 1993 ACT document is the completeness of the data set, which includes 122 models of lean-burn SI engine. The test data from the other sources are not as comprehensive.

One potential drawback with the 1993 ACT NO_X emission level for lean-burn SI engines is that it does not differentiate between 2-stroke and 4-stroke engines. However, as discussed above in Section 3.1.2.3, we do not believe that the difference in NO_X emissions between these two types of engines is so great that a single, composite average is unacceptable. On the contrary, we believe that the advantages of the underlying data set outweigh this relatively minor shortcoming.

For the reasons discussed above, we believe that a factor of 16.8 g/bhp-hr for uncontrolled NO_X emissions for lean-burn SI engines is appropriate and reasonable for the purposes of this report. Accordingly, the cost analysis presented in Chapter 5 of this report is based on this uncontrolled NO_X emission level for this class of IC engines.

3.2 RICH-BURN SI ENGINES

This section presents and discusses information on uncontrolled NO_X emissions from rich-burn SI engines. Section 3.2.1 presents the information, and Section 3.2.2 provides a discussion of the information and presents conclusions.

3.2.1 Information on Uncontrolled NO_X Emissions from Rich-Burn SI Engines

Many of the same information sources discussed above for lean-burn engines also contain NO_X emission factors based on aggregated test data or include actual test results for rich-burn engines. The information on rich-burn engine NO_X emissions from these sources is summarized briefly in the paragraphs that follow.

The 1994 GRI report includes a NO_X emission level for rich-burn natural gas prime movers of 8.6 g/bhp-hr. The emission levels included in the report are based on an extensive data base of emission test results, although the number of rich-burn engine tests is not stated. The reported emission level is a weighted average, based on the natural gas prime mover population and on horsepower. The report notes that emissions from these engines typically range from 4 g/bhp-hr to 26 g/bhp-hr, while a few models have very low emissions. (The lowest test result that appears in the report is 1 g/bhp-hr.)[22]

The current AP-42 Section 3.2 on natural gas prime movers characterizes uncontrolled NO_X emissions as 10.0 g/bhp-hr for rich-burn engines, based on emission test data. The section assigns an A rating (excellent) to this emission factor. As noted previously, this document includes many of the same test data references as the GRI report discussed above, including compilations of test data prepared for the natural gas industry that contain the bulk of the test

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results considered.[23] Differing averaging methodology may explain the difference between this emission factor and that in the GRI report.

The 1997 draft revision for AP-42 Section 3.2 indicates uncontrolled NO_X emissions of 20.9 g/bhp-hr for rich-burn engines, based on eight emission test data points. This emission factor is rated B (above average).[24, 25]

The 1996 GRI report includes emission test data for two uncontrolled rich-burn SI engines of the same model at one facility. Uncontrolled emissions were tested for each engine from two to four times. One of these engines averaged 7.7 g/bhp-hr over four tests, and the other averaged 14.4 g/bhp-hr over two tests. It is of interest to note that the engine with lower NO_X emissions had carbon monoxide emissions nearly 40 times those of the engine with higher NO_X emissions. Engine adjustments often involve tradeoffs between NO_X and carbon monoxide emissions, although there is no information available in the report to allow a conclusive interpretation of the results.[26]

Several other documents noted above in Section 3.1.1 include information on uncontrolled NO_X emissions that was not based directly on test data. These are primarily general statements regarding NO_X emissions from knowledgeable sources. This information is described briefly below:

- The 1990 GRI report states that uncontrolled NO_X emissions for natural gas pipeline engines (both lean burn and rich burn) range from about 7 g/bhp-hr to 26 g/bhp-hr.[27] The report reflects the prime mover population prior to widespread regulation of these engines.

- The 1992 paper prepared for a meeting of the Society of Petroleum Engineers by Cooper Industries personnel states that, prior to regulation, NO_X emissions from natural gas-fired engines (both lean burn and rich burn) ranged from 10 g/bhp-hr to 20 g/bhp-hr.[28]

- The 1997 report prepared by MECA indicates that typical NO_X emission levels for natural gas-fired engines operated slightly rich of the stoichiometric A/F ratio range from 8.3 to 11.0 g/bhp-hr.[29]

- A 1994 article in the *Oil & Gas Journal* states that natural gas compressor station engines typically emit NO_X at 15 g/bhp-hr.[30] This would include both lean-burn and rich-burn engines.

The 1993 ACT document is a comprehensive source of data on uncontrolled NO_X emissions from uncontrolled rich-burn SI engines. This document presents an average uncontrolled NO_X emission level for these engines of 15.8 g/bhp-hr. This value was calculated based on manufacturers' information on 83 models.[31]

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3.2.2 Discussion and Conclusions on Uncontrolled NO_X Emissions from Rich-Burn SI Engines

Much of the discussion related to lean-burn SI engines above in Section 3.1.2 applies to rich-burn SI engines, as well. The paragraphs that follow briefly discuss the manufacturer information and test data information reviewed for this project.

As discussed previously for lean-burn SI engines, manufacturers' guaranteed uncontrolled NO_X emission levels provide a reliable upper bound on actual emissions from well-maintained, well-operated engines. Potential liability may motivate engine manufacturers to elevate emissions guarantees slightly to ensure that each individual engine within the model line will meet the guaranteed levels.

The manufacturers' data behind the 1993 ACT document's analysis of uncontrolled NO_X emissions is very comprehensive. Data on 83 engine models provided by several engine manufacturers were included in the analysis. While most manufacturers supplied data only on current production models, some provided data on older models, as well. This is important because with good maintenance, IC engines often have a very long life. For example, the 1994 GRI report indicates that many rich-burn engines used in these natural gas compression, transmission, and storage were installed as early as the 1940's.[32]

It is not clear that the test data underlying the uncontrolled NO_X emission factors from other sources is as comprehensive. We are not able to evaluate from the information reviewed for this study how representative the tested population is. It should be noted that the 1994 GRI report indicates that a large data base of test results from many models of rich-burn engines in the natural gas industry was used to develop the uncontrolled NO_X emission factor (8.6 g/bhp-hr) presented in that document. Using much of the same data, the 1996 AP-42 section assigned an A rating to its emission factor (10.0 g/bhp-hr). However, the 1997 draft AP-42 section dropped some of the data used in the other two documents, indicating that the tests were not conducted using currently approved test methods and/or the tests did not include sufficient process data to characterize engine operation. Using the more limited data (eight tests on from five to seven engine models), the 1997 draft AP-42 section arrived at a B-rated emission factor of 20.9 g/bhp-hr.

Product literature from one engine manufacturer provides an example of the enormous effect engine adjustments can have on uncontrolled NO_X emissions. This manufacturer lists four different carburetor settings for its rich-burn engine families: (1) Lowest Manifold (Best Power), (2) Equal NO_X and CO, (3) Catalytic Converter Input (3-way), and (4) Standard (Best Economy). For all the engine families and models, the Lowest Manifold setting (operating slightly fuel rich with an excess air ratio of 0.97) gives the lowest NO_X emissions, ranging from 8.5 g/bhp-hr to 12 g/bhp-hr. The Standard setting (operating slightly fuel lean with an excess air ratio of 1.06 to 1.12) results in the highest NO_X emissions, ranging from 18.0 to 28.0 g/bhp-hr. For every engine family, the Standard setting results in emissions at more than twice the level of the Lowest Manifold setting, with one model at nearly three times (28.0 versus 9.5 g/bhp-hr).[33]

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The tested NO_X level upstream of an add-on control device is sometimes represented as "uncontrolled" test data. However, some control devices, such as nonselective catalytic reduction (NSCR), dictate certain engine adjustments. For the rich-burn engine families presented in the product literature discussed above, the Standard (Best Economy) carburetor setting results in NO_X emissions from 50 to 75 percent higher than the Catalytic Converter Input setting.[34] Thus, "uncontrolled" test data from an engine equipped with an NSCR control system may be significantly lower than actual uncontrolled emissions from the same model engine in the absence of the control system (or other constraints on emissions).

For this reason, "inlet" values from NSCR-equipped engines in available data bases of emission test results were not analyzed for this report. Similarly, test results from engines equipped with prestratified charge (PSC) control technology with the PSC system turned off were not analyzed. (In the case of PSC, we have no information to indicate whether the modifications necessary to install PSC would affect "uncontrolled" emissions measured with the PSC system turned off.) We were unable to evaluate the test data underlying the 1994 GRI report, the 1996 AP-42 section, or the 1997 draft AP-42 section to determine whether any of the "uncontrolled" NO_X emissions data were from controlled engines (particularly NSCR-equipped engines).

Based on the discussion above, the uncontrolled NO_X emission level of 15.8 g/bhp-hr published in the 1993 ACT document is appropriate and reasonable for the purposes of this report. While this value based on manufacturers' guarantees may represent the upper bound on well-operated and well-maintained lean-burn engines, it is also based on the most complete and most certain data set of the data reviewed for this report. The 1993 ACT document's analysis of uncontrolled NO_X emission levels remains the most comprehensive and representative analysis to date. Much of the other data presented above in Section 3.2.1 generally supports this value. The range of values in the information sources based on aggregated emission test data (i.e., the 1994 GRI report, the 1996 AP-42 section, and the 1997 draft AP-42 section) span this value.

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4.0 UPDATE ON NO_X CONTROL TECHNOLOGIES

This chapter presents information on nitrogen oxides (NO_X) control technologies for stationary reciprocating internal combustion (IC) engines that has been generated since EPA published its *Alternative Control Techniques Document–NO_X Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).[1] This chapter updates the information in the 1993 ACT document, but is not intended to replace it. For example, this chapter does not present an in-depth description of the control technologies; the reader should refer to the 1993 ACT document for a complete description of each control technology.

For purposes of this report, "control technologies" include any measures undertaken primarily to reduce NO_X emissions. This definition includes modifying or adjusting the combustion system to reduce NO_X formation, as well as installing add-on control devices to remove NO_X from the engine exhaust. The definition includes modifying engine design to produce new engines with inherently lower NO_X emissions. Thus, for example, new engines manufactured with low-emission combustion (LEC) technology are considered controlled, just as are engines retrofitted with LEC. In contrast, turbocharging and intercooling alone are not necessarily considered NO_X control technologies (despite the fact that they typically reduce NO_X emissions) because these technologies may be introduced primarily to increase power and efficiency.

This chapter focuses primarily on LEC technology (Section 4.1), with less extensive updates on selective catalytic reduction (SCR) in Section 4.2, nonselective catalytic reduction (NSCR) in Section 4.3, and prestratified charge™ (PSC) technology in Section 4.4. Section 4.5 presents information on high-energy ignition system (HEIS) technology, which was not addressed in the 1993 ACT document. Section 4.6 presents information on emerging NO_X control technologies that have been developed since release of the 1993 ACT document. References for the entire chapter appear in Section 4.7.

This chapter concentrates on the more effective control technologies because these controls are of primary interest in nonattainment areas seeking significant emission reductions from IC engines. The chapter does not address air-to-fuel (A/F) ratio adjustment, ignition timing retard, or a combination of the two; see the 1993 ACT document for a discussion of these less effective technologies.[2]

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4.1 LOW-EMISSION COMBUSTION TECHNOLOGY

This section on LEC updates Section 5.2.5 of the 1993 ACT document, which addresses application of LEC to lean-burn, spark-ignited (SI) engines. This section includes a brief description of the technology (Section 4.1.1) and its applicability (Section 4.1.2), new information on NO_X emissions (Section 4.1.3), a discussion of the emissions data (Section 4.1.4), and conclusions regarding the level of NO_X emissions achievable using LEC (Section 4.1.5).

4.1.1 Technology Description–LEC

Low-emission combustion in IC engines involves modifying the combustion system to achieve very lean combustion compared to the A/F ratios that are used in "conventional" lean-burn engines. The additional combustion air acts as a heat sink, lowering the temperature in the cylinder and reducing NO_X formation.

To deliver the additional combustion air required for LEC, turbocharging and intercooling capacity normally are required. In retrofit situations, this typically involves upgrading or replacing the turbocharger and intercooler, or adding this equipment where it is not already present (i.e., on naturally aspirated engines). Although they typically reduce NO_X emissions, turbocharging and intercooling alone do not qualify as LEC because additional engine modifications are required to minimize NO_X emissions and because these technologies may have been originally introduced to improve engine performance. However, turbocharging and intercooling are integral to LEC technology; in LEC applications they are considered part of the control system.

Other equipment associated with increased air flows may also need to be modified for LEC, such as the air intake and filtration system, the intercooler radiator, and the exhaust system and muffler. To maintain the optimum A/F ratio, an automated A/F ratio controller typically is used.

The challenge with this very lean combustion is to achieve proper ignition and stable combustion. Vendors of LEC technology (i.e., engine manufacturers and third-party retrofitters) have met these requirements with some combination of improved combustion chamber design, enhanced air-fuel mixing, and improved ignition systems.

In many cases, a precombustion chamber is used for enhanced ignition. In this system, ignition is initiated in a small chamber in a fuel-rich environment. The flame propagates rapidly and forcefully from this chamber into the main combustion chamber, providing uniform ignition of the very lean air-fuel mixture in the main chamber, as well as improved mixing.

Some engine manufacturers offer their smaller engines with "open chamber" LEC design. These engines feature a redesigned combustion chamber, rather than a precombustion chamber. These open-chamber LEC designs typically incorporate improved air-fuel mixing systems to achieve stable combustion under very lean conditions.

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Engines with open-chamber LEC technology typically are designed for excess air levels only slightly above 50 percent, while engines with precombustion chambers typically are designed for excess air levels of 75 percent to over 100 percent. Consequently, prechambered engines have generally lower NO_X emissions than do open-chamber models.

Low-emission combustion based on precombustion chamber technology has been in use for about 20 years, when Cooper-Bessemer began manufacturing CleanBurn™ engines. Subsequently, other engine manufacturers began to manufacture LEC-equipped engines (open chamber and/or prechambered models). Presently, all major manufacturers of lean-burn SI engines offer LEC-equipped models, and many models are available only with LEC. At least two manufacturers offer some models that are available either in a rich-burn configuration or in an LEC configuration.[3, 4]

Shortly after beginning to offer new LEC-equipped engines, some engine manufacturers began to offer retrofit "kits" and installation services for existing engines. Originally, the retrofits involved completely replacing the cylinder heads with redesigned heads and replacing or modifying numerous other engine components. The retrofit cylinder heads are cast with a precombustion chamber within the interior of the head. This type of retrofit was all that was commercially available at the time the data were gathered for the 1993 ACT document. These retrofits understandably involve relatively high capital costs, although the incremental expense is reduced if the retrofit is undertaken when the cylinder heads and other engine components are to be replaced anyway as part of an engine overhaul.

In more recent years, simpler and less expensive LEC retrofit technologies have been developed. One advance has been the development of "screw-in" precombustion chambers. These precombustion chambers screw into the existing spark plug hole in each cylinder head, eliminating the need to replace the existing cylinder heads. These screw-in precombustion chambers now are offered for retrofits by some engine manufacturers, as well as by third-party vendors. In addition, advances have been made in upgrading existing turbocharging systems, with the result that retrofits do not as often require replacement of the turbocharger. Contemporary retrofits may involve modifications to improve air-fuel mixing, as well, such as installing higher-pressure fuel valves. Chapter 5 includes a reevaluation of LEC retrofit costs based on more recent capital cost data.

4.1.2 Applicability of LEC

Low-emission combustion technology is applicable to IC engines fired with gaseous fuels. This includes both SI engines and dual-fuel engines operating in dual-fuel mode (as opposed to firing only diesel fuel). No additional information on dual-fuel engine applications was gathered for this report; refer to the 1993 ACT document for information on LEC technology for dual-fuel engines.

New SI engines equipped with LEC technology are, by definition, lean-burn engines. Both 2-stroke and 4-stroke lean-burn SI engines equipped with LEC technology are available in a full range of sizes, and many models are available only with LEC.

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Low-emission combustion retrofit equipment and services are generally available, particularly for the most plentiful engine models. Cooper Energy Services, maker of Cooper-Bessemer, Ajax, Superior, and Delaval engines provides CleanBurn™ retrofits for all of its larger models and offers these services for engines manufactured by other companies, as well.[5, 6, 7] Dresser-Rand, manufacturer of Ingersoll-Rand, Clark, and Worthington engines also offers retrofit services for its lean-burn engines.[8] The Waukesha Engine Division of Dresser Industries manufactures two engine families that are available either in rich-burn or LEC configurations. The company offers LEC retrofit services for those engines originally sold in the rich-burn configuration.[9] At least three third-party vendors (Diesel Supply Company; Enginuity, Inc.; and Emissions Plus, Inc.) offer retrofit services for a wide variety of engine makes and models. These vendors will work with any model engine, although economies of scale can reduce capital costs for plentiful engines. For other engines, customized precombustion chambers can result in somewhat higher costs.[10]

This report evaluates LEC retrofits only for lean-burn engines. In practice, although not impossible for rich-burn engines (as noted above for certain Waukesha engine families), LEC retrofits are primarily applied to lean-burn engines. Other control technologies, notably NSCR and PSC, are much more common for rich-burn engines. These technologies are discussed in later sections of this chapter.

4.1.3 Data on NO_X Emissions from LEC-Equipped IC Engines

For this report, we reviewed a variety of information on LEC performance that has become available in the years since the 1993 ACT document was published. This information includes information from LEC technology vendors, test data, analyses of test data carried out by EPA and others, and other "anecdotal" data obtained from a variety of sources. These new data are presented below in Sections 4.1.3.1 through 4.1.3.3. Section 4.1.3.4 summarizes the LEC test data.

4.1.3.1 Information from LEC Vendors. Information from several engine manufacturers indicates that they guarantee NO_X emissions at or below 2.0 grams NO_X per brake horsepower hour (g/bhp-hr) for nearly all new LEC-equipped engines. Some new models are guaranteed at up to 3.0 g/bhp-hr, but these are smaller models with open-chamber designs. These smaller engines are generally less than 1,200 bhp. Some new models are guaranteed to 1.0 g/bhp-hr.[11]

Information from engine manufacturers that provide retrofit equipment and services indicates guaranteed levels typically in the range from 1.5 to 3.0 g/bhp-hr.[12] These guarantees reflect the performance of standard retrofit "kits" that have been developed by these engine manufacturers. A number of sources have indicated that retrofits can be tailored to meet a target emission level, although the cost may be greater than for the standard retrofit kit.[13, 14, 15]

One third-party retrofitter has guaranteed emissions as low as 1.0 g/bhp-hr. This vendor has retrofitted approximately 125 engines to improve NO_X emissions. These retrofits are designed to achieve the applicable emission limit on a site-specific basis, so not all have involved LEC. Approximately one third of these retrofits have been guaranteed to meet 2.0 g/bhp-hr or

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lower, and all guarantees have been met. Many of the vendor's other retrofits have achieved this level as well, based on test data. This vendor estimated that 90 percent of engine models can be retrofitted to achieve 2.0 g/bhp-hr using the screw-in precombustion chambers the company manufactures, along with associated upgrades to the turbocharger, intercooler, air-fuel mixing system, etc.[16]

This vendor cannot achieve 2.0 g/bhp-hr for some engine models. In particular, some Worthington models are designed so that adequate air cannot be delivered to achieve the necessary A/F ratio. The design of others prevents adequate air-fuel mixing. In some Worthington engines, the precombustion chamber is extended deep inside the cylinder head, which makes chamber cooling and engine misfires a real concern. This vendor has achieved a level of 6 g/bhp-hr for certain Worthington engines.[17, 18] As an example of uncontrolled emissions from Worthington engines, the vendor indicated that he has measured the uncontrolled emissions of one Worthington Model SUTC located in New York at 18 to 22 g/bhp-hr and another located in the Gulf Coast at 24 to 28 g/bhp-hr using a portable NO_X emissions monitor (uncertified).[19]

The vendor noted that the original engine manufacturers have the capability to reduce NO_X emissions to lower levels on engines that third-party vendors find problematic. The engine manufacturers are able to replace engine parts, such as the cylinder heads, with redesigned parts to overcome the impediments to low NO_X emissions. However, significant use of redesigned parts involves increased costs.[20]

The information provided by engine manufacturers does not suggest any notable difference in the guaranteed NO_X emission level for new 2-stroke and 4-stroke lean-burn engines equipped with LEC. Similarly, no significant difference based on operating cycle is apparent in the guaranteed performance of engines retrofit with LEC.

It should be noted that NO_X emission guarantees most often are made for specific operating conditions, typically firing pipeline-quality natural gas and operating at 100 percent of rated speed and torque. Most sources of information indicate that NO_X emissions are highest at full load and fall as load declines.[21, 22, 23] However, some sources indicate otherwise, and emission test results sometimes show an inconsistent relationship between NO_X emissions, engine speed, and engine torque.[24, 25, 26] All sources indicate that guaranteed NO_X emission levels can be maintained over a wider operating range through the use of good A/F ratio controls.

4.1.3.2 Emission Test Data. A considerable body of test data has accumulated in the years since LEC was first introduced. Some of the data were available when the 1993 ACT document was developed, but additional data have come available in the intervening years. Test data and associated analyses that were reviewed for this report are summarized in the paragraphs that follow. Except as otherwise noted, the test data are from short-term emission tests conducted at or near rated speed and load. Where necessary, test data were converted to brake-specific terms using a factor of 1 g/bhp-hr per 75 parts per million by volume (ppmv), dry basis, at 15 percent oxygen, consistent with the 1993 ACT document.[27]

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A May 2000 memo prepared by the EPA compiles data from seven different sources of NO_X emission test data. In all, the memo summarizes the results of 269 emission tests conducted on 49 different engines, including a wide variety of makes, models, and sizes. The memo notes that only 11 of the 269 tests exceeded 2 g/bhp-hr; 96 percent of the test results were below this level. Only one test was above 4 g/bhp-hr, and 71 percent of the tests were below 1 g/bhp-hr. A few of these tests were conducted under part speed, part load conditions.[28]

One of the sources of data compiled in the EPA memo discussed above is the Ventura County, California, Air Pollution Control District (VCAPCD). Ventura County has regulated IC engine NO_X emissions since 1981. As a result, VCAPCD has an extensive data base of short-term emission test results, including many engines that have been tested multiple times over the years. The version of the data base evaluated for the EPA memo includes test data only through 1992. A more recent version of the data base, including data through 1999, was obtained for this report. This version of the data base includes the results of 320 tests conducted on 23 engines equipped with LEC. Eight different engine models are included, with five models of 4-stroke engines and three models of 2-stroke engines. The NO_X emissions range from a low of 0.08 g/bhp-hr up to a high of 4.0 g/bhp-hr, with a mean of 0.66 g/bhp-hr. Only two of the tests (less than 1 percent) are greater than 2.0 g/bhp-hr. Almost 86 percent of the tests are below 1.0 g/bhp-hr, and nearly 32 percent are below 0.5 g/bhp-hr.[29]

A 1998 paper based on the VCAPCD emission test data base examined long-term test results for three engine models equipped with LEC technology. For these three engine models, the results were as follows:

- Ajax DPC-180 (180-bhp, 2-stroke engine): Sixty-eight individual tests were conducted on four different engines fired with natural gas between 1982 and 1996. The engines averaged NO_X emissions of 0.6 g/bhp-hr, with a high of 1.1 g/bhp-hr and a low of 0.2 g/bhp-hr.

- Waukesha L7042GL (1,100-bhp, 4-stroke engine): One hundred twenty-eight individual tests were conducted on eight different engines fired with natural gas between 1987 and 1995. The engines averaged 0.8 g/bhp-hr, with a high of 2.3 g/bhp-hr and a low of 0.2 g/bhp-hr. Besides the one test at 2.3 g/bhp-hr, the remaining tests were at or below 1.9 g/bhp-hr, with most well below this level.

- Superior 16SGTA (2,650-bhp, 4-stroke engine): Eighty-nine individual tests were conducted on three different engines fired with landfill waste gas between 1986 and 1997. The engines averaged NO_X emissions of 0.7 g/bhp-hr, with a high of 1.2 g/bhp-hr and a low of 0.3 g/bhp-hr.[30]

Another source of data included in the EPA memo discussed above is the Santa Barbara County, California, Air Pollution Control District (SBCAPCD). A recent version of the SBCAPCD emission test data base, including data from 1991 through 1999, was obtained and evaluated. This data base contains results for 14 NO_X emission tests conducted on 4 engines equipped with LEC. Of these, the results of 12 tests on 3 engines included NO_X data that could

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be converted to terms of grams NO_X per brake horsepower hour. These 12 tests averaged about 0.5 g/bhp-hr, ranging from a low of 0.14 g/bhp-hr to a high of 0.67 g/bhp-hr.[31]

Test data from the San Diego County, California, Air Pollution Control District (SDCAPCD) also were reviewed for this report. These data include the results of 121 NO_X emission tests conducted between 1991 and 1996 on 13 engines equipped with LEC. Overall, the emissions ranged from 0.3 g/bhp-hr to 4.8 g/bhp-hr with a mean of 1.1 g/bhp-hr.[32]

Eleven of the engines represented in the SDCAPCD data are of open-chamber LEC design. In 107 tests, NO_X emissions from these engines ranged from 0.4 g/bhp-hr to 4.8 g/bhp-hr, with a mean of 1.2 g/bhp-hr. Only one test was over 3.0 g/bhp-hr, and five tests were between 2 and 3 g/bhp-hr. Fifty-two percent of the tests were between 1 and 2 g/bhp-hr, and 42 percent were less than or equal to 1 g/bhp-hr. By engine, the highest average NO_X emission rate was 1.5 g/bhp-hr, and the lowest was 0.9 g/bhp-hr.

The two remaining engines included in the SDCAPCD data are prechambered models fired with landfill waste gas. In 14 tests, these engines averaged NO_X emissions of 0.5 g/bhp-hr, with a range from 0.3 to 1.0 g/bhp-hr.

Another source of NO_X emission data is the EPA's *Compilation of Air Pollutant Emission Factors*, commonly known as the "AP-42." This document presents emission factors for various types of emission sources based on aggregated source test data. The current AP-42 section on IC engines was published in October 1996. This section lists the following two NO_X emission factors for 2-stroke, lean-burn engines equipped with LEC:

- Clean Burn–2.3 g/bhp-hr
- Precombustion Chamber–2.9 g/bhp-hr

We believe that this terminology corresponds to trademarks used by two engine manufacturers that offer precombustion chamber LEC technology. These technologies are not differentiated in this report; both are considered LEC.

The AP-42 assigns these emission factors a rating of C, or average. The references for the AP-42 section reveal that the test data behind these factors are from 1990 or earlier.[33] The AP-42 section does not state that the data are from short-term emission tests, but this appears likely based on the references. The engine operating conditions (load and speed) of the testing are not specified in the section.

The EPA has begun a revision of the AP-42 section on IC engines. A draft section dated February 1997 was posted on the Internet for public comment. This draft section classifies lean-burn engines equipped with LEC as distinct "engine families" and specifies the following terminology and NO_X emission factors:

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- 2-stroke clean-burn engines–1.1 g/bhp-hr

- 4-stroke clean-burn engines–0.5 g/bhp-hr

These emission factors are rated C (average) and D (below average), respectively. The draft AP-42 section includes some more recent references, as well as some of the same references as the current section.[34, 35]

Commenters from industry on the draft AP-42 section objected to the "clean burn" designation. They noted that "CleanBurn" is a trademark of Cooper Energy Systems. Today, many engine manufacturers refer to their engines equipped with precombustion chambers simply as "lean-burn engines." The EPA has recognized that it is unable to distinguish with certainty between engines with and without prechamber LEC technology on the basis of the test reports it is using to develop the revised AP-42 section. As a result, the EPA plans to further revise the section.

Additional NO_X emission test information obtained for this report are summarized below:

- Seven Clark Model TLA-6, 2-stroke, lean-burn, 2,000-bhp engines retrofitted with LEC, tested in April 1998. Six engines retrofitted by a third-party vendor ranged from 0.8 to 1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr. One engine retrofitted by the original equipment manufacturer (OEM) tested at 1.7 g/bhp-hr.[36]

- Three Ingersoll-Rand Model 412KVS, 4-stroke, lean-burn, 2,000-bhp engines retrofitted with LEC by the OEM, tested in August 1992. Tested at 0.51, 0.62, and 0.64 g/bhp-hr, with a mean of 0.59 g/bhp-hr.[37]

- One Cooper-Bessemer Model GMV-10C, 2-stroke, lean-burn, 1,100-bhp engine retrofitted with LEC by the OEM, tested in September 1999. Tested at 0.61 g/bhp-hr.[38]

- Five Delaval Model HVA16C, 4-stroke, lean-burn, 5,500-bhp engines retrofitted with LEC by the OEM. Test results from June 1991 (four engines) and May 1996 (three engines) range from 0.43 to 0.68 g/bhp-hr, with a mean of 0.59 g/bhp-hr.[39]

- Two Cooper-Bessemer Model W-330, 2-stroke, lean-burn engines retrofitted with LEC by the OEM, tested in 1995 or 1996. Tested at 1.0 and 1.3 g/bhp-hr.[40]

- Two engines retrofitted as a research project for the OEM attempting to develop a lower-cost retrofit kit. One Cooper-Bessemer Model GMV-6, 2-stroke, lean-burn engine tested at 1.4 g/bhp-hr immediately after the retrofit (September 1992), at 2.4 g/bhp-hr after the A/F ratio controller was adjusted to achieve low NO_X emissions over the widest range of operating conditions (September 1992), and at 1.8 g/bhp-hr after 4,000 operating hours (April 1993). These emission levels all were measured at rated load and speed. One Cooper-Bessemer Model GMV-TF-10, 2-stroke, lean-burn

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engine was tested after retrofit at a variety of horsepowers ranging from approximately 50 percent to 110 percent of rated horsepower. The maximum NO_X emission level was about 5 g/bhp-hr and the minimum was less than 0.5 g/bhp-hr. All but one test point were at or below about 4 g/bhp-hr. The emission rate generally increased as the horsepower increased. (The uncertainty for this engine stems from test results displayed only in a plot of emissions versus horsepower.) The research project report indicated that both these engines met their target NO_X emission rates (2 to 5 g/bhp-hr).[41]

In all, the sources of NO_X emission test data summarized above include the results of 476 individual tests conducted on 58 engines. (This count does not include the aggregated data in some of the sources discussed above, such as the May 2000 EPA memo and the AP-42 sections.) In these tests, NO_X emissions ranged from 0.1 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests measured NO_X emissions greater than or equal to 4 g/bhp-hr. The emission test data are summarized by information source in Table 2-1 of Chapter 2 of this report.

4.1.3.3 Other Information on LEC Performance. Some additional information on the level of NO_X emissions that is achievable with LEC technology was obtained for this report. This "anecdotal" information consists of statements regarding LEC performance that are not accompanied by documentation (e.g., test data) or vendor guarantees. The additional information is summarized below:

- A 1990 report prepared for the Gas Research Institute (GRI) states that new engines equipped with precombustion chamber LEC technology can often achieve NO_X emission levels of 2 g/bhp-hr or below, corresponding to 80 to 90 percent reduction from conventional spark plug designs. The report indicates that this technology is well demonstrated in retrofit applications for newer, turbocharged lean-burn engines, and ascribes the same 80 to 90 percent emission reduction to such retrofits.[42]

- A 1994 report prepared for GRI states that an engine retrofitted with precombustion chamber LEC technology can average NO_X emissions of less than 2 g/bhp-hr, but for purposes of its cost analysis assumes emissions of 2.5 g/bhp-hr. The report notes that retrofits have been carried out and successfully demonstrated on many lean-burn engines, with the most likely candidates for retrofit being newer model designs. The report also states that improvements are routinely incorporated into the retrofit kits. This is the final report for a project developed in 1991 and 1992.[43]

- Three GRI flyers from 1994 and 1995 advertize new, low-cost NO_X controls for Ingersoll-Rand, Clark, and Cooper-Bessemer engines. The controls offered are the newer generation of OEM LEC retrofit technologies, featuring such improvements as screw-in precombustion chambers and turbocharger upgrades. The flyers indicate that the retrofit controls can reduce NO_X emissions to below 3 g/bhp-hr, which appears to

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be the target level based on expectations at that time regarding upcoming reasonably available control technology (RACT) requirements for lean-burn engines.[44]

- A paper prepared by the Manufacturers of Emission Controls Association (MECA) in 1997 indicates that NO_X emissions of 0.7 g/bhp-hr are typical from natural gas-fired engines operating at 74 percent excess air (lambda equal to 1.74).[45] Engines operating at such excess air levels typically require precombustion chambers to achieve stable combustion.

- Material submitted to the EPA by the Interstate Natural Gas Association of America (INGAA) in 1999 states that most existing engine models with OEM LEC retrofit equipment can achieve 4 g/bhp-hr at 100 percent torque and 100 percent speed. However, INGAA stated that some engines with poor air-fuel mixing characteristics can achieve only 7 g/bhp-hr at 100 percent torque and speed. The latter engines include some models manufactured by Worthington (ML and UTC models). This material also indicates that OEM LEC retrofit technology is available for most lean-burn engine models found at natural gas transmission and storage facilities, but is not available for a few models.[46]

- Southern California Gas Company operates continuous emissions monitoring systems (CEMS) on five engines equipped with LEC at a natural gas storage facility.[47] Based on knowledge of the CEMS data, the company has indicated that NO_X emissions from the engines are typically about 1.0 g/bhp-hr, and normally range from about 0.5 to 3.0 g/bhp-hr.[48] (Three of these engines are the Ingersoll-Rand Model 412KVS for which August 1992 emission test data are presented in the preceding section.)

Another source of information on achievable NO_X emissions is the 1997 California Air Resources Board (CARB) proposed determinations of RACT and best available retrofit control technology (BARCT) for stationary IC engines. These proposed determinations have not yet been finalized.

The proposed NO_X RACT for lean-burn SI engines is an 80 percent reduction in emissions, or emissions not to exceed 125 ppmv, dry basis, at 15 percent oxygen. This emission level corresponds to 1.7 g/bhp-hr based on the conversion factor used in this report for LEC-equipped engines. The basis for the proposed NO_X RACT is the VCAPCD rule that applied between September 1989 and December 1993. The CARB document also cites the VCAPCD test data in support of the proposed level. The document indicates that LEC is expected to be the most popular means of meeting the RACT requirements, although SCR may be used as an alternative if LEC is unsuitable for a particular model engine.

The proposed NO_X BARCT for lean-burn SI engines is a 90 percent reduction in emissions, or emissions not to exceed 65 ppmv, dry basis, at 15 percent oxygen. This corresponds to 0.9 g/bhp-hr. The basis for the proposed NO_X BARCT is the current VCAPCD rule, the Federal Implementation Plan for the Sacramento area, and the Sacramento Metropolitan Air Quality Management District rule. The proposed BARCT is identical to the latter two rules,

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but less stringent than the current VCAPCD rule (94 percent control or 45 ppmv limit). The CARB document also cites the VCAPCD test data to support the proposed level, noting that the majority of tests showed compliance with the proposed level despite the fact that the applicable requirement at the time of testing was 125 ppmv. The document indicates that LEC is expected to be the most common control method for meeting the proposed BARCT, although SCR may be used as an alternative if LEC is unsuitable for a particular model engine.[49]

4.1.4 Discussion of NO_X Emissions Data for LEC

The primary sources of data on controlled NO_X emissions are control equipment vendors (in the form of guarantees) and emission tests. As discussed above, general statements regarding achievable emissions may be made by sources familiar with these types of primary data.

Emissions data from LEC vendors (both engine manufacturers and third-party retrofit vendors) may overstate emissions somewhat. The vendor typically must provide a performance guarantee to the engine owner, leaving the vendor potentially liable if the engine fails to meet the guaranteed emission level.

This potential liability may motivate the control equipment vendor to design the LEC system to comfortably meet guaranteed performance, which is generally dictated by regulatory requirements. The typical result is LEC-equipped engines that meet or outperform the guarantee, as evidenced by information from retrofit vendors that all installations have met guaranteed emission levels, by one vendor's statement that many retrofits guaranteed at higher levels have achieved NO_X emissions of 2 g/bhp-hr, and by the test data discussed above that are consistently well below the applicable emission limits.[50, 51] Given these considerations, vendor guarantees provide a reasonable upper bound on NO_X emissions from well-maintained, well-operated engines equipped with LEC technology.

In contrast to the conservatism of guarantees, emission tests give an accurate picture of how a particular IC engine equipped with LEC performed during a particular test period. However, test results may tend to understate long-term emissions from the tested engine because owners may typically tune engines to minimize NO_X prior to testing. For example, a 1994 rule effectiveness study in Ventura County, California found that 5 out of 22 engines subjected to unannounced emission testing (23 percent) violated the NO_X limit. In comparison, the study found that only 1 out of 11 engines (9 percent) failed the regularly scheduled annual compliance test. One of the conclusions of the study was that most non-compliant engines can come into compliance easily and quickly with minor adjustments. (The source of these data does not identify the types of controls included in the study. Nonselective catalytic reduction clearly was included; it is not clear whether LEC was included.)[52] Because nearly all emission testing is scheduled by the engine owner, it is reasonable to conclude that test results represent a floor on the NO_X emission level achieved by the tested engine under the operating and ambient conditions of the test.

Other factors can also confound the relationship between test data and the performance of which a control technology is capable. Control systems typically are designed to meet the

emission limits that apply to each individual engine. Therefore, test data from controlled engines do not necessarily reflect what the technology is capable of achieving, but rather what the engine is required to meet. In addition, control technologies evolve and improve over time as vendors and operators gain experience. For this reason, older test results may not reflect the emission levels achievable with current technology.

4.1.5 Achievable NO_X Emissions from Lean-Burn SI Engines Equipped with LEC

Based on information from engine manufacturers, available emission test data, and the considerations presented in the preceding section, 2.0 g/bhp-hr is representative of the NO_X emission level achieved across all new engines equipped with LEC, including open-chamber designs. Among new engines equipped with precombustion chamber LEC technology (which includes some smaller engines and all larger engines), this level is achieved by all models.

Further, 2.0 g/bhp-hr also is a representative NO_X emission level that can be achieved in nearly all LEC retrofit situations, based on the use of precombustion chambers and associated equipment. Suppliers of retrofit equipment and services (both engine manufacturers and third-party vendors) typically guarantee NO_X levels in the range from 1.5 to 3.0 g/bhp-hr. However, a number of sources have indicated that retrofits can be tailored to the emission limit the engine is required to meet, so, for example, 2.0 g/bhp-hr is often achievable even for engines where the guarantee associated with the standard retrofit kit is higher. Nevertheless, it is to be expected that some engines will not be able to achieve 2.0 g/bhp-hr, particularly certain Worthington models.

The NO_X emission test results discussed previously support the conclusion that 2.0 g/bhp-hr is achievable for new engines and most engines retrofitted with LEC technology. While emission test results generally represent a floor on the long-term emissions from a particular engine, the available test data are dominated by very low NO_X test results, in some cases numerous tests of the same engines over the course of years. The test results from California are frequently well below the applicable NO_X emission limits, which were in the range of 2 g/bhp-hr when most of the tests were conducted. These data suggest a long-term emission level no greater than 2.0 g/bhp-hr for the tested engines.

4.2 SELECTIVE CATALYTIC REDUCTION

This section on SCR primarily updates Sections 5.2.4, 5.3.1.2, and 5.3.2.2 of the 1993 ACT document, which address application of SCR to lean-burn SI engines, diesel compression-ignition (CI) engines, and dual-fuel CI engines, respectively. The primary reason for the update is to describe new SCR technology and its implications for IC engines in load-following service. This section includes a brief description of the technology (Section 4.2.1) and its applicability (Section 4.2.2), information gathered on SCR for this report (Section 4.2.3), and conclusions regarding the level of NO_X control achievable using SCR (Section 4.2.4).

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4.2.1 Technology Description–SCR

Conventional SCR technology, as described in the 1993 ACT document, involves injecting anhydrous ammonia into the exhaust gas stream upstream from a catalyst bed. As the exhaust passes through the catalyst bed, the ammonia and NO_X react to form nitrogen gas and water. The system typically includes a NO_X CEMS upstream and/or downstream of the catalyst bed as a feedback mechanism to ensure that the proper quantity of ammonia is injected to avoid emissions of either unreacted ammonia or NO_X.

In recent years, the technology has been undergoing a change. The systems marketed today typically use an aqueous solution of urea in place of anhydrous ammonia as the reducing agent. This reduces the hazard and handling costs associated with anhydrous ammonia, because urea is not classified as a hazardous material as anhydrous ammonia is. Sometimes an aqueous solution of ammonia is used, which is less hazardous than anhydrous ammonia, although not as safe as urea.

For urea systems, the first stage of the catalyst bed is a hydrolysis catalyst, which converts the urea to ammonia. In the second stage of the catalyst, the ammonia and NO_X react to form nitrogen gas and water. As a beneficial secondary reaction, hydrocarbons react with oxygen to form water, carbon dioxide, and some carbon monoxide. The third stage of the catalyst bed is an oxidation catalyst where any unreacted ammonia is oxidized to nitrogen gas and water. A beneficial secondary reaction in this stage is the oxidation of carbon monoxide to carbon dioxide.

These systems use a "feedforward" system for determining the urea injection rate based on engine operating parameters (load, speed, and type of fuel, if variable) and exhaust temperature. The feedforward system is essentially a predictive emissions monitoring system (PEMS). The PEMS is calibrated by "mapping" the engine as part of the SCR system installation. Some systems complement the feedforward system with a feedback NO_X CEMS downstream from the catalyst to "trim" the urea injection rate.[53, 54, 55]

4.2.2 Applicability of SCR

As discussed in the 1993 ACT document, the types of IC engines that SCR can be applied to include lean-burn SI engines, diesel CI engines, and dual-fuel CI engines. To date in the United States, diesel engines are the most prevalent applications. Available data gathered for this report indicate that at least 44 IC engines at 12 facilities have had SCR installed since 1991. Thirty-eight of these are CI engines, with 31 fired with diesel fuel, 4 fired with distillate fuel oil (#2), 1 fired with residual fuel oil (#6), and 1 dual-fuel engine fired with diesel and natural gas. The remaining seven engines are lean-burn SI engines fired with natural gas. These include three engines at a natural gas pipeline compressor station in Southern California. Most of these SCR systems use anhydrous ammonia, although at least six of the engines use urea as the reducing agent. One source indicates that there are over 700 IC engines controlled with SCR systems in Europe and Japan, including approximately 80 to 100 2-stroke engines. (From the context, we believe that the source of this last data meant 2-stroke lean-burn SI engines fired with natural gas, although it is not explicit in the reference.)[56, 57, 58, 59]

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An issue with SCR technology has been its ability to maintain a high level of control, while minimizing emissions of unreacted ammonia (referred to as "ammonia slip"), on IC engines in load-following applications. This issue has specifically been raised for natural gas-fired, lean-burn SI engines at natural gas compressor stations. The potential problems associated with load following include variations in NO_X emissions, variations in exhaust gas flow and temperature, and thermal cycling (rising and falling gas temperature, which can degrade the catalyst). The natural gas transmission industry does not believe these concerns have been resolved sufficiently for their applications.[60] Vendors of SCR equipment believe that these issues have been addressed in modern, feedforward systems using improved catalysts.

4.2.3 Information on SCR-Equipped Engines

Although SCR technology was not a major focus, some information came to light during data gathering for this report. This information includes one facility's operational experience with SCR, some emission test data, and information from vendors of modern SCR equipment.

One facility that was visited for this project discussed experiences with SCR control on one lean-burn SI engine from 1984 to 1996. The SCR system met or exceeded the guaranteed level of NO_X control (70 percent), allowing the facility to meet the applicable emission limit. However, the facility found the system difficult and expensive to operate. Operating expenses included the CEMS needed for control system feedback, the anhydrous ammonia reducing agent, and catalyst replacement. The facility found operation and maintenance difficult because it required work beyond that normally required for an engine. The CEMS was especially problematic because it required facility personnel to learn new analytical and instrumental skills. Some neighbors objected to the facility transporting and storing the hazardous anhydrous ammonia. The company ultimately took this engine out of service, as well as a second identical engine controlled with SCR at another facility, shifting all duty to LEC-equipped engines located at these sites.[61] Emission test results from 1993 for these two engines show outlet NO_X emissions of 2.86 and 2.80 g/bhp-hr, corresponding to reductions of 87 and 84 percent, respectively.[62]

The VCAPCD emission test data base includes seven lean-burn SI engines equipped with SCR control technology. Five models ranging from 291 bhp to 800 bhp are represented. In 49 tests of these engines, NO_X emissions ranged from 0.1 g/bhp-hr to 3.0 g/bhp-hr, with a mean of 1.1 g/bhp-hr. Six tests of three engines (two different models) found emissions greater than 2 g/bhp-hr. For 43 tests, NO_X emissions upstream of the catalyst bed also were provided, allowing the percent reduction to be calculated. The reductions ranged from 41 to 97 percent, with an average percent reduction of 84 percent.

The test dates in the VCAPCD data range from 1986 to 1993. During this period, lean-burn SI engines were subject to a NO_X emission limit of 125 ppmv, dry basis, at 15 percent oxygen, or an emission reduction of 80 percent. In all but two tests of one engine, the test results indicate compliance with at least one of these alternative standards. The engine that failed two emission tests was taken out of service after the second test.

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In 1993, the VCAPCD tightened the NO_X emission limit for lean-burn SI engines to 45 ppmv, dry basis, at 15 percent oxygen, or an emission reduction of 94 percent. We do not know what the phase-in period for the new limits was, but the VCAPCD data base includes no test results for lean-burn SI engines equipped with SCR after 1993. This suggests that these engines were removed from service. The data base indicates that three of the seven engines were removed from service and replaced with electric motors.[63] According to a 1998 paper by a representative of the VCAPCD, one aim of VCAPCD's tighter NO_X emission limits was to encourage electrification of IC engines.[64]

Test result summary data also were obtained for 1997 emission tests of three 3,130-bhp, 4-stroke, lean-burn SI engines equipped with SCR control systems, which we believe to be urea based. These engines are located at a liquid fuel pipeline pumping station and operate at variable load and variable speed depending on the quantity, pressure, and density of the fuel being pumped. The SCR system utilizes a feedforward system based on engine load and speed and on exhaust temperature. The engines are subject to stringent permit emission limits for NO_X, volatile organic compounds (VOC), and carbon monoxide which correspond to 15 ppmv, 25 ppmv, and 32 ppmv, respectively (all on a dry basis corrected to 15 percent oxygen). This NO_X limit corresponds to about 0.2 g/bhp-hr. During testing in January 1997, the engines achieved the NO_X and carbon monoxide limits, but exceeded the limit for VOC. In repeat testing in March 1997 after the catalyst was checked and cleaned, the engines achieved all the emission limits. In 20 individual test runs on these three engines, NO_X emissions ranged between 0.11 g/bhp-hr and 0.21 g/bhp-hr.[65, 66, 67]

These test results indicate that SCR can achieve design NO_X control levels during short-term emission tests, including, in the case of the VCAPCD data, multiple tests on the same engine over the course of several years. However, these test results do not directly address performance during engine load swings. Continuous emissions data are necessary to address this issue fully.

We obtained one plot of continuous data over a 10 minute period from a trade association that includes SCR vendors. This figure plots data from a heavy duty diesel truck engine equipped with a feedforward urea SCR system. During this period, the engine varied from a speed of about 700 rotations per minute (rpm) at idle to about 2,300 rpm, with load varying concurrently from nearly 0 foot-pounds (ft-lbs) to about 800 ft-lbs. Inlet NO_X concentrations varied closely with load, ranging from a less than 10 ppmv up to over 150 ppmv. Outlet NO_X concentrations remained relatively stable, varying from nearly 0 ppmv up to about 20 ppmv. It is not clear from the figure at what percent oxygen the NO_X concentrations are expressed.[68]

Vendors of SCR systems indicate that the feedforward controls on modern systems provide for excellent NO_X control in load-following applications. One representative indicated that the advance in technology has been driven by the interest of diesel engine manufacturers, working with catalyst vendors, in developing urea SCR for on-road vehicles. Such vehicles exhibit varying load by nature.[69] Another source also stressed that the PEMS feedforward system, with optional CEMS feedback system, has been advanced by a strong research and

development effort. This vendor has supplied such SCR systems for a variety of applications, including stationary IC engines, ship engines, railroad engines, and diesel truck engines.[70]

Selective catalytic reduction system vendors also believe that they have solved other problems with SCR systems for IC engines. Advances in catalysts have eliminated thermal shock and vibration impacts and broadened the available temperature operating window.[71]

Vendors of SCR systems typically indicate that NO_X control efficiencies greater than 90 percent are achievable. These systems typically are designed on a case-by-case basis to achieve the required emission reduction, so design values do not necessarily represent the limit of the technology. One vendor source indicates that a number of SCR systems installed on U.S. IC engines since 1993 have been designed for NO_X control ranging from 80 percent to 95 percent. The design outlet NO_X emission level for three lean-burn SI engines at one natural gas pipeline compressor facility is less than 30 ppmv (oxygen concentration not specified by this information source). Another vendor source indicates that one urea SCR system installed in 1999 on a natural gas-fired, 389-bhp, lean-burn SI engine was guaranteed at 90 percent NO_X control, but has achieved over 95 percent control. Another such system on a diesel electric generator was designed for 70 percent reduction, but achieved 79 percent.[72, 73]

4.2.4 Achievable Level of NO_X Control with SCR

Based on the information presented and discussed above, 90 percent control of NO_X emissions is generally achievable through use of SCR systems on IC engines, including lean-burn SI engines, diesel CI engines, and dual-fuel CI engines. Recent installations with lower control levels are the result of the systems' having been designed to meet applicable NO_X emission limits, rather than any inherent limitation of the technology.

Based on information provided by SCR vendors, the shortcomings of earlier SCR systems have been corrected by the new generation of the technology, which includes improved catalysts, PEMS feedforward system controls (with the option for supplemental CEMS feedback control, where desired), and use of urea as the reducing agent. However, this technology has yet to be widely demonstrated in the United States on lean-burn SI engines in load-following applications. Vendors of this technology still must convince U.S. lean-burn SI engine operators that modern SCR systems are as effective, reliable, easy to operate, and cost effective as alternative control technologies, most notably LEC.

4.3 NONSELECTIVE CATALYTIC REDUCTION

This section on NSCR primarily updates Section 5.1.5 of the 1993 ACT document, which addresses application of NSCR to rich-burn SI engines. This technology was not a focus for this effort, but some information was gathered during the course of the project. This section includes a brief description of the technology (Section 4.3.1) and its applicability (Section 4.3.2), information gathered on NSCR (Section 4.3.3), and conclusions regarding the level of NO_X control achievable using NSCR (Section 4.3.4).

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4.3.1 Technology Description–NSCR

In NSCR, the engine exhaust is routed to a catalyst bed across which NO_X is reduced to nitrogen gas. At the same time, VOC and carbon monoxide are oxidized to water and carbon dioxide. Because emissions of these three pollutants all are reduced by the catalyst, NSCR is often referred to as a "three-way catalyst" system. These systems are similar to the catalytic converters used on automobiles.

For an NSCR system to operate optimally (i.e., to minimize NO_X emissions), the inlet exhaust stream must have very low oxygen content, as well as proper concentrations of NO_X, VOC, and carbon monoxide. This requires initial engine adjustments, followed by careful monitoring of oxygen content in the exhaust. For this reason, an automatic A/F ratio controller typically is used to regulate the exhaust oxygen content entering the catalyst bed. The controller adjusts the A/F ratio based on input from an oxygen sensor upstream from the catalyst bed.

The engine adjustments required to optimize NSCR systems typically reduce the efficiency of the engine, harming fuel economy. One source indicated that the brake-specific fuel consumption (BSFC) of these engines increases to 8,500 Btu/bhp-hr, at best.[74] Without the NSCR operating constraints, the BSFC is typically well below 8,000 Btu/bhp-hr for rich-burn engines, depending on model and other operational factors.

4.3.2 Applicability of NSCR

Because of the requirement for low oxygen content, NSCR systems are limited to rich-burn SI engines. As noted above, the engines must be adjusted to generate exhaust gas with specified characteristics.

4.3.3 Information on NSCR-Equipped Engines

A number of facilities in California that operate NSCR-equipped engines were visited during information-gathering for this report. The biggest operational problem associated with NSCR at these facilities has been damage to the catalyst caused by excessive temperature. This is caused when the exhaust stream is too fuel rich. In this situation, the uncombusted natural gas is rapidly oxidized in the catalyst bed, burning it out.

One natural gas storage facility that uses NSCR uses a bypass system during engine startup, in case the engine backfires and exhausts uncombusted fuel. The engine exhaust at this facility is typically about 950 °F. If the temperature reaches 1,200 °F, the system shuts down. At about 1,300 °F, the catalyst sustains damage. Another facility that uses NSCR-equipped engines to pump a variable water flow has had a significant problem with catalyst burnout.[75, 76]

Most of the visited facilities have achieved applicable NO_X emission limits using NSCR. Depending on jurisdiction and installation date, these NO_X limits are equal to or less than 50 ppmv, dry basis, at 15 percent oxygen (approximately 0.75 g/bhp-hr). However, one facility with very low permitted emission levels (equivalent to about 0.2 g/bhp-hr) has had difficulty

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maintaining this level. To improve system performance, this facility replaced the standard ignition systems on its engines with improved electronic ignition systems. A recent measure that has been successful for the facility has been to install an insulation blanket on the exhaust piping upstream from the catalyst bed, thereby maintaining a higher temperature when the exhaust stream reaches the catalyst bed. This has moved the exhaust into a temperature range where the NSCR system is more efficient.[77]

At one facility visited for this project, the rich-burn engines are subject to emission limits of 50 ppmv for NO_X and 1,700 ppmv for carbon monoxide, both on a dry basis at 15 percent oxygen. The carbon monoxide limit is a facility-specific limit based on an offset agreement with the SBCAPCD; otherwise, the limit would be 4,500 ppmv. A facility representative indicated that tuning these NSCR-equipped engines to achieve the NO_X emission limit is relatively easy because of the less-restrictive carbon monoxide limit. In contrast, best achievable control technology (BACT) for new engines in California is 9.5 ppmv or 0.15 g/bhp-hr for NO_X and 225 ppmv or 0.6 g/bhp-hr for carbon monoxide (concentrations on a dry basis at 15 percent oxygen). This NO_X level is only achievable with rich-burn engines controlled with NSCR. The combination of these restrictive levels for both NO_X and carbon monoxide makes the engine operating window for compliance very narrow.[78]

Emission test data for NSCR-equipped engines from three local air pollution agencies in California were reviewed for this report. These data from VCAPCD, SBCAPCD, and SDCAPCD are summarized below:

- The VCAPCD test data include 114 engines equipped with NSCR control technology. Forty-seven models ranging in size from 25 bhp to 1,250 bhp are represented in the data. In 902 tests of these engines, NO_X emissions ranged from less than 0.01 g/bhp-hr to 19 g/bhp-hr, with a mean of 0.3 g/bhp-hr. Ninety-nine percent of the tests (893) found emissions of less than 1 g/bhp-hr. For 543 tests, inlet NO_X emissions are included in the data base, allowing the percent reduction to be calculated. Percent reductions range from 0 to nearly 100 percent, with an average reduction of 92 percent. It should be noted that for the two tests with 0 percent emission reduction the inlet NO_X value was unusually low (0.12 and 0.03 g/bhp-hr), giving the appearance that the NO_X outlet value was mistakenly entered as the inlet value as well. Among tests that show NO_X reductions of less than 70 percent, the majority have NO_X inlet values of less than 2 g/bhp-hr.[79]

- The SBCAPCD test data include 78 engines equipped with NSCR. Seventeen models ranging in size from 48 bhp to 747 bhp are represented. In 163 tests of these engines, NO_X emissions ranged from less than 0.01 g/bhp-hr to 1.5 g/bhp-hr, with a mean of 0.17 g/bhp-hr. Tests dates range from 1991 to 1999.[80]

- The SDCAPCD test data include 33 engines equipped with NSCR. In 249 tests of 7 different models, NO_X emissions ranged from 0 g/bhp-hr (reported in the data we reviewed as 0 ppmv at 3 percent oxygen) to 18 g/bhp-hr, with a mean of about 1.0 g/bhp-hr. Fifty-eight percent of the tests found emissions less than or equal to

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0.5 g/bhp-hr. Over 85 percent of the tests (217) found emissions of 2.0 g/bhp-hr or less. The tested engines apparently had site-specific emission limits, which ranged from 180 ppmv at 3 percent oxygen (equivalent to about 0.9 g/bhp-hr) to 456 ppmv at 3 percent oxygen (equivalent to about 2.2 g/bhp-hr). All but 1 of the 32 tests with emissions greater than 2.0 g/bhp-hr were out of compliance with their permitted NO_X limits; an additional 9 tests with emissions less than 2.0 g/bhp-hr were out of compliance. A percent NO_X reduction was provided for 27 tests of 7 engines. The reductions ranged from 87 to 100 percent, with a mean of 97 percent. Tests dates ranged from 1984 to 1996.[81]

Test result summaries for two additional NSCR-equipped engines not included in the data above were received from one natural gas storage facility in California. In these 1997 tests, the NO_X emissions from these engines were less than 10 ppmv (dry basis at 15 percent oxygen) and less than 0.1 g/bhp-hr.[82]

As noted above in Section 4.1.3.3, another source of information on achievable NO_X emissions is the 1997 CARB proposed determinations of RACT and BARCT for stationary IC engines. These proposed determinations have not yet been finalized.

The proposed NO_X RACT for rich-burn SI engines is a 90 percent reduction in emissions, or emissions not to exceed 50 ppmv, dry basis, at 15 percent oxygen. This emission level corresponds to about 0.75 g/bhp-hr. The basis for the proposed NO_X RACT is the VCAPCD rule that applied between September 1989 and December 1993. The CARB document also cites the VCAPCD test data in support of the proposed level. The document indicates that NSCR is expected to be the most popular means of meeting the RACT requirements, although PSC may be used for engines fired with waste-derived fuels (e.g., landfill gas or sludge digester gas) where contaminants may poison the NSCR catalyst.

The proposed NO_X BARCT for rich-burn SI engines is a 96 percent reduction in emissions, or emissions not to exceed 25 ppmv, dry basis, at 15 percent oxygen. This corresponds to about 0.37 g/bhp-hr. (For engines fired with waste-derived fuel, the limits are 90 percent reduction of 50 ppmv.) The basis for the proposed NO_X BARCT is the current VCAPCD rule, the Federal Implementation Plan for the Sacramento area, and the Sacramento Metropolitan Air Quality Management District rule. The proposed BARCT is identical to these rules. The CARB document also cites the VCAPCD test data to support the proposed level, noting that the majority of tests showed compliance with the proposed level despite the fact that the applicable requirement at the time of most testing was 50 ppmv. The document indicates that NSCR is expected to be the most common control method for meeting the proposed BARCT, except for engines fired with waste-derived fuel. These engines are expected to use PSC.[83]

Information from vendors of NSCR systems indicates that NSCR three-way catalysts have been installed on over 1,000 IC engines in the United States and have been in use for over 10 years. This source indicates that these catalyst systems reduce NO_X emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent.[84]

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4.3.4 Achievable Level of NO_X Control with NSCR

Based on the information presented and discussed above, 95 percent control of NO_X emissions is generally achievable through the use of NSCR systems on rich-burn SI engines. These systems typically are designed on a case-by-case basis to meet applicable emission limits, with percent reduction more a function of design than any inherent limitation in the control technology.

Consistent operation at this level of control requires an automatic A/F ratio controller and implementation by the facility of a good inspection and monitoring program. The inspection and monitoring program is necessary to ensure that engines remain adjusted to optimize the NSCR systems' effectiveness and to detect signs of catalyst inactivity at the earliest possible time.

4.4 PRESTRATIFIED CHARGE™

This section on PSC primarily updates Section 5.1.4 of the 1993 ACT document, which address application of PSC to rich-burn SI engines. This technology was not a focus for this effort, but some information was gathered during the course of the project. This information is presented briefly below.

Prestratified charge technology involves injecting air into the intake manifold so that during the intake stroke, the piston initially draws in air, followed by a fuel-rich air-fuel mixture. Thus, the mixture near the spark plug is fuel rich, promoting good combustion, while the mixture away from the spark plug is very lean, acting as a heat sink and suppressing NO_X formation. Prestratified charge technology is applicable only to carbureted (i.e., non-fuel-injected) rich-burn engines.

Some California facilities using PSC technology were visited during information-gathering for this report. In the mid-1980's, one company retrofitted seven engines at two facilities with PSC technology. These engines are used to generate electricity for onsite consumption. The technology has performed well, achieving NO_X emission reductions of 85 to 90 percent, although the vendor guarantee was for only 80 percent. However, the PSC retrofit has resulted in a 20-percent power derating for the engines. In addition, while the PSC system itself requires very little maintenance, the engines are more "touchy"and require more frequent overall maintenance. Results from 11 emission tests of these 7 engines submitted by this source show NO_X emissions ranging from 1.0 g/bhp-hr to 3.2 g/bhp-hr. The average over the tests is about 2.0 g/bhp-hr.[85, 86]

Another facility located in the VCAPCD retrofitted several engines with PSC to meet the older emission standard that required a 90 percent reduction in NO_X emissions or a limit of 50 ppmv. When the VCAPCD standard was tightened to 96 percent reduction or 25 ppmv, the facility removed the PSC system and added NSCR. Other engines at this facility that are fired with waste-derived fuel continue to use PSC technology. These engines also use exhaust gas recirculation (EGR), with the air injected by the PSC system coming from the engines' exhaust.

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Emission test data for PSC-equipped engines from two local air pollution agencies in California were reviewed for this report. These data from VCAPCD and SBCAPCD are summarized below:

- The VCAPCD test data include tests of 18 engines equipped with PSC control technology. Ten models ranging in size from 100 bhp to 800 bhp are represented. In 150 tests of these engines, NO_X emissions ranged from about 0.1 g/bhp-hr to 9.5 g/bhp-hr, with a mean of 0.6 g/bhp-hr. Eighty-nine percent of the tests (134) found emissions of less than 1 g/bhp-hr. The 16 tests with emissions greater than 1 g/bhp-hr were from 8 engines ranging in size from 300 bhp to 800 bhp. For 37 tests, the data base includes NO_X emissions without PSC so that the percent change in emissions can be calculated without and with control. (In a number of tests, it appears that the value without PSC is repeated from an earlier test without retesting.) In one test, the emissions increased by about 6 percent with PSC. In the remaining 36 tests, the lowest percent reduction is 90 percent, with an average reduction of 95 percent. The data base includes tests from 1987 to 1999.[87]

- The SBCAPCD test data include tests of 32 engines equipped with PSC control technology. Six different models are represented in 126 tests. The engines range in size from 49.5 bhp to 410 bhp. Fifty-four tests (67 percent) were on engines of less than 50 bhp. Many of the engines are fired on field gas. These are likely to be cyclical load engines powering rod pumps in oil and natural gas fields. Emissions of NO_X ranged from less than 0.1 g/bhp-hr to 12.5 g/bhp-hr, with a mean of 1.3 g/bhp-hr. All of the fifteen tests (19%) that found emissions greater than 2.0 g/bhp-hr were on engines of less than 50 bhp. For 17 of the engines, there were comparison test runs with the PSC turned off and turned on. Emissions of NO_X with the PSC turned on were on average 77 percent less than with the PSC turned off. All these comparison tests were conducted on engines less than 50 bhp. Test dates ranged from 1991 to 1999.[88]

The 1993 ACT document found that the achievable NO_X emission level for PSC is 2.0 g/bhp-hr, based on the vendor's guarantees. This value is generally consistent with the information gathered for this project and is a representative value for the NO_X emission level that can be achieved using PSC control technology.

4.5 HIGH-ENERGY IGNITION SYSTEMS

With traditional spark plug ignition, the life of the spark is very short–only a fraction of a degree of crankshaft rotation. If the mix of air and fuel in the area of the spark is not exact, there is poor combustion or no combustion at all. With HEIS technology, also known as plasma ignition systems, a continuous electrical discharge is provided at the gap of a conventional spark plug for 10 to 90 degrees of crankshaft rotation. This extended energy delivery ensures combustion will occur even in the leanest of conditions. High-energy ignition systems can be used only in lean-burn, natural gas-fired SI engines.

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One well-known high-energy ignition system was developed by ENOX Technologies under the trade name of INOx™. With the INOx™ system, a very lean air-fuel mixture is fired using a turbocharger to boost pressure, thus reducing combustion temperatures. The lower combustion temperatures results in reduced NO_X formation. The electronic plasma combustion system ignites the mixture through a conventional spark plug opening; therefore, installation does not require modification to the engine's head and can be accomplished in 3 to 5 days.[89]

During development, the INOx™ system was tested in the laboratory and on at least two field engines. The lowest NO_X emission level achieved on a 2,750-bhp V-275 Cooper-Bessemer engine while maintaining acceptable engine operation was 2.5 g/bhp-hr, an 84 percent reduction from the uncontrolled level.[90]

Since that time, HEIS has been installed on numerous engines to meet NO_X RACT requirements in the range of 2.5 to 3.0 g/bhp-hr in the Eastern United States. One source indicates that a natural gas transmission company purchased INOx™ technology for installation on as many as 53 compressor station engines in New York and Pennsylvania.[91] Another source indicates that ENOX has successfully retrofitted over 100 engines with its INOx™ technology. Several clients have reported over 80 percent reduction in NO_X emissions.[92]

Another company, Plasmachines, Inc., has also developed HEIS technology that has been demonstrated on two operating IC engines. This ignition system has demonstrated the capability to reduce NO_X emissions from these engines from the level of 10 g/bhp-hr to the regulatory level at or near 2.0 g/bhp-hr.[93]

Stack test data from between 1995 and 1998 for three Clark TLA-8 reciprocating engines retrofitted with HEIS technology (make unknown) found average NO_X emission rates ranging from 1.2 to 4.2 g/bhp-hr, with an average of 2.05 g/bhp-hr.[94] There is little information available on the effects of HEIS technology on other pollutants.

4.6 EMERGING NO_X CONTROL TECHNOLOGIES

Three emerging technologies that show promise for reducing NO_X emissions from IC engines were identified during information-gathering for this project. The SCONOx® system uses a single catalyst to remove NO_X, carbon monoxide, and VOC. The NOxTech® system uses a non-catalytic chemical reaction to reduce NO_X, particulate matter, VOC, and carbon monoxide emissions. High-pressure fuel injection enhances mixing of air and fuel in the combustion chamber. These emerging technologies are described briefly below.

4.6.1 SCONOx® Technology

The SCONOx® system, developed by Goal Line Environmental Technologies, uses a single catalyst to remove NO_X, carbon monoxide, and VOC. Initially applied to gas turbines, SCONOx® IC-N and IC-D have been developed for use on internal combustion engines that are, respectively, natural gas-fired and diesel-fired.

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According to product literature, the SCONOx® process uses no hazardous materials; all utilities required to operate the system–natural gas, steam, water, ambient air, and electricity–are often already present at the site.[95] At temperatures between 300 and 700 °F, nitrogen dioxide (NO_2) is absorbed onto the catalyst surface through the use of a potassium carbonate coating, which reacts with the NO_2 to form potassium nitrites. The SCONOx® catalyst undergoes regeneration periodically to maintain the maximum NO_X absorption. The catalyst is regenerated by passing a controlled mixture of regeneration gases across its surface in the absence of oxygen. The regeneration gases react with the nitrites to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites to form potassium carbonate–the absorber coating that was on the surface of the catalyst before the oxidation cycle began. Water (as steam) and elemental nitrogen are exhausted up the stack and potassium carbonate is once again present on the surface of the catalyst allowing the oxidation adsorption cycle to begin again. There is no net gain or loss of potassium carbonate.[96]

Testing conducted by the vendor shows SCONOx® IC-N reduces NO_X, carbon monoxide, and VOC up to 95 percent in lean-burn engine exhaust.[97] Three SCONOx® IC-N systems were purchased for natural gas-fired IC engines and were scheduled to go one line in May 2000.[98]

Cummins Engine Company is testing SCONOx® IC-D for use on mobile and stationary diesel IC engines.[99] Preliminary testing in diesel IC engines found the SCONOx® and the related SCOSOx® catalyst systems reduced NO_X by 98.9 percent to 0.4 g/bhp-hr.[100] The fuel penalty for use of these systems was 1 percent or less. Three SCONOx® IC-D units have been sold but have not yet been commissioned.

4.6.2 NOxTech® Emission Control System

According to product literature, the NOxTech® emission control system, developed by NOxTech Inc., involves chemically treating exhaust gases with a nonhazardous liquid chemical. NOxTech® can be used on both diesel and lean-burn natural gas-fired IC engines. It replaces the exhaust silencer on IC engines with a reaction chamber. The non-catalytic chemical reagent is injected into the exhaust at temperatures between 1,400 and 1,500 °F. The NO_X and reagent react to form nitrogen, water vapor, and carbon dioxide. There is no toxic waste, although there are trace ammonia emissions of less than 2 to 5 ppmv.[101] The NOxTech® system is fully automated. Installation requires no major modifications and takes 2 to 3 weeks.

The exhaust gas must be heated to achieve the temperatures necessary for the NOxTech® system reactions. A heat exchanger is located downstream from the reactor to reclaim and reuse this heat energy.

The NOxTech® system has been installed and is operating on several diesel generators owned by Southern California Edison. Its Catalina Island facility uses NOxTech® on 2.5 MW and 3.8 MW diesel electric generators. Southern California Edison also uses NOxTech® on 1.5 MW and 2.8 MW diesel generators at its Pebbly Beach generating station.

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According to the vendor, NOxTech® has been proven to remove 90 to 95 percent of NO_X, 60 to 80 percent of particulate matter, 90 percent of VOC, and 50 to 70 percent of carbon monoxide from the exhaust of the 4,000-bhp diesel-powered generator on Catalina Island.[102] Based on its demonstrated commercial performance, NOxTech® has been demonstrated as BACT for some diesel engines.[103]

4.6.3 High-Pressure Fuel Injection

Another technology with potential for reducing NO_X emissions from IC engines is the use of high-pressure fuel injector systems to enhance the mixing of air and fuel in the combustion cylinder. According to one vendor of NO_X control equipment and retrofit services, this technology represents a "second generation" LEC, which may accomplish the same emission reductions without requiring precombustion chambers or as much excess air. Reducing the quantity of excess air would diminish the turbocharging and intercooling retrofit requirements. High-pressure fuel injection could significantly reduce the cost and complexity of retrofitting IC engines to control NO_X emissions.[104]

A representative of a company visited during this project to collect information on IC engine control technology discussed high-pressure fuel injection as a potential NO_X-reduction technology. He mentioned that in a test, a high-pressure fuel injection system reduced NO_X emissions by 80 percent from a large (around 5,000 bhp) turbocharged Clark engine. He also noted, however, that Clark engines typically have relatively poor mixing, so reductions from other engines might not be as great.[105]

It should be noted that another LEC retrofit vendor stated that NO_X emissions cannot be reduced to 2 g/bhp-hr through the use of a high-pressure fuel system alone. This vendor noted that less stringent regulatory requirements can sometimes be met with a combination of ignition timing adjustment, high-pressure fuel injectors, and improved A/F ratio and ignition system controls. This vendor's LEC retrofits typically include high-pressure fuel injectors.[106]

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104. Telecon. C. Fletcher, Enginuity, Inc., with S. Edgerton, EC/R Inc. Information on low-emission combustion and high-pressure fuel injection. April 6, 2000

105. EC/R Incorporated. Site visit reports for Southern California Gas Company's Aliso Canyon Station in Northridge, California, and Honor Ranch Station in Santa Clarita, California. June 20, 2000. Pg. 10.

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5.0 CONTROL COSTS

This chapter presents information on the costs associated with nitrogen oxides (NO_X) emission controls for stationary reciprocating internal combustion (IC) engines. The primary emphasis is on low-emission combustion (LEC) control for lean-burn, spark-ignited (SI) engines, for which an updated cost analysis is included in Section 5.1. Some cost data on modern selective catalytic reduction (SCR) systems are presented Section 5.2. Section 5.3 provides the references for this chapter.

5.1 COSTS FOR LEC NO_X CONTROL OF LEAN-BURN SI ENGINES

A primary emphasis of this report is to update the information on LEC technology for lean-burn SI engines, including costs. There are two reasons for this emphasis. First, many of the IC engines that will be affected by the NO_X State implementation plan (SIP) call in the Eastern United States are lean-burn SI engines. Second, developments in LEC technology have brought retrofit costs down in recent years. Accordingly, capital and annual costs have been reevaluated, as has cost effectiveness. In general, this cost analysis follows the methodology used in *Alternative Control Techniques Document–NO_X Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document), which is based on the *OAQPS Control Cost Manual*.[1, 2] Deviations from that methodology are pointed out in the material below.

This section presents costs in terms of both 1990 and 1997 dollars. Costs in terms of 1990 dollars have been used for many past analyses produced by the U. S. Environmental Protection Agency's Office of Air Quality Planning and Standards (OAQPS), including the cost analysis for the NO_X SIP call affecting the Eastern United States. In recent years, a number of regulatory analyses prepared by OAQPS have been conducted in terms of 1997 dollars. To facilitate comparison with other analyses, this report presents both.

5.1.1 Capital Costs

Section 5.1.1.1 below discusses the methodology used to determine representative purchased equipment costs (PEC) for LEC retrofits. Section 5.1.1.2 presents the methodology for determining total capital investment (TCI), which includes expenses incurred by the facility in addition to the PEC. Section 5.1.1.3 presents additional cost data and a discussion of how site-specific and engine-specific factors influence costs.

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5.1.1.1 Purchased Equipment Costs. One engine manufacturer and one third-party vendor provided actual installed costs for recent LEC retrofits in 1999 dollars.[3, 4] The cost data include costs for low-speed and medium-speed engines. The costs provided by the vendors are believed to represent the installed costs of all equipment related to the LEC retrofit, including any equipment required for increased air flows (e.g., inlet air filtration ductwork, exhaust silencers and ductwork, and aerial coolers). For this reason we have not inflated this hardware cost by a factor of 30 percent as was done for the LEC analysis in the 1993 ACT document.[5]

To conform to the 1993 ACT document analysis, this report assumes that the vendors' installed costs do not include such items as the purchaser's engineering and project management costs, field connections, painting, and training. (The third party vendor's cost data included a number of such items, but costs were aggregated in such a way that these items could not be backed out.) Accordingly, we have treated the vendor cost data as the purchased equipment costs (PEC).

After adding in the cost of an electronic air-to-fuel (A/F) ratio controller, the vendors' cost data were aggregated and plotted against horsepower, and a linear regression was carried out. Figure 5-1 presents the results. As can be seen from the figure, the data are reasonably linear (R-square value of 0.78). There is no sign of the pronounced divergence between costs for low-speed and medium-speed engines presented in the 1993 ACT document. In addition, no one contacted during the preparation of this report indicated that LEC costs differ substantially between low-speed and medium-speed engines. Accordingly, this report addresses LEC costs for all lean-burn SI engines together, without the subdivisions used in the 1993 ACT document. Based on the regression analysis, PEC ranges from $171,000 for a 1,000 brake horsepower (bhp) engine to $444,000 for an 8,000 bhp engine.

5.1.1.2 Total Capital Investment. To account for costs incurred by the facility beyond the PEC, we followed the 1993 ACT document methodology in applying the following cost elements: (1) direct installation–25 percent of PEC, (2) indirect installation–20 percent of PEC, (3) contingency–20 percent of PEC, (4) sales tax–3 percent of PEC, and (5) freight–5 percent of PEC. To calculate TCI, we summed PEC and these five cost elements. Figures 5-2a and 5-2b present the results in 1990 dollars and 1997 dollars, respectively. To de-escalate the LEC equipment costs from 1999 dollars to 1990 and 1997 dollars, the *Chemical Engineering* plant cost indices for each year were used. See Chapter 2, Tables 2-2a and 2-2b for a summary of TCI values for selected engine sizes in 1990 dollars and 1997 dollars, respectively.

5.1.1.3 Discussion of Capital Costs. The current capital cost of LEC retrofits was discussed with representatives of one natural gas supply company during site visits and follow-up contacts. The company has a current estimate for a third-party retrofit of a Clark Model HSRA, 2-stroke, 1,000 bhp, 8-cylinder engine at a pipeline station. The estimate for the total capital investment for this project, which would use screw-in precombustion chambers, is $710,000, including $570,000 to be paid to the LEC vendor and $140,000 in in-house expenses. The estimate includes $93,000 for an oxidation catalyst to reduce carbon monoxide emissions, as will be required in this Southern California air pollution control district if carbon monoxide emissions

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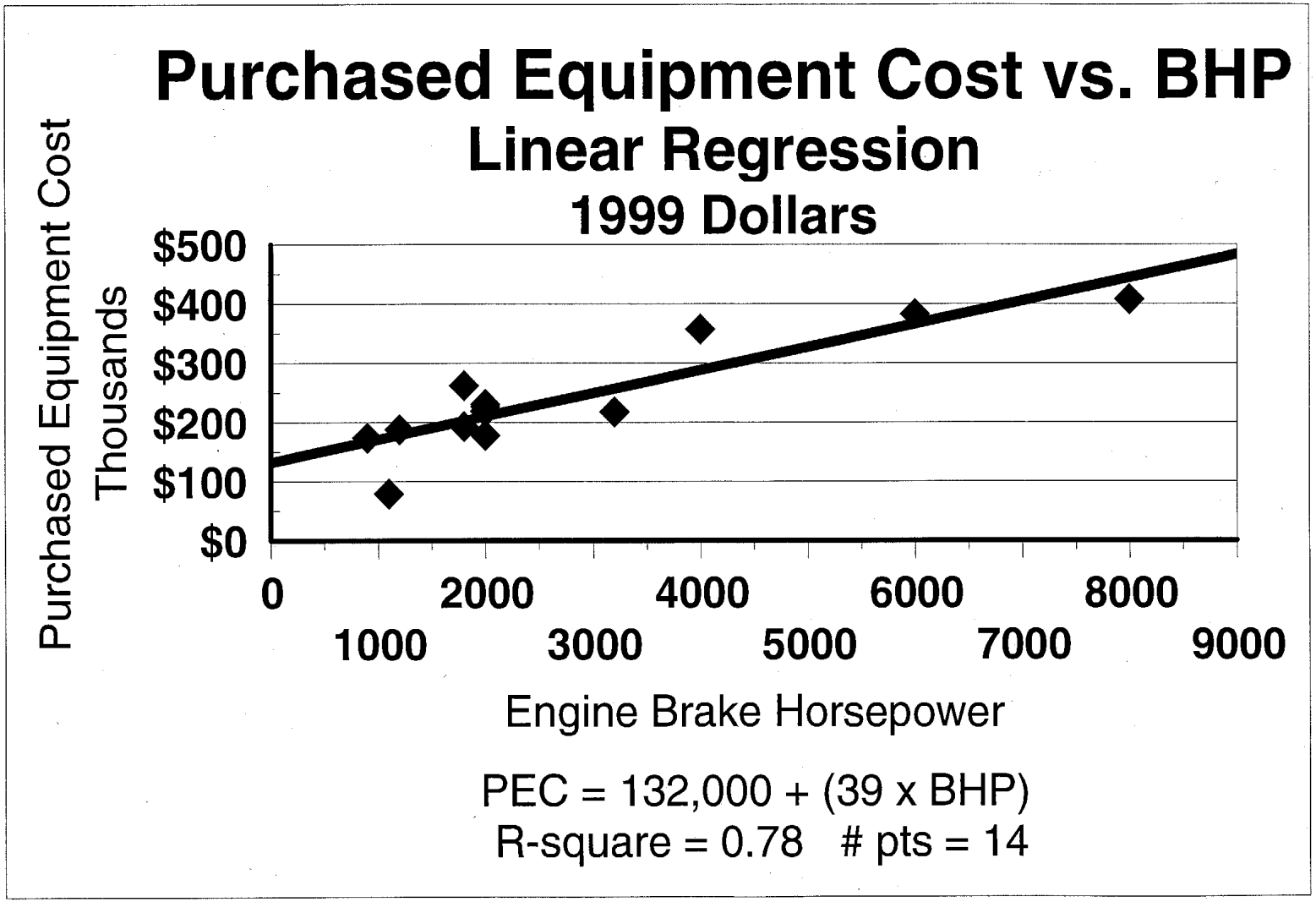


Figure 5-1. Purchased equipment cost for LEC retrofit versus rated brake horsepower.

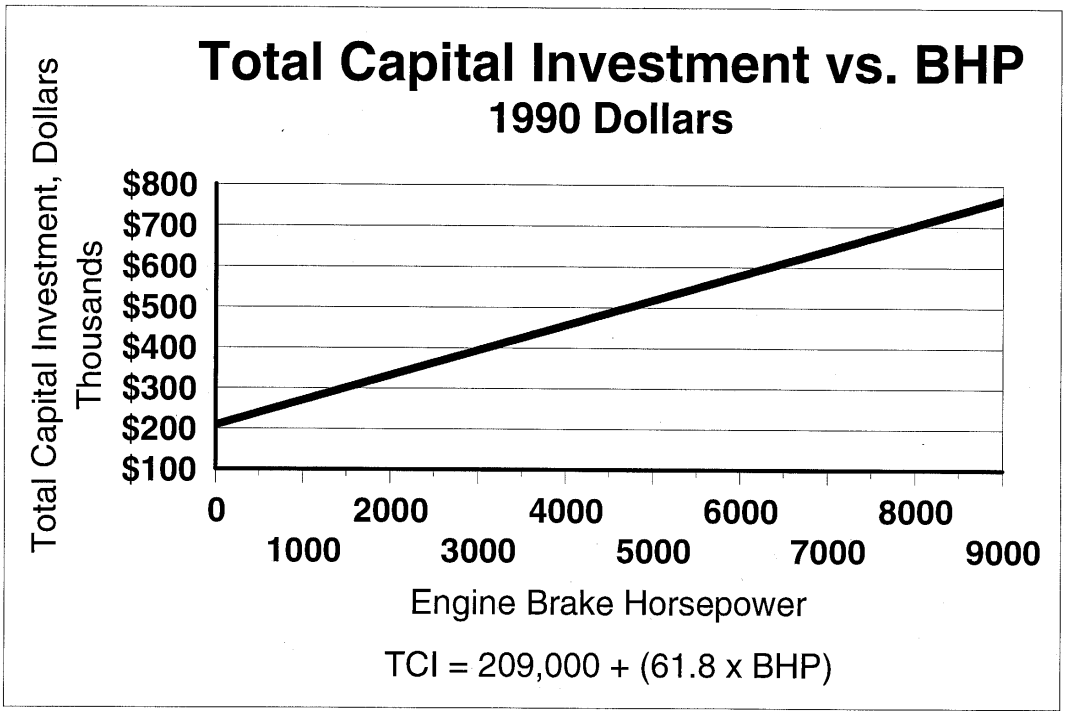


Figure 5-2a. Total capital investment for LEC retrofit (1990 Dollars) versus rated brake horsepower.

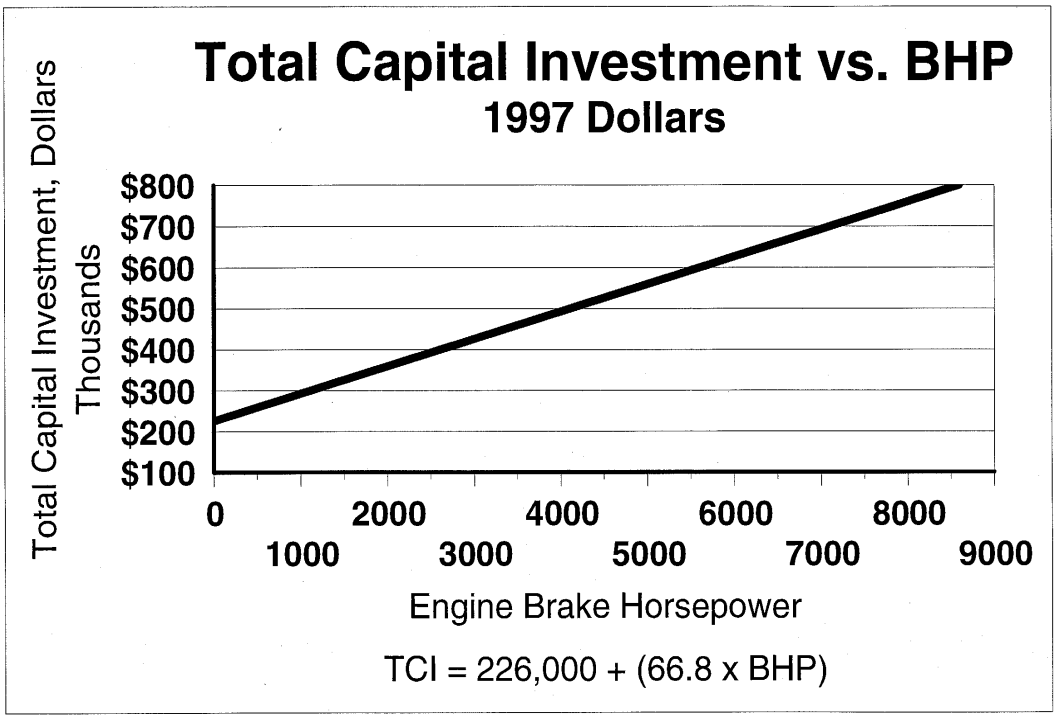


Figure 5-2b. Total capital investment for LEC retrofit (1997 Dollars) versus rated brake horsepower.

increase as a result of the retrofit. In addition to the oxidation catalyst itself, the $93,000 includes the cost of engineering, structural support, instrumentation, and exhaust piping changes. Of the $140,000 in in-house expenses, about 70 percent is for the labor required for engineering, construction coordinating, testing, permitting, etc. About 20 percent of the in-house expenses is for construction work (foundations, conduit, electric power) that was outside the scope of the LEC vendor. The remaining 10 percent is for the cost of the permit and other expenses.

Representatives of the company estimated that an LEC retrofit by the original equipment manufacturer (OEM) of a 2,000 bhp engine like the Ingersoll-Rand Model KVS engines at their facilities would cost approximately $1 million today. This estimate was based on the quote for the Clark engine retrofit discussed above, scaled up to account for the fact that the KVS engines have four more cylinders and would require a much larger turbocharger. In addition, the OEM retrofit would involve replacing the cylinder heads, rather than the use of screw-in precombustion chambers. However, the largest single component of the cost would be the new turbocharger and intercooler. For example, they noted that the current price for the turbochargers on some 5,500 bhp Delaval engines they had retrofitted with LEC is $350,000 apiece.

The company representatives indicated that LEC vendors typically state that retrofits cost $200,000 to $300,000, which includes $200,000 paid to the vendor and $100,000 in other costs incurred by the facility. This company has accomplished LEC retrofits at about this cost, but only when all conditions were right, including an existing turbocharger with adequate capacity and use of screw-in precombustion chambers. These representatives indicated that LEC retrofit costs at the levels discussed in the previous paragraphs are more typical because LEC vendors' quotes do not include all the options that the engine operator may feel are necessary. Site-specific situations such as safety concerns, limited room for the turbocharger, out-of-the-ordinary permit conditions, unmanned operation, company procedures, construction schedule restrictions, warranty requirements, more stringent acceptance testing, and so forth can have a great impact on costs. Because the engine operator is liable if the engine fails to meet the applicable NO_X emission limit, the operator needs a good specification and contract to hold the LEC vendor accountable in the event of a violation.[6, 7, 8]

These costs are well in excess of the costs predicted by Figure 5-2b, which would be about $290,000 for a 1,000 bhp engine and $360,000 for a 2,000 bhp engine. The amounts estimated by these company representatives are over twice as much.

There is a large divergence between the information from LEC retrofit vendors and this information from company representatives. One of the recently-retrofitted engines included in the cost information provided by the third-party LEC retrofit vendor is an Ingersoll-Rand Model KVS412, 2,000 bhp engine. The retrofit included replacing the engine's turbocharger and cleaning the intercooler for reuse. The cost of the retrofit (i.e., the amount paid to the vendor) was about $218,000. Adding $8,000 for an electronic A/F ratio controller and applying the factors for installation, etc. discussed in Section 5.1.1.2 above would bring the TCI to about $390,000.

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One explanation for the discrepancy between this estimate and the company's estimate of $1 million for an OEM retrofit was offered by the third-party vendor. This vendor indicated that conventional OEM retrofits have high costs because they involve a nearly complete make-over of the engine. This involves replacement of many engine components in addition to the cylinder heads, including cylinder sleeves, pistons, the exhaust manifold, etc. As an example, the third-party vendor noted that one client had several identical Clark Model TLA-6 2,000 bhp engines retrofitted with LEC. One engine was retrofitted by the OEM at a cost of $1.1 million. The remaining six engines were retrofitted by the third-party vendor at a cost of $205,000 each. This vendor also indicated that the cost of some OEM retrofits has come down. In cases where the engine owner does not wish to purchase the full engine make-over, the OEM may offer less extensive modifications. These retrofits may include screw-in precombustion chambers manufactured by a third-party vendor.[9]

The third-party vendor also noted that the cost of an LEC retrofit is very dependent on the particular engine being serviced. Many engines have been upgraded and modernized over time with such improvements as electronic ignition systems. However, others have not, and such engines require these additional upgrades at the time of the LEC retrofit. In some cases, other atypical costs may be incurred, such as foundation improvements to bear the weight of added equipment.[10] Foundation requirements appear to be a factor in the case of the relatively costly Clark Model HSRA retrofit mentioned above. In addition, the cost of an oxidation catalyst is included in the costs provided by the company. It is not appropriate to include this cost in a nationwide cost analysis because it is specific to the Southern California area where the company is located.

In light of the discussion above, the cost analysis in this report was conducted based on the regression curves derived from LEC retrofit vendor data. These cost data represent the actual costs for recent LEC retrofits and are believed to be typical. However, in some cases, costs may be higher due to site-specific and/or engine-specific factors.

5.1.2 Annual Costs

This report closely follows the 1993 ACT document methodology for calculating annual costs, including the following cost elements:

- Maintenance: labor and materials calculated as 10 percent of PEC. (Based on available information, this factor is high for LEC. The factor was retained in the interests of conservatism and consistency with the 1993 ACT document.)

- Overhead: 60 percent of maintenance costs.

- Fuel savings: 1 percent of annual fuel cost, based on the average 1998 cost of natural gas to industrial users. This is consistent with the ACT document and appears conservatively representative. Other information indicates that the effect has ranged from a fuel penalty of 2 or 3 percent to a fuel savings of up to 10 percent.

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- Taxes, insurance, and administration: 4 percent of TCI.

- Annual compliance test: $3,270. (Based on the value of $2,440 and escalation methodology [5 percent per year] used in the 1993 ACT document.)

- Capital recovery factor: 0.1098. (Based on 15-year equipment life and 7 percent interest rate.)

Annual costs were calculated by summing these cost elements based on 7,000 hours of operation annually. (Capacity utilization affects annual costs only in the fuel credit, which is based on annual operating hours, brake horsepower, and heat rate.) Figures 5-3a and 5-3b show the results in 1990 and 1997 dollars, respectively. See Chapter 2, Tables 2-2a and 2-2b for a summary of annual costs for selected engine sizes in 1990 dollars and 1997 dollars, respectively.

The 1993 ACT document primarily used 8,000 hours of operation in its calculations, but also showed the effect of some different levels of capacity utilization. This report uses 7,000 hours per year based on information obtained for IC engines used in the natural gas transmission and storage industry.

The natural gas transmission and storage industry accounts for a significant portion of the larger SI engines in the United States. A 1994 report prepared for the Gas Research Institute (GRI) states that 7,000 hours per year (80 percent capacity utilization) is representative of engines in natural gas transmission service. That report indicates that engines in natural gas storage service are typically smaller and operate at capacity utilizations in the range of 25 to 40 percent.[11]

The data base of large IC engines compiled by the Ozone Transport Assessment Group (OTAG) indicates a higher capacity utilization. This data base includes engines in the 22 Eastern States with average daily NO_X emissions of 1 ton or more during the ozone season (May through September).[12] Based on an analysis of the seasonal throughput and operating hours per day, days per week, and weeks per year listed in the data base for these engines, they average about 93 percent capacity utilization during the ozone season. On an annual basis, this corresponds to about 8,150 hours per year.

A data base of IC engines also was compiled for the Industrial Combustion Coordinated Rulemaking (ICCR) effort. This is a nationwide data base. The IC engines in this data base with the Standard Industrial Classification (SIC) code for natural gas transmission and storage (SIC code 4922) average about 6,900 operating hours per year.[13]

One source indicated that capacity utilization might be lower, at least for larger engines. In comments on the final NO_X SIP call, the Interstate Natural Gas Association of America (INGAA) indicated that IC engines with horsepower greater than or equal to 4,000 bhp at natural gas transmission facilities in the OTAG States average less that 25 percent capacity usage during the 2nd and 3rd quarters, which encompass the ozone season. These data are based on a survey of the natural gas industry conducted by the industry.[14]

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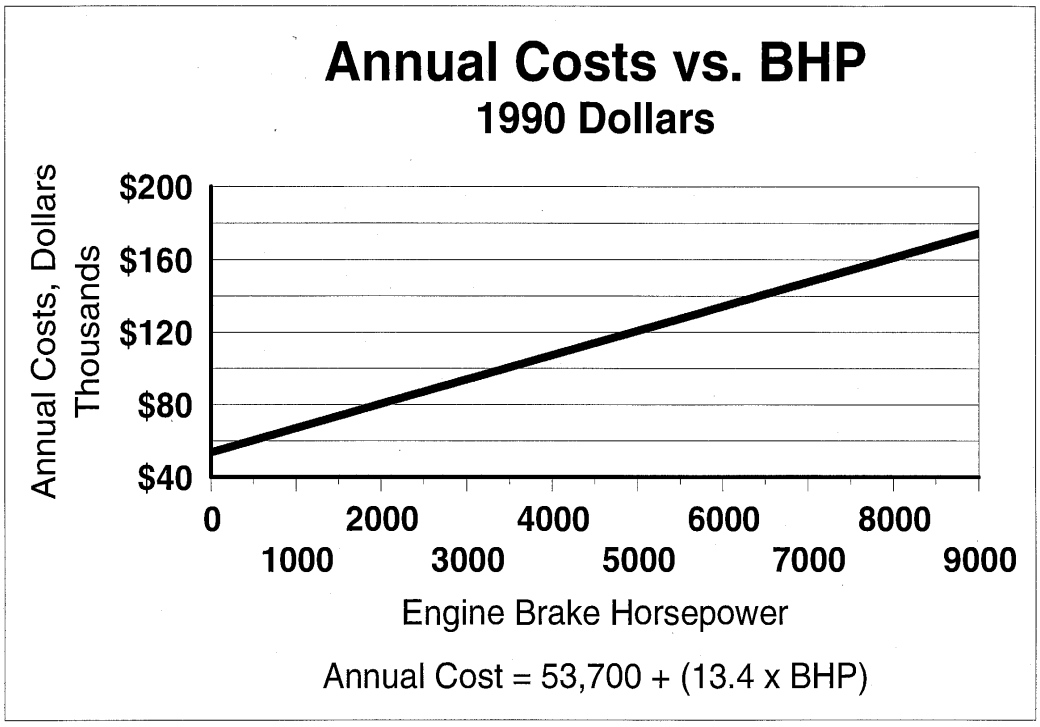


Figure 5-3a. Annual costs for LEC retrofit (1990 Dollars) versus rated brake horsepower.

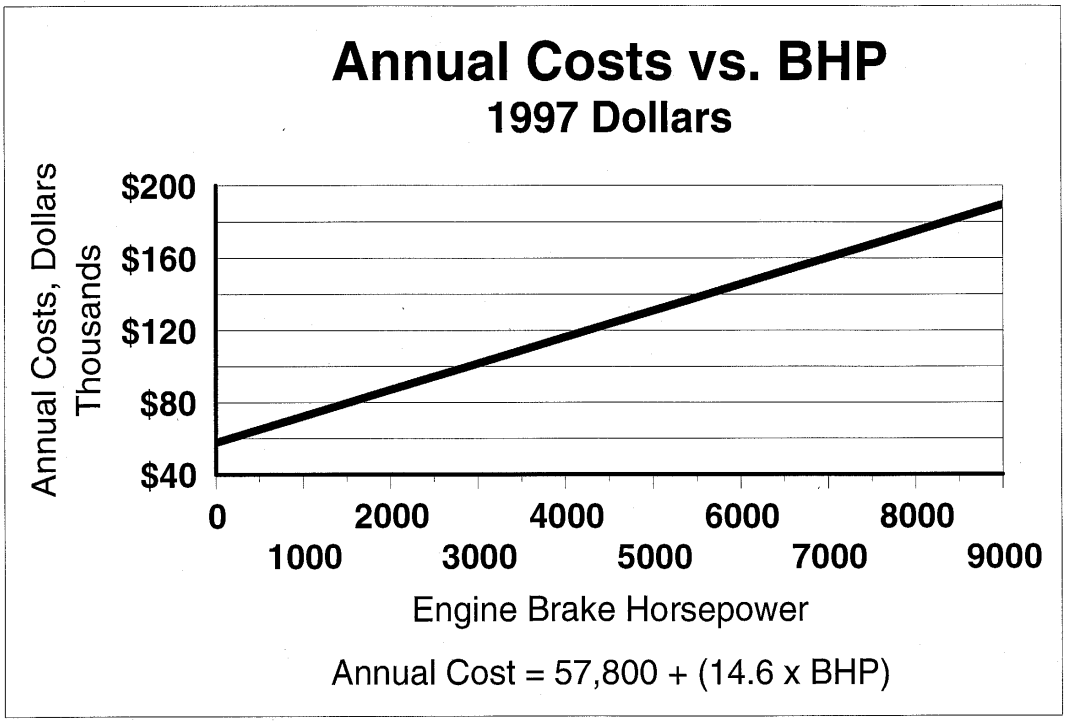


Figure 5-3b. Annual costs for LEC retrofit (1997 Dollars) versus rated brake horsepower.

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Based on all this information, 7,000 hours per year is a representative value for IC engines used in the natural gas transmission and storage industry. Because this industry represents a significant fraction of all SI engines likely to come under NO_X regulations, it is reasonable to use this value for the entire population of SI engines, as well.

5.1.3 Cost Effectiveness

This report closely follows the 1993 ACT document methodology for calculating cost effectiveness on an annual basis. In addition, cost effectiveness based only on the ozone season was calculated.

On an annual basis, cost effectiveness is determined for an engine by calculating the tons of NO_X emissions reduced through the use of the control technique, and dividing this quantity into the annual cost. The results of this analysis for lean-burn SI engines appear in Figures 5-4a and 5-4b for 1990 dollars and 1997 dollars, respectively. These figures show cost effectiveness below $500 per ton of NO_X reduced for all engines larger than 2,000 bhp.

For the ozone season, a similar approach was used. However, in this case the NO_X emission reduction was calculated for the 5 months of the ozone season. This value was divided into the total annual costs to determine cost effectiveness for the ozone season. The entire annual cost was used because LEC technology is integral to the engine and must be operated and maintained throughout the year. Figures 5-5a and 5-5b present the results of this analysis in 1990 dollars and 1997 dollars, respectively. These figures show cost effectiveness below $1,000 per ton for all engines larger than about 2,000 bhp, falling to $500 per ton for engines larger than about 5,000 bhp. See Chapter 2, Tables 2-2a and 2-2b for a summary of annual and ozone season cost-effectiveness values for selected engine sizes in 1990 dollars and 1997 dollars, respectively.

The NO_X emission reductions used in the annual cost effectiveness calculations were based on uncontrolled emissions of 16.8 grams per brake horsepower hour (g/bhp-hr), controlled emissions of 2.0 g/bhp-hr, and 7,000 operating hours. For the ozone season cost effectiveness, the NO_X emission reduction was prorated to the 5 months of the ozone season. The rationale for these uncontrolled and controlled emissions values appears in Chapters 3 and 4, respectively. As discussed in Section 5.1.2, this capacity utilization value is believed to be representative based on available information.

Some other sources also have estimated the cost effectiveness of LEC. A 1990 GRI report estimated cost effectiveness at about $500 to $700 per ton of NO_X reduced. These calculations included a significant cost savings for improved engine performance (increased power and better fuel efficiency).[15] Another GRI report published in 1994 included LEC cost analyses for three engines of 1,100 bhp, 1,800 bhp, and 2,000 bhp. The cost effectiveness values for these engines were calculated to be about $1,700 to $1,800 per ton. These values exceed those of this report's analysis because the GRI report estimated higher capital costs and smaller NO_X emission percent reductions (80 percent). That report was prepared before LEC technology was simplified and improved in the later 1990's.[16]

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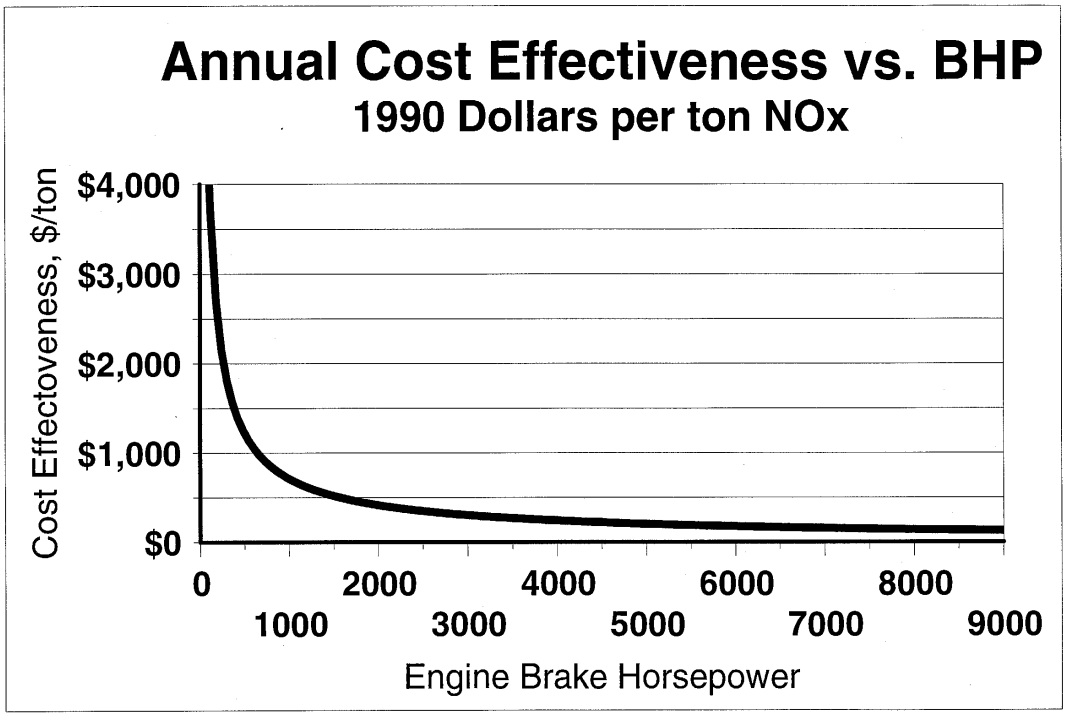


Figure 5-4a. Annual cost effectiveness of LEC retrofit (1990 Dollars) versus rated brake horsepower.

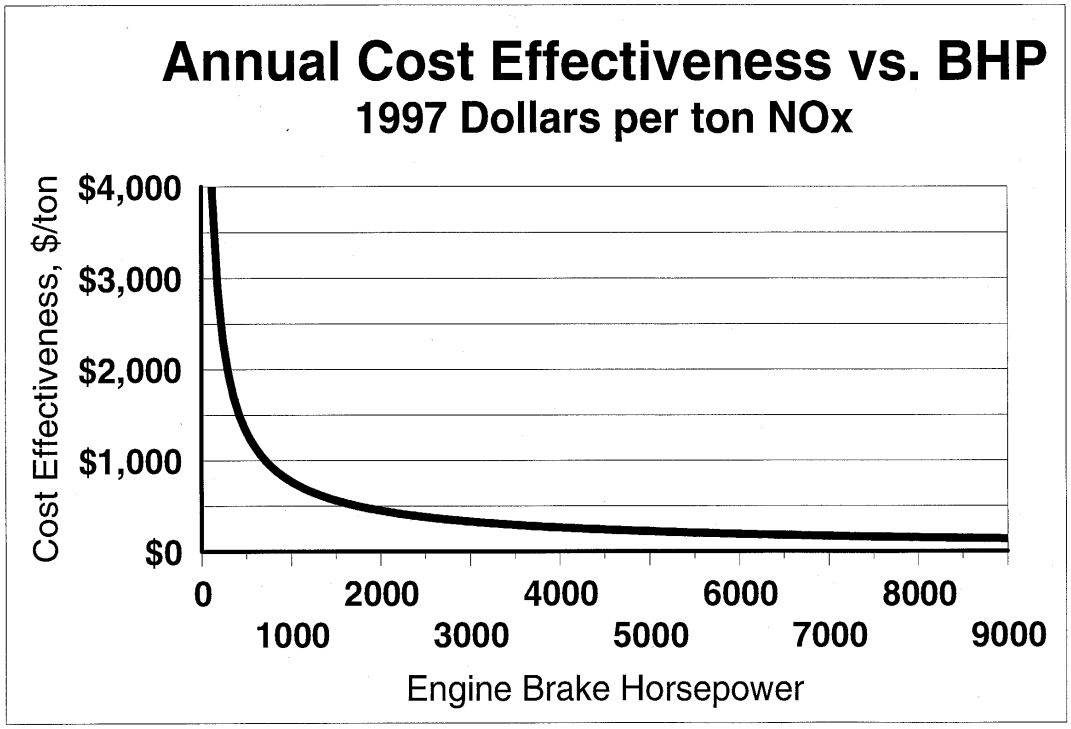


Figure 5-4b. Annual cost effectiveness of LEC retrofit (1997 Dollars) versus rated brake horsepower.

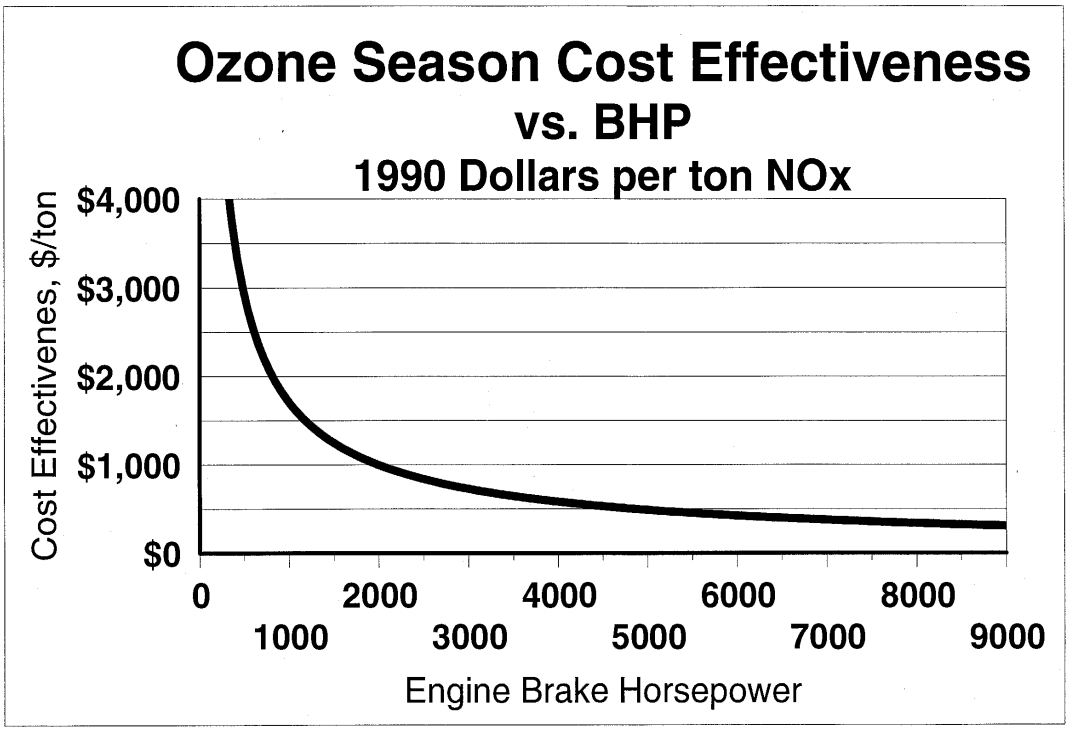


Figure 5-5a. Ozone season cost effectiveness of LEC retrofit (1990 Dollars) versus rated brake horsepower.

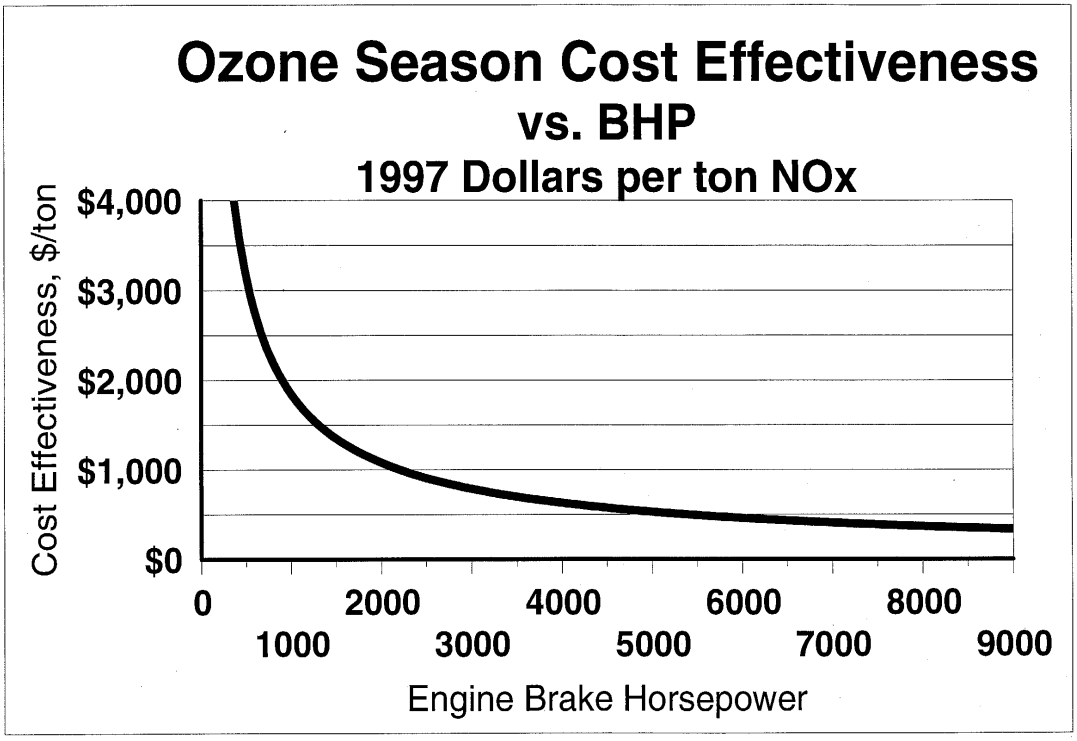


Figure 5-5b. Ozone season cost effectiveness of LEC retrofit (1990 Dollars) versus rated brake horsepower.

A 1997 proposed determination of reasonable available control technology (RACT) and best available retrofit technology (BARCT) prepared by the California Air Resources Board (CARB) also includes some cost effectiveness estimates. This document reproduces findings from a 1991 Santa Barbara County Air Pollution Control District (SBCAPCD) staff paper that indicate that LEC retrofits have a cost effectiveness of $7,400 per ton for 500 bhp to 1,100 bhp engines. The document also includes recalculated cost effectiveness based on the SBCAPCD data and 1996 LEC vendor prices. The updated cost effectiveness is $1,300 to $2,000 per ton for 300 bhp to 500 bhp engines.[17] These figures are higher than this report's analysis because SBCAPCD used a much lower capacity utilization, presumably based on actual data from the engines in the district, and included relatively small engines. The combination of low capacity utilization, smaller engines, and old, higher capital costs resulted in the very high cost effectiveness values in the original SBCAPCD analysis.

Data on LEC cost effectiveness also were received from an engine manufacturer that provides OEM retrofit services. This vendor prepared a curve relating annual cost effectiveness to engine horsepower, much like Figures 5-4a and 5-4b. This curve shows cost effectiveness falling to below $500 per ton for engines larger than 500 bhp. These estimated costs are lower than those of this report's analysis because of lower capital cost estimates, based largely on lower direct and indirect installation costs.[18]

A 2000 report prepared by E. H. Pechan & Associates, Inc. for the U. S. Environmental protection Agency (EPA) estimated annual and ozone season cost effectiveness for 2,000 bhp, 4,000 bhp, and 8,000 bhp engines under a variety of scenarios. In most scenarios, costs were based on the LEC retrofit cost information from an engine manufacturer that was also used for the analysis carried out for this report, although one scenario involved costs from the 1993 ACT document. The other scenarios involved variations in the uncontrolled NO_X emission level, the controlled NO_X emission level, or the capacity utilization. For these scenarios, the average annual cost effectiveness varied between $168 per ton and $390 per ton in 1990 dollars. The average ozone season cost effectiveness varied between $404 per ton and $936 per ton in 1990 dollars.

Overall, these other cost analyses are not inconsistent with the analysis in this report. When the reasons for the differences in cost effectiveness values are understood, particularly the reduced cost of modern retrofits, these results are reasonable.

5.1.4 Monitoring Costs

Costs for monitoring are not included in the cost analyses above. For information on the cost of a continuous emissions monitoring system (CEMS) for NO_X, see the *U. S. Environmental Protection Agency's Continuous Emission Monitoring System Cost Model Version 3.0* (available at www.epa.gov/ttn/emc/cem.html).

One natural gas storage facility that was visited for this study operates predictive emissions monitoring systems (PEMS) on some engines. A new type of PEMS the company is beginning to install and certify utilizes a pressure sensor in each cylinder. The sensors cost only

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$800 apiece, and are expected to last about 8,000 hours of engine run time. Currently, the company is required to certify the PEMS using the procedures of 40 CFR part 75, subpart E. This requires 800 hours of testing against a certified CEMS or EPA test method, which greatly increases the cost of the PEMS. The company and its PEMS vendor believe that they have demonstrated that good PEMS models can be developed with only a few days of testing.

The company prefers PEMS to CEMS. The equipment is much cheaper, easier to maintain, and more reliable. In addition, the skills required for a PEMS match the skills of the engine personnel. Finally, the PEMS generates data that are useful in determining engine health, unlike a CEMS which only indicates that emissions are high. The company believes that the full cost of a CEMS is greater than indicated by the EPA cost model.[19]

5.2 COSTS FOR SCR

As discussed in Section 4.2, SCR technology is undergoing a change. An analysis of the costs of modern SCR systems was not conducted for this study, but a cost analysis was obtained from an SCR vendor.[20] The costs are presented below.

The vendor calculated costs and cost effectiveness for two situations involving 2,600 bhp natural gas-fired SI engines: (1) three engines each operated 400 hours per year and (2) one engine operated 2,000 hours per year. For the first case, capital costs were calculated at $187,000, including catalyst, urea control, injectors, engine map, startup assistance, reagent tank, and installation. For the second case, with just one engine, these costs totaled $68,000.

Annual costs for the first case totaled $48,200 based on capital recovery (equipment life of 7 years and 10 percent interest rate) and reagent costs. The emission reduction at 90 percent efficiency totaled 27 tons of NO_X . In combination, this results in a cost effectiveness of about $1,800 per ton. Based on the same components (except for an equipment life of only 5 years) annual costs for the second case would total $35,680, the emission reduction would be 45 tons of NO_X, and the cost effectiveness would be under $800 per ton.

The vendor carried out a similar analysis for a 1,000 bhp diesel engine. For an engine operating 200 hours per year, the cost effectiveness was calculated at almost $4,000 per ton. For an engine operating 2,000 hours per year, the cost effectiveness dropped to less than $900 per ton.

These cost and cost effectiveness calculations do not include all the cost elements normally considered by the EPA. For example, no indirect installation costs are included in the capital costs. In addition, the annual costs do not include any operating or maintenance costs.

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5.3 REFERENCES FOR CHAPTER 5

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6. Facsimile from G. Arney, Southern California Gas Company, to S. Edgerton, EC/R Incorporated. Information on Low Emission Combustion Engines. December 17, 1999. 2pp.

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20. Manufacturers of Emission Controls Association. *Urea SCR for Stationary IC Engines.* Slides from a presentation to the NESCAUM Stationary Source and Permits Committee. October 6, 1999.

NMED Exhibit 48

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Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

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SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

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WHAT THIS SUBPART COVERS

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§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

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§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

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§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c).

These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013]

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§63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

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EMISSION AND OPERATING LIMITATIONS

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§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a

stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

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§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

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§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

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§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

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§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder

that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

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GENERAL COMPLIANCE REQUIREMENTS

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§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

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TESTING AND INITIAL COMPLIANCE REQUIREMENTS

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§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

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§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

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§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

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§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

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§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

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Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

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Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

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Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

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Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

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§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply

with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when

the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

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§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

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CONTINUOUS COMPLIANCE REQUIREMENTS

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§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

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§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during

the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing

2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

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NOTIFICATIONS, REPORTS, AND RECORDS

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§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

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§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports

pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

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§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

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§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

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OTHER REQUIREMENTS AND INFORMATION

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§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

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§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

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§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities

or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_x) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_x, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash

emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

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Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

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Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

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Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

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Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source	

of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

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Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of	

	operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	

11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

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Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of	Minimize the engine's time spent at idle and minimize the

	operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours	

	of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of	

	operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

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Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.

5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

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Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO and O_2 measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-

				point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] [c] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005)[a] [b] [c] (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point

				long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03[a]	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formalde-hyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

3. Stationary RICE	a. limit the concentra-tion of formalde-hyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005)[a] (heated probe not necessary)	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the station-ary RICE exhaust at the	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40	(a) Measurements to determine moisture content must be made at the same time and

		sampling port location; and	CFR part 63, appendix A, or ASTM D 6348-03[a]	location as the measurements for formaldehyde or CO concentration.
		iv. Measure formalde-hyde at the exhaust of the station-ary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03[a], provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the station-ary RICE	(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005)[a c], Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[b]You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

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Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major	a. Limit the concentration of CO,	i. The average CO concentration determined from the initial

source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	and not using oxidation catalyst	performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises

		the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.

9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as

an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year		specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

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Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620;

of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP		and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating

		parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and

		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that

		your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average

remote stationary RICE and that are operated more than 24 hours per calendar year		reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

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Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7),	i. Semiannually according to the requirements in §63.6650(b).

		the information in §63.6650(e); or	
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

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Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	

§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	

§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as	

		specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.

§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	

§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i)(C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

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Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 DEFINITIONS

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to

the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 SAFETY. [RESERVED]

6.0 EQUIPMENT AND SUPPLIES.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell.

Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) "Development of an Electrochemical Cell Emission Analyzer Test Protocol", Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Facility_____ Engine I.D._____ Date_____											
Run Type:	(_)		(_)		(_)		(_)				
(X)	Pre-Sample Calibration		Stack Gas Sample		Post-Sample Cal. Check		Repeatability Check				
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
″											
″											
″											
″											
″											
″											
″											

"											
"											
Mean											
Refresh Phase											
"											
"											
"											
"											

[78 FR 6721, Jan. 30, 2013]

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Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

SOURCE: 73 FR 3591, Jan. 18, 2008, unless otherwise noted.

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WHAT THIS SUBPART COVERS

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§60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

(i) On or after July 1, 2008; or

(ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

(5) Owners and operators of stationary SI ICE that are modified or reconstructed after June 12, 2006, and any person that modifies or reconstructs any stationary SI ICE after June 12, 2006.

(6) The provisions of §60.4236 of this subpart are applicable to all owners and operators of stationary SI ICE that commence construction after June 12, 2006.

(b) The provisions of this subpart are not applicable to stationary SI ICE being tested at an engine test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(d) For the purposes of this subpart, stationary SI ICE using alcohol-based fuels are considered gasoline engines.

(e) Stationary SI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR parts 90 and 1048, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(f) Owners and operators of facilities with internal combustion engines that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37972, June 28, 2011]

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EMISSION STANDARDS FOR MANUFACTURERS

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§60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008 to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as follows:

If engine displacement is * * *	and manufacturing dates are * * *	the engine must meet emission standards and related requirements for nonhandheld engines under * * *
(1) below 225 cc	July 1, 2008 to December 31, 2011	40 CFR part 90.
(2) below 225 cc	January 1, 2012 or later	40 CFR part 1054.
(3) at or above 225 cc	July 1, 2008 to December 31, 2010	40 CFR part 90.
(4) at or above 225 cc	January 1, 2011 or later	40 CFR part 1054.

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a

maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

(e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048 applicable to engines that are not severe duty engines.

(f) Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, to the extent they apply to equipment manufacturers.

(g) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary SI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed stationary SI ICE.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59175, Oct. 8, 2008; 76 FR 37973, June 28, 2011; 78 FR 6697, Jan. 30, 2013]

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§60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

Engines manufactured by stationary SI internal combustion engine manufacturers must meet the emission standards as required in §60.4231 during the certified emissions life of the engines.

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EMISSION STANDARDS FOR OWNERS AND OPERATORS

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§60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(a) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, must comply with the emission standards in §60.4231(a) for their stationary SI ICE.

(b) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in §60.4230(a)(4) that use gasoline must comply with the emission standards in §60.4231(b) for their stationary SI ICE.

(c) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in §60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in §60.4231(c) for their stationary SI ICE.

(d) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in Table 1 to this subpart for their emergency

stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) manufactured prior to January 1, 2011, that were certified to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP, may optionally choose to meet those standards.

(e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

(f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.

(1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with emission standards in §60.4231(a) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in §60.4231(a) applicable to engines manufactured on July 1, 2008.

(2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline engines and are modified or reconstructed after June 12, 2006, must comply with the emission standards in §60.4231(b) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in §60.4231(b) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in §60.4231(c). Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in §60.4231(c) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO_x) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of

1.0 g/HP-hr, or a NO_x emission standard of 250 ppmvd at 15 percent oxygen (O_2), a CO emission standard 540 ppmvd at 15 percent O_2 (675 ppmvd at 15 percent O_2 for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O_2, where the date of manufacture of the engine is:

(i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP (except lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;

(iii) Prior to January 1, 2009, for emergency engines;

(iv) Prior to January 1, 2008, for non-emergency lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP.

(5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines. Engines with maximum engine power less than 500 HP and a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power less than 500 HP manufactured on July 1, 2008. Engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) and a date of manufacture prior to July 1, 2007 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) manufactured on July 1, 2007. Lean burn engines greater than or equal to 500 HP and less than 1,350 HP with a date of manufacture prior to January 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE that are lean burn engines greater than or equal to 500 HP and less than 1,350 HP and manufactured on January 1, 2008.

(g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.

(h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37973, June 28, 2011]

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§60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 over the entire life of the engine.

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OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

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§60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

Owners and operators of stationary SI ICE subject to this subpart that use gasoline must use gasoline that meets the per gallon sulfur limit in 40 CFR 1090.205.

[73 FR 3591, Jan. 18, 2008, as amended at 85 FR 78463, Dec. 4, 2020]

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§60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?

(a) After July 1, 2010, owners and operators may not install stationary SI ICE with a maximum engine power of less than 500 HP that do not meet the applicable requirements in §60.4233.

(b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in §60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in §60.4233 may not be installed after January 1, 2010.

(c) For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in §60.4233 after January 1, 2011.

(d) In addition to the requirements specified in §§60.4231 and 60.4233, it is prohibited to import stationary SI ICE less than or equal to 19 KW (25 HP), stationary rich burn LPG SI ICE, and stationary gasoline SI ICE that do not meet the applicable requirements specified in paragraphs (a), (b), and (c) of this section, after the date specified in paragraph (a), (b), and (c) of this section.

(e) The requirements of this section do not apply to owners and operators of stationary SI ICE that have been modified or reconstructed, and they do not apply to engines that were removed from one existing location and reinstalled at a new location.

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§60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

(a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(b) Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(c) If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

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COMPLIANCE REQUIREMENTS FOR MANUFACTURERS

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§60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(a) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

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§60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

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§60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

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§60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?

(a) Manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to certify their engines to the emission standards in §60.4231(d) or (e), as applicable, under the voluntary certification program described in this subpart. Manufacturers who certify their engines under the voluntary certification program must meet the requirements as specified in paragraphs (b) through (g) of this section. In addition, manufacturers of stationary SI internal combustion engines who choose to certify their engines under the voluntary certification program, must also meet the requirements as specified in §60.4247.

(b) Manufacturers of engines other than those certified to standards in 40 CFR part 90 or 40 CFR part 1054 must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must follow the same test procedures that apply to large SI nonroad engines under 40 CFR part 1048, but must use the D-1 cycle of International Organization of Standardization 8178-4: 1996(E) (incorporated by reference, see 40 CFR 60.17) or the test cycle requirements specified in Table 3 to 40 CFR 1048.505, except that Table 3 of 40 CFR 1048.505 applies to high load engines only. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

(c) Certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, is voluntary, but manufacturers who decide to certify are subject to all of the requirements indicated in this subpart with regard to the engines included in their certification. Manufacturers must clearly label their stationary SI engines as certified or non-certified engines.

(d) Manufacturers of natural gas fired stationary SI ICE who conduct voluntary certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the definition of pipeline-quality natural gas. The fuel used for certifying stationary SI natural gas engines must meet the definition of pipeline-quality natural gas as described in §60.4248. In addition, the manufacturer must provide information to the owner and operator of the certified stationary SI engine including the specifications of the pipeline-

quality natural gas to which the engine is certified and what adjustments the owner or operator must make to the engine when installed in the field to ensure compliance with the emission standards.

(e) Manufacturers of stationary SI ICE that are lean burn engines fueled by LPG who conduct voluntary certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the specifications in 40 CFR 1065.720.

(f) Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in §60.4231(d) or (e), as applicable, when operating on that fuel. The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition. The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on gaseous fuels with different quality than the fuel that it was certified to.

(g) A stationary SI engine manufacturer may certify an engine family solely to the standards applicable to landfill/digester gas engines as specified in §60.4231(d) or (e), as applicable, but must certify their engines for operation using landfill/digester gas and must add a permanent label stating that the engine is for use only in landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

(i) For engines being certified to the voluntary certification standards in Table 1 of this subpart, the VOC measurement shall be made by following the procedures in 40 CFR 1065.260 and 1065.265 in order to determine the total NMHC emissions by using a flame-ionization detector and non-methane cutter. As an alternative to the nonmethane cutter, manufacturers may use a gas chromatograph as allowed under 40 CFR 1065.267 and may measure ethane, as well as methane, for excluding such levels from the total VOC measurement.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59176, Oct. 8, 2008; 76 FR 37974, June 28, 2011]

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§60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as applicable, as well as 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1048 or 1054, except that engines certified pursuant to the voluntary certification procedures in §60.4241 are subject only to the provisions

indicated in §60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of paragraphs §60.4241(c) through (f). Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, as applicable. Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.

(b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054 for that model year may certify any such family that contains both nonroad and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts. This provision also applies to equipment or component manufacturers certifying to standards under 40 CFR part 1060.

(c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words "and stationary" after the word "nonroad" to the label.

(d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230. Stationary SI engines subject to standards in 40 CFR part 90 may use the provisions in 40 CFR 90.909. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.

(f) For manufacturers of gaseous-fueled stationary engines required to meet the warranty provisions in 40 CFR 90.1103 or 1054.120, we may establish an hour-based warranty period equal to at least the certified emissions life of the engines (in engine operating hours) if we determine that these engines are likely to operate for a number of hours greater than the applicable useful life within 24 months. We will not approve an alternate warranty under this paragraph (f) for nonroad engines. An alternate warranty period approved under this paragraph (f) will be the specified number of engine operating hours or two years, whichever comes first. The engine manufacturer shall request this alternate warranty period in its application for certification or in an earlier submission. We may approve an alternate warranty period for an engine family subject to the following conditions:

(1) The engines must be equipped with non-resettable hour meters.

(2) The engines must be designed to operate for a number of hours substantially greater than the applicable certified emissions life.

(3) The emission-related warranty for the engines may not be shorter than any published warranty offered by the manufacturer without charge for the engines. Similarly, the emission-related warranty for any component shall not be shorter than any published warranty offered by the manufacturer without charge for that component.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008]

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COMPLIANCE REQUIREMENTS FOR OWNERS AND OPERATORS

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§60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in §60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in §60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if you are an owner or operator.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in §60.4233(d) or (e) and according to the requirements specified in §60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in §60.4233(f).

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order

for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine is rebuilt or undergoes major repair or maintenance. A rebuilt stationary SI ICE means an engine that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

(h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.

(1) Purchasing an engine certified according to 40 CFR part 1048. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(i) If you are an owner or operator of a modified or reconstructed stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according to one of the methods specified in paragraphs (i)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4233(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4244. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37974, June 28, 2011; 78 FR 6697, Jan. 30, 2013]

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TESTING REQUIREMENTS FOR OWNERS AND OPERATORS

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§60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

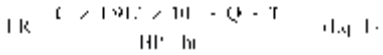
Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in §60.8 and under the specific conditions that are specified by Table 2 to this subpart.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(d) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_x in the engine exhaust using Equation 1 of this section:



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Where:

ER = Emission rate of NO_x in g/HP-hr.

C_d = Measured NO_x concentration in parts per million by volume (ppmv).

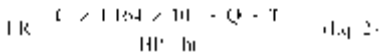
1.912×10^{-3} = Conversion constant for ppm NO_x to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:



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Where:

ER = Emission rate of CO in g/HP-hr.

C_d = Measured CO concentration in ppmv.

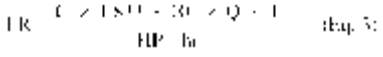
1.164×10^{-3} = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:



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Where:

ER = Emission rate of VOC in g/HP-hr.

C_d = VOC concentration measured as propane in ppmv.

1.833×10^{-3} = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.



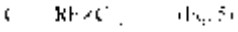
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Where:

RF_i = Response factor of compound i when measured with EPA Method 25A.

C_{Mi} = Measured concentration of compound i in ppmv as carbon.

C_{Ai} = True concentration of compound i in ppmv as carbon.



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Where:

C_{icorr} = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

C_{imeas} = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Eq} = 0.6098 \times C_{icorr} \quad \text{(Eq. 6)}$$

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Where:

C_{Peq} = Concentration of compound i in mg of propane equivalent per DSCM.

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NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

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§60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

(b) For all stationary SI emergency ICE greater than or equal to 500 HP manufactured on or after July 1, 2010, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit

an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.

(1) Name and address of the owner or operator;

(2) The address of the affected source;

(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(4) Emission control equipment; and

(5) Fuel used.

(d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference—see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7.

(e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4243(d)(2)(ii) and (iii) or that operates for the purposes specified in §60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4243(d)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4243(d)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(3)(i). The

report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 78 FR 6697, Jan. 30, 2013; 81 FR 59809, Aug. 30, 2016]

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General Provisions

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§60.4246 What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

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Mobile Source Provisions

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§60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Manufacturers certifying to emission standards in 40 CFR part 90, including manufacturers certifying emergency engines below 130 HP, must meet the provisions of 40 CFR part 90. Manufacturers certifying to emission standards in 40 CFR part 1054 must meet the provisions of 40 CFR part 1054. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060 to the extent they apply to equipment manufacturers.

(b) Manufacturers required to certify to emission standards in 40 CFR part 1048 must meet the provisions of 40 CFR part 1048. Manufacturers certifying to emission standards in 40 CFR part 1048

pursuant to the voluntary certification program must meet the requirements in Table 4 to this subpart as well as the standards in 40 CFR 1048.101.

(c) For manufacturers of stationary SI internal combustion engines participating in the voluntary certification program and certifying engines to Table 1 to this subpart, Table 4 to this subpart shows which parts of the mobile source provisions in 40 CFR parts 1048, 1065, and 1068 apply to you. Compliance with the deterioration factor provisions under 40 CFR 1048.205(n) and 1048.240 will be required for engines built new on and after January 1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008]

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DEFINITIONS

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§60.4248 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 90.105, 40 CFR 1054.107, and 40 CFR 1060.101, as appropriate. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a maximum engine power greater than 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first. You may request in your application for certification that we approve a shorter certified emissions life for an engine family. We may approve a shorter certified emissions life, in hours of engine operation but not in years, if we determine that these engines will rarely operate longer than the shorter certified emissions life. If engines identical to those in the engine family have already been produced and are in use, your demonstration must include documentation from such in-use engines. In other cases, your demonstration must include an engineering analysis of information equivalent to such in-use data, such as data from research engines or similar engine models that are already in production. Your demonstration must also include any overhaul interval that you recommend, any mechanical warranty that you offer for the engine or its components, and any relevant customer design specifications. Your demonstration may include any other relevant information. The certified emissions life value may not be shorter than any of the following:

(i) 1,000 hours of operation.

(ii) Your recommended overhaul interval.

(iii) Your mechanical warranty for the engine.

Certified stationary internal combustion engine means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as appropriate.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide (CO_2).

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4243(d).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4243(d)(2)(ii) or (iii) and §60.4243(d)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

Manufacturer has the meaning given in section 216(1) of the Clean Air Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1048.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Pipeline-quality natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to June 12, 2006, with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to either: a gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Stationary internal combustion engine test cell/stand means an engine test cell/stand, as defined in 40 CFR part 63, subpart PPPPP, that tests stationary ICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Subpart means 40 CFR part 60, subpart JJJJ.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in §60.4231(d) or (e), as applicable.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 76 FR 37974, June 28, 2011; 78 FR 6698, Jan. 30, 2013]

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Table 1 to Subpart JJJJ of Part 60—NO_x, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_x	CO	VOC[d]	NO_x	CO	VOC[d]
Non-Emergency SI Natural Gas[b] and Non-Emergency SI Lean Burn LPG[b]	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60

Non-Emergency SI Lean Burn Natural Gas and LPG	500≤HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas [BP1]and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≤HP<1,350)	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≤HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25<HP<130	1/1/2009	[c]10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

[a]Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.

[b]Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

[c]The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_x + HC.

[d]For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

[76 FR 37975, June 28, 2011]

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Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

As stated in §60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to §60.4244	a. Limit the concentration of NO_x in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for NO_x, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005)[ad]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_x concentration.

		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR part 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for NO_x concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03[de]	(d) Measurements to determine moisture must be made at the same time as the measurement for NO_x concentration.
		v. Measure NO_x at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 7E of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (Reapproved 2005),[ad] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03[de]	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of CO in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-

				point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005)[ad]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for CO concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A,[e] or	(d) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.

		sampling port location; and	ASTM Method D6348-03[de]	
		v. Measure CO at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM Method D6522-00 (Reapproved 2005),[ade] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03[de]	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	c. Limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for VOC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.

		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005)[ad]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for VOC concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03[dc]	(d) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.
		v. Measure VOC at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Methods 25A and 18 of 40 CFR part 60, appendices A-6 and A-7, Method 25A with the use of a hydrocarbon cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A-6,[ce] Method 320 of 40 CFR part 63, appendix A,[e] or	(e) Results of this test consist of the average of the three 1-hour or longer runs.

			ASTM Method D6348-03[de]	

[a]Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

[b]You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

[c]You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (*http://www.epa.gov/ttn/emc/prelim/otm11.pdf*).

[d]Incorporated by reference; see 40 CFR 60.17.

[e]You must meet the requirements in §60.4245(d).

[85 FR 63408, Oct. 7, 2020]

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Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ

[As stated in §60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4245.

§60.8	Performance tests	Yes	Except that §60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

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Table 4 to Subpart JJJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ

[As stated in §60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	
1048 subpart B	Emission Standards and Related Requirements	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No	

1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	
1048.140	Certifying Blue Sky Series Engines	No	
1048.145	Interim Provisions	No	
1048 subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes	
1048.205(p)(2)	Liquid Fuels as they require	No	
1048.240(b)(c)(d)	Deterioration Factors	Yes	
1048 subpart D	Testing Production-Line Engines	Yes	
1048 subpart E	Testing In-Use Engines	No	
1048 subpart F	Test Procedures	Yes	
1065.5(a)(4)	Raw sampling (refers reader back to the specific emissions regulation for guidance)	Yes	
1048 subpart G	Compliance Provisions	Yes	
1048 subpart H	Reserved		
1048 subpart I	Definitions and Other Reference Information	Yes	
1048 appendix I and II	Yes		
1065 (all subparts)	Engine Testing Procedures	Yes	Except for the specific section below.
1065.715	Test Fuel Specifications for Natural Gas	No	
1068 (all subparts)	General Compliance Provisions for Nonroad Programs	Yes	Except for the specific sections below.

1068.245	Hardship Provisions for Unusual Circumstances	No	
1068.250	Hardship Provisions for Small-Volume Manufacturers	No	
1068.255	Hardship Provisions for Equipment Manufacturers and Secondary Engine Manufacturers	No	

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Commonwealth of Pennsylvania



Technical Support Document

For the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268)

And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267)

FINAL
June 2018

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IV. Abbreviations and Acronyms

A/F	Air-to-Fuel
AVO	Auditory, Visual, and Olfactory Inspections
BAT	Best Available Technology
bhp	Brake Horsepower
BMP	Best Management Practices
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPI	Consumer Price Index
DEA	Diethanolamine
DEP	Pennsylvania Department of Environmental Protection
EGR	Exhaust Gas Recirculation
EPA	U.S. Environmental Protection Agency
g/bhp-h	Grams per Brake Horsepower-Hour
GHG	Greenhouse Gas(es)
GP	General Plan Approval/General Operating Permit
GP-5	General Plan Approval/General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations
GP-5A	General Plan Approval/General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations
H_2O	Water
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCHO	Formaldehyde
GPU	Gas Production Unit
MEA	Monoethanolamine
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units
MMBtu/h	Million British Thermal Units per Hour
N_2	Molecular Nitrogen
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquid
NGStar	The Natural Gas Star Program
NMNEHC	Non-Methane, Non-Ethane Hydrocarbon
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standard
OGI	Optical Gas Imaging Camera
PennDOT	Pennsylvania Department of Transportation
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter with an Aerodynamic Diameter Less Than 2.5 Microns
PM_{10}	Particulate Matter with an Aerodynamic Diameter Less Than 10 Microns
ppmvd	Parts Per Million, Dry, by Volume

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ppmv	Parts Per Million by Volume
PRO	Partner Reported Opportunities
PTE	Potential to Emit
RBLC	RACT/BACT/LAER Clearinghouse
REC	Reduced Emission Completion
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SI-RICE	Spark Ignition Reciprocating Internal Combustion Engine
SO_2	Sulfur Dioxide
SO_X	Oxides of Sulfur
THC	Total Hydrocarbons
tpy	Tons Per Year
TSD	Technical Support Document
VOC	Volatile Organic Compound

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V. Executive Summary

This technical support document (TSD) was prepared by the Pennsylvania Department of Environmental Protection (Department or DEP) to include background information about the General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A) and the General Plan Approval and General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations (GP-5) released on *June 9, 2018.* The TSD includes the rationale for the air permitting requirements for air pollution sources and the associated air pollution controls covered by the General Permits. The TSD also describes sources common to all types of facilities, sources specific to GP-5A-eligible facilities, and sources specific to GP-5-eligible facilities.

According to 25 Pa. Code § 127.1, air contamination sources must be regulated to protect the public welfare, and new sources shall control air pollutant emissions to the maximum extent consistent with Best Available Technology (BAT) as determined by the Department. The federal New Source Performance Standards (NSPS) are incorporated into the Department's regulations by reference in 25 Pa. Code § 122.3, and the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations are incorporated by reference in 25 Pa. Code § 127.35. Additionally, the current requirements of the U.S. Environmental Protection Agency's (EPA) NSPS for Crude Oil and Natural Gas Facilities (40 CFR Part 60, Subparts OOOO and OOOOa) and other federal requirements are incorporated by reference into the General Permits when the conditions are no different than the conditions determined by the Department to be BAT.

VI. Introduction

GP-5A and GP-5 have been developed under the authority of Section 6.1(f) of the Pennsylvania Air Pollution Control Act (APCA, 35 P.S § 4006.1) and under section 504(d) of the Clean Air Act (CAA, 42 U.S.C. § 7661c(d)) which authorizes the establishment of a general permit program to regulate air contamination sources. *See also* 25 Pa. Code Chapter 127, Subchapter H. Additionally, section 6.6(c) of the APCA, 35 P.S. § 4006.6(c), authorizes the Department to require new sources to control air pollution through the use of BAT at the time of plan approval. *See also* 25 Pa. Code § 127.1.

The Department's regulatory General Permit program and BAT provisions were established in 1994. (24 Pa.B. 5899 (November 26, 1994)). These regulations were subsequently approved by EPA as part of Pennsylvania's State Implementation Plan (SIP) in 1996. (61 Fed. Reg. 39594 (July 30, 1996)). Currently, the Department has 18 air quality General Permits that regulate air contamination sources in several industrial categories, including small boilers, burn off ovens, storage tanks, lithographic printing, mineral processing, petroleum dry cleaning, powder metal sintering furnaces, and natural gas production.

A General Permit is a pre-approved plan approval and operating permit which applies to a specific category of sources, if the Department determines that those sources can be adequately regulated using standardized specifications and conditions. (35 P.S. § 4006.1(f)). As part of the General Permit process, the Department establishes BAT requirements for new sources. Those BAT requirements can include equipment, devices, methods, or techniques as determined by the Department, which will prevent, reduce, or control air emissions to the maximum degree possible and which are available or may be made available. (25 Pa. Code § 121.1). BAT is not a regulation but an analysis of control techniques that are determined at the time of the issuance of a plan approval. The Pennsylvania Environmental Hearing Board (EHB) has indicated that the requirement to conduct a BAT analysis for new sources extends to greenhouse gases (GHGs), including methane. (*Snyder v. DEP*, 2015 EHB 027). Moreover,

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the Commonwealth Court has endorsed the Department's position that the General Assembly, through the APCA, gave the agency the authority to reduce GHG emissions. (*Wolf v. Funk,* 144 A.3d 228, 250 (Pa. Cmwlth. 2016)).

On September 21, 1996, the Department published the Air Quality Permit Exemptions, which specified sources or classes of sources that were determined to be exempt from the plan approval and permitting requirements of the APCA, 35 P.S. §4001 *et seq.* and 25 Pa. Code Chapter 127, which included crude oil and natural gas wells. The Department issued GP-5 on March 10, 1997, for natural gas production facilities. This established BAT for stationary natural gas-fired spark ignition reciprocating internal combustion engines (engines) rated from 100 brake horsepower (bhp) to 1,500 bhp and for glycol dehydrators with an uncontrolled potential to emit (PTE) volatile organic compounds (VOC) in excess of 10 tons per year (tpy) at natural gas production facilities. On July 27, 2006, DEP revised the GP-5 to expand the applicability to natural gas, coal bed methane, and gob gas production or recovery facilities, including gathering stations.

EPA has developed several regulations applicable to oil and natural gas production sites, natural gas compression stations, processing plants, and transmissions stations; these are 40 CFR Part 60, Subparts KKK, JJJJ, KKKK, OOOO, and OOOOa and 40 CFR Part 60 Subparts HH, HHH, and ZZZZ. Some of these regulations require the control of methane emissions from sources at these facilities. Other pollutants that are regulated under these standards include VOC and hazardous air pollutants (HAP). The federal regulations apply to all oil and gas operations in the U.S. The Department is required to implement these federal regulations under Section 4 of the APCA, 35 P.S. §4004. In addition, these federal regulations are incorporated by reference into the *Pennsylvania Code* and, as a result, are Pennsylvania law. *See* 25 Pa. Code §§122.1, 124.1, and 127.35(b).

On February 2, 2013, the Department changed the applicability of GP-5 to natural gas compression and/or processing facilities, and established BAT requirements for engines, stationary natural gas-fired simple cycle turbines (turbines), natural gas compressors, storage vessels, glycol dehydrators, natural gas fractionation units, equipment leaks, pneumatic controllers, and sweetening units. The Air Quality Permit Exemptions were amended by the Department on August 10, 2013, to change the unconditional exemption of all crude oil and natural gas wells to the unconditional exemption of sources located at conventional well sites and a conditional exemption for sources located at unconventional natural gas well sites.

In 2009, based on a large body of scientific evidence, EPA issued an "Endangerment Finding" under the Clean Air Act (CAA) section 202(a)(1), 42 U.S.C. § 7521(a)(1), related to GHGs.[1] EPA found that six well-mixed GHGs — carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride — endanger both the public health and the public welfare of current and future generations by causing or contributing to climate change.[2] New scientific assessments and observations strengthen the conclusions of this Endangerment Finding that GHGs endanger public health and the environment.[3] Methane traps 86 times more heat in the atmosphere than carbon dioxide in the short-term, increasing the consequences of climate change. Additionally, methane is often accompanied by toxic air pollutants such as benzene, formaldehyde, and ethylbenzene.

[1] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 Fed. Reg. 66496 (December 15, 2009) (''Endangerment Finding'').
[2] *Id.*
[3] "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," 81 Fed. Reg. 35824 (June 3, 2016).

Methane is also a precursor to ground level ozone, which can cause a number of harmful effects on public health and the environment.[4] Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation.[5] In addition, long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma.[6]

There are also independent peer-reviewed studies which indicate that shale gas development is associated with the production of secondary pollutants such as tropospheric (ground-level) ozone, formed through the interaction of methane, VOC, and nitrogen oxides (NO_X) in the presence of sunlight.[7,8] Tropospheric ozone is a strong respiratory irritant associated with increased respiratory and cardiovascular morbidity and mortality.[9] Although toxicological data suggest that pure methane is not by itself health damaging (excluding its role as an asphyxiant and an explosive), it is a precursor to global tropospheric ozone.[10]

Based on all the information reviewed by the Department, which it adopts as its own, and incorporates by reference into this TSD, there is a strong scientific basis to show that methane meets the definition of air contaminant, air contamination, and air pollution under section 3 of the APCA. As a GHG and ozone precursor, methane is, among other things, inimical or may be inimical to the public health, safety, or welfare.

According to the U.S. Energy Information Agency (EIA), Pennsylvania was the nation's second-largest natural gas producer for the fourth consecutive year. The largest key sources of anthropogenic methane emissions in Pennsylvania include natural gas and oil systems (30.5 percent), coal mining (30.3 percent), landfills (21.1 percent), enteric fermentation from domestic livestock (9.9 percent), wastewater (3.9 percent), and manure management (2.3 percent). Of these major categories, natural gas and oil systems are the only areas that show significant growth, increasing threefold from the 1990s. The other major categories are either flat or slightly down from the 1990s. This shows that the oil and gas industry is therefore the largest category for methane emissions.

Based on information from the Department's emission inventory, there are approximately 31,224 sources at 4,960 well pad facilities and 4,285 sources at 493 compressor stations. The overall methane emissions from this source category in 2015 amounted to approximately 123,081 tons in Pennsylvania, which is an increase from 2014 levels. One peer-reviewed study indicates that new emissions data suggest that the recently instituted Pennsylvania methane emissions inventory substantially underestimates measured facility-level methane emissions by 10-40 times.[11]

Pennsylvania Governor Tom Wolf introduced a methane reduction strategy on January 19, 2016. The four-point plan included the following strategies:

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[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] Shonoff, Hays, Finkel, *Environmental Health Dimensions of Shale and Tight Gas*, Environ Health Perspect., 2014 Aug; 122(8): 787–795.
[8] Jerrett M, Burnett RT, Pope CA III, Ito K, Thurston G, Krewski D, *et al*. *Long-term ozone exposure and mortality,* N Engl J Med 360:1085–1095, 2009 and *U.S. EPA Integrated Science Assessment for Ozone and Related Photochemical Oxidants* (EPA 600/R-10/076F) Available at: http://www.epa.gov/ncea/isa/ozone.htm, last accessed on May 9, 2018.
[9] Jerrett *et al*.
[10] Smith KR, Jerrett M, Anderson HR, Burnett RT, Stone V, Derwent R, *et al. Public health benefits of strategies to reduce greenhouse-gas emissions: health implications of short-lived greenhouse pollutants*. Lancet 374:2091–2103, 2009.
[11] Omara, *et al*., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin,* Environ. Sci. Technol. 2016, 50, 2099−2107.

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- To reduce leaks at new unconventional natural gas well pads, DEP will develop a new General Permit for oil and gas exploration, development, and production facilities, requiring BAT for equipment and processes, better recordkeeping, and quarterly monitoring inspections.
- To reduce leaks at new compression stations and processing facilities, DEP will revise its current General Permit, updating BAT requirements and applying more stringent leak detection and repair (LDAR) and other requirements to minimize leaks.
- To reduce leaks at existing oil and natural gas facilities, DEP will develop a regulation for existing sources for consideration by the Environmental Quality Board.
- To reduce emissions along production, gathering, transmission and distribution lines, DEP will establish best management practices (BMP), including LDAR programs.

On February 4, 2017, the Department published notice in the *Pennsylvania Bulletin* of the availability of the Proposed General Plan Approval and/or General Operating Permit No. 5A for Unconventional Natural Gas Well Site Operations or Remote Pigging Stations ("GP-5A") and Proposed Modifications to General Plan Approval and/or General Operating Permit No. 5 for Natural Gas Compressor Stations, Processing Plants and Transmission Stations ("GP-5") and proposed revisions to the Air Quality Permit Exemptions document (TGD Document No. 275-2101-003) for public review and comment. (47 Pa.B. 733). The public comment period was originally scheduled to close on March 22, 2017. However, due to increased public and legislative interest, the comment period was extended until June 5, 2017. (47 Pa.B. 1235). Then on March 31, 2018, the Department published another *Pennsylvania Bulletin* notice announcing an additional opportunity to submit comments on the draft final GPs until May 15, 2018. (48 Pa.B. 1902).

The final General Permits set forth standardized terms and conditions related to BAT, compliance certification, notification, recordkeeping, reporting, and source testing requirements. In addition, the General Permits require permittees to comply with any applicable federal NSPS. Under the final GPs, the Department determined that BAT for certain new sources is more stringent than the applicable NSPS, and, in other cases, the Department determined that BAT is the same as the applicable NSPS limit for certain new sources. A BAT standard does not replace a NSPS, but is in addition to a NSPS. The Department made its determinations based on a technical and economic feasibility analysis contained in this TSD. For instance, under GP-5, the Department made 13 separate BAT determinations for 13 separate sources, nine of which were more stringent than the applicable NSPS. Under GP-5A, the Department made 11 separate BAT determinations for 11 separate sources, of which eight were more stringent than the applicable NSPS.

The BAT emission reductions in Table 1 and Table 2 below are from sources that may be located at an unconventional well site or a mid-stream compressor station and are scientifically-based estimates. Actual emissions at an individual site depend on a case-by-case analysis that accounts for: gas production or throughput; type of equipment; management practices; and composition of the gas or liquids. Estimates of reductions are based on changes due to BAT requirements from the previous GP-5 and Exemption 38 to the final GP-5A and GP-5.

The new GP-5A is applicable to the sources located at unconventional natural gas well site operations and remote pigging stations, and the revised GP-5 is applicable to sources located at natural gas compression stations, processing plants, and transmission stations. The use of the GP-5 and GP-5A are restricted to facilities with actual emissions less than 100 tpy of criteria pollutants (NO_X, CO, SO_2, PM_{10}, and $PM_{2.5}$), less than 50 tpy of VOC, less than 10 tpy of any single HAP, and less than 25 tpy of total HAPs. For facilities located in Philadelphia, Bucks, Chester, Montgomery, or Delaware Counties, the NO_X and VOC emissions thresholds are less than 25 tpy each.

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While the terms and conditions of both General Permits incorporate both federal and state requirements, it is the duty of the Responsible Official to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations, including 25 Pa. Code, Subpart C, Article III. Nothing in these General Permits relieves the Responsible Official from this obligation to comply.

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Table 1 - Emissions Reduction Estimates for Sources at Unconventional Natural Gas Wells Sites

Source	Emissions Reduction Estimate									
	CH_4 (tpy)		VOC (tpy)		HAP (lbpy)		NO_X (tpy)		CO (tpy)	
Glycol Dehydration Units	1.04[3]	29%	No Change		No Change		NA		NA	
Lean-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		1.93	57%	NA		No Change		6.27	65%
Lean-Burn Engines (500 hp < rating < 2,370 hp)	NA		10.28	64%	NA		11.43	50%	40.00	88%
Lean-Burn Engines (rating ≥ 2,370 hp, 0.3 g/bhp-h NO_X)	NA		10.29	64%	NA		16.01	70%	40.01	88%
Lean-Burn Engines (rating ≥ 2,370 hp, SCR)	NA		10.29	64%	NA		21.72	95%	40.01	88%
Rich-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		2.41	71%	NA		3.62	75%	8.20	85%
Rich-Burn Engines (rating > 500 hp)	NA		2.42	71%	NA		3.87	80%	8.22	85%
Reciprocating Compressors (EPA Emission Factors)	0.04	80%	0[4]	80%	0[4]	80%	NA		NA	
Reciprocating Compressors (UT Average Emission Factors)	3.03	80%	0.16	80%	0.07	80%	NA		NA	
Storage Vessels	1.04[3]	29%	No Change		No Change		NA		NA	
Fugitive Emissions Components	6.36	20%	0.33	20%	0.15	20%	NA		NA	
Pigging Operations[1] (Monthly Frequency)	No Change[5]									
Pigging Operations[1] (Monthly Frequency – BMP reduces pressure to 125 psi)	1.57	90%	0.08	90%	0.04	90%	NA		NA	
Pigging Operations[1] (Daily Frequency	50.41	95%	2.62	95%	1.18	95%	NA		NA	
Wellbore Liquids Unloading[2] (Monthly Frequency – BMP halves volume)	27.91	50%	1.45	50%	0.65	50%	NA		NA	
Wellbore Liquids Unloading[2] (Monthly Frequency – routed to control)	53.03	95%	2.76	95%	1.24	95%	NA		NA	

[1] Pigging Operations were assumed to emit a volume of 90 ft^3 at 1,250 psi.
[2] Wellbore Liquids Unloading Operations were assumed to emit a volume of 4,500 ft^3 at 800 psi.
[3] Methane emissions reductions based on assumed 93% destruction efficiency correlated to operating temperature for 95% VOC destruction efficiency.
[4] Even though the table shows zero tons reduced, emissions are reduced by the following percentage.
[5] Pigging Operations at the assumed volume and pressure to not exceed the control threshold at the monthly frequency.

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Table 2 - Emissions Reduction Estimates for Sources at Natural Gas Compression Stations

Source	Emissions Reduction Estimate									
	CH_4 (tpy)		VOC (tpy)		HAP (lbpy)		NO_X (tpy)		CO (tpy)	
Glycol Dehydration Units	4.14[2]	61%	0.12[3]	46%	0.05[3]	46%	NA		NA	
Lean-Burn Engines (100 hp ≤ rating ≤ 500 hp)	NA		1.93	57%	NA		No Change		6.27	NA
Lean-Burn Engines (rating ≥ 2,370 hp, 0.3 g/bhp-h NO_X)	NA		No Change		NA		4.57	40%	No Change	
Lean-Burn Engines (rating ≥ 2,370 hp, SCR)	NA		No Change		NA		10.29	90%	No Change	
Storage Vessels	5.48[2]	68%	0.17[3]	55%	0.07[3]	55%	NA		NA	
Tanker Truck Load-Out Operations	0.83[3]	55%	0.04[3]	55%	0.02[3]	55%	NA		NA	
Pigging Operations[1] (Monthly Frequency)	No Change[4]									
Pigging Operations[1] (Monthly Frequency – BMP reduces pressure to 125 psi)	1.57	90%	0.08	90%	0.04	90%	NA		NA	
Pigging Operations[1] (Daily Frequency	50.41	95%	2.62	95%	1.18	95%	NA		NA	
Natural Gas-Fired Combustion Units (rating ≥ 10 MMBtu/h)	NA		NA		NA		0.80	50%	5.49	57%
Turbine (5,000 hp ≤ rating <15,900 hp)	NA		4.96	44%	NA		No Change		11.81	60%
Turbine (rating ≥ 15,900 hp – 9 ppm NO_X)	NA		No Change		NA		11.40	40%	No Change	
Turbine (rating ≥ 15,900 hp – SCR)	NA		No Change		NA		25.65	90%	No Change	
Centrifugal Compressor (Wet Seal Degassing Systems)	9.52[2]	29%	No Change		No Change		NA		NA	

[1] Pigging Operations were assumed to emit a volume of 90 ft^3 at 1,250 psi.
[2] Methane emissions reductions based on assumed 93% destruction efficiency correlated to operating temperature for 95% VOC destruction efficiency.
[3] Emissions reduction primarily based on reduction in control threshold.
[4] Pigging Operations at the assumed volume and pressure to not exceed the control threshold at the monthly frequency.

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I. Definitions

Words and terms that are not otherwise defined in the General Permits have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III, including 25 Pa. Code § 121.1 (relating to definitions), unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Code of Federal Regulations including 40 CFR Part 60 Subparts JJJJ, KKKK, OOOO, and OOOOa or 40 CFR Part 63 Subparts HH and ZZZZ also apply to these General Permits.

Coal bed methane – Methane that is extracted from a coal bed and the surrounding rock strata by extraction wells drilled in advance of a mining operation, which is typically of pipeline quality.

Fugitive Emissions Component – Any component that has the potential to emit fugitive emissions of methane, VOC, or HAP at a facility, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, compressors, instruments, meters, covers, and closed vent systems. Devices that vent as part of normal operations are not considered fugitive sources unless the emission originates from a place other than the vent.

Gob gas – Methane that is mixed with air from a mine ventilation system due to the mining operation reaching the area of an extraction well, which is typically below pipeline quality.

Leak – A leak is defined as any release of gaseous hydrocarbons that is detected by Auditory, Visual, or Olfactory (AVO) inspection; an optical gas imaging (OGI) camera calibrated according to 40 CFR §60.18 and a detection sensitivity level of 60 g/h; a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21 that detects a concentration of 500 ppm calibrated as methane or greater; or other leak detection methods approved by the Department's Division of Source Testing and Monitoring. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

Natural Gas Compression Station – A facility that compresses and/or processes natural gas, coal bed methane, or gob gas prior to the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Natural Gas Processing Plant – A facility that engages in the extraction of natural gas liquids from field gas, the fractionation of mixed natural gas liquids to natural gas products, or both extracts and fractionates natural gas liquids.

Natural Gas Transmission Station – A facility that compresses and/or processes natural gas after the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Pigging Operations – The process of removing and collecting condensed liquids including condensate, intermediate hydrocarbons, or produced water from a pipeline using a spherical or bullet-shaped device, known as a pig, forced through the pipeline by natural gas pressure. The liquids are then collected at their eventual destination in a storage tank, often referred to as a slug tank. This process also includes operation conducted for pipeline integrity evaluation.

Point of Custody Transfer – The location after the processing and/or treatment of natural gas in the production sector, typically after a natural gas processing plant, where control and/or ownership of the natural gas is transferred from one owner or operator to another.

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Remote Pigging Station – A facility where pigging operations are conducted that is not located at an unconventional natural gas well site, natural gas compression station, natural gas processing plant, or natural gas transmission station and which meets or exceeds the exemption criteria in Category 38(c) of the Air Quality Permit Exemptions List.

Sour Gas – Natural gas where the Hydrogen Sulfide (H_2S) content is in excess of 4 ppmv at standard temperature and pressure.

Start of Production – The beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water. A well whose owner or operator is selling gas through temporary equipment designed for flowback shall not be considered in production until either the sales continue through the temporary equipment for more than 30 days or the gas is routed to a permanent production separator.

Unconventional Natural Gas Well – A well drilled to produce natural gas from shale formations below the Elk Group or its geologic equivalent stratigraphic interval, where recovery of the resource is generally not economic without the bores being stimulated by hydraulic fracturing, multilateral well bores, or other techniques to expose more of the formation to the well bore.

Unconventional Natural Gas Well Site – A location with one or more unconventional natural gas wells at which unconventional natural gas well site operations are conducted.

Unconventional Natural Gas Well Site Operations – Equipment and processes at unconventional natural gas well sites including, but not limited to, well completion, gas dehydration, tanker truck load-out, wellbore liquids unloading, gas compression, pigging, and storage.

Wellbore Liquids Unloading – The process of removing accumulated liquids from a natural gas well in order to restore well pressure and natural gas production.

VII. Applicability/Scope

GP-5A authorizes the construction, modification, and/or operation of sources located at an unconventional natural gas well site or remote pigging station. The applicability of the GP-5A may include one or more of the following operations or emissions sources:

- Glycol Dehydration Units
- Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- Reciprocating Compressors
- Storage Vessels
- Tanker Truck Load-Out Operations
- Fugitive Emissions Components
- Controllers
- Pumps
- Enclosed Flares and Other Control Devices
- Pigging Operations
- Wellbore Liquids Unloading Operations

GP-5 authorizes the construction, modification, and/or operation of sources located at natural gas compression station, processing plant, or transmission station. The applicability of the GP-5 may include one or more of the following operations or emissions sources:

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- Glycol Dehydration Units
- Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
- Reciprocating Compressors
- Storage Vessels
- Tanker Truck Load-Out Operations
- Fugitive Emissions Components
- Controllers
- Pumps
- Enclosed Flares and Other Control Devices
- Pigging Operations
- Natural Gas-Fired Combustion Units
- Stationary Natural Gas-Fired Combustion Turbines
- Centrifugal Compressors

An Application for Authorization to Use GP-5 or GP-5A may be submitted for the operation of an eligible source if the source is exempted from plan approval requirements under 25 Pa. Code §127.14. If any source located at a facility cannot be regulated under the appropriate General Permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B and/or Subchapter F will be required.

VIII. Prohibited Use of GP-5 and GP-5A

The proposed GP-5 and GP-5A are different from many other General Permits issued by the Department. The General Permit program typically establishes a general plan approval/general operating permit with requirements for a specific type of **source**, and can be used at Title V facilities when they are adding that type of source to the facility. However, GP-5 and 5A are eligible for sources located at non-major facilities. Since 1997, Authorizations to Use GP-5 issued for natural gas facilities were applicable only for sources located at non-major facilities. The sources located at Title V or major facilities must obtain a site-specific plan approval and operating permit.

In addition, because most of the natural gas production in the Marcellus Shale and Utica Shale Region is not sour gas, the GP-5 and 5A are prohibited for use by those facilities that produce or process sour gas. This removes the necessity to include the sweetening unit requirements and means many of the federal SO_2 requirements in 40 CFR Part 60 are presumptively met.

The owner or operator of a facility is also prohibited from circumventing the requirements for Title V applicability, the prevention of significant deterioration, or non-attainment new source review by allowing a pattern of ownership or development that conceals that the facility would otherwise be required to submit a plan approval or operating permit application. This includes specifically phasing, staging, delaying, or engaging in incremental construction over the geographical extent of the facility or using a device, stack height that exceeds good engineering practice, dispersion technique, or other technique to conceal or dilute emissions of air contaminants without reducing the amount of emissions in order to appear to qualify for the General Permit when the facility should actually be authorized under a plan approval or operating permit.

IX. Authorization to Use the General Permits

The general procedure to apply for an Authorization to Use the General Permit; the terms; expiration and reauthorization procedure; transfer of ownership; administrative amendment; and conditions relating

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to the modification, suspension, or revocation of the General Permit or an Authorization to Use the General Permit are detailed in Condition 6 of the General Permits. Application Instructions and Application Forms for the General Permits can be found in the Department's e-Library. In addition, electronic applications can be submitted using the Department's e-Permitting system, accessible through DEP's Greenport.

Another important modification to this Condition is the Transfer of Ownership procedure. In previous versions of the GP-5, the new owner or operator was required to submit a new application form within 30 days of the transfer of ownership. The new procedure, which is available in both GP-5 and GP-5A, is for the new owner or operator to file the appropriate form; for a transfer of ownership that does not modify any existing source, is not adding a new source, and is not subject to a new Single Source Determination the owner or operator may submit the Transfer of Ownership Form with the appropriate fee. For a transfer of ownership that does not modify any existing source, is not adding a new source, but requires a new Single Source Determination (i.e., equipment or activities located on the same site or on sites that share equipment and are within ¼ mile of each other) the new owner or operator shall submit an application for Authorization to Use the General Permit as a General Plan Approval with the appropriate fee. For a transfer of ownership that modifies an existing source or adds a new source, the new owner or operator shall submit an application for Authorization to Use the General Permit using the standard procedure.

X. General Permit Fees

The fees related to the General Permits are detailed in Condition 7. All fees are assessed in accordance with 25 Pa. Code Chapter 127 Subchapter I.

XI. Applicable Laws

The terms and conditions of the proposed GP-5 and 5A incorporate both federal and state requirements. It is the duty of the Responsible Official to ensure that the facility is in compliance with all applicable laws and regulations, and nothing in the General Permits relieves the Responsible Official of that duty. Therefore, it is suggested that owners and operators carefully review the listed sources and the federal, state, and local requirements applicable to them and compare them to the terms and conditions of the General Permit.

The Department's review has found that the applicable federal regulations include the following NSPS and NESHAP subparts:

(a) **40 CFR Part 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.** This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition internal combustion engines that commenced construction, modification or reconstruction after June 12, 2006, where the SI-RICE are manufactured on or after specified manufacture trigger dates. The manufacture trigger dates are based on the engine type, fuel used, and maximum engine horsepower. The state BAT requirements for engines at natural gas compression and/or processing facilities under the current GP-5 are either equivalent or more stringent than the federal requirements.

(b) **40 CFR Part 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.** This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10 million British thermal units per hour (MMBtu/h) that commenced construction,

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modification or reconstruction after February 18, 2005. The pollutants regulated by this subpart are NO_X and sulfur dioxide (SO_2). However, the SO_2 requirements can be met by fuel composition analysis, and the prohibition of using the General Permits for facilities that produce or process sour gas ensures that the fuel composition analysis will be met.

(c) **40 CFR Part 60, Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.** This subpart establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities. In Subpart OOOO, the only SO_2 emission source is the sweetening unit typically located at natural gas processing plants. The prohibition of using the General Permits for facilities that produce or process sour gas makes it unlikely that a sweetening unit will produce significant SO_2 emissions, so the requirements for the sweetening unit were not included.

(d) **40 CFR Part 60, Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced After September 18, 2015.** This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The GHG standard in this subpart is in the form of a limitation on emissions of methane. This subpart also establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions. As for Subpart OOOO, the prohibition of using the General Permits for facilities that produce or process sour gas makes it unlikely that a sweetening unit will produce significant SO_2 emissions, so the requirements for the sweetening unit were not included.

(e) **40 CFR Part 63, Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.** This subpart applies to the owners and operators of affected units located at natural gas production facilities that are major or area sources of HAPs and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. Because the GP-5 and 5A require that the facility is non-major with respect to air pollution, only the area source requirements apply. Area sources are broken down into two categories, those located within an Urbanized Area (UA) plus offset or an Urbanized Cluster (UC) and those not located within a UA plus offset or UC.

(f) **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE).** This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary RICE. This rule applies to owners or operators of new and reconstructed stationary RICE of any horsepower rating which are located at a major or area source of HAP emissions. While all stationary RICE located at major or area sources are subject to the final rule, in the context of these General Permits, only four-stroke engines above 500 bhp have BACT requirements; all others have work practice requirements. In addition, for engines that commenced construction, modification or reconstruction after June 12, 2006, compliance with 40 CFR Part 60, Subpart JJJJ meets the requirements of this subpart.

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XII. Best Available Technology Requirements

New sources are required to control emissions of air pollutants to the maximum extent, consistent with BAT as determined by the Department as of the date of issuance of the plan approval for the new source as required under 25 Pa. Code §127.1. Condition 1 (BAT Compliance Requirements) in Sections B through L of GP-5A and in Sections B through N of GP-5 are determined to meet the BAT requirements.

XIII. Compliance Requirements and Compliance Certification

These General Permits function as a plan approval and operating permit only for a synthetic minor or natural minor facility. The Conditions of Section A lay out general terms and conditions to ensure that a facility remains a minor facility. The primary requirement to use these GPs is that the emissions from all sources and associated air pollution control equipment located at a facility must not exceed the major source thresholds on a 12-month rolling sum basis.

The owner or operator must constrain the facility throughput, hours of operation, and/or emissions from sources at the facility to ensure that the major source thresholds are not exceeded and keep records adequate to demonstrate compliance.

This Condition also contains requirements that all sources and associated air pollution control equipment are operated so as not to cause air pollution, operated and maintained in accordance with the manufacturer's specifications, operated and maintained in accordance with the fugitive emission requirements, and operated and maintained to limit the detection of malodors outside the property boundary. The addition of the fugitive emission requirements clause in the revised permit replaces the proposed version's Section B. Fugitive Particulate Matter, which was removed from both the GP-5 and GP-5A.

Another key compliance requirement is that the General Permits cannot be used to relax BAT previously established through the air quality permitting process. The owner and operator may not obtain a General Permit if BAT requirements in their current permit are more stringent than those in the revised General Permits. However, an owner or operator may elect to obtain a General Permit in lieu of their current plan approval or operating permit if they demonstrate they will be able to meet the applicable General Permit BAT requirements.

Finally, the Responsible Official must sign and submit a Certification of Compliance with the annual report.

XIV. Notification Requirements

There are several notifications that the owner or operator of a facility must perform, including a municipal notification to the local governments where the air pollution source is to be located. A copy of this notification is required to be included in the Application for Authorization to Use GP-5 or GP-5A. The notification to the local governments should include a description of the proposed sources and/or modification of existing sources to be authorized under the application.

Notifications to the Department for individual sources include prior notification of the commencement of operation of a source, which must include the completion of construction date. Notification of malfunctions are performed according to the GP-5 Malfunction Reporting Instructions (See Appendix I

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– GP-5 Malfunction Reporting Instructions). All notices must be submitted to the Air Program Manager of the appropriate DEP Regional Office.

XV. Recordkeeping Requirements

Any records generated as part of the terms and conditions of the General Permits are required to be maintained on site or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format. The key records generated and maintained by the owner or operator of a facility authorized under the General Permit are those that show the facility is in compliance with the facility-wide emission limits on a 12-month rolling basis. All records, reports, or other information obtained by the Department under the General Permit is publicly available unless the owner or operator of the facility shows cause that the information is confidential. Under no circumstance are records of emission data eligible for confidentiality as set forth in Section 13.2 of the APCA. 35 P.S. § 4013.2.

XVI. Reporting Requirements

In order to manage the federal and state reporting requirements, the Department merged all reporting requirements into a single annual report that is required to be sent to the Department no later than 60 days from the anniversary of the Authorization to Use the General Permit. The owner or operator may send a copy of the annual report to the EPA as all federal requirements are included, or the owner or operator may send a version that redacts all state requirements at their discretion. The annual report serves as the basis for the Compliance Certification, which the Responsible Official must sign. The annual report must be submitted either in electronic format or by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office. The owner or operator of the facility must also submit an annual emissions inventory via AES*Online or AES*XML to the Department by March 1st of each year.

XVII. Source Testing Requirements

All submittals, including all reports, protocols, and test completion notifications and excluding periodic monitoring data, related to Source Testing must include one hard copy and one electronic copy sent to the Air Program Manager of the appropriate DEP Regional Office and one hard copy and one electronic copy sent to the PSIMS Administrator for the Source Testing Section in DEP Central Office.

The submission of a test protocol must be done at least 60 days prior to the performance of a source test to demonstrate compliance with the General Permits. An operator may request an approval from the Department for a test protocol that covers testing of all currently operated sources in service at that operator's various facilities. In such a request, the operator will submit the test protocol that includes a list of currently permitted sources and that meets the applicable requirements specified in the most current version of the Department's Source Testing Manual for review and approval. In the case that the owner or operator has a test protocol previously approved by the Department (including the testing contractor), a new test protocol is not required provided that there are no changes, and the owner or operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

The frequency of the tests required is based on federal and state requirements. In most cases, the requirements are identical; however, in the case of engines, there are some discrepancies in the timing and frequency of the tests. These discrepancies are outlined in Table 3, with the caveats noted below the table.

Table 3 - Engine Source Testing Requirements

Engine Size	Initial Compliance Performance Test	Continuous Compliance Performance Test	Periodic Monitoring
<100 hp	None Required	None Required	Every 2,500 hours of operation
100 hp ≤ ER ≤ 500 hp	Within 180 days of startup of the engine	Within 180 days of each reauthorization	Every 2,500 hours of operation
>500 hp and not subject to 40 CFR Part 60 Subpart ZZZZ	Within 180 days of startup of the engine	Every 8,760 hours of operation **or** every three years **and** within 180 days of each reauthorization	Every 2,500 hours of operation
> 500 hp and subject to 40 CFR Part 60, Subpart ZZZZ	Not Applicable	Every year	Every 2,500 hours of operation

For an engine rated greater than or equal to 100 hp and less than or equal to 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the performance testing requirements are waived.

For an engine rated greater than 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the continuous compliance performance testing requirements every 8,760 hours of operation or every three years are waived.

There are also some differences between the federal and state requirements for testing for combustion turbines, primarily which pollutants are analyzed during the test. The Department requires testing for NO_X, CO, and NMNEHC (as propane) while the federal regulation requires testing of NO_X and SO_2 only. It is the Department's determination that SO_2 testing is not required based on 40 CFR §60.4415(a)(1) if the fuel used is either pipeline quality gas or field gas that does not meet the definition of sour gas. There is also a frequency difference in that the federal regulations require annual testing for turbines that do not use water or steam injection for NO_X control. The annual requirement can be waived if the owner or operator installs a continuous monitoring system.

In all cases and for all sources, the Department may alter the frequency of performance testing for reauthorization based on available performance data from the source, unless the performance tests are required by federal regulation.

XVIII. General Methodology of Determining Best Available Technology

New sources are required to control the emission of air pollutants to the maximum extent, consistent with BAT as determined by the Department. BAT is defined in 25 Pa. Code §121.1 as equipment, devices, methods, or techniques as determined by the Department which will prevent, reduce, or control emissions of air contaminants to the maximum degree possible and which are available or may be made available. The applicable emission limits of federal NSPS and NESHAPs serve as minimum

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requirements for determining BAT. The resources utilized in the determination of BAT include the conditions established for similar sources in Category 38 of the Air Quality Permit Exemptions; the current GP-5; the data in EPA's RACT/BACT/LAER Clearinghouse (RBLC); case-by-case BAT determined in recently issued plan approvals; and permits recently issued by other states. The Department also evaluated vendors' guaranteed emission limits, available stack test data for the applicable sources, and documents related to EPA's Natural Gas Star (NGStar) program. The emission limitations included in the General Permits must be technically and economically feasible and must be sustainable during the life of the air pollution source.

The general classes of air emissions from the sources at facilities covered by GP-5 and GP-5A include NO_X, CO, VOC, HAP, SO_X, PM_{10}, $PM_{2.5}$, CO_2, and methane. These pollutants are described in more detail below.

A. Oxides of Nitrogen

Oxides of nitrogen are a family of compounds which includes nitrogen oxide (NO) and nitrogen dioxide (NO_2) that are produced as a byproduct of the combustion of fuel and air. The heat of combustion causes the molecular nitrogen (N_2) in the combustion air to disassociate and oxidize, forming NO and NO_2. NO_X is a criteria pollutant, but it is also a precursor to acid rain, ozone, and $PM_{2.5}$; NO_X emissions are typically expressed as NO_2.

There are three types of NO_X created during combustion: thermal, fuel, and prompt. Thermal NO_X is produced at very high temperatures by the reaction of atmospheric oxygen and nitrogen and is heavily influenced by combustion temperature. Fuel NO_X results from oxidation of nitrogen contained in the fuel. Prompt NO_X is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions.

Strategies for the control of NO_X include combustion control and post-combustion control. In combustion control, the combustion temperature is lowered in order to limit the disassociation of molecular nitrogen through premixing, staging, or excess air. Post-combustion control typically includes an add-on device, such as nonselective catalytic reduction (NSCR) systems or selective catalytic reduction (SCR) systems. Both systems are described in greater detail in the individual source BAT analysis.

B. Carbon Monoxide

Carbon monoxide is a colorless, odorless gas that results from the incomplete combustion of carbon. CO is formed when insufficient oxygen or poor mixing interferes with the combustion reaction to produce CO_2. CO formation is greatest when the air-to-fuel (A/F) mixture is rich; however, CO also forms when a very fuel-lean mixture cannot sustain complete combustion.

Techniques for control of carbon monoxide also include combustion control and post-combustion controls. As for combustion control, a balance must be sought with NO_X control as lower combustion temperatures that prevent thermal NO_X formation can lead to incomplete combustion and therefore increase CO formation. Post-combustion controls include NSCR systems and oxidation catalysts. Individual source BAT analyses tend to favor minimizing NO_X production through combustion control techniques even though there may be an increase of CO, and then use post-combustion controls to mitigate the CO impact because Pennsylvania is a non-attainment state in the Ozone Transport Region.

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C. Volatile Organic Compounds

VOCs are defined in 25 Pa Code §121.1. For engines and turbines, the Department uses non-methane, non-ethane hydrocarbons (NMNEHC) expressed as propane, excluding formaldehyde, in lieu of VOC. Also, the final General Permits include a separate emission limit for formaldehyde (HCHO), which is both a VOC and a HAP, for engines.

Techniques for the control of VOC are different depending on whether they are byproducts of combustion, due to venting or processing natural gas, or a result of fugitive emissions. Control techniques considered for the reduction of post-combustion VOC include NSCR systems and oxidation catalysts. The primary control technique considered for the reduction of venting or process emissions is the installation of a closed vent system routed to a process or a control. The primary control technique considered for the reduction of fugitive emissions is an LDAR program.

D. Hazardous Air Pollutants

HAPs are air pollutants known to cause cancer or to have other serious health impacts. There are currently 187 listed HAPs. While combustion accounts for a portion of HAP emissions, HAPs are also released through fugitive emissions, venting, and the processing of natural gas. The HAPs of primary concern at unconventional natural gas well site operations, remote pigging stations, natural gas compression stations, processing plants, and transmission stations are n-hexane; benzene, toluene, ethylbenzene, xylenes (collectively known as BTEX); and formaldehyde. Formaldehyde is of interest because it is the predominant HAP component of combustion emissions, resulting from the incomplete combustion of methane.

Similar to the control of VOC, the techniques for mitigating HAP emissions are dependent on whether the emissions are byproducts of combustion, due to venting or processing natural gas, or a result of fugitive emissions. The techniques to reduce HAP in these cases are the same as those used to reduce VOCs.

E. Oxides of Sulfur

Oxides of sulfur are the byproduct of combustion of a fuel that contains sulfur. In the Marcellus Shale region, natural gas does not contain sulfur above trace amounts. The Department has determined that for a typical combustion process using natural gas, SO_2 emissions are of minor significance. Therefore, neither GP-5 nor GP-5A include SO_2 emission limitations or SO_2 stack testing requirements for combustion sources. An example of this determination of minor significance is given in the calculation below.

$$\left|\frac{4\ lb\cdot mol\ H_2S}{10^6\ lb\cdot mol\ natural\ gas}\right|\left|\frac{lb\cdot mol\ SO_2}{lb\cdot mol\ H_2S}\right|\left|\frac{64.07\ lb\ SO_2}{lb\cdot mol\ SO_2}\right|\left|\frac{lb\cdot mol\ natural\ gas}{386.8\ scf\ natural\ gas}\right|\left|\frac{scf\ natural\ gas}{1{,}030\ Btu}\right|\left|\frac{10^6\ Btu}{MMBtu}\right|$$
$$= 6.42\times10^{-4}\frac{lb\ SO_2}{MMBtu} < 6.00\times10^{-2}\ \frac{lb\ SO_2}{MMBtu}\left(40\ CFR\ §60.4330(a)(2)\right)$$

Another example is the sweetening unit sulfur feed rate, where the lowest applicable limit is two long tons per day. Using the equations provided in 40 CFR §60.5406a(b)(1) and assuming the 4 ppm H_2S limit, the "acid gas" flow rate would have to be nearly 13,500 MMscf/day to reach a sulfur feed rate of

two long tons of sulfur per day. According to a EIA report,[12] an average transmission station moves approximately 700 MMscf/day and the largest compression station at the time moves as much as 4,600 MMscf/day. Neither type of facility would reach the required sulfur feed rate for control under 40 CFR §60.5405(a). This is also true for gathering stations as they are generally smaller than transmission stations.

F. Particulate Matter

There are many types of particulate matter emissions, with classifications based on size (i.e., PM_{10} and $PM_{2.5}$) and state (i.e., filterable and condensable). Some particles are emitted directly from a source, such as construction sites, unpaved roads, or combustion, and are called primary particles. Others are formed in complicated reactions in the atmosphere from SO_2 and NO_X and are called secondary particles. The clearing, grading, and construction of a site as well as the drilling of a well can create primary particle emissions. The combustion of natural gas produces very little primary particle emissions, and the control of precursor emissions helps reduce secondary particle emissions. Because the primary particle emissions from combustion sources are of minor significance, and the primary precursor emissions are either of minor significance or well controlled, GP-5 and GP-5A do not include PM emission limitations or stack testing requirements from most combustion sources.[13]

G. Carbon Dioxide

Carbon dioxide is sometimes present in natural gas in significant quantities and is also a primary byproduct of combustion. CO_2 is a greenhouse gas; however, since the explicit control of CO_2 emissions such as carbon capture and sequestration (CCS) from minor facilities such as sources covered by these General Permits are not readily available. However, many of the BMP, maintenance requirements, and operating limitations included in the General Permits have the co-benefit of increasing the source's efficiency and therefore reducing CO_2 on an output basis.

H. Methane

Methane is the primary component of natural gas and represents a major portion of the emissions from unconventional natural gas well site operations, remote pigging stations, natural gas compression stations, processing plants, and transmission stations. While methane is harmless in low concentrations, it can explode when the concentration reaches the lower explosive limit. Methane is also a greenhouse gas and a precursor to ground level ozone.

Based on the 2015 Air Emissions Inventory for unconventional natural gas operations, methane emissions from 2011 through 2015 ranged from 107,375 tpy to 122,589 tpy. The sources of methane emissions included dehydration units, fugitive sources such as connectors, flanges, pump lines, pump seals, valves, heaters, pneumatic pumps, stationary engines, tanks, venting, blowdowns, well completions and pigging operations. Details of methane emissions from the above sources are shown in Table 4 and Table 5.

[12] Technical Report: Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments Since 1996, November 2007, Energy Information Administration, Office of Oil and Gas.

[13] Technical Report: Development of Fine Particulate Emission Factors and Speciation Profiles for Oil and Gas-fired Combustion Systems, Update: Critical Review of Source Sampling and Analysis Methodologies for Characterizing Organic Aerosol and Fine Particulate Source Emission Profiles, February 2004, Gas Research Institute, *et.al.*

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The Exemption 38, finalized in 2013, required 95% control of any emission unit exceeding emission thresholds of 2.7 tpy of VOC, 0.5 tpy of single HAP, and 1.0 tpy of total HAP. It should be noted that not a single plan approval was submitted for an unconventional natural gas well site despite the requirement to install 95% VOC control on storage vessels and other equipment. This means either the installation of control is cost effective, or that the sources in question emit less than 2.7 tpy of VOC, 0.5 tpy of single HAP, and 1.0 tpy of total HAP.

The control of methane emissions in the earlier GP-5s and Exemption 38 were addressed as a collateral benefit due to the control of VOC emissions; however, because of the great success with the 2.7 tpy VOC threshold in Exemption 38, the Department decided to do something similar with methane related to a cost-effective control threshold under BAT. In addition, the leak definition for oil and gas operations included in GP-5 and Exemption 38 expressly addressed methane emissions from fugitive sources. As previously discussed in the Introduction, Governor Wolf's Methane Reduction Strategy sought to explicitly address the control of methane from the oil and gas industry. Also, as previously discussed in the Introduction, the EHB indicated to the Department that BAT also applies to GHG. Therefore, BAT for methane control was determined for sources authorized under the final General Permits to satisfy both regulatory and policy requirements.

Table 4 - Methane Emissions from Unconventional Well Site Operations in Pennsylvania

Source Type	2012		2013		2014		2015		2016	
	(tpy)		(tpy)		(tpy)		(tpy)		(tpy)	
Blowdown Vent	2,483	3%	3,745	7%	13,336	23%	12,527	21%	12,090	22%
Well Completion	39,449	54%	12,101	24%	2,237	4%	6,237	11%	7,071	13%
Dehydration Units	8,130	11%	6,402	13%	11,630	20%	6,112	10%	5,531	10%
Drilling Rigs	47	0%	33	0%	105	0%	20	0%	8	0%
Engines	3	0%	79	0%	102	0%	2	0%	26	0%
Fugitive Emissions	3,675	5%	6,081	12%	6,708	11%	11,136	19%	8,561	16%
Heaters	127	0%	12	0%	10	0%	33	0%	33	0%
Pumps	15,270	21%	19,157	38%	22,716	39%	22,007	37%	20,688	38%
Tanks	3,626	5%	3,041	6%	1,544	3%	1,169	2%	853	2%
Total	**72,809**	**100%**	**50,650**	**100%**	**58,388**	**100%**	**59,244**	**100%**	54,860	100%

Table 5 - Methane Emissions from Midstream Gas Compression and Processing Facilities in Pennsylvania

Source Type	2012		2013		2014		2015		2016	
	(tpy)		(tpy)		(tpy)		(tpy)		(tpy)	
Blowdown Vent	5,572	12%	10,575	19%	8,883	20%	16,640	26%	17,731	30%
Dehydration Units	14,259	29%	24,846	44%	16,066	36%	11,705	19%	12,290	20%
Engines	3,916	8%	5,731	10%	8,574	19%	11,418	18%	7,706	13%
Fugitive Emissions	2,930	6%	3,320	6%	4,032	9%	8,813	14%	7,429	12%
Heaters	5	0%	13	0%	8	0%	1,054	2%	769	1%
Pigging	NA	NA	NA				997	2%	192	0%

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Pumps	8,102	17%	9,810	17%	4,309	10%	9,382	15%	12,410	21%
Tanks	13,638	28%	2,602	5%	2,490	6%	2,998	5%	1,450	2%
Total	**48,424**	**100%**	**56,897**	**100%**	**44,363**	**100%**	**63,007**	**100%**	59,976	100%

The Department originally proposed a BAT methane control threshold of 200 tpy based on calculating the amount of methane based on the VOC control threshold and an average gas composition as shown in Table 15 of Appendix A – Average Gas Composition Analysis. To calculate the BAT methane control threshold, the Department used a standard mass-balance calculation; the general methodology for determining the methane control threshold was to calculate the amount of methane in a natural gas release relative to the amount of VOC that reaches the VOC control threshold. Using twelve different gas samples, the BAT methane control thresholds ranged from a minimum of 21.2 tpy to a maximum of 1,615.3 tpy. The average of the twelve calculated control thresholds is 714.9 tpy, which is 17,872 tpy of CO_{2e}. This value is nearly 25% of the 75,000 tpy of CO_{2e} major modification facility threshold for greenhouse gases.

Therefore, the Department calculated an average gas composition from the twelve samples and followed the same methodology for determining the methane control threshold with a result of 191.6 tpy. The Department conservatively used 200 tpy methane to account for the scientific uncertainty due to the limited number of gas samples used in the calculation, which is equivalent to 5,000 tpy CO_{2e}. This is approximately 7% of the facility greenhouse gas threshold.

Several commentators stated that the Department's calculated average gas composition was not representative of natural gas in Pennsylvania because of its small sample size and limited geographic scope. To improve the average gas composition calculation, the Department decided to expand the scope of the analysis; for every county with wells displayed on eMapPA, the Department attempted to obtain at least five reasonable representative gas analyses, two from compressor stations or processing plants, and three from unconventional natural gas well sites. The Department then calculated a county average gas composition for each county, and a state average gas composition by averaging the county average gas compositions.

The average composition for the counties with at least one representative gas analysis and the calculated state average gas composition are shown in Table 16 of Appendix A – Average Gas Composition Analysis. The Department believes that this state average gas composition is representative of the regions where oil and gas operations are occurring. The same process was followed as in the previous analysis, where methane emissions were calculated based on a standard mass-balance and the VOC control threshold of 2.7 tpy for each county. The methane control thresholds ranged from 5.8 tpy for Mercer County and 1,474.8 tpy for Somerset County with an average methane control threshold of 444.0 tpy. While this value is lower than the 714.9 tpy value of the previous analysis, the Department determined that it is unreasonable to be used as a control threshold; this is because it is approximately 15% of the major modification facility threshold for GHG. For the calculated state average composition, the methane control threshold is calculated to be 51.9 tpy; this is lower than in the previous calculation because there were more representative gas analyses with VOC weight percentages higher than 2%.

In the first analysis, there were only two samples with VOC weight percentages over 2% and one of them was questionable due to the high nitrogen content; this means only 10% - 17% of the samples had a VOC weight percentage over 2%. In the second analyses, approximately 25% of the samples had VOC weight percentages over 2%; half of those samples had VOC weight percentages over 5% and one

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had a VOC weight percentage over 25%. This higher VOC weight percentage had the effect of lowering the methane emissions calculated from the mass-balance and increasing the VOC weight percentage of the state average gas composition from 1.25% in the first analysis to 4.47% in the second analysis. The 51.9 tpy methane control threshold calculated from the state average gas composition is approximately 2% of the major modification facility threshold for GHG meaning it is appropriate to use it as a control threshold in the permit. However, as is shown in the analysis in Appendix D – Cost Analysis for Combustion Control Devices, control of methane at 51.9 tpy is not cost-effective.

The average gas composition determined in the second analysis is comparable to other sources such as E $^{C}/_{R}$ Incorporated's memorandum[14] to EPA, which was used in establishing the requirements of 40 CFR Part 60 Subparts OOOO and OOOOa. In most cases the cost-effectiveness threshold for methane control was determined to be $1,000/ton of methane reduced, which is based on an analysis of EPA's technical support document for Subpart OOOOa where the cost-effectiveness threshold appeared to be $1,000/ton based on which methane control techniques were implemented and which were not. The $1,000/ton of methane reduced also coincides with the central estimate of the Social Cost of Methane as determined by EPA in 2012.

As shown in Appendix D – Cost Analysis for Combustion Control Devices, the BAT methane control is cost-prohibitive at $2,239/ton of methane reduced when considering the 51.9 tpy calculated control threshold. Even though methane control is cost-effective at approximately 163 tpy methane based on the $1,000/ton reduced threshold based on a linear interpolation, the 200 tpy BAT methane control threshold previously proposed is maintained for new or modified unconventional natural gas sources at $581/ton of methane reduced. One reason for conservatively establishing the BAT methane control threshold is due to the scientific uncertainty inherent in any analysis, including the second analysis discussed above and in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices. BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). For those sources that wish to forgo controls, they can use methods or techniques to reduce methane emissions below the BAT control threshold.

Another reason in establishing the BAT 200 tpy methane control threshold is that, according to the Air Emissions Inventory, between 2012 and 2016 various sources at natural gas production, compression, and processing facilities have emissions exceeding 200 tpy of methane. While the number of sources fluctuate, generally speaking the number of sources have increased from year to year; details are shown in Table 6.

Table 6 - Reported Methane Emissions Greater Than 200 tpy

Source	Number of Sources				
	2012	2013	2014	2015	2016
Pumps	9	12	5	8	22
Heaters				2	1
Pigging				2	
Blowdowns	4	6	14	25	17
Completions	52	10	1	6	11
Dehydrators	33	40	37	28	30

[14] Memorandum on Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking, E $^{C}/_{R}$ Incorporated, July 28, 2011.

Fugitive			3	9	7

It should be noted, however, that even when not explicitly stated for control of methane, such as for sources that were constructed prior to August 8, 2018, the BMP, maintenance requirements, operating limitations, and control requirements often have a co-benefit of reducing methane emissions. As an illustration of this co-benefit, assume the 95% control requirement for VOC from a storage vessel authorized under Category Number 38(b) is met using an enclosed flare. Assuming a pre-control VOC emission rate of 10 tpy, the updated average gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis, a methane destruction efficiency of 95%, and that 100% of the destroyed methane becomes CO_2, it is possible to calculate the greenhouse gas reduction in CO_{2e}. The following equation shows the amount of methane emissions that coincide with the 10 tpy VOC assumption:

$$\left|\frac{10 \text{ ton VOC}}{\text{year}}\right|\left|\frac{1 \text{ ton natural gas}}{0.0447 \text{ ton VOC}}\right|\left|\frac{0.8603 \text{ ton } CH_4}{1 \text{ ton natural gas}}\right| = 192.5 \text{ tpy } CH_4$$

The next calculation shows the amount of CO_2 generated by combusting the methane in the control device, using the 95% destruction efficiency and 100% conversion assumptions:

$$\left|\frac{192.5 \text{ tons } CH_4}{\text{year}}\right|\left|\frac{2000 \text{ lb } CH_4}{1 \text{ ton } CH_4}\right|\left|\frac{1 \text{ lb} \cdot \text{mol } CH_4}{16.04 \text{ lb } CH_4}\right|\left|\frac{0.95 \text{ lb} \cdot \text{mol } CH_4}{1 \text{ lb} \cdot \text{mol } CH_4}\right|\left|\frac{1 \text{ lb} \cdot \text{mol } CO_2}{1 \text{ lb} \cdot \text{mol } CH_4}\right|\left|\frac{44.02 \text{ lb } CO_2}{\text{lb} \cdot \text{mol } CO_2}\right|\left|\frac{1 \text{ ton } CO_2}{2000 \text{ lb } CO_2}\right|$$
$$= 501.8 \text{ tpy } CO_2 \text{ produced from the combustion of methane}$$

The final equation shows the total amount of CO_{2e} reduced by showing the amount of CO_{2e} equivalent to the reduced methane and subtracting the CO_{2e} of the CO_2 emissions produced in the combustion process:

$$(0.95)(192.5 \text{ tpy } CH_4)\left(\frac{25 \text{ tpy } CO_{2e}}{1 \text{ tpy } CH_4}\right) - (501.8 \text{ tpy } CO_2)\left(\frac{1 \text{ tpy } CO_{2e}}{1 \text{ tpy } CO_2}\right)$$
$$= 4{,}070.1 \text{ tpy } CO_{2e} \text{ eliminated by the combustion of methane}$$

Techniques for the control of methane emissions differ depending on whether they are due to venting, processing natural gas, or fugitive emissions. The primary control technique considered for the reduction of venting or process emissions is the installation of a closed vent system routed to a process or control. The primary control technique considered for the reduction of fugitive emissions is an LDAR program.

XIX. Sources Common to GP-5 and GP-5A

A. Glycol Dehydration Units and Associated Equipment

All natural gas well streams contain water vapor as they leave the reservoir, and this water is produced along with the natural gas. As the natural gas travels up the well bore, it cools as a result of pressure reduction and the conduction of heat through the casing to cooler formations. Therefore, since the ability of gas to hold water vapor decreases as the gas temperature decreases, natural gas is nearly always saturated with water vapor when it reaches surface equipment. Additional cooling of the saturated gas will cause the formation of free water. The process for removal of water vapor from natural gas is known as dehydration.

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Dehydrators are designed to remove water from the natural gas vapor stream, thereby reducing corrosion and preventing the formation of hydrates, which are solid compounds that can cause flow restrictions and plugging in valves and even pipelines. The water-lean glycol usually flows downward in an absorption tower, counter-current to the natural gas. The glycol absorbs most of the water from the natural gas, but it also absorbs other materials present in the gas stream. The dried natural gas exits the top of the tower. The water-rich glycol leaves the bottom of the tower and flows to the regenerator. The regenerator heats the glycol to drive off water vapor, and the water vapor is usually vented directly to the atmosphere through the regenerator vent stack. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This difference in the boiling points allows for the easy removal of water from the glycol. The water-lean glycol is then returned to the absorber. Glycol has a high affinity for water and a relatively low affinity for non-aromatic hydrocarbons, which makes it a very good absorbent fluid for drying natural gas. However, the glycol does absorb small amounts of methane and other hydrocarbons from the natural gas. The hydrocarbons are released to the atmosphere along with the water vapor from the regenerator vent.

Some glycol dehydrators have additional equipment. Two common additions are flash tanks and regenerator vent emissions control equipment. The flash tank is placed in the rich glycol loop between the absorber and the regenerator. The glycol line pressure is dropped in the flash tank, causing most of the light hydrocarbons to flash into the vapor phase. The flash gas is usually routed to the regenerator burner as fuel. The methane emissions from the regenerator vent can be significantly reduced by using a flash tank. Regenerator vent control devices on units reduce emissions of BTEX and VOC to the atmosphere. These compounds are absorbed from the gas stream and driven off with the water in the regenerator vent. Control devices usually condense the water and hydrocarbons (containing BTEX and heavier VOC), then decant the hydrocarbons for sale and the water for disposal.

Emissions from glycol dehydration units are often controlled by using a condenser on the regenerator still vent and then venting to the atmosphere or to the regenerator firebox, other heaters, or a flare. Emissions from water-rich glycol flash tank vents are often controlled by combustion or by recycling back to low-pressure inlet gas streams. These systems have been shown to recover 90 to 99 percent of methane that would otherwise be flared into the atmosphere.[15]

1. Emission Limits for Glycol Dehydrators

a. Existing Glycol Dehydrators

The owner or operator of each existing glycol dehydrator located at an unconventional natural gas well site, remote pigging station, natural gas compression station, natural gas processing plant, or natural gas transmission station shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH, which are incorporated by reference in the General Permits. It is important to note that the locations listed in the technical support documents of 40 CFR Part 63, Subpart HH as urbanized areas and urban clusters were updated in the 2010 Census. The new list can be found in Appendix F.

The owner or operator of each existing glycol dehydrator installed prior to February 2, 2013, which has a total uncontrolled PTE of VOC in excess of 10 tpy, shall be controlled by at least 85% with a condenser, enclosed flare, or other air cleaning device approved by the Department.

The owner or operator of each existing glycol dehydrator installed on or after February 2, 2013, but before August 8, 2018 at a natural gas compression station or processing plant, which has a total

[15] NaturalGas.org, last accessed on May 24, 2018.

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uncontrolled PTE of VOC in excess of 5 tpy, shall be controlled by at least 95% with a condenser, enclosed flare or other air cleaning device approved by the Department.

The owner or operator of each existing glycol dehydrator installed on or after August 10, 2013, but before August 8, 2018 at an unconventional natural gas well site or remote pigging station, which has a total uncontrolled VOC emission rate greater than or equal to 2.7 tpy, an uncontrolled single HAP emission rate greater than or equal to 0.5 tpy, or a total HAP emission rate greater than or equal to 1.0 tpy, shall be controlled by at least 95%.

b. New Glycol Dehydrators

The owner or operator of each new glycol dehydrator located at an unconventional natural gas well site, remote pigging station, natural gas compression station, processing plant, or transmission station shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH, which are incorporated by reference in the General Permits.

For new glycol dehydrators whose emissions are greater than or equal to the control thresholds for methane of 200 tpy, VOC of 2.7 tpy, single HAP of 0.5 tpy, **or** combined HAP of 1.0 tpy, emission must be controlled by at least 95%. A cost analysis was done by the Department for sources that emit above the control thresholds and included in Appendix D – Cost Analysis for Combustion Control Devices. A revised analysis was done based on comments received and is also included in Appendix D – Cost Analysis for Combustion Control Devices. The control requirements are summarized in Table 7.

Table 7 - Glycol Dehydrator Control Thresholds and Control Requirements

Uncontrolled VOC PTE	Still Vent Control Level
Permitted Under GP-5 Prior to Feb 2, 2013	
>10 tpy	85%
Permitted Under GP-5 On or After Feb 2, 2013 but Prior to Aug 8, 2018	
>5 tpy	95%
Permitted on or After Aug 8, 2018	
≥2.7 tpy	95%

B. Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines

In an engine, a mixture of air and fuel is burned within the engine cylinder and the energy of expanding gases is converted into mechanical work at the engine crank shaft. The relative proportions of air and fuel in the combusted mixture is called the air-to-fuel (A/F) ratio. The A/F ratio is called "stoichiometric" if the mixture contains the precise amount of air that supplies sufficient oxygen for complete combustion of the fuel with no oxygen or fuel left over after combustion.

Reciprocating engines are grouped into two general categories based on the combustion model used in their design: “rich-burn” and “lean-burn.” The primary distinction between the two is the amount of excess air admitted prior to combustion. Rich-burn engines operate with a minimum amount of air required for combustion and lean-burn engines use 50% to 100% more air than is necessary for combustion.

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In the natural gas industry, engines are used as prime movers to drive compressors or vapor recovery units and as electric generators. Both rich-burn and lean-burn engines are used in the natural gas industry.

1. Emissions from Lean-Burn and Rich-Burn Engines

The main pollutants emitted from the exhaust of SI-RICE are NO_X, CO, NMNEHC, formaldehyde, SO_X, PM, and methane, depending on the composition of the fuel used. Natural gas is the only fuel authorized by GP-5A and GP-5.

2. Emission Control Technology

Control technologies that may be used on engines primarily fall into two categories, combustion control and post-combustion control.

a. Combustion Control

Control of combustion temperature is the principal focus of combustion process control in natural gas-fired engines. Combustion control requires tradeoffs – higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO but result in increased NO_X formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and therefore reduces NO_X formation. This allows a higher compression ratio or peak firing pressures resulting in higher efficiency. However, if the mixture is too lean, misfiring and incomplete combustion may occur, increasing CO and VOC emissions.[16]

Because the NO_X produced by SI-RICE is primarily thermal NO_X, reducing the combustion temperature will result in less NO_X production. Thus, the most common strategy for NO_X control is to control the combustion temperature. This is most easily done by adding more air than what is required for complete combustion of the fuel. This raises the heat capacity of the gases in the cylinder so that for a given amount of energy released in the combustion reaction, the maximum temperature will be reduced.

Combustion temperature can also be controlled to some extent in reciprocating engines by one or more of the following techniques:

- Diluting the fuel-air mixture with exhaust gas recirculation (EGR), which replaces some of the air and contains water vapor that has a relatively high heat capacity and absorbs some of the heat of combustion.
- Modifying valve timing, compression ratio, turbocharging, and the combustion chamber configuration.

b. Post-Combustion Emission Reduction Technology for Rich-Burn Engines

i. Three-Way Catalyst (for NO_X, CO, and NMNEHC reduction)

In rich-burn engines, an after-treatment system such as NSCR, also known as a three-way catalyst, can be added to reduce NO_X, CO, and NMNEHC emission levels. Three-way catalysts use oxygen to treat exhaust emissions. However, three-way catalysts do not use unburned combustion oxygen to reduce emissions. They make use of the oxygen within the constituent compounds. Oxygen from NO_X is used

[16] Technical Report: Technology Characterization: Reciprocating Engines, March 2015, Prepared by Darrow, K. *et al.*, of ICF International on behalf of the EPA and US DOE.

to oxidize the CO and NMNEHC. This converts the three pollutants into N_2, CO_2 and H_2O. Catalysts may be used in series to obtain lower emission levels. Typically, the reduction level for NO_X is > 95%, CO is >95%, and NMNEHC is >50%. For this analysis, the Department has determined that an NSCR is economically feasible for engines if the cost per ton of NO_X, CO, and NMNEHC removal is approximately $5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

c. Post-Combustion Emission Reduction Technology for Lean-Burn Engines

i. Oxidation Catalyst (for CO and NMNEHC reduction)

On lean-burn engines, oxidation catalysts using platinum and palladium are effective for lowering CO and NMNEHC levels in exhaust emissions. Methane that is not combusted in the engine is exhausted with the other products of combustion; however, methane is difficult to oxidize at exhaust temperatures provided by lean-burn engines. Therefore, the control efficiency for methane using an oxidation catalyst can be very low, and no specific emission limit for methane is included in the final General Permits for engines. No A/F ratio control system is required with this type of catalyst and it can be applied to either rich-burn or lean-burn engines. For this analysis, the Department has determined that an oxidation catalyst is economically feasible for engines if the cost per ton of CO and NMNEHC removal is approximately $5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

ii. Selective Catalytic Reduction (for NO_X reduction)

SCR is an exhaust gas after-treatment that specifically targets the NO_X in engine exhaust and converts it to N_2 and H_2O. Unlike the three-way catalyst which uses oxygen from the exhaust stream to treat emissions, SCR injects a compound into the exhaust stream to start the reaction. The process begins when a small amount of urea is injected into the exhaust stream. After hydrolysis, the urea becomes ammonia and reacts with NO_X. On closed-loop control systems SCR can reduce natural gas-fired engine NO_X emissions by 90% as per the SCR system manufacturers.[17]

In the GP-5 issued on February 2, 2013, the Department required add-on control for CO emissions which also controls VOC and HCHO emissions. The Department also established an uncontrolled NO_X emission limit of 0.5 grams per brake horsepower-hour (g/bhp-h) for lean-burn engines rated at greater than 500 brake horsepower (bhp) based on vendor's guaranteed emission rates. The Department evaluated the economic feasibility of SCR for engines and determined that SCR is economically cost-prohibitive for engines rated below 4,000 bhp. The Department did not evaluate SCR for larger engines at that time because the information received from natural gas compression facility owners led us to believe that the typical engine sizes were between 1,300 bhp and 4,000 bhp.

The Department has reviewed the manufacturers' current guaranteed level for NO_X emissions for lean-burn engines and found that some manufacturers now offer a guaranteed emissions rate of 0.30 g/bhp-h NO_X for certain engines rated greater than or equal to 1,875 bhp. For the current analysis, the Department has determined that SCR is economically feasible for engines if the cost per ton of NO_X removal is approximately $10,000; see the updated Appendix B – SCR Cost Analysis for Engines and Turbines.

[17] Emails from Vendor A and Vendor B, as referenced in Appendix B – SCR Cost Analysis for Engines and Turbines of this document.

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3. Engine Size Grouping

The Department chose the engine size groups based on information for various engine makes and models available. The General Permits group the engines into the following categories:

- Less than 100 bhp;
- Greater than or equal to 100 bhp and less than 500 bhp;
- Greater than or equal to 500 bhp and less than 2,370 bhp; and
- Greater than or equal to 2,370 bhp.

The groupings are comparable to the bhp categories in 40 CFR Part 60, Subpart JJJJ. The Department made BAT determinations for these categories.

4. Engine Emission Limits

The BAT for most of the engine size categories in the proposed GP-5A and GP-5 is adapted from the current GP-5 for Natural Gas Compression and/or Processing Facilities, revised January 16, 2015. For engines rated above a certain size, the Department evaluated uncontrolled emissions, control efficiency of various controls and associated costs, and stack test results for SI-RICE to establish BAT.

It should be noted that there were engines permitted through GP-5 prior to February 2, 2013, which could include sources at natural gas well sites. The scope of the revised GP-5, issued on February 2, 2013, did not include sources at natural gas well sites. Therefore, specific categories for these existing engines authorized to operate under previous versions of GP-5 and their emissions limits have been included in GP-5A.

a. Rich-Burn Engines Less Than 100 bhp

Due to the limited available emissions data for rich-burn engines less than 100 hp, the Department determined BAT for rich-burn engines less than 100 bhp equivalent to the emissions standards specified in 40 CFR Part 60 Subpart JJJJ. The emission limits included in the final General Permits are 1.0 g/bhp-h of NO_X, 2.0 g/bhp-h of CO, and 0.70 g/bhp-h of NMNEHC.

b. Rich-Burn Engines Greater Than or Equal To 100 bhp but Less Than 500 bhp

Vendor data for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp indicate weighted average emission rates[18] of 15.9 g/bhp-h for NO_X, 8.3 g/bhp-h for CO, 1.5 g/bhp-h for THC, and 0.3 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

All NSCR cost estimations were based on an analysis by E $^{C}/_{R}$ Incorporated[19], where they determined total annual costs based on vendor data. The equations are for retrofitted technology and give the cost in 2009 dollars. The total annual cost in the cost analysis was then multiplied by the consumer price index (CPI) of 1.12 for inflating 2009 dollars to 2016 dollars. Because the equations were designed as a retrofit, it is assumed that it is a conservative cost estimate for new installations. It was assumed that the control efficiencies for NO_X and CO are 95% and for NMNEHC is 50%.

[18] The weighted average emission rates for all engine categories is based on data gathered by the Department and included in the Excel Spreadsheet titled GP-5 NG Engine Data 03152018.

[19] Memorandum on Control Costs for Existing Stationary SI-RICE, E $^{C}/_{R}$ Incorporated, June 29, 2010.

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Using the weighted average emission rates and the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between $138 and $11,480 per ton of pollutants reduced. The $11,480 per ton of pollutants reduced figure is for a 100 hp engine operating at the BAT emissions rate, which presumes installation of NSCR. Discarding this point, the control cost for an NSCR is then estimated to be between $138 and $5,126 per ton of pollutant reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determines NSCR to be BAT for rich-burn engines greater than or equal to 100 bhp but less than 500 bhp where emission limits of 0.25 g/bhp-h for NO_X, 0.30 g/bhp-h for CO, and 0.20 g/bhp-h for NMNEHC remains as in the previously issued GP-5.

c. Rich-Burn Engines Greater Than or Equal To 500 bhp

Vendor data for rich-burn engines greater than or equal to 500 bhp indicate uncontrolled weighted average emission rates of 15.4 g/bhp-h for NO_X, 8.2 g/bhp-h for CO, 1.7 g/bhp-h for THC, and 0.3 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

Using the weighted average emission rates and the BAT emissions rates, the assumed control efficiencies, and assuming full-year operation, the control cost for rich-burn engines greater than or equal to 500 bhp is estimated between $30 and $3,256 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determines NSCR to be BAT for rich-burn engines greater than or equal to 500 bhp where emission limits of 0.20 g/bhp-h for NO_X, 0.30 g/bhp-h for CO, and 0.20 g/bhp-h for NMNEHC remains as in the previously issued GP-5.

d. Lean-Burn Engines Less Than 100 bhp

Due to the limited available emissions data for lean-burn engines less than 100 hp, the Department determined BAT for lean-burn engines less than 100 bhp equivalent to the emissions standards specified in 40 CFR Part 60 Subpart JJJJ. The emission limits included in the final General Permits are 1.0 g/bhp-h of NO_X, 2.0 g/bhp-h of CO, and 0.70 g/bhp-h of NMNEHC.

e. Lean-Burn Engines Greater Than or Equal To 100 bhp but Less Than 500 bhp

Vendor data for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp indicate uncontrolled weighted average emission rates of 7.8 g/bhp-h for NO_X, 6.7 g/bhp-h for CO, 1.9 g/bhp-h for THC, and 0.6 g/bhp-h for NMNEHC. Both the weighted average emission rates and BAT emission rates were used in the BAT analysis.

Using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between $286 and $1,956 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determines oxidation catalyst to be BAT for lean-burn engines greater than 100 bhp but less than 500 bhp with emission limits of 0.70 g/bhp-h for CO and 0.30 g/bhp-h for NMNEHC based on the weighted average emission factors and the given control efficiencies.

In the previous analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 100 bhp but

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less than 500 bhp is estimated between $25,843 and $62,940 per ton of NO_X reduced. In the revised analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp is estimated between $22,183 and $71,821 per ton of NO_X reduced. The Department maintains the determination that SCR is not BAT for lean-burn engines greater than or equal to 100 bhp but less than 500 bhp because it is not economically feasible; therefore, the Department established emission limit of 1.00 g/bhp-h NO_X remains as in the previously issued GP-5.

f. Lean-Burn Engines Greater Than or Equal To 500 bhp but Less Than 2,370 bhp

Vendor data for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp indicate uncontrolled weighted average emission rates of 1.4 g/bhp-h for NO_X, 2.0 g/bhp-h for CO, 4.0 g/bhp-h for THC, and 0.5 g/bhp-h for NMNEHC. Both the weighted average emission rates and the current uncontrolled BAT for NO_X were used in the BAT analysis.

In the previous analysis, using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 500 bhp but less than 1,875 bhp is estimated between $232 and $2,081 per ton of pollutants reduced. Under the new category, using the previous analysis, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp is estimated between $185 and $2,081 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department maintains the determination that oxidation catalyst is BAT for engines greater than 500 bhp but less than 2,370 bhp with an emission limit of 0.25 g/bhp-h for CO based on the weighted average emission factor and the given control efficiencies and an emission limit of 0.25 g/bhp-h for NMNEHC as in the previously issued GP-5.

In the previous analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 500 bhp but less than 1,875 bhp is estimated between $10,466 and $13,477 per ton of NO_X reduced. In the revised analysis, using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp is estimated between $11,792 and $24,541 per ton of NO_X reduced. Therefore, the Department determines that SCR is not BAT for lean-burn engines greater than or equal to 500 bhp but less than 2,370 bhp because it is not economically feasible, and the emission limit remains 0.50 g/bhp-h for NO_X as in the previously issued GP-5.

g. Lean-Burn Engines Greater Than or Equal To 2,370 bhp

Vendor data for lean-burn engines greater than or equal to 2,370 bhp indicate uncontrolled weighted average emission rates of 0.7 g/bhp-h for NO_X, 2.1 g/bhp-h for CO, 5.7 g/bhp-h for THC, and 0.8 g/bhp-h for NMNEHC.

In the previous analysis, using the weighted average emission rates and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 1,875 bhp is estimated between $123 and $873 per ton of pollutants reduced. Under the new category, using the previous analysis, the control cost for an oxidation catalyst for lean-burn engines greater than or equal to 2,370 bhp is estimated between $123 and $781 per ton of pollutants reduced, which are within the cost-effectiveness benchmark (~$5,000/ton of pollutant removed). Therefore, the Department determined oxidation catalyst to be BAT for lean-

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burn engines greater than 2,370 bhp with an emission limit of 0.25 g/bhp-h for CO based on the weighted average emission factor and the given control efficiency and an emission limit of 0.25 g/bhp-h for NMNEHC as in the previously issued GP-5.

In the previous analysis, using the BAT emission rate of 0.50 g/bhp-h as baseline, the assumed control efficiency, and assuming full-year operation, the control cost effectiveness for SCR for lean-burn engines greater than 1,875 bhp was estimated to be less than $8,818 per ton of NO_X reduced. In the revised analysis, lean-burn engines rated below 2,370 bhp were included in the previous category. However, the Department learned in recent conversations with Caterpillar that engines rated at 1,875 bhp are from a special class of engine designed to emit 0.30 g NO_X/bhp-h. Engines of the same model designation, but not of the same class as the 1,875 bhp model, are rated at 1,775 bhp. SCR is estimated to be $11,792 per ton of NO_X reduced for the 1,775 bhp model and $19,178 per ton of NO_X reduced for the 1,875 bhp model, therefore, SCR is a cost-prohibitive option for lean-burn engines designed to emit 0.30 g NOx/bhp-h. This was one reason for changing the engine categories.

The Department previously relied on stack test data that shows that approximately 33% of engines rated greater than or equal to 1,875 bhp are capable of achieving a NO_X emissions rate of 0.35 g/bhp-h uncontrolled. Therefore, the Department performed the previous analysis using 0.35 g/bhp-h of NO_X as a baseline, the assumed control efficiency, and assuming full-year operation, and found the control cost effectiveness for SCR for lean-burn engines rated greater than or equal to 1,875 bhp but less than 3,000 bhp is estimated to increase to between $10,241 and $12,597. The control cost effectiveness for SCR for engines rated greater than or equal to 3,000 bhp, using a NO_X emissions rate of 0.35 g/bhp-h as the baseline, the assumed control efficiency, and assuming full-year operation, is estimated to be less than $9,064. The Department therefore determined that lean-burn engines greater than or equal to 1,875 bhp but less than 3,000 bhp would have a dual BAT where engines with a NO_X emission rate of 0.50 g/bhp-h required SCR and engines with a NO_X emission rate of 0.35 g/bhp-h did not require SCR based on economic feasibility. However, as many of the commentators pointed out, relying on stack test data to establish an uncontrolled emission rate based on 33% of sources tested basically means that two in three engines, or an engine in two out of three tests, would be incapable of meeting that emission rate. This was another reason for changing the engine categories.

The Department conducted a revised analysis based on available engine models. For engines with a NO_X emission rate of 0.50 g/bhp-h, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 2,370 bhp is estimated between $7,611 and $10,451 per ton of NO_X reduced. This was the final reason for changing the engine categories.

For engines with a NO_X emission rate of 0.30 g/bhp-h, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for lean-burn engines greater than or equal to 2,370 bhp is estimated between $13,706 and $17,072 per ton of NO_X reduced. The Department therefore determined that lean-burn engines greater than or equal to 2,370 bhp have a dual BAT where engines with a NO_X emission rate of 0.50 g/bhp-h require SCR and engines with a NO_X emission rate of 0.30 do not require SCR based on economic feasibility. Based on the comments received, the Department has revised the ammonia slip limit to 10 ppmvd corrected to 15% O2 in the final general permits.

The BAT emission limits for the proposed General Permits are summarized in Table 8 and Table 9.

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Table 8 - BAT Emission Limits for Existing SI-RICE

Engine Type	Rated bhp	NO_X	CO	NMNEHC as propane (excluding HCHO)	HCHO
Permitted Under GP-5 Prior to Feb 2, 2013					
NG-fired Lean- and Rich-Burn Engines	<1,500	2.0 g/bhp-h	2.0 g/bhp-h	2.0 g/bhp-h	
Permitted Under GP-5 On or After Feb 2, 2013 but Prior to Aug 8, 2018					
NG-fired Lean- and Rich-burn Engines	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
NG-fired Lean-burn Engines	>100 to ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
NG-fired Lean-burn Engines	>500	0.50 g/bhp-h	47 ppmvd @ 15% O_2 **or** 93% reduction	0.25 g/bhp-h	0.05 g/bhp-h
NG-fired Rich-burn Engines	>100 to ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	
NG-fired Rich-burn Engines	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

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Table 9 - Proposed BAT Emission Limits for New SI-RICE

Engine Type	Rated bhp	NO_X	CO	NMNEHC as propane (excluding HCHO)	HCHO
Permitted on or After Aug 8, 2018					
New NG-fired Lean-burn Engines	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
New NG-fired Lean-burn Engines	>100 to ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h	-
New NG-fired Lean-burn Engines	>500 to <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
New NG-fired Lean-burn Engines	≥2,370	0.30 g/bhp-h Uncontrolled **or** 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
New NG-fired Rich-burn Engines	≤100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
New NG-fired Rich-burn Engines	>100 to ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	
New NG-fired Rich-burn Engines	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O_2 **or** 76% reduction

In addition, the engines shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ. For engines constructed on or after June 12, 2006, compliance with the requirements in Table 10 guarantees compliance with the requirements of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ.

Table 10 - 40 CFR Part 60 Subpart JJJJ Requirements

Engine Size	Manufacture Date	NO_X	NMNEHC (as propane) excluding HCHO	CO
≤25 bhp and <225 cc displacement	7/1/2008	12 g/bhp-h		387 g/bhp-h
	1/1/2012	7.5 g/bhp-h		455 g/bhp-h
≤25 bhp and ≥225 cc displacement	7/1/2008	10. g/bhp-h		387 g/bhp-h
	1/1/2011	6.0 g/bhp-h		455 g/bhp-h
25 bhp < ER < 100 bhp	1/1/2007	2.8 g/bhp-h		4.9 g/bhp-h
	1/1/2011	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h
100 hp ≤ ER < 500 bhp	7/1/2008	2.0 g/bhp-h	1.0 g/bhp-h	4.0 g/bhp-h
	1/1/2011	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h
≥500 bhp	7/1/2007	2.0 g/bhp-h	1.0 g/bhp-h	4.0 g/bhp-h
	7/1/2010	1.0 g/bhp-h	0.70 g/bhp-h	2.0 g/bhp-h

The Department's proposed BAT requirements are at least as or more stringent than those listed in the table above. Therefore, by complying with the Department's BAT requirements, the owner or operator of an engine will be guaranteed compliant with the applicable emission limits of 40 CFR Part 60 Subpart JJJJ and 40 CFR Part 63 Subpart ZZZZ for new engines.

For engines constructed prior to June 12, 2006, compliance with the requirements in Table 11 guarantees compliance with the requirements of 40 CFR Part 63 Subpart ZZZZ:

Table 11 - 40 CFR Part 63 Subpart ZZZZ Requirements

Engine Category	Oil and Filter Change	Spark Plug Inspection, Plugs Replaced as Necessary	Hose Inspection, Hoses Replaced as Necessary
Emergency SI-RICE; 4SRB and 4SLB > 500 hp that operate ≤ 24 hours per year	500 hours or annually	1,000 hours or annually	500 hours or annually
4SRB and 4SLB > 500 hp in remote locations	2,160 hours or annually	2,160 hours or annually	2,160 hours or annually
4SLB > 500 hp	Install Oxidation Catalyst to Reduce HAP Emissions		
4SRB > 500 hp	Install NSCR to Reduce HAP Emissions		
4SRB and 4SLB ≤ 500 hp	1,440 hours or annually	1,440 hours or annually	1,440 hours or annually
2SLB	4,320 hours or annually	4,320 hours or annually	4,320 hours or annually

Visible emissions shall not meet or exceed 10% opacity for a period or periods aggregating more than three minutes in any one hour nor meet or exceed 30% opacity at any time.

C. Reciprocating Natural Gas Compressors

Fluids, such as natural gas, travel naturally from areas of high pressure to areas of low pressure. Natural gas compressors take advantage of this property by increasing the pressure of natural gas at one location in a pipeline in order to promote the movement of the gas to a lower pressure area downstream. The pipeline pressure tends to drop over the length of a pipeline due to friction. This decrease in pressure is the reason why compression stations are located along the length of the pipeline.

Reciprocating natural gas compressors provide this increase of pressure by using a piston and cylinder arrangement. As the piston moves through the chamber, the pressure at the forward edge of the piston is increased as the volume in the cylinder is decreased. The high-pressure gas is then forced through a valve into the high-pressure section of the pipeline. On the reverse stroke, the pressure at the trailing edge of the piston is decreased as the volume in the cylinder is increased. This reduction in pressure allows the low-pressure gas in the pipeline to be drawn into the cylinder. The piston is connected to its prime mover by a rod, and the rod utilizes rod packings to reduce wear on the compressor components and to seal in the gas pressure. Over time, these packings can wear, resulting in methane, VOC, and HAP emissions.

It is not typical for reciprocating compressors to be installed at an unconventional natural gas well site. According to 40 CFR Part 60, Subparts OOOO and OOOOa, reciprocating compressors located at well sites are not affected facilities. Since reciprocating compressors located at well sites are air contaminant sources subject to BAT requirements, the final GP-5A requires reciprocating compressors located at well sites to meet the same requirements for reciprocating compressors located at compression stations as BAT; see Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis.

1. Existing Reciprocating Natural Gas Compressors

40 CFR Part 60, Subpart OOOO provides two options for controlling VOC emissions from reciprocating natural gas compressors. The first is to replace the rod packings either every 26,000 hours of operation (operating hours must be monitored and documented) or every 36 months (monitoring and documentation of operating hours not required). The second is to utilize a rod packing emissions collection system that operates under negative pressure to route the rod packing emissions to a process through a closed vent system.

The previous GP-5 required the owner or operator of reciprocating compressors to meet the requirements of 40 CFR Part 60, Subpart OOOO. Therefore, the owner or operator of an existing reciprocating natural gas compressor shall continue to comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO, which are incorporated by reference in the General Permit.

2. New Reciprocating Natural Gas Compressors

EPA finalized NSPS OOOOa on June 3, 2016, which requires reciprocating natural gas compressors to replace the rod packing on or before 26,000 hours of operation or 36 calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure. Based on the Department's evaluation, no additional requirements are needed. Therefore, the Department determines that the recently promulgated requirements of 40 CFR Part 60, Subpart OOOOa are determined to be BAT. Therefore, the owner or operator of a new reciprocating natural gas compressor at natural gas compression stations, processing plants, and transmission stations shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOOa, which are incorporated by reference in the GP-5.

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The Department examined whether the rod-packing replacement requirements of 40 CFR Part 60, Subpart OOOOa could also be applied to reciprocating compressors at unconventional natural gas well sites. Reciprocating compressors at these facilities are exempt based on EPA's determination in their Technical Support Document for Subpart OOOOa.[20] In their TSD, EPA determined that the cost to replace the rod-packings is $1,620 per cylinder in 2008 dollars. Adjusting to 2016 dollars using the CPI, using EPA's base assumptions for emissions and number of cylinders, and assuming 7% for future worth calculations, the Department calculates that the cost per ton of methane reduced and cost per ton of pollutant reduced is $15,802 and $12,365, respectively, based on the 0.271 scf/h emission factor from the TSD.

However, a more recent study by the University of Texas[21] (UT) lists compressor seal emission factors from different sources in Table 1-4 on pages 16 and 17 of the report including calculated emission factors from measurements conducted during the study. Table 1-4 of UT's report also includes EPA's methane emission factor of 0.271 scf/h for production sources, a natural gas emission factor of 0.343 scf/h per cylinder calculated from the methane emission factor using a default methane content of 78.8 mol%, and a natural gas emission factor of 42.2 scf/h per cylinder from a 1992 study by Picard. The UT study found the average rod packing emissions to be 241 Mscf/year, which translates to 27.5 scf/h per cylinder.

In Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis, the costs associated with rod-packing replacement requirements identical to those in EPA's TSD for 40 CFR Part 60, Subpart OOOOa were reevaluated for unconventional natural gas well sites based on the additional natural gas emission factors from the UT study. Based on the emissions estimate using average emissions from the UT study, the requirement of rod-packing replacement was determined to be cost effective as BAT. The Center for Responsible Shale Development (CRSD) certifies participants, which includes energy companies such as Chevron, CNX, EQT, and Shell Appalachia, that conform to their performance standards. CRSD standard #14 also requires rod-packing replacement every 36 months or every 26,000 hours of operation at all new and existing sites, including those at the wellhead. The voluntary participation of natural gas producers in the CRSD performance standards supports the Department's determination that the rod-packing replacement requirement is technically and economically feasible and therefore BAT.

D. Storage Vessels

Storage vessels are used to collect and store condensate (also known as natural gas liquids or NGLs) and/or produced water that are byproducts of natural gas production. Most storage vessels in the natural gas industry are fixed-roof structures and are equipped with a variety of pressure equalization devices to protect the structural integrity of the tank.

There are several federal regulations that pertain to storage vessels including requirements found in 40 CFR Part 60, Subparts K, Ka, Kb, OOOO, and OOOOa and 40 CFR Part 63, Subpart HH. In addition, state regulations found in 25 Pa. Code §§ 129.56 and 129.57 have applicable requirements. 40

[20] E $^{C}/_{R}$ Incorporated/US Environmental Protection Agency. Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities. Background Technical Support Document for the Proposed Standards 40 CFR Part 60, Subpart OOOOa. August 2015.

[21] URS Corporation/University of Texas at Austin. 2011. Natural Gas Industry Methane Emission Factor Improvement Study, Final Report. December 2011. https://dept.ceer.utexas.edu/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf, last accessed May 24, 2018.

CFR Part 60, Subparts OOOO and OOOOa include inspection and monitoring requirements for storage vessels which are incorporated in the final General Permits by reference.

1. Emission Limits for Storage Vessels

a. Existing Storage Vessels

Existing storage vessels at crude oil and natural gas production (except unconventional natural gas facilities constructed on or after August 10, 2013 but prior to August 8, 2018), transmission, and distribution facilities constructed on or after August 23, 2011, but prior to August 8, 2018, with uncontrolled potential VOC emissions greater than or equal to 6.0 tpy are required to be controlled by 95% or more, install a fixed-roof tank with an internal floating roof, an external floating roof, or maintain the actual uncontrolled VOC emissions below 4.0 tpy as required by 40 CFR Part 60 Subparts OOOO and OOOOa.

Existing storage vessels at unconventional natural gas facilities constructed on or after August 10, 2013 but prior to August 8, 2018 are required to meet the conditions in Category 38(b) of the Air Quality Permit Exemptions document. This means that existing storage vessels at unconventional natural gas well sites shall be equipped with controls achieving VOC emission reductions of 95% or greater unless the facility's uncontrolled VOC emissions for all sources are below 2.7 tpy. If the storage vessels' HAP emissions are uncontrolled, they must also be included in the facility-wide uncontrolled single HAP emissions limit of 0.5 tpy and total uncontrolled HAP emissions limit of 1.0 tpy. The facility-wide uncontrolled emission limits do not include emissions from any source that is equipped with emission controls.

In addition, the owner or operator of any storage vessel, without regard to when it was constructed, must meet the applicable requirements of 25 Pa. Code §§129.56 and 129.57, which are incorporated by reference in the General Permits.

b. New Storage Vessels

Storage vessels at unconventional natural gas well sites constructed on or August 8, 2018, must meet the requirements of Category 38(c) of the Air Quality Permit Exemptions document.

Because the Department has not issued any plan approval for sources located at any unconventional natural gas well site, either the VOC and HAP emissions from each storage vessel installed at well sites on or after August 10, 2013 are below the control threshold requirement or emissions are being reduced by 95% or more. Therefore, based on the updated cost analysis in Appendix D – Cost Analysis for Combustion Control Devices and the lack of plan approvals for sources located at any unconventional natural gas well site, the Department has determined BAT for the General Permits to be the reduction of methane, VOC, and HAP emissions by 95% or more for a storage vessel that exceeds any control threshold of 200 tpy methane, 2.7 tpy VOC, 0.5 tpy of a single HAP, or 1.0 tpy of total HAP.

In addition, the owner or operator of any storage vessel, without regard to when it was constructed, must meet the applicable requirements of 25 Pa. Code §§129.56 and 129.57, which is incorporated by reference in the General Permits.

E. Tanker Truck Load-Out Operations

The storage tanks at unconventional natural gas well sites, natural gas compression facilities, and natural gas processing facilities must be unloaded on occasion. This is done by loading the liquids from the

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tanks into tanker trucks so the liquids may be transported to a processing facility. The unloading process may emit methane, VOC, and HAP based on the composition of the liquids.

Since August 10, 2013, in accordance with Category 38 of the Air Quality Permit Exemptions document tanker truck load out operations are required to be equipped with controls achieving VOC, and HAP emissions reductions of 95% or greater unless their uncontrolled VOC, single HAP, and total HAP emissions are below the control thresholds of 2.7 tpy, 0.5 tpy, and 1.0 tpy, respectively. Because the Department has not issued any plan approval for tanker truck load out operations, either VOC and HAP emissions from each tanker truck load out operation on or after August 10, 2013 is below the control threshold requirement or emissions are being reduced by 95% or more.

All tanker truck load-out operations were required to use a vapor recovery load-out system that meets the closed vent system requirements in Section N, Enclosed Flares and Other Control Devices, in the originally proposed General Permits. This was an error, which was pointed out by several commentators, as there should be no requirement to use a vapor recovery load-out system for tanks that handle produced water. This was not the Department's intent, and to be consistent with Exemption 38 and the Internal Implementation Instructions for Exemption Category No. 38, a source that is below the control thresholds is not required to install controls.

Therefore, in the final General Permits, only tanker truck load-out operations that take liquids from storage vessels with emissions above the control thresholds are required to use a vapor balancing system and ensure each truck used to unload liquids has passed one of the annual leak checks below.

When calculating the emissions from tanker truck load-out operations, the collection efficiency may be assumed to be 99.2% for tanker trucks that pass the MACT-level annual leak test and 98.7% for tanker trucks that pass the NSPS-level annual test. The MACT-level leak test is passed if the tanker does not indicate more than a 1" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum. The NSPS-level leak test is passed if the tanker does not indicate more than a 3" H_2O pressure change within 5 minutes after being pressurized to 18" H_2O and after being depressurized to 6" H_2O vacuum. A leak test performed in accordance with 49 CFR §180.407 – *Requirements for Test and Inspection of Specification Cargo Tanks*, or EPA Method 27 – *Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test*, will be accepted as equivalent to an NSPS-level collection efficiency (i.e., 98.7%).

Originally, the Department required the owner or operator to keep records of the entire fleet of tanker trucks that collect liquids from the facility, including the date and rating of each leak test and an identification number for each truck. However, based on comments received, the Department decided to drop this recordkeeping requirement. Instead, the load-out records will identify the truck performing the load-out, identify the leak test classification, the date and time the load-out occurred, and the type and volume of liquids loaded. These records can then be used to calculate emissions due to the load-out operations for the emissions inventory.

F. Fugitive Emissions Components

Equipment leaks are typically low-level, unintentional losses of process gas from the sealed surfaces of above-ground process equipment. Equipment components that tend to leak include valves, flanges and other connectors, pump seals, compressor seals, pressure relief valves, open-ended lines, and sampling connections. These components represent mechanical joints, seals, and rotating surfaces, which in time tend to wear and develop leaks. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater

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contamination, gas migration, or an emergency situation is not considered a leak. The following requirements have been included to minimize and/or eliminate the equipment leaks.

In accordance with the Department's requirements under the previous version of GP-5, the owner or operator of a natural gas compression facility and/or natural gas processing facility shall, at a minimum on a monthly basis, perform an LDAR program which includes AVO inspections. This requirement is to be extended to unconventional natural gas well sites, remote pigging stations, and natural gas transmission stations covered by the final General Permits.

In the previous version of the GP-5, the owner or operator of the facility was required to use an OGI camera or other leak detection device to conduct an LDAR program inspection within 180 days after the initial startup of a source and at a minimum of once a quarter thereafter. This requirement has been changed to within 60 days after the initial startup of a source to meet the 40 CFR Part 60 Subpart OOOOa requirement and align with the LDAR requirements for unconventional natural gas well sites, which are required to perform an LDAR program inspection within 60 days of the start of production.

Based upon the cost-effectiveness analysis of Appendix E – LDAR Cost Analysis, the Department determined that quarterly inspections are BAT for unconventional natural gas well sites and remote pigging stations. An owner or operator of an unconventional natural gas well site or remote pigging station may track the number of leaking components in the LDAR program and reduce the inspection interval from once per quarter to semi-annually if the percentage of leaking components is less than 2.0% for two consecutive inspections. If the percentage of leaking components is higher than 2.0% in any inspection, the quarterly LDAR inspection interval must be resumed or maintained.

Consistent with 40 CFR Part 60, Subparts KKK, OOOO, and OOOOa, the LDAR requirements for natural gas processing plants are to use Method 21. As per 40 CFR §65.7(e), when a Method 21 inspection is required in any subpart of Parts 60, 61, 63, and 65, OGI camera inspections are an accepted alternative work practice for monitoring equipment for leaks. Therefore, the Department requires that all LDAR inspections covered by GP-5 and GP-5A use the same criteria, including those at natural gas processing plants under 40 CFR §§60.484 and 60.484a.

A leak is defined as any positive indication, whether audible, visual, or odorous, determined during an AVO inspection, any visible emission detected by an OGI camera calibrated according to 40 CFR §60.18 and a detection sensitivity level of 60 g/h, or a concentration of 500 ppm or greater calibrated as methane detected by an instrument that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, regardless of source. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

If any leak is detected, the owner or operator of the facility shall make a first attempt of repair within five days of the detection of the leak. The leak must be repaired no later than 15 days after the leak is detected, unless the repair requires the ordering of parts, in which case the repair must be completed no later than 10 days after receipt of the parts, or if the repair is technically infeasible without a vent blowdown, facility shutdown, or well shut-in or would be unsafe to repair during operation of the unit, in which case the repair must be completed at the earliest of the next scheduled facility shutdown, after a planned vent blowdown, or within two years.

Several commentators were concerned over the requirement that a repair that is technically infeasible without a blowdown, shutdown, or shut-in must be completed during an unscheduled blowdown. This was consistent with EPA's requirement in 40 CFR Part 60 Subpart OOOOa. The commentators were

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concerned that if the facility undergoes an emergency shutdown and parts are not on hand to complete the repair, the facility would have to remain shut down until the repair is completed. The commentators petitioned the EPA to change the requirement, which was granted; subsequently, the Department amended the final General Permits to reflect the change.

A leak is considered repaired if one of the following can be demonstrated:

- No detectable emissions consistent with 40 CFR Part 60, Appendix A-7, Method 21 Section 8.3.2;
- A concentration of less than 500 ppm calibrated as methane is detected when the gas leak detector probe inlet is placed at the surface of the component;
- No visible leak image when using an OGI camera calibrated in accordance with 40 CFR §60.18 with a detection sensitivity of 60 g/h; or
- No bubbling at leak interface using a soap solution bubble test specified in Section 8.3.3 of 40 CFR Part 60, Appendix A-7, Method 21.

LDAR is considered to have a fugitive emission control rate based on the frequency of the inspection. According to EPA and Colorado[22] the emissions reductions from annual LDAR is 40% and from quarterly LDAR is 60%. In 40 CFR Part 60, Subpart OOOOa, LDAR is required semi-annually for well pads and quarterly for compression stations and processing plants. Using 50% emissions reduction for semi-annual LDAR and 60% emission reduction for quarterly LDAR programs, the Department evaluated cost-effectiveness. As shown in Appendix E – LDAR Cost Analysis, the cost-effectiveness is $516 for well pad and $144 for transmission facilities. Therefore, the final GP-5A requires quarterly LDAR for sources at unconventional natural gas well sites or remote pigging stations and the final GP-5 requires quarterly LDAR for sources at natural gas compression, processing, and transmission facilities to minimize fugitive emissions.

The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own merits, be preventing or interfering with the attainment or maintenance of an ambient air quality standard.

G. Controllers

Controllers are automated instruments used for maintaining liquid levels, pressure, and temperature at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, natural gas processing plants, and natural gas transmission stations. These controllers often are powered by high-pressure natural gas and may release methane, VOC, and HAP with every valve movement (i.e., intermittent bleed), or continuously (i.e., continuous bleed) as part of their normal operations.

Existing controllers shall comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO. For pneumatic controllers located at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, and natural gas transmission stations this means they must be low-bleed controllers with an emission rate less than or equal to 6.0 standard cubic feet per hour unless a higher bleed rate is required for operational reasons such as speed, safety, or positive actuation.

[22] ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March 2014.

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The Department originally proposed that new controllers constructed on or after the effective date of the final General Permits should either be an electric controller if the facility has access to electricity on site or meet the requirements of 40 CFR Part 60 Subpart OOOOa if electricity is not available on site. Several commentators pointed out that electric controllers can compromise facility reliability because electric power can fail; using electric controllers could compromise safety. The Department removed the requirement to install electric controllers at facilities based on these safety and reliability concerns. However, pneumatic controllers must comply with Subpart OOOOa when located at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, and natural gas transmission stations. This means they must be low-bleed controllers with an emission rate less than or equal to 6.0 standard cubic feet per hour unless a higher bleed rate is required for operational reasons as above.

The owner or operator of new and existing controllers located at a natural gas processing plant shall employ no-bleed pneumatic controllers. These can be electrically actuated controllers or pneumatic controllers driven by instrument air. Natural gas actuated controllers that route the emissions into the downstream pipeline can also be used.

H. Pumps

Pumps are primarily used at unconventional natural gas well sites, remote pigging stations, natural gas compression stations, processing plants, and transmission stations for glycol circulation or for injecting chemicals used in normal operations. Pneumatic pumps use pressurized air or natural gas to operate the pump; at natural gas facilities, it is common to use natural gas from the production stream to operate the pumps. The pressurized natural gas, after being used to operate the pump, is often vented to the atmosphere through the exhaust port. There are many options available to reduce or eliminate emissions to the atmosphere.

Pneumatic pumps had no standards in 40 CFR Part 60, Subpart OOOO other than the LDAR requirements for pumps at natural gas processing facilities. In 40 CFR Part 60, Subpart OOOOa, natural gas-driven diaphragm pumps have control requirements for GHG and VOC depending upon the type of facility at which they are located and the number of days they are operated. Subpart OOOOa does not have a requirement for pumps located at natural gas compression stations.

In the proposed GPs, the Department required that electric pumps be used at any facility other than a natural gas processing plant that has access to electricity on site. For facilities that do not have access to electricity on site, the Department proposed that the requirements of 40 CFR Part 60, Subpart OOOOa, which were detailed in the General Permit, are BAT for pumps located at unconventional natural gas well sites and natural gas processing plants. The Department also proposed that the requirements for pumps at well sites are also BAT for pumps located at remote pigging stations, natural gas compression stations, and transmission stations. The Department also proposed to collect information on other types of pneumatic pumps by having notification, recordkeeping, and reporting requirements for all pneumatic pumps.

However, based on comments received, and the current challenges to Subpart OOOOa, the Department reevaluated the requirements for pumps. Based on the cost analysis in Appendix D – Cost Analysis for Combustion Control Devices, the Department determined that pumps with emissions greater than or equal to the control thresholds for methane of 200 tpy, VOC of 2.7 tpy, a single HAP of 0.5 tpy, or combined HAP of 1.0 tpy must control methane, VOC, and HAP emissions by 95%. For pumps with methane, VOC, and HAP emissions below the control thresholds, they must meet the applicable

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requirements of 40 CFR Part 60 Subpart OOOOa. These requirements were incorporated into the General Permits by reference.

I. Enclosed Flares and Other Control Devices

Most of the BAT requirements for emissions sources are dependent on a control to reduce those emissions to the atmosphere. The conditions for operating, maintaining, and performance testing those control devices are included in this section of the General Permits. The proposed General Permits required 98% control efficiency which was based on the economic feasibility of combustion control devices, as shown in Appendix D – Cost Analysis for Combustion Control Devices. In addition, the Department demonstrated that at a combustion zone temperature of 1,600 °F a methane destruction of 98% is achievable.

However, in 40 CFR Part 60 Subparts OOOO and OOOOa, the operators have the option to purchase manufacturer-tested models, which require 95% VOC control efficiency. Therefore, the Department revised the methane, VOC, and HAP destruction efficiency required from 98% to 95% to enable the owners or operators to comply with the federal requirements and terms and conditions of the general permits using manufacturer-tested models. Even so, the manufacturer-tested models generally achieve higher than 95% destruction. The manufacturer-tested models also minimize the amount of performance tests required to be performed by the owner or operator relying instead on parametric monitoring to ensure compliance.

J. Pigging Operations

Pigging operations are undertaken to remove accumulated water and condensate liquids in natural gas gathering pipelines or to conduct pipeline integrity checks. These operations are done as necessary to maintain the optimal pressure in the pipeline that keeps the natural gas flowing and to push valuable condensate to tanks where it can be transported to a processing plant and ensure pipeline safety. The "pig" is a spherical or bullet-shaped device that travels through the pipeline to push the liquids to their eventual destination.

A pig must be loaded into the pipeline at a launching station and recovered at a receiving station. When the pig is launched and recovered, some of the natural gas in the chamber is vented to the atmosphere. This venting can be reduced by routing the gas to a vapor recovery unit, flare, or other control device. It can also be minimized in high-pressure pipelines by equalizing the high-pressure chamber with a low-pressure line before venting. Some of these technologies and techniques are employed in practice by MarkWest for their pigging operations. The EPA's Partner Reported Opportunities (PRO) for Reducing Methane Emissions, also called NGStar, PRO Fact Sheet No. 505, gives information on other ways to minimize emissions from pigging operations.

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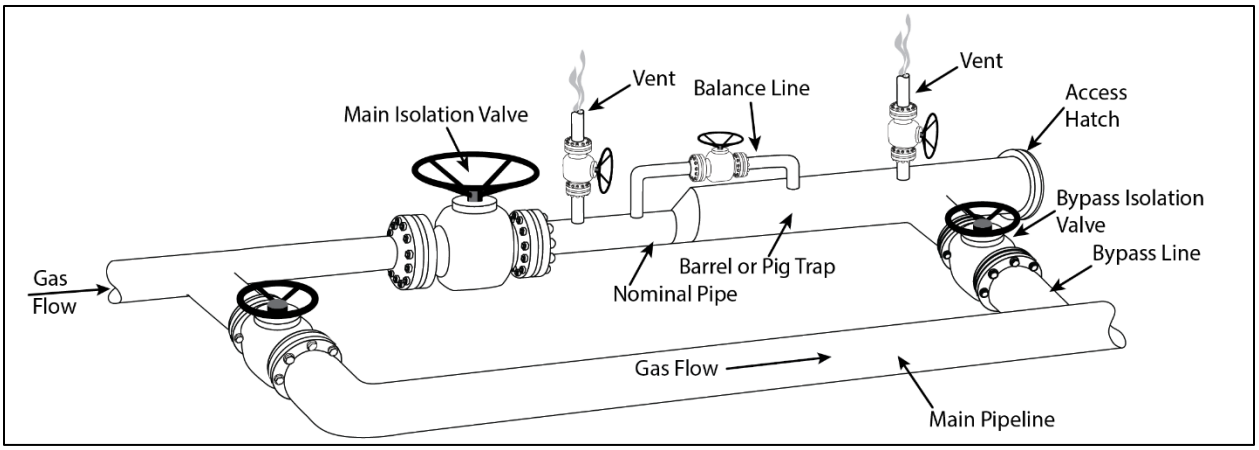


Figure 1: Drawing of a barrel type design of a pig launcher and receiver equipped with uncontrolled depressurization vents.[23]

Even though EPA is familiar with pigging operations through the NGStar program, they did not address emissions from pigging operations in 40 CFR Part 60 Subpart OOOOa. However, the Department has evaluated and set requirements for pigging operations. As part of the Annual Emissions Inventory reporting requirements, the Department requires that the owner or operator of each pigging-affected facility calculate the total annual emissions of VOC and methane using the Pigging Emissions Spreadsheet.

The owner or operator of a pigging operation shall minimize all emissions to the atmosphere to the highest extent possible. Originally, the Department required all pig receiver chambers to be equipped with a liquids drain and that all high-pressure pig launcher and receiver chambers be vented to a low-pressure pipeline or vessel if available in addition to any other best management practices (BMP) the operator decides to employ. The Department received comments recommending that DEP remove the proposed specific requirements and allow owners and operators to select all of the BMP they will implement for a specific operation. However, an owner or operator of a pigging operation whose emissions, after the application of BMP, still exceed the control thresholds for methane of 200 tpy, the total VOC of 2.7 tpy, the single HAP of 0.5 tpy, or the combined HAP of 1.0 tpy shall control methane, VOC, and HAP emissions by at least 95%.

XX. Sources Specific to GP-5A

A. Site Preparation, Well Drilling and Hydraulic Fracturing Operations

The first step in establishing a natural gas well is site preparation, which entails clearing, grading, and constructing access roads at the well site. This involves construction equipment which uses non-road engines that must meet the applicable non-road engine standards. The next step is the drilling phase; this typically entails drilling the wellbore in stages using either a diesel engine rig or a natural gas engine rig. Because the drill rig is on-site for a short period of time, the only standards that apply are that any drill rig engine must meet the applicable non-road engine standards. The owner or operator must provide at least 24 hours advance notification to the Department's Office of Oil and Gas Management before drilling. After the wellbore is completed and encased, the wellhead or "Christmas Tree" is installed.

[23] *Quantifying the Potential Impact of Natural Gas Condensate Holdup on Uncontrolled Volatile Organic Compound Emissions from Pig Receivers During Depressurization in Wet Gas Gathering Operations*, EPA Discussion Draft, May 2016.

After the installation of the wellhead, the well is ready for hydraulic fracturing. Large volumes of water mixed with chemicals and proppants are pumped into the formation to create and hold open fractures in the shale; this fracturing technique greatly enhances natural gas production. Again, the owner or operator must provide at least 24 hours advance notification to the Department's Office of Oil and Gas Management before fracture. The trucks responsible for mixing the fracturing fluid and pumping underground also use non-road engines and must meet the applicable non-road engine standards. These are summarized in the tables in Appendix G – Non-road Engine Standards.

Several commentators informed the Department that these temporary operations may be carried out a year or more in advance of the installation of any permanent air emissions source. The well drilling and hydraulic fracturing typically lasts from a few weeks to a few months. In addition, except for California, States are preempted from establishing emission standards for non-road engines under Section 209 of the CAA. However, these engines must comply with applicable EPA non-road engine standards at 40 CFR Parts 89, 1039, and 1048. Therefore, the Department has removed requirements related to site preparation, well drilling, hydraulic fracturing, and well completion from the final GP-5A and maintained the exemption for these temporary operations in Category 38(c) of the Air Quality Permit Exemptions document.

B. Well Completion Operations

After a natural gas well is hydraulically fractured, the well must be prepared to produce natural gas by removing the fluid used in the fracturing process from the well. During this process, equipment such as a separator is used to separate and remove the sand and water from the natural gas stream. The separated gas, instead of being vented, is either captured and routed to a sales pipeline, or is flared. By not directly venting the gas to the atmosphere, both methane and VOC emissions are greatly reduced. This method of completing a natural gas well is called reduced emission completion (REC) or green completion.

The owner or operator shall use REC methods in accordance with requirements specified in 40 CFR Part 60, Subpart OOOOa. Also, any existing well that is refractured after the applicability date of Subpart OOOOa subjects existing sources at a facility to the fugitive emissions components requirements in the final GP-5A. As stated above, these operations are also temporary in nature. While well completion is likely to occur much closer to the installation of permanent air emission sources, there may still be significant time between when the completion occurs and when air contamination sources are due to be installed. This could lead to inaccurate applications being submitted and many reauthorizations of the General Permit, increasing the administrative burden on the industry and the Department. Because the requirements for well completion operations are no different than those required by state and federal regulations, the Department removed these temporary operations from the final GP-5A and maintained the exemption for them in the Category 38(c). Even though these operations will not require an air permit, the operators will still be required to meet the applicable state and federal regulations, including notifying both the Air Program Manager of the appropriate Regional Office and the Department's Office of Oil and Gas Management 24 hours prior to the start of flowback.

C. Wellbore Liquids Unloading

Over time, liquids may accumulate in a producing natural gas well and may reduce the well pressure to the point where production is reduced, especially in wells located in the wet gas areas. When this happens, the accumulated fluids need to be removed in order to restore production through a process called liquids unloading. There are many techniques that can be used to accomplish this, including venting, soaping, swabbing, and using a plunger lift system. As indicated in EPA's white paper on Oil

and Natural Gas Sector Liquids Unloading Processes[24], the use of technologies like a plunger lift system can reduce the frequency of liquids unloading operations.

However, the basic criteria for the installation of a plunger lift, as found in EPA's NGStar program[25], are as follows:

- Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.
- Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.
- Wells with scale or paraffin buildup.

These conditions may not be found at all wells covered by the GP-5A, so plunger lift systems remain an option but not a requirement for wellbore liquids unloading. Furthermore, in comments to EPA in the rulemaking for 40 CFR Part 60 Subpart OOOOa, the American Petroleum Institution (API) states that it is a misconception that plunger lift systems are the single emission control action for wells where venting for liquids unloading occurs.

> "This misconception is exacerbated by a lack of understanding, even among those purporting plunger lift systems as *the* solution to liquids unloading, of liquids loading or plunger lift systems and their appropriate uses, limitations, and efficacy. Plungers work by providing a mechanical barrier between a small volume of water and the gas that is used to transport it up the well-bore. The mechanical barrier isolates the gas from the liquids, prevents gas from moving up through the liquids hence making better use of the gas energy, and helps prevent liquids from falling back into the well-bore. If the gas could flow faster, then that mechanical barrier would not be necessary or helpful.
>
> Although plungers are among the most common tools used in middle stage deliquification, there is a misconception that plungers eliminate the need to vent to atmosphere. In many cases, wells are vented to atmosphere to generate the differential pressure necessary to lift the plunger and liquid column up the well-bore. While this can be controlled and minimized, it cannot be eliminated.
>
> As the API/ANGA report and the GHGRP data show, venting of wells to aid liquids unloading occurs in both plunger equipped wells and non-plunger equipped wells with plunger equipped wells having higher reported emissions overall."

There was another EPA white paper[26] that detailed other alternatives to repeated well venting to remove accumulated liquids including surfactants, velocity tubing, manual plunger lifts, automated plunger lifts, and downhole pumps. However, EPA did not address emissions from wellbore liquids unloading operations in 40 CFR Part 60 Subpart OOOOa. However, the Department evaluated emissions from

[24] U.S. EPA Office of Air Quality Planning and Standards, *Report for Oil and Natural Gas Sector Liquids Unloading Processes Review Panel,* April 2014, located at http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-liquids-unloading.pdf, last accessed on May 24, 2018.
[25] U.S. EPA's Natural Gas STAR Program, *Lessons Learned from Natural Gas STAR Partners: Installing Plunger Lift Systems in Gas Wells,* October 2006, located at https://www.epa.gov/sites/production/files/2016-06/documents/ll_plungerlift.pdf, last accessed on May 24, 2018.
[26] U.S. EPA's Natural Gas STAR Program, *Lessons Learned from Natural Gas STAR Partners: Options for Removing Accumulated Fluid and Improving Flow in Gas Wells,* 2011, located at https://www.epa.gov/sites/production/files/2016-06/documents/ll_options.pdf, last accessed on May 24, 2018.

wellbore liquid operations to determine BAT. In general, there has been great support in the comments for including wellbore liquids unloading operations in the GP-5A.

The Department learned through conversations with some industry representatives, that one of the largest factors in emissions from wellbore liquids unloading events is the length of time that flow is directed to atmospheric pressure. Therefore, one of the most effective methods to reduce the time venting to atmospheric pressure would be to ensure that an operator remains on site for the duration of a manual unloading operation. However, one commentator stressed that the requirement to have an operator onsite for the entire duration of a wellbore liquids unloading operation is burdensome, especially to small businesses. An unloading operation can take a significant amount of time, which is typically spent by an operator travelling to another site to initiate another unloading operation. The operator then travels back to each site, ending each unloading operation in turn. The time spent by an operator onsite would necessitate hiring significant additional staff that small businesses cannot easily afford.

Therefore, the Department has removed the requirement that the owner or operator shall ensure that an operator remains on site for the duration of a manual unloading operation. The requirement that the owner or operator use BMP including, but not limited to, a plunger lift system, soaping, swabbing, or venting to atmospheric pressure to minimize methane and VOC emissions during wellbore liquids unloading operations to mitigate emissions. In all cases, where technically feasible, the owner or operator shall direct the gas to a separator, storage vessel, or control device, unless it is necessary to vent to the atmosphere for safety.

XXI. Sources Specific to GP-5

A. Natural Gas-Fired Combustion Units

There are many different combustion units used at natural gas production and processing facilities. Some are small integrated units, typically rated at less than 2.5 MMBtu/h, such as those found on gas production units (GPU), heated flash separators, or glycol dehydration units. Others are large units, some larger than 10 MMBtu/h, such as the fractionation column heaters found at natural gas processing plants.

Often when natural gas first exits the wellbore, it contains free water, condensate, and water vapor that must be removed from the natural gas stream. GPUs perform this task, and many have small boilers that facilitate the removal of natural gas from the liquids stream through flashing, which volatilizes the gas from the liquids. In dry-gas regions, the liquid is primarily water, and is referred to as produced water. In rich-gas regions, the high percentage of condensate in the natural gas stream often requires further processing to ensure that the water and condensate are separated. Heated flash separator units are used for this purpose and are also equipped with small boilers to facilitate the condensate removal from the water by flashing. The flow of the natural gas and liquids through the GPUs and heated flash separator units are often controlled by integrated controllers and pumps.

Combustion units with a rated capacity of less than 10 MMBtu/h of heat input fired on natural gas supplied by a public utility are exempt from plan approval and operating permit requirements by the Air Quality Permit Exemptions document. Under Category 39 of the final Air Quality Permit Exemptions document, combustion units rated at less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be exempt from plan approval, and the General Permits may function as the required operating permit. Even though the combustion units are exempt from plan approval and/or operating permits, the owner or operator will be required to list these sources in the *Application for*

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Authorization to Use GP-5 or GP-5A for reference purposes to ensure compliance with the facility emissions limits. Any associated fugitive emissions components, controllers, and pumps will be subject to their respective requirements of the General Permit.

Table 12 identifies the applicable BAT emission limitations for combustion units rated greater than or equal to 10 MMBtu/h and less than or equal to 50 MMBtu/h:

Table 12 - BAT Emission Limits for Natural Gas-Fired Combustion Units

Constructed After:	NO_X (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)	PM (lb/MMBtu)	Opacity (No more than 3 minutes in an hour)	Opacity (At any time)
December 2, 1995	30	300	0.4	20%	60%
August 8, 2018	30	130	0.4	10%	30%

1. NO_X Limit

The Department has found that there are few vendors that offer natural gas-fired combustion units with a NOx emission rate of lower than 30 ppmvd corrected at 3% oxygen. These units are typically used in production facilities for producing steam. However, GP-5 includes combustion units including, but not limited to, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers. Typically, these combustion units are rated at less than 10 MMBtu/hr, which are exempted from permitting. Due to the availability of limited emissions data for units operating at natural gas production, compression and transmission facilities, the Department has established a NOx emission limit for natural gas-fired combustion units at 30 ppmvd corrected @ 3% oxygen. The Department will continue to evaluate NOx emissions data from these units.

2. CO Limit

The CO emission limit of 130 ppmvd corrected to 3% oxygen is consistent with the CO limit established in 40 CFR Part 63 Subpart DDDDD. Specifically, Table 1, Item 16 in Subpart DDDDD establishes for new or reconstructed boilers and process heaters the above-noted CO limit for "units designed to burn light liquid fuel." While this limit is specific to light liquid fuels, like No. 2 fuel oil, the Department proposed this limit for both No. 2 fuel oil and natural gas.

B. Natural Gas-Fired Simple Cycle Turbines

A simple cycle turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A turbine is composed of three major components: the compressor, the combustor, and the power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times the ambient pressure and directed to the combustor section where fuel is injected, ignited, and burned. The resultant gases are diluted with additional air from the compressor section and are expanded through the power turbine section, which consists of a series of rotors and stators to extract mechanical work via a shaft. A portion of the generated shaft power is used to drive the internal compressor; the rest is directed to external load. At natural gas compression stations, natural gas processing facilities, and natural gas transmission stations, turbines are used mainly as prime movers to drive centrifugal compressors or generators.

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1. Emissions from Natural Gas-Fired Turbines

Natural gas-fired turbines produce many of the same pollutants as SI-RICE which are emitted from the exhaust, depending on the composition of the fuel used. In addition, PM emissions are an issue for turbines due to the high exhaust flows. Since formaldehyde emissions from natural gas-fired turbines are on the order of 7.10×10^{-4} lb/MMBtu uncontrolled as per EPA's AP-42 Emissions Factors, a 30,000 hp simple cycle turbine may emit approximately 0.6 tpy. However, this size turbine is required to install an oxidation catalyst, which would also reduce formaldehyde by 85-90%. Therefore, the Department has not established a formaldehyde limit for simple cycle turbines. Natural gas is the primary fuel used by the natural gas industry and is the only fuel authorized by GP-5.

2. Emission Control Technology

Several technologies may be used to control emissions from turbines. They primarily fall into two categories: combustion control and post-combustion control.

a. Combustion Control

Control of combustion temperature has been the principal focus of combustion process control in turbines. Combustion control requires tradeoffs – higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons and CO, but result in NO_X formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and NO_X formation.

Because the NO_X produced by combustion turbines is primarily thermal NO_X, reducing the combustion temperature will result in less NO_X production. Thus, the most common strategy for NO_X control is to control the combustion temperature. This is often done by using wet methods, such as steam or water injection, or dry methods, such as lean combustion or two-stage combustion.

i. Steam or Water Injection

Steam or water injection has been demonstrated to effectively suppress NO_X emissions from turbines. The effect of steam or water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. Steam or water is typically injected at a water-to-fuel weight ratio of less than one. Depending on the initial NO_X levels, such rates of injection may reduce NO_X by 60% or more. Both CO and VOC emissions are increased by steam or water injection, and the level of increase will depend on the water-to-fuel weight ratio.

ii. Dry Controls

Since thermal NO_X is a function of both temperature and time, the basis of dry controls is to either lower the combustor temperature using lean mixtures of air and fuel, fuel staging, or decreasing the residence time of the combustor. A combination of these methods may also be used to reduce NO_X emissions.

Lean combustion involves increasing the A/F ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_X formation. Introducing excess air not only creates a leaner mixture, but also reduces residence time at peak temperatures.

Two-stage combustion can be broken down into lean/lean and rich/lean staging, which both serve to reduce NO_X. In lean/lean staging, the combustor is a fuel-staged premixed combustor that operates at an extremely lean A/F ratio. A small stoichiometric pilot flame ignites the premixed gas to provide flame

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stability. Because the NO_X emissions from the high temperature pilot flame are insignificant and the combustor is designed to operate at lower flame temperatures and to avoid localized "hot spots," low NO_X emission levels are achieved. In rich/lean staging, the combustor is an air-staged premixed combustor where the primary zone is operated fuel rich and the secondary zone is fuel lean. The fuel-rich zone operates at an A/F ratio less than one, which produces higher concentrations of CO and decreases the amount of NO_X due to a lack of available oxygen and lower flame temperatures. The exhaust from the primary zone is then quenched and mixed with large amounts of air, creating a lean mixture which is pre-ignited and introduced to the secondary zone where combustion is completed. The lower temperature and lean mixture results in low NO_X emission levels. Staged combustion is identified through a variety of names, including Dry-Low NO_X (DLN), Dry-Low Emissions (DLE), or $SoLoNO_X$.

b. Post-Combustion Emission Reduction Technology for Turbines

i. Oxidation Catalyst (for CO and NMNEHC reduction)

Oxidation catalysts using platinum and palladium are effective for lowering CO, NMNEHC, and formaldehyde levels in exhaust emissions from turbines. For this analysis, the Department has determined that an oxidation catalyst is economically feasible for turbines if the cost per ton of CO and NMNEHC removal is approximately $5,000; see Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines.

ii. Selective Catalytic Reduction (for NO_X reduction)

SCR is technically feasible on turbine exhaust streams, and the systems operate much like they do on engine exhaust streams. Urea or ammonia is typically used in SCR systems that control turbine NO_X emissions, which also results in ammonia emissions. For this analysis, the Department has determined that SCR is economically feasible for turbines if the cost per ton of NO_X removal is approximately $10,000; see Appendix B – SCR Cost Analysis for Engines and Turbines.

3. Turbine Size Grouping

The Department chose to slightly alter the turbine size groups for natural gas compression stations, natural gas processing plants, and natural gas transmission stations. In the previous GP-5, the turbines were placed into the following categories:

- Greater than or equal to 1,000 bhp but less than 5,000 bhp;
- Greater than or equal to 5,000 bhp but less than 15,000 bhp; and
- Greater than or equal to 15,000 bhp.

In the final GP-5, the turbines were placed into the following categories:

- Greater than or equal to 1,000 bhp but less than 5,000 bhp;
- Greater than or equal to 5,000 bhp but less than 15,900 bhp; and
- Greater than or equal to 15,900 bhp.

4. Turbine Emission Limits

New sources are required to control the emission of air pollutants to the maximum extent, consistent with BAT as determined by the Department. The Department evaluated uncontrolled emissions, control

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efficiency of various controls and associated costs, and stack test results for turbines to establish BAT. In the following sections, all references to the pollutant concentrations are given as ppm @ 15% O_2.

a. Turbines Rated Greater Than or Equal To 1,000 bhp but Less Than 5,000 bhp

Vendor data for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp gave uncontrolled emission rates of 25 ppm NO_X, 25 ppm CO, and 25 ppm THC as methane. This was the basis of the BAT from the previous GP-5, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane.

SCR cost estimations were based on vendor quotes, cited as from Vendor A and Vendor B. It was assumed that the control efficiency for SCR is 90% for NO_X. All oxidation catalyst cost estimations were based on vendor data, with the costs quoted in 2007 dollars. The costs in the analysis were then multiplied by the CPI of 1.16 for inflating 2007 dollars to 2016 dollars. It was assumed that the control efficiencies for oxidation catalysts are 93% for CO and 50% for NMNEHC. See Appendix B – SCR Cost Analysis for Engines and Turbines and Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines for the analyses.

Using the uncontrolled and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp is estimated between $8,142 and $13,810 per ton of pollutants reduced. The Department determines that an oxidation catalyst is not economically feasible based on the cost-effectiveness benchmark of approximately $5,000 per ton of pollutant reduced. Therefore, BAT for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp are emission limits of 25 ppm for CO and 9 ppm for NMNEHC as in the previously issued GP-5.

Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp is estimated between $11,622 and $18,853 per ton of NO_X reduced. The Department determines SCR is not BAT for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp because it is not economically feasible based on a cost-effectiveness benchmark of $10,000 per ton of NO_X reduced and the emission limit remains 25 ppm for NO_X as in the previously issued GP-5.

b. Turbines Rated Greater Than or Equal To 5,000 bhp but Less Than 15,900 bhp

Vendor data for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp gave uncontrolled emission rates of 25 ppm NO_X, 25 ppm CO, and 25 ppm THC as methane. This was the basis of the BAT from the previous GP-5 for CO and NMNEHC, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. BAT for NO_X was established as 15 ppm based on stack test results.

Using the uncontrolled and BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $4,836 and $6,612 per ton of pollutants reduced. However, according to stack test data, emission rates of 10 ppm CO and 5 ppm NMNEHC are achievable without control. Using the stack test emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $11,082 and $15,153 per ton of pollutants reduced. Therefore, it is the Department's determination that turbines greater than 5,000 bhp but less than 15,900 bhp have BAT criteria with emission limits of 10.00 ppm for CO and 5.00 ppm for

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NMNEHC whether attained through use of an oxidation catalyst or good combustion engineering practices.

Using the uncontrolled emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $7,714 and $9,810 per ton of NO_X reduced. Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 5,000 bhp but less than 15,900 bhp is estimated between $12,858 and $16,351 per ton of NO_X reduced. Therefore, it is the Department's determination that turbines greater than 5,000 bhp but less than 15,900 bhp have BAT criteria with emission limits of 15.00 ppm for NO_X whether attained through use of an SCR or good combustion engineering practices.

c. Turbines Rated Greater Than or Equal To 15,900 bhp

Vendor data for turbines greater than or equal to 15,900 bhp gave uncontrolled emission rates of 25 ppm NO_X, 25 ppm CO, and 25 ppm THC as methane. This was the basis of establishing oxidation catalysts as BAT from the previous GP-5 for CO and NMNEHC, and the THC emission rate was converted to NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. An alternative BAT of 10 ppm CO and 5 ppm NMNEHC based on stack test results was offered in the previous GP-5. BAT for NO_X was established as 15 ppm also based on stack test results.

Using the uncontrolled emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for an oxidation catalyst for turbines greater than or equal to 15,900 bhp is estimated between $3,576 and $4,321 per ton of pollutants reduced. Using the alternative BAT emission rates, the assumed control efficiencies, and assuming a full year of operation, the control cost for an oxidation catalyst for turbines greater than or equal to 15, 900 bhp is estimated between $8,243 and $9,903 per ton of pollutants reduced. Therefore, it is the Department's determination that turbines greater than 15,900 bhp have dual BAT criteria with emission limits of 10.00 ppm for CO uncontrolled or 1.75 ppm for CO through use of an oxidation catalyst. It is the Department's determination that turbines greater than 15,900 bhp have BAT criteria with emission limits of 5.00 ppm for NMNEHC whether attained through use of an oxidation catalyst or good combustion engineering practices.

Using the BAT emission rates, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 15,900 bhp is estimated to be less than $11,466 per ton of NO_X reduced. The Department determines SCR is BAT for turbines greater than or equal to 15,900 bhp. However, recently issued permits and plan approval applications show turbines greater than or equal to 15,900 bhp are capable of achieving 9.0 ppm for NO_X uncontrolled. Using the 9.0 ppm emission rate, the assumed control efficiencies, and assuming full-year operation, the control cost for SCR for turbines greater than or equal to 15,900 bhp is estimated to be between $16,946 and $19,106 per ton of NO_X reduced.

Most SCR vendors guarantee NO_X emissions reduction of 90% or more and therefore, with an uncontrolled baseline NOx emission rate of 15 ppmvd corrected to 15% oxygen, which is established as achievable, the Department proposed a NO_X emission limit of 1.5 ppmvd @ 15% O_2. The Department has permitted several turbines equipped with SCR with emission limits of 2 to 2.5 ppmvd NO_X @ 15% O_2. The stack test results for these turbines show NOx emissions range from 1.6 to 1.8 ppmvd. Therefore, the Department has determined that 2.0 ppmvd NO_X @ 15% O_2 is BAT in the final GP-5 for turbines rated greater than or equal to 15, 900 hp.

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Therefore, it is the Department's determination that turbines greater than or equal to 15,900 bhp have dual BAT criteria with emission limits of 9.00 ppmvd for NO_X uncontrolled and 2.0 ppmvd for NO_X through use of SCR.

Table 13 - BAT Emission Limits for Existing Turbines

Turbine Rating (bhp)	NO_X (ppmvd @ 15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane) (ppmvd @ 15% O_2)	Total PM (lbs/MMBtu)
1,000 ≤ TR < 5,000	25	25	9.0	0.03
5,000 ≤ TR < 15,000	15	25	9.0	0.03
≥ 15,000	15	10. **or** 93% reduction	5.0 **or** 50% reduction	0.03

Table 14 - Proposed BAT Emission Limits for New Turbines

Turbine Rating (bhp)	NO_X (ppmvd @ 15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane) (ppmvd @ 15% O_2)	Total PM (lbs/MMBtu)
1,000 ≤ TR < 5,000	25	25	9.0	0.03
5,000 ≤ TR < 15,900	15	10.	5.0	0.03
≥ 15,900	9.0 Uncontrolled or 2.0 with Control	10. Uncontrolled or 1.8 with Control	5.0	0.03

In addition, the turbines shall comply with all applicable requirements specified in 40 CFR Part 60, Subpart KKKK.

However, for all previous versions of the GP-5, the Department's BAT requirements are more stringent than those required under Subpart KKKK. Therefore, by complying with the Department's BAT requirements, the owner or operator of a turbine will be guaranteed compliant with the applicable requirements of 40 CFR Part 60 Subpart KKKK.

Visible emissions shall not meet or exceed 10% opacity for a period or periods aggregating more than three minutes in any one hour nor meet or exceed 30% opacity at any time.

Based on the comments received, the Department added a provision that the owner or operator shall also operate the turbine and air pollution control equipment consistent with good air pollution control practices during periods of low ambient air temperature (at or below 0 °F) during which times the emission standards do not apply. This is consistent with the requirements of 40 CFR Part 60 Subpart KKKK.

5. Turbine Core Replacement

A turbine core must be done in accordance with the terms and conditions of the GP-5; these terms and conditions are consistent with turbine core replacement requirements established for landfill gas-fired turbines in GP-22.

C. Centrifugal Natural Gas Compressors

Like reciprocating natural gas compressors, centrifugal natural gas compressors are used to increase the pressure of natural gas in a pipeline in order to take advantage of the property of fluids moving from high-pressure to low-pressure areas. In a centrifugal compressor, however, rotary motion from the prime mover is used to drive an impeller that imparts energy into the gas which serves to increase its pressure. There can be multiple stages of impellers that can generate a large change in pressure.

Like the reciprocating natural gas compressor, the centrifugal compressor has a shaft that must be sealed to reduce wear and maintain gas pressure. These seals can be either dry or wet; the wet seal uses an oil film in its operation. However, the oil used in a wet seal system collects natural gas, which must be removed in order to maintain the seal effectiveness.

It is not typical for centrifugal compressors to be installed at an unconventional natural gas well site. According to 40 CFR Part 60, Subparts OOOO and OOOOa, centrifugal compressors located at well sites are not affected facilities. The Department is therefore not proposing to authorize centrifugal compressors at unconventional well sites or remote pigging stations through the GP-5A; centrifugal compressors at natural gas compression stations, processing plants, and transmission stations are authorized in the GP-5.

1. Existing Centrifugal Natural Gas Compressors

The owner or operator of an existing wet seal centrifugal natural gas compressor shall continue to comply with the 95% control and other applicable requirements specified in 40 CFR Part 60, Subpart OOOO, which are incorporated by reference in the GP-5.

2. New Centrifugal Natural Gas Compressors

40 CFR Part 60, Subpart OOOOa requires centrifugal compressor to be equipped with dry seal or wet seal where methane and VOC emissions from the wet seal degassing system is reduced by 95% or more. Based on the Department's evaluation, no additional requirements are needed. Therefore, the Department determines that the recently promulgated requirements of 40 CFR Part 60, Subpart OOOOa are determined to be BAT.

D. Natural Gas Fractionation Process Units

Condensates, or NGLs, are an important product of natural gas production. In much of the production segment, the condensates are separated from the natural gas stream and stored in tanks before eventually being shipped to a processing plant via truck. However, condensates are still part of the natural gas stream and may fall out during transport in a pipeline. The fluid buildup can cause flow problems, which are typically cleaned through a pigging operation. In this case, the NGLs can be sent to a tank called a slug catcher which may be located at a compression station or processing plant. The liquids at a compression station are also commonly transported via a truck.

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Natural gas fractionation is the process of separating the various hydrocarbons in NGLs by extracting them in sequence in heated columns. Any methane, which is the lightest of the hydrocarbons, remaining in the condensate is separated first, and put into the pipeline for transmission and storage. Then ethane, propane, and butane are removed in turn and sent to their respective storage tanks; butane may be further divided into isobutane and n-butane. The heavier NGLs are called natural gasoline and will typically be sent to another plant for further refinement.

Potential emissions from natural gas fractionation units are from the process heaters and the fugitive emissions associated with piping, valves, flanges, pumps, compressors, and pressure relief devices. Process heaters for fractionation columns eligible for authorization under the GP-5 range in size up to 50 MMBtu/h. Combustion units rated less than 2.5 MMBtu/h are exempt from plan approval by 25 Pa. Code §127.14(a). Under Category 39 of the Air Quality Permit Exemptions document, combustion units rated less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be given the same consideration given to similarly sized sources that fire natural gas provided by a public utility. Even though the process heaters described are exempt, these sources will be listed in the permit for reference purposes. However, emissions from these exempt units must be included in the facility emissions totals for tracking compliance with the General Requirements (i.e., the 12-month rolling sum must remain below the major source emissions thresholds) and in the annual emissions inventory.

Natural gas processing, which includes fractionation, is subject to federal requirements under 40 CFR Part 60, Subpart KKK for units which were constructed, reconstructed, or modified after January 20, 1984, and on or before August 23, 2011. After August 23, 2011, and on or before September 18, 2015, fractionation process units are subject to the requirements of 40 CFR Part 60, Subpart OOOO. After September 18, 2015, fractionation process units are subject to the requirements of 40 CFR Part 60, Subpart OOOOa. In all cases, the primary standards are monitoring for equipment leaks using 40 CFR Part 60, Appendix A-7, Method 21.

Because potential emission sources associated with natural gas fractionation are addressed individually, i.e. in the sections related to combustion units and fugitive emissions components, a separate section for natural gas fractionation units was not incorporated into the final General Permit.

E. Sweetening Units

Natural gas from some wells contains sulfur and carbon dioxide, which must be removed to protect personnel, the environment, and equipment. Sulfur typically exists in natural gas in the form of hydrogen sulfide (H_2S), and natural gas where the H_2S content exceeds 4 ppm is referred to as sour gas. The process for removing H_2S from sour gas is called sweetening the gas.

The primary process for sweetening sour gas is similar to the process of glycol dehydration. An amine solution is used to remove the H_2S by passing the sour gas through a tower where it contacts the solution and is absorbed. There are two primary amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulfur compounds and CO_2 from the sour gas leaving the effluent gas virtually free of these contaminants. Both MEA and DEA can be regenerated and the resultant gases can be used to feed a Claus process, which involves using thermal and catalytic reactions to extract elemental sulfur from the hydrogen sulfide solution.[27]

Potential emissions from sweetening units are from the process heaters; the fugitive emissions associated piping, valves, flanges, pumps, compressors, and pressure relief devices; and the tail gas of

[27] NaturalGas.org, last accessed on May 24, 2018.

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the Claus process. Process heaters for sweetening units are eligible for authorization under the GP-5 up to 50 MMBtu/h in size. Combustion units rated less than 2.5 MMBtu/h are exempt from plan approval by 25 Pa. Code §127.14(a). Under Category 39 of the Air Quality Permit Exemptions document, combustion units rated less than 10 MMBtu/h firing natural gas supplied by an independent producer shall be given the same consideration given to similarly sized sources that fire natural gas provided by a public utility. Even though the described process heaters are exempt, these sources will be listed in the permit for reference purposes. However, emissions from these exempt units must be included in the facility emissions totals for tracking compliance with the General Requirements (i.e., the 12-month rolling sum must remain below the major source emissions thresholds) and in the annual emissions inventory.

Sweetening units are subject to federal requirements under 40 CFR Part 60, Subpart LLL for units which were constructed, reconstructed, or modified after January 20, 1984, and on or before August 23, 2011. After August 23, 2011, and on or before September 18, 2015, sweetening units are subject to the requirements of 40 CFR Part 60, Subpart OOOO. After September 18, 2015, sweetening units are subject to the requirements of 40 CFR Part 60, Subpart OOOOa. The standards are for a target control efficiency for SO_2 emissions based on sulfur production.

Because the Authorization to Use the GP-5 and GP-5A cannot be granted to facilities that produce or process sour gas as shown in the basic calculations in the section on Oxides of Sulfur in General Methodology of Determining Best Available Technology, the SO_2 emissions limits from the federal regulations were not included in the General Permits. Should a sweetening unit be needed to remove excess CO_2, the potential emissions sources from the sweetening unit are addressed individually, i.e., in the sections on combustion units and fugitive emissions components, and therefore a separate section on sweetening units was not incorporated into the General Permits.

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XXII. Appendix A – Average Gas Composition Analysis

Table 15 - Methane de Minimis Calculations

	Average Gas Composition	Donald R. Bowser #1M-207	Roundwood Wyo	Martin Sanders 1M	Liberty	Kenneth L. Crosby #1M-69	Petraitis	Boyanowski Wyo	Jack Wyo	Lopatofsky Wyo	Fanclaire Wyo	Susan Sus	Delhagen Sus
Methane	88.78%	63.08%	93.85%	83.21%	93.51%	70.94%	91.37%	93.90%	94.52%	95.41%	94.32%	95.49%	95.72%
Ethane	5.93%	7.91%	4.94%	4.98%	4.48%	17.15%	6.69%	4.77%	4.44%	3.86%	4.58%	3.71%	3.60%
Propane	0.88%	1.53%	0.36%	0.55%	0.36%	5.64%	0.73%	0.34%	0.26%	0.18%	0.31%	0.17%	0.15%
Butane (iso- and n-)	0.27%	0.44%	0.05%	0.03%	0.05%	2.30%	0.13%	0.07%	0.04%	0.01%	0.05%	0.01%	0.01%
Pentane (iso- and n-)	0.05%	0.09%	0.00%	0.00%	0.00%	0.49%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Hexane and above	0.05%	0.00%	0.00%	0.00%	0.00%	0.62%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Carbon Dioxide	0.21%	0.16%	0.05%	0.30%	0.75%	0.17%	0.66%	0.06%	0.05%	0.06%	0.05%	0.07%	0.10%
Molecular Nitrogen	3.85%	26.78%	0.74%	10.93%	0.41%	3.32%	0.41%	0.83%	0.69%	0.48%	0.65%	0.54%	0.42%
Sum of Parts	100.01%	99.99%	99.99%	100.00%	99.56%	100.63%	100.03%	99.97%	100.00%	100.00%	99.96%	99.99%	100.00%
VOC (sum of propane and above)	1.25%	2.06%	0.41%	0.58%	0.41%	9.05%	0.90%	0.41%	0.30%	0.19%	0.36%	0.18%	0.16%
VOC de minimis (TPY)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Methane de minimis (TPY)	191.6	82.7	618.0	387.4	615.8	21.2	274.1	618.4	850.7	1,355.8	707.4	1,432.4	1,615.3
Average of Columns (C through N) Methane de minimis (TPY)					714.9								

The general methodology for determining the methane control threshold is to calculate the amount of methane in a natural gas release relative to the amount of VOC that reaches the VOC control threshold using a standard mass-balance calculation. Using twelve different gas samples, the methane control thresholds ranged from a minimum of 21.2 tpy to a maximum of 1,615.3 tpy. The average of the twelve calculated control thresholds is 714.9 tpy, which is 17,872 tpy of CO_{2e}. This value is nearly 25% of the 75,000 tpy CO_{2e} major modification facility threshold for greenhouse gases.

Therefore, the Department calculated an average gas composition from the twelve samples and followed the same methodology for determining the methane control threshold with a result of 191.6 tpy. The Department conservatively used 200 tpy methane to account for the scientific uncertainty due to the limited number of gas samples used in the calculation, which is equivalent to 5,000 tpy CO_{2e}. This is approximately 7% of the facility greenhouse gas threshold and is much more reasonable to use as the methane control threshold.

However, several commentators stated that the Department's calculated average gas composition was not representative of natural gas in Pennsylvania because of its small sample size and limited geographic scope. To improve the average gas composition calculation, the Department decided to expand the scope of the analysis. For every county with wells displayed on eMapPA, the Department attempted to obtain at least five reasonable representative gas analyses, two from compressor stations or processing plants, and three from unconventional natural gas well sites. The sample included 59 representative gas analyses across all of the regions with oil and gas activity including the Southwest, Northwest, North Central, and Northeast Regions of Pennsylvania. The Department then calculated a county average gas composition for each county, and a state average gas composition by averaging the county average gas compositions. Therefore, the Department reduced the scope of scientific uncertainty based on geographic location.

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Table 16 - Average Gas Composition Data

County	Allegheny	Armstrong	Beaver	Bradford	Butler	Cambria	Clarion	Crawford	Fayette	Greene	Indiana	Lawrence	Lycoming	Mercer	Somerset	Sullivan	Susquehanna	Tioga	Washington	Westmoreland	Wyoming	Appendix A Table 11 of the TSD	Appendix A Table 11 of the TSD Discarding Bowers and Sanders	New Analysis
	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%	wt%
Methane	92.65%	83.91%	79.23%	94.06%	81.42%	87.18%	76.96%	88.62%	93.18%	91.51%	95.15%	75.50%	95.14%	54.26%	95.60%	94.46%	95.22%	94.71%	67.26%	93.29%	94.92%	88.78%	91.90%	86.03%
Ethane	6.18%	10.13%	11.39%	4.79%	11.58%	3.71%	12.29%	5.04%	4.21%	6.38%	2.93%	15.37%	4.07%	19.53%	2.81%	4.60%	3.87%	4.40%	17.08%	4.42%	4.13%	5.93%	5.82%	7.93%
Propane	0.41%	2.46%	4.56%	0.34%	3.40%	0.54%	4.79%	1.05%	0.60%	0.68%	0.24%	4.88%	0.24%	11.89%	0.14%	0.32%	0.19%	0.25%	8.09%	0.53%	0.23%	0.88%	0.85%	2.42%
Butane (iso- and n-)	0.08%	0.92%	2.20%	0.05%	1.42%	0.19%	2.43%	0.54%	0.28%	0.13%	0.08%	2.25%	0.03%	7.33%	0.04%	0.08%	0.02%	0.02%	4.14%	0.20%	0.02%	0.27%	0.27%	1.21%
Pentane (iso- and n-)	0.00%	0.24%	0.80%	0.01%	0.44%	0.00%	1.05%	0.48%	0.13%	0.02%	0.01%	0.50%	0.00%	3.24%	0.00%	0.00%	0.00%	0.00%	1.82%	0.06%	0.00%	0.05%	0.05%	0.48%
Hexane and above	0.00%	0.28%	0.50%	0.00%	0.21%	0.02%	1.30%	0.21%	0.17%	0.01%	0.05%	0.39%	0.01%	2.78%	0.00%	0.00%	0.00%	0.00%	0.61%	0.10%	0.00%	0.05%	0.06%	0.36%
Carbon Dioxide	0.19%	0.26%	0.65%	0.08%	1.21%	7.48%	0.09%	0.00%	0.63%	0.82%	0.57%	0.65%	0.04%	0.27%	0.74%	0.05%	0.14%	0.15%	0.37%	0.56%	0.05%	0.21%	0.20%	0.72%
Molecular Nitrogen	0.49%	1.80%	0.66%	0.65%	0.32%	0.87%	1.01%	4.05%	0.80%	0.46%	0.94%	0.46%	0.46%	0.70%	0.65%	0.49%	0.55%	0.45%	0.58%	0.82%	0.62%	3.85%	0.85%	0.85%
Molecular Oxygen	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.07%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.01%	0.03%	0.02%	0.02%	0.00%	0.00%	0.01%
Benzene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Toluene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
Ethylbenzene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Xylene	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sum of Parts	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.01%	100.01%	100.00%
VOC (sum of propane and above)	0.49%	3.90%	8.06%	0.41%	5.47%	0.76%	9.57%	2.29%	1.17%	0.84%	0.38%	8.02%	0.28%	25.25%	0.18%	0.41%	0.22%	0.28%	14.67%	0.89%	0.25%	1.25%	1.24%	4.47%
VOC de minimis (TPY)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Methane de minimis (TPY)	506.8	58.0	26.5	616.3	40.2	310.3	21.7	104.4	214.5	295.0	667.9	25.4	907.0	5.8	1,474.8	629.5	1,189.3	924.9	12.4	282.2	1,012.1	191.6	200.6	51.9
Density of Gas (lb/lb-mol)	16.63	17.41	18.13	16.51	17.81	17.31	18.42	17.01	16.63	16.75	16.44	18.48	16.42	22.05	16.40	16.48	16.41	16.46	19.69	16.60	16.43	16.95	16.71	17.36
Density of Gas (lb/cf)	0.0423	0.0443	0.0461	0.0420	0.0453	0.0441	0.0469	0.0433	0.0423	0.0426	0.0418	0.0470	0.0418	0.0561	0.0417	0.0419	0.0418	0.0419	0.0501	0.0422	0.0418	0.0431	0.0425	0.0442
Average of per County Methane De Minimis					444.0																			

The average composition for the counties with at least one representative gas analysis and the calculated state average gas composition are shown in Table 16. The Department believes that this state average gas composition is representative of the regions where oil and gas operations are occurring. The same process was followed as in the previous analysis, where methane emissions were calculated based on a standard mass-balance and the VOC control threshold of 2.7 tpy for each county. The methane control thresholds ranged from 5.8 tpy for Mercer County and 1,474.8 tpy for Somerset County with an average methane control threshold of 444.0 tpy. While this value is lower than the 714.9 tpy value of the previous analysis, the Department determined that it is unreasonable to be used as a control threshold; this is because it is approximately 15% of the major modification facility threshold for GHG. For the calculated state average composition, the methane control threshold is calculated at 51.9 tpy; this is lower than in the previous calculation because there were more representative gas analyses with VOC weight percentages higher than 2%.

In the first analysis, there were only two samples with VOC weight percentages over 2% and one of them was questionable due to the high nitrogen content; this means only 10% - 17% of the samples had a VOC weight percentage over 2%. In the second analyses, approximately 25% of the samples had VOC weight percentages over 2%; half of those samples had VOC weight percentages over 5% and one had a VOC weight percentage over 25%. This higher VOC weight percentage had the effect of lowering the methane emissions calculated from the mass-balance and increasing the VOC weight percentage of the state average gas composition from 1.25% in the first analysis to 4.47% in the second analysis. The 51.9 tpy methane control threshold calculated from the state average gas composition is approximately 2% of the major modification facility threshold for GHG meaning it is appropriate to use it as a control threshold in the permit. However, as is shown in the analysis in Appendix D for Combustion Control Devices, control of methane at 51.9 tpy is not cost-effective.

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XXIII. Appendix B – SCR Cost Analysis for Engines and Turbines

Table 17 - SCR Cost Analysis for 1,380 hp Engine

(All dollar values in 2016 dollars)	Vendor A @ 0.50 g/bhp-h (2016 Quote)	Vendor B @ 0.50 g/bhp-h (2016 Quote)	Vendor C @ 0.50 g/bhp-h (2016 Quote)	Vendor A @ 0.35 g/bhp-h (2016 Quote)	Vendor B @ 0.35 g/bhp-h (2016 Quote)	Vendor C @ 0.35 g/bhp-h (2016 Quote)
SCR Purchased Equipment Costs	$107,000	$150,000		$107,000	$150,000	
Reductant Tank Purchased Equipment Costs	$11,000	$30,000		$11,000	$30,000	
Total Purchased Equipment Costs	$118,000	$180,000	$146,000	$118,000	$180,000	$146,000
Freight	$5,900	$9,000	$7,300	$5,900	$9,000	$7,300
Commissioning Costs	$0	$0	$11,500	$0	$0	$11,500
Total Indirect Installation Costs	$23,600	$36,000	$29,200	$23,600	$36,000	$29,200
Project Contingency	$21,240	$32,400	$26,280	$21,240	$32,400	$26,280
Total Plant Cost	$168,740	$257,400	$220,280	$168,740	$257,400	$220,280
Preproduction Cost	$3,375	$5,148	$4,406	$3,375	$5,148	$4,406
Inventory Capital - Initial Fill of Reductant	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Capital Investment	$174,615	$265,048	$227,186	$174,615	$265,048	$227,186
Operating and Supervisory Labor Costs	$886	$886	$6,716	$886	$886	$6,716
Maintenance Cost	$2,619	$3,347	$3,408	$2,619	$3,347	$3,408
Reductant Consumption Cost	$18,540	$18,540	$24,090	$18,540	$18,540	$24,090
Annual Electricity Cost	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Annual Catalyst Replacement Cost	$11,525	$11,525	$22,500	$11,525	$11,525	$22,500
Direct Annual Costs	$38,570	$39,297	$61,714	$38,570	$39,297	$61,714
Indirect Annual Costs	$16,482	$25,019	$21,445	$16,482	$25,019	$21,445
Total Annual Costs	$55,052	$64,316	$83,158	$55,052	$64,316	$83,158
TPY of NO_X Emissions Reduced	5.99	5.99	5.99	4.19	4.19	4.19
Cost Per Ton	$9,189	$10,735	$13,880	$13,127	$15,336	$19,829

Table 18 - SCR Cost Analysis for 4,735 hp Engine

(All dollar values in 2016 dollars)	Vendor A @ 0.50 g/bhp-h (2016 Quote)	Vendor B @ 0.50 g/bhp-h (2016 Quote)	Vendor A @ 0.35 g/bhp-h (2016 Quote)	Vendor B @ 0.35 g/bhp-h (2016 Quote)
SCR Purchased Equipment Costs	$105,000	$225,000	$105,000	$225,000
Reductant Tank Purchased Equipment Costs	$20,000	$50,000	$20,000	$50,000
Total Purchased Equipment Costs	$125,000	$275,000	$125,000	$275,000
Freight	$6,250	$13,750	$6,250	$13,750
Commissioning Costs	$0	$0	$0	$0
Total Indirect Installation Costs	$25,000	$55,000	$25,000	$55,000
Project Contingency	$22,500	$49,500	$22,500	$49,500
Total Plant Cost	$178,750	$393,250	$178,750	$393,250
Preproduction Cost	$3,575	$7,865	$3,575	$7,865
Inventory Capital - Initial Fill of Reductant	$2,172	$2,172	$2,172	$2,172
Total Capital Investment	$184,497	$403,287	$184,497	$403,287
Operating and Supervisory Labor Costs	$1,771	$1,771	$1,771	$1,771
Maintenance Cost	$2,767	$6,694	$2,767	$6,694
Reductant Consumption Cost	$37,080	$37,080	$37,080	$37,080
Annual Electricity Cost	$5,000	$5,000	$5,000	$5,000
Annual Catalyst Replacement Cost	$23,050	$23,050	$23,050	$23,050
Direct Annual Costs	$69,668	$73,595	$69,668	$73,595
Indirect Annual Costs	$17,415	$38,067	$17,415	$38,067
Total Annual Costs	$87,083	$111,662	$87,083	$111,662
TPY of NO_X Emissions Reduced	20.56	20.56	14.39	14.39
Cost Per Ton	$4,236	$5,432	$6,052	$7,760

Table 19 - SCR Cost Analysis for Turbines

(All dollar values in 2016 dollars)	Vendor A 1,590 HP 25 ppm NO_X (2016 Quote)	Vendor A 30,000 HP 25 ppm NO_X (2016 Quote)	Vendor B 30,000 HP 25 ppm NO_X (2016 Quote)	Vendor A 30,000 HP 15 ppm NO_X (2016 Quote)	Vendor B 30,000 HP 15 ppm NO_X (2016 Quote)	Vendor A 30,000 HP 9 ppm NO_X (2016 Quote)	Vendor B 30,000 HP 9 ppm NO_X (2016 Quote)
SCR Purchased Equipment Costs	$514,600	$932,800	$2,000,000	$932,800	$2,000,000	$932,800	$2,000,000
Reductant Tank Purchased Equipment Costs	$15,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000
Total Purchased Equipment Costs	$529,600	$992,800	$2,060,000	$992,800	$2,060,000	$992,800	$2,060,000
Freight	$26,480	$49,640	$103,000	$49,640	$103,000	$49,640	$103,000
Commissioning Costs	$0	$0	$0	$0	$0	$0	$0
Total Indirect Installation Costs	$105,920	$198,560	$412,000	$198,560	$412,000	$198,560	$412,000
Project Contingency	$95,328	$178,704	$370,800	$178,704	$370,800	$178,704	$370,800
Total Plant Cost	$730,848	$1,419,704	$2,945,800	$1,419,704	$2,945,800	$1,419,704	$2,945,800
Preproduction Cost	$14,617	$28,394	$58,916	$28,394	$58,916	$28,394	$58,916
Inventory Capital - Initial Fill of Reductant	$203	$1,408	$1,408	$1,408	$1,408	$1,408	$1,408
Total Capital Investment	$745,668	$1,449,506	$3,006,124	$1,449,506	$3,006,124	$1,449,506	$3,006,124
Operating and Supervisory Labor Costs	$6,716	$6,716	$6,716	$6,716	$6,716	$6,716	$6,716
Maintenance Cost	$11,185	$21,743	$45,092	$21,743	$45,092	$21,743	$45,092
Reductant Consumption Cost	$2,467	$17,150	$17,150	$17,150	$17,150	$17,150	$17,150
Annual Electricity Cost	$1,545	$17,501	$17,501	$17,501	$17,501	$17,501	$17,501
Annual Catalyst Replacement Cost	$20,741	$138,216	$138,216	$138,216	$138,216	$138,216	$138,216
Direct Annual Costs	$42,654	$201,326	$224,675	$201,326	$224,675	$201,326	$224,675
Indirect Annual Costs	$70,386	$136,823	$283,757	$136,823	$283,757	$136,823	$283,757
Total Annual Costs	$113,040	$338,149	$508,432	$338,149	$508,432	$338,149	$508,432
TPY of NO_X Emissions Reduced	6.00	69.38	69.38	41.62	41.62	24.98	24.98
Cost Per Ton	$18,853	$4,874	$7,329	$8,124	$12,215	$13,538	$20,355

Because the quotes furnished to the Department by the vendors were determined based on the assumption of 8,760 hours of operation, the Department proposes to determine cost effectiveness of the control of NO_X with an SCR system without regard to variability of hours of operation.

The Department proposed to use the average of the total annual costs for each engine size as determined in Table 17 and Table 18 above as a point on a line to determine the cost effectiveness of SCR for sizes for which a quote was not obtained. The reason for using the average total annual cost versus the average cost in dollars per ton is that the emission limit for NO_X emissions for engines rated equal to or less than 500 hp is 1.0 g/bhp-h while for engines rate greater than 500 hp the emission limit for NO_X is 0.5 g/bhp-h. This difference in emission limits would not be reflected using the average cost in dollars per ton, as can be seen in Table 20 below.

Table 20 - Calculated Cost per Ton NO_X Reduced vs Average Cost per Ton NO_X Reduced for Engines

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,500	3,000	4,735	5,500
Average Total Annual Costs	$54,650	$56,097	$58,509	$63,334	$67,000	$68,158	$71,777	$77,807	$82,632	$99,373	$106,754
TPY of NO_X Emissions Reduced	0.87	2.17	4.34	4.34	5.99	6.51	8.14	10.85	13.02	20.56	23.88
Cost Per Ton	$62,940	$25,843	$13,477	$14,588	$11,183	$10,466	$8,818	$7,169	$6,344	$4,834	$4,471
Average Cost Per Ton	$13,603	$13,320	$12,847	$11,901	$11,182	$10,955	$10,245	$9,063	$8,117	$4,834	$3,387
TPY of NO_X Emissions Reduced, Alternative BAT							5.70	7.60	9.12	14.39	16.71
Alternative Cost Per Ton							$12,597	$10,241	$9,064	$6,906	$6,387

The Department proposed that installing an SCR system on lean-burn engines rated at or above 1,875 hp is BAT if the uncontrolled emission rate is 0.50 g/bhp-h, resulting in an emission limit of 0.05 g/bhp-h. However, engine stack test data shows that engines in this size range are capable of achieving an uncontrolled emissions rate of 0.35 g/bhp-h. As can be seen in Table 20 above, SCR is not economically feasible for an engine with uncontrolled emissions rate of 0.35 g/bhp-h until an engine is rated at or above 3,000 hp. Therefore, the Department proposed dual BAT criteria for lean-burn engines rated at or above 1,875 hp and less than 3,000 hp of 0.35 g/bhp-h uncontrolled or 0.05 g/bhp-h with control. The Department proposed a BAT criterion for lean-burn engines rated at or above 3,000 hp of 0.05 g/bhp-h.

Based on additional information submitted and comments received, the Department determined that the installation of SCR should be reevaluated for cost effectiveness. One of the issues raised is that the original BAT cost estimates did not include direct installation costs. Even though the EPA's Air Pollution Control Cost Manual 6th Edition Section 4.2 did not include direct installation costs in Table 2.5, and the 7th Edition Section 4.2 calculates the TCI based on operational parameters, the Department used vendor quotes and the standard cost estimate method from Section 1 of the 6th Edition to calculate cost effectiveness. There appears to be little difference in the method in Section 1 of the 7th Edition except for the use of the bank prime rate of 4.25% for the annualization of capital costs. The Department continues to use the 7% rate from the previous analysis for consistency.

Table 21 - Revised SCR Cost Analyses

(All dollar values in 2016 dollars)[A]	Vendor A 1,380 hp @ 0.50 g/bhp-h	Vendor B 1,380 hp @ 0.50 g/bhp-h	GCA Vendor C[1,2] 1,380 hp @ 0.50 g/bhp-h	Vendor C 1,380 hp @ 0.50 g/bhp-h	Vendor A 1,380 hp @ 0.35 g/bhp-h	Vendor B 1,380 hp @ 0.35 g/bhp-h	Vendor C 1,380 hp @ 0.35 g/bhp-h	Cardinal[1,2,3] 1,775 hp @ 0.50 g/bhp-h	Cardinal 1,775 hp @ 0.50 g/bhp-h	GCA[1,2] 1,775 hp @ 0.50 g/bhp-h	GCA 1,775 hp @ 0.50 g/bhp-h	Vendor A 4,735 hp @ 0.50 g/bhp-h	Vendor B 4,735 hp @ 0.50 g/bhp-h	GCA[4] 4,735 hp @ 0.50 g/bhp-h	GCA 4,735 hp @ 0.50 g/bhp-h
SCR System	$107,000	$150,000	$146,000	$146,000	$107,000	$150,000	$146,000	$152,484	$152,484	$130,000	$130,000	$105,000	$225,000	$495,685	$495,685
Reductant Tank and Other Auxiliary Equipment	$11,000	$30,000	$0	$0	$11,000	$30,000	$0	$37,043	$37,043	$0	$0	$20,000	$50,000	$58,257	$58,257
Customer Supplied Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Instrumentation	$0	$0	$14,600	$0	$0	$0	$0	$16,110	$0	$13,000	$0	$0	$0	$0	$0
Initial Fill of Reductant	$711	$711	$2,500	$3,960	$498	$498	$3,960	$5,000	$5,000	$2,500	$3,600	$2,440	$2,440	$9,750	$3,024
Freight	$5,936	$9,036	$7,300	$7,498	$5,925	$9,025	$7,498	$10,532	$9,726	$6,500	$6,680	$6,372	$13,872	$13,750	$27,848
Total Purchased Equipment Costs	$124,647	$189,747	$170,400	$157,458	$124,423	$189,523	$157,458	$221,169	$204,253	$152,000	$140,280	$133,812	$291,312	**$577,442**	$584,814
Total Direct Installation Costs	$162,041	$246,671	$131,400	$204,695	$161,750	$246,380	$204,695	$144,989	$265,529	$117,000	$182,364	$173,956	$378,706	$0	$760,259
Commissioning Costs	$0	$0	$11,500	$11,500	$0	$0	$11,500	$100,000	$100,000	$11,500	$11,500	$0	$0	$0	$0
Total Indirect Installation Costs	$38,640	$58,821	$58,878	$48,812	$38,571	$58,752	$48,812	$113,030	$63,319	$52,450	$43,487	$41,482	$90,307	$463,072	$181,292
Total Capital Investment	$200,681	$305,492	$372,178	$265,007	$200,321	$305,132	$265,007	$548,284	$428,848	$332,950	$237,351	$215,437	$469,012	$1,040,514	$941,551
Operating and Supervisory Labor Costs	$5,009	$2,362	$65,000	$5,009	$5,009	$2,362	$5,009	$62,400	$5,009	$65,000	$5,009	$5,009	$4,723	$21,000	$5,009
Maintenance Cost	$9,583	$3,347	$3,722	$9,583	$9,583	$3,347	$9,583	$8,224	$9,583	$3,330	$9,583	$9,583	$6,694	$37,500	$9,583
Reductant Consumption Cost	$4,326	$18,540	$24,090	$24,090	$3,028	$18,540	$24,090	$8,760	$8,760	$24,090	$21,900	$14,843	$37,080	$18,396	$14,843
Annual Electricity Cost	$3,524	$3,524	$5,000	$3,524	$3,524	$3,524	$3,524	$5,807	$3,993	$5,000	$3,993	$10,551	$10,551	$5,000	$10,551
Annual Catalyst Replacement Cost	$14,248	$11,614	$22,500	$14,248	$14,023	$11,614	$14,023	$20,000	$8,078	$18,000	$14,827	$22,371	$23,227	$47,388	$22,371
Direct Annual Costs	$36,690	$39,387	$120,312	$56,454	$35,167	$39,387	$56,229	$105,191	$35,423	$115,420	$55,312	$62,357	$82,275	$129,284	$62,357
Overhead	$11,351	$14,549	$0	$23,209	$10,572	$14,549	$23,209	$0	$14,011	$0	$21,895	$17,661	$29,098	$0	$17,661
Administrative Charges	$4,014	$6,110	$0	$5,300	$4,006	$6,103	$5,300	$0	$8,577	$0	$4,747	$4,309	$9,380	$0	$18,831
Property Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Insurance	$2,007	$3,055	$0	$2,650	$2,003	$3,051	$2,650	$0	$4,288	$0	$2,374	$2,154	$4,690	$0	$9,416
Capital Recovery	$18,942	$28,835	$40,861	$25,014	$18,908	$28,801	$25,014	$89,233	$40,479	$36,555	$22,404	$20,335	$44,270	$98,214	$88,873
Indirect Annual Costs	$36,314	$52,550	$40,861	$56,173	$35,490	$52,505	$56,173	$89,233	$67,356	$36,555	$51,419	$44,459	$87,439	$98,214	$134,781
Total Annual Costs	$73,004	$91,937	$161,173	$112,627	$70,657	$91,892	$112,402	$194,424	$102,779	$151,975	$106,731	$106,816	$169,714	$227,498	$197,138
TPY of NO_X Emissions Reduced	5.99	5.99	5.99	5.99	4.19	4.19	4.19	7.71	7.71	7.71	7.71	20.56	20.56	20.56	20.56
Cost Per Ton	$12,185	$15,345	$26,902	$18,799	$16,848	$21,911	$26,802	$25,230	$13,337	$19,722	$13,850	$5,196	$8,256	$11,067	$9,590
TPY of All Polutants Emissions Reduced								55.63	55.63						
Cost Per Ton								$3,495	$1,848						

[1] Quote included instrumentation.

[2] Company used interest rate and/or equipment life different than EPA directed 7.0% interest rate and 20 years equipment life.

[3] Quote included oxidation catalyst.

[4] Company made arithmetic error; listed PEC as $517,942 when $495,685 + $58,257 = $553,942.

[A] The Department orginially used the Capital Cost Factors from Table 2.5 in the October 2000 version of the Control Cost Manual. The updated chapter uses a base equation to calculate TCI. The Department uses the base OAQPS calculation method in the reanalysis, which may result in an overestimation of cost.

Table 22 - Revised SCR Cost Analyses

(All dollar values in 2016 dollars)[A]	INGAA 1[1,2,5,6,7] 4,735 hp @ 0.35 g/bhp-h	INGAA 1 4,735 hp @ 0.35 g/bhp-h	INGAA 2[1,2,5,6,7] 4,735 hp @ 0.35 g/bhp-h	INGAA 2 4,735 hp @ 0.35 g/bhp-h	Vendor A 4,735 hp @ 0.35 g/bhp-h	Vendor B 4,735 hp @ 0.35 g/bhp-h	GCA[4,7] 4,735 hp @ 0.30 g/bhp-h	GCA 4,735 hp @ 0.30 g/bhp-h	MarkWest[1,2,3,7,8] 5,350 hp @ 0.30 g/bhp-h	MarkWest[9] 5,350 hp @ 0.30 g/bhp-h	MarkWest[1,2,7,8,10] 5,350 hp @ 0.30 g/bhp-h Revised	MarkWest[9,10] 5,350 hp @ 0.30 g/bhp-h	MarkWest[1,2,7,10] 5,350 hp @ 0.30 g/bhp-h No OxyCat	MarkWest[9,10] 5,350 hp @ 0.30 g/bhp-h No OxyCat
SCR System	$225,000	$225,000	$277,000	$227,000	$105,000	$225,000	$495,685	$495,685	$245,790	$245,790	$226,290	$226,290	$226,290	$226,290
Reductant Tank and Other Auxiliary Equipment	$0	$50,000	$0	$50,000	$20,000	$50,000	$58,257	$58,257	$13,253	$15,593	$13,253	$15,593	$13,253	$15,593
Customer Supplied Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$28,200	$28,200	$28,200	$25,963	$28,200	$25,963
Instrumentation	$85,000	$0	$27,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Initial Fill of Reductant	$0	$1,708	$0	$1,708	$1,708	$1,708	$9,750	$1,464	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Freight	$11,250	$13,835	$0	$13,935	$6,335	$13,835	$13,750	$27,770	$15,000	$14,729	$15,000	$13,642	$15,000	$13,642
Total Purchased Equipment Costs	$330,550	$290,543	$304,700	$292,643	$133,043	$290,543	**$577,442**	$583,176	$307,243	$309,312	$287,743	$286,488	$287,743	$286,488
Total Direct Installation Costs	$429,715	$377,706	$987,700	$380,436	$172,956	$377,706	$0	$758,129	$365,981	$454,847	$365,981	$420,991	$313,240	$372,434
Commissioning Costs	$0	$0	$0	$0	$0	$0	$0	$0	$30,875	$30,875	$30,875	$28,426	$30,875	$30,875
Total Indirect Installation Costs	$69,416	$90,068	$157,173	$90,719	$41,243	$90,068	$463,072	$180,785	$133,945	$95,887	$133,945	$88,811	$133,945	$88,811
Total Capital Investment	$499,131	$467,775	$1,144,873	$471,156	$214,200	$467,775	$1,040,514	$938,914	$838,044	$581,609	$818,544	$538,228	$765,803	$492,121
Operating and Supervisory Labor Costs	$14,375	$5,009	$14,375	$5,009	$5,009	$5,009	$21,000	$5,009	$0	$5,009	$0	$5,009	$0	$5,009
Maintenance Cost	$17,500	$9,583	$17,500	$9,583	$9,583	$9,583	$37,500	$9,583	$0	$9,583	$0	$9,583	$0	$9,583
Reductant Consumption Cost	$37,000	$10,390	$37,000	$10,390	$10,390	$10,390	$18,396	$8,906	$0	$17,520	$0	$17,520	$0	$17,520
Annual Electricity Cost	$5,000	$10,551	$5,000	$10,551	$10,551	$10,551	$5,000	$10,551	$0	$11,856	$0	$11,856	$0	$11,856
Annual Catalyst Replacement Cost	$23,050	$21,984	$23,050	$21,984	$21,984	$21,984	$47,388	$21,855	$0	$37,668	$0	$37,668	$0	$18,834
Direct Annual Costs	$116,925	$57,517	$116,925	$57,517	$57,517	$57,517	$129,284	$55,904	$85,000	$81,636	$85,000	$81,636	$85,000	$62,802
Overhead	$19,125	$14,989	$19,125	$14,989	$14,989	$14,989	$0	$14,099	$0	$19,267	$0	$19,267	$0	$19,267
Administrative Charges	$9,983	$9,355	$22,897	$9,423	$4,284	$9,355	$0	$18,778	$0	$11,632	$0	$10,765	$0	$9,842
Property Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Insurance	$4,991	$4,678	$11,449	$4,712	$2,142	$4,678	$0	$9,389	$0	$5,816	$0	$5,382	$0	$4,921
Capital Recovery	$81,234	$44,153	$186,328	$44,472	$20,218	$44,153	$98,214	$88,624	$0	$54,898	$0	$50,803	$0	$46,451
Indirect Annual Costs	$120,321	$73,176	$251,243	$73,596	$41,634	$73,176	$98,214	$130,890	$134,386	$91,613	$166,483	$86,217	$159,235	$80,482
Total Annual Costs	$237,246	$130,693	$368,168	$131,113	$99,151	$130,693	$227,498	$186,794	$219,386	$173,249	$251,483	$167,853	$244,235	$143,284
TPY of NO_X Emissions Reduced	13.70	14.39	13.70	14.39	14.39	14.39	11.74	12.33	12.90	13.94	12.90	13.94	12.90	13.94
Cost Per Ton	$17,315	$9,082	$26,869	$9,112	$6,890	$9,082	$19,370	$15,145	$17,009	$12,432	$19,497	$12,045	$18,935	$10,282
TPY of All Polutants Emissions Reduced									133.27	134.31				
Cost Per Ton									$1,646	$1,290				

[1] Quote included instrumentation.

[2] Company used interest rate and/or equipment life different than EPA directed 7.0% interest rate and 20 years equipment life.

[3] Quote included oxidation catalyst.

[4] Company made arithmetic error; listed PEC as $517,942 when $495,685 + $58,257 = $553,942.

[5] Company included sales tax in their calculation. Under 61 Pa. Code §32.35, pollution control devices are exempt from tax in mining operations, which includes oil and gas drilling. Under 61 Pa. Code §155.11, pollution control devices are deductable from property tax calculations.

[6] Company included $20,000 Testing and QA/QC costs in the Direct Annual Costs.

[7] Calculated NO_X reduction to limit of 0.05 g/bhp-h rather than by 90% control.

[8] Site Preparation Costs of $52,741 were included.

[9] The Department included the additional $2,340 for the Maintenance Pack listed in the scope of supply.

[10] The oxidation catalyst costs were removed from the system cost; however, the company did not pro-rate any other costs in their analysis. The Department prorated all costs based on the ratio of costs for the oxidation catalyst to the SCR system.

[A] The Department orginially used the Capital Cost Factors from Table 2.5 in the October 2000 version of the Control Cost Manual. The updated chapter uses a base equation to calculate TCI. The Department uses the base OAQPS calculation method in the reanalysis, which may result in an overestimation of cost.

Table 23 - Derivation of Average Total Annual Cost Parameters

Quote Source	Purchased Equipment Costs	Engine Rating (HP)	NOx Emission Factor (g/bhp-h)	SCR Control Efficiency	Interest Rate	Equipment Life (years)	Total Annual Cost	Estimation Method	NOx Emissions Reduced (tons)	Cost Effectiveness ($/ton reduced)	Total Emissions Reduced (tons)	Cost Effectiveness ($/ton reduced)
Vendor A	$118,000	1,380	0.50	90.0%	7.0%	20	$55,052	First TSD Analysis	5.99	**$9,189**		
Vendor A	$118,000	1,380	0.50	90.0%	7.0%	20	$73,004	OAQPS (Revised)	5.99	$12,185		
Vendor B	$180,000	1,380	0.50	90.0%	7.0%	20	$64,316	First TSD Analysis	5.99	$10,735		
Vendor B	$180,000	1,380	0.50	90.0%	7.0%	20	$91,937	OAQPS (Revised)	5.99	$15,345		
GCA Vendor C	$146,000	1,380	0.50	90.0%	7.0%	**15**	$161,173	Company OAQPS Based	5.99	$26,902		
Vendor C	$146,000	1,380	0.50	90.0%	7.0%	20	$83,158	First TSD Analysis	5.99	$13,880		
Vendor C	$146,000	1,380	0.50	90.0%	7.0%	20	$112,627	OAQPS (Revised)	5.99	$18,799		
Vendor A	$118,000	1,380	0.35	90.0%	7.0%	20	$55,052	First TSD Analysis	4.19	$13,127		
Vendor A	$118,000	1,380	0.35	90.0%	7.0%	20	$70,657	OAQPS (Revised)	4.19	$16,848		
Vendor B	$180,000	1,380	0.35	90.0%	7.0%	20	$64,316	First TSD Analysis	4.19	$15,336		
Vendor B	$180,000	1,380	0.35	90.0%	7.0%	20	$91,892	OAQPS (Revised)	4.19	$21,911		
Vendor C	$146,000	1,380	0.35	90.0%	7.0%	20	**$83,158**	First TSD Analysis	4.19	$19,829		
Vendor C	$146,000	1,380	0.35	90.0%	7.0%	20	$112,402	OAQPS (Revised)	4.19	$26,802		
Cardinal	**$189,527**	1,775	0.50	90.0%	**10.0%**	**10**	$194,424	Company Quote	7.71	$25,230	55.11	$3,528
Cardinal	**$189,527**	1,775	0.50	90.0%	7.0%	20	$102,779	OAQPS (Revised)	7.71	$13,338	55.11	$1,865
GCA	$130,000	1,775	0.50	90.0%	7.0%	**15**	$151,975	Company Quote	7.71	$19,722		
GCA	$130,000	1,775	0.50	90.0%	7.0%	20	$106,731	OAQPS (Revised)	7.71	$13,850		
Vendor A	$125,000	4,735	0.50	90.0%	7.0%	20	$87,083	TSD	20.56	**$4,236**		
Vendor A	$125,000	4,735	0.50	90.0%	7.0%	20	$106,816	OAQPS (Revised)	20.56	**$5,196**		
Vendor B	$275,000	4,735	0.50	90.0%	7.0%	20	$111,662	TSD	20.56	**$5,432**		
Vendor B	$275,000	4,735	0.50	90.0%	7.0%	20	$169,714	OAQPS (Revised)	20.56	**$8,256**		
GCA	**$553,942**	4,735	0.50	90.0%	7.0%	20	$227,498	Company TSD Method	20.56	$11,067		
GCA	$553,942	4,735	0.50	90.0%	7.0%	20	$197,138	OAQPS (Revised)	20.56	**$9,590**		
INGAA	$310,000	4,735	0.35	**85.7%**	**10.0%**	**10**	$237,246	Company OAQPS Based	13.70	$17,315		
INGAA	$275,000	4,735	0.35	90.0%	7.0%	20	$130,693	OAQPS (Revised)	14.39	**$9,082**		
INGAA	$304,700	4,735	0.35	**85.7%**	**10.0%**	**10**	$368,168	Company Quote	13.70	$26,869		
INGAA	$277,000	4,735	0.35	90.0%	7.0%	20	$131,113	Company Quote	14.39	**$9,112**		
Vendor A	$125,000	4,735	0.35	90.0%	7.0%	20	$87,083	TSD	14.39	**$6,052**		
Vendor A	$125,000	4,735	0.35	90.0%	7.0%	20	$99,151	OAQPS (Revised)	14.39	**$6,890**		
Vendor B	$275,000	4,735	0.35	90.0%	7.0%	20	$111,662	TSD	14.39	**$7,760**		
Vendor B	$275,000	4,735	0.35	90.0%	7.0%	20	$130,693	OAQPS (Revised)	14.39	**$9,082**		
GCA	**$553,942**	4,735	0.30	**85.7%**	7.0%	20	$227,498	Company TSD Method	11.74	$19,370		
GCA	$553,942	4,735	0.30	90.0%	7.0%	20	$186,794	OAQPS (Revised)	12.33	$15,145		
MarkWest	**$287,243**	5,350	0.30	**83.3%**	**6.0%**	20	$219,386	Company Quote	12.90	$17,009	133.27	$1,646
MarkWest	**$289,583**	5,350	0.30	90.0%	7.0%	20	$173,249	OAQPS (Revised)	13.94	$12,432	134.31	$1,290
MarkWest	$267,743	5,350	0.30	**83.3%**	7.0%	20	$251,483	Company Revised Quote	12.90	$19,497		
MarkWest	$267,846	5,350	0.30	90.0%	7.0%	20	$167,853	OAQPS (Revised)	13.94	$12,045		
MarkWest	$267,743	5,350	0.30	**83.3%**	7.0%	20	$244,235	Company Revised Quote	12.90	$18,935		
MarkWest	$267,846	5,350	0.30	90.0%	7.0%	20	$143,284	OAQPS (Revised)	13.94	**$10,282**		

Engine Rating (HP)	Average Total Annual Cost
1,380	$86,057
1,380	$79,798
1,775	$138,977
1,775	$104,755
4,735	$163,126
4,735	$143,186
5,530	$199,915
5,530	$196,021

m	$28.01
b	$41,150

Table 24 - Calculated SCR Cost Effectiveness

Engine Rating (HP)	Caterpillar Model	Emission Rate	Emissions Reduced (90% Reduction)	Estimated Annual Cost	$/ton reduced
100		1.0	0.87	$43,951	$50,618
145	G3306	0.5	0.63	$45,211	$71,821
250		1.0	2.17	$48,153	$22,183
255	G3408	0.5	1.11	$48,293	$43,622
425	G3408C	0.5	1.85	$53,054	$28,754
500		1.0	4.34	$55,155	$12,704
524	G3508	0.5	2.27	$55,827	$24,541
690	G3508B	0.5	3.00	$60,477	$20,189
790	G3512	0.5	3.43	$63,278	$18,450
1,000		0.5	4.34	$69,160	$15,930
1,035	G3512B	0.5	4.49	$70,140	$15,610
1,380	*G3516B*	*0.5*	*5.99*	*$79,804*	*$13,320*
1,480	G3520B	0.5	6.43	$82,605	$12,856
1,500		0.5	6.51	$83,165	$12,771
1,775	G3606	0.5	7.71	$90,868	$11,792
1,875	G3606A4	0.3	4.88	$93,669	$19,178
2,370	G3608	0.5	10.29	$107,534	**$10,451**
2,500	G3608A4	0.3	6.51	$111,175	$17,072
3,000		0.5	13.02	$125,180	**$9,611**
3,550	G3612	0.5	15.41	$140,586	**$9,122**
3,750	G3612A4	0.3	9.77	$146,188	$14,966
4,735	*G3616*	*0.5*	*20.56*	*$173,777*	***$8,454***
5,350	G3616A4	0.3	13.94	$191,004	$13,706
5,500		0.5	23.88	$195,205	**$8,175**
6,135	G12CM34	0.5	26.63	$212,991	**$7,997**
8,180	G16CM34	0.5	35.51	$270,272	**$7,611**
6,135		0.3	15.98	$212,991	$13,328
8,180		0.3	21.31	$270,272	$12,684

Based on the costs determined in Table 24 above, and the cost-effectiveness threshold of $10,000 per ton of NO_X reduced, SCR is cost effective for engines greater than or equal to 2,370 hp if the starting NO_X emission rate is 0.50 g/bhp-h. Installation of SCR becomes economically infeasible for engines greater than or equal to 2,370 hp if the starting NO_X emission rate is 0.30 g/bhp-h. For this reason, the Department proposes a dual BAT criterion for lean burn engines greater than or equal to 2,370 hp of 0.30 g/bhp-h NO_X uncontrolled, or 0.05 g/bhp-h NO_X with control.

Following the original methodology described above for engines with the turbine data results in cost per ton and average cost per ton as summarized in Table 5 below. The BAT emissions limits of 25 ppm for NO_X for turbines below 5,000 bhp, of 15 ppm for turbines 5,000 bhp and above were used in the analysis.

Table 25 - Calculated Cost per Ton NO_X Reduced vs Average Cost per Ton NO_X Reduced for Turbines using BAT Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Average Total Annual Costs	$107,277	$113,040	$130,449	$153,621	$166,713	$182,586	$224,875	$279,908	$298,446	$327,411	$385,341	$423,291
TPY of NO_X Emissions Reduced, Uncontrolled	6.79	6.00	11.22	15.66	18.95	21.21	29.15	42.75	43.39	48.93	60.02	69.38
Uncontrolled Cost Per Ton	$15,804	$18,853	$11,622	$9,810	$8,799	$8,611	$7,714	$6,547	$6,879	$6,691	$6,420	$6,101
Average Cost Per Ton	$15,912	$15,933	$15,987	$16,062	$16,104	$16,155	$16,292	$16,470	$16,530	$16,624	$16,812	$16,999
TPY of NO_X Emissions Reduced, BAT	6.79	6.00	11.22	9.40	11.37	12.72	17.49	25.65	26.03	29.36	36.01	41.62
BAT Cost Per Ton	$15,804	$18,853	$11,622	$16,351	$14,665	$14,352	$12,858	$10,913	$11,466	$11,153	$10,701	$10,170
TPY of NO_X Emissions Reduced, Alternative BAT								15.39	15.62	17.62	21.61	24.98
Alternative Cost Per Ton								$18,184	$19,106	$18,585	$17,832	$16,946

For turbines rated at 5,000 hp and above with uncontrolled emissions of 25 ppm NO_X, SCR is cost effective. However, for turbines rated 5,000 hp and above but below 15,900 hp and operating at 15 ppm NO_X uncontrolled, SCR is not cost effective. Therefore, for turbines rated at or above 5,000 hp and below 15,900 hp, the Department proposes an emission limit of 15 ppm NO_X. For turbines rated at or above 15,900 hp, SCR is cost effective even when the uncontrolled emission rate is 15 ppm NO_X. However, a recently issued permit in New York establishes a NO_X emission limit of 9 ppm for two Solar Mars Turbines which, according to the Solar Turbines website, are rated at 15,900 bhp. A recent plan approval application to the Department also proposes 9 ppm NO_X for combustion turbines. Based on the availability of these low-emission models, the Department proposes an emission limit of 9 ppm NO_X uncontrolled or 1.5 ppm NO_X with control for turbines greater than 15,900 hp.

XXIV. Appendix C – Oxidation Catalyst and NSCR Cost Analysis for Engines and Turbines

Unlike the methodology used in Appendix B – SCR Cost Analysis for Engines and Turbines for SCR, the Department relied on a memorandum from E $^{C}/_{R}$ Incorporated dated June 29, 2010, to Melanie King at EPA OAQPS/SPPD/ESG for engine emission control devices. The memorandum determined a linear equation for total annual cost for oxidation catalysts for lean-burn engines. The Department then calculated the cost per ton based on weighted average emission rates and on BAT emission rates.

Table 26 - Oxidation Catalyst Cost Analysis for Lean-Burn Engines - Weighted Average Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,370	2,500	3,500	4,735	5,500
Total Annual Costs	$4,058	$4,362	$4,869	$5,882	$6,653	$6,896	$7,656	$8,660	$8,923	$10,950	$13,454	$15,005
TPY of CO Emissions Reduced	5.82	14.54	8.68	17.37	23.96	26.05	34.19	43.21	45.58	63.82	86.34	100.29
TPY of NMNEHC Emissions Reduced	0.29	0.72	1.21	2.41	3.33	3.62	7.24	9.15	9.65	13.51	18.27	21.22
Cost Per Ton	$664	$286	$492	$297	$244	$232	$185	$165	$162	$142	$129	$123

Table 27 - Oxidation Cost Analysis for Lean-Burn Engines - BAT Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	1,875	2,370	2,500	3,500	4,735	5,500
Total Annual Costs	$4,058	$4,362	$4,869	$5,882	$6,653	$6,896	$7,656	$8,660	$8,923	$10,950	$13,454	$15,005
TPY of CO Emissions Reduced	1.74	4.34	1.74	3.47	4.79	5.21	6.51	8.23	8.68	12.16	16.45	19.10
TPY of NMNEHC Emissions Reduced	0.34	0.84	0.60	1.21	1.66	1.81	2.26	2.86	3.01	4.22	5.71	6.63
Cost Per Ton	$1,956	$841	$2,081	$1,257	$1,030	$983	$873	$781	$763	$669	$607	$583

The same memorandum also determined a linear equation for the total annual cost for NSCR for rich-burn engines. As for lean-burn engines, the Department calculated the cost per ton for NSCR on rich-burn engines using the cost per ton based on weighted average emission rates and on BAT emission rates.

Table 28 - NSCR Cost Analysis for Rich-Burn Engines - Weighted Average Emissions

Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	2,500	3,500	4,735	5,500
Total Annual Costs	$6,895	$7,696	$9,032	$11,703	$13,733	$14,374	$19,716	$25,059	$31,657	$35,744
TPY of NO_X Emissions Reduced	14.57	36.43	70.57	141.14	194.78	211.72	352.86	494.00	668.32	776.29
TPY of CO Emissions Reduced	7.61	19.02	37.58	75.15	103.71	112.73	187.89	263.04	355.86	413.35
TPY of NMNEHC Emissions Reduced	0.14	0.36	0.72	1.45	2.00	2.17	3.62	5.06	6.85	7.96
Cost Per Ton	$309	$138	$83	$54	$46	$44	$36	$33	$31	$30

Table 29 - NSCR Cost Analysis for Rich-Burn Engines - BAT Emissions

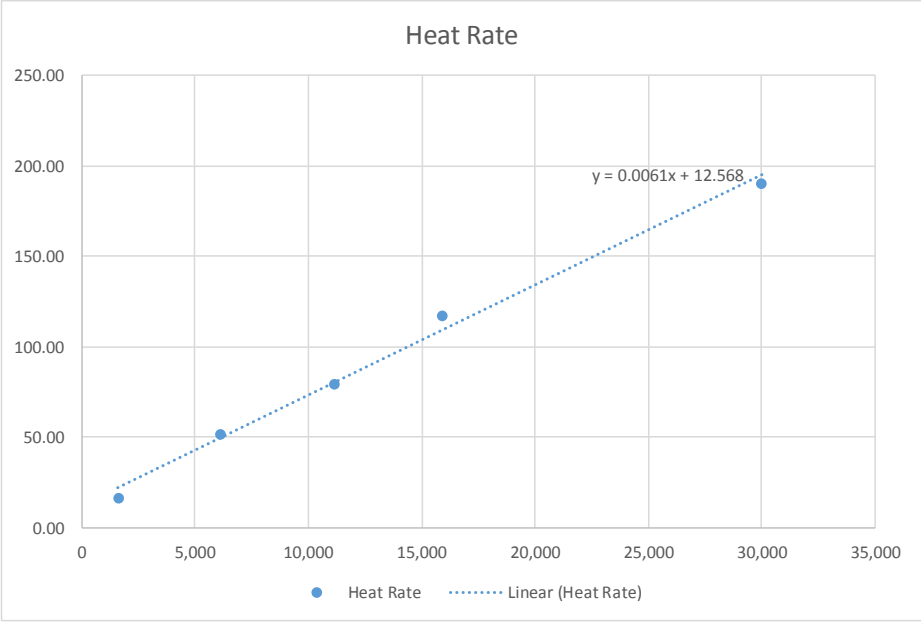
Engine HP (All dollar values in 2016 dollars)	100	250	500	1,000	1,380	1,500	2,500	3,500	4,735	5,500
Total Annual Costs	$6,895	$7,696	$9,032	$11,703	$13,733	$14,374	$19,716	$25,059	$31,657	$35,744
TPY of NO_X Emissions Reduced	0.23	0.57	0.92	1.83	2.53	2.75	4.58	6.42	8.68	10.08
TPY of CO Emissions Reduced	0.27	0.69	1.37	2.75	3.79	4.12	6.87	9.62	13.02	15.12
TPY of NMNEHC Emissions Reduced	0.10	0.24	0.48	0.96	1.33	1.45	2.41	3.38	4.57	5.31
Cost Per Ton	$11,480	$5,126	$3,256	$2,110	$1,794	$1,727	$1,422	$1,291	$1,205	$1,172

For lean-burn engines, using both the weighted average emissions and the BAT emissions, the cost effectiveness of control was less than the cost-effectiveness threshold of $5,000 per ton of pollutant reduced was shown for engines rated at 100 bhp and above. Therefore, the Department determines that oxidation catalysts are required for all lean-burn engines rated greater than or equal to 100 bhp.

For rich-burn engines, using the BAT emissions shows that NSCR is not cost effective below 250 hp; however, NSCR was previously established as BAT for rich-burn engines rated greater than or equal to 100 bhp. Therefore, the Department determines that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp.

Table 30 - Turbine Characteristics and Emissions Data

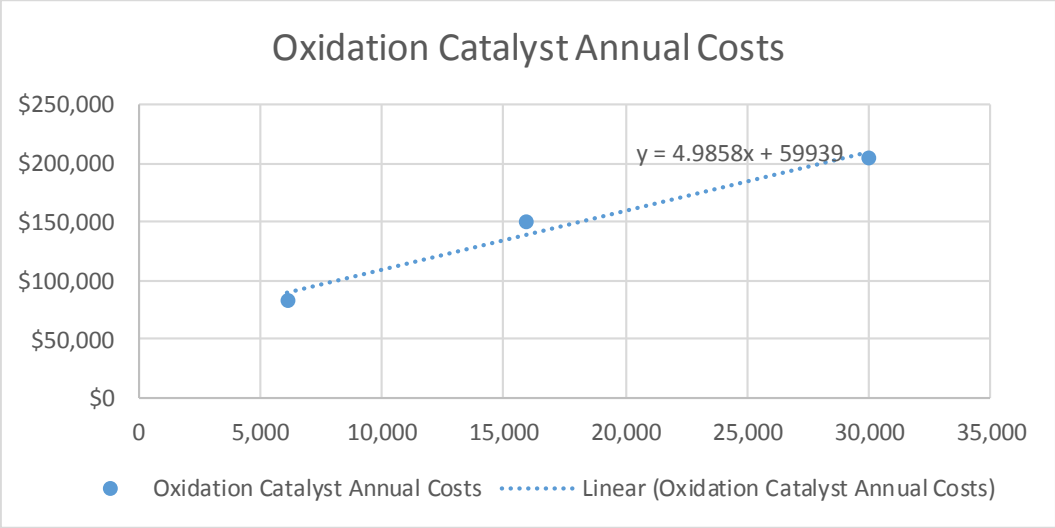
	Turbine A	Turbine B	Turbine C	Turbine D	Tubine E
Power (bhp)	1,590	6,130	11,150	15,900	30,000
Heat Rate (Btu/bhp-h)	10,370	8,500	7,190	7,395	6,360
Exhaust Flow (lb/h)	51,615	149,380	215,990	337,850	541,590
Exhaust Temperature (°F)	970	960	935	905	865
Heat Input (MMBtu/h)	16.49	52.11	80.17	117.58	190.80
Exhaust Flow (scfh)	720,747	2,085,927	3,016,063	4,717,703	7,562,708
Exhaust Flow (acfm)	32,411	93,145	132,308	202,505	315,113
NO_X Emission Rate (ppm)	2.50E-05	1.50E-05	1.50E-05	9.00E-06	9.00E-06
NO_X Emission Rate (lb/MMBtu)	0.09224	0.05534	0.05534	0.03321	0.03321
NO_X Emission Rate (tpy)	6.66	12.63	19.43	17.10	27.75
CO Emission Rate (ppm)	2.50E-05	2.50E-05	2.50E-05	1.00E-05	1.00E-05
CO Emission Rate (lb/MMBtu)	0.05607	0.05607	0.05607	0.02243	0.02243
CO Emission Rate (tpy)	4.05	12.80	19.69	11.55	18.74
NMNEHC Emission Rate (ppm)	9.00E-06	9.00E-06	9.00E-06	5.00E-06	5.00E-06
NMNEHC Emission Rate (lb/MMBtu)	0.03179	0.03179	0.03179	0.01766	0.01766
NMNEHC Emission Rate (tpy)	2.30	7.25	11.16	9.09	14.76



Unfortunately, a convenient analysis for oxidation catalysts for turbines was not found. Instead, the Department relied on vendor quotes and performed an analysis similar to the one for SCR in Appendix B – SCR Cost Analysis for Engines and Turbines. Three independent quotes were given for different sized turbines, and those formed the basis for the extrapolation of total annual costs for turbines of other sizes.

Table 31 - Oxidation Catalyst Cost Data for Turbines

(All dollar values in 2016 dollars)	6,130	15,900	30,000
Oxidation Catalyst Purchased Equipment Costs	$96,785	$205,918	$215,090
Direct Installation Costs (0.30PEC)	$29,035	$61,775	$64,527
Total Indirect Installation Costs (0.27PEC)	$26,132	$55,598	$58,074
Project Contingency (0.15(DIC+IIC))	$8,275	$17,606	$18,390
Total Capital Investment	$160,227	$340,897	$356,082
Operating and Supervisory Labor Costs	$18,889	$18,889	$18,889
Maintenance Cost	$2,904	$6,178	$6,453
Natural Gas Penalty	$12,553	$28,325	$45,964
Catalyst Disposal	$130	$338	$637
Annual Catalyst Replacement Cost	$14,204	$36,841	$69,512
Direct Annual Costs	$48,679	$90,570	$141,454
Indirect Annual Costs	$34,609	$60,854	$63,060
Total Annual Costs	$83,288	$151,424	$204,514



The uncontrolled emissions rates assume 25 ppm for CO and total hydrocarbons, which when adjusted to NMNEHC as propane becomes 9 ppm. The BAT emissions rates, in ppm, were taken from the previous GP-5. The values for CO and NMNEHC are used in the table below for the turbine oxidation catalyst cost analysis.

Table 32 – Oxidation Catalyst Cost Analysis for Turbines - Uncontrolled Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Total Annual Costs	$64,925	$67,866	$74,896	$84,868	$83,288	$97,333	$115,531	$151,424	$147,191	$159,655	$184,584	$204,514
TPY of CO Emissions Reduced	4.26	3.77	7.05	9.84	11.90	13.32	18.31	26.85	27.25	30.73	37.70	43.58
TPY of NMNEHC Emissions Reduced	1.30	1.15	2.15	3.00	3.63	4.06	5.58	8.19	8.31	9.37	11.49	13.62
Cost Per Ton	$11,670	$13,810	$8,142	$6,612	$5,363	$5,600	$4,836	$4,321	$4,139	$3,981	$3,752	$3,576

Table 33 - Oxidation Catalyst Cost Analysis for Turbines - BAT Emissions

Turbine HP (All dollar values in 2016 dollars)	1,000	1,590	3,000	5,000	6,130	7,500	11,150	15,900	17,500	20,000	25,000	30,000
Total Annual Costs	$64,925	$67,866	$74,896	$84,868	$83,288	$97,333	$115,531	$151,424	$147,191	$159,655	$184,584	$204,514
TPY of CO Emissions Reduced	4.26	3.77	7.05	9.84	11.90	13.32	18.31	10.74	10.90	12.29	15.08	17.43
TPY of NMNEHC Emissions Reduced	1.30	1.15	2.15	3.00	3.63	4.06	5.58	4.55	4.61	5.20	6.38	7.38
Cost Per Ton	$11,670	$13,810	$8,142	$6,612	$5,363	$5,600	$4,836	$9,903	$9,486	$9,123	$8,599	$8,243
TPY of CO Emissions Reduced, Alternative BAT				3.93	4.76	5.33	7.32					
TPY of NMNEHC Emissions Reduced, Alternative BAT				1.67	2.02	2.26	3.10					
Cost Per Ton				$15,153	$12,291	$12,834	$11,082					

As can be seen in Table 32 and Table 33 above, oxidation catalysts for turbines greater than or equal to 1,000 hp but less than 5,000 hp are not cost-effective; for turbines greater than or equal to 5,000 hp, oxidation catalysts are cost-effective based on a cost-effectiveness threshold of $5,000 per ton of pollutant reduced. It is important to point out that for turbines less than 15,000 hp, the uncontrolled emissions and the BAT emissions are identical, with identical results.

For turbines greater than or equal to 15,900 hp, oxidation catalysts are cost-effective if one considers the uncontrolled emission rates of 25 ppm CO and 9 ppm NMNEHC as propane as a baseline. However, if one considers the alternative BAT emissions rate established in the previous GP-5 of 10 ppm CO and 5 ppm NMNEHC, oxidation catalysts are not cost-effective. Oxidation catalysts are also cost prohibitive for turbines rated greater than or equal to 5,000 hp but less than 15,900 hp with uncontrolled emissions rates of 10 ppm CO and 5 ppm NMNEHC, which is achievable according to stack test data. Therefore, it is the Department's determination that turbines greater than or equal to 5,000 hp but less than 15,900 hp have BAT criteria of 10 ppm CO and 5 ppm NMNEHC and that turbines greater than or equal to 15,900 hp have dual BAT criteria with BAT of 10 ppm CO uncontrolled and 1.75 ppm CO with control and 5 ppm NMNEHC.

XXV. Appendix D – Cost Analysis for Combustion Control Devices

Table 34 - Combustion Control Device Cost Analysis

(All dollar values in 2016 dollars)	Vendor A	Sensitivity Analysis			
Combustor	$19,186				
Auto Ignitor	$1,740				
Surveilannce System	$4,176				
Total Purchased Equipment Cost	$25,102				
Freight and Design	$1,740				
Installation	$7,371				
Total Capital Investment	$34,213	$40,000	$50,000	$75,000	$100,000
Pilot Fuel	$2,201	$2,573	$3,216	$4,824	$6,432
Maintenance Cost	$2,320	$2,712	$3,391	$5,086	$6,781
Data Management	$1,160	$1,356	$1,695	$2,543	$3,391
Direct Annual Costs	$5,681	$6,641	$8,302	$12,453	$16,603
Indirect Annual Costs	$3,756	$4,392	$5,490	$8,235	$10,979
Total Annual Costs (7% Intrest, 15 Year Life)	$9,437	$11,033	$13,791	$20,687	$27,583
TPY of Methane	200.00	200.00	200.00	200.00	200.00
TPY of VOC	2.70	2.70	2.70	2.70	2.70
TPY of HAP	1.00	1.00	1.00	1.00	1.00
Cost Per Ton (95% Reduction)	$49	$57	$71	$107	$143
Cost Per Ton (95% Reduction, Excluding Methane)	$2,685	$3,139	$3,924	$5,885	$7,847
Cost Per Ton (98% Reduction)	$47	$55	$69	$104	$138
Cost Per Ton (98% Reduction, Excluding Methane)	$2,603	$3,043	$3,803	$5,705	$7,607

As can be seen from the table above, it is cost effective for a combustion control device that controls methane, VOC, and HAP based on the vendor quote and assuming an emission rate at the control threshold. In the sensitivity analysis, it is assumed that the annual costs scale relative to the increased total capital investment. If the cost-effectiveness threshold including methane is considered, it is cost-effective to install a combustion control device with a total capital investment of $100,000 (and arguably much more) because it is much less than the $1,000 per ton of pollutant reduced. If the cost-effectiveness threshold excluding methane is considered, combustion control devices are cost-effective up to a total capital investment of $75,000 because it is close to the $5,000 per ton of pollutant reduced.

Many commentators provided additional information on combustion control devices capabilities and cost, and so the Department conducted another cost analysis based on the new information. One aspect the Department explored was the effect of gas composition on the number of hours of operation an enclosed flare of the given characteristics would take to reach the proposed control thresholds. As seen in Table 35 below, the time varies for each pollutant, and establishes a range of operating hours. In Table 36 below, the emissions calculations were done based on the gas composition and the minimum and maximum operating hours calculated in Table 35.

Table 35 - Operating Hours to Reach Control Thresholds

Gas Composition Analysis	Original TSD Average Gas Composition	TSD Reanalysis Average Gas Composition	Rich Gas - Washington County Average	Dry Gas - Susquehanna County Average
Methane (vol%)			82.6%	97.4%
Methane (wt%)	88.8%	86.0%	67.3%	95.1%
VOC (vol%)			5.65%	0.08%
VOC (wt% as propane)	1.3%	4.5%	12.7%	0.2%
HAP (vol%)			0.0024%	0.0000%
HAP (wt% as hexane)	0.0500%	0.0000%	0.0105%	0.0000%
Total Weight of Gas (lb/cf gas)	0.0453	0.0442	0.0501	0.0418
Enclosed Flare Statistics				
Gas Throughput (lb/h)	4,800	4,800	4,800	4,800
Gas Throughput (Mcf/h)	106	109	96	115
Number of Pilots	3	3	3	3
Pilot Fuel Consumption (cf/h)	65	65	65	65
Annual Pilot Fuel Consumption (Mcf/yr)	1,708	1,708	1,708	1,708
Natural Gas Price ($/Mcf)	$2.50	$2.50	$2.50	$2.50
Power Consumption (kWh/yr)	616	616	616	616
Electricity Price ($/kWh)	$0.07	$0.07	$0.07	$0.07
Control Efficiency	95%	95%	95%	95%
Operational Assumptions				
Estimated Hours to Reach Control Threshold for Methane	94	97	124	88
Estimated Hours to Reach Control Threshold for VOC	90	25	9	524
Estimated Hours to Reach Control Threshold for Single HAP	417	-	1,983	-
Estimated Hours to Reach Control Threshold for Total HAP	833	-	3,967	-
Minimum Estimated Hours of Operation	90	25	9	88
Maximum Estimated Hours of Operation	833	97	3,967	524

Table 36 - Cost Sensitivity to Gas Composition and Hours of Operation

Gas Composition Analysis	Original TSD Average Gas Composition	TSD Reanalysis Average Gas Composition	Rich Gas - Washington County Average	Dry Gas - Susquehanna County Average
Maximum Emission Reductions				
Methane Reduced (tpy)	1,687	190	6,083	1,136
VOC Reduced (tpy)	23.75	9.87	1,144.39	2.57
Total HAP Reduced (tpy)	0.95	0.00	0.95	0.00
Minimum Emission Reductions				
Methane Reduced (tpy)	182	49	14	190
VOC Reduced (tpy)	2.57	2.57	2.57	0.43
Total HAP Reduced (tpy)	0.10	0.00	0.00	0.00
Emission Reductions from Control Thresholds				
Methane Reduced (tpy)	190	190	190	190
VOC Reduced (tpy)	2.57	2.57	2.57	2.57
Single HAP Reduced (tpy)	0.48	0.48	0.48	0.48
Total HAP Reduced (tpy)	0.95	0.95	0.95	0.95
Dollars Per Ton of Methane Reduced ($/ton)	$581	$581	$581	$581
Dollars Per Ton of VOC Reduced ($/ton)	$43,047	$43,047	$43,047	$43,047
Dollars Per Ton of Single HAP Reduced ($/ton)	$232,453	$232,453	$232,453	$232,453
Dollars Per Ton of Total HAP Reduced ($/ton)	$116,226	$116,226	$116,226	$116,226
Dollars Per Ton of All Pollutants Reduced Maximum ($/ton)	$65	$552	$15	$97
Dollars Per Ton of All Pollutants Reduced Minimum ($/ton)	$598	$2,126	$6,816	$580

The cost effectiveness for all pollutants at both the minimum and maximum hours of operation show that regardless of gas composition, an enclosed combustion device is economically feasible for the control of methane, VOC, and HAP.

Another commentator pointed out that control devices need to be sized for the worst-case scenario, which drives up the cost of the system based on the maximum gas flow to the control. The commentator provided operational data, summarized in Table 37 below, that gives both volume flow rates and mass flow rates as well as hours of operation.

Table 37 - Gas Flow Rates and Annual Hours of Operation

	Purge Gas	Closed Drain Vapors	Pigging Vapors (30" Receiver)	Pigging Vapors (12" C3+ Launcher)	Amine Unit Flash Gas	Total Maximum Flow Rate		Total Minimum Flow Rate	
						scfh	Mscfd	scfh	Mscfd
Volume Flow Rate (scfh)	434	26	120,000	48,135	2,154	170,749	4,098	2,588	62
Volume Flow Rate %	0.25%	0.02%	70.28%	28.19%	1.26%				
Mass Rate (lb/h)	18.68	1.43	6,723.53	6,885.81	177.91	13,807		197	
Annual Hours of Operation	8,760	2,190	12	1	8,760				

Another consideration is the effect of the previously calculated methane control threshold versus the newly calculated methane control threshold; as seen in Table 38 below, there is a significant increase in the cost per ton of methane reduced, as well as the cost per ton of all pollutants reduced. Cost-effectiveness on the basis of methane alone at 51.9 tpy is significantly beyond EPA's threshold of approximately $1,000 per ton of methane reduced;

Table 38 - Cost-Effectiveness of Proposed vs. Recalculated Control Thresholds for Enclosed Combustion Devices

(All dollar values in 2016 dollars)	MSC Enclosed Oxidizer @ 250 Mscfd CH_4	MSC Enclosed Oxidizer @ 250 Mscfd CH_4	Vendor D Enclosed Flare @ 2,606 Mscfd	Vendor D Enclosed Flare @ 2,606 Mscfd	Vendor D Enclosed Flare @ 26,064 Mscfd	Vendor D Enclosed Flare @ 26,064 Mscfd
Total Annual Costs	$68,059	$68,059	$110,415	$110,415	$445,745	$445,745
TPY of CH_4 Emissions Reduced	190.00	49.31	190.00	49.31	190.00	49.31
Cost Per Ton	$358	$1,380	$581	$2,239	$2,346	$9,041
TPY of VOC Emissions Reduced	2.57	2.57	2.57	2.57	2.57	2.57
Cost Per Ton	$26,534	$26,534	$43,047	$43,047	$173,780	$173,780
TPY of HAP Emissions Reduced	0.95	0.95	0.95	0.95	0.95	0.95
Cost Per Ton	$71,641	$71,641	$116,226	$116,226	$469,206	$469,206
TPY of All Pollutants Emissions Reduced	193.52	52.82	193.52	52.82	193.52	52.82
Cost Per Ton	$352	$1,289	$571	$2,090	$2,303	$8,439

ranging from $1,380 to $9,041 per ton of methane reduced. However, considering all pollutants, an enclosed combustion device is still cost effective based on the cost-effectiveness threshold of $5,000 per ton of pollutant reduced, ranging from $1,289 to $8,439 per ton of pollutant reduced. The Department must maintain, however, that the control threshold of 51.9 tpy is cost-prohibitive because for dry gas regions, methane is the likely trigger

for control, and as there are insignificant amounts of VOC and HAP in the gas stream, only the cost per ton of methane reduced should be considered for determining the cost-effectiveness. Performing a linear interpolation between the 51.2 tpy control threshold and the 200 tpy control threshold for the 2,606 Mscfd enclosed flare, the $1,000 per ton of methane reduced threshold is approximately 163 tpy methane. This would provide a range from $441 to $2,886 per ton of methane reduced. However, the Department determines that BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). One reason for conservatively establishing the methane control threshold at 200 tpy instead of 163 tpy is due to the inherent scientific uncertainty in the second analysis control threshold calculation discussed in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices.

For the primary BAT analysis, the Department determined the total annual flow through the enclosed flare based on the operational information from Table 37 and the average natural gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis. Where the flow was given as a volume of methane, the Department used the methane density of 0.0416 lb/scf and the average gas composition density of 0.0442 lb/scf to determine the adjusted flow rate. For Vendor D, the flow was given in lb/h; the Department used the average gas composition density to determine the volume flow. The Department used EPA's Air Pollution Control Cost Manual to determine the total capital investment and total annual costs based on the purchased equipment prices provided by the commentators. The results can be seen in Table 39 below.

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Table 39 - BAT Analysis for Enclosed Flare

(All dollar values in 2016 dollars)	MSC Enclosed Oxidizer @ 20 Mscfd CH_4	MSC Enclosed Oxidizer @ 50 Mscfd CH_4	MSC Enclosed Oxidizer @ 100 Mscfd CH_4	MSC Enclosed Oxidizer @ 250 Mscfd CH_4	MSC Enclosed Oxidizer @ 500 Mscfd CH_4	MSC Enclosed Oxidizer @ 1,000 Mscfd CH_4	Vendor D Enclosed Flare @ 2,606 Mscfd	MSC Enclosed Oxidizer @ 3,000 Mscfd CH_4	MSC Enclosed Oxidizer @ 5,000 Mscfd CH_4	Vendor D Enclosed Flare @ 26,064 Mscfd
Control Flow Rate (Mscfh)	0.88	2.21	4.43	11.07	22.13	44.27	108.60	132.81	221.35	1,085.97
Control Equipment Costs	$50,500	$90,900	$111,100	$146,450	$212,100	$373,700	$300,000	$479,750	$757,500	$1,500,000
Instrumentation	$5,050	$9,090	$11,110	$14,645	$21,210	$37,370	$30,000	$47,975	$75,750	$150,000
Freight	$2,778	$5,000	$6,111	$8,055	$11,666	$20,554	$16,500	$26,386	$41,663	$82,500
Total Purchased Equipment Costs	$58,328	$104,990	$128,321	$169,150	$244,976	$431,624	$346,500	$554,111	$874,913	$1,732,500
Total Direct Installation Costs	$91,574	$164,834	$201,463	$265,565	$384,612	$677,649	$544,005	$869,955	$1,373,613	$2,720,025
Total Indirect Installation Costs	$20,415	$36,746	$44,912	$59,202	$85,741	$151,068	$121,275	$193,939	$306,219	$606,375
Total Capital Investment	$111,989	$201,580	$246,375	$324,768	$470,353	$828,717	$665,280	$1,063,894	$1,679,832	$3,326,400
Operating and Supervisory Labor Costs	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009	$5,009
Maintenance Cost	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583	$9,583
Pilot Gas Cost	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$4,271	$8,541
Annual Electricity Cost	$43	$43	$43	$43	$43	$43	$43	$43	$43	$86
Direct Annual Costs	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$18,906	$23,219
Overhead	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755	$8,755
Administrative Charges	$2,240	$4,032	$4,928	$6,495	$9,407	$16,574	$13,306	$21,278	$33,597	$66,528
Insurance	$1,120	$2,016	$2,464	$3,248	$4,704	$8,287	$6,653	$10,639	$16,798	$33,264
Capital Recovery	$10,571	$19,027	$23,255	$30,655	$44,397	$78,223	$62,796	$100,421	$158,559	$313,979
Indirect Annual Costs	$22,685	$33,830	$39,402	$49,153	$67,262	$111,839	$91,509	$141,093	$217,710	$422,526
Total Annual Costs	$41,591	$52,735	$58,307	$68,059	$86,168	$130,745	$110,415	$159,999	$236,615	$445,745
Total Annual Gas Flow (TPY)	2.76	6.91	13.85	34.60	69.18	138.38	339.43	415.12	691.85	3,394.31
TPY of CH_4 Emissions Reduced	2.25	5.65	11.32	28.28	56.54	113.10	277.41	339.27	565.44	2,774.12
Cost Per Ton	$18,462	$9,341	$5,152	$2,406	$1,524	$1,156	$398	$472	$418	$161
TPY of VOC Emissions Reduced	0.12	0.29	0.59	1.47	2.94	5.88	14.41	17.63	29.38	144.14
Cost Per Ton	$355,329	$179,782	$99,151	$46,315	$29,334	$22,249	$7,660	$9,076	$8,054	$3,092
TPY of HAP Emissions Reduced	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03
Cost Per Ton	$1,579,159,879	$798,991,326	$440,647,863	$205,835,023	$130,364,846	$98,879,212	$34,044,084	$40,337,559	$35,792,683	$13,743,595
TPY of All Pollutants Emissions Reduced	2.37	5.94	11.91	29.75	59.47	118.98	291.83	356.90	594.83	2,918.29
Cost Per Ton	$17,550	$8,880	$4,897	$2,288	$1,449	$1,099	$378	$448	$398	$153

Table 40 – Cost-Effectiveness of Proposed vs. Recalculated Control Thresholds for Open Flares

(All dollar values in 2016 dollars)	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 26,064 Mscfd	Vendor D Open Flare @ 26,064 Mscfd
Total Annual Costs	$38,563	$38,563	$53,779	$53,779
TPY of CH_4 Emissions Reduced	190.00	49.31	190.00	49.31
Cost Per Ton	$203	$782	$283	$1,091
TPY of VOC Emissions Reduced	2.57	2.57	2.57	2.57
Cost Per Ton	$15,034	$15,034	$20,966	$20,966
TPY of HAP Emissions Reduced	0.95	0.95	0.95	0.95
Cost Per Ton	$40,593	$40,593	$56,609	$56,609
TPY of All Pollutants Emissions Reduced	193.52	52.82	193.52	52.82
Cost Per Ton	$199	$730	$278	$1,018

As can be seen in Table 40, open flares are less expensive and have lower annual operating costs than enclosed flares, ranging from $203 to $283 per ton of methane reduced for the 200 tpy methane control threshold. At the recalculated 51.9 tpy methane control threshold, the costs range from $782 to $1,091 per ton of methane reduced which just meets EPA's Social Cost of Methane. However, the Department determines that BAT control measures for methane must be implemented for sources with emissions that meet or exceed 200 tpy methane; this requirement is also included in the exemption criteria for facilities seeking exemption under Category 38(c). One reason for conservatively establishing the methane control threshold at 200 tpy instead of 51.9 tpy is due to the inherent scientific uncertainty in the second analysis control threshold calculation discussed in Appendix A – Average Gas Composition Analysis and the site-specific uncertainty in the control costs from Appendix D – Cost Analysis for Combustion Control Devices.

For the primary BAT analysis, the Department determined the total annual flow through the open flare based on the operational information from Table 37 and the average natural gas composition as determined in Table 16 of Appendix A – Average Gas Composition Analysis. Where the flow was given as a volume of methane, the Department used the methane density of 0.0416 lb/scf and the average gas composition density of 0.0442 lb/scf to determine the adjusted flow rate. For Vendor D, the flow was given in lb/h; the Department used the average gas composition density to determine the volume flow. The Department used EPA's Air Pollution Control Cost Manual to determine the total capital investment and total annual costs based on the purchased equipment prices provided by the commentators. The results can be seen in Table 41 below.

Open flares are only authorized to be used at remote facilities and with infrequent operations.

Table 41 - BAT Analysis for Open Flare

(All dollar values in 2016 dollars)	Vendor D Open Flare @ 2,606 Mscfd	Vendor D Open Flare @ 26,064 Mscfd
Control Flow Rate (Mscfh)	108.60	1,085.97
Control Equipment Costs	$50,000	$100,000
Instrumentation	$5,000	$10,000
Freight	$2,750	$5,500
Total Purchased Equipment Costs	$57,750	$115,500
Total Direct Installation Costs	$90,668	$181,335
Total Indirect Installation Costs	$20,213	$40,425
Total Capital Investment	$110,880	$221,760
Operating and Supervisory Labor Costs	$5,009	$5,009
Maintenance Cost	$9,583	$9,583
Pilot Gas Cost	$1,424	$2,847
Annual Electricity Cost	$0	$0
Direct Annual Costs	$16,016	$17,439
Overhead	$8,755	$8,755
Administrative Charges	$2,218	$4,435
Insurance	$1,109	$2,218
Capital Recovery	$10,466	$20,932
Indirect Annual Costs	$22,548	$36,340
Total Annual Costs	$38,563	$53,779
Total Annual Gas Flow (TPY)	339.43	3,394.31
TPY of CH_4 Emissions Reduced	277.41	2,774.12
Cost Per Ton	$139	$19
TPY of VOC Emissions Reduced	14.41	144.14
Cost Per Ton	$2,675	$373
TPY of HAP Emissions Reduced	0.00	0.03
Cost Per Ton	$11,890,087	$1,658,157
TPY of All Pollutants Emissions Reduced	291.83	2,918.29
Cost Per Ton	$132	$18

XXVI. Appendix E – LDAR Cost Analysis

ICF has conducted two analyses on LDAR, one for the Environmental Defense Fund (EDF) in March of 2014[28] and one for ONE Future Inc. in May of 2016[29]. In both analyses, they broke down the costs associated with an LDAR program into an hourly cost number. This was an adaptation of the analysis used by Colorado in their rulemaking. In the March 2014 analysis, the determination was that the total cost as an hourly rate was $101.64 and that inspections would be performed on a quarterly basis. This resulted in an LDAR cost that ranged between $2.15 and $7.60 per Mcf of methane reduced, which approximates to between $95 and $336 per ton of methane reduced, when not counting the recovered gas value. In the May 2016 analysis, the determination was that the total cost as an hourly rate was $142.06 and that inspections would be performed annually. This resulted in an LDAR cost that ranged between $1.41 and $6.94 per Mcf of methane reduced, which approximates to between $62 and $306 per ton of methane, when not counting the recovered gas value.

The Department conducted two independent LDAR cost analyses, the first using the ICF analyses as a basis and a second based on two vendors' quotes. The Department's assumptions in the first analysis included a semi-annual and quarterly survey interval for unconventional natural gas well sites and a quarterly survey interval for natural gas compression stations, processing plants, and transmission stations. The semi-annual frequency is assumed to result in a 50% emissions reduction and the quarterly frequency is assumed to result in a 60% emissions reduction. The Department favored the ONE Future Equipment Costs as the basis of the cost analysis as it includes a high-flow system for leak quantification in the analysis.

Table 42 and Table 43 below represent the Department's assumptions on frequency with the respective assumptions on emissions and hours for each survey from the two ICF analyses.

Table 42 - LDAR Costs with ONE Future Equipment Costs and EDF Assumptions

	Wellpads	Wellpads	Gathering	Processing	Transmission
Methane (Mcf/yr)	440	440	1,676	2,448	4,671
% Reduction	50%	60%	60%	60%	60%
Reduction (Mcf)	220	264	1,006	1,469	2,803
Hours each Inspection	2.7	2.7	8.0	8.0	8.0
Frequency per Year	2	4	4	4	4
Annual Inspection Cost	$767	$1,534	$4,546	$4,546	$4,546
Initial Set-Up	$77	$153	$455	$455	$455
Repair Labor Cost	$575	$1,151	$3,409	$3,409	$3,409
Total Cost per Year	$1,419	$2,838	$8,410	$8,410	$8,410
Cost of Reduction ($/Mcf)	$6.45	$10.75	$8.36	$5.73	$3.00
Cost of Reduction ($/ton)	$309.39	$515.65	$401.11	$274.62	$143.92

[28] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, ICF International on behalf of the Environmental Defense Fund, March 2014.
[29] Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems, ICF International on behalf of ONE Future Inc., May 2016.

Table 43 - LDAR Costs with ONE Future Equipment Costs and Assumptions

	Wellpads	Wellpads	Gathering	Processing	Transmission
Methane (Mcf/yr)	3,057	3,057	3,605	5,986	3,605
% Reduction	50%	60%	60%	60%	60%
Reduction (Mcf)	1,529	1,834	2,163	3,592	2,163
Hours each Inspection	5.5	5.5	32.0	40.0	32.0
Frequency per Year	2	4	4	4	4
Annual Inspection Cost	$1,563	$3,125	$18,184	$22,730	$18,184
Initial Set-Up	$156	$313	$1,818	$2,273	$1,818
Repair Labor Cost	$1,172	$2,344	$13,638	$17,047	$13,638
Total Cost per Year	$2,891	$5,782	$33,640	$42,050	$33,640
Cost of Reduction ($/Mcf)	$1.89	$3.15	$15.55	$11.71	$15.55
Cost of Reduction ($/ton)	$90.71	$151.19	$745.92	$561.53	$745.92

As can be seen in the tables, the cost of reduction in both cases is well within the cost-effective range of $1,000 per ton of methane reduced.

A. The Department's Independent LDAR Cost Analysis

Since the number of leaking components, amount of leakage from individual components, duration, and frequency is uncertain at an individual facility, it is impractical to perform a generic cost-analysis for LDAR requirements for static and rotating components (flanges, valves, joints, packing of compressor rods, etc.) at well sites, natural gas compression, processing or transmission facilities.

However, the Department contacted representatives of two companies that offer services for LDAR for the sources at well sites, and natural gas compression, processing or transmission facilities, to determine the estimated costs for leak detection, quantification, and repair tasks. Neither company offered quotes for repair costs since the costs for repairs vary significantly, depending on which components are leaking and what type of maintenance is required to repair the leaks. Therefore, the analysis is based only on the quoted costs for methane gas leak detections and quantifications.

According to the representative of the first company, a dry natural gas well pad contains approximately 1,000 components. Wet gas well pads, and compression, processing, or transmission facilities contain approximately 2,000 components. Typically, it takes one person and one day (10 hours) to complete the leak detection task using an OGI camera for a dry gas well pad. It takes one person two days to complete the leak detection using an OGI camera for a wet gas well pad, or natural gas compression, processing, or transmission station. The company charges $75 per hour for manpower, $400 per day for travel costs, $150 per day for camera rental, and $300 per day for gas leak detection device rental.

The company charges the same amount for labor for leak quantification, and assuming all components are leaking it takes two people three days to quantify leaks from all 1,000 components at a dry gas well pad, and two people six days to quantify leaks from all 2,000 components at a wet gas well pad, or natural gas compression, processing, or transmission facility. This yields a labor rate of 0.06 man-hours per component that is leaking, and in the analysis the Department will round up to the nearest full day.

The Department also contacted representatives of the second company to determine their costs for LDAR services, and they echoed the cost that was suggested by the first company. According to the company representatives, typically it costs $750 - $1,500 for any well pad or natural gas compression station for leak detection and quantification.

Based on the above information, the Department performed cost-effectiveness analysis for leak detection and quantification requirements stated for sources located at well pads, and natural gas compression, processing, or transmission facilities. The costs for leak detection were assumed to be at the full quoted cost and the costs for leak quantification were based on the amount of time to survey 1%, 2%, and 3% of the components rounded up to the nearest full day for sources at dry gas well pads, wet gas well pads, and natural gas compression, processing, and transmission facilities.

According to Method 21, the detector must have a sampling rate between $3.53x10^{-3}$ and 0.11 cf/min. At the maximum sampling rate, a 500 ppm indication on a Method 21 detector would be approximately equivalent to a 0.08 cf/day emission rate for a component if it is assumed that 100% of the leak is captured. For leaks above 500 ppm, it is less likely that 100% of the leak is captured, but for purposes of this analysis, it is assumed the detector does capture all of the emissions up to the 100,000 ppm level for a calculated leak rate of 15.84 cf/day. For any leak above 100,000 ppm on a Method 21 device, a high-flow sampler must be used for quantification. A high-flow device has a sampling rate of 10 cf/min and can detect leaks between 0.05 cf/min and 8.00 cf/min. This results in leak emission rates of 72.00 cf/day and 11,520 cf/day, respectively.

Based on the several leak studies, one vendor informed the Department that the majority of leak emissions come from a small percentage of "super-emitters." The Department assumes the "super-emitters" emit at the 11,520.00 cf/day rate and the total daily emission rate is based on the equation:

$$E = \frac{(P_{SE})(C_l)\left(11{,}520\ \frac{cf}{day}\right)}{(P_E)}$$

Where:

E = Total Daily Emission Rate
P_{SE} = Percentage of "Super-Emitters"
C_l = Number of Leaking Components
P_E = Percentage of Total Emissions Attributed to "Super-Emitters"

The following table outlines the calculated total daily emission rate for 1% of the total components at a dry gas well site found leaking.

Table 44 - Super-Emitter Study Data and LDAR Costs[30]

Study Author	Percent	Percent of Total Emissions	Calculated Total Daily Emission Rate	Annual Emissions	Annual Avoided Emissions	Cost per Ton of Methane Reduced
	"Super-Emitters"	(P_E)	(E)	(Mcf/y)	(TPY)	($/ton)
	(P_{SE})		(cf/day)			
Brandt, et. al.	5.00%	50%	11,520.00	4,204.80	52.6	$228.13
Rella, et. al.	6.60%	50%	15,206.40	5,550.30	69.4	$172.82
	22%	80%	9,642.60	3,519.50	44	$272.54
Clearstone Engineering	0.06%	58%	119.2	43.5	0.5	$22,047.27
British Columbia Oil & Gas	6.00%	80%	8,640.00	3,153.60	39.5	$304.17

The ONE Future emissions estimate from well sites is 3,057 Mcf/y, and the EDF emission estimate from well sites is 440 Mcf/y. Assuming the Department's costs and that the emissions estimates are from 1% of the total components, this results in costs of $313.78 per ton of methane reduced and $2,180.07 per ton of methane reduced, respectively. The British Columbia Oil & Gas and the Rella, *et al.* top 22% of leaks responsible for 80% of total emissions estimates are in line with ONE Future's emissions estimates from well sites.

Brandt, *et al.* and the Rella, *et al.* top 6.6% responsible for 50% of total emissions estimates are nearly 80% higher than ONE Future's emissions estimates. This serves to drive down the cost per ton of methane reduced. The Clearstone Engineering emissions estimate is approximately 1.5% of the ONE Future emission estimate, which serves to significantly drive up the cost per ton of methane reduced. The Department therefore focused on the British Columbia and Rella, *et al.* 22% cases in the cost analysis.

Based on our independent analysis, the Department determines that quarterly LDAR is technically and economically feasible for the control of methane emissions. The Department preserves the off-ramp originally proposed if less than 2% of components are found to be leaking in two consecutive inspections to help small businesses that operate effectively to reduce the frequency of inspections, and thereby reduce costs.

[30] The second line under Rella, et. al. is calculated assuming that 6.6% emit at the 11,520 cf/day rate and the remaining 15.4% emit at the 72.0 cf/day rate.

Table 45 - LDAR Costs from Vendor Quotes

TOTAL ANNUAL COST FOR LEAK DETECTION										
Facility	**~No. of Components**	**Leak Detection Duration (Days)**	**Labor Cost Per Man-Hour**	**Number of Hours/Day**	**Manpower**	**Travel Cost ($400/Day-Man)**	**Equipment Rental (OGI) ($150/Day-Man)**	**Contingency ($200/Day-Man)**	**Frequency per Year**	**Annual Cost for Leak Detection**
Wellpad (Dry Gas)	1,000	1	$75	10	1	$400	$150	$200	4	$6,000
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	2,000	2	$75	10	1	$800	$300	$400	4	$12,000

TOTAL ANNUAL COST FOR LEAK QUANTIFICATION											
Facility	**Percent Leaking Components**	**~No. of Components Leaking**	**Leak Quantification Duration (Days)**	**Labor Cost Per Man-Hour**	**Number of Hours/Day**	**Manpower**	**Travel Cost ($400/Day-Man)**	**Equipment Rental (Method 21) ($150/Day-Man)**	**Contingency ($200/Day-Man)**	**Frequency per Year**	**Annual Cost for Leak Quantification**
Wellpad (Dry Gas)	1.0%	10	1	$75	10	1	$400	$150	$200	4	$6,000
	2.0%	20	1	$75	10	1	$400	$150	$200	4	$6,000
	3.0%	30	1	$75	10	1	$400	$150	$200	4	$6,000
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	1.0%	20	1	$75	10	1	$400	$150	$200	4	$6,000
	2.0%	40	1	$75	10	1	$400	$150	$200	4	$6,000
	3.0%	60	1	$75	10	1	$400	$150	$200	4	$6,000

Table 46 - LDAR Cost Analysis Based on Rella *et al.* and British Columbia Emissions Assumptions

TOTAL ANNUAL COST FOR LEAK DETECTION AND LEAK QUANTIFICATION												
Facility	**Percent Leaking Components**	**Total Annual Cost**	**Rella et. al.**					**British Columbia Oil and Gas**				
			Total Flow Rate (CF/Day)	**Undetected Annual PTE (CFY)**	**Avoided Emissions (CFY)**	**Mass of Avoided Emissions (TPY)**	**$/ton**	**Total Flow Rate (CF/Day)**	**Undetected Annual PTE (CFY)**	**Avoided Emissions (CFY)**	**Mass of Avoided Emissions (TPY)**	**$/ton**
Wellpad (Dry Gas)	1.0%	$12,000	9,643	3,519,549	2,111,729	44.03	$272.54	8,640	3,153,600	1,892,160	39.45	$304.17
	2.0%	$12,000	19,285	7,039,098	4,223,459	88.06	$136.27	17,280	6,307,200	3,784,320	78.90	$152.09
	3.0%	$12,000	28,928	10,558,647	6,335,188	132.09	$90.85	25,920	9,460,800	5,676,480	118.35	$101.39
Wellpad (Wet Gas), Compressor Station, Processing Plant, or Transmission Station	1.0%	$18,000	19,285	7,039,098	4,223,459	88.06	$204.41	17,280	6,307,200	3,784,320	78.90	$228.13
	2.0%	$18,000	38,570	14,078,196	8,446,918	176.12	$102.20	34,560	12,614,400	7,568,640	157.81	$114.06
	3.0%	$18,000	57,856	21,117,294	12,670,376	264.18	$68.14	51,840	18,921,600	11,352,960	236.71	$76.04

B. The Department's Revised LDAR Cost Analysis

Based on comments received, the Department has performed a brief reanalysis of LDAR costs, which are summarized in Table 47 below. Even with a leak rate at 0.13% of production or throughput, the mass and volume of emissions are very high. The corresponding costs, which are based on the Annual Costs for Leak Detection in Table 45, the assumed leak rate, and the assumed production and throughput rates yield cost effectiveness numbers well below EPA's Social Cost of Methane. Based on our revised analysis, the Department determines that quarterly LDAR is technically and economically feasible for the control of methane emissions. The Department preserves the off-ramp originally proposed if less than 2% of components are found to be leaking in two consecutive inspections to help small businesses that operate effectively to reduce the frequency of inspections, and thereby reduce costs.

Table 47 - Revised LDAR Cost Analysis

TOTAL ANNUAL COST FOR LEAK DETECTION[1]						
Facility	**Total Annual Cost**	**Total Flow Rate (CF/Day)**	**Undetected Annual PTE (CFY)**	**Avoided Emissions (CFY)**	**Mass of Avoided Emissions (TPY)**	**$/ton**
Wellpad (Dry Gas)[2]	$6,000	13,000	4,745,000	2,847,000	59.36	$101.08
Wellpad (Wet Gas)[2]	$12,000	13,000	4,745,000	2,847,000	59.36	$202.16
Compressor Station, Processing Plant, or Transmission Station[3]	$12,000	910,000	332,150,000	199,290,000	4,155.20	$2.89

[1] The Annual Cost reflects only leak detection, as the leak quantification requirements were removed.

[2] The assumed production was 10 MMcf/d, with an assumed leak rate of 0.13% of production.

[3] The assumed throughput was 700 MMcf/d based on the previously referenced U.S. EIA report (see page 26), with an assumed leak rate of 0.13% of throughput.

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XXVII. Appendix F – Urbanized Areas and Urban Clusters from the 2010 Census

Albion, PA Urban Cluster (2010)
Allentown, PA--NJ Urbanized Area (2010)
Altoona, PA Urbanized Area (2010)
Ashland, PA Urban Cluster (2010)
Bedford, PA Urban Cluster (2010)
Bellefonte, PA Urban Cluster (2010)
Belvidere, NJ--PA Urban Cluster (2010)
Binghamton, NY--PA Urbanized Area (2010)
Blairsville, PA Urban Cluster (2010)
Bloomsburg--Berwick, PA Urbanized Area (2010)
Bonneauville, PA Urban Cluster (2010)
Bradford, PA--NY Urban Cluster (2010)
Brockway, PA Urban Cluster (2010)
Brookville, PA Urban Cluster (2010)
Burgettstown, PA Urban Cluster (2010)
Butler, PA Urban Cluster (2010)
Cambridge Springs, PA Urban Cluster (2010)
Chambersburg, PA Urbanized Area (2010)
Clarion, PA Urban Cluster (2010)
Cresson, PA Urban Cluster (2010)
Cumberland, MD--WV--PA Urbanized Area (2010)
East Liverpool, OH--WV--PA Urban Cluster (2010)
East Prospect, PA Urban Cluster (2010)
East Stroudsburg, PA--NJ Urbanized Area (2010)
Edinboro, PA Urban Cluster (2010)
Ellwood City, PA Urban Cluster (2010)
Emmitsburg, MD--PA Urban Cluster (2010)
Emporium, PA Urban Cluster (2010)
Erie, PA Urbanized Area (2010)
Everett, PA Urban Cluster (2010)
Fairdale, PA Urban Cluster (2010)
Franklin (Venango County), PA Urban Cluster (2010)
Greenville, PA Urban Cluster (2010)
Grove City, PA Urban Cluster (2010)
Hagerstown, MD--WV--PA Urbanized Area (2010)
Hanover, PA Urbanized Area (2010)
Harrisburg, PA Urbanized Area (2010)
Hazleton, PA Urbanized Area (2010)
Honesdale, PA Urban Cluster (2010)
Houtzdale, PA Urban Cluster (2010)
Huntingdon, PA Urban Cluster (2010)
Jersey Shore, PA Urban Cluster (2010)
Jim Thorpe, PA Urban Cluster (2010)
Johnstown, PA Urbanized Area (2010)
Kutztown, PA Urban Cluster (2010)
Lake Meade, PA Urban Cluster (2010)
Lancaster, PA Urbanized Area (2010)
Lebanon, PA Urbanized Area (2010)
Lewistown, PA Urban Cluster (2010)
Ligonier, PA Urban Cluster (2010)
Littlestown, PA Urban Cluster (2010)
Lock Haven, PA Urban Cluster (2010)
Lykens, PA Urban Cluster (2010)
Mansfield, PA Urban Cluster (2010)
Martinsburg, PA Urban Cluster (2010)
Masontown, PA Urban Cluster (2010)
Meadville, PA Urban Cluster (2010)
Mercer, PA Urban Cluster (2010)
Meyersdale, PA Urban Cluster (2010)
Mifflinburg, PA Urban Cluster (2010)
Mifflintown, PA Urban Cluster (2010)
Milford, NJ--PA Urban Cluster (2010)
Millersburg, PA Urban Cluster (2010)
Millsboro, PA Urban Cluster (2010)
Milton--Lewisburg, PA Urban Cluster (2010)
Monessen--California, PA Urbanized Area (2010)
Montgomery, PA Urban Cluster (2010)
Moscow, PA Urban Cluster (2010)

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Mount Holly Springs, PA Urban Cluster (2010)
Mount Union, PA Urban Cluster (2010)
Muncy, PA Urban Cluster (2010)
Nanty-Glo, PA Urban Cluster (2010)
New Castle, PA Urban Cluster (2010)
New Freedom--Shrewsbury, PA--MD Urban Cluster (2010)
New Wilmington, PA Urban Cluster (2010)
North East, PA Urban Cluster (2010)
Northern Cambria, PA Urban Cluster (2010)
Oil City, PA Urban Cluster (2010)
Orwigsburg, PA Urban Cluster (2010)
Philadelphia, PA--NJ--DE--MD Urbanized Area (2010)
Philipsburg, PA Urban Cluster (2010)
Pine Grove, PA Urban Cluster (2010)
Pittsburgh, PA Urbanized Area (2010)
Portage, PA Urban Cluster (2010)
Pottstown, PA Urbanized Area (2010)
Pottsville, PA Urban Cluster (2010)
Punxsutawney, PA Urban Cluster (2010)
Quarryville, PA Urban Cluster (2010)
Reading, PA Urbanized Area (2010)
Reynoldsville, PA Urban Cluster (2010)
Ridgway, PA Urban Cluster (2010)
Roaring Spring, PA Urban Cluster (2010)
Saw Creek, PA Urban Cluster (2010)
Sayre--Waverly, PA--NY Urban Cluster (2010)
Scranton, PA Urbanized Area (2010)
Shamokin--Mount Carmel, PA Urban Cluster (2010)
Shippensburg, PA Urban Cluster (2010)
Sierra View--Indian Mountain Lake, PA Urban Cluster (2010)
Slippery Rock, PA Urban Cluster (2010)
Somerset, PA Urban Cluster (2010)
State College, PA Urbanized Area (2010)
Stewartstown, PA Urban Cluster (2010)
Susquehanna Depot, PA Urban Cluster (2010)
Titusville, PA Urban Cluster (2010)
Towanda, PA Urban Cluster (2010)
Treasure Lake, PA Urban Cluster (2010)
Tunkhannock, PA Urban Cluster (2010)
Tyrone, PA Urban Cluster (2010)
Union City, PA Urban Cluster (2010)
Uniontown--Connellsville, PA Urbanized Area (2010)
Waynesboro, PA--MD Urban Cluster (2010)
Waynesburg, PA Urban Cluster (2010)
Weirton--Steubenville, WV--OH--PA Urbanized Area (2010)
Williamsport, PA Urbanized Area (2010)
Williamstown, PA Urban Cluster (2010)
Youngstown, OH--PA Urbanized Area (2010)
Youngsville, PA Urban Cluster (2010)

XXVIII. Appendix G – Non-road Engine Standards

The emission limits in the following tables are expressed in g/bhp-h.

Table 48 - Non-Road Compression Ignition Engine Emission Standards

	Tier 1					Tier 2					Tier 3					Tier 4i					Tier 4f				
	Model Year	NO_X	HC	CO	PM	Model Year	NO_X	HC	CO	PM	Model Year	NO_X	HC	CO	PM	Model Year	NO_X	HC	CO	PM	Model Year	NO_X	HC	CO	PM
HP < 11	2000	7.83		5.97	0.75	2005	5.59		5.97	0.6						2008	5.59		5.97	0.3	2014	5.59		5.97	0.3
11 ≤ HP < 25	2000	7.08		4.92	0.75	2005	5.59		4.92	0.6						2008	5.59		4.92	0.3	2014	5.59		4.92	0.3
25 ≤ HP < 50	1999	7.08		4.1	0.75	2004	5.59		4.1	0.45						2008	5.59		4.1	0.22	2014	3.5		4.1	0.02
																2013	3.5		3.73	0.02					
50 ≤ HP < 75	1998	6.86				2004	5.59		3.73	0.3	2008	3.5		3.73	0.3	2013	3.5		3.73	0.02	2014	3.5		3.73	0.01
75 ≤ HP < 100																2014	0.3	0.14	3.73	0.01	2014	0.3	0.14	3.73	0.01
100 ≤ HP < 175	1997	6.86				2003	4.92		3.73	0.22	2007	2.98		3.73	0.22	2014	0.3	0.14	3.73	0.01					
175 ≤ HP < 300	1996	6.86	0.97	8.5	0.4	2003	4.92		2.61	0.15	2006	2.98		2.61	0.15	2014	0.3	0.14	2.61	0.01	2014	0.3	0.14	2.61	0.01
300 ≤ HP < 600	1996	6.86	0.97	8.5	0.4	2001	4.77		2.61	0.15	2006	2.98		2.61	0.15										
600 ≤ HP ≤ 750	1996	6.86	0.97	8.5	0.4	2002	4.77		2.61	0.15	2006	2.98		2.61	0.15										
750 < HP ≤ 1205	2000	6.86	0.97	8.5	0.54	2006	4.77		2.61	0.15						2014	2.61	0.3	2.61	0.07	2014 Gen Set	0.5	0.14	2.61	0.02
1205 < HP																2014 Gen Set	0.5	0.3	2.61	0.07	2014 Other	2.61	0.14	2.61	0.03
																2014 Other	2.61	0.3	2.61	0.07					

Table 49 - Non-Road Spark Ignition Engine Emission Standards

		General Emission Standards		Severe-Duty Engine Emission Standards	
		NO_X + HC	CO	NO_X + HC	CO
Certification and Production-Line Testing	Tier 1 Model Year 2004-2006	2.98	37.29	2.98	96.94
Field Testing		4.03	37.92	4.03	96.94
Steady-State Testing	Tier 2 Model Year 2007-	2.01	3.28	2.01	96.94
Transient Testing		2.01	3.28		
Field Testing		2.83	4.85	2.83	149.14

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XXIX. Appendix H – Well Site Rod Packing Replacement Cost-Effectiveness Analysis

Table 50 - Rod Packing Cost Analysis with Revised Emission Factors

(All dollar values in 2016 dollars)	EPA TSD Production	UT Methane Emission Factor Production - low	UT Methane Emission Factor Production - high	UT Methane Emission Factor Production - measured	UT Methane Emission Factor Production - average
Packing Replacement Costs (Materials and Installation)	$1,814	$1,814	$1,814	$1,814	$1,814
Annualized Packing Replacement Cost	$698	$698	$698	$698	$698
Total Annualized Costs	$698	$698	$698	$698	$698
TPY of CH_4 Emissions Reduced	0.0456	0.0456	5.6104	0.9144	2.1901
TPY of VOC Emissions Reduced	0.0024	0.0024	0.2915	0.0475	0.1138
TPY of HAP Emissions Reduced	0.0000	0.0000	0.0001	0.0000	0.0000
Cost Per Ton Pollutant	$14,551	$14,551	$118	$726	$303
Cost Per Ton Methane	$15,307	$15,307	$124	$763	$319
Cost Per Ton VOC	$294,603	$294,603	$2,395	$14,692	$6,134
Cost Per Ton HAP	$1,316,877,281	$1,316,877,281	$10,703,529	$65,671,548	$27,418,845

XXX. Appendix I – GP-5 Malfunction Reporting Instructions

GP-5 Malfunction Reporting Instructions

1. **Malfunction reporting to the PA Department of Environmental Protection (DEP or Department) under GP-5 must be conducted as follows:**

   a. The owner/operator authorized to use GP-5 shall report to DEP each malfunction that results in a potential exceedance of the GP-5 emissions limits. For GP-5 purposes, the term malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control or process equipment, or, operating in a non-permitted manner, which results in, or may possibly be resulting in, the emission of air contaminants in excess of any applicable limitations specified in GP-5.

   b. The notification, recordkeeping and reporting requirements relating to performance testing, work practice and monitoring standards, equipment leaks or fugitive emissions noted in GP-5 are not subject to the malfunction reporting requirements.

   c. When the malfunction or incident poses an imminent and substantial danger to the public health and safety, and/or potential harm to the environment, the owner/operator shall report the incident to the Department and the County Emergency Management Agency immediately after the discovery of an incident. The owner/ operator shall submit a written report of instances of such malfunctions or incidents to the Department within three (3) business days of the telephone report.

      i. The Report shall include the following:
         a) name and location of the facility;
         b) nature and cause of the malfunction or incident;
         c) time when the malfunction, incident or breakdown was first observed;
         d) expected duration of increased emissions; and
         e) estimated rate of emissions

      ii. The Owner/Operator shall notify the Department immediately when corrective measures have been accomplished.

   d. Incidents covered by the notification, recordkeeping and reporting requirements relating to performance testing, work practice and monitoring standards, equipment leaks or fugitive emissions noted in this general permit are not subject to the reporting requirements of this section.

   e. Any malfunction or incident that is not subject to the notice requirements of paragraph (c) of this document shall be reported to the Department by telephone within 24 hours (or by 4:00 PM of the next business day, whichever is later) of discovery and in writing or e-mail within five days of discovery of the incident. The report shall contain the same information required by paragraph (c)(i).

   f. The Department may require, when a malfunction or other incident results in citizen complaints, the Owner/Operator to report the incident immediately to the Department. The Department will review the incident and determine if a written follow up report including corrective action is needed.

   g. Malfunctions shall be reported to the appropriate DEP Regional Office Air Program Manager.

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2. **Examples of Malfunctions or Incidents are provided below.**

   a. Malfunctions or incidents posing an imminent and substantial danger to the public health and safety.

      i. Reportable
         a) Fire;
         b) Explosion; or
         c) Explosive or other condition that may impact outside of the fence-line or require evacuations.

   b. Malfunctions or incidents that do not pose an imminent and substantial danger to public health and safety but may result in an exceedance of GP-5 emissions limits.

      i. Reportable Malfunctions or Incidents
         a) Process equipment incidents, or air pollution control equipment shutdown or reduction in control which results in VOC, NOX, CO, HAP, or Formaldehyde emissions in excess of the General Permit's emissions limits or permit requirements.
         b) Equipment or operation failure, or malfunctions in process or pollution control equipment that result in fugitive particulate emission or odor beyond the facility boundary.

      ii. Non-reportable Malfunctions or Incidents
         a) Air Pollution Control equipment shutdowns that are rectified by automatic restarts, other adjustments of the operation as per the manufacturer.
         b) Air Pollution Control equipment shutdowns which are manually restarted within one hour of the malfunction and do not result in emissions in excess of GP limitations.
         c) Malfunctions in process or pollution control equipment which result in odor or fugitive dust emissions which are contained within the facility's fence-line.
         d) Building fire eyes or gas detector trips that pose no harm to the public.
         e) False fire eyes or other safety device trips which do not pose harm to the public.
         f) Upset conditions within the site boundaries which do not pose a threat to the public provided that they do not result in a potential exceedance of the GP-5 emissions limits.

   c. Emergency Releases

      i. Reportable Releases
         a) Unplanned Emergency Shut-down events that result in a potential exceedance of permit emission limits or create an offsite risk.
         b) Relief valves that stay open, or frequently relieve and may result in a potential exceedance of permit limits.

      ii. Non- Reportable Releases
         a) Vents from pressure safety relief valves (PSVs) that do not result in a potential exceedance of permit limits or create an offsite risk. However, DEP should be notified by telephone if there is noise from the release that results in community complaints to the facility owner/operator, or there are multiple PSV incidents.

   d. Planned Compressor Vents, Engine Starters and Other Emissions Included in the Application

      i. Non-Reportable Releases
         a) Venting from compressors as described in the GP-5 Application that do not result in an exceedance of emission limits.

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b) Gas from engine starters as described in the application that do not result in an exceedance of emission limits. Planned or required ESDs included in the application that do not result in an exceedance of emission limits.
c) Rod packing or crankcase vent emissions – source of minor significance normally detailed in the permit application.

e. Malfunctions or Other Incidents That Result in Citizen Complaints – Courtesy Reporting

i. Incident Reporting
a) Noise from pressure relief valves or other safety devices that result in community complaints to the facility owner/operator.
b) Odors from an off-site source when detected in the area.
c) Issues that have received prior community complaints.
d) Emergency Response Drills held at the facility where a number of emergency vehicles may be present.

f. Dehydrators

i. Reportable Incidents
a) Still vent bypass or flash tank venting from freezing or process malfunction that has the potential to exceed permit emission limitations.
b) Malfunctions of process controls that may or may not result in exceedances of permit limits.

ii. Non-Reportable Incidents
a) Still vent or flash tank bypass of oxidizers or other controls during automated restart sequence, without any potential to exceed permit emission limits.

NOTE: Emissions (including emissions from malfunctions) from all sources must be included in the source reports submitted to DEP by March 1st each year as prescribed in 25 Pa. Code Chapter 135 (relating to reporting of sources).

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EPA-453/R-93-007

Alternative Control Techniques Document— NO_x Emissions from Stationary Gas Turbines

Emission Standards Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993

NMED Exhibit 53

ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

This report is issued by the Emission Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, to provide information to State and local air pollution control agencies. Mention of trade names and commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available—as supplies permit—from the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711 ([919] 541-2777) or, for a nominal fee, from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161 ([800] 553-NTIS).

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1.0 INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Stationary gas turbines have been identified as a category that emits more than 25 tons of nitrogen oxide (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from stationary gas turbines. Additional ACT documents are being developed for other stationary source categories.

Gas turbines are available with power outputs ranging from 1 megawatt (MW) (1,340 horsepower [hp]) to over 200 MW (268,000 hp) and are used in a broad scope of applications. It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable for every gas turbine application. The size and design of the turbine, the operating duty cycle, site conditions, and other site-specific factors must be taken into consideration, and the suitability of an

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alternative control technique must be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by gas turbine manufacturers, control equipment vendors, gas turbine users, and regulatory agencies. Chapter 2.0 presents a summary of the findings of this study. Chapter 3.0 presents information on gas turbine operation and industry applications. Chapter 4.0 contains a discussion of NO_x formation and uncontrolled NO_x emission factors. Alternative control techniques and achievable controlled emission levels are included in Chapter 5.0. The cost and cost effectiveness of each control technique are presented in Chapter 6.0. Chapter 7.0 describes environmental and energy impacts associated with implementing the NO_x control techniques.

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2.0 SUMMARY

This chapter summarizes the more detailed information presented in subsequent chapters of this document. It presents a summary of nitrogen oxide (NO_x) formation mechanisms and uncontrolled NO_x emission factors, available NO_x emission control techniques, achievable controlled NO_x emission levels, the costs and cost effectiveness for these NO_x control techniques applied to combustion gas turbines, and the energy and environmental impacts of these control techniques. The control techniques included in this analysis are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR).

Section 2.1 includes a brief discussion of NO_x formation and a summary of uncontrolled NO_x emission factors. Section 2.2 describes the available control techniques and achievable controlled NO_x emission levels. A summary of the costs and cost-effectiveness for each control technique is presented in Section 2.3. Section 2.4 reviews the range of controlled emission levels, capital costs, and cost effectiveness. Section 2.5 discusses energy and environmental impacts.

2.1 NO_x FORMATION AND UNCONTROLLED NO_x EMISSIONS

The two primary NO_x formation mechanisms in gas turbines are thermal and fuel NO_x. In each case, nitrogen and oxygen present in the combustion process combine to form NO_x. Thermal NO_x is formed by the dissociation of atmospheric nitrogen (N_2) and oxygen (O_2) in the turbine combustor and the subsequent formation of NO_x. When fuels containing nitrogen are combusted, this additional source of nitrogen results in fuel NO_x formation. Because most turbine installations burn natural gas or light

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distillate oil fuels with little or no nitrogen content, thermal NO_x is the dominant source of NO_x emissions. The formation rate of thermal NO_x increases exponentially with increases in temperature. Because the flame temperature of oil fuel is higher than that of natural gas, NO_x emissions are higher for operations using oil fuel than natural gas.

Uncontrolled NO_x emission levels were provided by gas turbine manufacturers in parts per million, by volume (ppmv). Unless stated otherwise, all emission levels shown in ppmv are corrected to 15 percent O_2. These emission levels were used to calculate uncontrolled NO_x emission factors, in pounds (lb) of NO_x per million British thermal units (Btu) (lb NO_x/MMBtu). Sample calculations are shown in Appendix A. These uncontrolled emission levels and emission factors for both natural gas and oil fuel are presented in Table 2-1

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TABLE 2-1. UNCONTROLLED NO_x EMISSION FACTORS FOR GAS TURBINES

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% 0_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.

[b]Not available.

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. Uncontrolled NO_x emission levels range from 99 to 430 ppmv for natural gas fuel and from 150 to 680 ppmv for distillate oil fuel. Corresponding uncontrolled emission factors range from 0.397 to 1.72 lb NO_x/MMBtu and 0.551 to 2.50 lb NO_x/MMBtu for natural gas and distillate oil fuels, respectively. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with combustor design. There is no discernable correlation between turbine size and NO_x emission levels evident in Table 2-1.

2.2 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

Reductions in NO_x emissions can be achieved using combustion controls or flue gas treatment. Available combustion controls are water or steam injection and dry low-NO_x combustion designs. Selective catalytic reduction is the only available flue gas treatment.

2.2.1 Combustion Controls

Combustion control using water or steam lowers combustion temperatures, which reduces thermal NO_x formation. Fuel NO_x formation is not reduced with this technique. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower

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flame temperatures. This control technique is available for all new turbine models and can be retrofitted to most existing installations.

Although uncontrolled emission levels vary widely, the range of achievable controlled emission levels using water or steam injection is relatively small. Controlled NO_x emission levels range from 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel. Achievable guaranteed controlled emission levels, as provided by turbine manufacturers, are shown for individual turbine models in Figures 2-1 and 2-2

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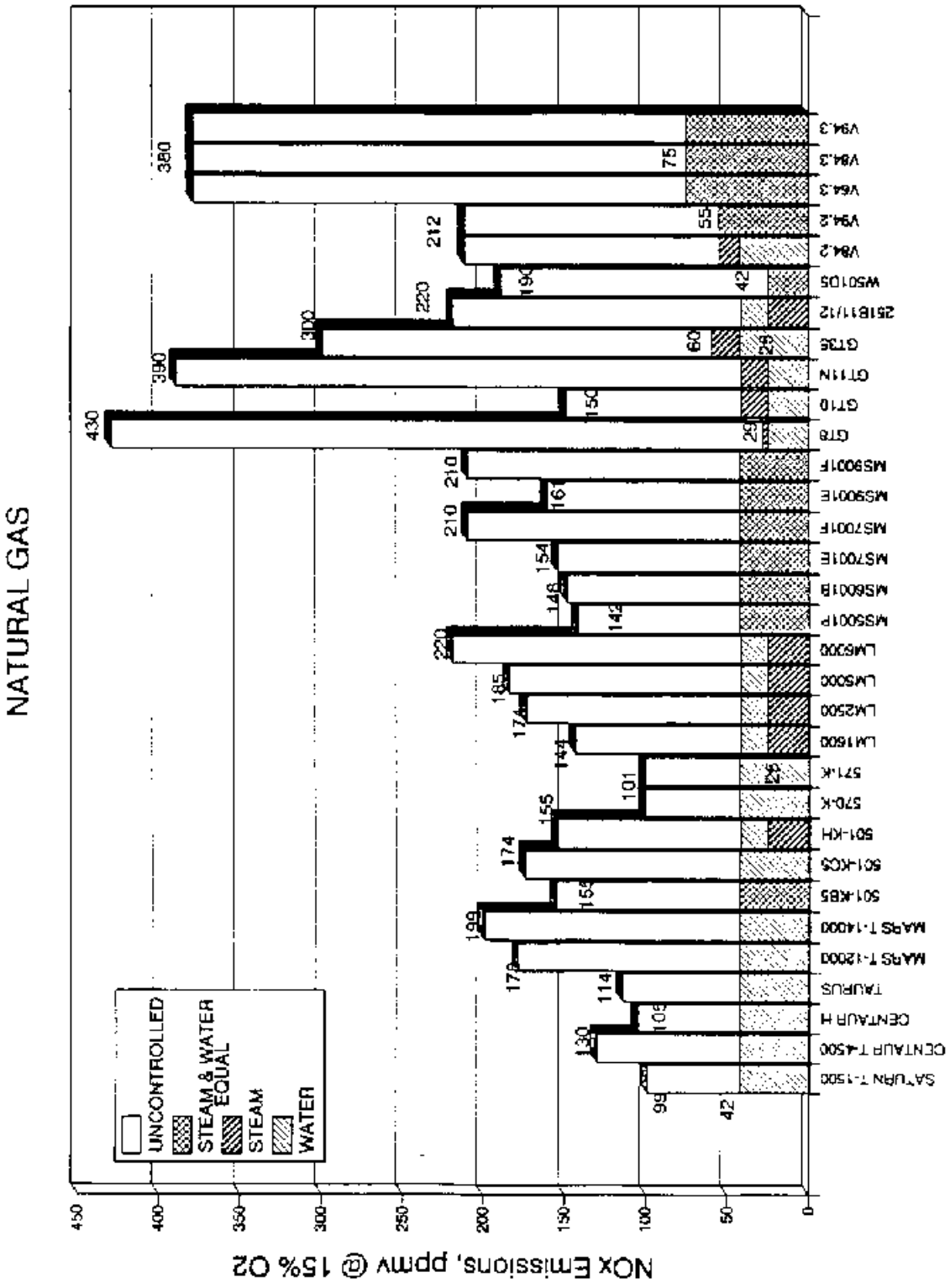


Figure 2-1. Uncontrolled NOx emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.

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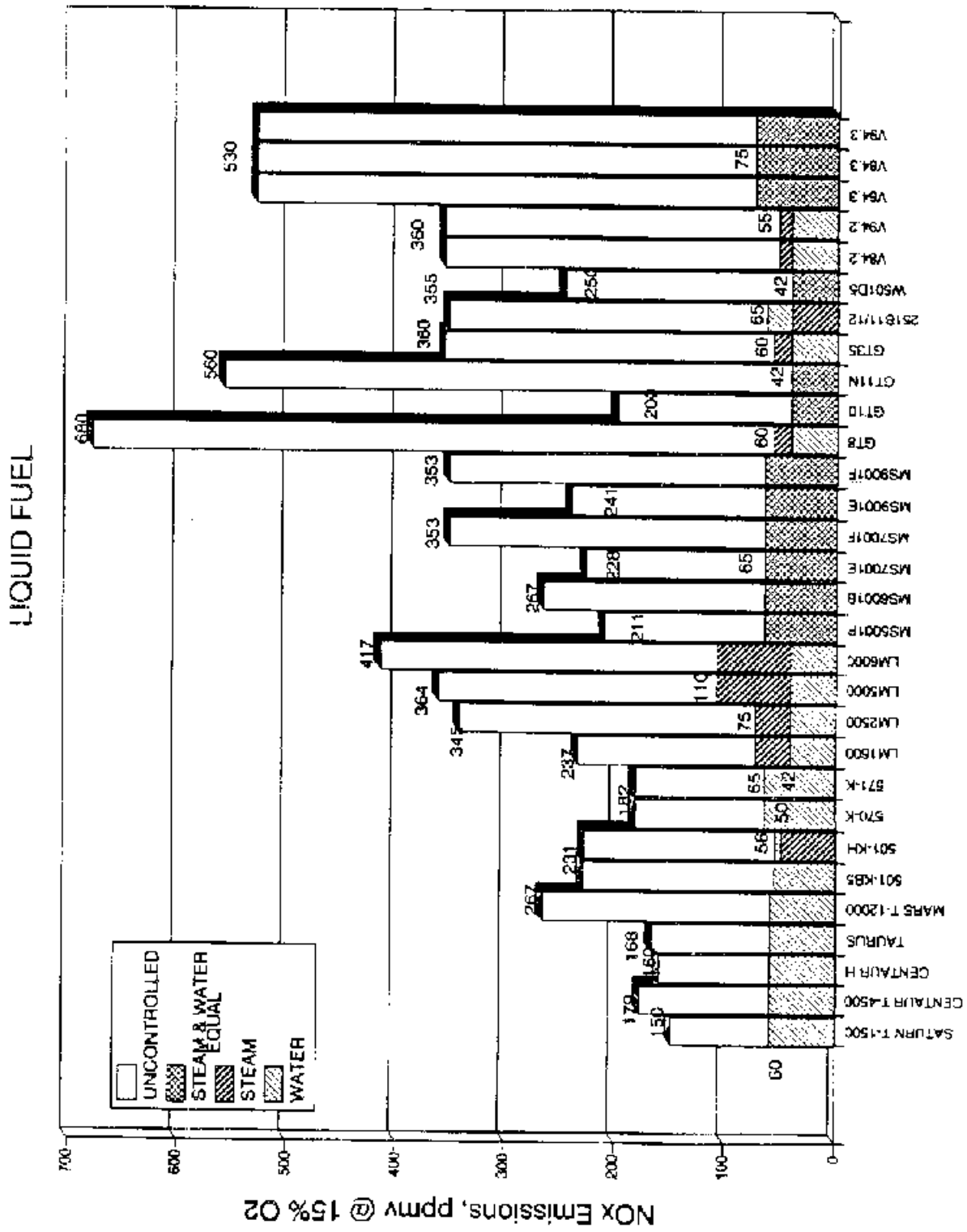


Figure 2-2. **Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate oil fuel.**

for natural gas and oil fuels, respectively.

The decision whether to use water versus steam injection for NO_x reduction depends on many factors, including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

A system that allows treated water to be mixed with the fuel prior to injection is also available. Limited testing of water-in-oil emulsions injected into the turbine combustor have achieved NO_x reductions equivalent to direct water injection but at reduced water-to-fuel rates. The vendor reports a similar system is available for natural gas-fired applications.

Dry low-NO_x combustion control techniques reduce NO_x emissions without injecting water or steam. Two designs, lean premixed combustion and rich/quench/lean staged combustion have been developed.

Lean premixed combustion designs reduce combustion temperatures, thereby reducing thermal NO_x. Like wet injection, this technique is not effective in reducing fuel NO_x. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs simultaneously with combustion. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogeneous air/fuel mixture, which minimizes

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localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air acts as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Lean premixed combustors are currently available from several turbine manufacturers for a limited number of turbine models. Development of this technology is ongoing, and availability should increase in the coming years. All turbine manufacturers state that lean premixed combustors are designed for retrofit to existing installations.

Controlled NO_x emission levels using dry lean premixed combustion range from 9 to 42 ppmv for operation on natural gas fuel. The low end of this range (9 to 25 ppmv) has been limited to turbines above 20 megawatts (MW) (27,000 horsepower [hp]); to date, three manufacturers have guaranteed controlled NO_x emission levels of 9 ppmv at one or more installations for utility-sized turbines. Controlled NO_x emissions from smaller turbines typically range from 25 to 42 ppmv. For operation on distillate oil fuel, water or steam injection is required to achieve controlled NO_x emissions levels of approximately 65 ppmv. Development continues for oil-fueled operation in lean premixed designs, however, and one turbine manufacturer reports having achieved controlled NO_x emission levels below 50 ppmv in limited testing on oil fuel without wet injection.

A second dry low-NO_x combustion design is a rich/quench/lean staged combustor. Air and fuel are partially combusted in a fuel-rich primary stage, the combustion products are then rapidly quenched using water or air, and combustion is completed in a fuel-lean secondary stage. The fuel-rich primary stage inhibits NO_x formation due to low O_2 levels. Combustion temperatures in the fuel-lean secondary stage are below NO_x formation temperatures as a result of the quenching process and the presence of excess air. Both thermal and fuel NO_x are controlled with this design. Limited testing with fuels including natural

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gas and coal have achieved controlled NO_x emissions of 25 ppmv. Development of this design continues, however, and currently the rich/quench/lean combustor is not available for production turbines.

2.2.2 Selective Catalytic Reduction

This flue gas treatment technique uses an ammonia (NH_3) injection system and a catalytic reactor to reduce NO_x. An injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water (H_2O) in the catalyst reactor. This control technique reduces both thermal NO_x and fuel NO_x.

Ammonia injection systems are available that use either anhydrous or aqueous NH_3. Several catalyst materials are available. To date, most SCR installations use a base-metal catalyst with an operating temperature window ranging from approximately 260° to 400°C (400° to 800°F). The exhaust temperature from the gas turbine is typically above 480°C (900°F), so the catalyst is located within a heat recovery steam generator (HRSG) where temperatures are reduced to a range compatible with the catalyst operating temperature. This operating temperature requirement has, to date, limited SCR to cogeneration or combined-cycle applications with HRSG's to reduce flue gas temperatures. High-temperature zeolite catalysts, however, are now available and have operating temperature windows of up to 600°C (1100°F), which is suitable for installation directly downstream of the turbine. This high-temperature zeolite catalyst offers the potential for SCR applications with simple cycle gas turbines.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x and avoids excessive NH_3 emissions downstream of the catalyst, known as ammonia slip. The selected catalyst formulation must be resistant to potential masking and/or poisoning agents in the flue gas.

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To date, most SCR systems in the United States have been installed in gas-fired turbine applications, but improvements in SCR system designs and experience on alternate fuels in Europe and Japan suggest that SCR systems are suitable for firing distillate oil and other sulfur-bearing fuels. These fuels produce sulfur dioxide (SO_2), which may oxidize to sulfite (SO_3) in the catalyst reactor. This SO_3 reacts with NH_3 slip to form ammonium salts in the low-temperature section of the HRSG and exhaust ductwork. The ammonium salts must be periodically cleaned from the affected surfaces to avoid fouling and corrosion as well as increased back-pressure on the turbine. Advances in catalyst formulations include sulfur-resistant catalysts with low SO_2 oxidation rates. By limiting ammonia slip and using these sulfur-resistant catalysts, ammonium salt formation can be minimized.

Catalyst vendors offer NO_x reduction efficiencies of 90 percent with ammonia slip levels of 10 ppmv or less. These emission levels are warranted for 2 to 3 years, and all catalyst vendors contacted accept return of spent catalyst reactors for recycle or disposal.

Controlled NO_x emission levels using SCR are typically 9 ppmv or less for gas-fueled turbine installations. With the exception of one site, all identified installations operate the SCR system in combination with combustion controls that reduce NO_x emission levels into the SCR to a range of 25 to 42 ppmv. Most continuous-duty turbine installations fire natural gas; there is limited distillate oil-fired operating experience in the United States. Several installations with SCR in the northeast United States that use distillate oil as a back-up fuel have controlled NO_x emission limits of 18 ppmv for operation on distillate oil fuel.

2.3 COSTS AND COST EFFECTIVENESS FOR NO_x CONTROL TECHNIQUES

Capital costs and cost effectiveness were developed for the available NO_x control techniques. Capital costs are presented in Section 2.3.1. Cost-effectiveness figures, in $/ton of NO_x

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removed, are shown in Section 2.3.2. All costs presented are in 1990 dollars.

2.3.1 Capital Costs

Capital costs are the sum of purchased equipment costs, taxes and freight charges, and installation costs. Purchased equipment costs were estimated based on information provided by equipment manufacturers, vendors, and published sources. Taxes, freight, and installation costs were developed based on factors recommended in the Office of Air Quality and Planning and Standards Control Cost Manual (Fourth Edition). Capital costs for combustion controls and SCR are presented in Sections 2.3.1.1 and 2.3.1.2, respectively.

2.3.1.1 Combustion Controls Capital Costs. Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system consisting of pumps, piping and hardware, metering controls, and injection nozzles. All costs for wet injection are based on the availability of water at the site; no costs have been included for transporting water to the site. These costs apply to new installations; retrofit costs would be similar except that turbine-related injection hardware and metering controls purchased from the turbine manufacturer may be higher for retrofit applications.

The capital costs for wet injection are shown in Figure 2-3, and range from $388,000 for a 3.3 MW (4,430 hp) turbine to $4,830,000 for a 161 MW (216,000 hp) turbine.

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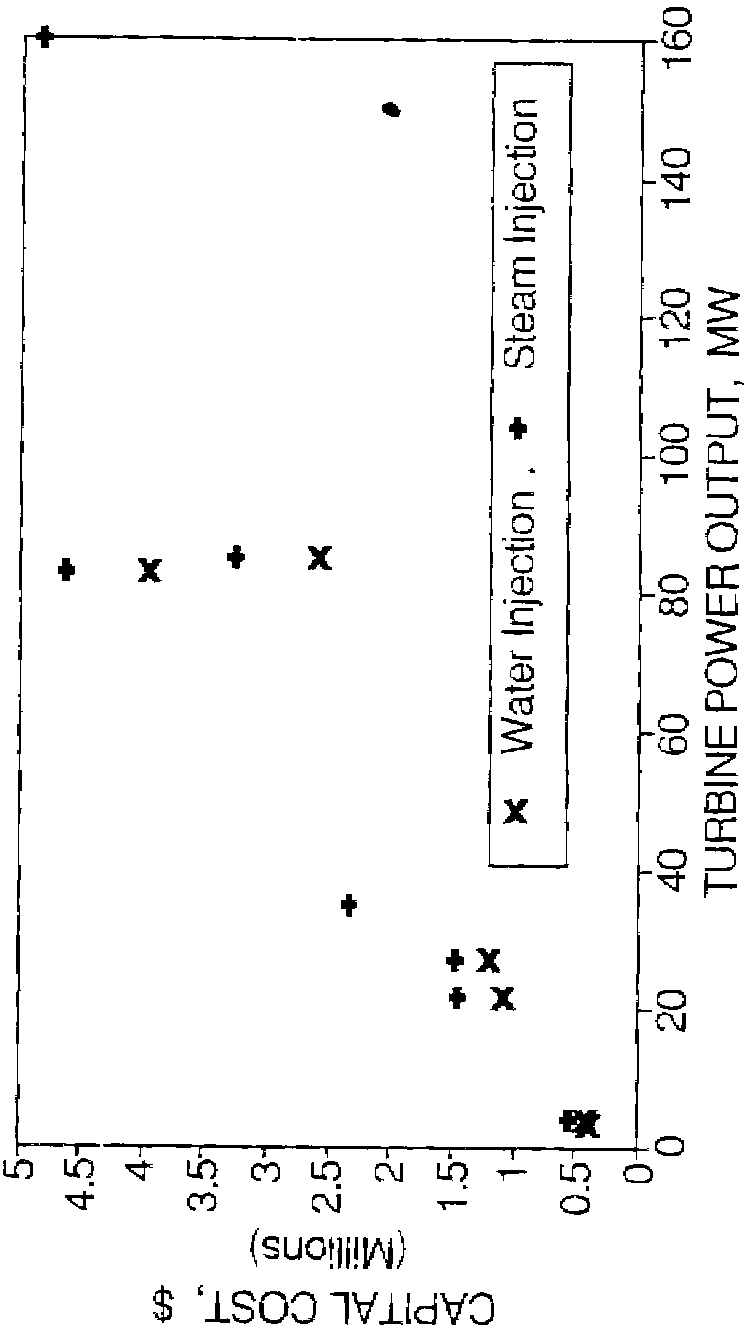


Figure 2-3. Capital costs for water or steam injection.

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These capital costs include both water and steam injection systems for use with either gas or distillate oil fuel applications. Figure 2-3 shows that the capital costs for steam injection are slightly higher than those for water injection for turbines in the 3 to 25 MW (4,000 to 33,500 hp) range.

The capital costs for dry low-NO_x combustors are the incremental costs for this design over a conventional combustor and apply to new installations. Turbine manufacturers estimate retrofit costs to be approximately 40 to 60 percent higher than new equipment costs. Incremental capital costs for dry low-NO_x

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combustion were provided by turbine manufacturers and are presented in Figure 2-4.

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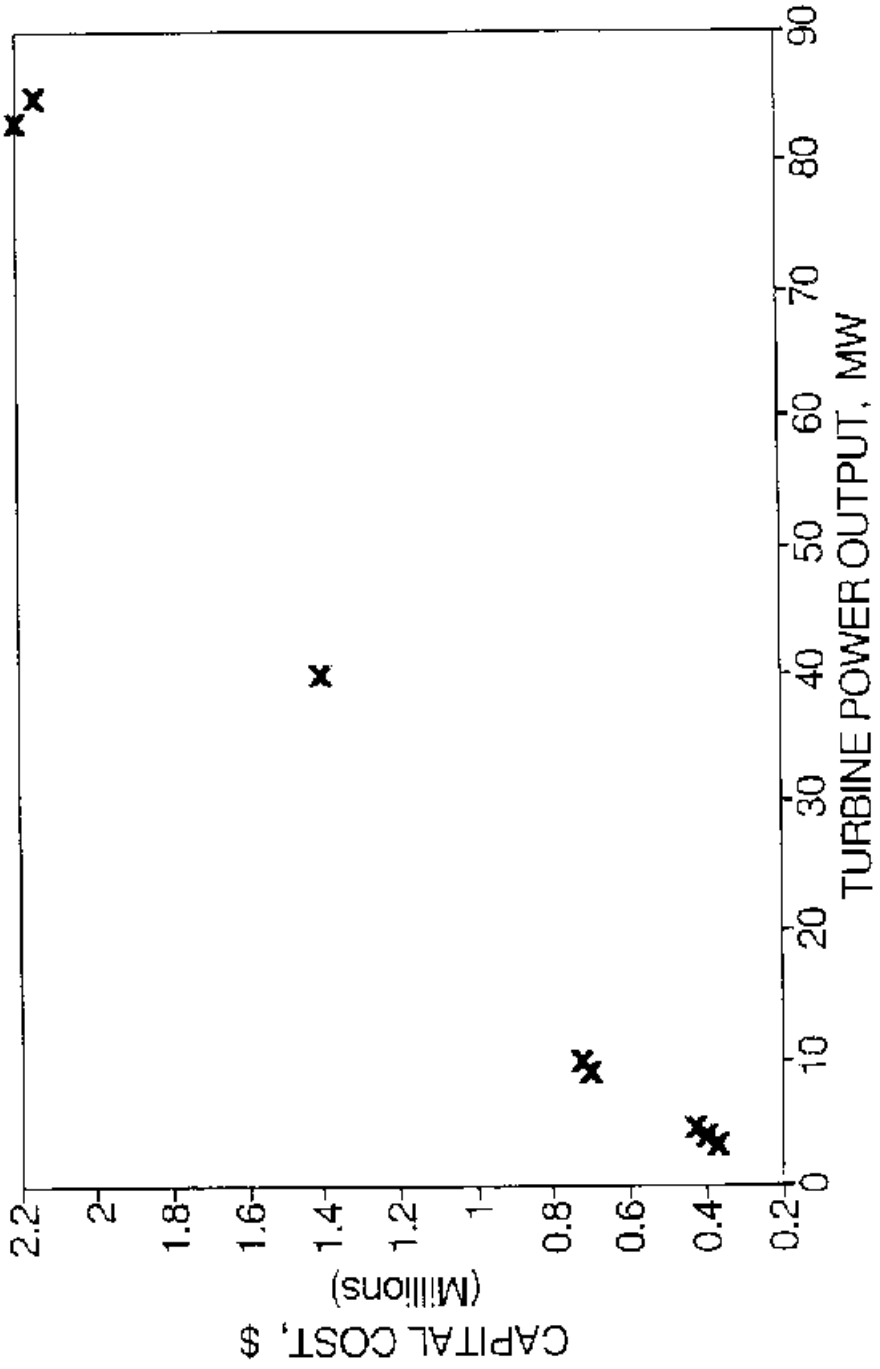


Figure 2-4. Capital costs for dry low-NO_x combustion.

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The incremental capital costs range from $375,000 for a 3.3 MW (4,430 hp) turbine to $2.2 million for an 85 MW (114,000 hp) machine. Costs were not available for turbines above 85 MW (114,000 hp).

When evaluated on a $/MW ($/hp) basis, the capital costs for wet injection or dry low-NO_x combustion controls are highest for the smallest turbines and decrease exponentially with increasing turbine size. The range of capital costs for combustion controls, in $/MW, and the effect of turbine size on capital costs are shown in Figure 2-5.

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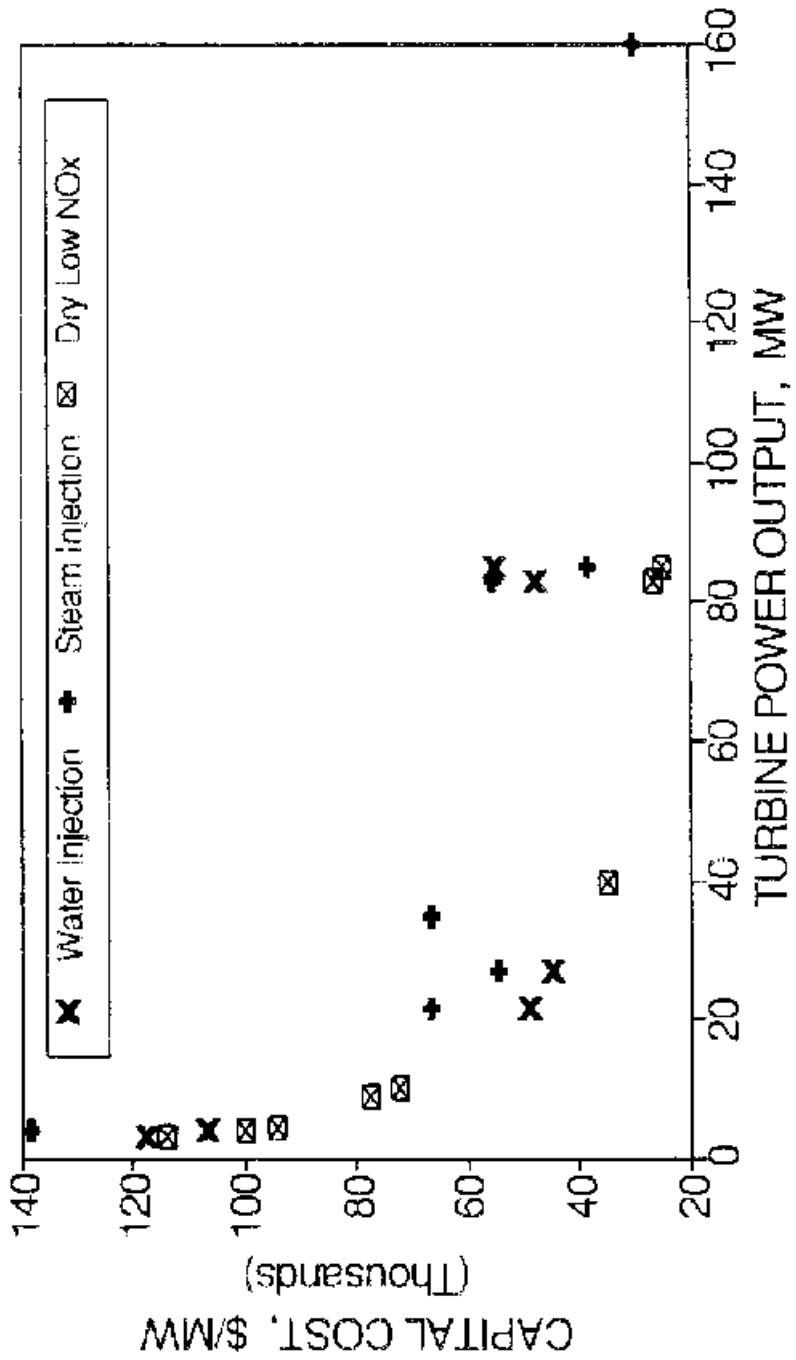


Figure 2-5. Capital costs, in $/MW, for cumbustion controls.

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For wet injection, the capital costs range from a high of $138,000/MW ($103/hp) for a 3.3 MW (4,430 hp) turbine to a low of $29,000/MW ($22/hp) for a 161 MW (216,000 hp) turbine. Corresponding capital cost figures for dry low-NO_x combustion range from $114,000/MW ($85/hp) for a 3.3 MW (4,430 hp) unit to $26,000/MW ($19/hp) for an 85 MW (114,000 hp) machine.

2.3.1.2 SCR Capital Costs. Capital costs for SCR include the catalyst reactor, ammonia storage and injection system, and controls and monitoring equipment. A comparison of available cost estimates for base-metal catalyst systems and high-temperature zeolite catalyst systems indicates that the costs for these systems are similar, so a single range of costs was developed that represents all SCR systems, regardless of catalyst type or turbine cycle (i.e., simple, cogeneration, or combined cycle).

The capital costs for SCR, shown in Figure 2-6, range from $622,000 for a 3.3 MW (4,430 hp) turbine to $8.46 million for a 161 MW (216,000 hp) turbine.

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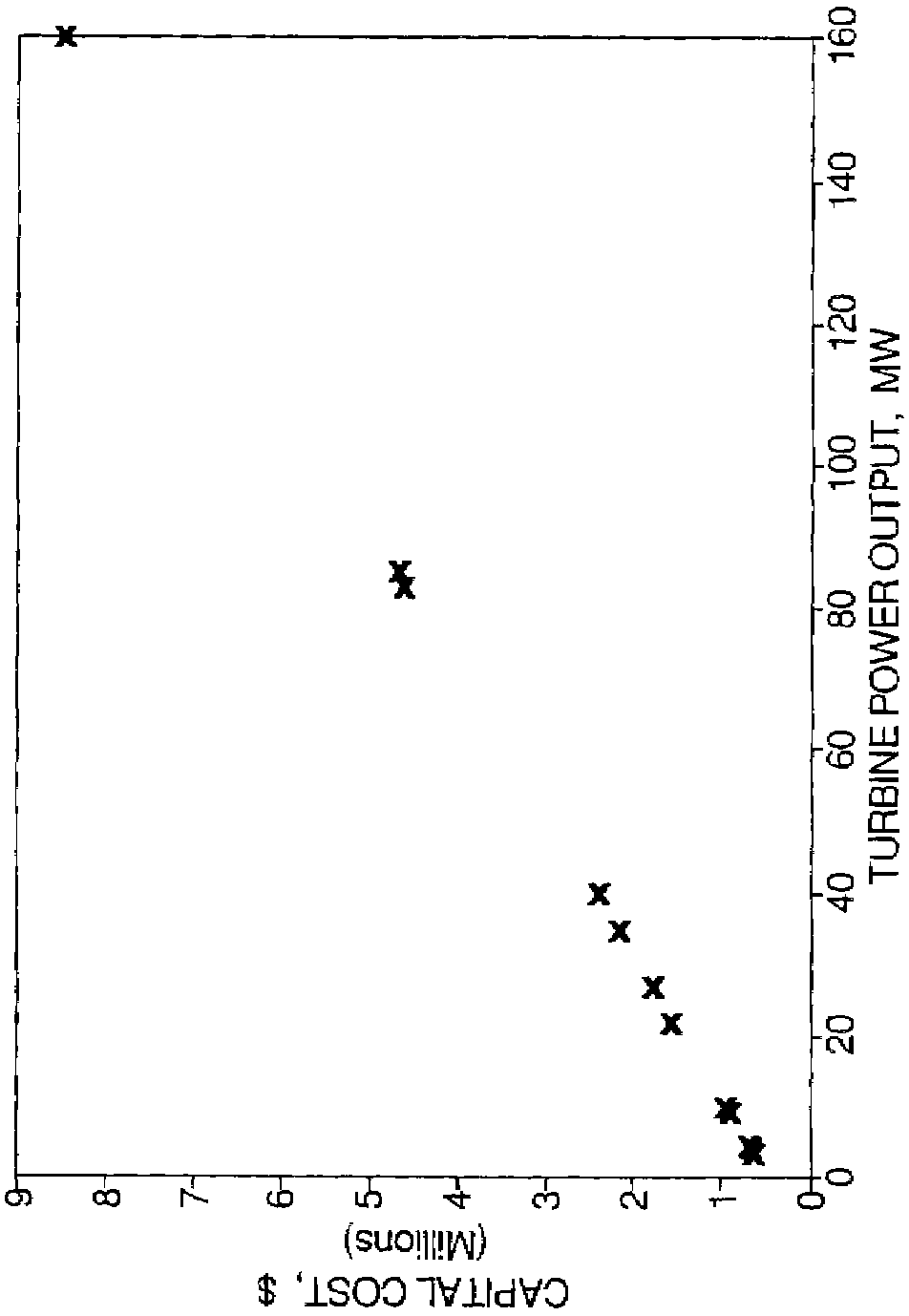


Figure 2-6. Capital costs for selective catalytic reduction.

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Figure 2-7 plots capital costs on a $/MW basis and shows that these costs are highest for the smallest turbine, at $188,000/MW ($140/hp) for a 3.3 MW (4,430 hp) unit, and decrease exponentially with increasing turbine size to $52/MW ($40/hp) for a 161 MW (216,000 hp) machine.

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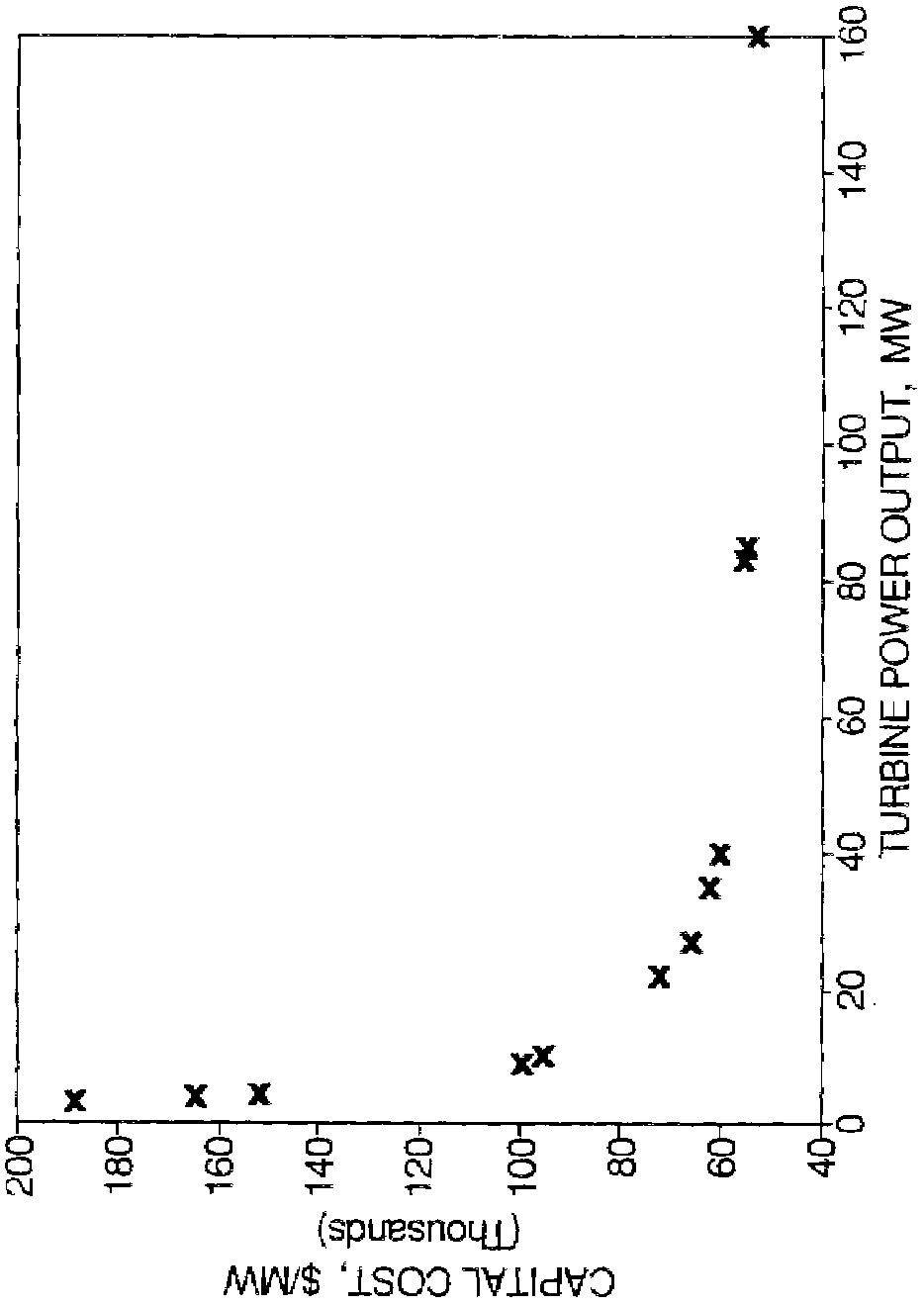


Figure 2-7. Capital costs, in $/MW, for selective catalytic reduction.

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These costs apply to new installations firing natural gas as the primary fuel. No SCR sites using oil as the primary fuel were identified, and costs were not available. For this

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reason, the costs for gas-fired applications were also used for oil-fired sites. Retrofit SCR costs could be considerably higher than those shown here for new installations, especially if an existing HRSG and ancillary equipment must be moved or modified to accommodate the SCR system.

2.3.2 Cost Effectiveness

The cost effectiveness, in $/ton of NO_x removed, was developed for each NO_x control technique. The cost effectiveness for a given control technique is calculated by dividing the total annual cost by the annual NO_x reduction, in tons. The cost effectiveness presented in this section correspond to 8,000 annual operating hours. Total annual costs were calculated as the sum of all annual operating costs and annualized capital costs. Annual operating costs include costs for incremental fuel, utilities, maintenance, applicable performance penalties, operating and supervisory labor, plant overhead, general and administrative, and taxes and insurance. Capital costs were annualized using the capital recovery factor method with an equipment life of 15 years and an annual interest rate of 10 percent. Cost-effectiveness figures for combustion controls and SCR are presented in Sections 2.3.2.1 and 2.3.2.2, respectively.

2.3.2.1 Combustion Controls Cost Effectiveness. Cost effectiveness for combustion controls is shown in Figure 2-8.

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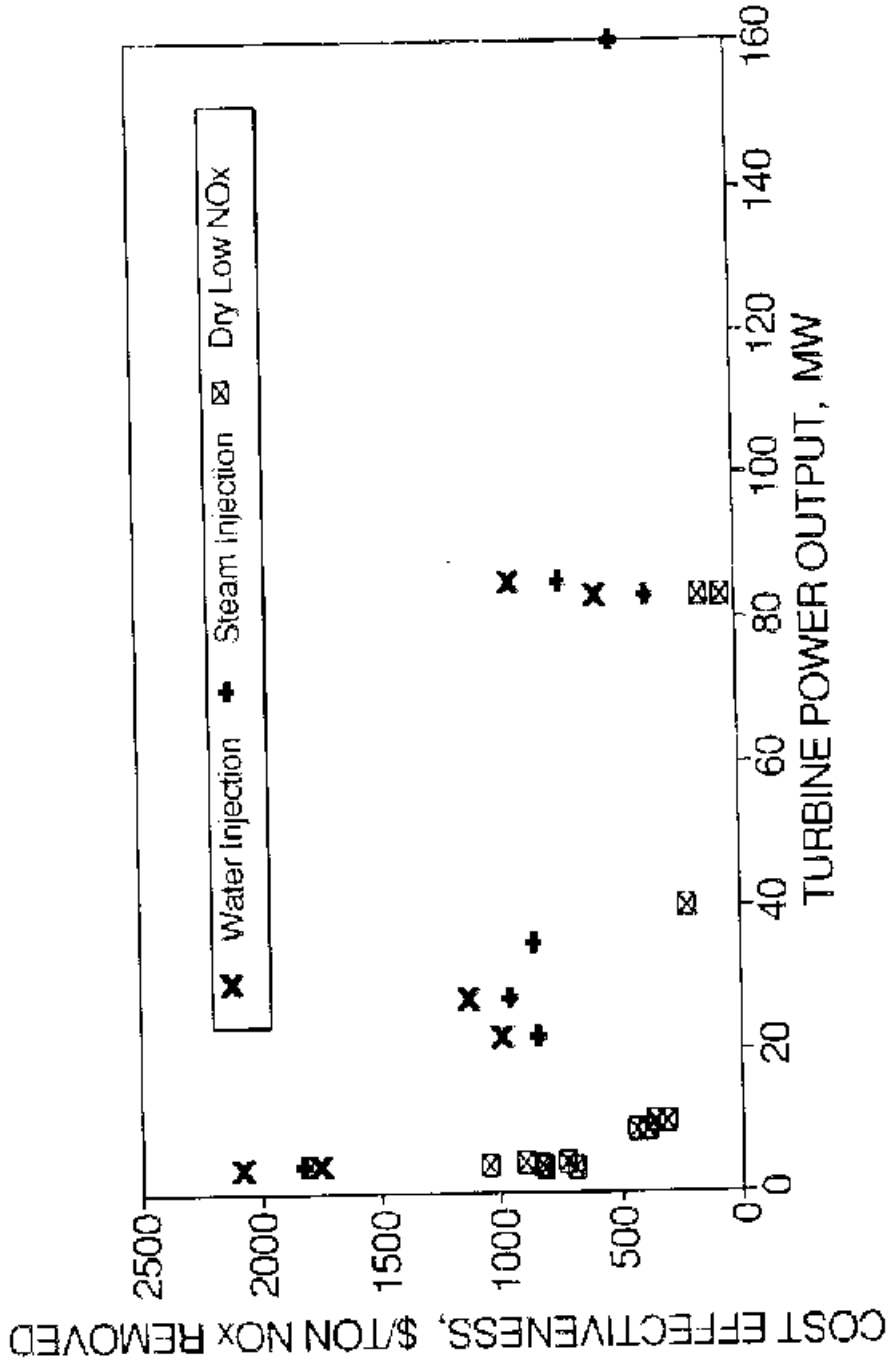


Figure 2-8. Cost effectiveness of combustion controls.

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Figure 2-8 indicates that cost effectiveness for combustion controls is highest for the smallest turbines and decreases exponentially with decreasing turbine size. Figure 2-8 also shows that the range of cost effectiveness for water injection is similar to that for steam injection, primarily because the total annual costs and achievable controlled NO_x emission levels for water and steam injection are similar. The cost-effectiveness range for dry low-NO_x combustion is lower than that for wet

$_x$ levels are similar (25 to 42 ppmv), due to the lower total annual costs for dry low-NO_x combustion.

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For water injection, cost effectiveness, in $/ton of NO_x removed, ranges from $2,080 for a 3.3 MW (4,430 hp) unit to $575 for an 83 MW (111,000 hp) turbine and $937 for an 85 MW (114,000 hp) turbine. For steam injection, cost effectiveness is $1,830 for a 3.3 MW (4,430 hp), decreasing to $375 for an 83 MW (111,000 hp) turbine, and increasing to $478 for a 161 MW (216,000 hp) turbine. The relatively low cost effectiveness for the 83 MW (111,000 hp) turbine is due to this particular turbine's high uncontrolled NO emissions, which result in a relatively high NO_x removal efficiency and lower cost effectiveness. The cost effectiveness shown in Figure 2-8

number of oil-fired applications with water injection indicates that the cost effectiveness ranges from 70 to 85 percent of the

NO_x removal efficiency achieved in oil-fired applications.

For dry low-NO_x combustion, cost effectiveness, in $/ton of NO_x removed, ranges from $1,060 for a 4.0 MW (5,360 hp) turbine down to $154 for an 85 MW (114,000 hp) machine. A cost effectiveness of $57 was calculated for the 83 MW (111,000 hp) unit. Again, the relatively high uncontrolled NO_x emissions and the resulting high NO_x removal efficiency for this turbine model yields a relatively low cost-effectiveness figure. Current dry low-NO_x combustion designs do not achieve NO_x reductions with oil fuels, so the cost-effectiveness values shown in this section apply only to gas-fired applications.

2.3.2.2 SCR Cost Effectiveness. Cost effectiveness for SCR was calculated based on the use of combustion controls upstream of the catalyst to reduce NO_x emissions to a range of 25 to 42 ppmv at the inlet to the catalyst. This approach was used because all available SCR cost information is for SCR applications used in combination with combustion controls and all but one of the 100+ SCR installations in the United States operate in combination with combustion controls. For this cost analysis, a 5-year catalyst life and a 9 ppmv controlled NO_x emission level was used to calculate cost effectiveness for SCR.

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Figure 2-9 presents SCR cost effectiveness. Figure 2-9 shows that, like combustion controls, SCR cost effectiveness is highest for the smallest turbines and decreases exponentially with decreasing turbine size.

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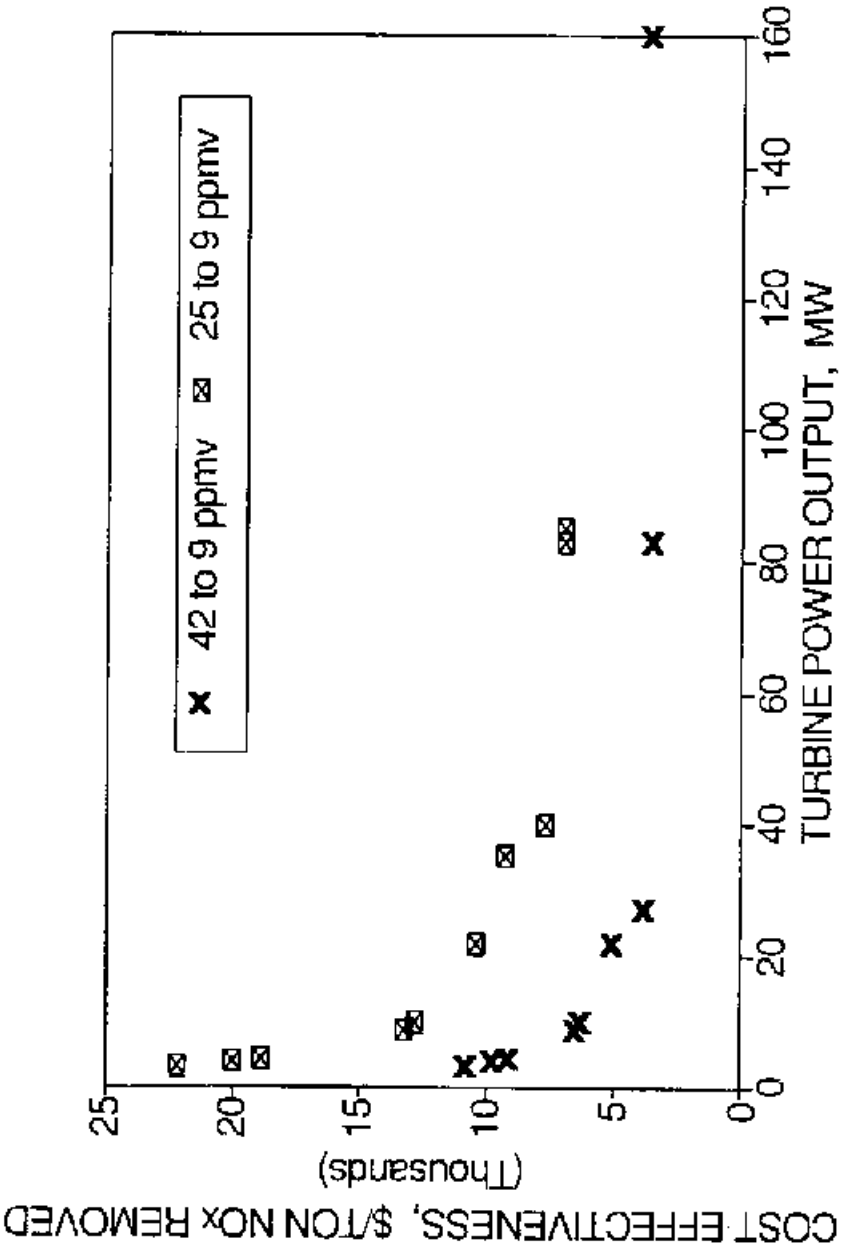


Figure 2-9. Cost effectiveness for selective catalytic reduction installed downstream of combustion controls.

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Also, because this cost analysis uses a 9 ppmv controlled NO_x emission level for SCR, NO_x reduction efficiencies are higher where the NO_x emission level into the SCR is 42 ppmv than for applications with a 25 ppmv level. Cost effectiveness corresponding to an inlet NO_x emission level of 42 ppmv, in $/ton of NO_x removed, ranges from a high of $10,800 for a 3.3 MW (4430 hp) turbine to $3,580 for a 161 MW (216,000 hp) turbine. For an inlet NO_x emission level of 25 ppmv, the cost-effectiveness range shifts higher, from $22,100 for a 3.3 MW (4,430 hp) installation to $6,980 for an 83 MW (111,000 hp) site.

The range of cost effectiveness for SCR shown in Figure 2-9 applies to gas-fired applications. Cost effectiveness developed for a limited number of oil-fired installations using capital costs from gas-fired applications yields cost-effectiveness values ranging from approximately 70 to 77 percent of those for gas-fired sites. The lower cost-effectiveness figures for oil-fired applications result primarily from the greater annual NO_x reductions for oil-fired applications; the gas-fired capital costs used for these oil-fired applications may understate the actual capital costs for these removal rates and actual oil-fired cost-effectiveness figures may be higher.

Combined cost-effectiveness figures, in $/ton of NO_x removed, were calculated for the combination of combustion controls plus SCR by dividing the sum of the total annual costs by the sum of the NO_x removed for both control techniques. The controlled NO_x emission level for the combination of controls is 9 ppmv. These combined cost-effectiveness figures are presented in Figure 2-10.

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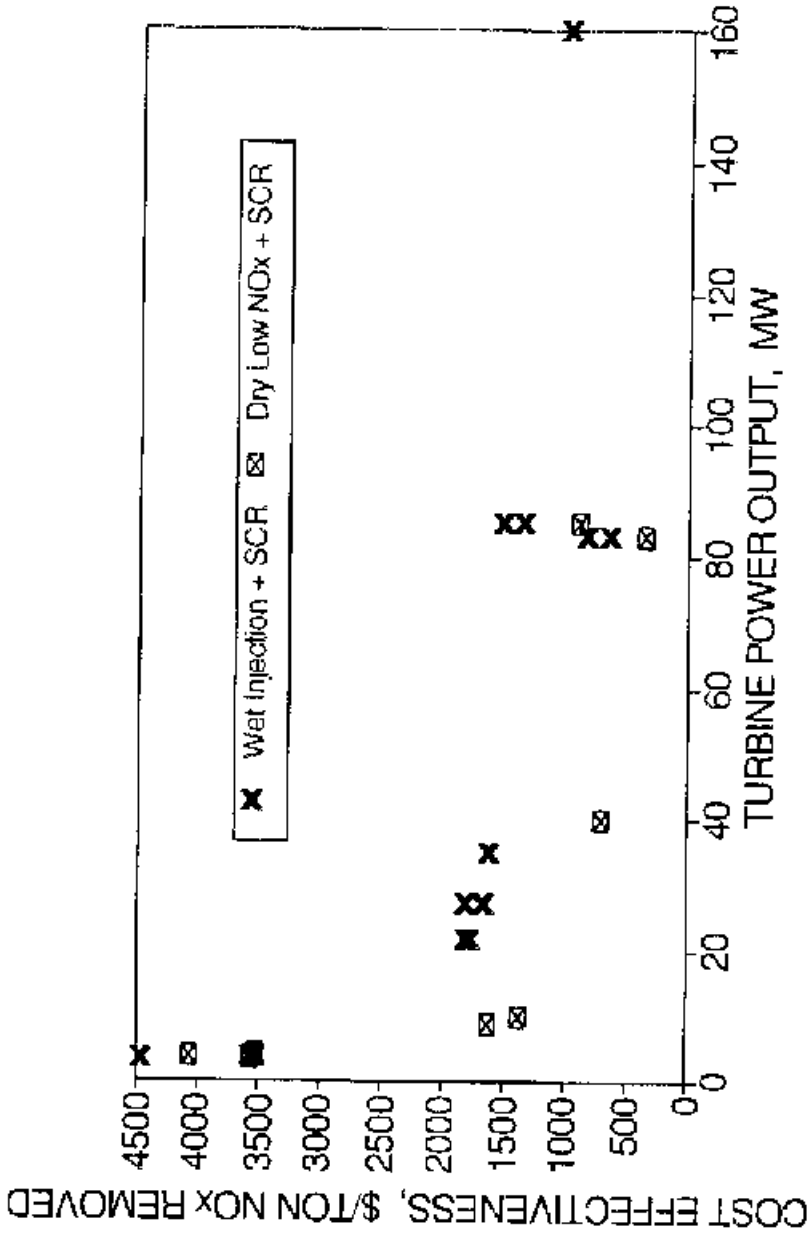


Figure 2-10. Combined cost effectiveness for combustion controls plus selective catalytic reduction.

For wet injection plus SCR, the combined cost effectiveness ranges from $4,460 for a 3.3 MW (4,430 hp) application to $988 for a 160 MW (216,000 hp) site. The $645 cost-effectiveness value for the 83 MW (111,000 hp) turbine is lower than the other turbine models shown in Figure 2-10 due to

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the relatively high uncontrolled NO_x emission level for this turbine, which results in relatively high NO_x removal rates and a lower cost effectiveness. For dry low-NO_x combustion plus SCR, combined cost-effectiveness values range from $4,060 to $348 for this turbine size range.

2.4 REVIEW OF CONTROLLED NO_x EMISSION LEVELS AND COSTS

An overview of the performance and costs for available NO_x control techniques is presented in Figure 2-11.

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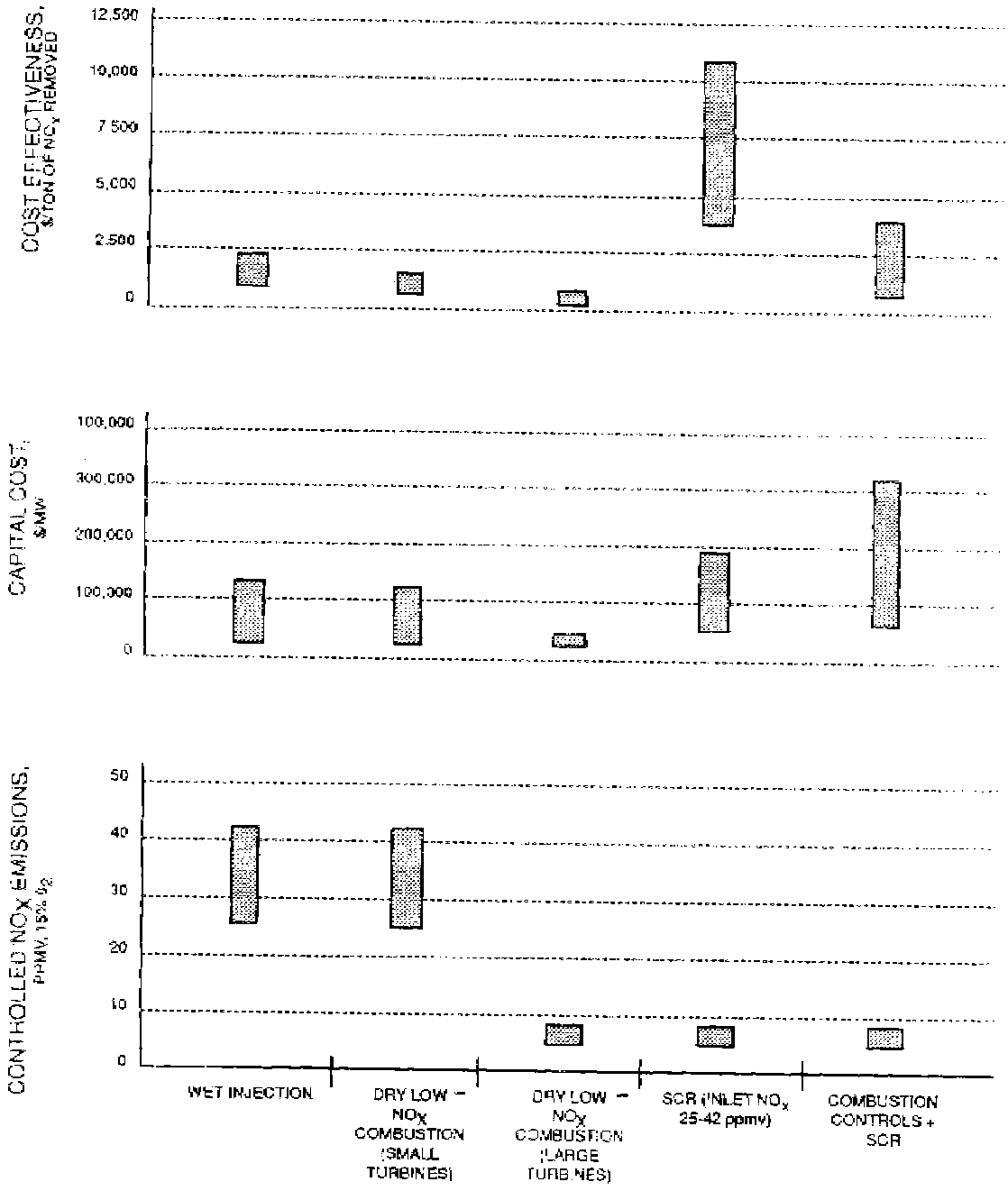


Figure 2-11. Controlled NO_x emission levels and associated capital costs and cost effectiveness for available NO_x control techniques. Natural gas fuel.

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Figure 2-11 shows relative achievable controlled NO_x emission levels, capital costs, and cost effectiveness for gas-fired turbine applications. Controlled NO_x emission levels of 25 to 42 ppmv can be achieved using either wet injection or, where available, dry low-NO_x combustion. Wet injection capital costs range from $30,000 to $140,000 per MW ($22 to $104 per hp), and cost effectiveness ranges from $375 to $2,100 per ton of NO_x removed. Dry low-NO_x combustion capital costs range from $25,000 to $115,000 per MW ($19 to $86 per hp), and cost effectiveness ranges from $55 to $1,050 per ton of NO_x removed.

A controlled NO_x emission level of 9 ppmv requires the addition of SCR, except for a limited number of large turbine models for which dry low-NO_x combustion designs can achieve this level. For turbine models above 40 MW (53,600 hp), the capital costs of dry low-NO_x combustion range from $25,000 to $36,000 per MW ($25 to $27 per hp), and the cost effectiveness ranges from $55 to $138 per ton of NO_x removed. Adding SCR to reduce NO_x emission levels from 42 or 25 ppmv to 9 ppmv adds capital costs ranging from $53,000 to $190,000 per MW ($40 to $142 per hp) and yields cost-effectiveness values ranging from $3,500 to $10,500 per ton of NO_x removed. The combination of combustion controls plus SCR yields combined capital costs ranging from $78,000 to $330,000 per MW ($58 to $246 per hp) and cost-effectiveness values ranging from $350 to $4,500 per ton of NO_x removed.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

The use of the NO_x control techniques described in this document may affect the turbine performance and maintenance

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requirements and may result in increased emissions of carbon monoxide (CO), hydrocarbons (HC), and NH_3. These potential energy and environmental impacts are discussed in this section.

Water or steam injection affects turbine performance and in some turbines also affects maintenance requirements. The increased mass flow through the turbine resulting from water or steam injection increases the available power output. The quenching effect in the combustor, however, decreases combustion efficiency, and consequently the efficiency of the turbine decreases in most applications. The efficiency reduction is greater for water than for steam injection, largely because the heat of vaporization energy cannot be recovered in the turbine. In applications where the steam can be produced from turbine exhaust heat that would otherwise be rejected to the atmosphere, the net gas turbine efficiency is increased with steam injection. Injection of water or steam into the combustor increases the maintenance requirements of the hot section of some turbine models. Water injection generally has a greater impact than steam on increased turbine maintenance. Water or steam injection has the potential to increase CO and, to a lesser extent, HC emissions, especially at water-to-fuel ratios above 0.8.

Turbine manufacturers report no significant performance impacts for lean premixed combustors. Power output and efficiency are comparable to conventional designs. No maintenance impacts are reported, although long-term operating experience is not available. Impacts on CO emissions vary for different combustor designs. Limited data from three manufacturers showed minimal or no increases in CO emissions for controlled NO_x emission levels of 25 to 42 ppmv. For a controlled NO_x level of 9 ppmv, however, CO emissions increased in from 10 to 25 ppmv in one manufacturer's combustor design.

For SCR, the catalyst reactor increases the back-pressure on the turbine, which decreases the turbine power output by approximately 0.5 percent. The addition of the SCR system and associated controls and monitoring equipment increases plant maintenance requirements, but it is expected that these

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maintenance requirements are consistent with maintenance schedules for other plant equipment. There is no impact on CO or HC emissions from the turbine caused by the SCR system, but ammonia slip through the catalyst reactor results in NH_3 emissions. Ammonia slip levels are typically guaranteed by SCR vendors at 10 ppmv, and operating experience indicates actual NH_3 emissions are at or below this level.

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3.0 STATIONARY GAS TURBINE DESCRIPTION AND INDUSTRY APPLICATIONS

This section describes the physical components and operating cycles of gas turbines and how turbines are used in industry. Projected growth in key industries is also presented.

3.1 GENERAL DESCRIPTION OF GAS TURBINES

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A common example of a gas turbine is the aircraft jet engine. In stationary applications, the hot combustion gases are directed through one or more fan-like turbine wheels to generate shaft horsepower rather than the thrust propulsion generated in an aircraft engine. Often the heat from the exhaust gases is recovered through an add-on heat exchanger.

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Figure 3-1

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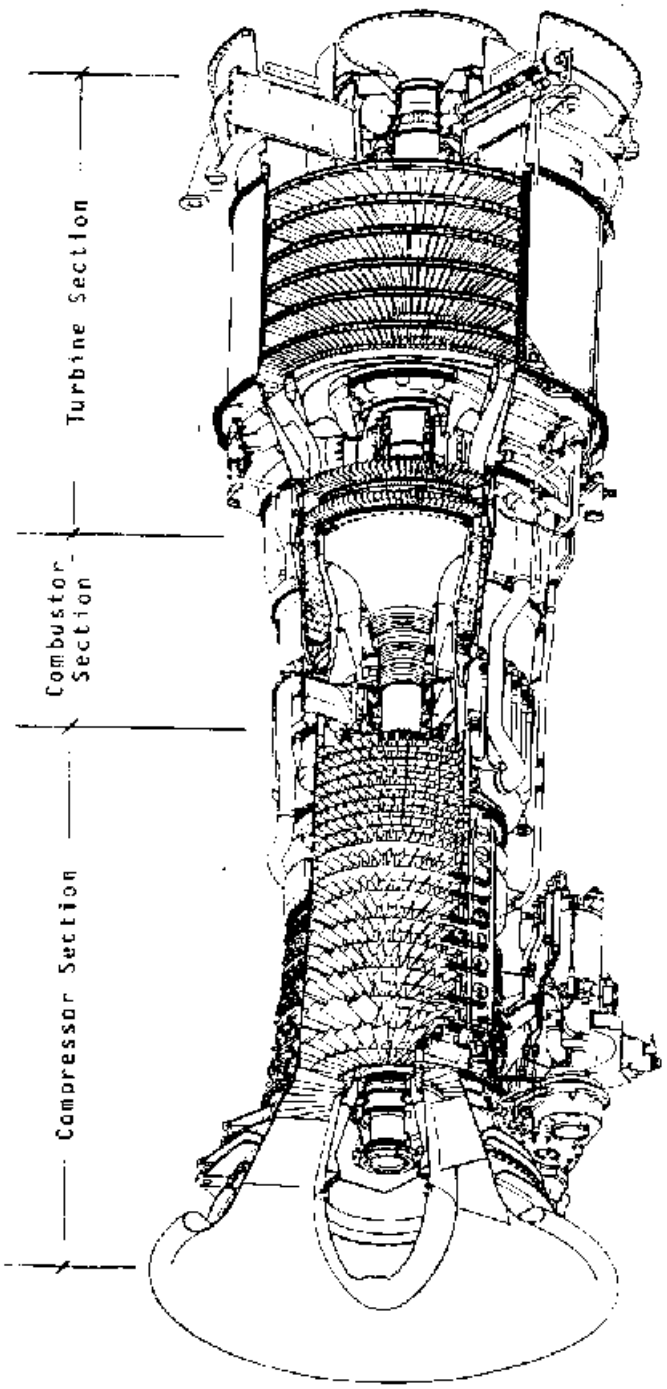


Figure 3-1. The three primary sections of a gas turbine.[1]

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presents a cutaway view showing the three primary sections of a gas turbine: the compressor, the combustor, and the turbine.[1] The compressor draws in ambient air and compresses it by a pressure ratio of up to 30 times ambient pressure.[2] The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. There are three types of combustors: annular, can-annular, and silo. An annular combustor is a single continuous chamber roughly the shape of a doughnut that rings the turbine in a plane perpendicular to the air flow. The can-annular type uses a similar configuration but is a series of can-shaped chambers rather than a single continuous chamber. The silo combustor type is one or more chambers mounted external to the gas turbine body. These three combustor types are shown in Figure 3-2

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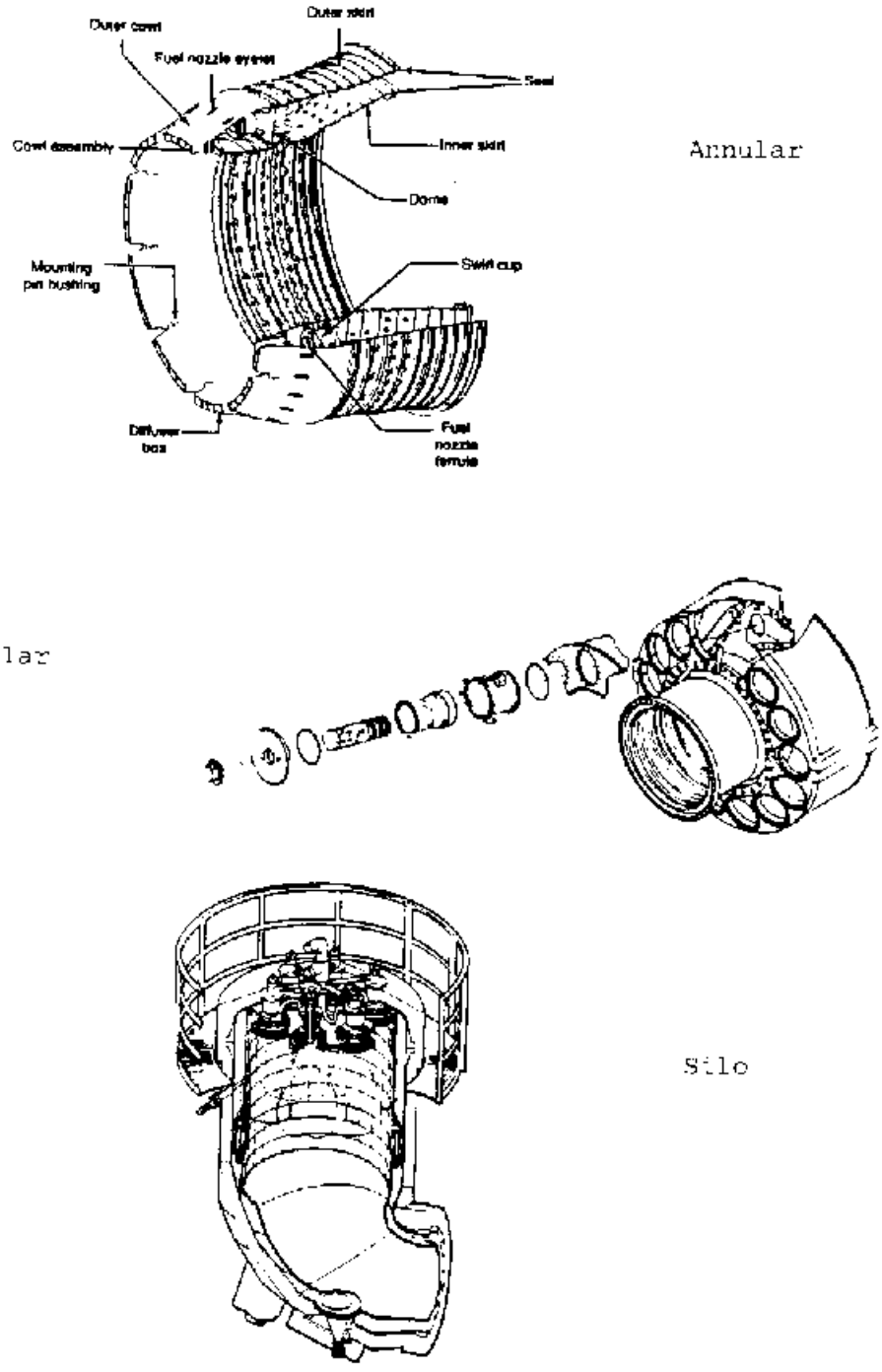


Figure 3-2. Types of gas turbine combustors.[3-5]

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; further discussion of combustors is found in Chapter 5.[3-5] Flame temperatures in the combustor can reach 2000°C (3600°F).[6] The hot combustion gases

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are then diluted with additional cool air from the compressor section and directed to the turbine section at temperatures up to 1285°C (2350°F).[6] Energy is recovered in the turbine section in the form of shaft horsepower, of which typically greater than 50 percent is required to drive the internal compressor section.[7] The balance of the recovered shaft energy is available to drive the external load unit.

The compressor and turbine sections can each be a single fan-like wheel assembly, or stage, but are usually made up of a series of stages. In a single-shaft gas turbine, shown in Figure 3-3

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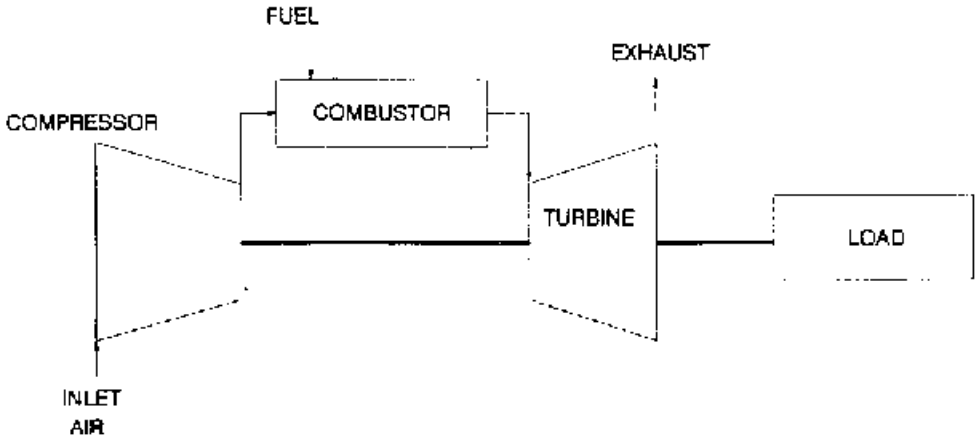


Figure 3-3. Single-shaft gas turbine.

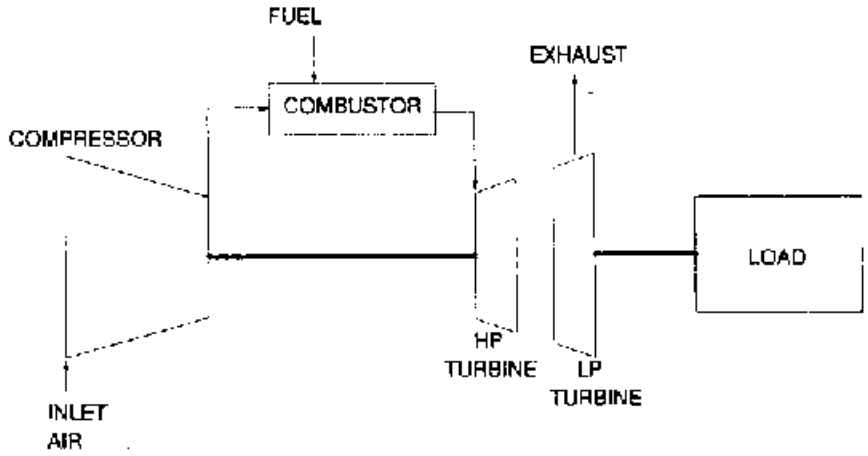


Figure 3-4. Two-shaft gas turbine.

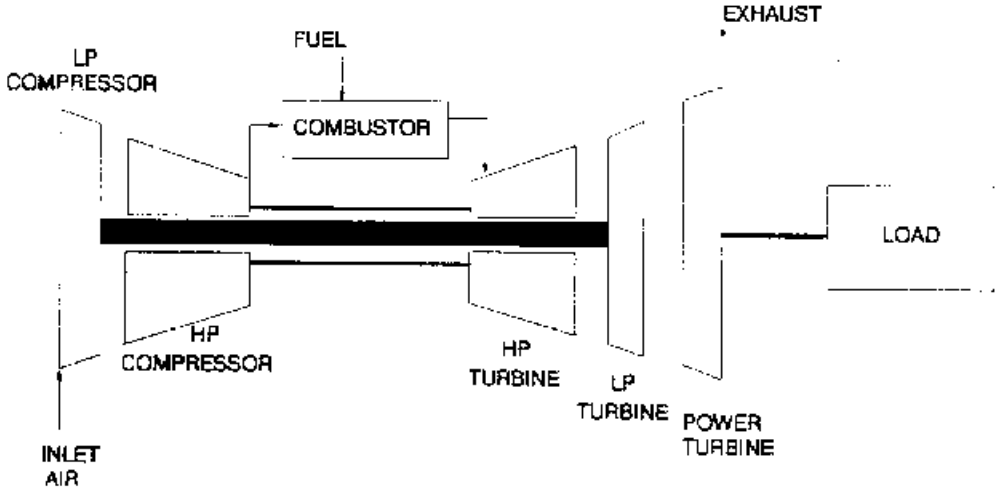


Figure 3-5. Three-shaft gas turbine.

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, all compressor and turbine stages are fixed to a single, continuous shaft and operate at the same speed. A single-shaft gas turbine is typically used to drive electric generators where there is little speed variation.

A two-shaft gas turbine is shown in Figure 3-4. In this design, the turbine section is divided into a high-pressure and low-pressure arrangement, where the high-pressure turbine is mechanically tied to the compressor section by one shaft, while the low-pressure turbine, or power turbine, has its own shaft and is connected to the external load unit. This configuration allows the high-pressure turbine/compressor shaft assembly, or rotor, to operate at or near optimum design speeds, while the power turbine rotor speed can vary over as wide a range as is required by most external-load units in mechanical drive applications (i.e., compressors and pumps).

A third configuration is a three-shaft gas turbine. As shown in Figure 3-5, the compressor section is divided into a low-pressure and high-pressure configuration. The low-pressure compressor stages are mechanically tied to the low-pressure turbine stages, and the high-pressure compressor stages are similarly connected to the high-pressure turbine stages in a concentric shaft arrangement. These low-pressure and high-pressure rotors operate at optimum design speeds independent of each other. The power turbine stages are mounted on a third independent shaft and form the power turbine rotor, the speed of

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which can vary over as wide a range as is necessary for mechanical drive applications.

Gas turbines can burn a variety of fuels. Most burn natural gas, waste process gases, or liquid fuels such as distillate oils (primarily No. 2 fuel oil). Some gas turbines are capable of burning lower-grade residual or even crude oil with minimal processing. Coal-derived gases can be burned in some turbines.

The capacity of individual gas turbines ranges from approximately 0.08 to over 200 megawatts (MW) (107 to 268,000 horsepower [hp]).[2] Manufacturers continue to increase the horsepower of individual gas turbines, and frequently they are "ganged," or installed in groups so that the total horsepower output from one location can meet virtually any installation's power requirements.

Several characteristics of gas turbines make them attractive power sources. These characteristics include a high horsepower-to-size ratio, which allows for efficient space utilization, and a short time from order placement to on-line operation. Many suppliers offer the gas turbine, load unit, and all accessories as a fully assembled package that can be performance tested at the supplier's facility. This packaging is cost effective and saves substantial installation time. Other advantages of gas turbines are:

1. Low vibration;
2. High reliability;
3. No requirement for cooling water;
4. Suitability for remote operation;
5. Lower capital costs than reciprocating engines; and
6. Lower capital costs than boiler/steam turbine-based electric power generating plants.[8]

3.2 OPERATING CYCLES

The four basic operating cycles for gas turbines are simple, regenerative, cogeneration, and combined cycles. Each of these cycles is described separately below.

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3.2.1 Simple Cycle

The simple cycle is the most basic operating cycle of a gas turbine. In a simple cycle application, a gas turbine functions with only the three primary sections described in Section 3.1, as depicted in Figure 3-6.

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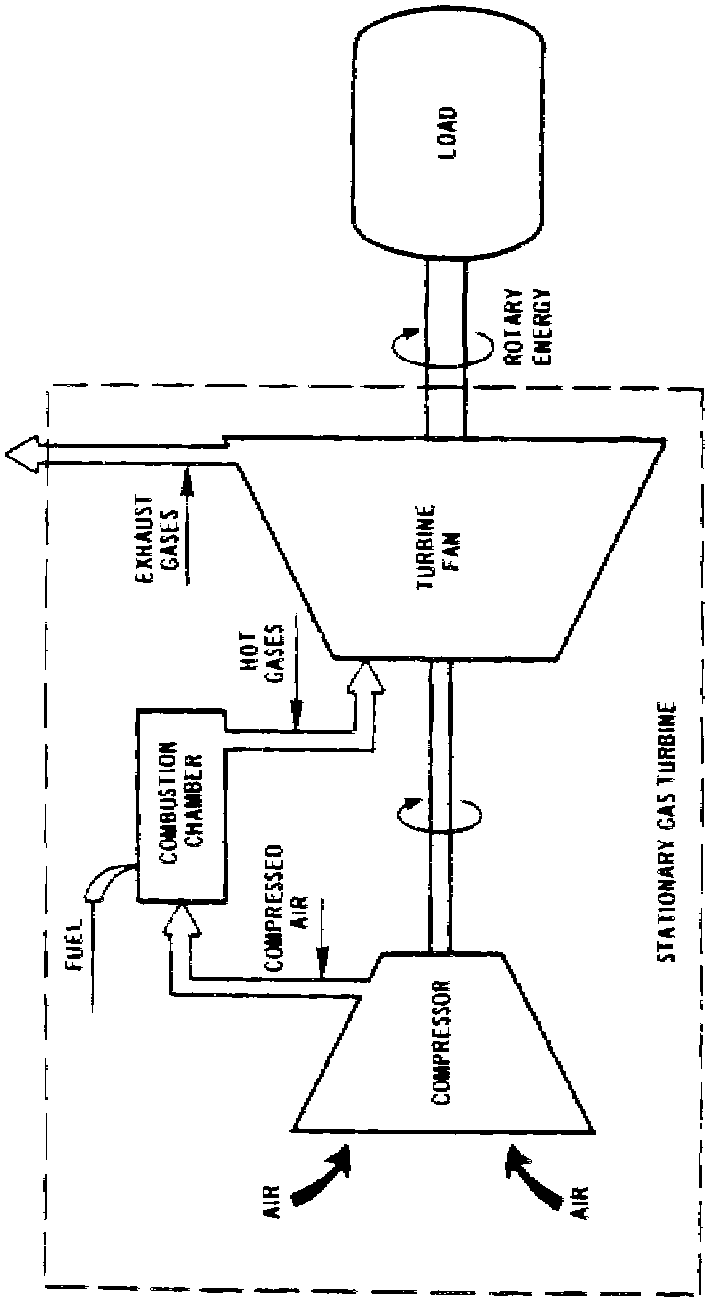


Figure 3-6. Simple cycle gas turbine appplication.[10]

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[10] Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range, although one manufacturer states an efficiency of 40 percent for an engine recently introduced to the market.[9] In addition to shaft energy output, 1 to 2 percent of the fuel input energy can be attributed to mechanical losses; the balance is exhausted from the turbine in the form of heat.[7] Simple cycle operation is typically used when there is a requirement for shaft horsepower without recovery of the exhaust heat. This cycle offers the lowest installed capital cost but also provides the least efficient use of fuel and therefore the highest operating cost.

3.2.2 Regenerative Cycle

The regenerative cycle gas turbine is essentially a simple cycle gas turbine with an added heat exchanger, called a regenerator or recuperator, to preheat the combustion air. In the regenerative cycle, thermal energy from the exhaust gases is transferred to the compressor discharge air prior to being introduced into the combustor. A diagram of this cycle is depicted in Figure 3-7

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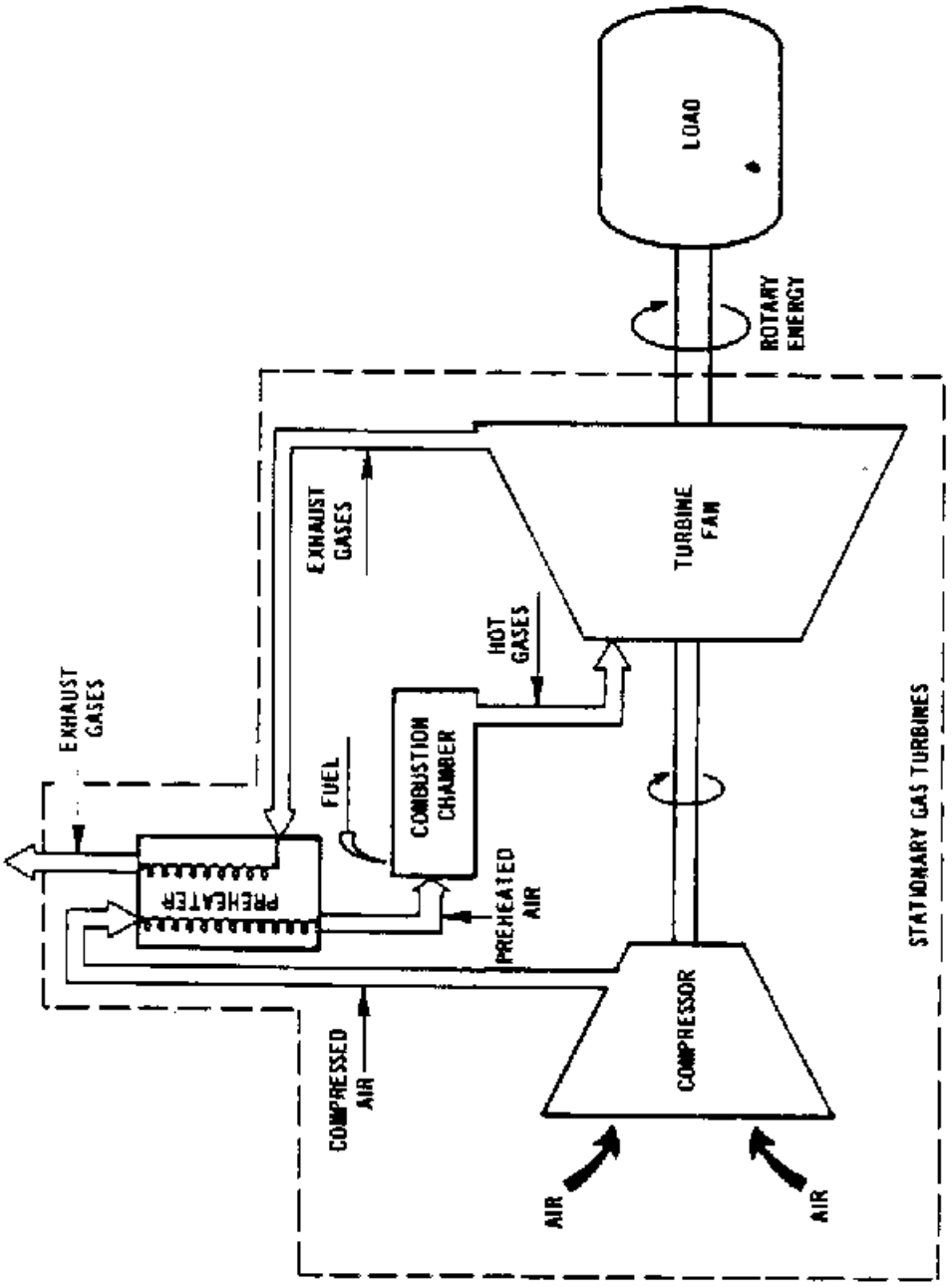


Figure 3-7. Regenerative cycle gas turbine.[11]

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.[11] Preheating the combustion air reduces the amount of fuel required to reach design combustor temperatures and therefore improves the overall cycle efficiency over that of simple cycle operation. The efficiency gain is directly proportional to the differential temperature between the exhaust gases and compressor discharge air. Since the compressor discharge air temperature increases with an increase in pressure ratio, higher regenerative cycle efficiency gains are realized from lower compressor pressure ratios typically found in older gas turbine models.[7] Most new or updated gas turbine models with high compressor pressure ratios render regenerative cycle operation economically unattractive because the capital cost of the regenerator cannot be justified by the marginal fuel savings.

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3.2.3 Cogeneration Cycle

A gas turbine used in a cogeneration cycle application is essentially a simple cycle gas turbine with an added exhaust heat exchanger, called a heat recovery steam generator (HRSG). This configuration is shown in Figure 3-8

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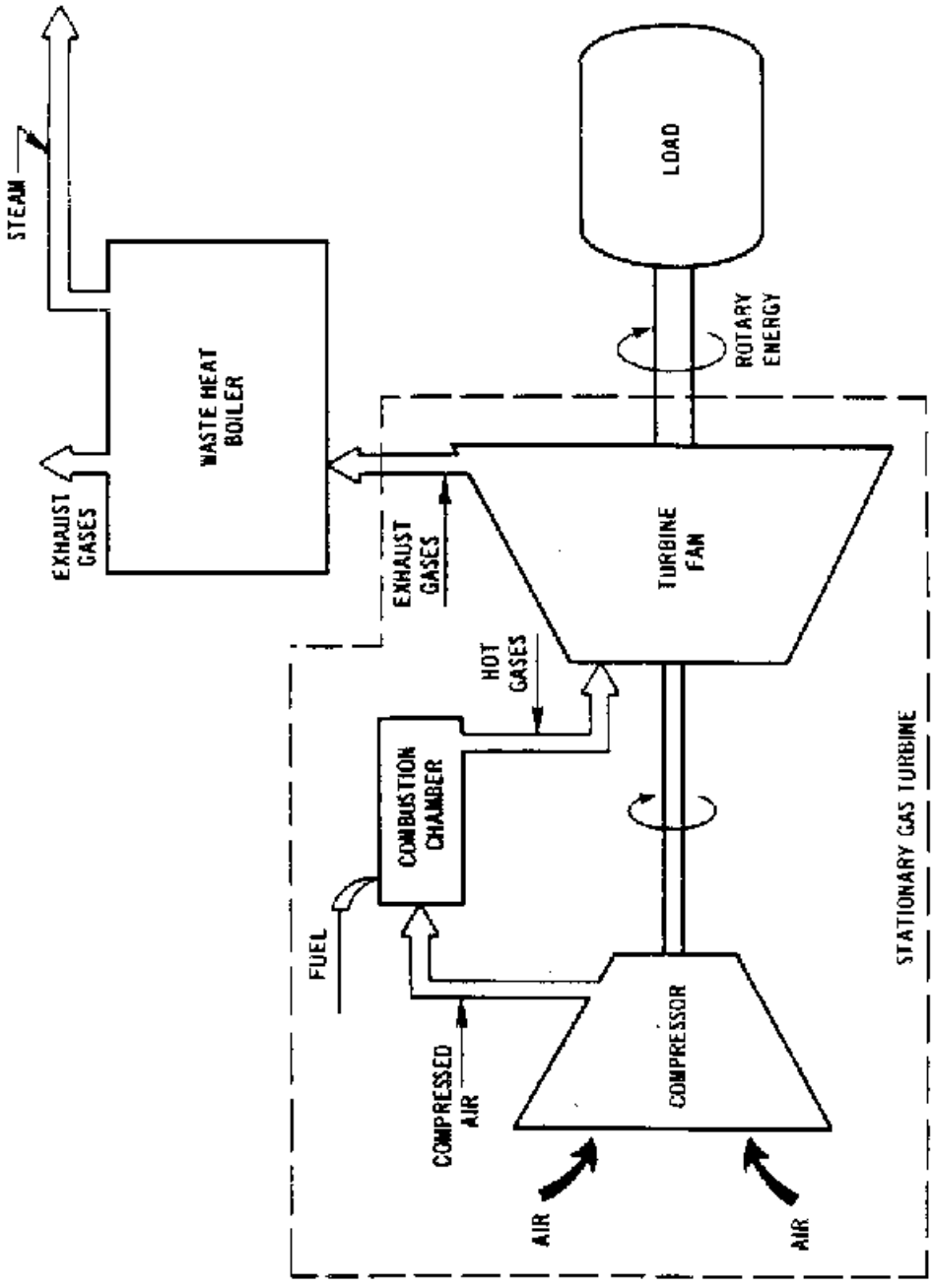


Figure 3-8. Cogeneration cycle gas turbine application.[12]

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.[12] The steam generated by the exhaust heat can be delivered at a variety of pressure and temperature conditions to meet site thermal process requirements. Where the exhaust heat is not sufficient to meet site requirements, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Adding the HRSG equipment increases the capital cost, but recovering the exhaust heat increases the overall cycle efficiency to as high as 75 percent.[13]

3.2.4 Combined Cycle

A combined cycle is the terminology commonly used for a gas turbine/HRSG configuration as applied at an electric utility. This cycle, shown in Figure 3-9

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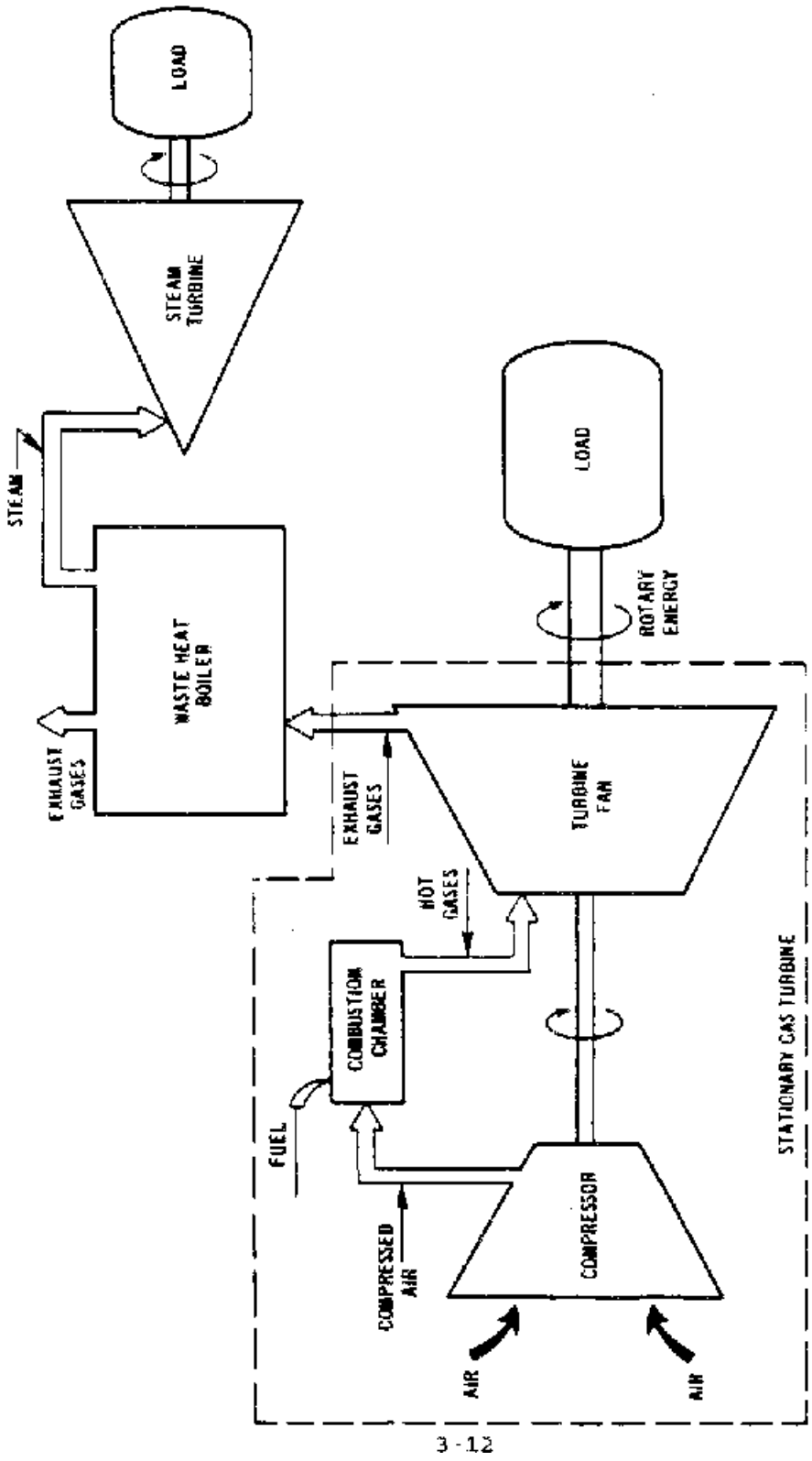


Figure 3-9. Combined cycle gas turbine application.[12]

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, is used to generate electric power.[12] The gas turbine drives an electric generator, and the steam produced in the HRSG is delivered to a steam turbine, which also drives an electric generator. The boiler may be supplementary-fired to increase the steam production where desired. Cycle efficiencies can exceed 50 percent.

3.3 INDUSTRY APPLICATIONS

Gas turbines are used by industry in both mechanical and electrical drive applications. Compressors and pumps are most often the driven load unit in mechanical drive applications, and electric generators are driven in electrical drive installations. Few sites have gas/air compression or fluid pumping requirements that exceed 15 MW (20,100 hp), and for this reason mechanical drive applications generally use gas turbines in the 0.08- to 15.0-MW (107- to 20,100-hp) range.[14] Electric power requirements range over the entire available range of gas turbines, however, and all sizes can be found in electrical drive applications, from 0.08 to greater than 200 MW (107 to 268,000 hp).[15]

The primary applications for gas turbines can be divided into five broad categories: the oil and gas industry,

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stand-by/emergency electric power generation, independent electric power producers, electric utilities, and other industrial applications.[16] Where a facility has a requirement for mechanical shaft power only, the installation is typically simple or regenerative cycle. For facilities where either electric power or mechanical shaft power and steam generation are required, the installation is often cogeneration or combined cycle to capitalize on these cycles' higher efficiencies.

3.3.1 Oil and Gas Industry

The bulk of mechanical drive applications are in the oil and gas industry. Gas turbines in the oil and gas industry are used primarily to provide shaft horsepower for oil and gas extraction and transmission equipment, although they are also used in downstream refinery operations. Most gas turbines found in this industry are in the 0.08- to 15.0-MW (107- to 20,100-hp) range.

Gas turbines are particularly well suited to this industry, as they can be fueled by a wide range of gaseous and liquid fuels often available at the site. Natural gas and distillate oil are the most common fuels. Many turbines can burn waste process gases, and some turbines can burn residual oils and even crude oil. In addition, gas turbines are suitable for remote installation sites and unattended operation. Most turbines used in this industry operate continuously, 8,000+ hours per year, unless the installation is a pipeline transmission application with seasonal operation.

Competition from reciprocating engines in this industry is significant. Although gas turbines have a considerable capital cost advantage, reciprocating engines require less fuel to produce the same horsepower and consequently have a lower operating cost.[17] Selection of gas turbines vs. reciprocating engines is generally determined by site-specific criteria such as installed capital costs, costs for any required emissions control equipment, fuel costs and availability, annual operating hours, installation and structural considerations, compatibility with existing equipment, and operating experience.

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3.3.2 Stand-By/Emergency Electric Power Generation

Small electric generator sets make up a considerable number of all gas turbine sales under 3.7 MW (5,000 hp). The majority of these installations provide backup or emergency power to critical networks or equipment and use liquid fuel. Telephone companies are a principal user, and hospitals and small municipalities also are included in this market. These turbines operate on an as-needed basis, which typically is between 75 and 200 hours per year.

Gas turbines offer reliable starting, low weight, small size, low vibration, and relatively low maintenance, which are important criteria for this application. Gas turbines in this size range have a relatively high capital cost, however, and reciprocating engines dominate this market, especially for applications under 2,000 kW (2,700 hp).[18,19]

3.3.3 Independent Electrical Power Producers

Large industrial complexes and refining facilities consume considerable amounts of electricity, and many sites choose to generate their own power. Gas turbines can be used to drive electric generators in simple cycle operation, or an HRSG system may be added to yield a more efficient cogeneration cycle. The vast majority of cogeneration installations operate in a combined cycle capacity, using a steam turbine to provide additional electric power. The Public Utility Regulatory Policies Act (PURPA) of 1978 encourages independent cogenerators to generate electric power by requiring electric utilities to (1) purchase electricity from qualifying producers at a price equal to the cost the utility can avoid by not having to otherwise supply that power (avoided cost) and (2) provide backup power to the cogenerator at reasonable rates. Between 1980 and 1986, approximately 20,000 MW of gas turbine-produced electrical generating capacity was certified as qualifying for PURPA benefits. This installed capacity by private industry power generators is more than the sum of all utility gas turbine orders for all types of central power plants during this period.[20] The Department of Energy (DOE) expects an additional 27,000 MW

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capacity to be purchased by private industry in the next 10 years.[21]

Gas turbines installed in this market range in power from 1 to over 100 MW (1,340 to 134,000 hp) and operate typically between 4,000 and 8,000 hours per year. While reciprocating engines compete with the gas turbine at the lower end of this market (under approximately 7.5 MW [10,000 hp]), the advantages of lower installed costs, high reliability, and low maintenance requirements make gas turbines a strong competitor.

3.3.4 Electric Utilities

Electric utilities are the largest user of gas turbines on an installed horsepower basis. They have traditionally installed these turbines for use as peaking units to meet the electric power demand peaks typically imposed by large commercial and industrial users on a daily or seasonal basis; consequently, gas turbines in this application operate less than 2,000 hours per year.[22] The power range used by the utility market is 15 MW to over 150 MW (20,100 to 201,000 hp). Peaking units typically operate in simple cycle.

The demand for gas turbines from the utility market was flat through the late 1970's and 1980's as the cost of fuel increased and the supplies of gas and oil became unpredictable. There are signs, however, that the utility market is poised to again purchase considerable generating capacity. The capacity margin, which is the utility industry's measure of excess generation capacity, peaked at 30 percent in 1982. By 1990, the capacity margin had dropped to approximately 20 percent, and, based on current construction plans, will reach the industry rule-of-thumb minimum of 15 percent by 1995.[21] The utility industry is adding new capacity and repowering existing older plants, and gas turbines are expected to play a considerable role.

Many utilities are now installing gas turbine-based combined cycle installations with provisions for burning coal-derived gas fuel at some future date. This application is known as integrated coal gasification combined cycle (IGCC). At least five power plant projects have been announced, and several more

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are being negotiated. Capital costs for these plants are in many cases higher than comparable natural gas-fueled applications, but future price increases for natural gas could make IGCC an attractive option for the future.[23]

Utility orders for gas turbines have doubled in each of the last 2 years. The DOE says that electric utilities will need to add an additional 73,000 MW to capacity to meet demand by the year 2000, and as Figure 3-10

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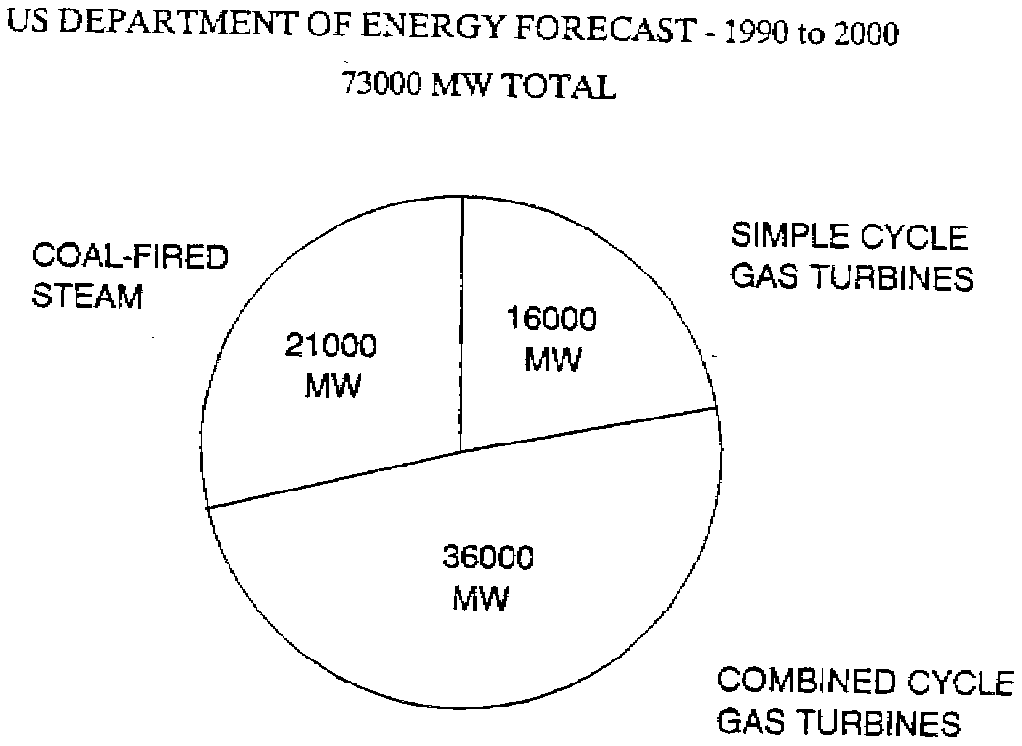


Figure 3-10. Total capacity to be purchased by the utility industry.[21]

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shows, DOE expects 36,000 MW of combined cycle and 16,000 MW of simple cycle gas turbines to be purchased. This renewed interest in gas turbines is a result of:

1. The introduction of new, larger, more efficient gas turbines;

2. Lower natural gas prices and proven reserves to meet current demand levels for more than 100 years;

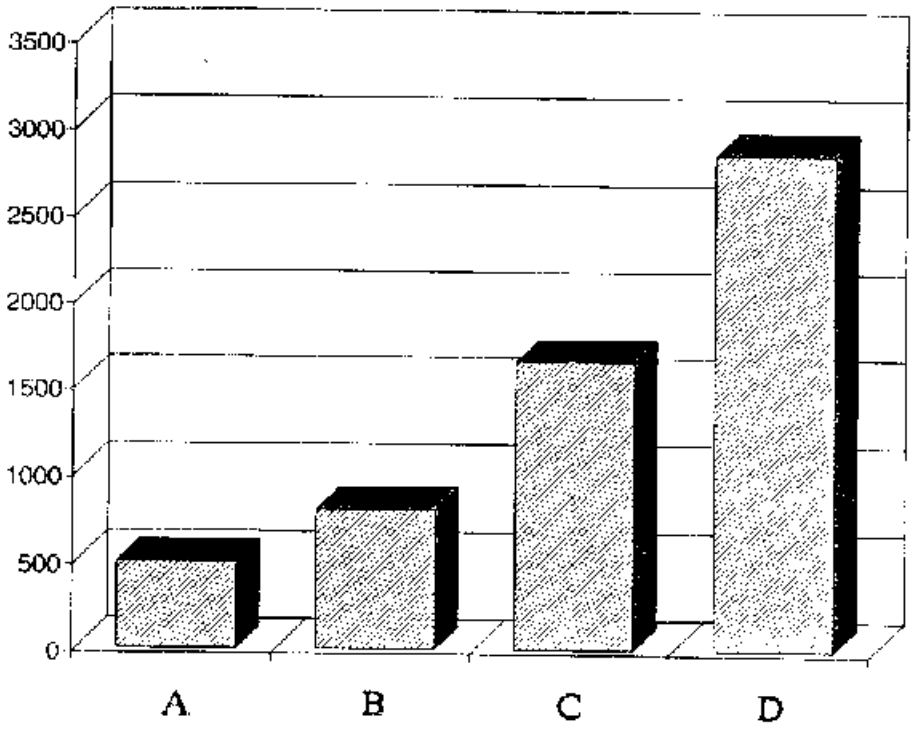
3. Shorter lead times than those of competing equipment; and

4. Lower capital costs for gas turbines.[21]

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Utility capital cost estimates, as shown in Figure 3-11

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A - Repower existing plant using combined cycle gas turbines
B - New plant using combined cycle gas turbines
C - New plant using coal fired boilers
D - New plant using nuclear power

Figure 3-11. Capital costs for electric utility plants.[24]

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, are (1) $500 per KW for repowering existing plants with combined cycle gas turbines, (2) $800 per KW for new combined cycle plants, (3) $1,650 per KW for new coal-fired plants, and (4) $2,850 per KW for new nuclear-powered plants.[24]

Gas turbines are also an alternative to displace planned or existing nuclear facilities. A total of 1,020 MW of gas turbine-generated electric power was recently commissioned in Michigan at a plant where initial design and construction had begun for a nuclear plant. Four additional idle nuclear sites are considering switching to gas turbine-based power production due to the legal, regulatory, financial, and public obstacles facing nuclear facilities.[24]

3.3.5 Other Industrial Applications

Industrial applications for gas turbines include various types of mechanical drive and air compression equipment. These applications peaked in the late 1960's and declined through the 1970's.[25] With the promulgation of PURPA in 1978 (see Section 3.3.3), many industrial facilities have found it

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economically feasible to install a combined cycle gas turbine to meet power and steam requirements. Review of editions of Gas Turbine World over the last several years shows that a broad range of industries (e.g., pulp and paper, chemical, and food processing) have installed combined cycle gas turbines to meet their energy requirements.

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4.0 CHARACTERIZATION OF NO_x EMISSIONS

This section presents the principles of NO_x formation, the types of NO_x emitted (i.e., thermal NO_x, prompt NO_x, and fuel NO_x), and how they are generated in a gas turbine combustion process. Estimated NO_x emission factors for gas turbines and the bases for the estimates are also presented.

4.1 THE FORMATION OF NO_x

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of nitrogen (N_2) and oxygen (O_2) into N and O, respectively. Reactions following this dissociation result in seven known oxides of nitrogen: NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, and N_2O_5. Of these, nitric oxide (NO) and nitrogen dioxide (NO_2) are formed in sufficient quantities to be significant in atmospheric pollution.[1] In this document, "NO_x" refers to either or both of these gaseous oxides of nitrogen.

Virtually all NO_x emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule.[2] There are two mechanisms by which NO_x is formed in turbine combustors: (1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x). These mechanisms are discussed below.

4.1.1 Formation of Thermal and Prompt NO_x

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen.

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The major contributing chemical reactions are known as the Zeldovich mechanism and take place in the high temperature area of the gas turbine combustor.[3] Simply stated, the Zeldovich mechanism postulates that thermal NO_x formation increases exponentially with increases in temperature and linearly with increases in residence time.[4]

Flame temperature is dependent upon the equivalence ratio, which is the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.[5] An equivalence ratio of 1.0 corresponds to the stoichiometric ratio and is the point at which a flame burns at its highest theoretical temperature.[5] Figure 4-1

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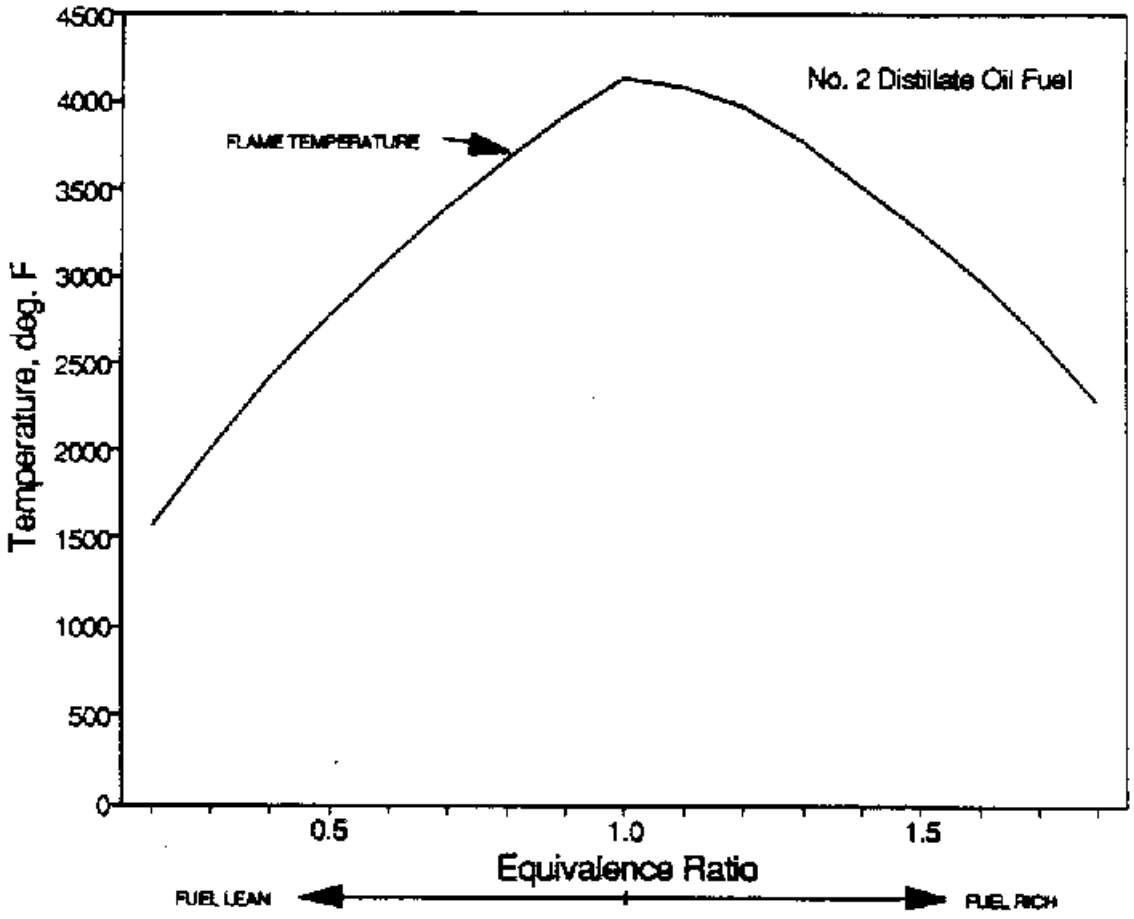


Figure 4-1. Influence of equivalence ratio on flame temperature.[4]

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shows the flame temperature and equivalence ratio relationship for combustion using No. 2 distillate fuel oil (DF-2).[4]

The series of chemical reactions that form thermal NO_x according to the Zeldovich mechanism are presented below.[3]

1. $O_2 \rightleftharpoons 2O$;

2. $N_2 \rightleftharpoons 2N$;

3. $N + O \rightleftharpoons NO$;

4. $N + O_2 \rightleftharpoons NO + O$; and

5. $O + N_2 \rightleftharpoons NO + N$.

This series of equations applies to a fuel-lean combustion process. Combustion is said to be fuel-lean when there is excess oxygen available (equivalence ratio <1.0). Conversely, combustion is fuel-rich if insufficient oxygen is present to burn all of the available fuel (equivalence ratio >1.0). Additional equations have been developed that apply to fuel-rich combustion. These equations are an expansion of the above series to add an intermediate hydroxide molecule (OH):[3]

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6. $N + OH \rightleftharpoons NO + H$,

and further to include an intermediate product, hydrogen cyanide (HCN), in the formation process:[3]

7. $N_2 + CH \rightleftharpoons HCN + N$ and

8. $N + OH \rightleftharpoons H + NO$.

The overall equivalence ratio for gases exiting the gas turbine combustor is less than 1.0.[4] Fuel-rich areas do exist in the overall fuel-lean environment, however, due to less-than-ideal fuel/air mixing prior to combustion. This being the case, the above equations for both fuel-lean and fuel-rich combustion apply for thermal NO_x formation in gas turbines.

Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_x as shown in the following equations:

1. $CH + N_2 \rightleftharpoons HCN + N$;

2. $CH_2 + N_2 \rightleftharpoons HCN + NH$; and

3. $HCN, N, NH + O_x \rightleftharpoons NO + ...$[6]

Prompt NO_x is formed in both fuel-rich flame zones and fuel-lean premixed combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution increases with decreases in the equivalence ratio (fuel-lean mixtures). For this reason, prompt NO_x becomes an important consideration for the low-NO_x combustor designs described in Chapter 5 and establishes a minimum NO_x level attainable in lean mixtures.[7]

4.1.2 Formation of Fuel NO_x

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as

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N_2 in some natural gas, does not contribute significantly to fuel NO_x formation.[8] However, nitrogen compounds are present in coal and petroleum fuels as pyridine-like (C_5H_5N) structures that tend to concentrate in the heavy resin and asphalt fractions upon distillation. Some low-British thermal unit (Btu) synthetic fuels contain nitrogen in the form of ammonia (NH_3), and other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x.[9] With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NO_x decreases with increasing nitrogen content, although the absolute magnitude of fuel NO_x increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NO_x, whereas a fuel with a 1.0 percent FBN may have only a 40 percent fuel NO_x conversion rate. The low-percentage FBN fuel has a 100 percent conversion rate, but its overall NO_x emission level would be lower than that of the high-percentage FBN fuel with a 40 percent conversion rate.[10]

Nitrogen content varies from 0.1 to 0.5 percent in most residual oils and from 0.5 to 2 percent for most U.S. coals.[11] Traditionally, most light distillate oils have had less than 0.015 percent nitrogen content by weight. However, today many distillate oils are produced from poorer-quality crudes, especially in the northeastern United States, and these distillate oils may contain percentages of nitrogen exceeding the 0.015 threshold; this higher nitrogen content can increase fuel NO_x formation.[4] At least one gas turbine installation burning coal-derived fuel is in commercial operation in the United States.[12]

Most gas turbines that operate in a continuous duty cycle are fueled by natural gas that typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not

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currently a major contributor to overall NO_x emissions from stationary gas turbines.

4.2 UNCONTROLLED NO_x EMISSIONS

The NO_x emissions from gas turbines are generated entirely in the combustor section and are released into the atmosphere via the stack. In the case of simple and regenerative cycle operation, the combustor is the only source of NO_x emissions. In cogeneration and combined cycle applications, a duct burner may be placed in the exhaust ducting between the gas turbine and the heat recovery steam generator (HRSG); this burner also generates NO_x emissions. (Gas turbine operating cycles are discussed in Section 3.2.) The amount of NO_x formed in the combustion zone is "frozen" at this level regardless of any temperature reductions that occur at the downstream end of the combustor and is released to the atmosphere at this level.[1]

4.2.1 Parameters Influencing Uncontrolled NO_x Emissions

The level of NO_x formation in a gas turbine, and hence the NO_x emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_x generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output level as a percentage of the rated full power output of the turbine. These factors are discussed below.

4.2.1.1 Combustor Design. The design of the combustor is the most important factor influencing the formation of NO_x. Design considerations are presented here and discussed further in Chapter 5.

Thermal NO_x formation, as discussed in Section 4.1.1, is influenced primarily by flame temperature and residence time. Design parameters controlling equivalence ratios and the introduction of cooling air into the combustor strongly influence thermal NO_x formation. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_x production

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takes place.[13] The dependence of thermal NO_x formation on flame temperature and equivalence ratio is shown in Figure 4-2

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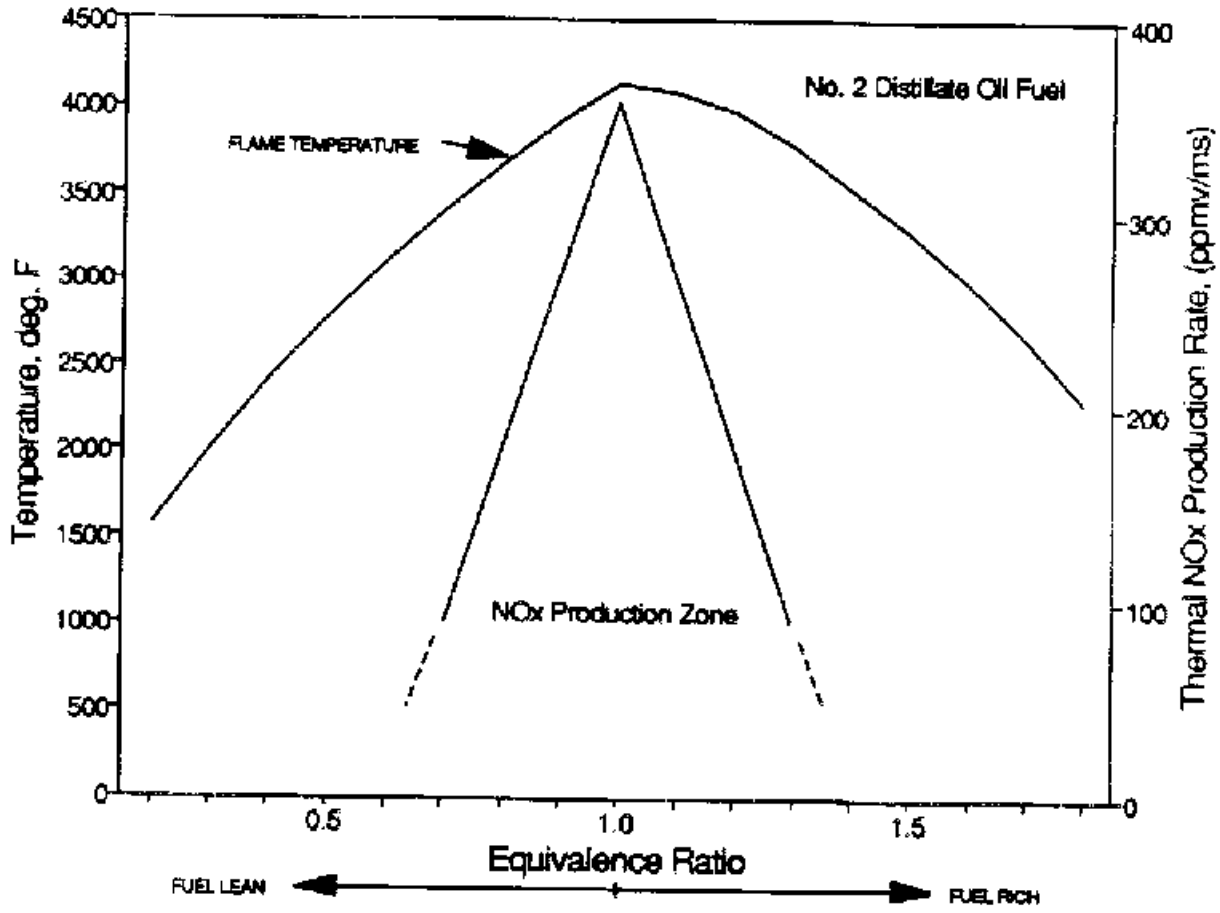


Figure 4-2. Thermal NO_x production as a function of flame temperature and equivalence ratio.[4]

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for DF-2.[4] Conversely, prompt NO_x is largely insensitive to changes in temperature and pressure.[7]

Fuel NO_x formation, as discussed in Section 4.1.2, is formed when FBN is released during combustion and oxidizes to form NO_x. Design parameters that control equivalence ratio and residence time influence fuel NO_x formation.[14]

4.2.1.2 Type of Fuel. The level of NO_x emissions varies for different fuels. In the case of thermal NO_x, this level increases with flame temperature. For gaseous fuels, the constituents in the gas can significantly affect NO_x emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (e.g., ethane, propane, and butane) burn at higher flame temperatures and as a result can increase NO_x emissions greater than 50 percent over NO_x levels for methane gas fuel. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons. Conversely, gas fuels that contain significant inert gases, such as CO_2, generally produce lower NO_x emissions. These inert gases serve to absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x emissions. Examples of this type of gas fuel are air-blown gasifier fuels and some field gases.[15] Combustion of hydrogen also results in high flame temperatures, and gases with significant hydrogen content produce relatively high NO_x emissions. Refinery gases can have hydrogen contents exceeding 50 percent.[16]

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As is shown in Figure 4-3

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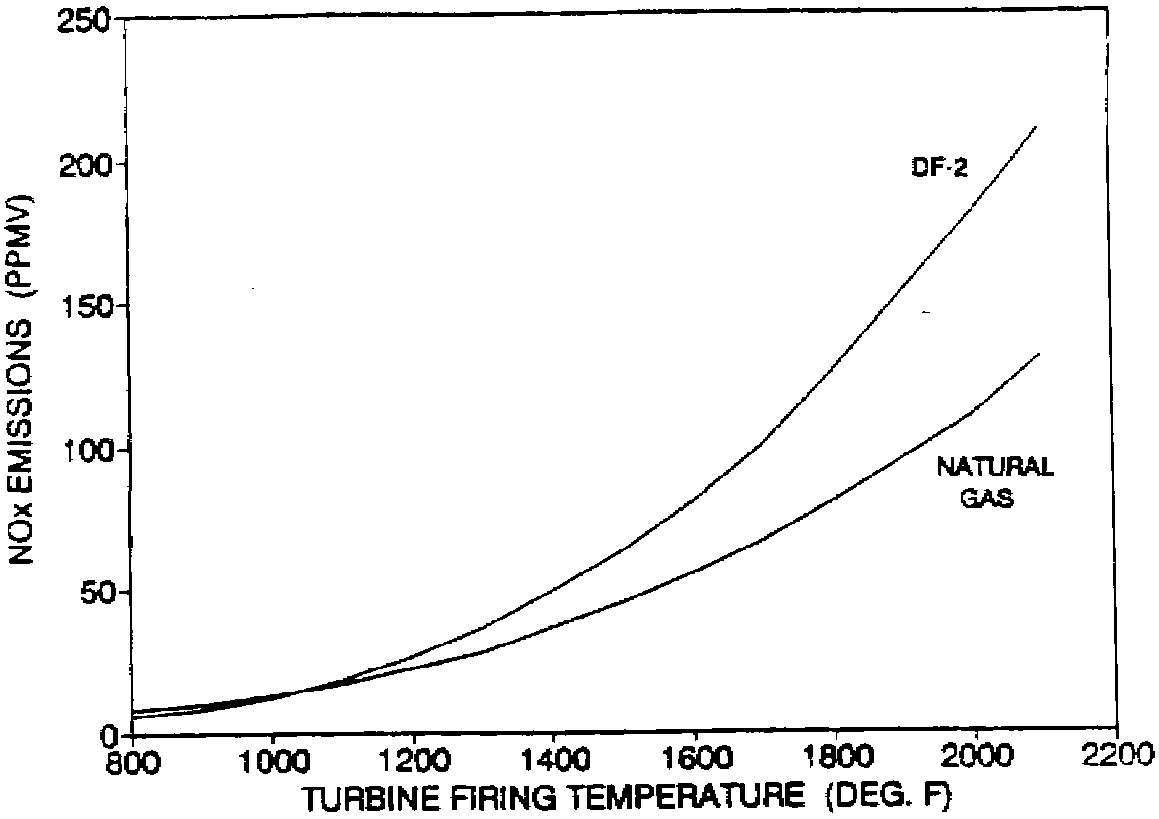


Figure 4-3. Influence of firing temperature on thermal NO_x formation.[17]

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, DF-2 burns at a flame temperature that is approximately 75°C (100°F) higher than that of natural gas, and as a result, NO_x emissions are higher when burning DF-2 than they are when burning natural gas.[17] Low-Btu fuels such as coal gas burn with lower flame temperatures, which result in

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substantially lower thermal NO_x emissions than natural gas or DF-2.[18] For fuels containing FBN, the fuel NO_x production increases with increasing levels of FBN.

4.2.1.3 Ambient Conditions. Ambient conditions that affect NO_x formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NO_x formation.[19] The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures, which reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NO_x formation varies. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 10°C (50°F), NO_x emissions decrease with increasing temperature.

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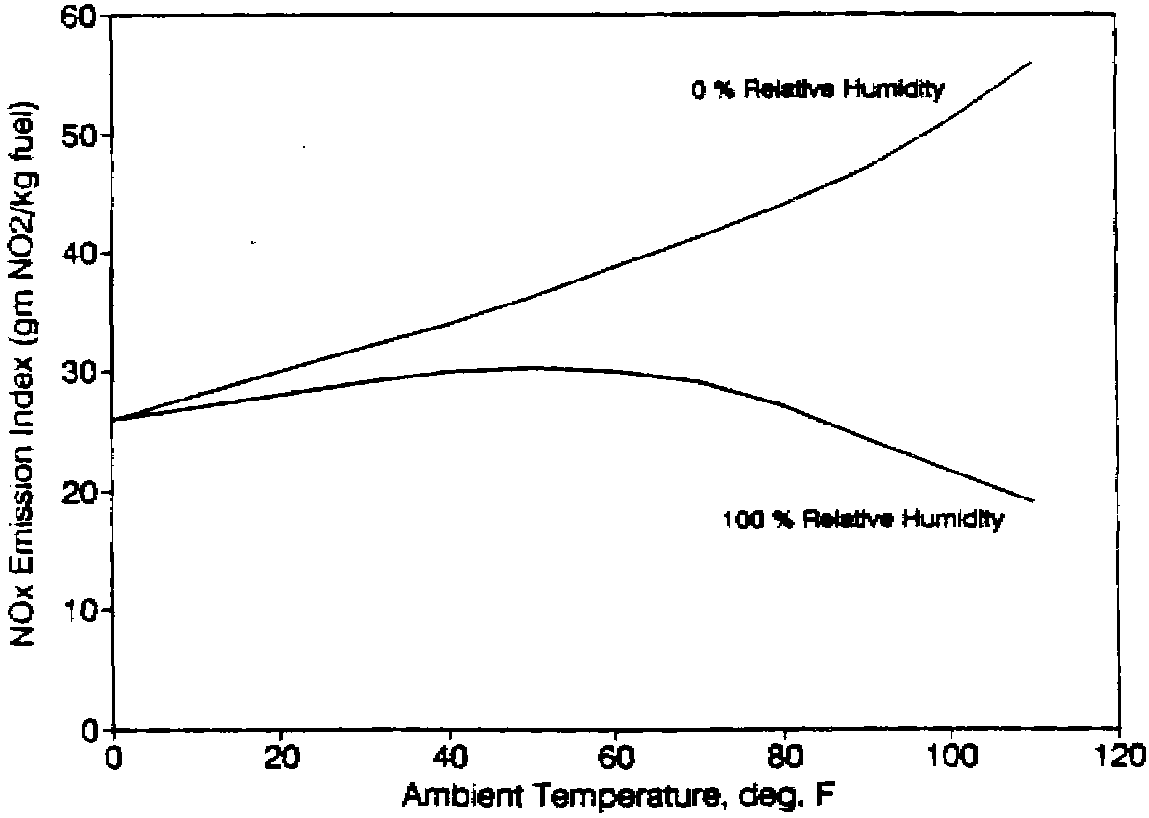


Figure 4-4. Influence of relative humidity and ambient temperature on NO_x formation.[19]

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This effect of humidity and temperature on NO_x formation is shown in Figure 4-4. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor and so No_x production levels increase with increases in ambient pressure.[19]

The influence of ambient conditions on measured NO_x emission levels can be corrected using the following equation:[20]

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5} e^{19(Ho-0.00633)} (288°K/T_a)^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O_2 and International Standards Organization (ISO) ambient conditions, volume percent;

NO_{xo} = observed NO_x concentration, parts per million by volume (ppmv) referenced to 15 percent O_2;

P_r = reference compressor inlet absolute pressure at 101.3 kilopascals ambient pressure, millimeters mercury (mm Hg);

P_o = observed compressor inlet absolute pressure at test, mm Hg;

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H_o = observed humidity of ambient air, g H_2O/g air;

e = transcendental constant, 2.718; and

T_a = ambient temperature, K.

At least two manufacturers state that this equation does not accurately correct NO_x emissions for their turbine models.[8,12] It is expected that these turbine manufacturers could provide corrections to this equation that would more accurately correct NO_x emissions for the effects of ambient conditions based on test data for their turbine models.

4.2.1.4 Operating Cycles. Emissions from identical turbines used in simple and cogeneration cycles have similar NO_x emissions levels, provided no duct burner is used in heat recovery applications. The NO_x emissions are similar because, as stated in Section 4.2, NO_x is formed only in the turbine combustor and remains at this level regardless of downstream temperature reductions. A turbine operated in a regenerative cycle produces higher NO_x levels, however, due to increased combustor inlet temperatures present in regenerative cycle applications.[21]

4.2.1.5 Power Output Level. The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature. Each gas turbine has a base-rated power level and corresponding NO_x level. At power outputs below this base-rated level, the flame temperature is lower, so NO_x emissions are lower. Conversely, at peak power outputs above the base rating, NO_x emissions are higher due to higher flame temperature. The NO_x emissions for a range of firing temperatures are shown in Figure 4-3 for one manufacturer's gas turbine.[17]

4.2.2 NO_x Emissions From Duct Burners

In some cogeneration and combined cycle applications, the exhaust heat from the gas turbine is not sufficient to produce the desired quantity of steam from the HRSG, and a supplemental burner, or duct burner, is placed in the exhaust duct between the gas turbine and HRSG to increase temperatures to sufficient

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levels. In addition to providing additional steam capacity, this burner also increases the overall system efficiency since essentially all energy added by the duct burner can be recovered in the HRSG.[22]

The level of NO_x produced by a duct burner is approximately 0.1 pound per million Btu (lb/MMBtu) of fuel burned. The ppmv level depends upon the flowrate of gas turbine exhaust gases in which the duct burner is operating and thus varies with the size of the turbine.[23]

Typical NO_x production levels added by a duct burner operating on natural gas fuel are:[23]

Gas turbine output, megawatts (MW)	Duct burner NO_x, ppmv, referenced to 15 percent O_2
3 to 50	10 to 30
50+	5 to 10

4.3 UNCONTROLLED EMISSION FACTORS

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TABLE 4-1. UNCONTROLLED NO_x EMISSIONS FACTORS FOR GAS TURBINES AND DUCT BURNERS[8,12,15,24-29]

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% O_2		NO_x emissions factor, lb NO_x/MMBtu[a]	
			Natural gas	Distillate oil No. 2	Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95
Duct burners	All	NA[c]	≤30	NA[b]	<0.100[d]	NA[b]

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.

[b]Not available.

[c]Not applicable.

[d]References 16 and 22.

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Uncontrolled emission factors are presented in Table 4-1. These factors are based on uncontrolled emission levels provided by manufacturers in ppmv, dry, and corrected to 15 percent O_2, corresponding to 100 percent output load and International Standards Organization (ISO) conditions of 15°C (59°F) and 1 atmosphere (14.7 psia). Sample calculations are given in Appendix A. The uncontrolled emissions factors range from 0.397 to 1.72 lb/MMBtu (99 to 430 ppmv) for natural gas and 0.551 to 2.50 lb/MMBtu (150 to 680 ppmv) for DF-2.

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4.4 REFERENCES FOR CHAPTER 4

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5.0 NO_x CONTROL TECHNIQUES

Nationwide NO_x emission limits have been established for stationary gas turbines in the new source performance standards (NSPS) promulgated in 1979.[1] This standard, summarized in Table 5-1

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TABLE 5-1. NO_x EMISSION LIMITS AS ESTABLISHED BY THE NEW SOURCE PERFORMANCE STANDARDS FOR GAS TURBINES[1]

Fuel input MMBtu/hr	Size, MW	Application(s)	NO_x limit, ppmv at 15% O_2, dry[a] [b]
<10	1[c]	All	None
10-100	1-10[c]	All	150
>100	10+[c] <30[c] >30[c]	Utility[d] Nonutility Nonutility	75 150 None
<100	10[c]	Regenerative cycle	None
All	All	e	None

[a]Based on thermal efficiency of 25 percent. This limit may be increased for higher efficiencies by multiplying the limit in the table by 14.4/actual heat rate, in kJ/watt-hr.

[b]A fuel-bound nitrogen allowance may be added to the limits listed in the table according to the table listed below:

Fuel-bound nitrogen (N), percent by weight	Allowable increase, ppmv
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	400 x N
$0.1 < N \leq 0.25$	40 + [6.7 x (N - 0.1)]
$N > 0.25$	50

[c]Based on gas turbine heat rate of 10,000 Btu/kW-hr.

[d]An installation is considered a utility if more than 1/3 of its potential electrical output is sold.

[e]Emergency/stand-by, military (except garrison facilities), military training, research and development, firefighting, and emergency fuel operation applications are exempt from NO_x emission limits.

, effectively sets a limit for new, modified, or reconstructed gas turbines greater than 10.7 gigajoules per hour (approximately 3,800 horsepower [hp]) of 75 or 150 parts per million by volume (ppmv), corrected to 15 percent oxygen (O_2) on a dry basis, depending upon the size and application of the turbine. State and regional regulatory agencies may set more restrictive limits, and two organizations have established limits as low as 9 ppmv: the South Coast Air Quality Management District (SCAQMD) has defined limits as listed in Table 5-2

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TABLE 5-2. NO_x COMPLIANCE LIMITS AS ESTABLISHED BY THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT (SCAQMD) FOR EXISTING TURBINES. RULE 1134. ADOPTED AUGUST 1989.[a,2]

Unit size, megawatt rating (MW)	NO_x limit, ppmv, 15% O_2 dry[b]
0.3 to <2.9 MW	25
2.9 to <10.0 MW	9
2.9 to <10.0 MW No SCR	15
10.0 MW and over	9
10.0 MW and over No SCR	12
60 MW and over Combined cycle No SCR	15
60 MW and over Combined cycle	9
Compliance limit = Reference limit X EFF/25 percent	
where: $EFF = \frac{3,413 \times 100\%}{\text{Actual heat rate at HHV of fuel (Btu/kW-hr)}}$ or EFF^c = (Manufacturer's rated efficiency at LHV) x $\frac{LHV}{HHV}$	

[a]The NO_x reference limits to be effective by December 31, 1995.
[b]Averaged over 15 consecutive minutes.
[c]EFF = the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any down-stream energy recovery from the actual heat rate (Btu/kW-hr), or 1.34 (Btu/hp-hr); corrected to the higher heating value (HHV) of the fuel and ISO conditions, as measured at peak load for that facility; or the manufacturer's continuous rated percent efficiency (manufacturer's rated efficiency) of the gas turbine after correction from lower heating value (LHV) to the HHV of the fuel, whichever efficiency is higher. The value of EFF shall not be less than 25 percent. Gas turbines with lower efficiencies will be assigned a 25 percent efficiency for this calculation.

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; and the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended limits as listed in Table 5-3.

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TABLE 5-3. NO_x EMISSION LIMITS RECOMMENDED BY THE NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

NEW TURBINES[3]

Fuel input, MMBtu/hr	Size, MW[a]	Fuel type	NO_x limit, ppmv[b]
1-100	1-10	Gas Oil	42 65
>100	10+	Gas Oil Gas/oil back-up	9[c] 9[c] 9[c]/18[c d]

[a]Based on gas turbine heat rate of 10,000 Btu/kW-hr.
[b]Dry basis, corrected to 15 percent oxygen.
[c]Based on use of selective catalytic reduction (SCR). Limits for operation without SCR, where permitted, should be the turbine manufacturer's lowest guaranteed NO_x limit.
[d]Based on the use of SCR and a fuel-bound nitrogen content of 600 ppm or less.

EXISTING TURBINES[4]

Operating cycle	Fuel	NO_x emission limit, ppmv, 15 percent O_2
Simple	Gas, no oil back-up	55
	Oil	75
	Gas, with oil back-up	55 (Gas fuel) 75 (Oil fuel)
Combined	Gas, no oil back-up	42
	Oil	65
	Gas, with oil back-up	42 (Gas fuel) 65 (Oil fuel)

Note: Applies to existing turbines rated at 25 MMBtu/hr or above (maximum heat input rate).

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This chapter discusses the control techniques that are available to reduce NO_x emissions for stationary turbines, the use of duct burners, the use of alternate fuels to lower NO_x emissions, and the applicability of NO_x control techniques to offshore applications. Each control technique is structured into categories to discuss the process description, applicability, factors that affect performance, and achievable controlled NO_x emission levels. Where information for a technique is limited, one or more categories may be combined. Section 5.1 describes wet controls, including water and steam injection. Section 5.2 describes combustion controls, including lean and staged combustion. Selective catalytic reduction (SCR), a postcombustion technique, is described in Section 5.3, and the combination of SCR with other control techniques is described in

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Section 5.4. Emissions from duct burners and their impact on total NO_x emissions are described in Section 5.5. Section 5.6 describes NO_x emission impacts when using alternate fuels. Two control techniques that show potential for future use, selective noncatalytic reduction (SNCR) and catalytic combustion, are described in Sections 5.7 and 5.8, respectively. Control technologies for offshore oil platforms are described in Section 5.9. Finally, references for Chapter 5 are found in Section 5.10.

5.1 WET CONTROLS

The injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. This control technique is available from all gas turbine manufacturers contacted for this study.[5-11]

The process description, applicability, factors affecting performance, emissions data and manufacturers' guarantees, impacts on other emissions, and gas turbine performance and maintenance impacts are discussed in this section.

5.1.1 Process Description

Injecting water into the flame area of a turbine combustor provides a heat sink that lowers the flame temperature and thereby reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio (WFR) and are usually given on a weight basis (e.g., lb water to lb fuel).

A water injection system consists of a water treatment system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and the necessary interconnecting piping. Water purity is essential to prevent or mitigate erosion and/or the formation of deposits in the hot section of the turbine; Table 5-4

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TABLE 5-4. WATER QUALITY SPECIFICATIONS OF SELECTED GAS TURBINE MANUFACTURERS FOR WATER INJECTION SYSTEMS[11-18]

	Turbine Manufacturer							
Element	A	B	C	D	E	F	G	H
Total solids, ppm (dissolved and nondissolved)	5	5	1	a	0.1 gram/gallon	15	5	8
Total alkali metals, ppm	0.1	0.5 (HD) 0.1 (AD)[d]	0.1	--	0.5	0.15	<0.05	--
Calcium, ppm	5	--	--	--	--	--	<1.0	--
Sulfates, ppm	--	--	--	--	--	--	--	0.5
Silica, ppm	0.02	--	0.02	--	--	0.1	<0.02	0.1
Silicon, ppm	--	--	--	18.0	--	--	--	--
Sulfur, ppm	0.1	--	--	--	--	1.0	--	--
Chlorides, ppm	--	--	--	6.0	--	1.0	--	0.5
Iron and copper, ppm	--	--	--	0.1	--	--	--	--
Sodium and potassium, ppm	--	--	--	--	--	--	--	0.1
Particle size, microns	10	--	10	--	5	--	--	20
Total hardness, ppm	--	--	--	--	--	0.2	--	--
Oxygen[f]	--	--	--	--	--	--	--	--
Acidity, pH	7.0-8.5	6.5-7.5	7.0-8.5	7.5-8.0	--	6.5-7.5	6.5-7.0	6.0-8.0

[a]Determined by local regulations for particulates exhausted from combustion process.
[b]HD - heavy-duty turbine.
[c]Including vanadium and lead.
[d]AD - aeroderivative turbine.
[e]90 percent of 0.1 gram particles shall be less than 5 microns.

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summarizes the water quality specifications for eight gas turbine manufacturers.

In a steam injection system, steam replaces water as the injected fluid. The injection system is similar to that for water injection, but the pump is replaced by a steam-producing boiler. This boiler is usually a heat recovery steam generator

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(HRSG) that recovers the gas turbine exhaust heat and generates steam. The balance of the steam system is similar to the water injection system. The water treatment required for boiler feed water to the HRSG yields a steam quality that is suitable for injection into the turbine. The additional steam requirement for NO_x control, however, may require that additional capacity be added to the boiler feed water treatment system.

Another technique that is commercially available for oil-fired aeroderivative and industrial turbines uses a water-in-oil emulsion to reduce NO_x emissions. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to injection. This emulsion has a water content of 20 to 50 percent by volume and is finely dispersed and chemically stabilized in the oil phase. The principle of NO_x control is similar to conventional water injection, but the uniform dispersion of the water in the oil provides greater NO_x reduction than conventional water injection at similar WFR's.[19]

A water-in-oil emulsion injection system consists of mechanical emulsification equipment, chemical stabilizer injection equipment, water metering valves, chemical storage and metering valves, and instrumentation. In most cases the emulsifying system can be retrofitted to the existing fuel delivery system, which eliminates the requirement for a separate delivery system for water injection. At multiunit installations, one emulsion system can be used to supply emulsified fuel to several turbines. For dual fuel turbines, the emulsion can be injected through the oil fuel system to control NO_x emissions.[19]

Data provided by the vendor for this technique indicates that testing has been performed on oil-fired turbines operating in peaking duty. Long-term testing has not been completed at this point to quantify the long-term effects of the emulsifier on the operation and maintenance of the turbine.

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5.1.2 Applicability of Wet Controls

Wet controls have been applied effectively to both aeroderivative and heavy-duty gas turbines and to all configurations except regenerative cycle applications.[20] It is expected that wet controls can be used with regenerative cycle turbines, but no such installations were identified. All manufacturers contacted have water injection control systems available for their gas turbine models; many also offer steam injection control systems. Where both systems are available, the decision of which control to use depends upon steam availability and economic factors specific to each site.

Wet controls can be added as a retrofit to most gas turbine installations. In the case of water injection, one limitation is the possible unavailability of injection nozzles for turbines operating in dual fuel applications. In this application, the injection nozzle as designed by the manufacturer may not physically accommodate a third injection port for water injection. This limitation also applies to steam injection. In addition, steam injection is not an available control option from some gas turbine manufacturers.

5.1.3 Factors Affecting the Performance of Wet Controls

The WFR is the most important factor affecting the performance of wet controls. Other factors affecting performance are the combustor geometry and injection nozzle(s) design and the fuel-bound nitrogen (FBN) content. These factors are discussed below.

The WFR has a significant impact on NO_x emissions. Tables 5-5 and 5-6 provide NO_x reduction and WFRs for natural gas and

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TABLE 5-5. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR NATURAL GAS FUEL OPERATION[5-11,21-24]

	NO_x emission levels, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	133	42[a]/68	25/81	0.61	1.49
LM2500	174	42[a]/76	25/86	0.73	1.46
LM5000	185	42[a]/77	25/87	0.63	1.67
LM6000	220	42[a]/81	25/89	0.68	1.67
MS5001P	142	42/70	42/70	0.72	1.08
MS6001B	148	42/72	42/72	0.77	1.16
MS7001E	154	42/73	42/73	0.81	1.22
MS7001F	210	42/80	42/80	0.79	1.34
MS9001E	161	42/74	42/74	0.78	1.18
MS9001F	210	42/86	42/80	NA[b]	NA[b]
Asea Brown Boveri					
GT10	150	25/83	42/72	0.93	1.07
GT8	430	25/94	29/93	1.86	2.48
GT11N	390	25/94	25/94	1.76	2.47
GT35	300	42/86	60/80	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	99	42/58	NA[c]/NA[c]	0.33	NA[c]
T-4500 Centaur	130	42/68	NA[c]/NA[c]	0.61	NA[c]
Type H Centaur	105	42/60	NA[c]/NA[c]	0.70	NA[c]
Taurus	114	42/63	NA[c]/NA[c]	0.79	NA[c]
T-12000 Mars	178	42/76	NA[c]/NA[c]	0.91	NA[c]
T-14000 Mars	199	42/79	NA[c]/NA[c]	1.14	NA[c]
Allison/GM					
501-KB5	155	42/73	42/73	0.80	1.53
501-KC5	174	42/76	NA[c]/NA[c]	NA[b]	NA[c]
501-KH	155	42/73	25/84	NA[b]	NA[b]
570-K	101	42/58	NA[c]/NA[c]	NA[b]	NA[c]
571-K	101	42/58	NA[c]/NA[c]	0.80	NA[c]
Westinghouse					
251B11/12	220	42/81	25/89	1.0	1.8
501D5	190	25/87	25/87	1.6	1.6
Siemens					
V84.2	212	42/80	55/74	2.0	2.0
V94.2	212	55/74	55/74	1.6	1.6
V64.3	380	75/80	75/80	1.6	1.4
V84.3	380	75/80	75/80	1.6	1.4
V94.3	380	75/80	75/80	1.6	1.4

[a]A NO_x emissions level of 25 ppmv can be achieved, but turbine maintenance requirements increase over those required for 42 ppmv.

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TABLE 5-6. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR DISTILLATE OIL FUEL OPERATION[5-11,21-24]

	NO_x emissions level, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	237	42/82	75/70	NA[a]	NA[a]
LM2500	345	42/88	75/78	0.99	NA[a]
LM5000	364	42/88	110/70	NA[a]	NA[a]
LM6000	417	42/90	110/74	NA[a]	NA[a]
MS5001P	211	65/69	65/69	0.79	1.06
MS6001B	267	65/76	65/76	0.73	1.20
MS7001E	228	65/72	65/72	0.67	1.19
MS7001F	353	65/82	65/77	0.72	1.35
MS9001E	241	65/73	65/72	0.65	1.16
MS9001F	353	65/82	65/76	NA[a]	NA[a]
Asea Brown Boveri					
GT10	200	42/79	42/79	0.75	1.25
GT8	680	42/94	60/91	1.62	2.15
GT11N	560	42/88	42/93	1.50	2.28
GT35	360	42/88	60/83	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	150	60/60	NA[b]/NA[b]	0.46	NA[b]
T-4500 Centaur	179	60/66	NA[b]/NA[b]	0.60	NA[b]
Type H Centaur	160	60/63	NA[b]/NA[b]	0.72	NA[b]
Taurus	168	60/64	NA[b]/NA[b]	0.96	NA[b]
T-12000 Mars	267	60/78	NA[b]/NA[b]	1.00	NA[b]
T-14000 Mars	NA[a]	60/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
Allison/GM					
501-KB5	231	56/76	NA[b]/NA[b]	NA[a]	NA[b]
501-KC5	NA[a]	NA[a]/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
501-KH	231	56/76[a]	50/78	NA[a]	NA[a]
570-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
571-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
Westinghouse					
251B11/12	355	65/82	42/88	1.0	1.8
501D5	250	42/83	42/83	1.0	1.6
Siemens					
V84.2	360	42/88	55/85	1.4	2.0
V94.2	360	42/88	55/85	1.4	1.6
V64.3	530	75/86	75/86	1.2	1.4
V84.3	530	75/86	75/86	1.2	1.4
V94.3	530	75/86	75/86	1.2	1.4

[a]Data not available.

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distillate oil fuels, respectively, based on information provided by gas turbine manufacturers. For natural gas fuel, WFR's for water or steam injection range from 0.33 to 2.48 to achieve controlled NO_x emission levels ranging from 25 to 75 ppmv, corrected to 15 percent oxygen. For oil fuel, WFR's range from 0.46 to 2.28 to achieve controlled NO_x emission levels ranging from 42 to 110 ppmv, corrected to 15 percent oxygen. Nitrogen oxide reduction efficiency increases as the WFR

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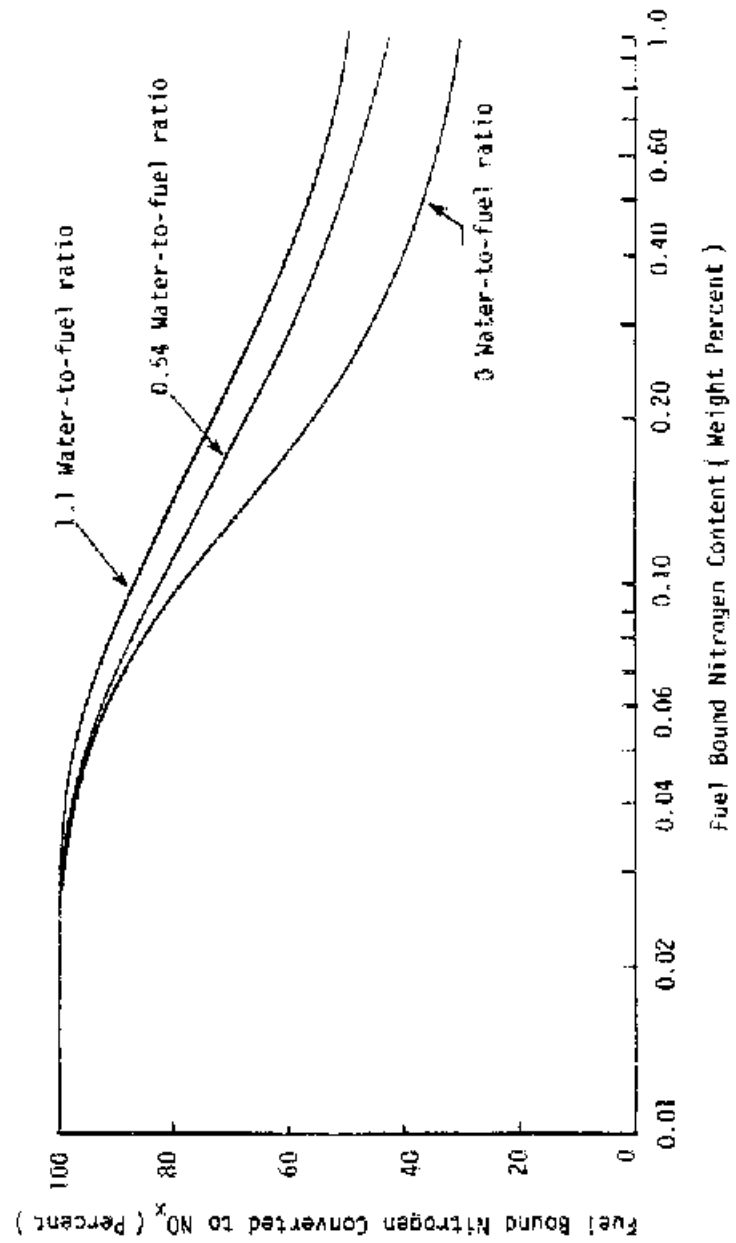
increases. As shown in Tables 5-5 and 5-6, reduction efficiencies of 70 to 90 percent are common. Note that, in general, the WFR's for steam are higher than for water injection because water acts as a better heat sink than steam due to the heat absorbed by vaporization; therefore, higher levels of steam than water must be injected for a given reduction level.

The combustor geometry and injection nozzle design and location also affect the performance of wet controls. For maximum NO_x reduction efficiency, the water must be atomized and injected in a spray pattern that provides a homogeneous mixture of water droplets and fuel in the combustor. Failure to achieve this mixing yields localized hot spots in the combustor that produce increased NO_x emissions.

The type of fuel affects the performance of wet controls. In general, lower controlled NO_x emission levels can be achieved with gaseous fuels than with oil fuels. The FBN content also affects the performance of wet controls. Those fuels with relatively high nitrogen content, such as coal-derived liquids, shale oil, and residual oils, result in significant fuel NO_x formation. Natural gas and most distillate oils are low-nitrogen fuels. Consequently, fuel NO_x formation is minimal when these fuels are burned.

Wet controls serve only to lower the flame temperature and therefore are an effective control only for thermal NO_x formation; water injection may in fact increase the rate of fuel NO_x formation, as shown in Figure 5-1.[25] The mechanisms responsible for this potential increase were not identified.

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5.1.4 Achievable NO_x Emissions Levels Using Wet Controls

This section presents the achievable controlled NO_x emission levels for wet injection, as guaranteed by gas turbine manufacturers. Emission test data, obtained using EPA Test Method 20 or equivalent, are also presented.

Guaranteed NO_x emission levels as provided by gas turbine manufacturers for wet controls are shown in Figures 5-2 and

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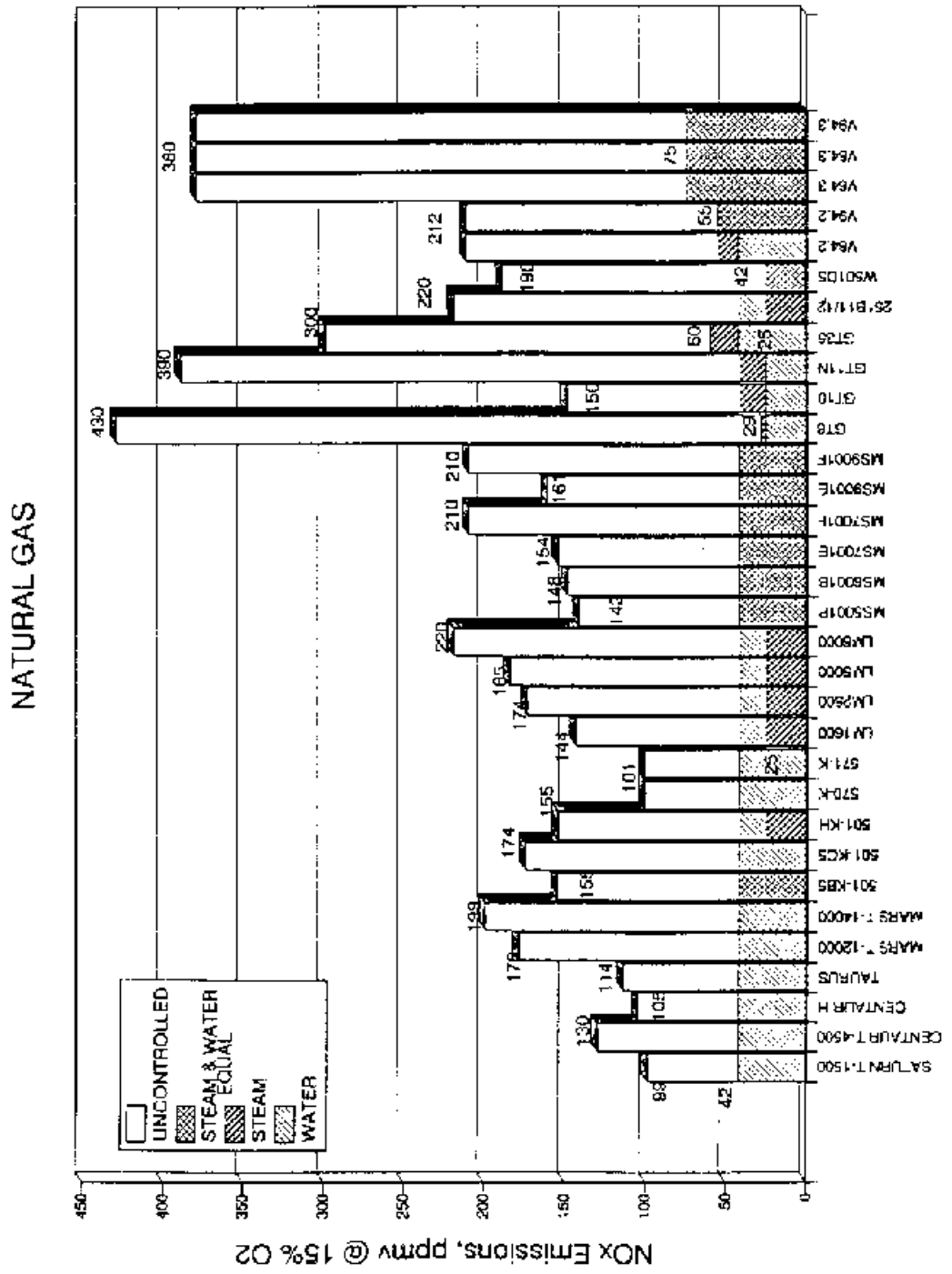
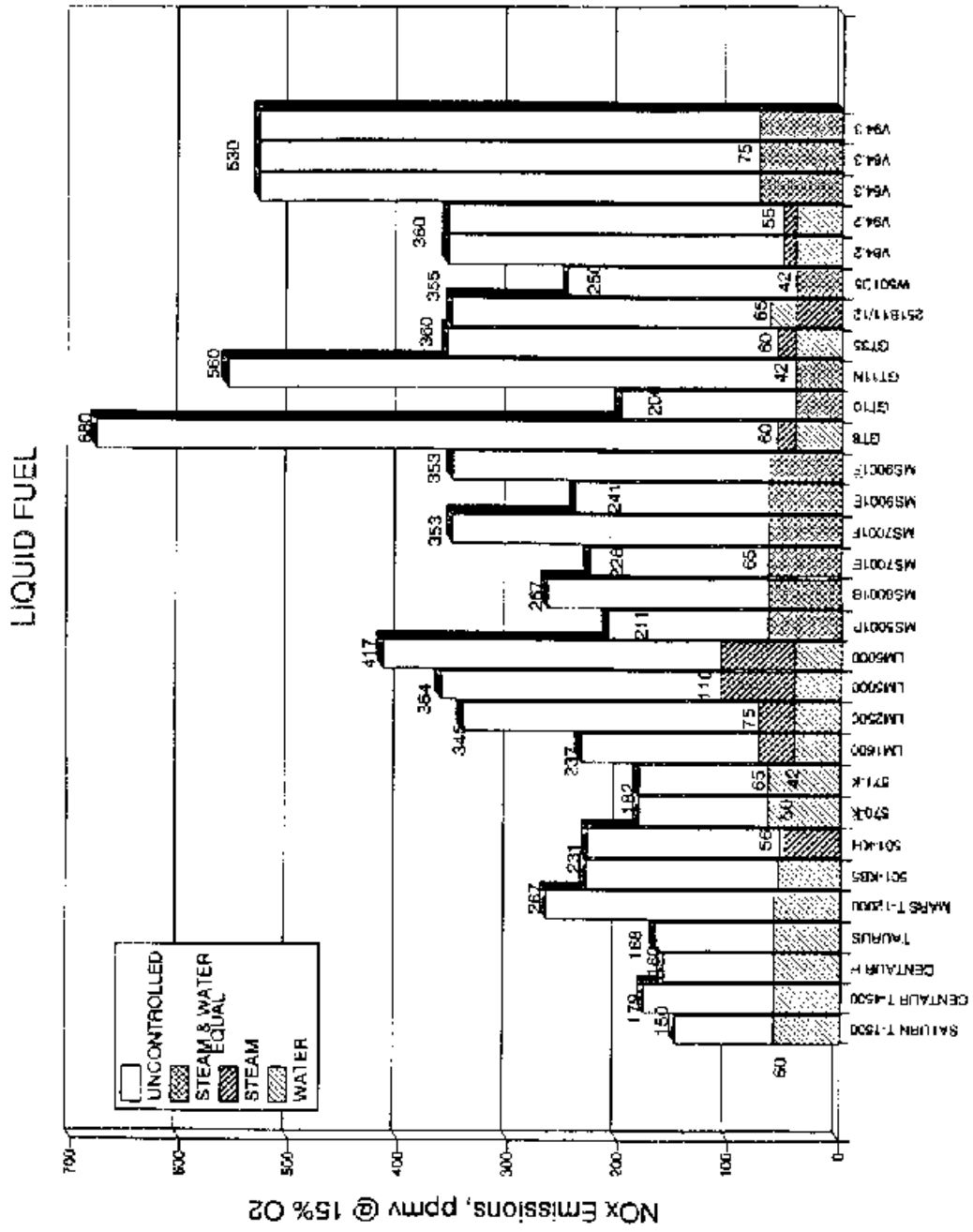


Figure 5-1. Percentage of fuel-bound nitrogen converted to NO_x versus the fuel-bound nitrogen content and the water-to-fuel ratio for uncontrolled NO_x emissions and guaranteed controlled levels using wet injection. Natural gas fuel.[6-11,17,18,23]

Figure 5-2. Correlation of uncontrolled NO_x emissions and gas turbine manufacturer's guaranteed controlled levels (1840 to 2000 F).[6-11,17,18,23,25,26]

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LIQUID FUEL
NOx Emissions, ppmv @ 15% O2
UNCONTROLLED
STEAM & WATER EQUAL
STEAM
WATER
0
100
200
300
400
500
600
700
SALURN T-150D
CENTAUR T-450D
CENTAUR H
TAURUS
MARS T-1200D
SGT-800
SGT-600
SGT6-5000F
SGT6-3000E
SGT6-2000E
SGT6-1000F

5-3. These figures show manufacturers' guaranteed NO_x emission levels of 42 ppmv for most natural gas-fired turbines, and from 42 to

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75 ppmv for most oil-fired turbines. The percent reduction in NO_x emissions varies for each turbine, ranging from 60 to 94 percent depending upon each model's uncontrolled emission level and whether water or steam is injected.

Emissions data for water and steam injection are presented to show the effects of wet injection on NO_x emissions. These data show:

1. That NO_x emissions decrease with increasing WFR's; and
2. That NO_x emissions are higher for oil fuel than for natural gas.

From the available data, reduction efficiencies of 70 to over 85 percent were achieved. The emission data and WFRs shown for specific turbine models may not reflect the emission levels of current production models, since manufacturers periodically update or otherwise modify their turbines, thereby altering specific emissions levels.

Each emission test in the following figures consists of one or more data points. Where data points were obtained under similar conditions, they are grouped together and presented as a single test. For these cases, each data point, along with the arithmetic average of all of the data points, is shown.

The nomenclature used to identify the tests consists of two letters followed by a number. The first letter of the two-letter designator specifies the turbine type. These types are as follows:

Letter	Turbine type
A	Aircraft-derivative turbine
H	Heavy-duty turbine
T	Small and low-efficiency turbine (less than 7.5 MW output, less than 30 percent simple-cycle efficiency)

The second letter identifies the facility. The number identifies the number of tests performed at the facility. Tests performed at the same facility on different turbines or at different times have the same two-letter designator but are followed by different test numbers. The short horizontal lines represent the average of the test data.

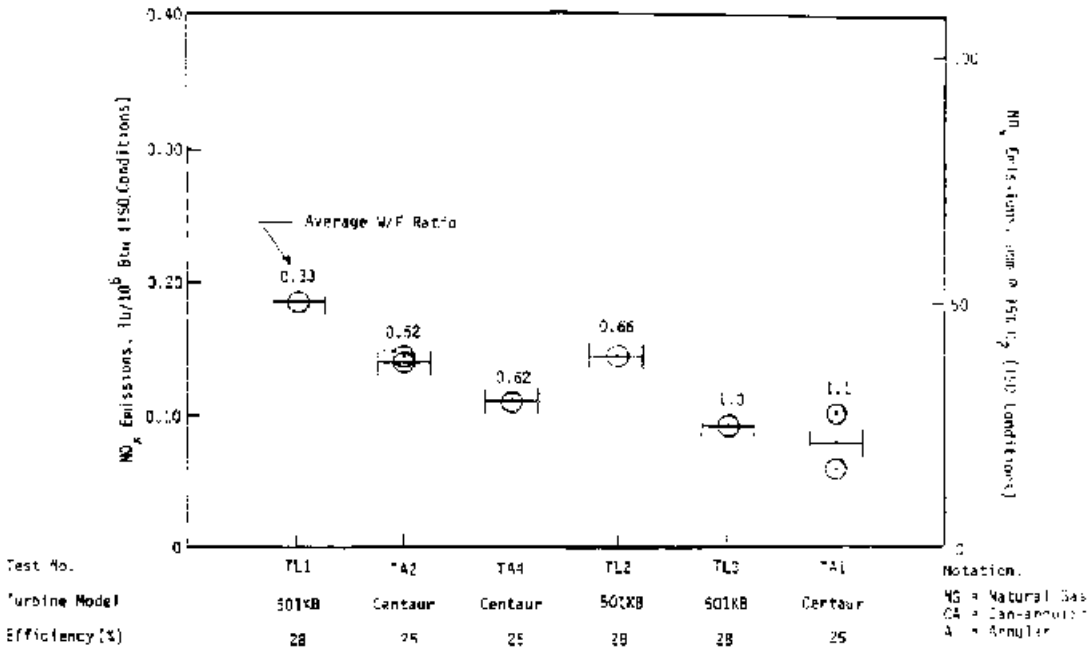
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Also presented are the available data on the turbine, wet controls, uncontrolled NO_x emissions, percent NO_x reduction, and fuel type. All of the data shown are representative of the performance of wet controls when the turbine is operated at base load or peak load. These loads represent the worst-case conditions for NO_x emission reduction. Information on the WFR, turbine model, efficiency, control type, and fuel are included with the emission test data.

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Figures 5-4, 5-5, and 5-6 present the emission test data

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Test No.	TL1	TA2	TA4	TL2	TL3	TA1
Turbine Model	501KB	Centaur	Centaur	501KB	501KB	Centaur
Efficiency (%)	28	25	25	28	28	25
Combustor Type	CA	A	A	CA	CA	A
Baseload Rating (MW)	2.5	2.8	2.8	2.5	2.5	2.8
Type of Fuel	NG	NG	NG	NG	NG	NG
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.33	0.49-0.55	0.62	0.66	1.0	0.96-1.32
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.394	0.486	0.486	0.394	0.394	0.486
NO_x Reduction (%)	54.0	71.4	76.7	53.4	78.1	81.7

Figure 5-4. Nitrogen oxide emission test data for small, low-efficiency gas turbines with water injection firing natural gas.[27]

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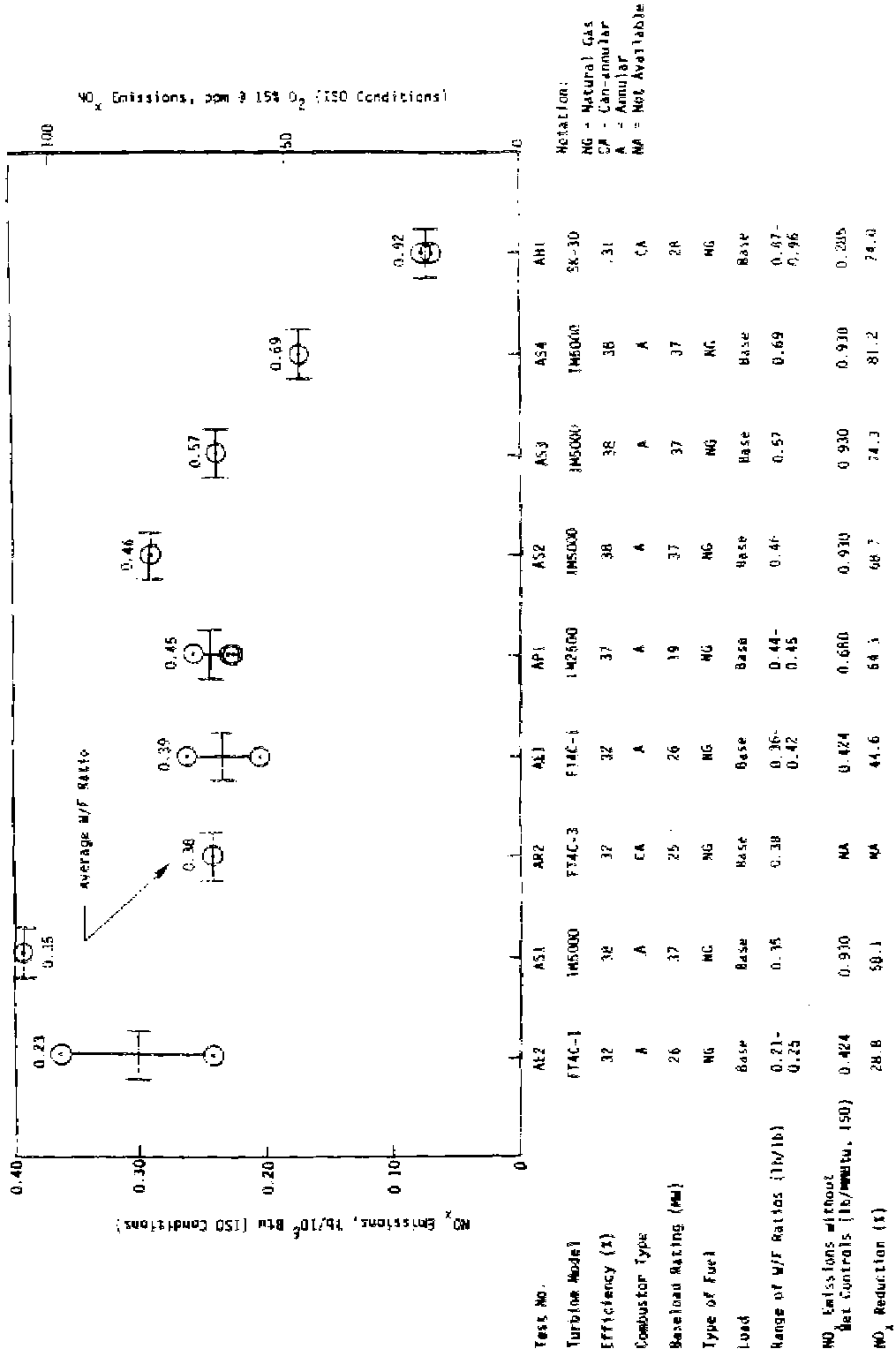


Figure 5-5. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing natural gas.[27]

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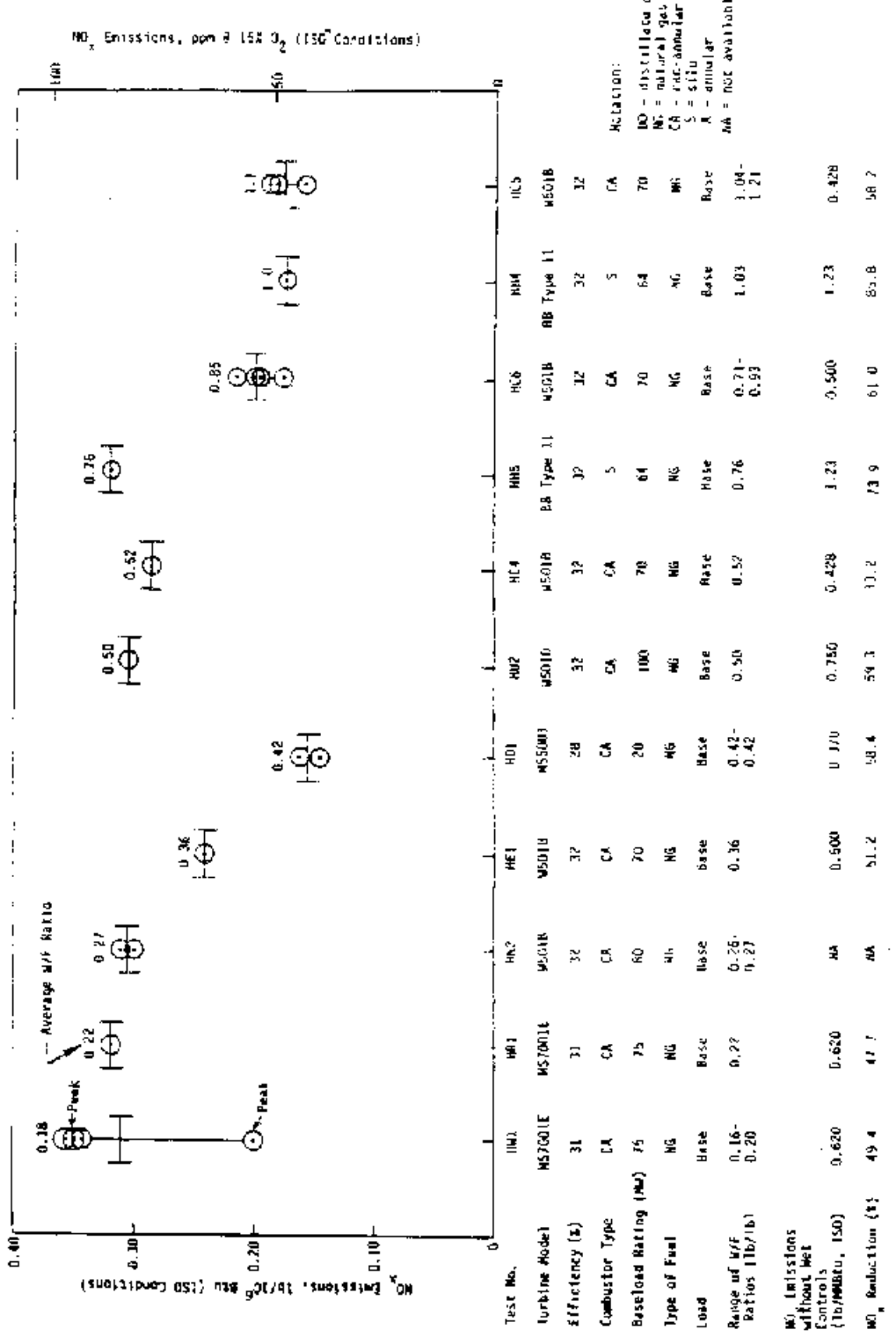


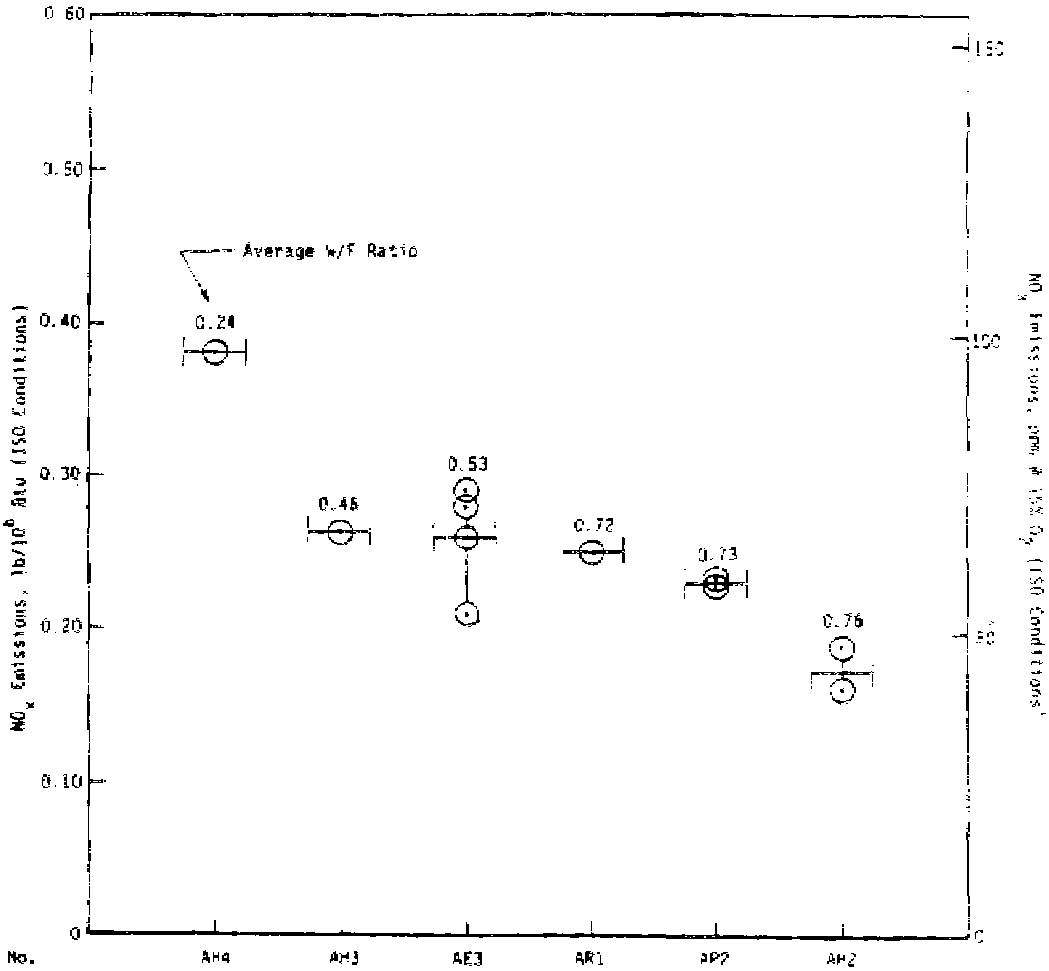
Figure 5-6. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection firing natural gas.[27]

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for water injection on turbines fired with natural gas. These turbines have NO_x emissions ranging from approximately 20 to 105 ppm with WFR's ranging from 0.16 to 1.32. Turbine sizes range from 2.8 to 97 MW. Based on these data, water injection is effective on all types of gas turbines and NO_x emission levels decrease as the WFR increases. However, some turbines require a higher WFR to meet a specific emission level. For example, the gas turbines at sites HH and HC (Figure 5-6) require much higher WFR's to achieve NO_x emission levels similar to the other gas turbine models shown. This particular gas turbine also has the highest uncontrolled NO_x emission levels. Conversely, the gas turbine at site AH, shown in Figure 5-5, has the lowest uncontrolled NO_x emission level and requires the least amount of water to achieve a given emission level. Uncontrolled NO_x emission levels vary for different turbine models depending upon design factors such as efficiency, firing temperature, and the extent of combustion controls incorporated in the combustor design (see Section 4.2.1.1). In general, aircraft-derivative and heavy-duty gas turbines require similar WFR's to achieve a specific emission level. Small, low-efficiency gas turbines require less water to achieve a specific emission level.

The NO_x emissions for turbines firing distillate oil are shown in Figures 5-7, 5-8, and 5-9. The data range from

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Test No.	AH4	AH3	AE3	AR1	AP2	AH2
Turbine Model	SK-30	SK-30	FT4C-1	FT4C-3F	LM2500	SK-30
Efficiency (percent)	31	31	32	32	37	31
Combustor Type	CA	CA	CA	CA	A	CA
Base Load Rating (MW)	28	28	26	25	20	28
Type of Fuel	DO	DO	DO	DO	DO	DO
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.24	0.46	0.51-0.55	0.72	0.73-0.73	0.68-0.84
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.559	0.559	0.787	0.840	1.37	0.559
NO_x Reduction (%)	32.0	52.8	66.8	70.5	83.4	58.9

Notation:
DO = distillate oil
NG = natural gas
CA = can-annular
A = annular

Figure 5-7. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing distillate oil.[27]

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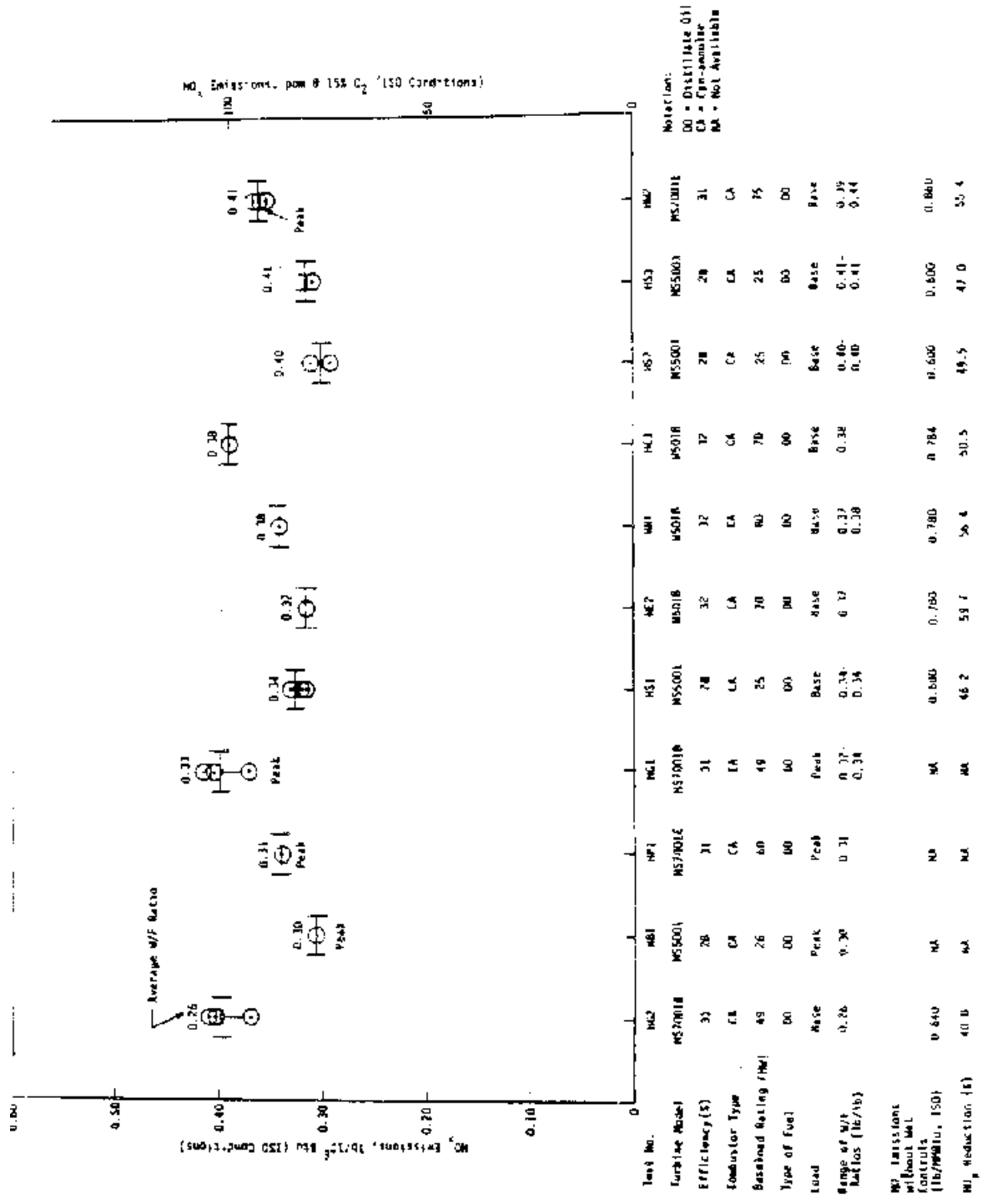


Figure 5-8. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs less than 0.5 and firing distillate oil.[27]

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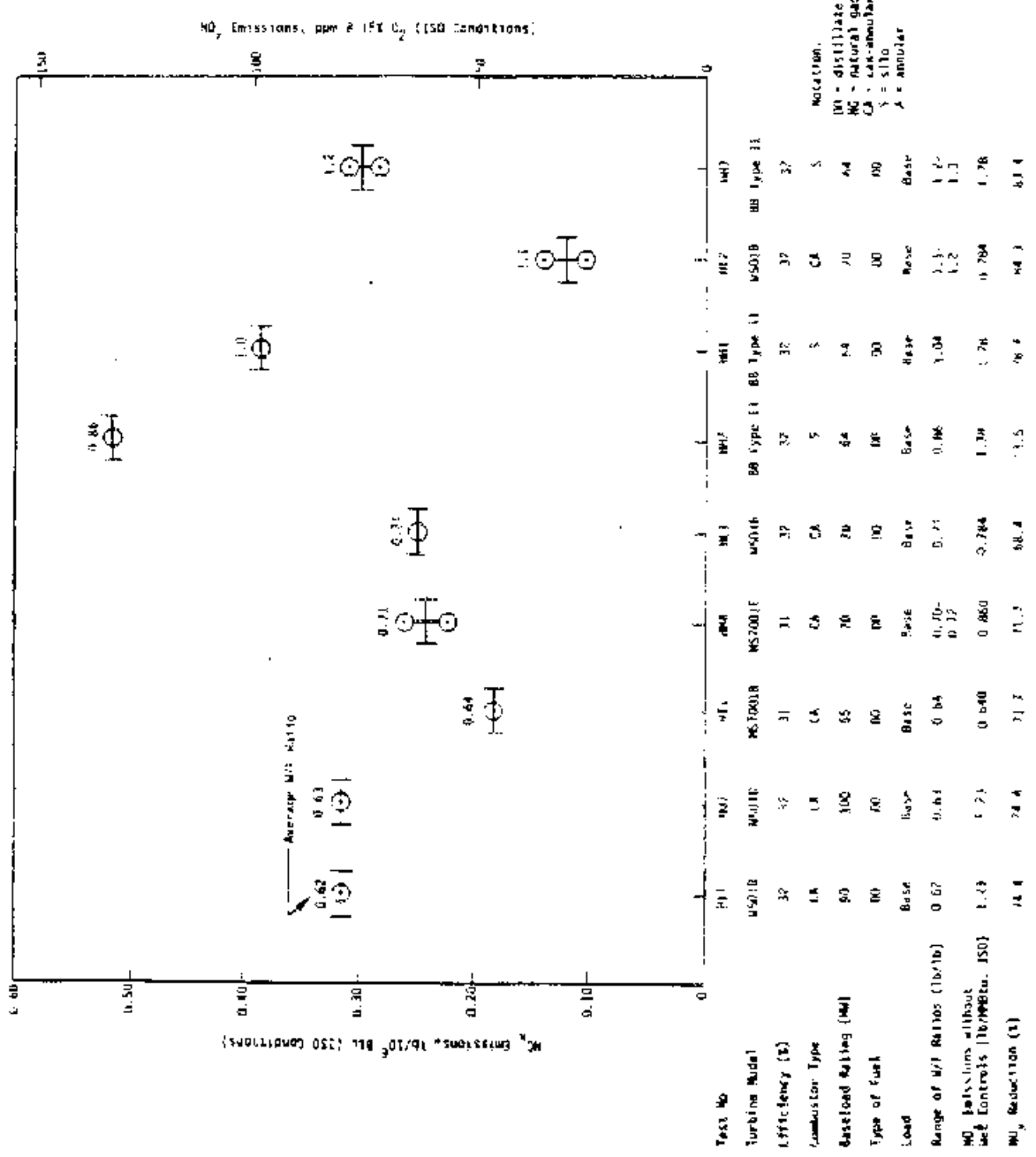


Figure 5-9. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs greater than 0.5 and firing distillate oil.[27]

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approximately 30 to 135 ppm, with WFR's ranging from 0.24 to 1.31. The gas turbine sizes range from 19 to 95 MW. The data for distillate oil-fired turbines show the same general trends as the data for natural gas-fired turbines. Site HH (Figure 5-9)

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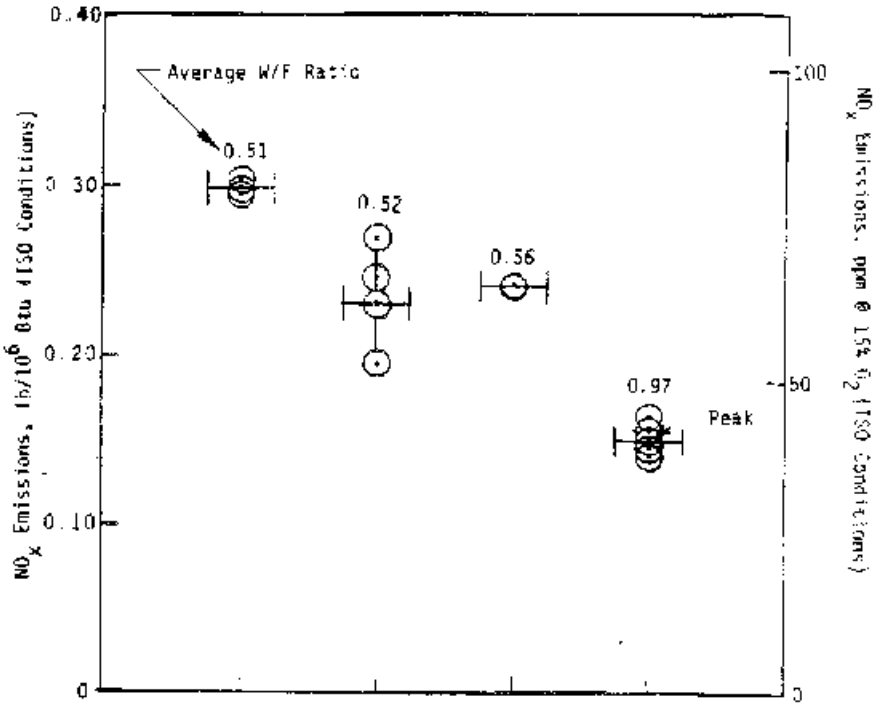
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again shows that higher WFR's are required due to the high uncontrolled NO_x emissions from this gas turbine. Also, by comparing the emission data for the distillate oil-fired turbines and natural gas-fired turbines, the data show that burning distillate oil requires higher WFR's than does burning natural gas for a given level of NO_x emissions. Higher WFR's are required because distillate oil produces higher uncontrolled NO_x levels than does natural gas (see Section 4.2.1.2).

The NO_x emission test data for steam injection are presented in Figures 5-10

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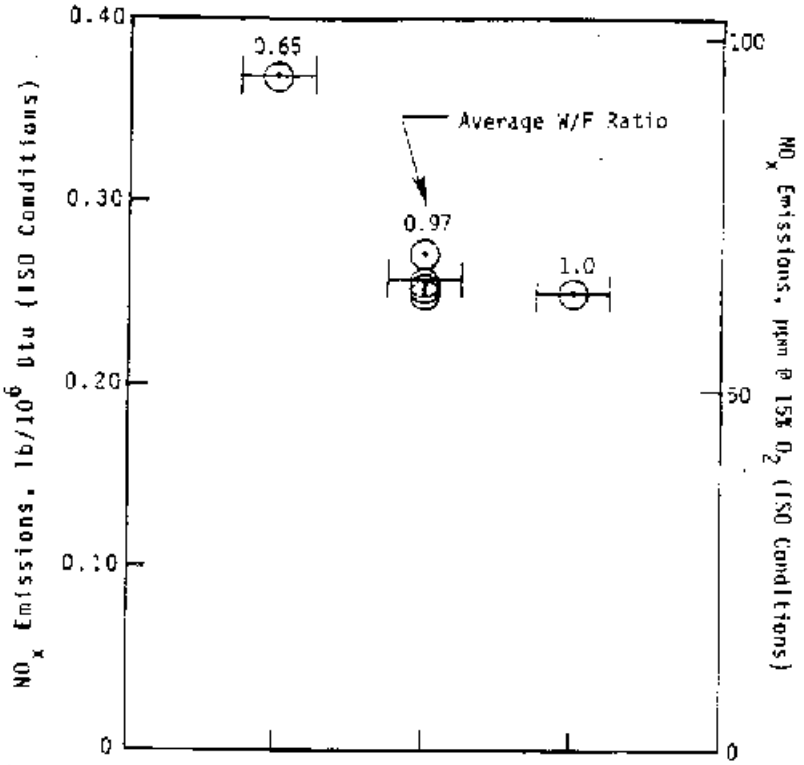


Test No.	HV1	HZ1	HM1	HZ2
Turbine Model	89 Type 9	MS6001B	MS7001E	MS6001B
Efficiency (percent)	29	31	32	31
Combustor Type	S	CA	CA	CA
Base Load Rating (MW)	30	36	70	36
Type of Fuel	NG	NG	NG	NG
Load	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.50-0.51	0.42-0.69	0.56	0.94-1.02
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	NA	0.423	0.620	0.423
NO_x Reduction (%)	NA	44.9	61.1	64.8

Notation:
DO = distillate oil
NG = natural gas
CA = can-annular
A = annular
S = silo
NA = not available

Figure 5-10. Nitrogen oxide emission test data for gas turbines with steam injection firing natural gas.[27]

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Test No.	HM2	HM3	HZ3
Turbine Model	MS7001E	MS7001E	MS6001B
Efficiency (percent)	32	32	31
Combustor Type	CA	CA	CA
Base Load Rating, MW	70	70	36
Fuel	DO	DO	DO
Load	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.65	0.91-0.99	1.01
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.860	0.860	0.749
NO_x Reduction (%)	56.5	70.2	66.6

Notation:

DO = distillate oil
NG = natural gas
CA = can-annular
S = silo
A = annular

Figure 5-11. Nitrogen oxide emission test data for gas turbines with steam injection firing distillate oil.[27]

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and 5-11 for natural gas-fired turbines and distillate oil-fired turbines, respectively. The turbines firing natural gas have NO_x emissions ranging from approximately 40 to 80 ppm, with WFR's ranging from 0.50 to 1.02. The gas turbine sizes range from 30 to 70 MW.

The NO_x emissions for turbines firing distillate oil range from approximately 65 to 95 ppm, with WFR's ranging from 0.65 to 1.01, and the gas turbine sizes tested were 36 and 70 MW. Fewer data points are available for steam injection than for water injection. However, the available data for both distillate oil-fired and natural gas-fired turbines show that NO_x emissions decrease as the steam-to-fuel ratio increases.

Reductions in NO_x emissions similar to water injection with oil-fired turbines have been achieved using water-in-oil emulsions. Results of emission tests for four turbines are shown in Table 5-7

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TABLE 5-7. ACHIEVABLE GAS TURBINE NO_x EMISSION REDUCTIONS FOR OIL-FIRED TURBINES USING WATER-IN-OIL EMULSIONS[19]

				NO_x emissions, ppmv at 15 percent O_2		
Turbine manufacturer	Turbine model	Power output, MW	Water-to-fuel ratio	Uncontrolled	Controlled	Percent reduction
Turbo Power and Marine	A4	35	0.65	184	53	68
	A9	33	0.55	150	50	66
	A9	33	0.92	126	29	77
General Electric	MS5001	15	0.49	131	60	54

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. The controlled NO_x emissions range from 29 to 60 ppmv, corresponding to NO_x reductions of 54 to 77 percent.[19] The controlled NO_x emission levels and percent reduction are consistent with those achieved using conventional water injection. Limited testing has shown that the emulsion achieves a given NO_x reduction level with a lower WFR than does a separate water injection arrangement. Test data for one oil-fired turbine showing a comparison of the WFR's for a water-in-oil emulsion versus a separate water injection system are shown in Figure 5-12

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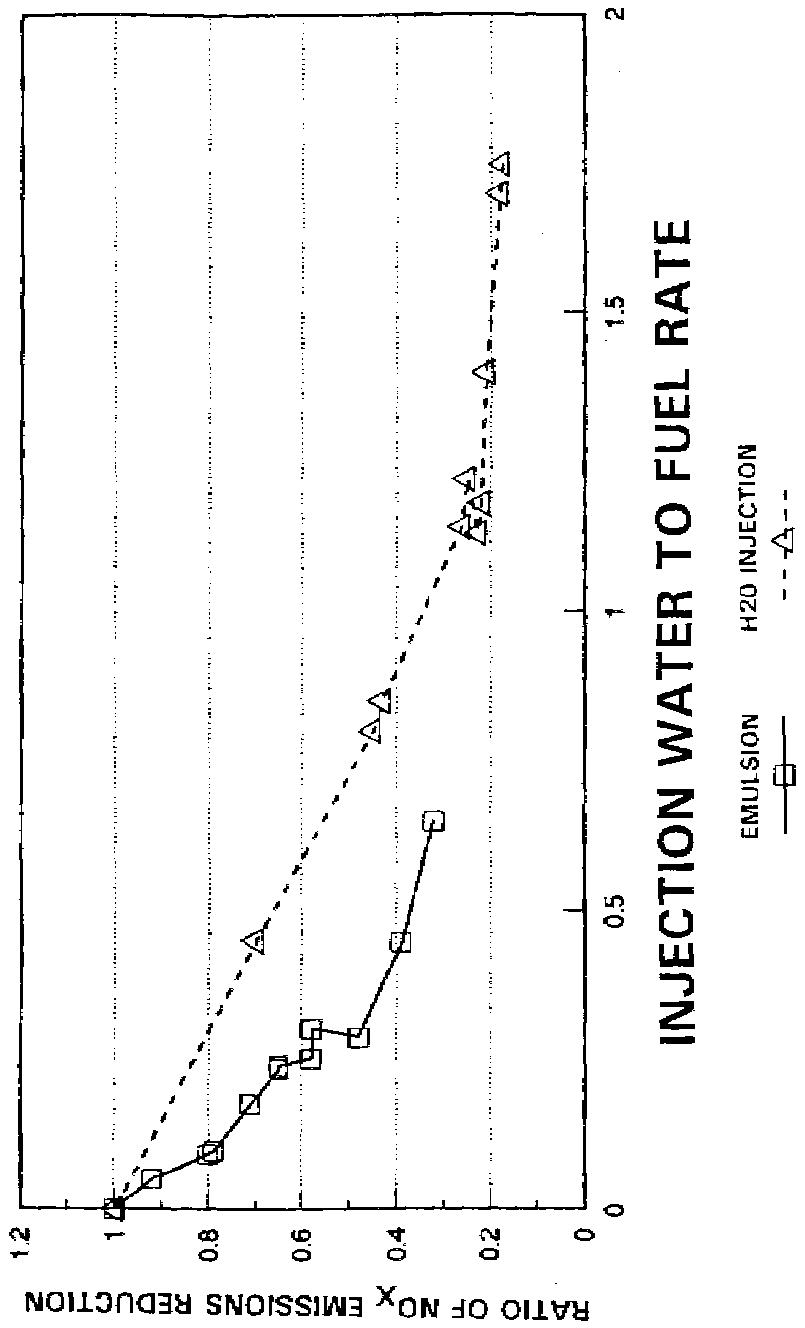


Figure 5-12. Comparison of the WFR requirement for water-in-oil emulsion versus separate water injection for an oil-fired turbine.[28]

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. As shown here, NO_x reductions achieved by a water injection system at a WFR of 1.0 can be achieved by a water-in-oil emulsion at a WFR of 0.6.

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On a mass basis, the reduction in NO_x emissions using water injection is shown in Table 5-8

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TABLE 5-8. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING WATER INJECTION

Gas turbine model	Power output, MW[a]	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c]	Oil fuel, tons/yr[c]
Saturn	1.1	6.4	9.9	2.8	4.1	14.3	23.3
Centaur	3.3	22.0	31.2	7.4	10.8	58.5	81.5
Centaur "H"	4.0	20.8	32.6	8.6	12.7	48.6	79.8
Taurus	4.5	24.7	37.6	9.4	13.9	61.1	94.9
Mars T-12000	8.8	69.4	107	17.0	24.9	210	329
Mars T-14000	10.0	85.4	NA[d]	18.7	NA[d]	267	NA[d]
501-KB5	4.0	31.6	48.5	8.9	12.2	90.9	145
570-K	4.9	22.7	41.0	9.8	15.2	51.8	103
571-K	5.9	24.2	44.0	10.4	16.3	55.1	111
LM1600	14.0	74.1	127	22.4	23.2	207	414
LM2500	22.7	146	301	36.4	37.9	438	1,050
LM5000	34.5	232	474	54.5	56.6	710	1,670
LM6000	43.0	310	609	61.3	63.5	996	2,180
MS5001P	26.8	181	274	55.5	87.4	503	747
MS6001B	39.0	250	459	73.2	116	704	1,370
MS7001E	84.7	544	822	154	243	1,560	2,320
MS7001F	161	1,290	2,190	267	417	4,090	7,090
MS9001E	125	810	1,320	219	369	2,370	3,820
MS9001F	229	1,850	3,150	382	600	5,850	10,200
GT8	47.4	899	1,440	54.1	92.3	3,380	5,410
GT10	22.6	143	196	24.6	42.6	472	614
GT11N	83.3	1,350	1,990	99.0	154	5,060	7,334
GT35	16.9	214	264	30.9	31.9	730	929
251B11/12	49.2	453	741	89.5	141	1,450	2,400
501D5	109	843	1,120	115	196	2,910	3,710
V84.2	105	858	1,570	176	190	2,730	5,520
V94.2	153	1,250	2,290	335	276	3,650	8,050
V64.3	61.5	859	1,290	176	188	2,740	4,390
V84.3	141	1,930	2,910	395	426	6,150	9,920
V94.3	204	2,790	4,170	571	611	8,890	14,200

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.
[c]Based on 8,000 hours operation per year.
[d]Data not available.

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; Table 5-9 shows uncontrolled NO$_x$ emissions and potential reduction.

TABLE 5-9. UNCONTROLLED NO$_x$ EMISSIONS AND POTENTIAL NO$_x$ REDUCTIONS FOR GAS TURBINES USING STEAM INJECTION

Gas turbine model	Power output, MW[a]	NO$_x$ emissions					
		Uncontrolled		Controlled		NO$_x$ reduction	
		Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c d]	Oil fuel, tons/yr[c d]
Saturn	1.1	6.4	9.9	6.4	9.9	0	0
Centaur	3.3	22.0	31.2	22.0	31.2	0	0
Centaur "H"	4.0	20.8	32.6	20.8	32.6	0	0
Taurus	4.5	24.7	37.6	24.7	37.6	0	0
Mars T-12000	8.8	69.4	107	69.4	107	0	0
501-KB5	4.0	31.6	48.5	8.6	48.5	194	0
570-K	4.9	22.7	41.0	22.7	41.0	0	0
571-K	5.9	24.2	44.0	24.2	44.0	0	0
LM1600	14.0	74.1	127	13.0	40.5	245	345
LM2500	22.7	146	301	21.2	66.0	499	938
LM5000	34.5	232	474	31.7	145	802	1,320
LM6000	43.0	310	609	35.6	162	1,100	1,790
MS5001P	26.8	181	274	54.1	85.3	508	755
MS6001B	39.0	250	459	71.4	113	711	1,380
MS7001E	84.7	544	822	150	237	1,580	2,340
MS7001F	161	1,290	2,190	260	407	4,110	7,130
MS9001E	125	810	1,320	214	360	2,390	3,850
MS9001F	229	1,850	3,150	373	585	5,890	10,200
GT8	47.4	899	1,440	61.2	129	3,350	5,260
GT10	22.6	143	196	40.4	41.6	410	618
GT11N	83.3	1,350	1,990	147	151	4,830	7,350
GT35	16.9	214	264	43.1	44.4	681	878
251B11/12	49.2	453	741	52.0	88.6	1,600	2,610
501D5	109	843	1,120	112	191	2,920	3,730
V84.2	105	858	1,570	225	242	2,530	5,310
V94.2	153	1,250	3,290	327	353	3,690	7,740
V64.3	61.5	859	1,290	171	184	2,750	4,410
V84.3	141	1,930	2,910	386	415	6,190	9,960
V94.3	204	2,790	4,170	557	596	8,940	14,300

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.

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As an example, a 21.8 MW turbine burning natural gas fuel can reduce NO_x emissions by 452 tons/yr (8,000 hours operation) using water injection and 511 tons/yr using steam injection. This same turbine burning oil fuel will reduce annual NO_x emissions by 1,040 tons using water injection and by 925 tons using steam injection.

5.1.5 Impacts of Wet Controls on CO and HC Emissions

While carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines, water injection may increase these emissions. Figure 5-13

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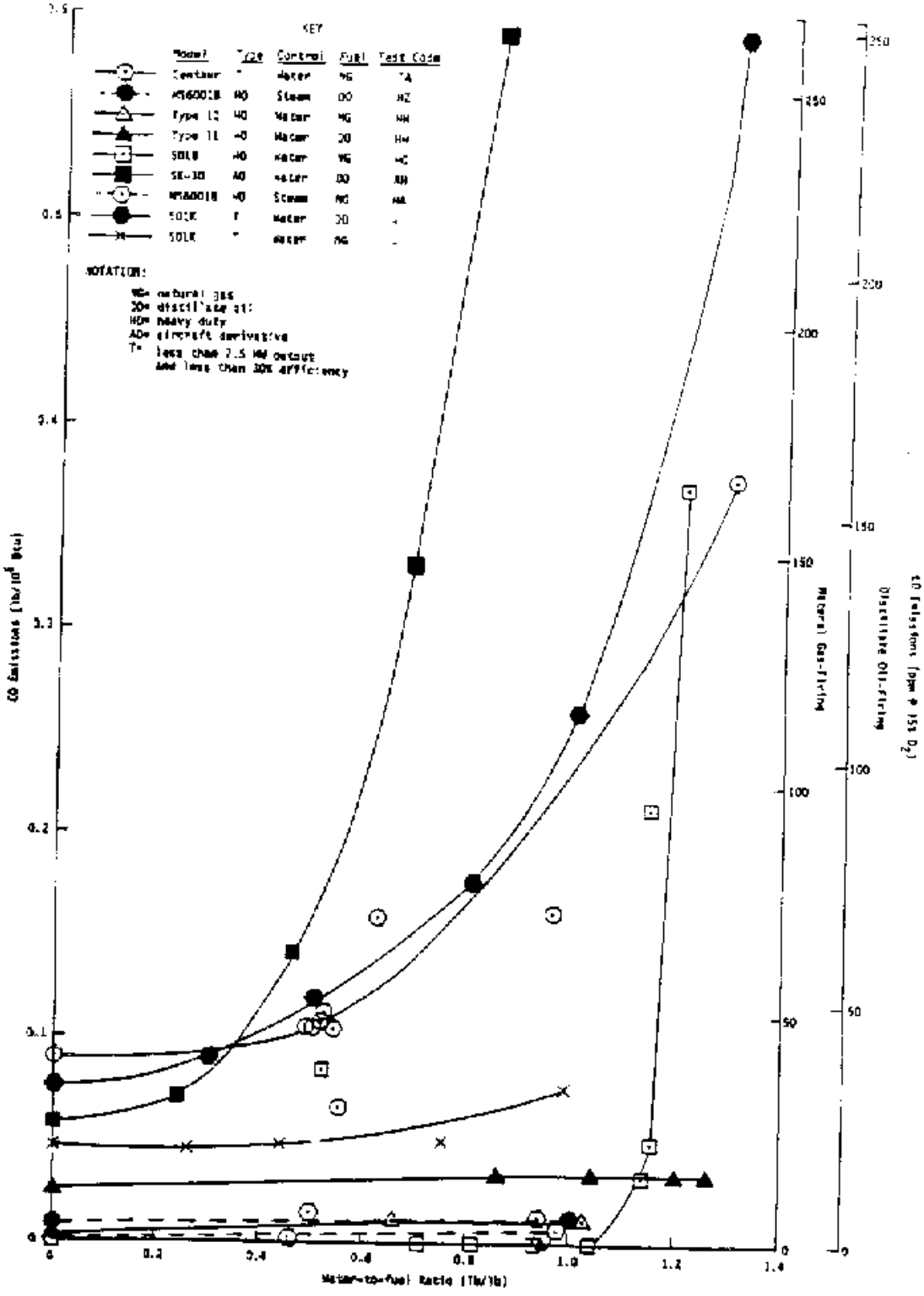


Figure 5-13. Effect of wet injection on CO emissions.[29]

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shows the impact of water injection on CO emissions for several production gas turbines. In many turbines, CO emissions increase as the WFR increases, especially at WFR's above 0.8. Steam injection also increases CO emissions at relatively high WFR's, but the impact is less than that of water injection.[29,30]

Water and steam injection also increase HC emissions, but to a lesser extent than CO emissions.[29,30] The effect of water injection on HC emissions for one turbine is shown in

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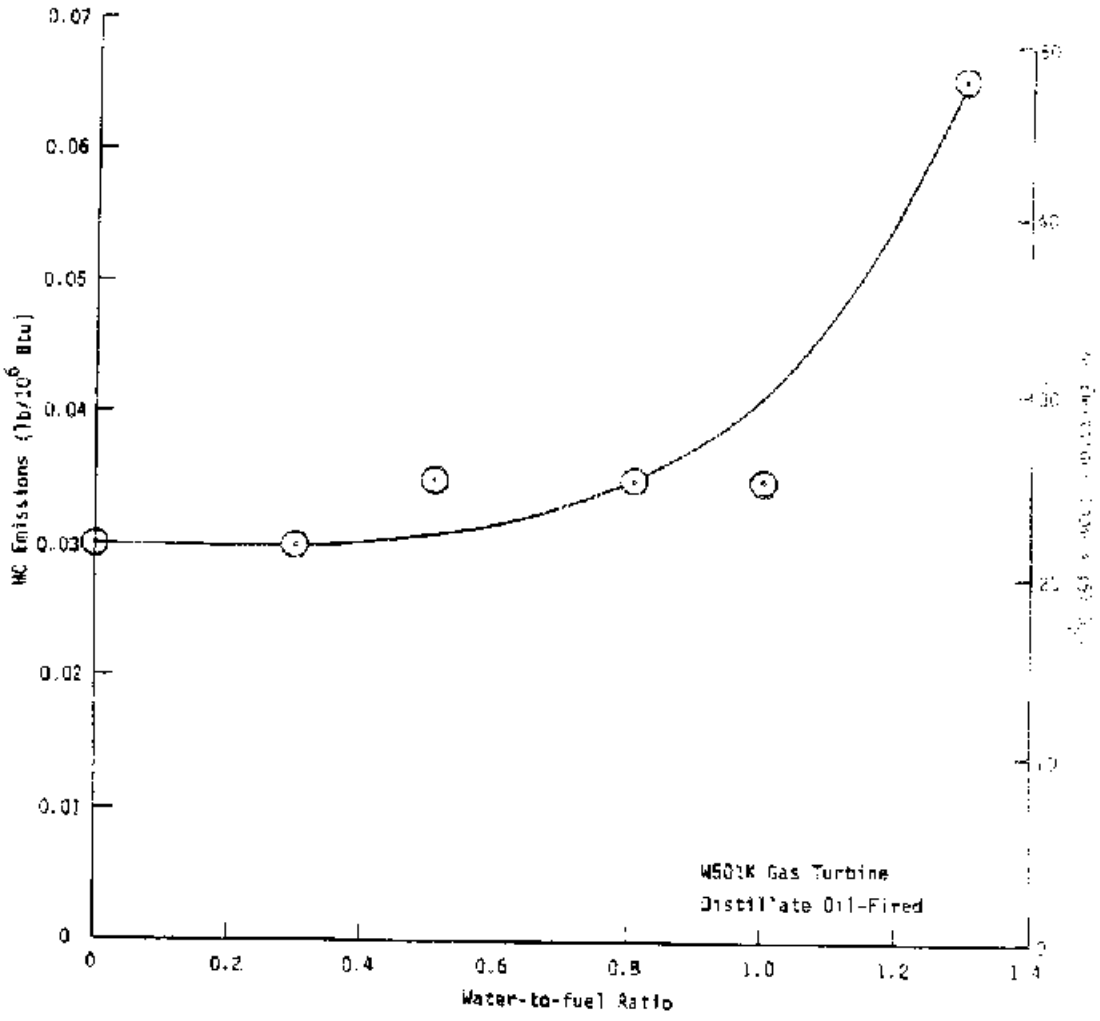


Figure 5-14. Effect of water injection on HC emissions for one turbine model.[29]

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Figure 5-14. Like CO emissions, hydrocarbon emissions increase at WFR's above 0.8.

For applications where the water or steam injection rates required for NO_x emission reductions result in excess CO and/or HC emissions, it may be possible to select an alternative turbine and/or fuel with a relatively flat CO curve, as indicated in Figure 5-13. Another alternative is an oxidation catalyst to reduce these emissions. This oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct or HRSG and serves to oxidize CO and HC to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium), and oxidation efficiencies of 90 percent or higher can be achieved. The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream.[31]

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5.1.6 Impacts of Wet Controls on Gas Turbine Performance

Wet controls affect gas turbine performance in two ways: power output increases and efficiency decreases. The energy from the added mass flow and heat capacity of the injected water or steam can be recovered in the turbine, which results in an increase in power output. For water injection, the fuel energy required to vaporize the water in the turbine combustor, however, results in a net penalty to the overall efficiency of the turbine. For steam injection, there is an energy penalty associated with generating the steam, which results in a net penalty to the overall cycle efficiency. Where the steam source is exhaust heat, which would otherwise be exhausted to the atmosphere, the heat recovery results in a net gain in gas turbine efficiency.[32] The actual efficiency reduction associated with wet controls is specific to each turbine and the actual WFR required to meet a specific NO_x reduction. The overall efficiency penalty increases with increasing WFR and is usually higher for water injection than for steam injection due to the heat of vaporization associated with water. The impacts on output and efficiency for one manufacturer's gas turbines are shown in Table 5-10.

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TABLE 5-10. REPRESENTATIVE WATER/STEAM INJECTION IMPACTS ON GAS TURBINE PERFORMANCE FOR ONE MANUFACTURER'S HEAVY-DUTY TURBINES[33]

NO_x level, ppmv	Water/fuel ratio	Percent overall efficiency change	Percent output change[a]	Remarks
75 NSPS	0.5	-1.8	+3	Oil-fired, simple cycle, water injection
42	1.0	<-3	+5	Natural gas, simple cycle, water injection
42	1.2	-2	+5	Natural gas, combined cycle, steam injection
25	1.2	-4	+6	Natural gas, water injection, multinozzle combustor
25	1.3	-3	+5.5	Natural gas, steam injection, combined cycle (Frame 6 turbine model)

[a]Compared with no injection.

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5.1.7 Impacts of Wet Controls on Gas Turbine Maintenance

Water injection increases dynamic pressure oscillation activity in the turbine combustor.[33] This activity can, in some turbine models, increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. As a result, the turbine must be removed from service more frequently for inspection and repairs to the hot section components. A summary of the maintenance impacts as provided by manufacturers is shown in Table 5-11.

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TABLE 5-11. IMPACTS OF WET CONTROLS ON GAS TURBINE MAINTENANCE USING NATURAL GAS FUEL[5-11,17,24]

Manufacturer/Model	NO_x emissions, ppmv @ 15% O_2			Inspection interval, hours		
	Standard combustor	Water injection	Steam injection	Standard	Water injection	Steam injection
General Electric						
LM1600	133	42/25	25	25,000	16,000[a]	25,000
LM2500	174	42/25	25	25,000	16,000[a]	25,000
LM5000	185	42/25	25	25,000	16,000[a]	25,000
LM6000	220	42/25	25	25,000	16,000[a]	25,000
MS5001P	142	42	42	12,000	6,000	6,000
MS6001B	148	42	42	12,000	6,000	8,000
MS7001E	154	42	42	8,000	6,500	8,000
MS7001F	179	42	42	8,000	8,000	8,000
MS9001E	176	42	42	8,000	6,500	8,000
MS9001F	176	42	42	8,000	8,000	8,000
Asea Brown Boveri						
GT10	150	25	42	80,000[b]	80,000[b]	80,000[b]
GT8	430	25	29	24,000	24,000	24,000
GT11N	400	25	25	24,000	24,000	24,000
GT35	300	42	60	80,000[b]	80,000[b]	80,000[b]
Siemens Power Corp.						
V84.2	212	42	55	25,000	25,000	25,000
V94.2	212	55	55	25,000	25,000	25,000
V64.3	380	75	75	25,000	25,000	25,000
V84.3	380	75	75	25,000	25,000	25,000
V94.3	380	75	75	25,000	25,000	25,000
Solar Turbines, Inc.						
T-1500 Saturn	99	42	NA[c]	NA[d]	NA[d]	NA[c]
T-4500 Centaur	150	42	NA[c]	NA[d]	NA[d]	NA[c]
Type H Centaur	105	42	NA[c]	NA[d]	NA[d]	NA[c]
Taurus	114	42	NA[c]	NA[d]	NA[d]	NA[c]
T-12000 Mars	178	42	NA[c]	NA[d]	NA[d]	NA[c]
T-14000 Mars	199	42	NA[c]	NA[d]	NA[d]	NA[c]
Allison/General Motors						
501-KB5	155	42	NA[c]	25,000	17,000	NA[d]
501-KC5	174	42	NA[c]	30,000	22,000	NA[d]
501-KH	155	42	25	25,000	17,000	20,000
570-K	101	42	NA[c]	20,000	12,000	NA[d]
571-K	101	42	NA[c]	20,000	12,000	NA
Westinghouse						
251B11/12	220	42	25	8,000	8,000	8,000
501D5	190	25	25	8,000	8,000	8,000

[a]Applies only to 25 ppmv level. No impact for 42 ppmv.
[b]This interval applies to time between overhaul (TBO).
[c]Steam injection is not available for this model.
[d]Data not available.

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As this table shows, the maintenance impact, if any, varies from manufacturer to manufacturer and model to model. Some manufacturers stated that there is no impact on maintenance intervals associated with water or steam injection for their turbine models. Data were provided only for operation with natural gas.

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5.2 COMBUSTION CONTROLS

The formation of both thermal NO_x and fuel NO_x depends upon combustion conditions, so modification of these conditions affects NO_x formation. The following combustion modifications are used to control NO_x emission levels:

1. Lean combustion;
2. Reduced combustor residence time;
3. Lean premixed combustion; and
4. Two-stage rich/lean combustion.

These combustion modifications can be applied singly or in combination to control NO_x emissions.

The mechanisms by which each of these techniques reduce NO_x formation, their applicability to new gas turbines, and the design or operating factors that influence NO_x reduction performance are discussed below by control technique.

5.2.1 Lean Combustion and Reduced Combustor Residence Time

5.2.1.1 Process Description. Gas turbine combustors were originally designed to operate with a primary zone equivalence ratio of approximately 1.0. (An equivalence ratio of 1.0 indicates a stoichiometric ratio of fuel and air. Equivalence ratios below 1.0 indicate fuel-lean conditions, and ratios above 1.0 indicate fuel-rich conditions.) With lean combustion, the additional excess air cools the flame, which reduces the peak flame temperature and reduces the rate of thermal NO_x formation.[34]

In all gas turbine combustor designs, the high-temperature combustion gases are cooled with dilution air to an acceptable temperature prior to entering the turbine. This dilution air rapidly cools the hot gases to temperatures below those required for thermal NO_x formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors. Because the combustion gases are at a high temperature for a shorter time, the amount of thermal NO_x formed decreases.[34]

Shortening the residence time of the combustion products at high temperatures may result in increased CO and HC emissions if

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no other changes are made in the combustor. In order to avoid increases in CO and HC emissions, combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves fuel/air mixing and reduces the time required for the combustion process to be completed. These designs may also incorporate fuel/air premixing chambers. Therefore, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length.[34]

5.2.1.2 Applicability. Lean primary zone combustion and reduced residence time combustion have been applied to annular, can-annular, and silo combustor designs.[35-37] Almost all gas turbines presently being manufactured incorporate lean combustion and/or reduced residence time to some extent in their combustor designs, incorporating these features into production models since 1975.[38,39] However, the varying uncontrolled NO_x emission levels of gas turbines shown in Figures 5-2 and 5-3 indicate that these controls are not incorporated to the same degree in every gas turbine and may be limited in some turbines by the quantity of dilution air available for lean combustion.

Lean primary zone and reduced residence time are most applicable to low-nitrogen fuels, such as natural gas and distillate oil fuels. These modifications are not effective in reducing fuel NO_x.[40]

5.2.1.3 Factors Affecting Performance. For a given combustor, the performance of lean combustion is directly affected by the primary zone equivalence ratio. As shown in Figure 4-2, the further the equivalence ratio is reduced below 1.0, the greater the reduction in NO_x emissions. However, if the equivalence ratio is reduced too far, CO emissions increase and flame stability problems occur.[41] This emissions tradeoff effectively limits the amount of NO_x reduction that can be achieved by lean combustion alone.

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For combustors with reduced residence time, the amount of NO_x emission reduction achieved is directly related to the decrease in residence time in the high-temperature flame zone.

5.2.1.4 Achievable NO_x Emission Levels Using Lean Combustion and Reduced Residence Time Combustors. Lean combustion reduces NO_x emissions, and when used in combination with reduced residence time, NO_x emissions are further reduced. Figure 5-1

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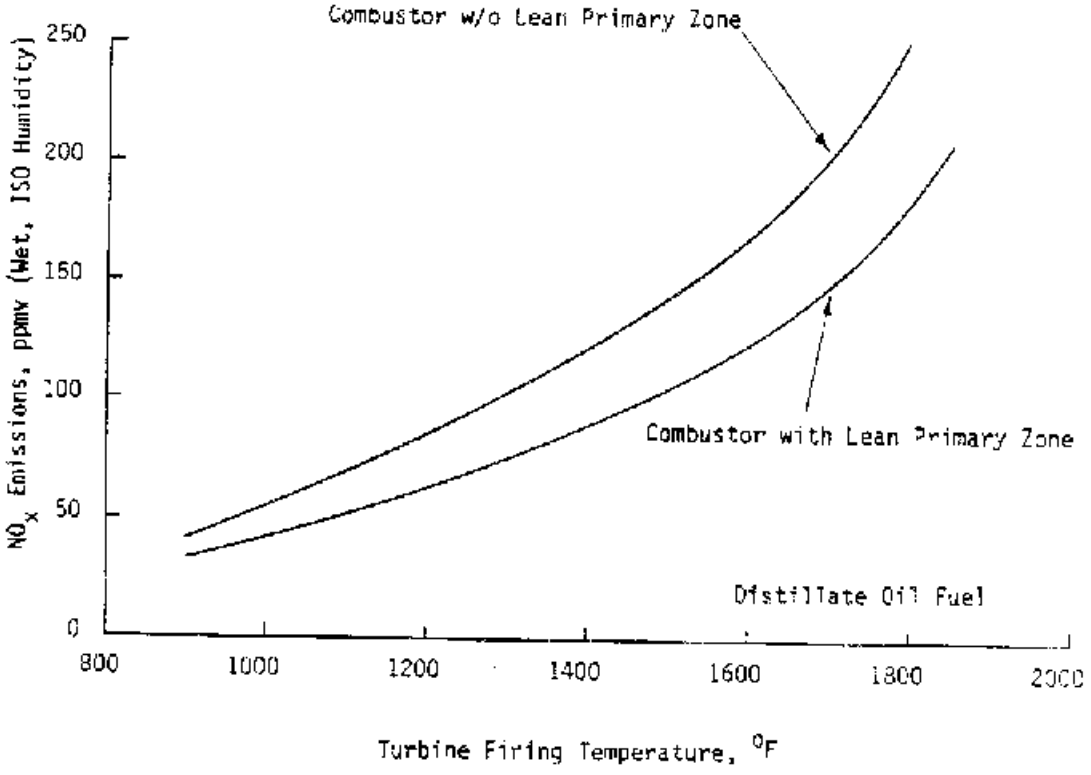


Figure 5-15. Nitrogen oxide emissions versus turbine firing temperature for combustors with and without a lean primary zone.[42]

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5 shows a comparison of NO_x emissions from a combustor with a lean primary zone and NO_x emissions from the same combustor without a lean primary zone. At the same firing temperature, NO_x emissions reductions of up to 30 percent are achieved using lean primary zone combustion without increasing CO emissions. Reducing the residence time at elevated temperatures reduces NO_x emissions. One test at 1065°C (1950°F) yielded a reduction in NO_x emissions of 40 percent by reducing the residence time. Carbon monoxide emissions increased from less than 10 to approximately 30 ppm.[42-45]

5.2.2 Lean Premixed Combustors

5.2.2.1 Process Description. In a conventional combustor, the fuel and air are introduced directly into the combustion zone and fuel/air mixing and combustion take place simultaneously. Wide variations in the air-to-fuel ratio (A/F) exist, and combustion of localized fuel-rich pockets produces significant levels of NO_x emissions. In a lean premixed combustor design, the air and fuel is premixed at very lean A/F's prior to introduction into the combustion zone. The excess air in the lean mixture acts as a heat sink, which lowers combustion temperatures. Premixing results in a homogeneous mixture, which minimizes localized fuel-rich zones. The resultant uniform, fuel-lean mixture results in greatly reduced NO_x formation rates.[17]

To achieve NO_x levels below 50 ppmv, referenced to 15 percent O_2, the design A/F approaches the lean flammability limit. To stabilize the flame, ensure complete combustion, and minimize CO emissions, a pilot flame is incorporated into the combustor or burner design. In most designs, the relatively

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small amount of air and fuel supplied to this pilot flame is not premixed and the A/F is nearly stoichiometric, so the pilot flame temperature is relatively high. As a result, NO_x emissions from the pilot flame are higher than from the lean premixed combustion.[46]

Virtually all gas turbine manufacturers have implemented lean premixed combustion development programs. Three manufacturers' designs that are available in production turbines are described below.

The first design uses a can-annular combustor and is shown in Figure 5-16

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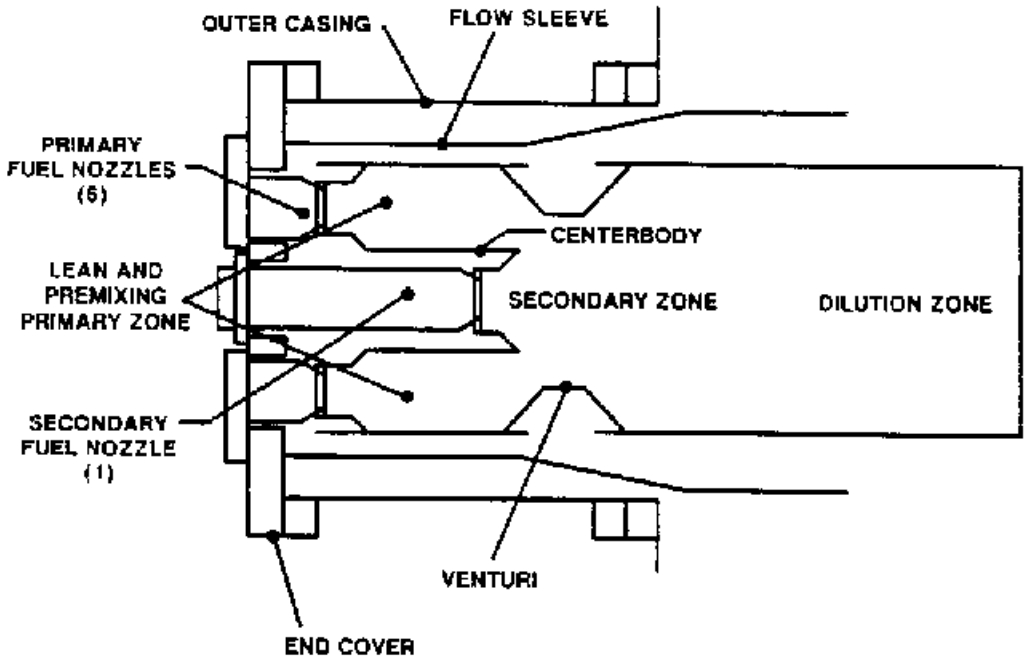


Figure 5-6. Cross-section of a lean premixed can-annular combustor.[47]

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. This is a two-stage premixed combustor: the first stage is the portion of the combustor upstream of the venturi section and includes the six primary fuel nozzles; the second stage is the balance of the combustor and includes the single secondary fuel nozzle.[33]

The operating modes for this combustor design are shown in Figure 5-17. For ignition, warmup, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor.

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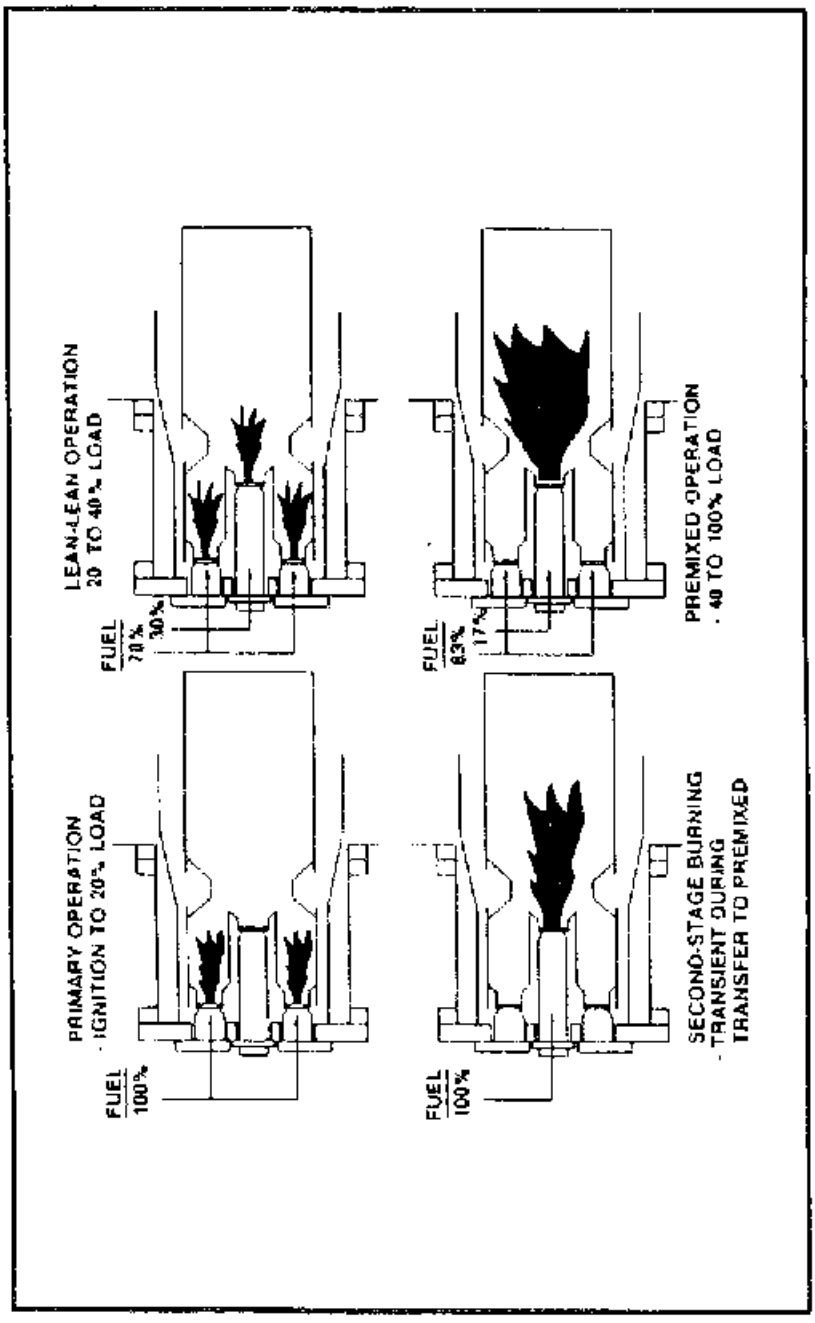


Figure 5-17. Operating modes for a lean premixed can-annular combustor.[33]

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Flame is present only in the first stage, and the equivalence ratio is kept as low as stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. Again, the equivalence ratio is kept as low as possible in both stages to minimize NO_x emissions. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.[33]

For operation on distillate oil, fuel is introduced and burned only in the first stage for ignition and for loads up to approximately 50 percent. For loads greater than 50 percent, fuel is introduced and burned in both stages.[33]

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Figure 5-18 shows a lean premixed combustor design used by another manufacturer for an annular combustor.

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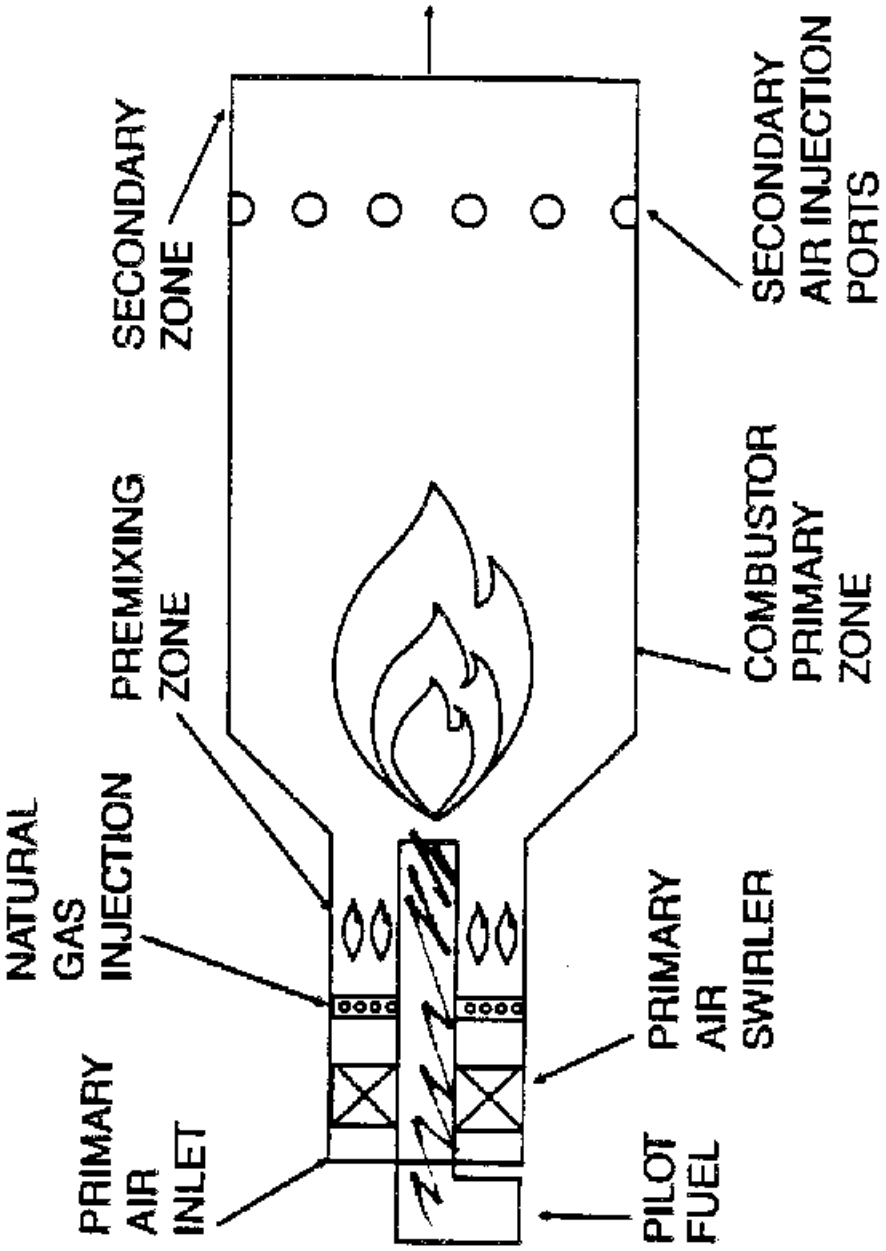


Figure 5-18. Cross-section of lean premixed annular combustion design.[47]

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The air and fuel are premixed using a very lean A/F, and the resultant uniform mixture is delivered to the primary combustion zone where combustion is stabilized using a pilot flame. Using one or more mechanical systems to regulate the airflow delivered to the combustor, the premix mode is operable for output loads between 50 and 100 percent. Below 50 percent load, only the pilot flame is operating, and NO_x emissions levels are similar to those for conventional combustors.[46]

Another manufacturer's production low-NO_x design uses a silo combustor. Unlike the can-annular and annular designs, the silo combustor is mounted externally to the turbine and can therefore be modified without significantly affecting the rest of the turbine design, provided the mounting flange to the turbine is unchanged. In addition, this large combustion chamber is fitted with a ceramic lining that shields the metal surfaces from peak flame temperatures. This lining reduces the requirement for cooling air, so more air is available for the combustion process.[17]

This silo low-NO_x combustor design uses six burners, as shown in Figure 5-19

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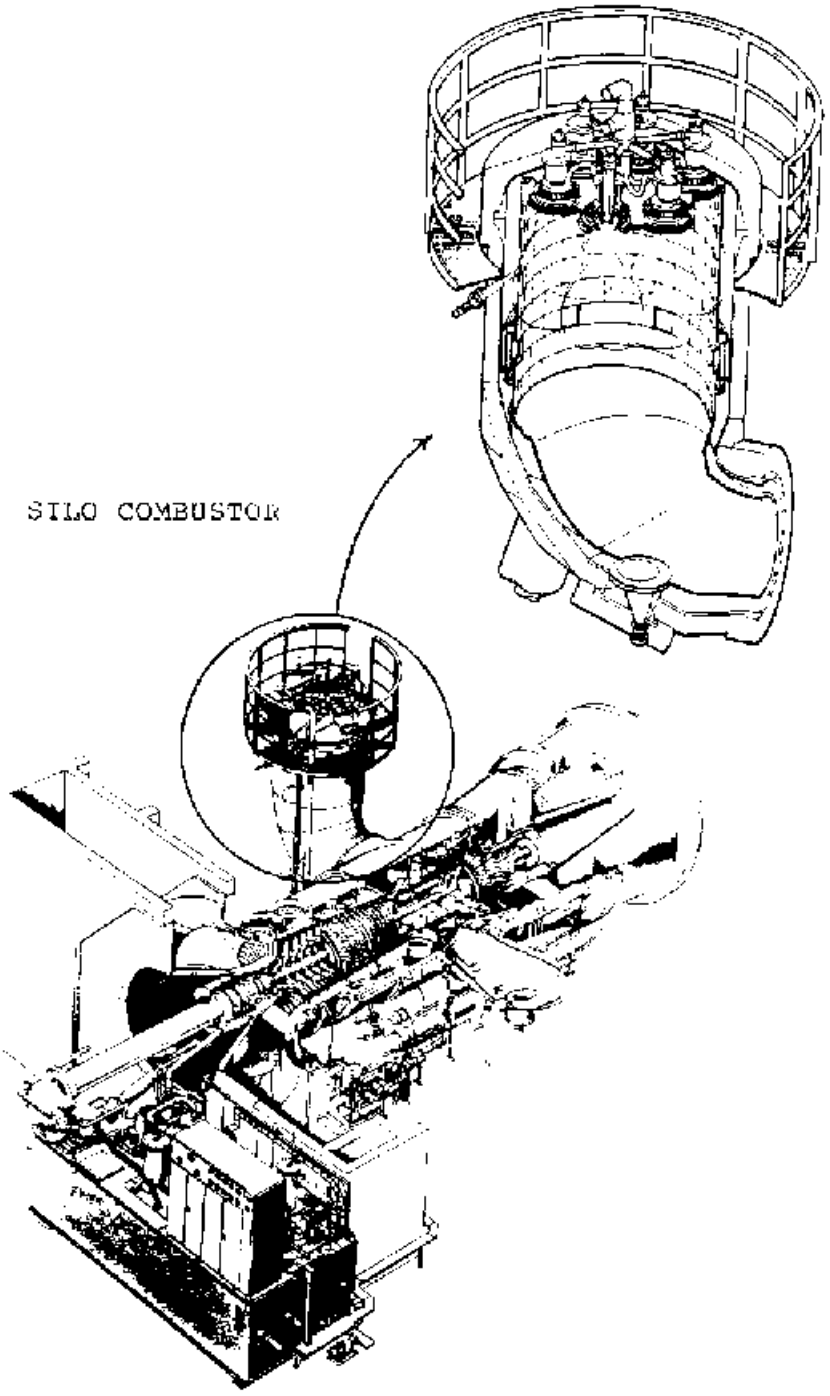


Figure 5-19. Cross-section of a low NO_x silo combustor.[35,48]

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. For operation on natural gas, each burner serves to premix the air and fuel to deliver a lean and uniform mixture to the combustion zone. To achieve the lowest possible NO_x emissions, the A/F of the premixed gases is kept very near the lean flammability limit and a pilot flame is used to stabilize the overall combustion process. This burner design is shown in Figure 5-20

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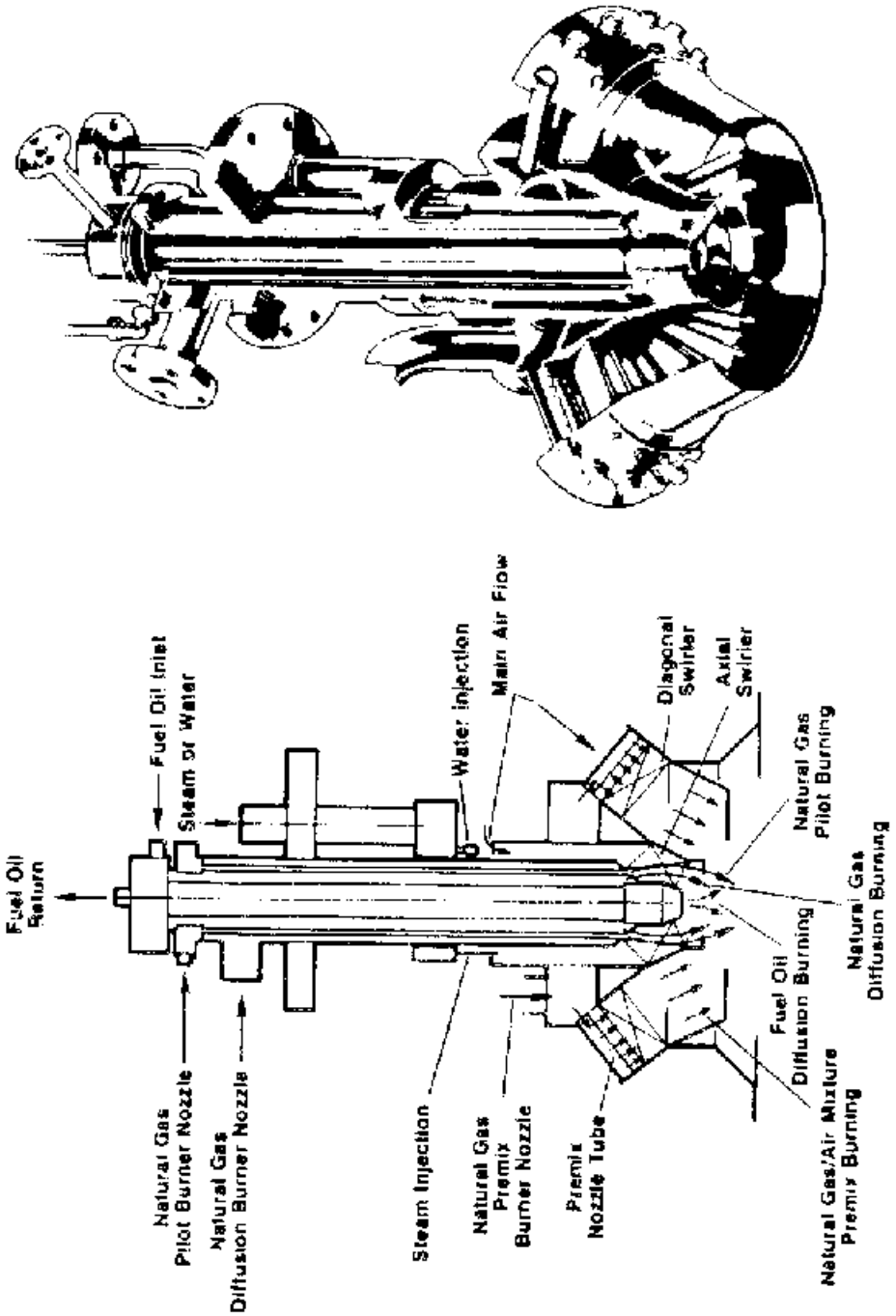


Figure 5-20. Low-NO_x burner for a silo combustor.[48]

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. Like the can-annular design, the burner in the silo combustor cannot operate over the full power range of the gas turbine in the premix mode due to inability of the premix mode to deliver suitable A/F's at low power output levels. For this reason, the burners are designed to operate in a conventional diffusion burning mode at startup and low power outputs and switch to a premix burning mode at higher power output levels.

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For operation on distillate oil with the current burner design, combustion occurs only in a diffusion mode and there is no premixing of air and fuel.

5.2.2.2 Applicability. As discussed in Section 5.2.2.1, lean premixed combustors apply to can-annular, annular, and silo combustors. This combustion modification is effective in reducing thermal NO_x emissions for both natural gas and distillate oil but is not effective on fuel NO_x. Therefore, lean premixed combustion is not as effective in reducing NO_x levels if high-nitrogen fuels are fired.[49]

The multiple operating modes associated with the percent operating load results in "stepped" NO_x emission levels. To date, low NO_x emission levels occur only at loads greater than 40 to 75 percent.

Lean premixed combustors currently are available for limited models from three manufacturers contacted for this study.[6,17,24] Two additional manufacturers project an availability date of 1993 or 1994 for lean premixed combustors for some turbine models.[11,50] All of these manufacturers state that these lean premixed combustors will be available for retrofit applications.

5.2.2.3 Factors Affecting Performance. The primary factors affecting the performance of lean, premixed combustors are A/F and the type of fuel. To achieve low NO_x emission levels, the A/F must be maintained in a narrow range near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this A/F at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that would occur as the A/F reaches the lean flammability limit, all manufacturers' lean premixed combustors switch to a diffusion-type combustion mode at reduced load conditions, typically between 40 and 60 percent load. This switchover to a diffusion combustion mode results in higher NO_x emissions.

Natural gas produces lower NO_x levels than do oil fuels. The reasons for this are the lower flame temperature of natural gas and the ability to premix this fuel with air prior to

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delivery into the second combustion stage. For operation on liquid fuels, currently available lean premixed combustor designs require water injection to achieve appreciable NO_x reduction.

5.2.2.4 Achievable NO_x Emission Levels. The achievable controlled NO_x emission levels for lean premixed combustors vary depending upon the manufacturer. At least three manufacturers currently guarantee NO_x emission levels of 25 ppmv, corrected to 15 percent O_2 for most or all of their gas turbines for operation on natural gas fuel without wet injection.[6,17,24] Each of these three manufacturers has achieved controlled NO_x emission levels of less than 10 ppmv at one or more installations in the United States and/or Europe and guarantee this NO_x level for a limited number of their gas turbine models.[51] All three manufacturers offer gas turbines in the 10+ MW (13,400 hp+) range and anticipate that guaranteed NO_x emission levels of 10 ppmv or less will be available for all of their gas turbines for operation on natural gas fuel in the next few years. These low-NO_x combustor designs apply to new turbines and existing installation retrofits.

For gas turbines in the range of 10 MW (13,400 hp) and under, one gas turbine manufacturer offers a guarantee for its lean premixed combustor, without wet injection, of 42 ppmv using natural gas fuel for two of its turbine models for 1994 delivery. This manufacturer states that a controlled NO_x emission level of 25 ppmv has been achieved by in-house testing, and this 25 ppmv level firing natural gas fuel is the goal for all of its gas turbine models, for both new equipment and retrofit applications.[50]

These controlled NO_x emission levels of 9 to 42 ppmv correspond to full output load; at reduced loads, the NO_x levels increase, often in "stepped" fashion in accordance with changes in combustor operation from premixed mode to conventional or diffusion-mode operation (see Section 5.2.2.3). Figure 5-21

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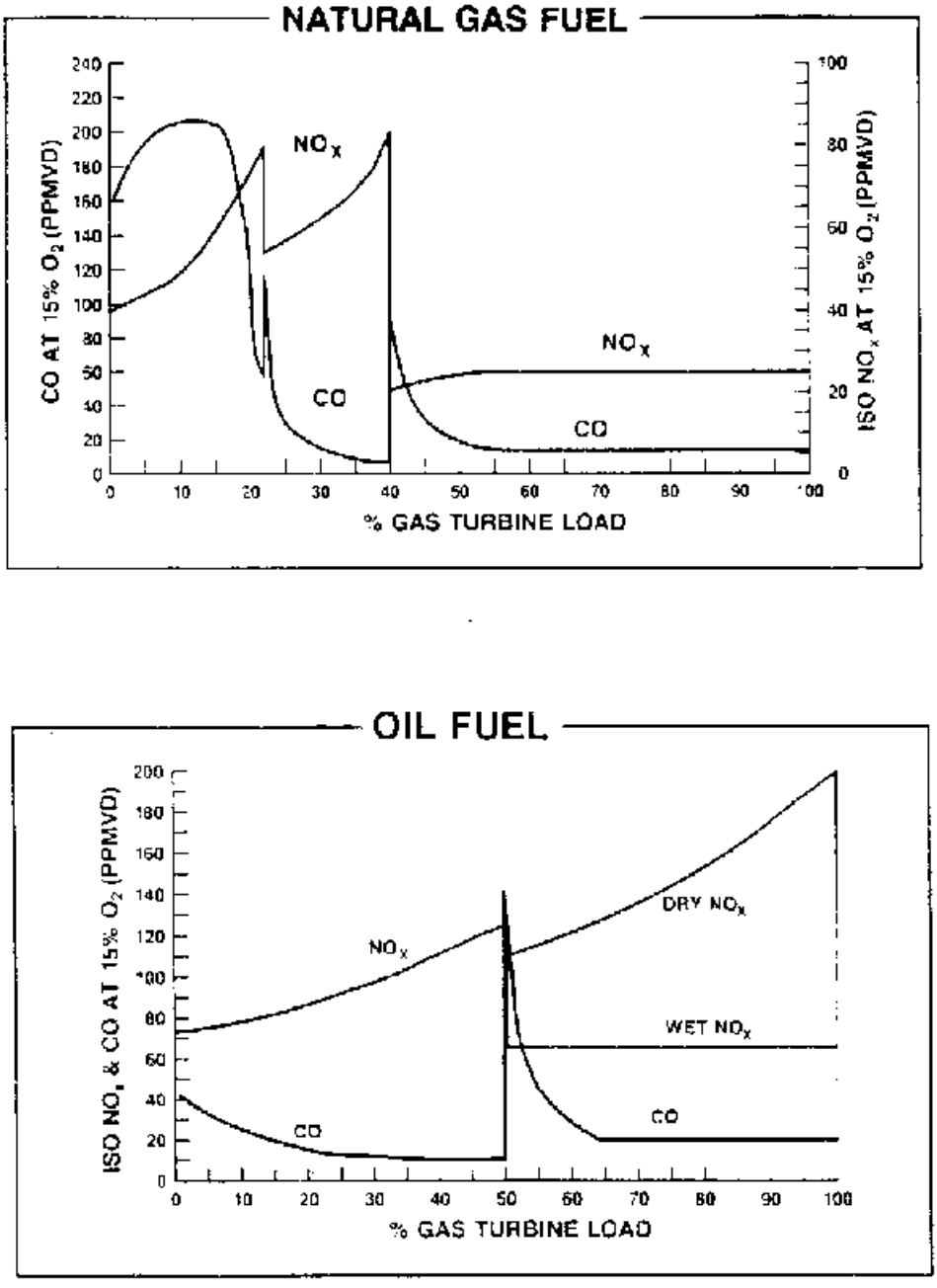


Figure 5-21. "Stepped" NO_x and CO emissions for a low-NO_x can-annular combustor burning natural gas and distillate oil fuels.[47]

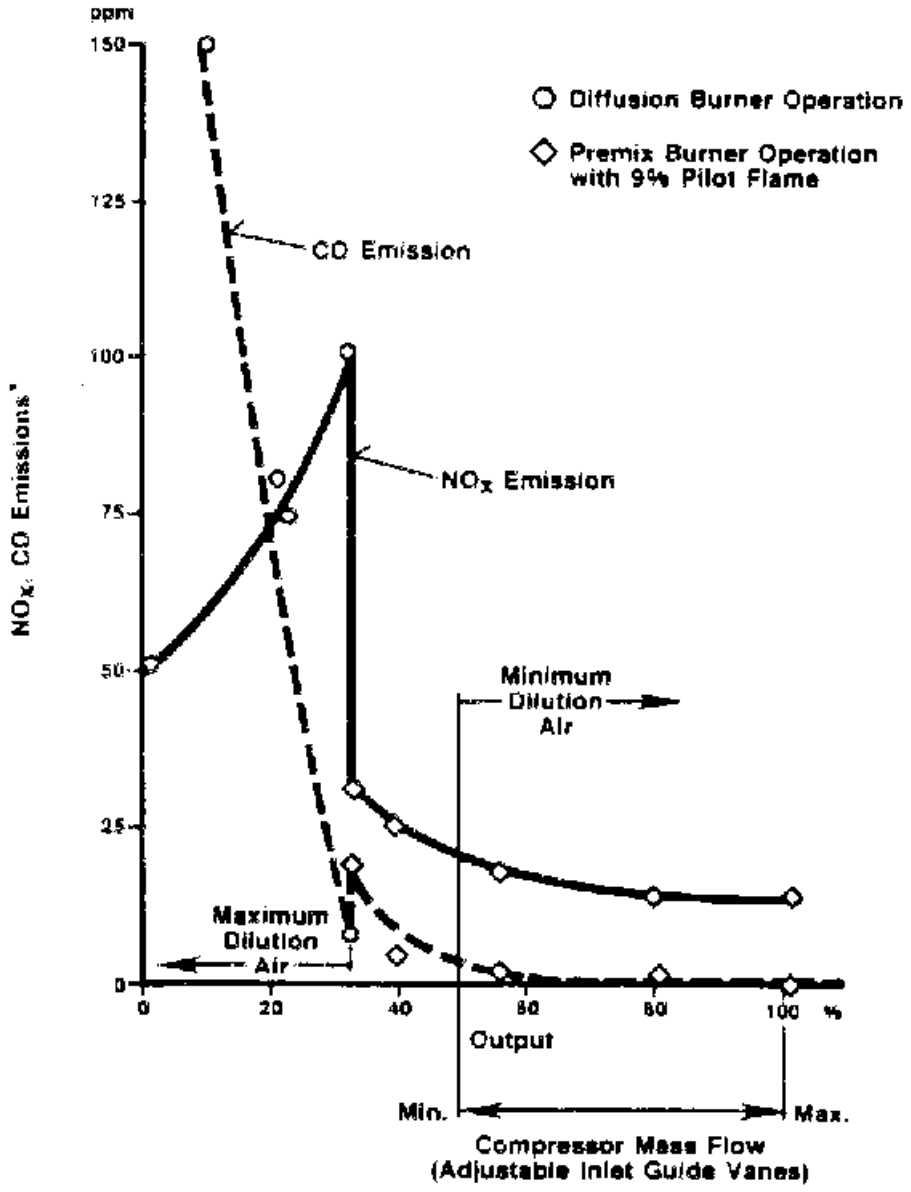


Figure 5-22. "Stepped" NO_x and CO emissions for a low-NO_x silo combustor burning natural gas.[35]

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shows these stepped NO_x emissions levels for a can-annular combustor for natural gas and oil fuel operation. Figure 5-22

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shows the emissions for a silo combustor operating on natural gas only.

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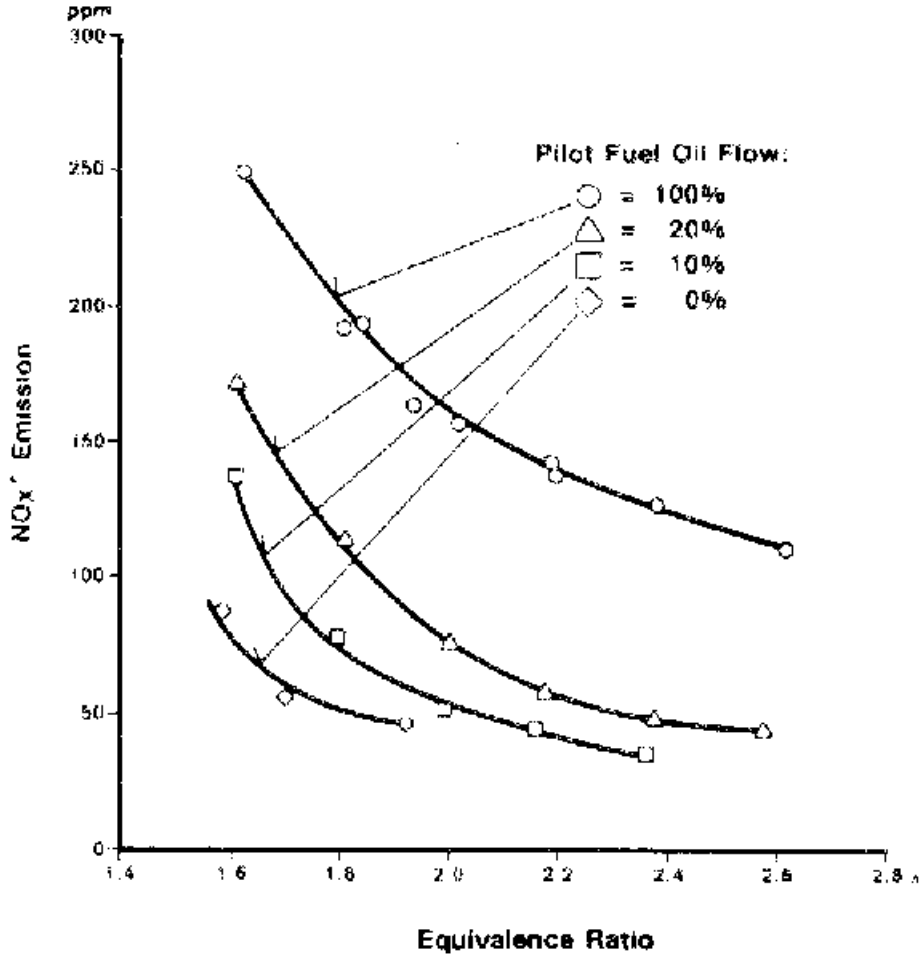


Figure 5-23. Nitrogen oxide emission text results from a lean premix silo combustor firing fuel oil without wet injection.[53]

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The emission levels shown in Figures 5-21 and 5-22 correspond to full-scale production turbines currently available from the manufacturers.

Reduced NO_x emissions when burning oil fuel in currently available lean premixed combustor designs have been achieved only with water or steam injection. With water or steam injection, a 65 ppmv NO_x level can be achieved in the turbine with a can-annular combustor design; a 65 ppmv level can also be met with water injection in the turbine with a silo combustor at a WFR of 1.4.[48,52] This 65 ppmv level for lean premixed combustors is higher than the controlled NO_x levels achieved with water injection in oil-fired turbines using a conventional combustor design.

Modification of the existing burner design used in the silo combustor to allow premixing of the oil fuel with air prior to combustion is under development. Tests performed using a 12 MW (16,200 hp) turbine achieved NO_x emission levels below 50 ppmv without wet injection, corrected to 15 percent O_2, compared to uncontrolled levels of 150 ppmv or higher. The NO_x levels, without wet injection, as a function of equivalence ratio are shown in Figure 5-23. The design equivalence ratio at rated load is approximately 2.1. As shown in this figure, NO_x emissions below 50 ppmv were achieved at rated power output at pilot fuel flow levels of 10 percent of the total fuel input.[52]

Site test data for two turbines using silo-type lean premixed combustors, as reported by the manufacturer, are shown in Table 5-12. As this table shows, NO_x emission levels as low as 16.5 ppmv were recorded for using natural gas fuel without

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TABLE 5-12. MEASURED NO_x EMISSIONS FOR COMPLIANCE TESTS OF A NATURAL GAS-FUELED LEAN PREMIXED COMBUSTOR WITHOUT WATER INJECTION[22]

Turbine No.	Output, percent of baseline	NO_x emission level, ppmv[a]
1	107	17.7
1	100	16.5
2	100	24.1
2	75	20.4
1	50	22.3
2	50	22.2

[a]In dry exhaust with 15 percent O_2, by volume.

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water injection. Subsequent emission tests have achieved levels below 10 ppmv.[51] Corresponding data for operation on oil fuel using only the pilot (diffusion) stage for combustion, and with water injection, is shown in Table 5-13. Levels of NO_x emissions

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TABLE 5-13. MEASURED NO_x EMISSIONS FOR OPERATION OF A LEAN PREMIXED COMBUSTOR DESIGN OPERATING IN DIFFUSION MODE ON OIL FUEL WITH WATER INJECTION[22]

Turbine No.	Output, percent of baseload	NO_x emission level, ppmv[a]
1	Peak	69.3
2	Peak	53.6
1	100	59.9
2	100	51.6
1	75	54.3
2	75	49.2
2	50	54.8

[a]In dry exhaust with 15 percent O_2, by volume.

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at base load for No. 2 fuel oil are between 50 and 60 ppmv.

Based on information provided by turbine manufacturers, the potential NO_x reductions using currently available lean premixed

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combustors are shown in Table 5-14. As this table indicates, NO_x emission reductions range from 14.7 tons/yr for a 1.1 MW (1,480 hp) turbine to 10,400 tons/yr

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TABLE 5-14. POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING LEAN PREMIXED COMBUSTORS

Turbine model	Power output, MW	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, ppmv	Oil fuel, ppvm	Gas fuel, ppmv	Oil fuel, ppmv	Gas fuel, tons/yr[a]	Oil fuel, tons/yr[a b]
Saturn[c]	1.1	99	150	42	NA[d]	14.7	NA[d]
Centaur T-4500[c]	3.3	130	179	42	NA[d]	59.5	NA[d]
Centaur "H"[c]	4.0	105	160	42	NA[d]	49.8	NA[d]
Taurus[c]	4.5	114	168	42	NA[d]	62.4	NA[d]
Mars T-12000[c]	8.8	178	267	42	NA[d]	212	NA[d]
Mars T-14000[c]	10.0	199	NA[d]	42	NA[d]	270	NA[d]
MS6001B	39.0	148	267	25/9[e]	65	829/937	1,139
MS7001E	84.7	154	228	25/9[e]	65	1,820/2,050	2,360
MS7001F	161	210	353	25	65	4,540	5,190
MS9001E	125	161	241	25/9[e]	65	2,740/3,060	3,490
MS9001F	229	210	353	25	65	6,500	7,250
GT10	22.6	150	200	25	42	476	620
GT11N	83.3	390	560	25/9[e]	42	5,070/5,290	7,360
V84.2	105	212	360	25/9[e]	NA[f]	3,030/3,290	NA[f]
V94.2	153	212	360	9[e]	NA[f]	4,410/4,780	NA[f]
V64.3	61.5	380	530	42	NA[d]	3,210	NA[d]
V84.3[c]	141	380	530	42	NA[d]	7,230	NA[d]
V94.3[e]	204	380	530	42	NA[d]	10,400	NA[d]

[a]Based on 8,000 hours operation per year.
[b]Requires water or steam injection.
[c]Scheduled availability is 1994 for natural gas fuel.
[d]NA = Data not available.
[e]Standard NO_x guarantee is 25 ppmv. Manufacturers offer guaranteed NO_x levels as low as 9 ppmv for these turbines.
[f]Scheduled availability 1993 for oil fuel without water injection. Reference 17.

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for a 204 MW (274,000 hp) turbine for operation on natural gas without wet injection. Corresponding NO_x emission reductions for operation on oil fuel, with water injection, range from 620 tons/yr for a 22.6 MW (30,300 hp) turbine to 7,360 tons/yr for an 83.3 MW (112,000 hp) turbine.

Limited data from two manufacturers showing the impact of lean premixed combustor designs on CO emissions are shown in Table 5-15.

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TABLE 5-15. COMPARISON OF NO_x AND CO EMISSIONS FOR STANDARD VERSUS LEAN PREMIXED COMBUSTORS FOR TWO MANUFACTURERS' TURBINES[46,54]

	Emissions, ppmv, referenced to 15 percent O_2[a]				
		Standard combustor		Lean premixed combustor	
GT Model	Power output, MW	NO_x	CO	NO_x	CO
Centaur H	4.0	105	15	25-42	50[b]
Mars T-14000	10.0	199	5.5	25-42	50[b]
MS6001B	39.0	148	10	9	25
MS7001E	84.7	154	10	9	25
MS9001E	125	161	10	9	25
MS7001F	161	210	25	25	15
MS9001F	229	210	25	25	15

[a]For operation at ISO conditions using natural gas fuel.

[b]Maximum design goal for CO emissions. Most in-house test configurations have achieved CO emission levels between 5 and 25 ppmv.

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For natural gas-fueled turbines with rated outputs of 10 MW (13,400 hp) or less, controlled NO_x emission levels of 25 to 42 ppmv result in a rise in CO emission levels from 25 ppmv or less to as high as 50 ppmv.[43] For turbines above 10 MW (13,400 hp), controlled NO_x emission levels of 9 ppmv result in a rise in CO emissions from 10 to 25 ppmv for natural gas fuel. Conversely, for controlled NO_x emission levels of 25 ppmv, the CO emissions drop from 25 to 15 ppmv.[51] For one manufacturer's lean premixed silo combustor design, CO emissions at rated load are less than 5 ppmv, as shown previously in Figure 5-21. This limited data suggest that the effect of lean premixed combustors on CO emissions depends upon the specific combustor design and the controlled NO_x emission level.

The emission levels shown in Table 5-15 correspond to rated power output. Like NO_x emission levels, CO emissions change with changes in combustor operating mode at reduced power output. The "stepped" effect on CO emissions is shown in Figures 5-21 and 5-22, shown previously.

Operation on oil fuel with wet injection, shown previously in Figure 5-21, shows CO emission levels of 20 ppmv. Additional CO emission data were not available for operation on oil fuel with water injection in lean premixed combustors. Developmental tests for operation on oil fuel without wet injection in a silo combustor are presented in Figure 5-24

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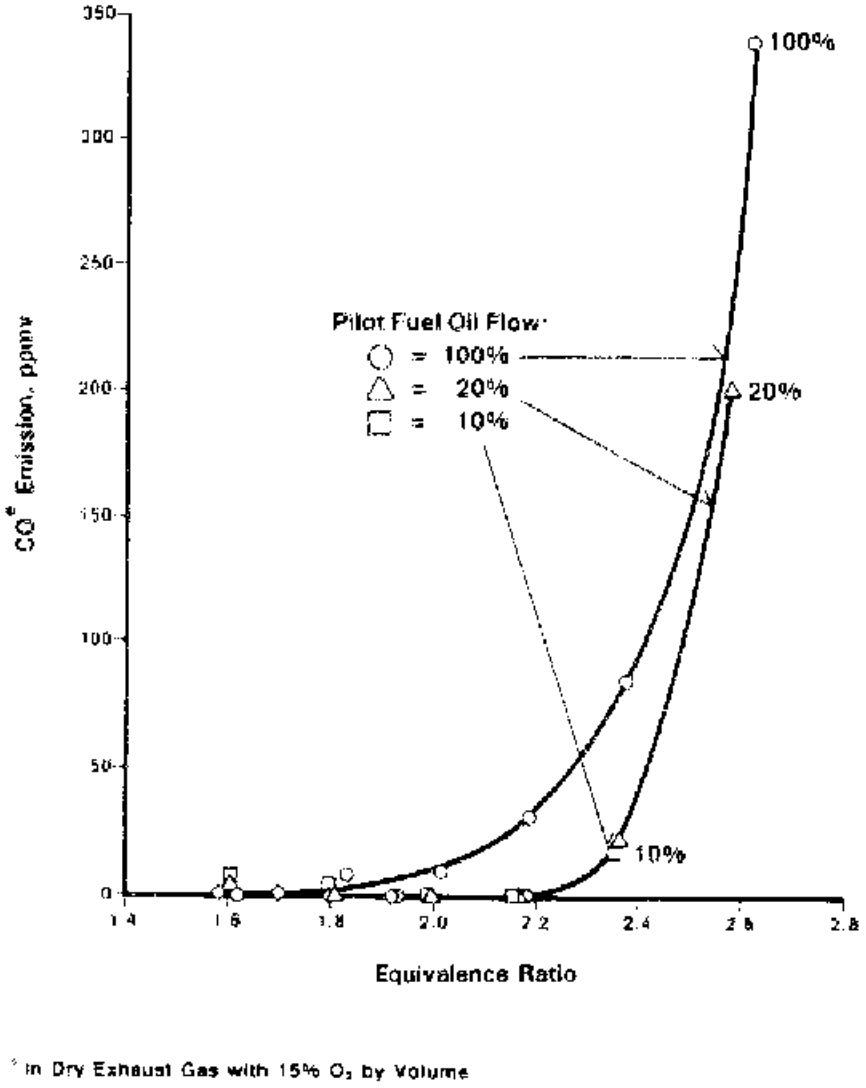


Figure 5-24. The CO emission test results from a lean premix silo combustor firing fuel oil without wet injection.

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. At rated load, shown in this figure at an equivalence ratio of approximately 2.1, CO emissions are less than 10 ppmv, corrected to 15 percent $O_{2,}$

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and are in the range of 0 to 2 ppmv for a pilot oil fuel flow of 10 percent (representing 10 percent of the total fuel flow).[53] This 10 percent pilot fuel flow corresponds to controlled NO_x emission levels below 50 ppmv, as shown previously in Figure 5-22. No data for HC emissions were available for lean premixed burner designs.

5.2.3 Rich/Quench/Lean Combustion

5.2.3.1 Process Description. Rich/quench/lean (RQL) combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and hydrogen (H_2). The CO and H_2 replace some of the oxygen normally available for NO_x formation and also act as reducing agents for any NO_x formed in the primary zone. Thus, fuel nitrogen is released with minimal conversion to NO_x. The lower peak flame temperatures due to partial combustion also reduce the formation of thermal NO_x.[55]

As the combustion products leave the primary zone, they pass through a low-residence-time quench zone where the combustion products are rapidly diluted with additional combustion air or water. This rapid dilution cools the combustion products and at the same time produces a lean A/F. Combustion is then completed under fuel-lean conditions. This secondary lean combustion step minimally contributes to the formation of fuel NO_x because most of the fuel nitrogen will have been converted to N_2 prior to the lean combustion phase. Thermal NO_x is minimized during lean combustion due to the low flame temperature.[55]

5.2.3.2 Applicability. The RQL combustion concept applies to all types of gas turbines. None of the manufacturers contacted for this study, however, currently have this design available for their production turbines. This may be due to lack of demand for this design due to the current limited use of high-nitrogen-content fuels in gas turbines.

5.2.3.3 Factors Affecting Performance. The NO_x emissions from RQL combustors are affected primarily by the equivalence ratio in the primary combustion zone and the quench airflow rate.

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Careful selection of equivalence ratios in the fuel-rich zone will minimize both thermal and fuel NO_x formation. Further NO_x reduction is achieved with increasing quench airflow rates, which serve to reduce the equivalence ratio in the secondary (lean) combustion stage.

5.2.3.4 Achievable NO_x Emissions Levels Using Rich/Quench/Lean Combustion. The RQL staged combustion has been demonstrated in rig tests to be effective in reducing both thermal NO_x and fuel NO_x. As shown in Figure 5-25, NO_x emissions are reduced by 40 to 50 percent in a test rig burning diesel fuel.

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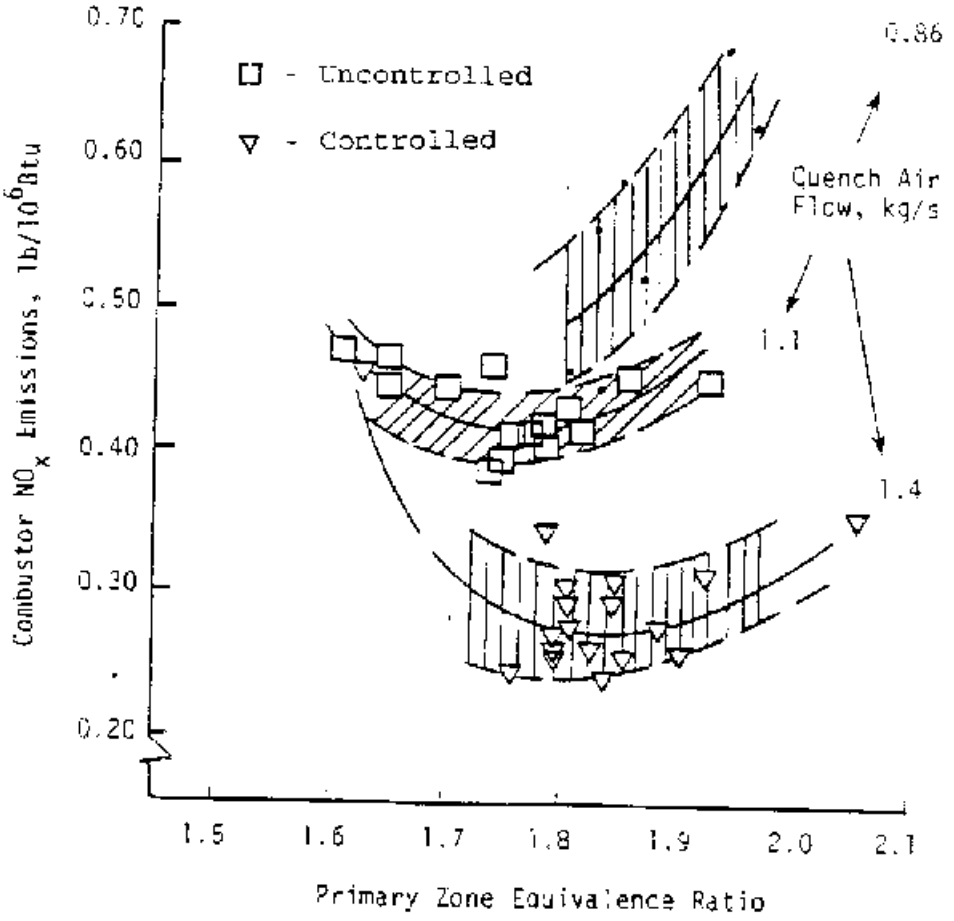


Figure 5-25. Nitrogen oxide emissions versus primary zone equivalence ratio for a rich/quench/lean combustor firing distillate oil.[56]

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At an equivalence ratio of 1.8, the NO_x emissions can be reduced from 0.50 to 0.27 lb/MMBtu by increasing the quench airflow from 0.86 to 1.4 kg/sec. Data were not available to convert the NO_x emissions figures to ppmv. The effectiveness of rich/lean staged combustion in reducing fuel NO_x when firing high-FBN fuels is shown in Figure 5-26.

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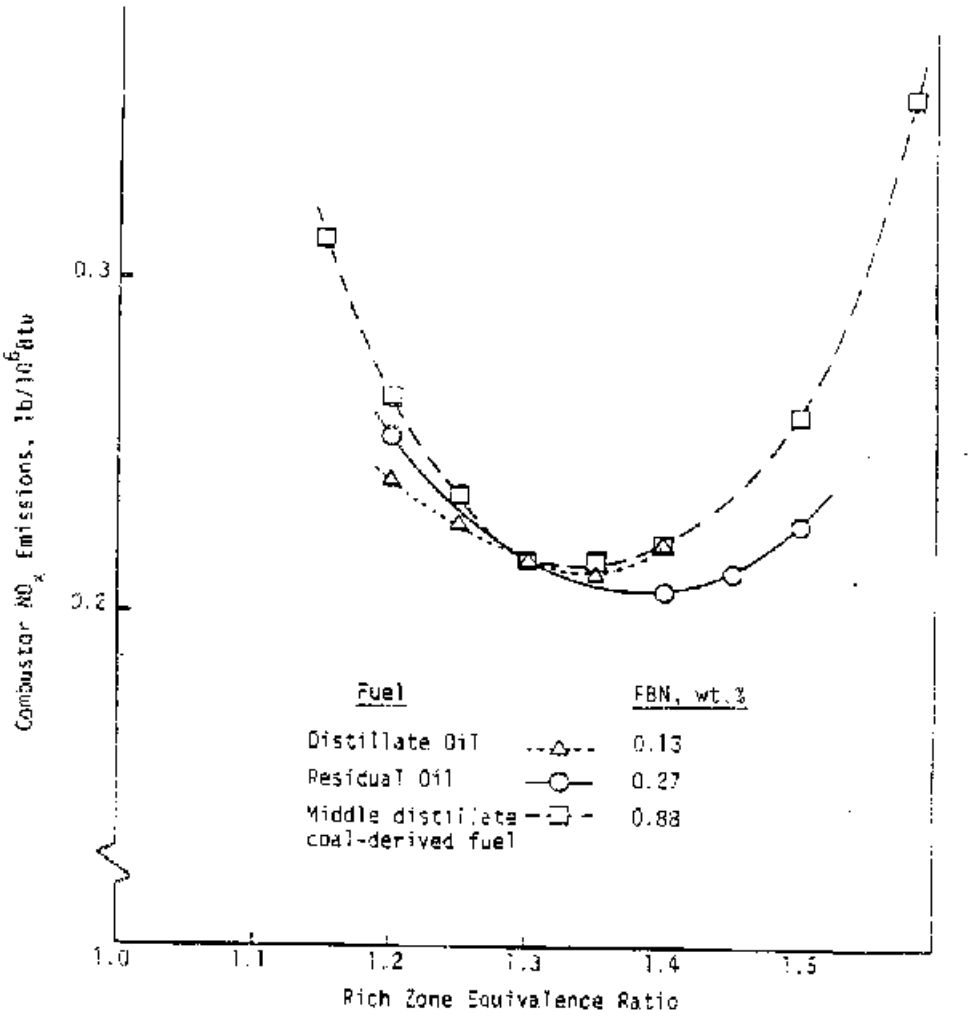


Figure 5-26. Effects of fuel bound nitrogen (FBN) content of NO_x emissions for a rich/quench/lean combustor.[57]

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Increasing the FBN content from 0.13 to 0.88 percent has little impact on the total NO_x formation at an operating equivalence ratio of 1.3 to 1.4. Tests on other rich/lean combustors indicate fuel nitrogen conversions to NO_x of about 7 to 20 percent.[58,59] These fuel nitrogen conversions represent a fuel NO_x emission reduction of approximately 50 to 80 percent.

One manufacturer has tested an RQL combustor design in a 4 MW (5,360 hp) gas turbine fueled with a finely ground coal and water mixture. The coal partially combusts in a fuel-rich zone at temperatures of 1650°C (3000°F), with low O_2 levels and an extremely short residence time. The partially combusted products are then rapidly quenched with water, cooling combustion temperatures to inhibit thermal NO_x formation. Additional combustion air is then introduced, and combustion is completed under fuel-lean conditions. In tests at the manufacturer's plant, cosponsored by the U. S. Department of Energy, a NO_x emission level of 25 ppmv at 15 percent O_2 was achieved. This combustor design can also be used with natural gas and oil fuels. Single-digit NO_x emission levels are reported for operation on

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natural gas fuel. This combustor design is not yet available for production turbines.[60]

5.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. Over 100 gas turbine installations use SCR in the United States.[61] An SCR process description, the applicability of SCR for gas turbines, the factors affecting SCR performance, and the achievable NO_x reduction efficiencies are discussed in this section.

5.3.1 Process Description

The SCR process reduces NO_x emissions by injecting ammonia into the flue gas. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. In the catalyst unit, the ammonia reacts with NO_x primarily by the following equations:[62]

$$NH_3 + NO + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O;\ \text{and}$$

$$NH_3 + 1/2\ NO_2 + 1/4\ O_2 \rightarrow 3/2\ N_2 + 3/2\ H_2O.$$

The catalyst's active surface is usually either a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path to maximize conversion efficiency and minimize back-pressure on the gas turbine. The most common catalyst body configuration is a monolith, "honeycomb" design, as shown in Figure 5-27.

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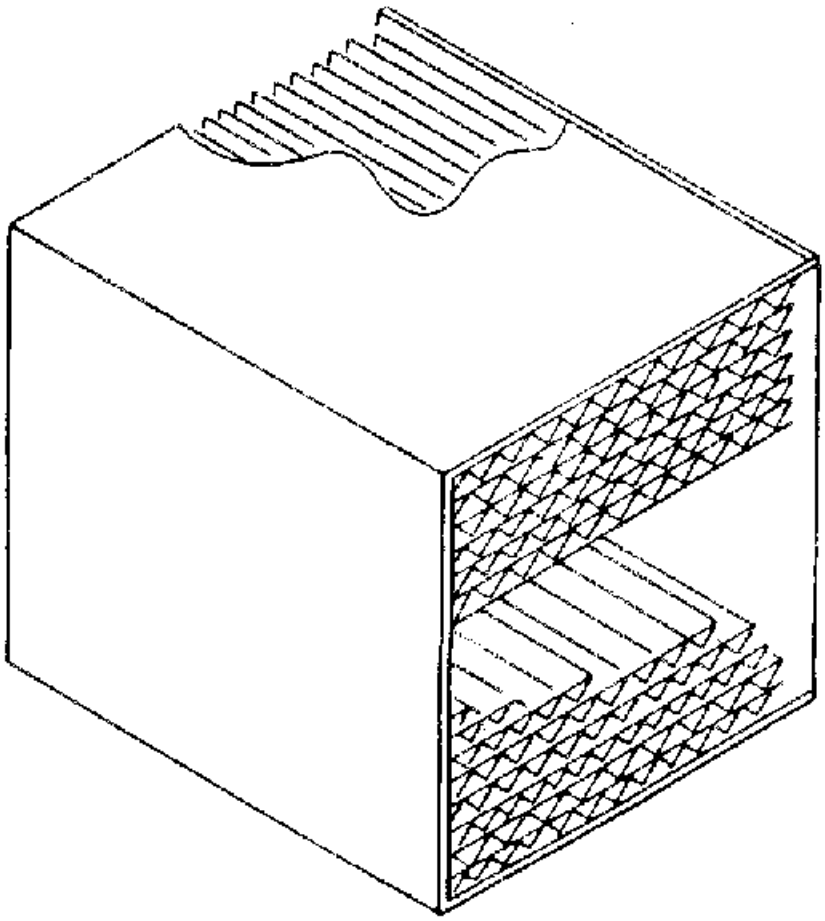


Figure 5-27. Cutaway view of a typical monolith catalyst body with honeycomb configuration.[62]

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An ammonia injection grid is located upstream of the catalyst body and is designed to disperse the ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. In a typical ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the

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injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about 5 percent.[62]

An alternative to using the anhydrous ammonia/carrier gas system is to inject an a aqueous ammonia solution. This system is currently not as common but removes the potential safety hazards associated with transporting and storing anhydrous ammonia and is often used in installations with close proximity to populated areas.[61,62]

The NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. As indicated by the chemical reaction equations listed above, it takes one mole of NH_3 to reduce one mole of NO, and two moles of NH_3 to reduce one mole of NO_2. The NO_x composition in the flue gas from a gas turbine is over 85 percent NO, and SCR systems generally operate with a molar NH_3/NO_x ratio of approximately 1.0.[63] Increasing this ratio will further reduce NO_x emissions but will also result in increased unreacted ammonia passing through the catalyst and into the atmosphere. This unreacted ammonia is known as ammonia slip.

5.3.2 Applicability of SCR for Gas Turbines

Selective catalytic reduction applies to all gas turbine types and is equally effective in reducing both thermal and fuel NO_x emissions. There are, however, factors that may limit the applicability of SCR.

An important factor that affects the performance of SCR is operating temperature. Gas turbines that operate in simple cycle have exhaust gas temperatures ranging from approximately 450° to 540°C (850° to 1000°F). Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 260° to 400°C (400° to 800°F). For sulfur-bearing fuels that produce greater than 1 ppm SO_3 in the flue gas, the catalyst operating temperature range narrows to 315° to 400°C (600° to 800°F). The upper range of this temperature window can be

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increased using a zeolite catalyst to a maximum of 590°C (1100°F).[64]

Base metal catalysts are most commonly used in gas turbine SCR applications, accounting for approximately 80 percent of all U.S. installations, and operate in cogeneration or combined cycle applications. The catalyst is installed within the HRSG, where the heat recovery process reduces exhaust gas temperatures to the proper operating range for the catalyst. The specific location of the SCR within the HRSG is application-specific; Figure 5-28 shows two possible SCR locations.

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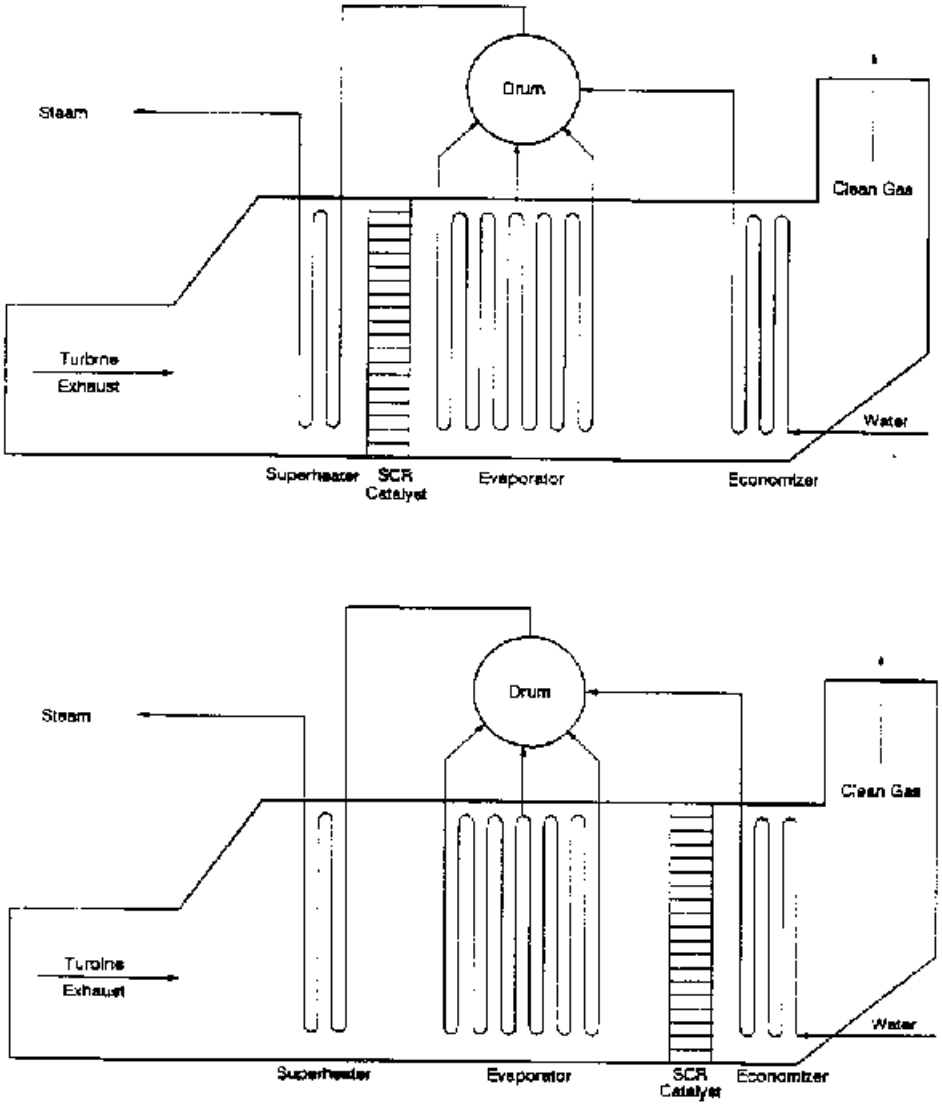


Figure 5-28. Possible locations for SCR unit in HRSG.[62]

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In addition to the locations shown, the catalyst may also be located within the evaporator section of the HRSG.

As noted above, zeolite catalysts have a maximum operating temperature range of up to 590°C (1100°F), which is compatible with simple cycle turbine exhaust temperatures. To date, however, there is only one SCR installation operating with a zeolite catalyst directly downstream of the turbine. This catalyst, commissioned in December 1989, has an operating range of 260° to 515°C (500° to 960°F) and operates approximately 90 percent of the time at temperatures above 500°C (930°F).[65]

Another consideration in determining the applicability of SCR is complications arising from sulfur-bearing fuels. The sulfur content in pipeline quality natural gas is negligible, but distillate and residual oils as well as some low-Btu fuel gases such as coal gas have sulfur contents that present problems when used with SCR systems. Combustion of sulfur-bearing fuels produces SO_2 and SO_3 emissions. A portion of the SO_2 oxidizes to SO_3 as it passes through the HRSG, and base metal catalysts have an SO_2-to-SO_3 oxidation rate of up to five percent.[64] In addition, oxidation catalysts, when used to reduce CO emissions, will also oxidize SO_2 to SO_3 at rates of up to 50 percent.[66]

Unreacted ammonia passing through the catalyst reacts with SO_3 to form ammonium bisulfate (NH_4HSO_4) and ammonium sulfate [$(NH_4)_2\ SO_4$] in the low-temperature section of the HRSG. The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and the formation rate increases with decreasing

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temperature. Below 200°C (400°F), ammonium salt formation occurs with single-digit ppmv levels of SO_3 and NH_3.[66]

The exhaust temperature exiting the HRSG is typically in the range of 150° to 175°C (300° to 350°F), so ammonium salt formation typically occurs in the low-temperature section of the HRSG.[66] Ammonium bisulfate is a sticky substance that over time corrodes the HRSG boiler tubes. Additionally, it deposits on both the boiler and catalyst bed surfaces, leading to fouling and plugging of these surfaces. These deposits result in increased back pressure on the turbine and reduced heat transfer efficiency in the HRSG. This requires that the HRSG be removed from service periodically to water-wash the affected surfaces. Ammonium sulfate is not corrosive, but like ammonium bisulfate, it deposits on the HRSG surfaces and contributes to plugging and fouling of the heat transfer system.[33]

Formation of ammonium salts can be avoided by limiting the sulfur content of the fuel and/or limiting the ammonia slip. Low SO_2-to-SO_3 oxidizing catalysts are also available. Base metal catalysts are available with oxidation rates of less than 1 percent, but these low oxidation formulas also have lower NO_x reduction activity per unit volume and therefore require a greater catalyst volume to achieve a given NO_x reduction level. Zeolite catalysts are reported to have intrinsic SO_2-to-SO_3 oxidation rates of less than 1 percent.[64,66] As stated above, pipeline-quality natural gas has negligible sulfur content, but some sources of natural gas contain H_2S, which may contribute to ammonium salt formation. For oil fuels, even the lowest-sulfur distillate oil or liquid aviation fuel contains sulfur levels that can produce ammonium salts. According to catalyst vendors, SCR systems can be designed for 90 percent NO_x reduction and 10 ppm or lower NH_3 slip for sulfur-bearing fuels up to 0.3 percent by weight.[64] Continuous emission monitoring equipment has been developed for NH_3, and may be instrumental in regulating ammonia injection to minimize slip.[67]

To date, there is limited operating experience using SCR with oil-fired gas turbine installations. One combined cycle

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installation using oil fuel, a United Airlines facility in San Francisco installed in 1985, experienced fuel-related catalyst problems and now uses only natural gas fuel.[33] In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with oil fuels in Europe and Japan, where catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas fuel.[64] A zeolite catalyst installed on a 5 MW (6710 hp) dual fuel reciprocating engine in the northeastern United States has operated for over 3 years and burned approximately 600,000 gallons of diesel fuel while maintaining a NO_x reduction efficiency of greater than 90 percent.[3]

In its guidance to member states, NESCAUM recommends that SCR be considered for NO_x reduction in dual-fueled turbine applications. There are four combined cycle gas turbines installations operating with SCR in the northeast United States burning natural gas as the primary fuel with oil fuel as a back-up.[3] These installations, listed in Table 5-16,

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TABLE 5-16. GAS TURBINE INSTALLATIONS IN THE NORTHEASTERN UNITED STATES WITH SCR AND PERMITTED FOR BOTH NATURAL GAS AND OIL FUELS[3]

Installation	State	Gas turbine model	Output, MW[a]	NO_x emissions, ppmv (gas fuel/oil fuel)		
				Uncontrolled[b]	Wet injection[b]	Wet injection + SCR[c]
Altresco-Pittsfield	MA	MS6001	38.3	148/267	42/65	9/18[d e]
Cogen Technologies	NJ	MS6001	38.3	148/267	42/65	15/65[f]
Ocean State Power	RI	MS7001E	83.5	154/277	42/65	9/42[f]
Pawtucket Power	RI	MS6001	38.3	148/267	42/65	9/18[d]

[a]Power output for a single gas turbine. Installation power output is higher due to multiple units and/or combined cycle operation.

[b]Per manufacturer at ISO conditions.

[c]Operating permit limits.

[d]This installation requires the SCR system to be operational when burning oil fuel.

[e]This installation operated 185 hours on oil fuel in 1991, burning approximately 354,000 gallons of oil fuel.

[f]Ammonia injection is shut down during operation on oil fuel.

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began operating recently and have limited hours of operation on oil fuel. As indicated in the table, two of these installations shut down the ammonia injection when operating on oil fuel to prevent potential operating problems arising from sulfur-bearing fuels. Permits issued more recently in this region for other dual-fuel installations, however, require that the SCR system be operational on either fuel.[3]

A final consideration for SCR is catalyst masking or poisoning agents. Natural gas is considered clean and free of contaminants, but other fuels may contain agents that can degrade catalyst performance. For refinery, field, or digester gas fuel applications, it is important to have an analysis of the fuel and properly design the catalyst for any identified contaminants. Arsenic, iron, and silica may be present in field gases, along with zinc and phosphorus. Catalyst life with these fuels depends upon the content of the gas and is a function of the initial

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design parameters. With oil fuels, in addition to the potential for ammonium salt formation, it is important to be aware of heavy metal content. Particulates in the flue gas can also mask the catalyst.[64]

Selective catalytic reduction may not be readily applicable to gas turbines firing fuels that produce high ash loadings or high levels of contaminants because these elements can lead to fouling and poisoning of the catalyst bed. However, because gas turbines are also subject to damage from these elements, fuels with high levels of ash or contaminants typically are not used.

Coal, while not currently a common fuel for turbines, has a number of potential catalyst deactivators. High dust concentrations, alkali, earth metals, alkaline heavy metals, calcium sulfate, and chlorides all can produce a masking or blinding effect on the catalyst. High dust can also erode the catalyst. Erosion commonly occurs only on the leading face of the catalyst. Airflow deflectors and dummy layers of catalyst can be used to straighten out the airflow and reduce erosion. There is currently no commercial U.S. experience with coal. In Japan, which burns low-sulfur coal with moderate dust levels, catalyst life has been 5 years or more without replacement. In Germany, with high dust loadings, the experience has also been 5 years or more.[64]

Masking agents deposit on the surface of the catalyst, forming a barrier between the active catalyst surface and the exhaust gas, inhibiting catalytic activity. Poisoning agents chemically react with the catalyst and render the affected area inactive. Masking agents can be removed by vacuuming or by using soot blowers or superheated steam. Catalysts cleaned in this manner can recover greater than 90 percent of the original reduction activity. The effects of poisoning agents, however, are permanent and the affected catalyst surface cannot be regenerated.[64]

Retrofit applications for SCR may require the addition of a heat exchanger for simple cycle installations, and replacement or extensive modification of the existing HRSG in cogeneration and

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combined cycle applications to accommodate the catalyst body. For these reasons, retrofit applications for SCR could involve high capital costs.

5.3.3 Factors Affecting SCR Performance

The NO_x reduction efficiency for an SCR system is influenced by catalyst material and condition, reactor temperature, space velocity, and the NH_3/NO_x ratio.[63] These design and operating variables are discussed below.

Several catalyst materials are available, and each has an optimum NO_x removal efficiency range corresponding to a specific temperature range. Proprietary formulations containing titanium dioxide, vanadium pentoxide, platinum, or zeolite are available to meet a wide spectrum of operating temperatures. The NO_x removal efficiencies for these catalysts are typically between 80 and 90 percent when new. The NO_x removal efficiency gradually decreases over the operating life of the catalyst due to deterioration from masking, poisoning, or sintering.[63] The rate of catalyst performance degradation depends upon operating conditions and is therefore site-specific.

The space velocity (volumetric flue gas flow divided by the catalyst volume) is an indicator of gas residence time in the catalyst unit. The lower the space velocity, the higher the residence time, and the higher the potential for increased NO_x reduction. Because the gas flow is a constant determined by the gas turbine, the space velocity depends upon the catalyst volume, or total active surface area. The distance across the opening between plates or cells in the catalyst, referred to as the pitch, affects the overall size of the catalyst body. The smaller the pitch, the greater the number of rows or cells that can be placed in a given volume. Therefore, for a given catalyst body size, the smaller the pitch, the larger the catalyst volume and the lower the space velocity. For natural gas applications the catalyst pitch is typically 2.5 millimeters (mm) (0.10 inch [in.]), increasing to 5 to 7 mm (0.20 to 0.28 in.) for coal-fuel applications.[64]

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As discussed in Section 5.3.1, the NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Increasing this ratio increases the level of NO_x reduction but may also result in higher ammonia slip levels.

5.3.4 Achievable NO_x Emission Reduction Efficiency Using SCR

Most SCR systems operating in the United States have a space velocity of about 30,000/hr, a NH_3/NO_x ratio of about 1.0, and ammonia slip levels of approximately 10 ppm. The resulting NO_x reduction efficiency is about 90 percent.[41] Reduction efficiency is the level of NO_x removed as a percentage of the level of NO_x entering the SCR unit. Only one gas turbine installation in the United States was identified using only SCR to reduce NO_x emissions. This installation has two natural gas-fired 8.5 MW gas turbines, each with its own HRSG in which is installed an SCR system. A summary of emission testing at this site lists NO_x emissions at the inlet to the SCR catalyst at 130 ppmv. Controlled NO_x emissions downstream of the catalyst were 18 ppmv, indicating a NO_x reduction efficiency of 86 percent. Maximum ammonia slip levels were listed at 35 ppmv.[68]

All other gas turbine installations identified as using SCR in the United States use this control method in combination with wet injection and/or low-NO_x combustors. The emission levels that can be achieved by this combination of controls are found in Section 5.4.

5.3.5 Disposal Considerations for SCR

The SCR catalyst material has a finite life, and disposal can pose a problem. The guaranteed catalyst life offered by catalyst suppliers ranges from 2 to 3 years.[64] In Japan, where SCR systems have been in operation since 1980, experience shows that many catalysts in operation with natural gas-fired boilers have performed well for 7 years or longer.[63,64] In any case, at some point the catalyst must be replaced, and those units containing heavy metal oxides such as vanadium or titanium potentially could be considered hazardous wastes. While the amount of hazardous material in the catalyst is relatively small, the volume of the catalyst body can be quite large, and disposal

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of this waste could be costly. Some suppliers provide for the removal and disposal of spent catalyst. Precious metal and zeolite catalysts do not contain hazardous wastes.

5.4 CONTROLS USED IN COMBINATION WITH SCR

With but one exception, SCR units installed in the United States are used in combination with wet controls or combustion controls described in Sections 5.1 and 5.2. Wet controls yield NO_x emission levels of 25 to 42 ppmv for natural gas and 42 to 110 ppmv for distillate oil, based on the data provided by gas turbine manufacturers and shown in Figures 5-10 and 5-11. A carefully designed SCR system can achieve NO_x reduction efficiencies as high as 90 percent, with ammonia slip levels of 10 ppmv or less for natural gas and low-sulfur (<0.3 percent by weight) fuel applications.[64]

As discussed for wet injection in Sections 5.1.4 and 5.2.2.4, controlled NO_x emission levels for natural gas range from 25 to 42 ppmv for natural gas fuel and from 42 to 110 ppmv for oil fuel. Applying a 90 percent reduction efficiency for SCR, NO_x levels can be theoretically reduced to 2.5 to 4.2 and 4.2 to 11.0 ppmv for natural gas and oil fuels, respectively. For oil fuels and other sulfur-bearing fuels, a reduction efficiency of 90 percent requires special design considerations to address potential operational problems caused by the sulfur content in the fuel. This subject is discussed in Section 5.3.2. The final controlled NO_x emission level depends upon the NO_x level exiting the turbine and the achievable SCR reduction efficiency.

Test reports provided by SCAQMD include three gas turbine combined cycle installations fired with natural gas that have achieved NO_x emission levels of 3.4 to 7.2 ppmv, referenced to 15 percent oxygen. The NO_x and CO emissions reported for these tests are shown in Table 5-17

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TABLE 5-17. EMISSIONS TESTS RESULTS FOR GAS TURBINES USING STEAM INJECTION PLUS SCR[69-71]

				NO_x emissions, ppmv (lb/hr)			
Test No.	Gas turbine model	Output, MW	Fuel	Uncontrolled	Wet injection	Wet injection + SCR	CO, ppmv
1	MS7001E	82.8	Natural gas + refinery gas mixture	154	42	5.66 (25.2)	<2.00
2	MS7001E	79.7	Natural gas + refinery gas + butane mixture	148	42	7.17 (31.7)	<2.00
3	MS6001B	33.8	LPG + refinery gas mixture	148	42	3.36 (5.82)	<2.00

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TABLE 5-18. SUMMARY OF SCR NO_x EMISSION REDUCTIONS AND AMMONIA SLIP LEVELS FOR NATURAL GAS-FIRED TURBINES[68]

Site	Gas turbine		Power output, MW	SCR operating temperature, °F	Maximum permit level for injection, NH_3/NO_x molar ratio	NO_x emissions, ppmv at 15% O_2			Compliance test NH_3 slip, ppmv at 15% O_2 [a]
	Manufacturer	Model				SCR in	SCR out	Percent reduction	
A	GE	LM2500	22	730	1.0	50	9.0	82	10
B	GE	MS5001	18	645	1.0	45	4.5	90	2
C	GE	LM2500	22	685	1.1	37	8.9	76	20
D	ABB	Type 8	44	760	1.2	27	4	85	9
E	GE	LM2500	22	680	1.0	60	12.6	79	7
F	GE	MS7001E	80	630	1.0	28	8.4	70	4.1
G	GE	LM2500	22	625	0.9	68	13.6	80	1
H	Allison	501-KB	3.5	650	1.1	25	1.0	96	10
I	Solar	Mars	8.5	580	1.6	130	18.2	86	35
J	GE	LM2500	22	750	1.0	37	14.8	60	11
K	GE	MS7001E	80	754	1.0	40	6.0	85	2
L	GE	MS6001	37	650	1.0	47	8.9	81	4
M	GE	MS6001	37	700	NA	33	3.3	90	8

[a]Calculated from ppmv entering the SCR and percent reduction figures.
[b]NH_3 permit limit. Test emission level not available.
[c]Test was run at less than permit NH_3/NO_x ratio of 1.1. SCR designed for exhaust from total of 5 turbines. Only one turbine operating during test.
[d]This site does not use wet injection for gas turbine NO_x reduction.
[e]NH_3 compliance test not required. NH_3 level from NH_3 monitor testing.

Ammonia slip levels were not reported. Ammonia slip levels

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were reported, however, in a summary of emission tests for 13 SCR installations and are presented in Table 5-18.[68] For these sites, operating on natural gas fuel, the NO_x reduction efficiency of the catalyst ranges

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from 60 to 96 percent, with most reduction efficiencies between 80 and 90 percent. Ammonia slip levels range from 1 to 35 ppmv. The site with the 35 ppmv ammonia slip level is unique in that it is the only site identified in the United States that uses only SCR rather than a combination of SCR and wet injection to reduce NO_x emissions. With the exception of this site, all NH_3 slip levels in Table 5-18 that are based on test data are less than 10 ppmv. Based on information received from catalyst vendors, it is expected that an SCR system operating downstream of a gas turbine without wet injection could be designed to limit ammonia slip levels to 10 ppmv or less.[64] No test data are available for SCR operation on gas turbines fired with distillate oil fuels.

5.5 EFFECT OF ADDING A DUCT BURNER IN HRSG APPLICATIONS

A duct burner is often added in cogeneration and combined cycle applications to increase the steam capacity of the HRSG (see Section 4.2.2). Duct burners in gas turbine exhaust streams consist of pipes or small burners that are placed in the exhaust gas stream to allow firing of additional fuel, usually natural gas. Duct burners can raise gas turbine exhaust temperatures to 1000°C (2000°F), but a more common temperature is 760°C (1400°F). The gas turbine exhaust is the source of oxygen for the duct burner.

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Figure 5-29 shows a typical natural gas-fired duct burner

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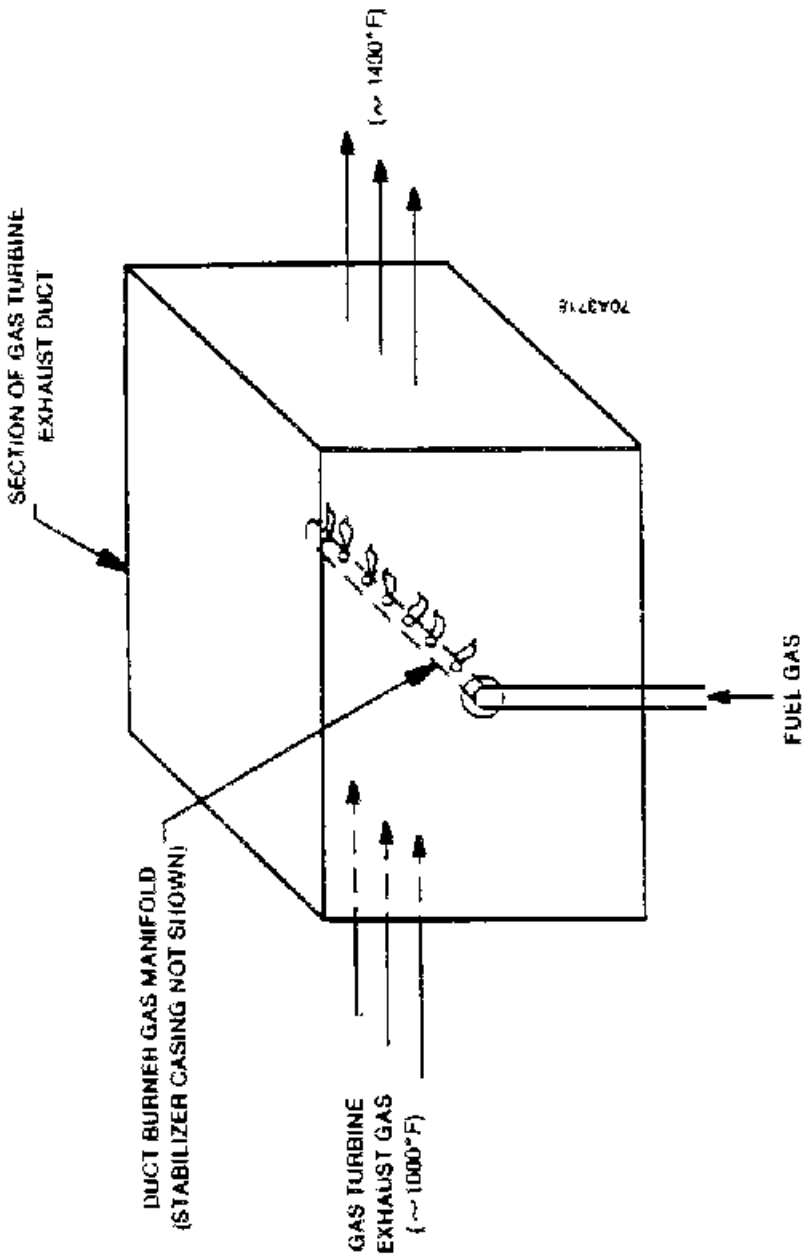


Figure 5-29. Typical duct burner for gas turbine exhaust application.[72]

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installation. Figure 5-30 is a cross-sectional view of one style

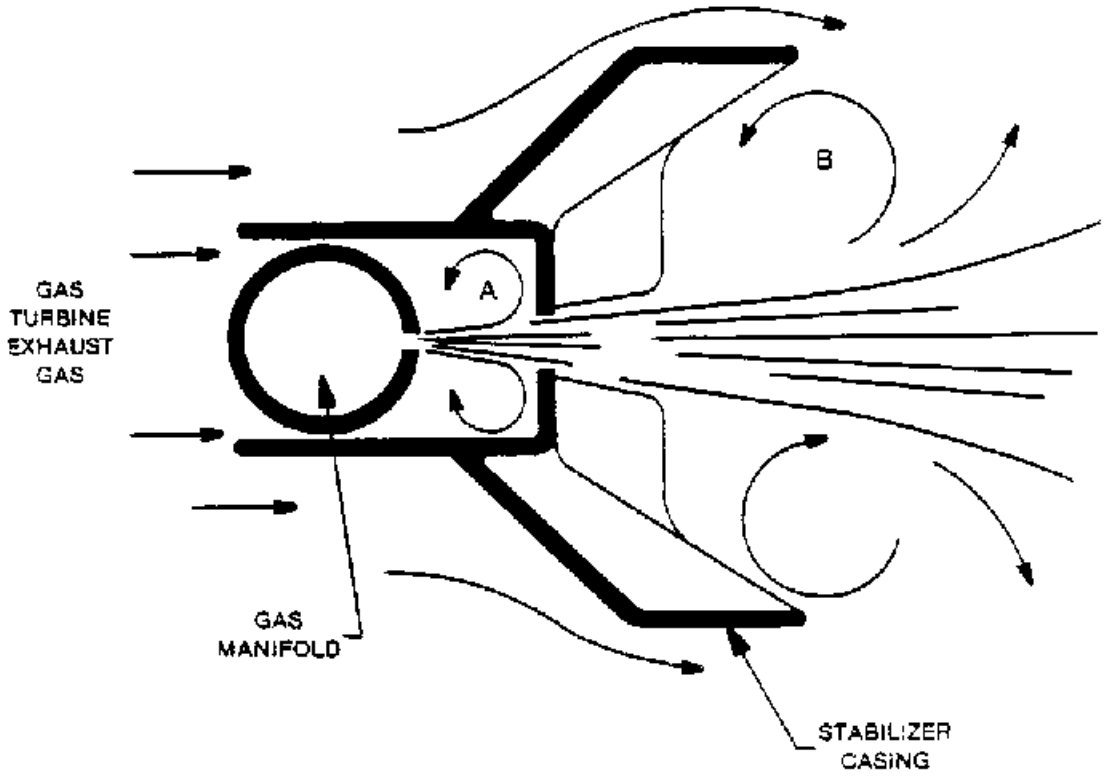


Figure 5-30. Cross-sectional view of a low-NO_x duct burner.[73,74]

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of duct burner that incorporates design features to reduce NO_x. In this low-NO_x design, natural gas exits the orifice in the manifold and mixes with the gas turbine exhaust entering through a small slot between the casing and the gas manifold. This mixture forms a jet diffusion flame that causes the recirculation shown in Zone "A." Due to the limited amount of turbine exhaust that can enter Zone A, combustion in this zone is fuel-rich. As the burning gas jet exits into Zone "B," it mixes with combustion products that are recirculated by the flow eddies behind the wings of the stabilizer casing. The flame then expands into the turbine exhaust gas stream, where combustion is completed.

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For oil-fired burners, the design principles of the burner are the same. However, the physical layout is slightly different, as shown in

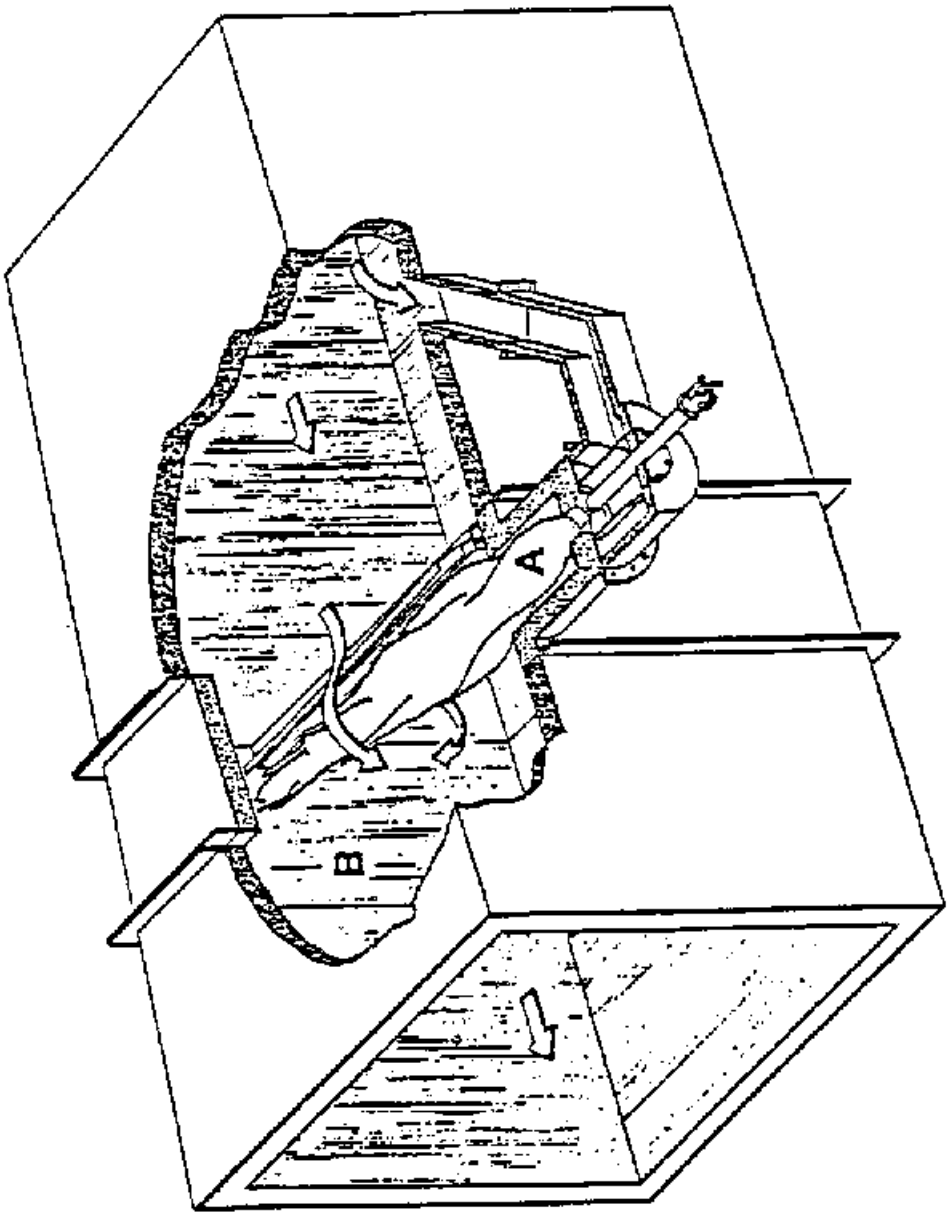


Figure 5-31. Low-NO_x duct burner designed for oil firing.[73,75]

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Figure 5-31. Turbine exhaust gas is supplied in substoichiometric quantities by a slip stream duct to the burner. This slip stream supplies the combustion air for the fuel-rich Zone A. The flame shield produces the flow eddies, which recirculate the combustion products into Zone B.[76]

Most duct burners now in service fire natural gas. In all cases, a duct burner will produce a relatively small level of NO_x emissions during operation (See Section 4.2.2), but the net impact on total exhaust emissions (i.e., the gas turbine plus the duct burner) varies with operating conditions, and in some cases may even reduce the overall NO_x emissions. Table 5-19 shows the NO_x emissions measured at one site upstream and downstream of a duct burner. This table shows that NO_x emissions are reduced across the duct burner in five of the eight test runs.

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TABLE 5-19. NO_x EMISSIONS MEASURED BEFORE AND AFTER A DUCT BURNER [77]

Gas turbine operation parameters			Duct burner operating parameters		Duct burner inlet		Duct burner outlet		Change across duct burner	
Test No.	Load, MW	Steam/fuel injection ratio, lb/lb	Heat input, MM Btu/hr	Load, percent	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr
1	33.8	0.94	133.8	82.1	0.149	61.4	0.097	55.7	-0.043	-5.7
2	35.0	0.97	93.3	57.3	0.142	58.8	0.113	58.9	0.001	0.1
3	34.5	0.95	40.8	25.0	0.134	57.5	0.118	58.7	0.029	1.2
4	32.0	0.50	137.5	84.4	0.207	85.8	0.151	83.9	-0.014	-1.9
5	32.8	0.46	43.8	26.8	0.228	95.2	0.192	94.0	-0.027	-1.2
6	31.5	0.00	136.7	83.9	0.392	159.7	0.270	156.2	-0.026	-3.5
7	33.0	0.00	42.0	25.8	0.384	166.7	0.313	156.7	-0.238	-10.0
8	11.1	0.00	140.9	86.5	0.157	29.1	0.132	42.1	0.092	13.0

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The reason for this net NO_x reduction is not known, but it is believed to be a result of the reburning process in which the intermediate combustion products from the duct burner interact with the NO_x already present in the gas turbine exhaust. The manufacturer of the burner whose emission test results are shown in Table 5-19 states that the following conditions are necessary for reburning to occur:

1. The burner flame must produce a high temperature in a fuel-rich zone;

2. A portion of the turbine exhaust containing NO_x must be introduced into the localized fuel-rich zone with a residence time sufficient for the reburning process to convert the turbine NO_x to N_2 and O_2; and

3. The burner fuel should contain no FBN.[78]

In general, sites using a high degree of supplementary firing have the highest potential for a significant amount of reburning. In practice, only a limited number of sites achieve these reburning conditions due to specific plant operating requirements.[78]

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5.6 ALTERNATE FUELS

Because thermal NO_x production is an exponential function of flame temperature (see Section 4.1.1), it follows that using fuels with flame temperatures lower than those of natural gas or distillate oils results in lower thermal NO_x emissions. Coal-derived gas and methanol have demonstrated lower NO_x emissions than more conventional natural gas or oil fuels. For applications using fuels with high FBN contents, switching to a fuel with a lower FBN content will reduce thermal NO_x formation and thereby lower total NO_x emissions.

5.6.1 Coal-Derived Gas

Combustor rig tests have demonstrated that burning coal-derived gas (coal gas) that has been treated to remove FBN produces approximately 30 percent of the NO_x emission levels experienced when burning natural gas. This is because coal gas has a low heat energy level of around 300 Btu or less, which results in a flame temperature lower than that of natural gas.[79] The cost associated with producing coal gas suitable for combustion in a gas turbine has made this alternative economically unattractive, but recent advances in coal gasification technology have renewed interest in this fuel.

A coal gas-fueled power plant is currently operating in the United States at a Dow Chemical plant in Placquemine, Louisiana. This facility operates with a subsidy from the Federal Government, which compensates for the price difference between coal gas and conventional fuels. Several commercial projects have been recently announced using technology developed by Texaco, Shell, Dow Chemical, and the U.S. Department of Energy. Facilities have been permitted for construction in Massachusetts and Delaware.[80]

A demonstration facility, known as Cool Water, operated using coal gas for 5 years in Southern California in the early 1980's. The NO_x emissions were reported at 0.07 lb/MMBtu.[80] Fuel analysis data is not available to convert this NO_x emission level to a ppmv figure. No other emissions data are available.

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5.6.2 Methanol

Methanol has a flame temperature of 1925°C (3500°F) versus 2015°C (3660°F) for natural gas and greater than 2100°C (3800°F) for distillate oils. As a result, the NO_x emission levels when burning methanol are lower than those for either natural gas or distillate oils.

Table 5-20 presents NO_x emission data for a full-scale turbine firing methanol.

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TABLE 5-20. NO_x EMISSIONS TEST DATA FOR A GAS TURBINE FIRING METHANOL AT BASELOAD[a,81]

Test	W/F ratio, lb/lb	NO_x emissions ISO conditions, ppm at 15% O_2	NO_x reduction, percent[b]
A	0	41	0
B	0	45	0
C	0	48	0
D	0	49	0
E	0	60	0
F	0	47	0
G	0	53	0
H	0	48	0
I	0	51	0
J	0	52	0
K	0	41	0
L	0	47	0
M	0	48	0
AVERAGE		49	
N	0.11	28	42.2
O	0.23	17	65.2
P	0.23	18	62.7
Q	0.24	18	62.7

[a]Baseload = 25 MW output
[b]Calculated using the average of the uncontrolled emissions.

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The NO_x emissions from firing methanol without water injection ranged from 41 to 60 ppmv and averaged 49 ppmv. This test also indicated that methanol increases turbine output due to the higher mass flows that result from methanol firing. Methanol firing increased CO and HC emissions slightly compared to the same turbine's firing distillate oil with water injection. All other aspects of turbine performance were as good when firing methanol as when the turbine fired natural gas or distillate oil.[82] Turbine maintenance requirements were estimated to be lower and turbine life was estimated to be longer on methanol fuel than on distillate oil fuel because methanol produced fewer deposits in the combustor and power turbine.

Table 5-20 also presents NO_x emission data for methanol firing with water injection. At water-to-fuel ratios from 0.11 to 0.24, NO_x emissions when firing methanol range from 17 to 28 ppmv, a reduction of 42 to 65 percent.

In a study conducted at an existing 3.2 MW gas turbine installation in 1984, a gas turbine was modified to burn methanol. This study was conducted at the University of California at Davis and was sponsored by the California Energy Commission. A new fuel delivery system for methanol was required, but the only major modifications required for the turbine used in this study were new fuel manifolds and nozzles. Tests conducted burning methanol showed no visible smoke emissions, and only minor increases in CO emissions. Figure 5-32 shows the NO_x emissions measured while burning

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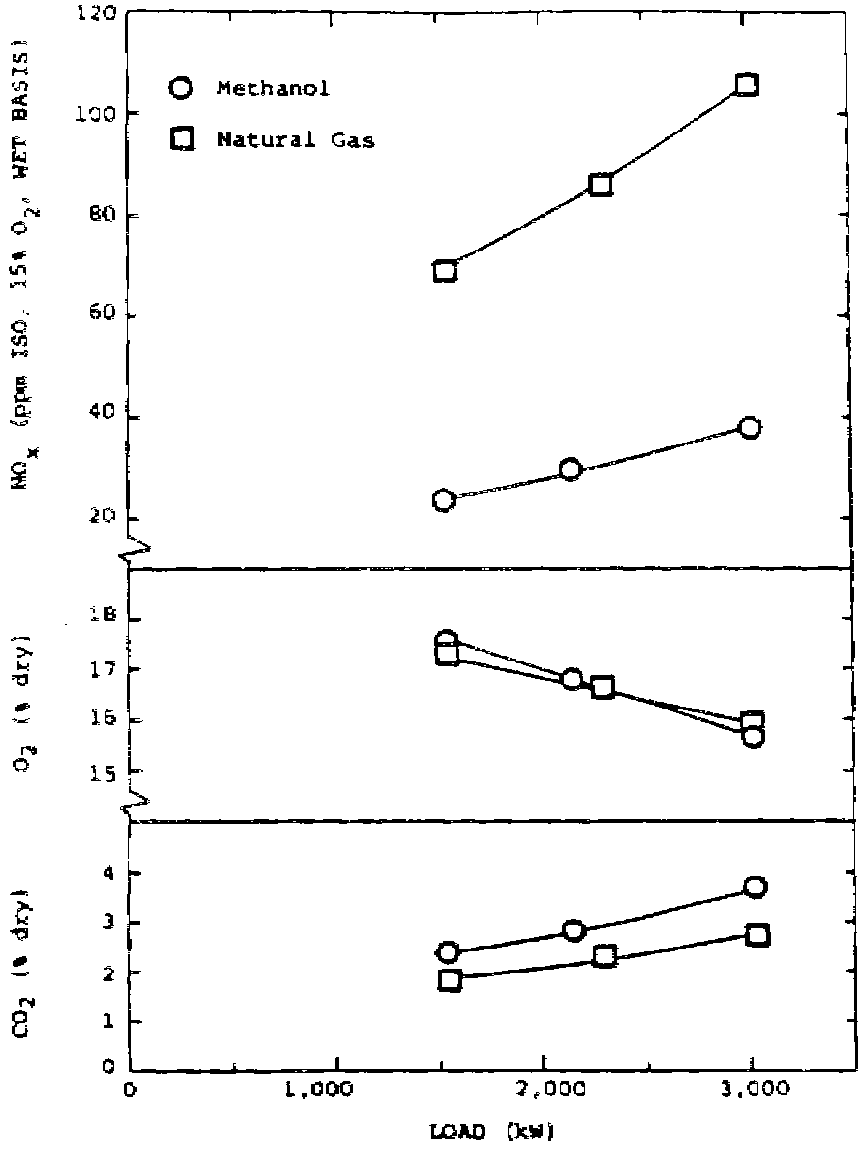


Figure 5-32. Influence of load on NO_x, and CO_2 emissions for methanol and natural gas.[83]

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methanol and natural gas. Reductions of up to 65 percent were achieved, as NO_x emissions were 22 to 38 ppm when burning methanol versus

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62 to 100 ppm for natural gas. In addition to the intrinsically lower NO_x production, water can be readily mixed with methanol prior to delivery to the turbine to obtain the additional NO_x reduction levels achievable with wet injection. Gas turbine performance characteristics, including startup, acceleration, load changes, and full load power, were all deemed acceptable by the turbine manufacturer.[83]

The current economics of using methanol as a primary fuel are not attractive. There are no confirmed commercial methanol-fueled gas turbine installations in the United States.

5.7 SELECTIVE NONCATALYTIC REDUCTION

Selective noncatalytic reduction (SNCR) is an add-on technology that reduces NO_x using ammonia or urea injection similar to SCR but operates at a higher temperature. At this higher operating temperature of 870° to 1200°C (1600° to 2200°F), the following reaction occurs:[84]

$$NO_x + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O.$$

This reaction occurs without requiring a catalyst, effectively reducing NO_x to nitrogen and water. The operating temperature can be lowered from 870°C (1600°F) to 700°C (1300°F) by injecting hydrogen (H_2) with the ammonia, as is shown in the above equation.

Above the upper temperature limit, the following reaction occurs:[84]

$$NH_3 + O_2 \rightarrow NO_x + H_2O.$$

Levels of NO_x emissions increase when injecting ammonia or urea into the flue gas at temperatures above the upper temperature limits of 1200°C (2200°F).

Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 600°C (1100°F). Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbine operating flow velocities.[85]

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It may be feasible, however, to initiate this reaction in the gas turbine where operating temperatures fall within the reaction window, if suitable gas turbine modifications and injection systems can be developed.[85] This control technology has not been applied to gas turbines to date.

5.8 CATALYTIC COMBUSTION

5.8.1 Process Description

In a catalytic combustor, fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front. Peak combustion temperatures can be limited to below 1540°C (2800°F), which is below the temperature at which significant amounts of thermal NO_x begin to form.[86] An example of a lean catalytic combustor is shown in Figure 5-33.

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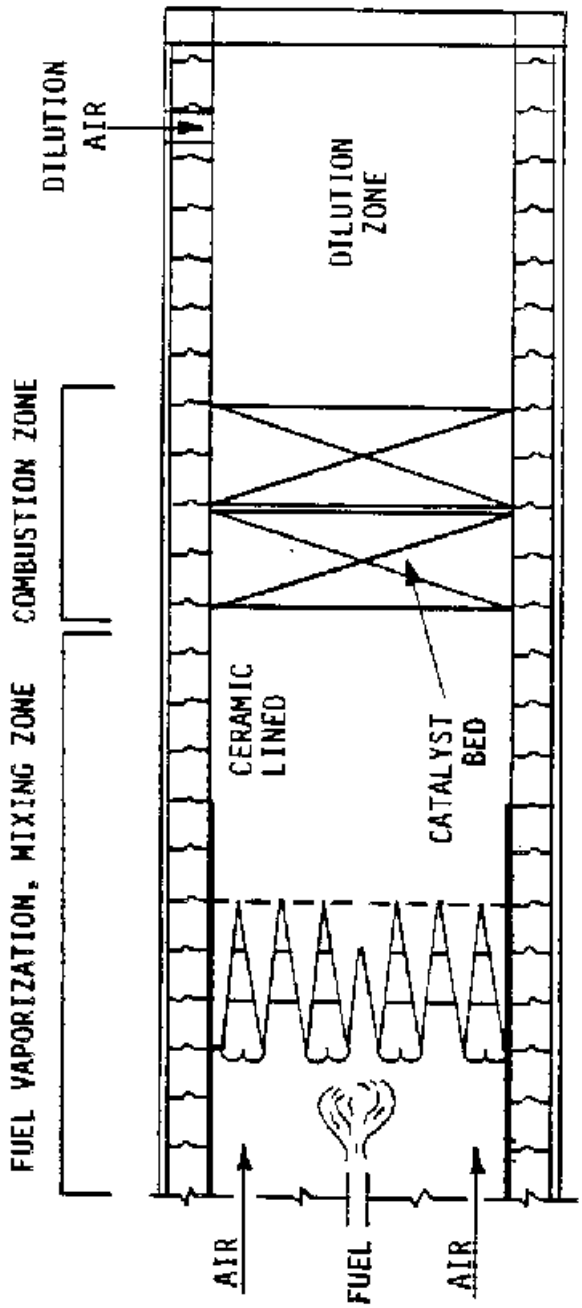


Figure 5-33. A lean catalytic combustor.87

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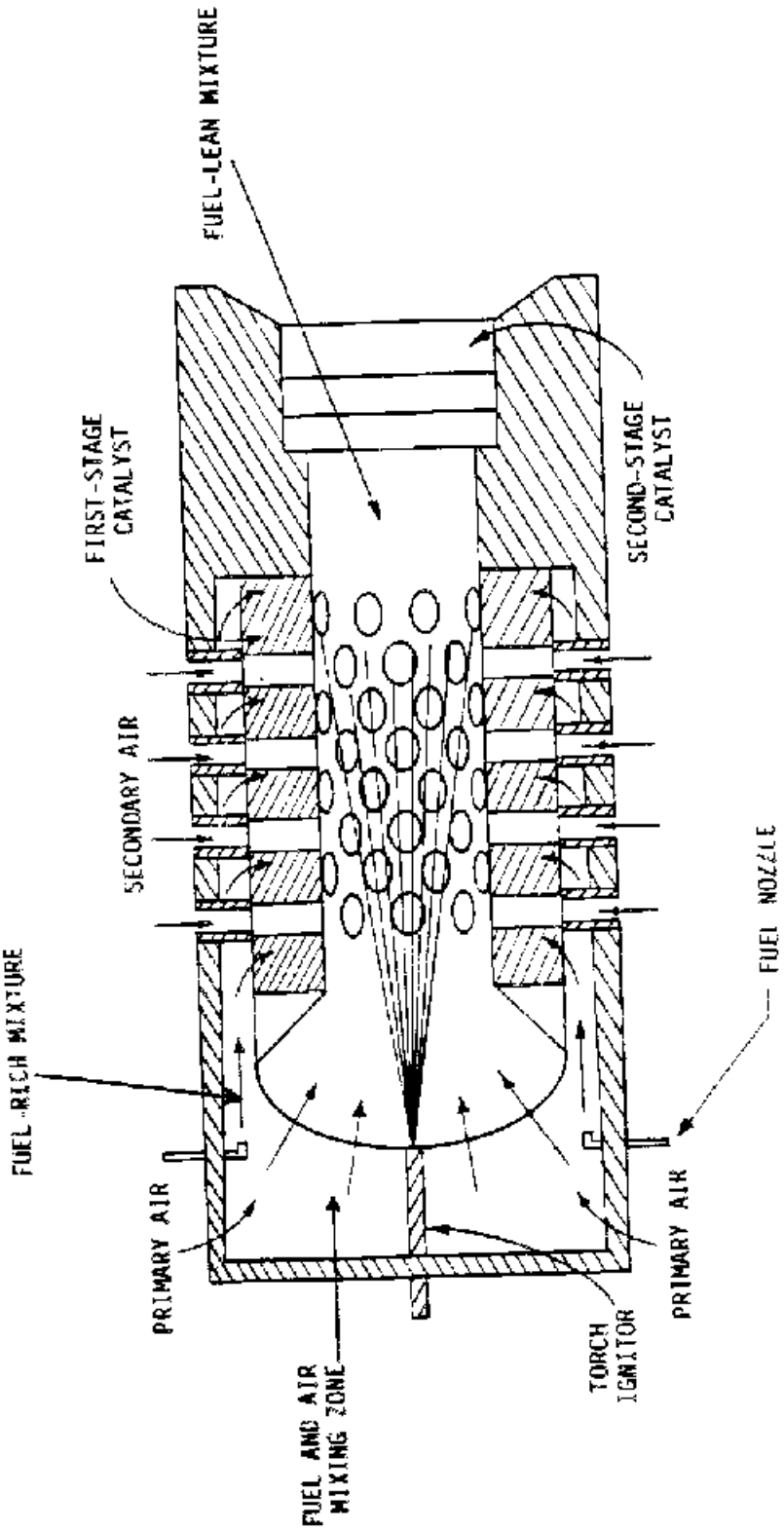


Figure 5-34. A rich/lean catalytic combustor.[89]

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Catalytic combustors can also be designed to operate in a rich/lean configuration, as shown in Figure 5-34. In this configuration, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.[89]

5.8.2 Applicability

Catalytic combustion techniques apply to all combustor types and are effective on both distillate oil- and natural gas-fired turbines. Because of the limited operating temperature range, catalytic combustors may not be easily applied to gas turbines subject to rapid load changes (such as utility peaking turbines).[90] Gas turbines that operate continuously at base load (such as industrial cogeneration applications) would not be as adversely affected by any limits on load following capability.[91]

5.8.3 Development Status

Presently, the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. The major problem is the development of a catalyst that will have an acceptable life in the high-temperature and -pressure environment

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of gas turbine combustors. Additional problems that must be solved are combustor ignition and how to design the catalyst to operate over the full gas turbine operating range (idle to full load).[92]

5.9 OFFSHORE OIL PLATFORM APPLICATIONS

Gas turbines are used on offshore platforms to meet compression and electrical power requirements. This application presents unique challenges for NO_x emissions control due to the duty cycle, lack of a potable water source for wet injection, and limited space and weight considerations. The duty cycle for electric power applications of offshore platforms is unique. This duty cycle is subject to frequent load changes that can instantaneously increase or decrease by as much as a factor of 10.[93] Fluctuating loads result in substantial swings in turbine exhaust gas temperatures and flow rates. This presents a problem for SCR applications because the NO_x reduction efficiency depends upon temperature and space velocity (see Section 5.3.3).

The lack of a potable water supply means that water must be shipped to the platform or sea water must be desalinated and treated. The limited space and weight requirements associated with an SCR system may also have an impact on capital costs of the platform.

A 4-year study is underway for the Santa Barbara County Air Pollution Control Board to evaluate suitable NO_x control techniques for offshore applications. The goals of the study are to reduce turbine NO_x emissions at full load to 9 ppmv, corrected to 15 percent O_2, firing platform gas fuel and to achieve part load reductions of 50 percent. The study consists of two phases. The first phase, an engineering evaluation of available and emerging emission control technologies, is completed. The second phase will select the final control technologies and develop these technologies for offshore platform applications. Phase I

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of this study concludes that the technologies with the highest estimated probability for success in offshore applications are:

- Water injection plus SCR (80 percent);
- Methanol fuel plus SCR (70 percent);
- Lean premixed combustion plus SCR (65 percent); and
- Steam dilution of fuel prior to combustion plus SCR (65 percent).

A key conclusion drawn from Phase I of this study is that none of the above technologies or combination of technologies in offshore platform applications currently has a high probability of successfully achieving the NO_x emission reduction goals of this study without substantial cost and impacts to platform and turbine operations, added safety considerations, and other environmental concerns. These issues will be further studied in Phase II for the above control technologies.

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6.0 CONTROL COSTS

Capital and annual costs are presented in this chapter for the nitrogen oxide (NO_x) control techniques described in Chapter 5.0. These control techniques are water and steam injection, low-NO_x combustion, and selective catalytic reduction (SCR) used in combination with these controls. Model plants were developed to evaluate the control techniques for a range of gas turbine sizes, fuel types, and annual operating hours. The gas turbines chosen for these model plants range in size from 1.1 to 160 megawatts (MW) (1,500 to 215,000 horsepower [hp]) and include both aeroderivative and heavy-duty turbines. Model plants were developed for both natural gas and distillate oil fuels. For offshore oil production platforms, cost information was available only for one turbine model.

The life of the control equipment depends upon many factors, including application, operating environment, maintenance practices, and materials of construction. For this study, a 15-year life was chosen.

Both new and retrofit costs are presented in this chapter. For water and steam injection, these costs were assumed to be the same because most of the water treatment system installation can be completed while the plant is operating and because gas turbine nozzle replacement and piping connections to the treated water supply can be performed during a scheduled downtime for maintenance. Estimated costs are provided for both new and retrofit low-NO_x combustion applications. No SCR retrofit applications were identified, and costs for SCR retrofit applications were not available. The cost to retrofit an

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existing gas turbine installation with SCR would be considerably higher than the costs shown for a new installation, especially for combined cycle and cogeneration installations where the heat-recovery steam generator (HRSG) would have to be modified or replaced to accommodate the catalyst reactor.

This chapter is organized into five sections. Water and steam injection costs are described in Section 6.1. Low-NO_x combustor costs are summarized in Section 6.2. Costs for SCR used in combination with water or steam injection or low-NO_x combustion are described in Section 6.3. Water injection and SCR costs for offshore gas turbines are presented in Section 6.4, and references are listed in Section 6.5.

a. WATER AND STEAM INJECTION AND OIL-IN-WATER EMULSION

Ten gas turbines models were selected, and from these turbines 24 model plants were developed using water or steam injection or water-in-oil emulsion to control NO_x emissions. These 24 models, shown in Table 6-1

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TABLE 6-1. GAS TURBINE MODEL PLANTS FOR NO_x CONTROL TECHNIQUES

Model plant[a]	GT model	Turbine output, MW	Annual operating hours	Fuel, natural gas or oil	Type of emission control	Aeroderivative (AD) or heavy-duty (HD) turbine
CON-G-W-3.3	Centaur T4500	3.3	8,000	Gas	Water	HD
CON-G-W-4.0	501-KB5	4.0	8,000	Gas	Water	AD
CON-G-W-22.7	LM2500	22.7	8,000	Gas	Water	AD
CON-G-W-26.8	MS5001P	26.8	8,000	Gas	Water	HD
CON-G-W-83.3	ABB GT11N	83.3	8,000	Gas	Water	HD
CON-G-W-84.7	MS7001E	84.7	8,000	Gas	Water	HD
CON-G-S-4.0	501-KB5	4.0	8,000	Gas	Steam	AD
CON-G-S-22.7	LM2500	22.7	8,000	Gas	Steam	AD
CON-G-S-26.8	MS5001P	26.8	8,000	Gas	Steam	HD
CON-G-S-34.4	LM5000	34.5	8,000	Gas	Steam	AD
CON-G-S-83.3	ABB GT11N	83.3	8,000	Gas	Steam	HD
CON-G-S-84.7	MS7001E	84.7	8,000	Gas	Steam	HD
CON-G-S-161	MS7001F	161	8,000	Gas	Steam	HD
CON-O-W-3.3	Centaur T4500	3.3	8,000	Oil	Water	HD
CON-O-W-26.3	MS5001P	26.3	8,000	Oil	Water	HD
CON-O-W-83.3	MS7001E	83.3	8,000	Oil	Water	HD
PKR-G-W-3.3	Centaur T4500	3.3	2,000	Gas	Water	HD
PKR-G-W-26.8	MS5001P	26.8	2,000	Gas	Water	HD
PKR-G-W-84.7	MS7001E	84.7	2,000	Gas	Water	HD
PKR-O-W-3.3	Centaur T4500	3.3	2,000	Oil	Water	HD
PKR-O-W-26.3	MS5001P	26.3	2,000	Oil	Water	HD
PKR-O-W-84.7	MS7001E	84.7	2,000	Oil	Water	HD
STD-O-W-1.1	Saturn T1500	1.0	1,000	Oil	Water	HD
STD-O-E-28.0	TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	AD

[a]Model plant legend:

First entry: annual operating hours
CON--continuous duty, 8,000 hours
PKR--peaking duty, 2,000 hours
STD--stand-by duty, 1,000 hours

Second entry: fuel type
G = natural gas fuel
O = oil fuel

Third entry: control type
W = water injection
S = steam injection
E = water-in-oil emulsion

Fourth entry: power output in MW

For example, CON-G-W-3.3 designates that the model plant is continuous-duty, uses natural gas fuel, has water injection, and has a power output of 3.3 MW.

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, characterize variations in existing units with respect to turbine size, type (i.e., aero-derivative vs. heavy duty), operating hours, and type of fuel. A total of 24 model plants were developed; 16 of these were continuous-duty (8,000 hours per year) and 8 were intermittent-duty (2,000 or 1,000 hours per year). Thirteen of the continuous-duty model plants burn natural gas fuel; 6 of the 13 use water injection, and 7 use steam injection to reduce NO_x emissions. The three remaining continuous-duty model plants burn distillate oil fuel and use water injection to reduce NO_x emissions. Of the eight intermittent-duty model plants, six operate 2,000 hours per year (three natural gas-fueled and three distillate oil-fueled), and two operate 1,000 hours per year (both distillate oil-fueled). All intermittent-duty model plants use water rather than steam for NO_x reduction because it was assumed that the additional capital costs associated with steam-generating equipment could not be justified for intermittent service.

Costs were available for applying water-in-oil emulsion technology to only one gas turbine, and insufficient data were available to develop costs for a similar water-injected model

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plant for this turbine. As a result, the costs and cost effectiveness for the water-in-oil emulsion model plant should not be compared to those of water-injected model plants.

Capital costs are described in Section 6.1.1, annual costs are described in Section 6.1.2, and emission reductions and the cost effectiveness of wet injection controls are discussed in Section 6.1.3. Additional discussion of the cost methodology and details about some of the cost estimating procedures are provided in Appendix B.

Fuel rates and water flow rates were calculated for each model plant using published design power output and efficiency, expressed as heat rate, in British thermal units per kilowatt-hour (Btu/kWh).[1] The values for these parameters are presented in Table 6-2

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TABLE 6-2. FUEL AND WATER FLOW RATES FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Turbine output, kW	Heat rate (HR), Btu/kW-hr	Fuel flow		Estimated WFR, lb water/lb fuel	Water flow, gal/min[c]	Treatment system capacity, gal/min[d]
				lb/hr[a]	MMBtu/yr[b]			
CON-G-W-3.3	Centaur T4500	3,270	12,900	2,050	337,000	0.61	2.50	4.20
CON-G-W-4.0	501-KB5	4,000	12,700	2,460	406,000	0.80	3.94	6.60
CON-G-W-22.7	LM2500	22,670	9,220	10,100	1,670,000	0.73	14.8	24.7
CON-G-W-26.8	MS5001P	26,800	11,870	15,400	2,540,000	0.72	22.2	37.2
CON-G-W-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	1.83	154	258
CON-G-W-84.7	MS7001E	84,700	10,400	42,700	7,050,000	0.81	69.2	116
CON-G-S-4.0	501-KB5	4,000	12,700	2,460	406,000	1.50	7.38	12.4
CON-G-S-22.7	LM2500	22,670	9,220	10,100	1,670,000	1.46	29.5	49.5
CON-G-S-26.8	MS5001P	26,800	11,870	15,400	2,540,000	1.08	33.3	55.8
CON-G-S-34.4	LM5000	34,450	9,080	15,200	2,500,000	1.67	50.8	85.2
CON-G-S-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	2.12	178	299
CON-G-S-84.7	MS7001E	84,700	10,400	42,700	7,050,000	1.22	104	175
CON-G-S-161	MS7001F	161,000	9,500	74,200	12,240,000	1.34	199	334
CON-O-W-3.3	Centaur T4500	3,270	12,900	2,300	337,000	0.60	2.76	4.63
CON-O-W-26.3	MS5001P	26,300	11,950	17,100	2,510,000	0.79	27.0	45.3
CON-O-W-83.3	MS7001E	83,300	10,470	47,600	6,980,000	0.67	63.8	107
PKR-G-W-3.3	Centaur T4500	3,270	12,900	2,050	84,400	0.61	2.50	4.20
PKR-G-W-26.8	MS5001P	26,800	11,870	15,400	640,000	0.72	22.2	37.2
PKR-G-W-84.7	MS7001E	84,700	10,400	42,700	1,760,000	0.81	69.2	116
PKR-O-W-3.3	Centaur T4500	3,270	12,900	2,300	84,000	0.60	2.76	4.63
PKR-O-W-26.3	MS5001P	26,300	11,950	17,100	630,000	0.79	27.0	45.3
PKR-O-W-84.7	MS7001E	83,300	10,470	47,600	1,740,000	0.67	63.8	107
STD-O-W-1.1	Saturn T1500	1,130	14,200	875	16,000	0.46	0.81	1.35
STD-O-F-28.0	TPM FT4	28,000	14,500	19,700	406,000	0.55	21.7	36.4

[a]Natural gas: lb/hr = HR x kW x (lb/20,610 Btu). Diesel oil: lb/hr = HR x kW x (lb/18,330 Btu).

[b]MMBtu/yr = HR x kW x (MM/10^6) x (operating hours/year).

[c]Water (or steam) flow, gal/min = Fuel flow (lb/hr) x (1 hr/60 min) x (1 gal/8.33, lb. H_2O) x WFR.

[d]A 30 percent design factor has been included per discussion with system supplier, and the waste stream from the water treatment system is calculated to be 29 percent. The design capacity is therefore Water Flow x 1.3 x 1.29.

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for each model plant. Fuel rates were estimated based on the heat rates, the design output, and the lower heating value (LHV) of the fuel. The LHV's used in this analysis for natural gas and diesel fuel are 20,610 Btu per pound (Btu/lb) and 18,330 Btu/lb, respectively, as shown in Table 6-3

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TABLE 6-3. FUEL PROPERTIES AND UTILITY AND LABOR RATES[a]

Fuel properties	Factor	Units	Reference
Natural gas	20,610	Btu/lb	Ref. 3
	930	Btu/scf[c] (LHV)	Ref. 3
Diesel fuel	18,330	Btu/lb (LHV)	Ref. 2
	7.21	lb/gal	Ref. 2
Utility rates			
Natural gas[b]	3.88	$/scf	Ref. 4
Diesel fuel	0.77	$/gal	Ref. 5
Electricity	0.06	$/kW-hr	Ref.'s 6 and 7
Raw water	0.384	$/1,000 gal	Ref. 2, escalated @ 5% per year
Water treatment	1.97	$/1,000 gal	Ref. 2, escalated @ 5% per year
Waste disposal	3.82	$/1,000 gal	Ref. 2, escalated @ 5% per year
Labor rate			
Operating	25.60	$/hr	Ref. 2, escalated @ 5% per year
Maintenance	31.20	$/hr	Ref. 2, escalated @ 5% per year

[a]All costs are average costs in 1990 dollars.
[b]Natural gas and electricity costs from Reference 4 are the average of the costs for industrial and commercial customers.
[c]scf = standard cubic foot.

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.[2] Water (or steam) injection rates were calculated based on published fuel rates and water-to-fuel ratios (WFR) provided by manufacturers.[8-12] According to a water treatment system supplier, treatment facilities are designed with a capacity factor of 1.3.[13] An additional 29 percent of the treated water flow rate is discarded as wastewater.[2] Consequently, the water treatment facility design capacity is 68 percent (1.30 x 1.29) greater than the water (or steam) injection rate.

i. Capital Costs

The capital costs for each model plant are presented in Table 6-4

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TABLE 6-4. CAPITAL COSTS FOR WET INJECTION IN THOUSAND OF DOLLARS [a]

Model plant	GT model	Injection system (IS)[b]	Water treatment system (WTS)[c]	Total system (TS) = (IS + WTS)	Taxes and freight (TF) = (8% of TS)	Direct install. costs (DC) = (45% [TS + TF])	Indirect install. costs (IC)=(33% of [TS + TF +DC] + 5,000)	Contingency (C) = (20% of [TS + TF + DC + IC])	Total capital cost (TCC) = [TS + TF + DC + IC + C]
CON-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
CON-G-W-4.0	501-KB5	115	113	228	18.2	50.0[d]	59.2[e]	71.0	426
CON-G-W-22.7	LM2500	212	218	430	34.4	209	227	180	1,080
CON-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
CON-G-W-83.3	ABB GT11N	874	705	1,580	126	768	822	659	3,950
CON-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
CON-G-S-4.0	501-KB5	154	154	308	24.7	50.0	76.6	92.0	552
CON-G-S-22.7	LM2500	278	309	587	46.9	285	308	245	1,470
CON-G-S-26.8	MS5001P	262	328	590	47.2	287	310	247	1,480
CON-G-S-34.4	LM5000	530	405	935	74.8	454	488	391	2,340
CON-G-S-83.3	ABB GT11N	1,090	759	1,850	148	899	961	772	4,630
CON-G-S-84.7	MS7001E	715	580	1,300	104	632	677	543	3,260
CON-G-S-161	MS7001F	1,130	802	1,930	154	938	1,000	804	4,830
CON-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
CON-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
CON-O-W-83.3	MS7001E	532	454	986	78.9	479	515	412	2,470
PKR-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
PKR-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
PKR-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
PKR-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
PKR-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
PKR-O-W-84.7	MS7001E	532	454	986	78.9	479	515	412	2,470
STD-O-W-1.1	Saturn T1500	71.9	51.0	123	9.83	50.0	36.6	43.9	263
STD-O-F-28.0	TPM FT4	128	NA[f]	128	10.2	62.2	71.1	54.3	326

[a]All costs in 1990 dollars.

[b]Injection nozzle costs provided by manufacturers. Balance of water injection system calculated at a cost of $4,200 x GPM.

[c]WTS = 43,900 x (design capacity, gal/min) $^{0.5}$

[d]Direct installation cost is estimated at $50,000 for model plants rated at 5 MW or less.

[e]Indirect installation cost factor of 33 percent is reduced to 20 percent for model plants rated at 5 MW or less.

[f]NA = cost calculations based on using a portable demineralizer systems during turbine operating periods. Cost for system usage is included in Table 6-5.

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. These costs were developed based on methodology in Reference 2, which is presented in this section. The capital costs include purchased equipment costs, direct and indirect installation costs, and contingency costs.

(1) Purchased Equipment Costs. Purchased equipment costs consist of the injection system, the water treatment system, taxes, and freight. All costs are presented in 1990 dollars.

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(a) Water injection system. The injection system delivers water from the treatment system to the combustor. This system includes the turbine-mounted injection nozzles, the flow metering controls, pumps, and hardware and interconnecting piping from the treatment system to the turbine. On-engine hardware (the injection nozzles) costs were provided by turbine manufacturers.[9,14-17] Flow metering controls and hardware, pumps, and interconnecting piping costs for all turbines were calculated using data provided by General Electric for four heavy-duty turbine models.[17] No relationship between costs and either turbine output or water flow was evident, so the sum of the four costs was divided by the sum of the water flow requirements for the four turbines. This process yielded a cost of $4,200 per gallon per minute (gal/min), and this cost, added to the on-engine hardware costs, was used for all model plants.

(b) Water treatment system. The water treatment process, and hence the treatment system components, varies according to the degree to which the water at a given site must be treated. For this cost analysis, the water treatment system includes a reverse osmosis and mixed-bed demineralizer system. The water treatment system capital cost for each model plant was estimated based on an equation developed in Reference 2:

$$WTS = 43{,}900 \times (G)^{0.50}$$

where

WTS = water treatment system capital cost, $; and

G = water treatment system design capacity, gal/min.

This equation yields costs that are generally consistent with the range of costs presented in Reference 18.

(c) Taxes and freight. This cost covers applicable sales taxes and shipment to the site for the injection and water treatment systems. A figure of 8 percent of the total system cost was used.[2,7]

(2) Direct Installation Costs. This cost includes the labor and material costs associated with installing the foundation and supports, erecting and handling equipment, electrical work, piping, insulation, and painting. For smaller

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turbines, the water treatment system is typically skid-mounted and is shipped to the site as a packaged unit, which minimizes field assembly and interconnections. The cost to install a skid-mounted water treatment skid is typically $50,000, and this cost is used for the direct installation cost for model plants less than 5 MW (6700 hp).[19] For larger turbines, it is expected that the water treatment system must be field-assembled and the direct installation costs were calculated as 45 percent of the injection and water treatment systems, including taxes and freight.[2]

(3) Indirect Installation Costs. This cost covers the indirect costs (engineering, supervisory personnel, office personnel, temporary offices, etc.) associated with installing the equipment. The cost was taken to be 33 percent of the systems' costs, taxes and freight, and direct costs, plus $5,000 for model plants above 5 MW (6,700 hp).[2] The indirect installation costs for skid-mounted water treatment systems are expected to be less than for field-assembled systems; therefore, for model plants with an output of less than 5 MW (6,700 hp), the cost percentage factor was reduced from 33 to 20 percent.

(4) Contingency Cost. This cost is a catch-all meant to cover unforeseen costs such as equipment redesign/ modification, cost escalations, and delays encountered in startup. This cost was estimated as 20 percent of the sum of the systems, taxes and freight, and direct and indirect costs.[2]

ii. Annual Costs

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The annual costs are summarized in Table 6-5

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TABLE 6-5. ANNUAL COSTS FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Fuel penalty (FP)[a]	Electricity (E)[b]	Added maintenance cost (M)[c]	Water treatment (WT)[d]					Plant overhead (PO) = (30% of M)	G&A taxes, insurance (GATI)[i]	Capital recovery (CR)[j]	Total annual cost (TAC)[k]
					Raw water[e]	Treat-ment[f]	Labor[g]	Disposal[h]	Total cost (TW)				
CON-G-W-3.3	Centaur T4500	30,000	193	16,000	595	3,050	1,080	1,330	6,050	4,800	15,500	51,000	124,000
CON-G-W-4.0	501-KB5	47,400	304	24,000	936	4,800	1,710	2,090	9,540	7,200	17,100	56,100	162,000
CON-G-W-22.7	LM2500	178,000	1,140	28,000	3,510	18,000	6,390	7,840	35,700	8,400	43,200	142,000	436,000
CON-G-W-26.8	MS5001P	267,000	1,714	33,000	5,270	27,100	9,620	11,800	53,800	9,900	48,400	159,000	573,000
CON-G-W-83.3	ABB GT11N	1,852,000	11,884	0	36,600	188,000	66,700	81,800	373,000	0	158,000	519,000	2,910,000
CON-G-W-84.7	MS7001E	834,000	5,348	25,700	16,500	84,400	30,000	36,800	168,000	7,710	103,000	339,000	1,480,000
CON-G-S-4.0	501-KB5	25,400	571	24,000	1,760	9,010	1,600	3,930	16,300	7,200	22,100	72,600	168,000
CON-G-S-22.7	LM2500	102,000	2,280	0	7,020	36,000	6,390	15,700	65,100	0	58,800	193,000	421,000
CON-G-S-26.8	MS5001P	114,000	2,572	33,000	7,910	40,600	7,210	17,700	73,400	9,900	59,200	195,000	487,000
CON-G-S-34.4	LM5000	174,000	3,925	0	12,100	62,000	11,000	27,000	112,000	0	93,600	308,000	692,000
CON-G-S-83.3	ABB GT11N	613,000	13,768	0	42,400	217,000	38,600	94,700	393,000	0	185,000	609,000	1,810,000
CON-G-S-84.7	MS7001E	359,000	8,055	0	24,800	127,000	22,600	55,400	230,000	0	130,000	429,000	1,160,000
CON-G-S-161	MS7001F	684,000	15,374	0	47,300	243,000	43,100	106,000	439,000	0	193,000	635,000	1,970,000
CON-O-W-3.3	Centaur T4500	41,200	213	20,800	657	3,370	1,200	1,470	6,700	6,240	15,800	52,100	143,000
CON-O-W-26.3	MS5001P	404,000	2,089	42,900	6,430	33,000	11,700	14,400	65,500	12,900	52,800	174,000	754,00
CON-O-W-83.3	MS7001E	954,000	4,931	33,400	15,200	77,800	27,700	33,900	155,000	10,020	98,800	325,000	1,580,000
PKR-G-W-3.3	Centaur T4500	7,500	48.3	4,000	149	760	270	330	1,510	1,200	15,500	51,000	80,800
PKR-G-W-26.8	MS5001P	67,000	429	8,250	1,320	6,770	2,400	2,950	13,400	2,500	48,400	159,000	299,000
PKR-G-W-84.7	MS7001E	208,000	1,337	6,430	4,110	21,100	7,500	9,200	41,900	1,929	103,000	339,000	702,000
PKR-O-W-3.3	Centaur T4500	10,300	53.3	5,200	164	840	300	370	1,670	1,560	15,800	52,100	86,700
PKR-O-W-26.3	MS5001P	101,000	522	10,725	1,610	8,240	2,930	3,590	16,400	3,200	52,800	174,000	359,000
PKR-O-W-84.7	MS7001E	238,000	1,233	8,350	3,790	19,500	6,910	8,480	38,700	2,505	99,000	325,000	713,000
STD-O-W-1.1	Saturn T1500	1,500	7.78	1,300	23.9	123	43.7	53.6	244	390	10,530	34,600	48,600
STD-O-E-28.0	TPM FT4	45,500	209	0	644	51,100	1,170	1,440	54,400	0	13,000	42,900	156,000

[a]FP for water = 0.035 x WFR x (MMBtu/yr) x (ft ^{3}/940 Btu) x ($3.88/1,000 ft ^{3}) x (10^6/MM).
[b]E = Water flow rate (gal/min) x 0.161 x operating hours x ($0.06/kWH).
[c]Maintenance costs for the Centaur and Allison 501 turbines were obtained from the manufacturers. Costs for the MS5001 and MS7001 were estimated based on information about inspections and parts replacement presented in Appendix B. Maintenance for turbines that use diesel fuel are 30 percent higher than costs for comparable turbines using natural gas. No additional maintenance costs were assessed for steam injection.
[d]WT includes treatment chemicals, raw water, sewage disposal, and operating labor.
[e]Raw Water Cost = Water Flow (gal/min) x ($0.384/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[f]Treatment Cost = Water Flow (gal/min) x ($1.97/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[g]Labor Cost for water = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29.
Labor Cost for steam = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29 x 0.5.
[h]Disposal Cost = Water Flow (gal/min) x ($3.82/1,000 gal) x (60 min/hour) x operating hours x 0.29.
[i]GATI = 0.04 x TCC (TCC is shown in Table 6-4).
[j]CR = 0.1315 x TCC based on an equipment life of 15 years and a 10 percent interest rate.

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for each model plant. Annual costs include the fuel penalty; electricity; maintenance requirements; water treatment; overhead, general and administrative, taxes, and insurance; and capital recovery, as discussed in this section.

(1) Fuel Penalty. The reduction in efficiency associated with water injection varies for each turbine model. Based on data in Reference 2, it was estimated that a WFR of 1.0 corresponds to a fuel penalty of 3.5 percent for water injection and 1.0 percent for steam injection. This percentage was multiplied by the actual WFR and the annual fuel cost to

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determine the fuel penalty for each model plant. The fuel flow was multiplied by the unit fuel costs to determine the annual fuel costs. As shown in Table 6-3, the natural gas cost is $3.88/1,000 standard cubic feet (scf) and the diesel fuel cost is $0.77/gal.[4,5]

An increase in output from the turbine accompanies the decrease in efficiency. This increase was not considered, however, because not all sites have a demand for the available excess power. In applications such as electric power generation, where the excess power can be used at the site or added to utility power sales, this additional output would serve to decrease or offset the fuel penalty impact.

(2) Electricity Cost. The electricity costs shown in Table 6-5 apply to the feedwater pump(s) for water or steam injection. The pump power requirements are estimated from the pump head (ft) and the water flow rate as shown in the following equation:[2]

$$\text{power pump } (kW_e) = \frac{FR}{3{,}960} \times H \times (S.G.) \times \frac{1}{0.6} \times \frac{0.7457\ kW}{hp} \times \frac{1}{0.9}$$

where:

FR = feedwater flow rate, gal/min (from Table 6-2);
H = total pump head (ft);
S.G. = specific gravity of the feed water;
0.6 = pump efficiency of 60 percent;
0.9 = electric motor efficiency of 90 percent;
3,960 = factor to correct units in FR and H to hp; and
0.7457 = factor to convert hp to kW.

For water injection, the feedwater pump(s) supply treated water to the gas turbine injection system. For steam injection, the feedwater pump(s) supply treated water to the boiler for steam generation. This cost analysis uses a feedwater temperature of 55°C (130°F) with a density of 61.6 lb/ft^3 and a total pump head requirement of 200 pounds per square inch, gauge (psig)

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(468 ft).[2] Based on these values, the pump electrical demand for either water or steam injection is calculated as follows:

$$\text{pump power } (kW_e) = \frac{FR \times 468}{3{,}960} \times \frac{61.6}{62.4} \times \frac{1}{0.6} \times 0.7457 \times \frac{1}{0.9}$$

$$= 0.161 \times FR$$

The electrical cost for each model plant is the product of the pump electrical demand, the annual hours of operation, and the unit cost of electricity. The unit cost of electricity, shown in Table 6-3, is $0.06/kWH.[6,7]

Maintenance costs were developed based on information from manufacturers, and water treatment labor costs were estimated based on information from a water treatment vendor. Other costs were developed based on the methodology presented in Reference 2.

No backup steam or electricity costs were developed for water or steam injection because it was assumed that no additional downtime would be required for scheduled inspections and repairs. Maintenance intervals could be scheduled to coincide with the 760 hr/yr of downtime that are currently allocated for scheduled maintenance. If this were done, the annual utilization of the backup source would not increase.

(3) Added Maintenance Costs. Based on discussions with gas turbine manufacturers, additional maintenance is required for some gas turbines with water injection. The analysis procedures used to develop the incremental maintenance costs are presented in Appendix B.

The incremental maintenance cost associated with water injection for natural gas-fueled turbines was provided by the gas turbine manufacturers.[10,20-24] All gas turbine manufacturers contacted stated that there were no incremental maintenance costs for operation with steam injection. Two manufacturers provided maintenance costs for natural gas and oil fuel operation without water injection.[10,20] Using an average of these costs, incremental maintenance costs for water injection are 30 percent higher for

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plants that use diesel fuel instead of natural gas. Costs were prorated for model plants that operate less than 8,000 hr/yr.

(4) Water Treatment Costs. Water treatment operating costs include the cost of treatment (e.g., for chemicals and media filters), operating labor, raw water, and wastewater disposal. The raw water flow rate is equal to the treated water flow rate (the water or steam injection rate) plus the flow rate of the wastewater generated in the treatment plant. As noted in Section 6.1, the wastewater flow rate is equal to 29 percent of the injection flow rate. The annual raw water, treated water, and wastewater flow rates were multiplied by the appropriate unit costs in Table 6-3 to determine the annual costs. Water treatment labor costs were calculated at $0.70/1,000 gal for water injection.[25] This cost was multiplied by the total annual treated water flow rate to determine the annual water treatment labor cost for water injection. Labor costs for steam injection were assumed to be half as much as the costs for water injection because it was assumed that the facility already has a water treatment plant for the boiler feedwater. Therefore, the operator requirements would be only those associated with the increase in capacity of the existing treatment plant.

(5) Plant Overhead. This cost is the overhead associated with the additional maintenance effort required for water injection. The cost was calculated as 30 percent of the added maintenance cost from Section 6.1.2.3.[2]

(6) General and Administrative, Taxes, and Insurance Costs (GATI). This cost covers those expenses for administrative overhead, property taxes, and insurance and was calculated as 4 percent of the total capital cost.[2]

(7) Capital Recovery. A capital recovery factor (CRF) was multiplied by the total capital investment to estimate uniform end-of-year payments necessary to repay the investment. The CRF used in this analysis is 0.1315, which is based on an equipment life of 15 years and an interest rate of 10 percent.

(8) Total Annual Cost. This cost is the sum of the annual costs presented in Sections 6.1.2.1 through 6.1.2.7 and is the

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total cost that must be paid each year to install and operate water or steam injection NO_x emissions control for a gas turbine.

iii. Emission Reduction and Cost-Effectiveness Summary for Water and Steam Injection

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TABLE 6-6. COST-EFFECTIVENESS SUMMARY FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $	Cost effectiveness, $/ton
		Uncontrolled NO_x		Controlled NO_x				
		ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	130	88.1	42	28.5	59.6	124,000	2,080
CON-G-W-4.0	501-KB5	155	126	42	34.2	91.9	162,000	1,760
CON-G-W-22.7	LM2500	174	581	42	140	441	436,000	989
CON-G-W-26.8	MS5001P	142	723	42	214	509	573,000	1,130
CON-G-W-83.3	ABB GT11N	390	5,410	25	347	5,060	2,910,000	575
CON-G-W-84.7	MS7001E	154	2,170	42	593	1,580	1,480,000	937
CON-G-S-4.0	501-KB5	155	126	42	34.2	91.9	168,000	1,830
CON-G-S-22.7	LM2500	174	581	25	83.5	497	421,000	846
CON-G-S-26.8	MS5001P	142	723	42	214	509	487,000	957
CON-G-S-34.4	LM5000	185	930	25	126	804	692,000	861
CON-G-S-83.3	ABB GT11N	390	5,410	42	583	4,830	1,810,000	375
CON-G-S-84.7	MS7001E	154	2,170	42	593	1,580	1,160,000	734
CON-G-S-161	MS7001F	210	5,150	42	1,030	4,120	1,970,000	478
CON-O-W-3.3	Centaur T4500	179	125	60	41.8	82.9	143,000	1,720
CON-O-W-26.3	MS5001P	211	1,090	65	337	753	754,000	1,000
CON-O-W-83.3	MS7001E	228	3,290	65	938	2,350	1,580,000	672
PKR-G-W-3.3	Centaur T4500	130	22.0	42	7.12	14.9	80,800	5,420
PKR-G-W-26.8	MS5001P	142	181	42	53.5	127	299,000	2,350
PKR-G-W-84.7	MS7001E	154	543	42	148	395	702,000	1,780
PKR-O-W-3.3	Centaur T4500	179	31.2	60	10.5	20.7	86,700	4,180
PKR-O-W-26.3	MS5001P	211	273	65	84.2	189	359,000	1,900
PKR-O-W-84.7	MS7001E	228	822	65	234	588	713,000	1,210
STD-O-W-1.1	Saturn T1500	150	4.97	60	1.99	2.98	48,600	16,300
STD-O-E-28.0	TPM FT4	150	122	50	37.3	84.7	156,000	1,840

[a]Example NO_x emission calculations are given in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-5.

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The uncontrolled and controlled NO_x emissions and the annual emission reductions for the model plants are shown in Table 6-6. The emissions, in tons per year (tons/yr), were calculated as shown in Appendix A.

The total annual cost was divided by the annual emission reductions to determine the cost effectiveness for each model plant. For continuous-duty natural gas-fired model plants, the cost-effectiveness figures range from approximately $600 to $2,100 per ton of NO_x removed for water injection, and decrease to approximately $400 to $1,850 per ton for steam injection. The lower range of cost-effectiveness figures for steam injection is primarily due to the greater NO_x reduction achieved with steam injection. For continuous-duty oil-fired model plants, the cost effectiveness ranges from approximately $675 to $1,750 per ton of NO_x removed, which is comparable to figures for gas-fired model plants. The cost-effectiveness figures are higher for gas turbines with lower power outputs because the fixed capital costs associated with wet injection system installation have the greatest impact on the smaller gas turbines.

Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hr/yr, the cost-effectiveness figures are two to nearly three times higher than those for continuous-duty model plants, and increase further for model plants operating 1,000 hr/yr. For the oil-in-water emulsion model plant, the cost effectiveness corresponding to 1,000 annual operating hours is $1,840/ton of NO_x removed. No data were available to prepare a conventional water injection model plant for this turbine to compare the relative cost-effectiveness values.

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b. LOW-NO_x COMBUSTORS

Incremental capital costs for low-NO_x combustors relative to standard designs for new applications were provided by three manufacturers for several turbines.[3,14,26] Based on information from the manufacturers, the performance and maintenance requirements for a low-NO_x combustor are expected to be the same as for a standard combustor, and so the only annual cost associated with low-NO_x combustors is the capital recovery. The capital recovery factor is 0.1315, assuming a life of 15 years and an interest rate of 10 percent.

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Table 6-7

TABLE 6-7. COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NO_x COMBUSTORS USING NATURAL GAS FUEL (1990 $)

Model plant [a]	GT model	Power output, MW	Annual operating hours	NO_x emissions [b]				NO_x removed, tons/yr	Incremental capital cost,$ [d]	Annual cost, $ [e]	Cost effectiveness, $/ton NO_x removed
				Uncontrolled NO_x		Controlled NO_x					
				ppmv [c]	Tons/yr	ppmv	Tons/yr				
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42.0	28.5	59.6	375,000	49,300	827
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42.0	33.2	49.8	400,000	52,600	1,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42.0	36.4	62.4	425,000	55,900	896
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42.0	65.5	212	700,000	92,100	434
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42.0	72.1	269	725,000	95,300	354
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25.0 [f]	16.9	71.2	375,000	49,300	693
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25.0 [f]	19.8	63.2	400,000	52,600	832
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25.0 [f]	21.7	77.1	425,000	55,900	725
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25.0 [f]	39.0	239	700,000	92,100	386
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25.0 [f]	42.9	299	725,000	95,300	319
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25.0	168	1,310	1,400,000	184,000	140
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25.0	347	5,070	2,200,000	289,000	57.0
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25.0	353	1,830	2,140,000	281,000	154
CON-L-39-9	MS6000	39.0	8,000	220	1,480	9.00	60.6	1,420	1,400,000	184,000	130
CON-L-83-9	ABB GT11N	83.3	8,000	390	5,420	9.00	125	5,290	2,200,000	289,000	54.6
CON-L-85-9	MS7001E	84.7	8,000	154	2,180	9.00	127	2,050	2,140,000	281,000	137
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42.0	7.12	14.9	375,000	49,300	3,310
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42.0	8.30	12.4	400,000	52,600	4,230
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42.0	9.09	15.6	425,000	55,900	3,590
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42.0	16.4	53.1	700,000	92,100	1,740
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42.0	18.0	67.3	725,000	95,300	1,420
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25.0 [f]	4.24	17.8	375,000	49,300	2,770
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25.0 [f]	4.94	15.8	400,000	52,600	3,330
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25.0 [f]	5.41	19.3	425,000	55,900	2,900
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25.0 [f]	9.75	59.7	700,000	92,100	1,540
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25.0 [f]	10.7	74.6	725,000	95,300	1,280
PKR-L-39-25	MS6000	39.0	2,000	220	371	25.0	42.1	328	1,400,000	184,000	560
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25.0	86.8	1,260	2,200,000	289,000	229
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25.0	88.3	452	2,140,000	281,000	622
*PKR-L-39-9	MS6000	39.0	2,000	220	371	9.00	15.2	355	1,400,000	184,000	518
PKR-L-83-9	ABB GT11N	83.3	2,000	390	1,350	9.00	31.3	1,320	2,200,000	289,000	219
PKR-L-85-9	MS7001E	84.7	2,000	154	540	9.00	31.8	508	2,140,000	281,000	553

[a]Model plant legend: First entry: annual operating hours Second entry: control technique Third entry: power output, in MW Fourth entry: controlled NO_x level, ppmv at 15 percent O
CON - Continuous duty, 8,000 hours L - dry low-NO_x combustor
PKR - peaking/intermittent duty, 2,000 hours

For example, CON-L-3.3-42 designates that the model plant operates 8,000 hours per year, is fitted with a dry low-NO_x combustor, has a power output of 3.3 MW, and has a controlled NO_x level of 42 ppmv.

[b]Example NO_x emission calculations are shown in Appendix A.

[c]Referenced to 15 percent oxygen.

[d]Incremental capital costs were provided by the manufacturers.

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presents the uncontrolled and controlled emission levels, the annual emission reductions, incremental costs for a low-NO_x combustor over a conventional design, and the cost effectiveness of low-NO_x combustors for all gas turbine models for which sufficient data were available. Cost-effectiveness figures were calculated for 8,000 and 2,000 hours of operation annually, using controlled NO_x emission levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, which are the achievable levels stated by the turbine manufacturers. The cost effectiveness varies according to the uncontrolled NO_x emission level for the conventional combustor design and the achievable controlled emission level for the low-NO_x design. For continuous-duty applications, cost effectiveness for a controlled NO_x emission level of 42 ppmv ranges from $353 to $1,060 per ton of NO_x removed. The cost-effectiveness range decreases to $57 to $832 per ton of NO_x removed for a controlled NO_x emission level of 25 ppmv and decreases further to $55 to $137 per ton of NO_x removed for a 9 ppmv control level. In all cases, the cost effectiveness increases as the operating hours decrease. In general, the cost effectiveness is higher for smaller gas turbines than for larger turbines due to the relatively higher capital cost per kW for low-NO_x combustors for smaller turbines.

The cost-effectiveness range is lower for low-NO_x combustors than for water or steam injection because the total annual costs are lower and, in some cases, the controlled emission levels are

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also lower. According to two turbine manufacturers, retrofit costs are 40 to 60 percent greater than the incremental costs shown in Table 6-7 for new installations.[3,14]

c. SELECTIVE CATALYTIC REDUCTION

The costs for SCR for new installations were estimated for all model plants. Retrofit costs for SCR were not available but could be considerably higher than the costs shown for new installations, especially in applications where an existing heat recovery steam generator (HRSG) would have to be moved, modified, or replaced to accommodate the addition of a catalyst reactor.

To date, most gas turbine SCR applications use a base metal catalyst with an operating temperature range that requires cooling of the exhaust gas from the turbine. For this reason, SCR applications to date have been limited to combined cycle or cogeneration applications that include an HRSG, which serves to cool the exhaust gas to temperatures compatible with the catalyst. The introduction of high-temperature zeolite catalysts, however, makes it possible to install the catalyst directly downstream of the turbine, and therefore feasible to use SCR with simple-cycle applications as well as heat recovery applications. As discussed in Section 5.3.2, to date there is at least one gas turbine installation with a high-temperature zeolite catalyst installed downstream of the turbine and upstream of an HRSG. At present, no identified SCR systems are installed in simple-cycle gas turbine applications.

An overview of the procedures used to estimate capital and annual costs are described in Sections 6.3.1 and 6.3.2, respectively; a detailed cost algorithm is presented in Appendix B. The emission reduction and cost-effectiveness calculations are described in Section 6.3.3.

i. <u>Capital Costs</u>

Five documents in the technical literature contained SCR capital costs for 21 gas turbine facilities. Most of these documents presented costs that were obtained from vendors, but some may have also developed at least some costs based on their own experiences.[27-31] Most of the documents presented only the

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total capital costs, not costs for individual components, and they did not provide complete descriptions of what the costs included. These costs were plotted on a graph of total capital costs versus gas turbine size. To this graph were added estimates of total installed costs for a high-temperature catalyst SCR system for installation upstream of the HRSG for four turbine installations ranging in size from 4.5 to 83 MW (6,030 to 111,000 hp). These high-temperature SCR system estimates include the catalyst reactor, air injection system for exhaust temperature control, ammonia storage and injection system, instrumentation, and continuous emission monitoring equipment. These SCR costs were estimated by the California Air Resources Board (CARB) in 1991 dollars and are based on NO_x emission levels of 42 ppmv into and 9 ppmv out of the SCR.[35] These estimated costs, shown in Appendix B, fit well within the range of costs from the 21 installations discussed above, and the equation of a line determined by linear regression adequately fits the data ($R^2 = 0.76$) for all 25 points. Based on this graph, the total capital cost for either a base-metal SCR system installed within the HRSG or a high-temperature zeolite catalyst SCR system installed directly downstream of the turbine can be calculated using the equation determined by the linear

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TABLE 6-8. PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR SCR CONTROL OF NO_X EMISSIONS FROM GAS TURBINES[a]

A. Total capital investment, $[b]	=	(49,700 x TMW) + 459,000
B. Direct annual costs, $/yr		
1. Operating labor[c]	=	(1.0 hr/8 hr-shift) x ($25.60/hr) x (H)
2. Supervisory labor	=	(0.15) x (operating labor)
3. Maintenance labor and materials	=	(1,250 x TMW) + 25,800
4. Catalyst replacement	=	(4,700 x TMW) + 37,200
5. Catalyst disposal[d]	=	(V) x ($15/ft^3) x (.2638)
6. Anhydrous ammonia[e]	=	(N) x ($360/ton)
7. Dilution steam[f]	=	(N) x (0.95/0.05) x (MW H_2O/MW NH_3) x ($6/1,000 lb steam) x (2,000 lb/ton)
8. Electricity[g]	=	N/A
9. Performance loss[h]	=	(0.005) x (TMW) x ($0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower (if needed)	=	0.1 x (Performance Loss)
11. Production loss[i]	=	None
C. Indirect annual costs, $/yr		
1. Overhead	=	(0.6) x (all labor and maintenance material costs)
2. Property taxes, insurance, and administration	=	(0.04) x (total capital investment)
3. Capital recovery[j]	=	(0.13147) x [total capital investment - (catalyst replacement/0.2638)]

[a]All costs are in average 1990 dollars.

[b]TMW=turbine output in MW for each model plant.

[c]The annual operating hours are represented by the variable H. The labor rate of $25.60/hr is from Table 6-3.

[d]The catalyst volume in ft^3 is represented by the variable V. The catalyst volume for each model plant is estimated as V = (TMW) x (6,180 ft^3/83 MW).

[e]The ammonia requirement in tons is represented by the variable N and is calculated using a NH_3-to-NO_x molar ratio of 1.0.

The annual tonnage of NO_x is taken from the controlled levels shown in Tables 6-11 and 6-12.

[f]The ammonia is diluted with steam to 5 percent by volume before injection.

[g]The amount of electricity required for ammonia pumps and exhaust fans is not known, but is expected to be small. The electricity cost comprised less than 1 percent of the total annual cost estimated by the South Coast Air Quality Management District (SCAQMD) for SCR applied to a 1.1 MW turbine.

[h]Based on information from three sources, the backpressure from the SCR reduces turbine output by an average of about 0.9 percent.

[i]No production losses are estimated because it is assumed that all SCR maintenance, inspections, cleaning, etc. can be performed during the 760 hours of scheduled downtime per year.

[j]The capital recovery factor for the SCR is 0.13147, based on a 15-year equipment life and 10 percent interest rate. The catalyst is replaced every 5 years. The 0.2638 figure is the capital recovery factor for a 5-year equipment life and a 10 percent interest rate.

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regression. This equation is shown in Table 6-8 and was used to calculate the total capital investment for SCR for each model plant shown in Tables 6-9 and 6-10.

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TABLE 6-9. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF WATER OR STEAM INJECTION (1990 $)

Model plant	GT model	Total capital investment, $[a]	Operating labor, $	Super-visory labor, $	Main-tenance labor & materials, $	Catalyst replace-ment, $	Catalyst disposal, $	Ammonia, $	Dilution steam, $	Perfor-mance loss, $	Blower (if needed), $	Over-head, $	Taxes, insurance & admin, $	Capital recovery, $	Total annual cost, $
CON-G-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	2,980	1,770	7,850	785	35,600	24,900	55,600	242,000
CON-G-W-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-W-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	14,700	8,740	54,400	5,440	50,100	63,600	137,000	568,000
CON-G-W-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-W-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-G-W-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-S-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	7,110	4,240	54,400	5,440	50,100	63,600	137,000	556,000
CON-G-S-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-S-34.4	LM5000	2,170,000	25,600	3,840	68,900	199,000	10,100	10,700	6,380	82,700	8,270	59,000	86,800	186,000	747,000
CON-G-S-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	61,000	36,300	200,000	20,000	95,700	184,000	391,000	1,600,000
CON-G-S-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-161	MS7001F	8,460,000	25,600	3,840	227,000	794,000	47,400	108,000	64,200	386,000	38,600	154,000	338,000	717,000	2,900,000
CON-O-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	3,890	2,320	7,850	785	35,600	24,900	55,600	244,000
CON-O-W-26.3	MS5001P	1,770,000	25,600	3,840	58,700	161,000	7,750	32,400	19,300	63,100	6,310	52,900	70,800	152,000	654,000
CON-O-W-83.3	MS7001E	4,600,000	25,600	3,840	130,000	429,000	24,500	90,000	53,800	200,000	20,000	95,700	184,000	391,000	1,650,000
PKR-G-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	740	440	1,960	196	8,900	24,900	75,300	141,000
PKR-G-W-26.8	MS5001P	1,790,000	6,400	960	14,800	40,800	1,970	5,600	3,330	16,100	1,610	13,300	71,600	215,000	391,000
PKR-G-W-84.7	MS7001E	4,670,000	6,400	960	32,900	109,000	6,240	15,500	9,240	50,800	5,080	24,200	187,000	560,000	1,010,000
PKR-O-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	970	580	1,960	196	8,900	24,900	75,300	141,000
PKR-O-W-26.3	MS5001P	1,770,000	6,400	960	14,700	40,200	1,940	8,100	4,830	15,800	1,580	13,200	70,800	213,000	392,000
PKR-O-W-84.7	MS7001E	4,600,000	6,400	960	32,500	107,000	6,140	22,500	13,440	50,000	5,000	23,900	184,000	552,000	1,000,000
STD-O-W-1.1	Saturn T1500	515,000	3,200	480	3,400	5,310	41.6	185	158	339	33.9	4,250	20,600	65,100	103,000
STD-O-E-28.0	TPM FT4	1,850,000	3,200	480	60,800	21,100	1,030	3,180	2,960	8,400	840	38,700	74,000	233,000	448,000

[a]Costs shown are for SCR systems used downstream of gas turbines with wet injection to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-6.

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TABLE 6-10. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF LOW-NO_x COMBUSTION

Model plant [a]	GT model	Total capital invest., $ [b]	Operating labor,$	Super-visory labor, $	Main-tenance labor & materials, $	Catalyst replacement, $	Catalyst disposal, $	Ammonia,$	Dilution steam, $	Perfor-mance loss, $	Blower (if needed), $	Over-head, $	Taxes, insurance & admin., $	Capital recovery, $	Total annual cost, $
CON-L-3.3-42	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	2,980	1,770	7,920	790	35,600	24,900	55,500	242,000
CON-L-4.0-42	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	3,470	2,070	9,600	960	36,100	26,300	58,600	255,000
CON-L-4.5-42	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	3,800	2,270	10,800	1,080	36,500	27,300	60,700	263,000
CON-L-8.8-42	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	6,850	4,080	21,100	2,110	39,700	35,800	78,600	336,000
CON-L-10-42	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	7,530	4,490	24,000	2,400	40,600	38,200	83,700	356,000
CON-L-3.3-25	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	1,440	860	7,920	790	35,600	24,900	55,500	240,000
CON-L-4.0-25	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	1,680	1,000	9,600	960	36,100	26,300	58,600	252,000
CON-L-4.5-25	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	1,840	1,100	10,800	1,080	36,500	27,300	60,700	260,000
CON-L-8.8-25	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	3,320	1,980	21,100	2,110	39,700	35,800	78,600	330,000
CON-L-10-25	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	3,650	2,180	24,000	2,400	40,600	38,200	83,700	350,000
CON-L-39-25	MS6000	2,400,000	25,600	3,840	74,600	221,000	11,490	14,300	8,550	93,600	9,360	62,400	96,000	205,000	826,000
CON-L-83-25	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,540	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-L-85-25	MS7001E	4,670,000	25,600	3,840	132,000	435,000	24,960	30,100	17,900	203,000	20,300	96,900	186,800	397,000	1,570,000
PKR-L-3.3-42	Centaur T4500	622,000	6,400	960	7,480	55,100	2,870	740	440	1,980	200	8,900	24,900	54,300	164,000
PKR-L-4.0-42	Centaur 'H'	658,000	6,400	960	7,700	107,000	6,140	870	520	2,400	240	9,000	26,300	33,200	201,000
PKR-L-4.5-42	Taurus	683,000	6,400	960	7,860	109,000	6,240	950	570	2,700	270	9,100	27,300	35,500	207,000
PKR-L-8.8-42	Mars T12000	896,000	6,400	960	9,200	9,300	0	1,710	1,020	5,280	530	9,900	35,800	113,000	193,000
PKR-L-10-42	Mars T14000	956,000	6,400	960	9,580	13,200	240	1,880	1,120	6,000	600	10,200	38,200	119,000	207,000
PKR-L-3.3-25	Centaur T4500	623,000	6,400	960	7,480	14,600	330	360	210	1,980	200	8,900	24,900	74,600	141,000
PKR-L-4.0-25	Centaur 'H'	658,000	6,400	960	7,700	19,600	650	420	250	2,400	240	9,000	26,300	76,800	151,000
PKR-L-4.5-25	Taurus	683,000	6,400	960	7,860	21,100	740	460	270	2,700	270	9,100	27,300	79,300	156,000
PKR-L-8.8-25	Mars T12000	896,000	6,400	960	9,200	9,300	0	830	490	5,280	530	9,900	35,800	113,000	192,000
PKR-L-10-25	Mars T14000	956,000	6,400	960	9,580	13,200	240	910	540	6,000	600	10,200	38,200	119,000	206,000
PKR-L-39-25	MS6000	2,400,000	6,400	960	18,600	14,000	290	3,590	2,140	23,400	2,340	15,600	96,000	309,000	492,000
PKR-L-83-25	ABB GT11N	4,600,000	6,400	960	32,500	14,600	330	7,390	4,410	50,000	5,000	23,900	184,000	598,000	927,000
PKR-L-85-25	MS7001E	4,670,000	6,400	960	32,900	19,600	650	7,520	4,480	50,800	5,080	24,200	186,800	604,000	943,000

[a] See Table 6-7 for model plant legend.

[b] Costs shown are for SCR systems used downstream of gas turbines with dry low-NO_x combustion to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-7.

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ii. Annual Costs

Total annual costs for SCR control were developed following standard EPA procedures described in the OAQPS Control Cost Manual for other types of add-on air pollution control devices (APCD's). Information about annual costs was obtained from the same sources that provided capital costs.[27-31] Total annual costs consist of direct and indirect costs; parameters that make up these categories and the equations for estimating the costs are

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presented in Table 6-8 and are discussed below. The annual costs are shown in Tables 6-9 and 6-10 for injection and dry low-NO_x combustion, respectively, for each of the model plants.

(1) Operating and Supervisory Labor. Information about operating labor requirements was unavailable. Most facilities have fully automated controls and monitoring/recording equipment, which minimizes operator attention. Therefore, it was assumed that 1 hr of operator attention would be required during an 8-hr shift, regardless of turbine size. This operating labor requirement is at the low end of the range recommended in the OAQPS Control Cost Manual for other types of APCD's.[7] Operator wage rates were estimated to be $25.60/hr in 1990, based on escalating the costs presented in Reference 2 by 5 percent per year to account for inflation. Supervisory labor costs were estimated to be 15 percent of the operating labor costs, consistent with the OAQPS Control Cost Manual.

(2) Maintenance Labor and Materials. Combined maintenance labor and materials costs for 14 facilities were obtained from four articles, but almost half of the data (6 facilities) were provided by one source.[27-30] The costs were escalated to 1990 dollars assuming an inflation rate of 5 percent per year. All of the data are for facilities that burn natural gas. Provided that ammonium salt formation is avoided by limiting ammonia slip and sulfur content, the cost for operation with natural gas should also apply for distillate oil fuel.[32] Therefore, it was assumed that the cost data also apply to SCR control for turbines that fire distillate oil fuel. The costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation, shown in Table 6-8, was used to estimate the maintenance labor and materials costs shown in Table 6-9 for the model plants.

(3) Catalyst Replacement. Replacement costs were obtained for nine gas turbine facilities, and combined replacement and disposal costs were obtained for another six gas turbine facilities.[27-30] The disposal costs were estimated for the six

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facilities as described below and in Appendix B. The replacement costs for these six facilities were then estimated by subtracting the estimated disposal costs from the combined costs. A catalyst life of 5 years was used. All replacement costs were escalated to 1990 dollars assuming a 5 percent annual inflation rate.

The estimated 1990 replacement costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation is shown in Table 6-8 and was used to estimate the catalyst replacement costs shown in Table 6-9 for the model plants.

(4) Catalyst Disposal. Catalyst disposal costs were estimated based on a unit disposal cost of $\$15/ft^3$, which was obtained from a zeolite catalyst vendor.[32] This cost was used for each model plant, but the disposal cost may in fact be higher for catalysts that contain heavy metals and are classified as hazardous wastes. The catalyst volume for each model plant was estimated based on information about the catalyst volume for one facility and the assumption that there is a direct relationship between the catalyst volume and the turbine output (i.e., the design space velocity is the same regardless of the SCR size). At one facility, 175 m^3 (6,180 ft^3) of catalyst is used in the SCR with an 83 MW (111,000 hp) turbine.[33] The disposal cost for this catalyst would be \$92,700, using a cost of $\$15/ft^3$.

(5) Ammonia. The annual ammonia (NH_3) requirement is calculated from the annual NO_x reduction achieved by the SCR system. Based on an NH_3/NO_x molar ratio of 1.0, the annual ammonia requirement, in tons, would equal the annual NO_x reduction, in tons, multiplied by the ratio of the molecular weights for NH_3 and NO_x. Anhydrous ammonia with a unit cost of \$360/ton was used.[34,35] The equation to calculate the annual cost for ammonia is shown in Table 6-8.

(6) Dilution Steam. As indicated in Section 5.3.1, steam is used to dilute the ammonia to about 5 percent by volume before injection into the HRSG. According to the OAQPS Control Cost

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Manual, the cost to produce steam, or to purchase it, is about $6/1,000 lb.

(7) Electricity. Electricity requirements to operate such equipment as ammonia pumps and ventilation fans is believed to be small. For one facility, the cost of electricity to operate these components was estimated to make up less than 1 percent of the total annual cost, but it is not clear that the number and size of the fans and pumps represent a typical installation.[27] This cost for electricity is expected to be minor, however, for all installations and was not included in this analysis.

For high-temperature catalysts installed upstream of the HRSG, a blower may be required to inject ambient air into the exhaust to regulate the temperature and avoid temperature excursions above the catalyst design temperature range. The cost to operate the blower is calculated to be 10 percent of the fuel penalty.[35]

(8) Performance Loss. The performance loss due to backpressure from the SCR is approximately 0.5 percent of the turbine's design output.[34-36] To make up for this lost output, it was assumed that electricity would have to be purchased at a cost of $0.06/kWH, as indicated in Table 6-3.

(9) Production Loss. No costs for production losses were included in this analysis. It was assumed that scheduled inspections, cleaning, and other maintenance will coincide with the 760 hr/yr of expected or scheduled downtime. It should be recognized that adding the SCR system increases the overall system complexity and the probability of unscheduled outages. This factor should be taken into account when considering the addition of an SCR system.

(10) Overhead. Standard EPA procedures for estimating annual control costs include overhead costs that are equal to 60 percent of all labor and maintenance material costs.

(11) Property Taxes, Insurance, and Administration. According to standard EPA procedures for estimating annual control costs, property taxes, insurance, and administration

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costs are equal to 4 percent of the total capital investment for the control system.

(12) Capital Recovery. The CRF for SCR was estimated to be 0.13147 based on the assumption that the equipment life is 15 years and the interest rate is 10 percent.

iii. Cost Effectiveness for SCR

As indicated in Section 5.4, virtually all gas turbine installations using SCR to reduce NO_x emissions also incorporate wet injection or low-NO_x combustors. The NO_x emission levels into the SCR, therefore, were in all cases taken to be equal to the controlled NO_x emission levels shown for these control techniques in Tables 6-6 and 6-7. The most common controlled NO_x emission limit for gas-fired SCR applications is 9 ppmv, referenced to 15 percent oxygen. The capital costs used in this analysis are expected to correspond to SCR systems sized to reduce controlled NO_x emissions ranging from 25 to 42 ppmv from gas-fired turbines to a controlled level of approximately 9 ppmv downstream of the SCR. Based on the controlled NO_x emission limits established by the Northeast States for Coordinated Air Use Management (NESCAUM), shown in Table 5-3, these SCR systems would reduce NO_x emissions to 18 ppmv for oil-fired applications. Cost-effectiveness figures for SCR in this analysis are therefore calculated based on controlled NO_x emission levels of 9 and 18 ppmv, corrected to 15 percent oxygen, for gas- and oil-fired SCR model plants, respectively.

Cost effectiveness for SCR used downstream of wet injection or dry low-NO_x combustion is shown in Tables 6-11

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TABLE 6-11. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF GAS TURBINES WIT H WET INJECTION (1990 $)

Model plant	GT model	Turbine output, MW	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $[c]	Cost effective-ness, $/ton
			Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	3.3	42	28.5	9.0	6.10	22.4	242,000	10,800
CON-G-W-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-W-22.7	LM2500	22.7	42	140	9.0	30.0	110	568,000	5,160
CON-G-W-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-W-83.3	ABB GT11N	83.3	25	347	9.0	125	222	1,550,000	6,980
CON-G-W-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-S-22.7	LM2500	22.7	25	83.5	9.0	30.0	53.4	556,000	10,400
CON-G-S-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-S-34.4	LM5000	34.4	25	126	9.0	45.2	80.4	747,000	9,290
CON-G-S-83.3	ABB GT11N	83.3	42	583	9.0	125	458	1,600,000	3,490
CON-G-S-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-161	MS7001F	161	42	1,030	9.0	221	809	2,900,000	3,580
CON-O-W-3.3	Centaur T4500	3.3	60	41.8	18.0	12.5	29.3	244,000	8,340
CON-O-W-26.3	MS5001P	26.3	65	337	18.0	93.3	244	654,000	2,690
CON-O-W-83.3	MS7001E	83.3	65	938	18.0	260	678	1,650,000	2,430
PKR-G-W-3.3	Centaur T4500	3.3	42	7.12	9.0	1.52	5.59	141,000	25,200
PKR-G-W-26.8	MS5001P	26.8	42	53.5	9.0	11.5	42.0	391,000	9,310
PKR-G-W-84.7	MS7001E	84.7	42	148	9.0	31.8	116	1,010,000	8,670
PKR-O-W-3.3	Centaur T4500	3.3	60	10.5	18.0	3.14	7.32	141,000	19,300
PKR-O-W-26.3	MS5001P	26.3	65	84.2	18.0	23.3	60.9	392,000	6,440
PKR-O-W-84.7	MS7001E	84.7	65	234	18.0	64.9	169	1,000,000	5,900
STD-O-W-1.1	Saturn T1500	1.1	60	1.99	18.0	0.60	1.39	103,000	74,000
STD-O-E-28.0	TPM FT4	28.0	50	37.3	18.0	13.4	23.9	448,000	18,800

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-9.

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and 6-12, respectively. For continuous-duty, natural gas-fired

TABLE 6-12. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF DRY LOW-NO_x COMBUSTION (1990 $)

Model plant[a]	GT model	Turbine output, MW	NO_x emissions[b]						Total NO_x removed, tons/yr	Total annual cost, $[d]	Cost effectiveness, $/ton
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv[c]	tons/yr	ppmv	tons/yr	ppmv	tons/yr			
CON-L-3.3-42	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.1	22.4	242,000	10,800
CON-L-4.0-42	Centaur 'H'	4.0	105	83.0	42	33.2	9.0	7.1	26.1	255,000	9,780
CON-L-4.5-42	Taurus	4.5	114	98.7	42	36.4	9.0	7.8	28.6	263,000	9,200
CON-L-8.8-42	Mars T12000	8.8	178	278	42	65.5	9.0	14.0	51.5	336,000	6,530
CON-L-10-42	Mars T14000	10.0	199	341	42	72.1	9.0	15.4	56.6	356,000	6,290
CON-L-3.3-25	Centaur T4500	3.3	130	88.1	25	16.9	9.0	6.1	10.8	240,000	22,100
CON-L-4.0-25	Centaur 'H'	4.0	105	83.0	25	19.8	9.0	7.1	12.6	252,000	19,900
CON-L-4.5-25	Taurus	4.5	114	98.7	25	21.7	9.0	7.8	13.9	260,000	18,800
CON-L-8.8-25	Mars T12000	8.8	178	278	25	39.0	9.0	14.0	25.0	330,000	13,200
CON-L-10-25	Mars T14000	10.0	199	341	25	42.9	9.0	15.4	27.5	350,000	12,800
CON-L-39-25	MS6000	39.0	220	1,480	25	168	9.0	61	108	826,000	7,660
CON-L-83-25	ABB GT11N	83.3	390	5,420	25	347	9.0	125	222	1,550,000	6,970
CON-L-85-25	MS7001E	84.7	154	2,180	25	353	9.0	127	226	1,570,000	6,940
PKR-L-3.3-42	Centaur T4500	3.3	130	22.0	42	7.12	9.0	1.52	5.6	164,000	29,300
PKR-L-4.0-42	Centaur 'H'	4.0	105	20.7	42	8.30	9.0	1.78	6.5	201,000	30,800
PKR-L-4.5-42	Taurus	4.5	114	24.7	42	9.09	9.0	1.95	7.1	207,000	29,000
PKR-L-8.8-42	Mars T12000	8.8	178	69.4	42	16.4	9.0	3.5	12.9	193,000	15,000
PKR-L-10-42	Mars T14000	10.0	199	85.4	42	18.0	9.0	3.9	14.2	207,000	14,600
PKR-L-3.3-25	Centaur T4500	3.3	130	22.0	25	4.24	9.0	1.52	2.7	141,000	52,000
PKR-L-4.0-25	Centaur 'H'	4.0	105	20.7	25	4.94	9.0	1.78	3.2	151,000	47,800
PKR-L-4.5-25	Taurus	4.5	114	24.7	25	5.41	9.0	1.95	3.5	156,000	45,000
PKR-L-8.8-25	Mars T12000	8.8	178	69.4	25	9.75	9.0	3.51	6.2	192,000	30,800
PKR-L-10-25	Mars T14000	10.0	199	85.4	25	10.7	9.0	3.9	6.9	206,000	30,000
PKR-L-39-25	MS6000	39.0	220	371	25	42.1	9.0	15.2	26.9	492,000	18,300
PKR-L-83-25	ABB GT11N	83.3	390	1,350	25	86.8	9.0	31.3	55.6	927,000	16,700
PKR-L-85-25	MS7001E	84.7	154	540	25	88.3	9.0	31.8	56.5	943,000	16,700

[a]See Table 6-7 for model plant legend.
[b]Example NO_x emission calculations are shown in Appendix A.
[c]Referenced to 15 percent oxygen.
[d]From Table 6-10.

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model plants using water or steam injection,the cost effectiveness for SCR ranges from approximately $3,500 to $10,800 per ton of NO_x removed.

The cost-effectiveness range for SCR installed downstream of continuous-duty, natural gas-fired turbines from 3 to 10 MW (4,000 to 13,400 hp) using dry low-NO_x combustion is $6,290 to $10,800 per ton of NO_x removed for an inlet NO_x emission level of 42 ppmv. The cost-effectiveness range for SCR increases for an

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inlet NO_x emission level of 25 ppmv due to the lower NO_x reduction efficiency. For an inlet NO_x level of 25 ppmv, the cost effectiveness ranges from $12,800 to $22,100 per ton of NO_x removed for 3 to 10 MW (4,000 to 13,400 hp) turbines and decreases to $6,940 to $7,660 per ton of NO_x removed for larger turbines ranging from 39 to 85 MW (52,300 to 114,000 hp). As these ranges indicate, the cost effectiveness for SCR is affected by the inlet NO_x emission level and not the type of combustion control technique used for the turbine. The cost effectiveness for continuous-duty, oil-fired model plants ranges from approximately $2,450 to $8,350 per ton of NO_x removed. The SCR cost-effectiveness range for oil-fired applications is lower than that for gas-fired installations in this cost analysis because the same capital costs were used for both fuels (capital costs were not available for applications using only distillate oil fuel). The percent NO_x reduction for oil-fired applications is higher, so the resulting cost-effectiveness figures for oil-fired applications are lower. It should be noted that this higher NO_x reduction for oil-fired applications may require a larger catalyst reactor, at a higher capital cost. As a result, the cost-effectiveness figures may actually be higher than those shown in Table 6-11 for oil-fired applications.

The cost-effectiveness figures are higher for smaller gas turbines because the fixed capital costs associated with the installation of an SCR system have the greatest impact on smaller gas turbines. Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hours per year, cost-effectiveness figures are more than double those for continuous-duty model plants, and they increase even further for model plants operating 1,000 hr/yr.

Because virtually all SCR systems are installed downstream of controlled gas turbines, combined cost-effectiveness figures for wet injection plus SCR and also dry low-NO_x combustion plus SCR have been calculated and are shown in Tables 6-13

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TABLE 6-13. COMBINED COST-EFFECTIVENESS SUMMARY FOR WET INJECTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	NO_x emissions[a]						Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton[c]
			Uncontrolled		Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv	tons/yr[b]	ppmv	tons/yr[b]			
CON-G-W-3.3	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.10	82.0	366,000	4,460
CON-G-W-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	417,000	3,510
CON-G-W-22.7	LM2500	22.7	174	581	42	140	9.0	30	551	1,000,000	1,820
CON-G-W-26.8	MS5001P	26.8	142	723	42	214	9.0	46	677	1,220,000	1,800
CON-G-W-83.3	ABB GT11N	83.3	390	5,410	25	347	9.0	125	5,290	4,460,000	843
CON-G-W-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	3,100,000	1,520
CON-G-S-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	423,000	3,560
CON-G-S-22.7	LM2500	22.7	174	581	25	83.5	9.0	30.0	551	977,000	1,770
CON-G-S-26.8	MS5001P	26.8	142	723	42	214	9.0	45.8	677	1,130,000	1,670
CON-G-S-83.3	LM5000	34.4	185	930	25	126	9.0	45.2	884	1,440,000	1,630
CON-G-S-84.7	ABB GT11N	83.3	390	5,410	42	583	9.0	125	5,290	3,410,000	645
CON-G-S-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	2,780,000	1,360
CON-G-S-161	MS7001F	161	210	5,150	42	1,030	9.0	220	4,930	4,870,000	988
CON-O-W-3.3	Centaur T4500	3.3	179	125	60	42	18.0	12.5	112	387,000	3,450
CON-O-W-26.3	MS5001P	26.3	211	1,090	65	337	18.0	93.3	997	1,410,000	1,410
CON-O-W-83.3	MS7001E	83.3	228	3,290	65	938	18.0	260	3,030	3,230,000	1,070
PKR-G-W-3.3	Centaur T4500	3.3	130	22.0	42	7.1	9.0	1.5	20.5	222,000	10,800
PKR-G-W-26.8	MS5001P	26.8	142	181	42	53.5	9.0	11.5	169	690,000	4,080
PKR-G-W-84.7	MS7001E	84.7	154	543	42	148	9.0	31.8	512	1,710,000	3,340
PKR-O-W-3.3	Centaur T4500	3.3	179	31.2	60	10	18.0	3.14	28.1	228,000	8,130
PKR-O-W-26.3	MS5001P	26.3	211	273	65	84	18.0	23.3	250	751,000	3,000
PKR-O-W-84.7	MS7001E	84.7	228	822	65	234	18.0	64.9	757	1,710,000	2,260
STD-O-W-1.1	Saturn T1500	1.1	150	4.97 122	60	1.99	18.0	0.60	4.4	152,000	34,700
STD-O-E-28.0	TPM FT4	28.0	150		50	37.3	18.0	13.4	109	604,000	5,563

[a]Example NO_x emission calculations are shown in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]Total for both wet injection plus SCR control techniques.

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TABLE 6-14. COMBINED COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NOx COMBUSTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	Annual operating hours	NO_x emissions[a]						Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effectiveness, $/ton
				Uncontrolled		Inlet to SCR		Downstream of SCR				
				ppmv[b]	tons/yr	ppmv	tons/yr[b]	ppmv	tons/yr[b]			
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42	28.5	9.0	6.1	82.0	291,000	3,550
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42	33.2	9.0	7.1	75.8	308,000	4,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42	36.4	9.0	7.8	90.9	319,000	3,510
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42	65.5	9.0	14.0	264	428,000	1,620
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42	72.1	9.0	15.4	326	451,000	1,380
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25	16.9	9.0	6.1	82.0	289,000	3,526
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25	19.8	9.0	7.1	75.8	305,000	4,020
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25	21.7	9.0	7.8	90.9	316,000	3,470
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25	39.0	9.0	14.0	264	422,000	1,600
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25	42.9	9.0	15.4	326	445,000	1,370
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25	168	9.0	60.6	1,420	1,010,000	710
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25	347	9.0	125	5,290	1,840,000	348
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25	353	9.0	127	2,050	1,850,000	902
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42	7.1	9.0	1.5	20.5	213,000	10,400
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42	8.3	9.0	1.8	19.0	254,000	13,400
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42	9.1	9.0	1.9	22.7	263,000	11,600
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42	16.4	9.0	3.5	65.9	285,000	4,320
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42	18.0	9.0	3.9	81.5	302,000	3,710
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25	4.2	9.0	1.5	20.5	190,000	9,300
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25	4.9	9.0	1.8	19.0	204,000	10,800
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25	5.4	9.0	1.9	22.7	212,000	9,300
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25	9.8	9.0	3.5	65.9	284,000	4,300
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25	10.7	9.0	3.9	81.5	301,000	3,700
PKR-L-39-25	MS6000	39.0	2,000	220	371	25	42.1	9.0	15.2	355	680,000	1,910
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25	86.8	9.0	31.3	1,320	1,220,000	924
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25	88.3	9.0	31.8	508	1,220,000	2,400

[a]Example NO_x emission calculations are shown in Appendix A.

[b]Referenced to 15 percent oxygen.

[c]Total for both dry low-NO_x combustion plus SCR control techniques.

and 6-14, respectively. These combined cost-effectiveness

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figures are calculated by dividing the sum of the total annual costs by the

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sum of the annual reduction of NO_x emissions for the combined emission control techniques. For continuous-duty, natural gas-fired model plants, the combined cost-effectiveness figures for wet injection plus SCR range from approximately $650 to $4,500 per ton of NO_x removed. For continuous-duty, oil-fired model plants, the combined cost effectiveness ranges from approximately $1,100 to $3,550 per ton of NO_x removed. The combined cost-effectiveness figures for dry low-NO_x combustion plus SCR for continuous-duty, natural gas-fired model plants range from approximately $350 to $3,550 per ton of NO_x removed.

The combined cost-effectiveness figures increase with decreasing turbine size and annual operating hours. Data were not available to quantify the wet injection requirements and controlled emissions levels for oil-fired turbines with low-NO_x combustors, so cost-effectiveness figures were not tabulated for this control scenario.

d. OFFSHORE TURBINES

The only available information about the cost of NO_x controls for offshore gas turbines was presented in a report prepared for the Santa Barbara County Air Pollution Control District (SBCAPCD) in California.[37] The performance and cost of about 20 NO_x control techniques for a 2.8 MW (3,750 hp) turbine were described in the report. Wet injection and SCR were included in the analysis; low-NO_x combustors were not. The costs from the report are presented in Table 6-15

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TABLE 6-15. PROJECTED WET INJECTION AND SCR COSTS FOR AN OFFSHORE GAS TURBINE[a]

	Wet injection costs	SCR costs
Capital cost, $	70,000	585,000
Annual costs, $/yr		
Ammonia	N/A[b]	3,050[c]
Catalyst replacement	N/A	28,000
Operating and maintenance[d]	24,600	18,000
Fuel penalty[e]	10,500	5,000
Capital recovery[f]	14,000	117,000
Total annual costs, $/yr	49,100	171,000

[a]Costs are for a 2.8 MW gas turbine and are obtained from Reference 37.
[b]N/A = Not applicable.
[c]Ammonia cost is based on $150/ton and 0.4 lb NH_3/lb NO_X.
[d]Operating and maintenance cost for SCR is estimated as 3 percent of the total capital investment.
[e]Fuel penalty is estimated as 2 percent of the annual fuel consumption for wet injection and 1 percent for SCR.
[f]Capital recovery is estimated based on an equipment life of 8 years and an interest rate of 13 percent.

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without adjustment because there is insufficient cost information to know what adjustments need to be made. Additionally, insufficient information is available to scale up these costs for larger turbines. The water and steam injection costs and SCR costs for offshore applications are discussed in Sections 6.4.1 and 6.4.2, respectively.

i. Wet Injection

The report prepared for SBCAPCD assumed water injection costs are the same as steam injection costs. The report did not describe the components in the capital cost analysis for these injection systems, but the results are much lower than those that

would be estimated by the procedures described in Section 6.1.1 of this report. The authors may have assumed that the engine-mounted injection equipment cost was included in the turbine capital cost and that a less rigorous water treatment process is installed. Annual costs are also much lower than those that would be estimated by the procedures described in Section 6.1.2 of this report. There are at least three reasons for the difference: (1) the low capital cost leads to a low CRF, even though the turbine life was assumed to be only 8 years; (2) overhead costs and taxes, insurance, and administration costs are not considered; and (3) the capacity factor is only 50 percent (i.e., about 4,400 hr/yr, vs. 8,000 hr/yr, as in Section 6.1.2). The turbine life was only 8 years, which may correspond to a typical service life of an offshore platform.

ii. Selective Catalytic Reduction

The total capital costs presented in the report for SBCAPCD are similar to those that would be estimated by the procedures in Section 6.2.1 of this report. However, it appears that $150,000 of the total in Reference 37 is for structural modifications to the platform and $75,000 is for retrofit installation. When the difference in the load factor is taken into account, some of the annual costs are similar to those that would be estimated by the procedures in Section 6.2.2 for a similarly sized turbine. The catalyst replacement cost, however, is much lower; neither the type of catalyst nor the replacement frequency were identified. Ammonia costs are lower because the uncontrolled NO_x emission level was assumed to be 110 ppmv instead of 150 ppmv and because a unit cost of $150/ton was used instead of $400/ton. The reference does not indicate whether or not catalyst disposal, overhead, taxes, freight, and administration costs were considered. Capital recovery costs are higher because the equipment life is assumed to be only 8 years on the offshore platform.

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7..0 ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the nitrogen oxide (NO_x) emissions control techniques described in Chapter 5.0. These control techniques are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR). The impacts of the control techniques on air pollution, solid waste disposal, water pollution, and energy consumption are discussed.

The remainder of this chapter is organized in five sections. Section 7.1 presents the air pollution impacts; Section 7.2 presents the solid waste disposal impacts; Section 7.3 presents the water pollution impacts; and Section 7.4 presents the energy consumption impacts. References for the chapter are listed in Section 7.5.

a. AIR POLLUTION

i. Emission Reductions

Applying any of the control techniques discussed in Chapter 5 will reduce NO_x emissions from gas turbines. These emission reductions were estimated for the model plants presented in Table 6-1 and are shown in Table 7-1. For each model plant, the uncontrolled and controlled emissions, emission reductions, and percent reductions are presented. The following paragraphs discuss NO_x emission reductions for each control technique.

Nitrogen oxide emission reductions for water or steam injection are estimated as discussed in Section 6.1.3. The percent reduction in emissions from uncontrolled levels varies for each model plant ranging, from 60 to 96 percent. This reduction depends on each model's uncontrolled emissions, the

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TABLE 7-1. MODEL PLANT UNCONTROLLED AND CONTROLLED NO_x EMISSIONS FOR AVAILABLE NO_x CONTROL TECHNIQUES

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
Centaur T4500	8,000	Water	Emissions, tons/yr	88.1	28.5	28.5	16.9	NA[d]	6.10	2.92
3.3 MW			Reduction, tons/yr		59.6	59.6	71.2	_	22.4	
Gas fuel			Total reduction, %		68%	68%	81%	_	93%	
501-KB5	8,000	Water	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		91.8	_	_	_	26.9	
Gas fuel			Total reduction, %		73%	_	_	_	94%	
LM2500	8,000	Water	Emissions, tons/yr	581	140	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		441	_	_	_	110	
Gas fuel			Total reduction, %		76%	_	_	_	95%	
MS5001P	8,000	Water	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	_	_	_	168	
Gas fuel			Total reduction, %		70%	_	_	_	94%	
ABB GT11N	8,000	Water	Emissions, tons/yr	5,410	347	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		5,060	_	5060	5290	222	
Gas fuel			Total reduction, %		94%	_	94%	98%	98%	
MS7001E	8,000	Water	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	_	1820	2040	466	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
501-KB5	8,000	Steam	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		92	_	_	_	26.9	
Gas fuel			Total reduction, %		73%	_	_	_	94%	
LM2500	8,000	Steam	Emissions, tons/yr	581	83.5	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		498	_	_	_	53.5	
Gas fuel			Total reduction, %		86%	_	_	_	95%	
MS5001P	8,000	Steam	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	_	_	_	168	
Gas fuel			Total reduction, %		70%	_	_	_	94%	

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TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
LM5000	8,000	Steam	Emissions, tons/yr	930	126	NA	NA	NA	45.2	20.5
34.4 MW			Reduction, tons/yr		804	_	_	_	80.8	
Gas fuel			Total reduction, %		86%	_	_	_	95%	
ABB GT11N	8,000	Steam	Emissions, tons/yr	5,410	583	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		4830	_	5060	5290	458	
Gas fuel			Total reduction, %		89%	_	94%	98%	98%	
MS7001E	8,000	Steam	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	_	1820	2040	466	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
MS7001F	8,000	Steam	Emissions, tons/yr	5,150	1,030	NA	610	NA	221	71.7
161 MW			Reduction, tons/yr		4120	_	4540	_	809	
Gas fuel			Total reduction, %		80%	_	88%	_	96%	
Centaur T4500	8,000	Water	Emissions, tons/yr	125	41.8	NA	NA	NA	12.5	2.9
3.3 MW			Reduction, tons/yr		83.2	_	_	_	29.3	
Oil fuel			Total reduction, %		67%	_	_	_	90%	
MS5001P	8,000	Water	Emissions, tons/yr	1,090	337	NA	NA	NA	46.6	20.4
26.3 MW			Reduction, tons/yr		753	_	_	_	290	
Oil fuel			Total reduction, %		69%	_	_	_	96%	
MS7001E	8,000	Water	Emissions, tons/yr	3,290	938	NA	NA	NA	130	49.6
83.3 MW			Reduction, tons/yr		2350	_	_	_	808	
Oil fuel			Total reduction, %		71%	_	_	_	96%	
Centaur T4500	2,000	Water	Emissions, tons/yr	22.0	7.1	NA	NA	NA	1.5	0.7
3.3 MW			Reduction, tons/yr		14.9	_	_	_	6	
Gas fuel			Total reduction, %		68%	_	_	_	93%	
MS5001P	2,000	Water	Emissions, tons/yr	181	53.5	NA	NA	NA	11.5	5.1
26.8 MW			Reduction, tons/yr		128	_	_	_	42	
Gas fuel			Total reduction, %		70%	_	_	_	94%	

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TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
MS7001E	2,000	Water	Emissions, tons/yr	543	148	NA	88	32	31.8	12.4
84.7 MW			Reduction, tons/yr		395	_	455	511	116	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
Centaur T4500	2,000	Water	Emissions, tons/yr	31.2	10.0	NA	NA	NA	3.14	0.7
3.3 MW			Reduction, tons/yr		21.2	_	_	_	6.9	
Oil fuel			Total reduction, %		68%	_	_	_	90%	
MS5001P	2,000	Water	Emissions, tons/yr	273	84	NA	NA	NA	23.3	5.1
26.8 MW			Reduction, tons/yr		189	_	_	_	61	
Oil fuel			Total reduction, %		69%	_	_	_	91%	
MS7001E	2,000	Water	Emissions, tons/yr	822	234	NA	NA	NA	64.9	12.4
84.7 MW			Reduction, tons/yr		588	_	_	_	169	
Oil fuel			Total reduction, %		72%	_	_	_	92%	
SATURN T1500	1,000	Water	Emissions, tons/yr	5.00	1.99	NA	NA	NA	0.30	0.13
1.1 MW			Reduction, tons/yr		3	_	_	_	1.7	
Oil fuel			Total reduction, %		60%	_	_	_	94%	
TPM FT4	1,000	Water-in-	Emissions, tons/yr	977	37.3	NA	NA	NA	6.72	NC[e]
28.0 MW		oil	Reduction, tons/yr		940	_	_	_	30.6	_
Oil fuel		emulsion	Total reduction, %		96%	_	_	_	99%	_

[a]Uncontrolled and controlled NO_x emissions are from cost-effectiveness tables in Chapter 6.

[b]Controlled NO_x emission level for wet injection plus SCR is 9 ppmv for natural gas fuel and 18 ppmv for distillate oil fuel.

[c]Ammonia emissions, in tons per year = (SLIP, ppmv) x (MM/1,000,000) x (GT exhaust,lb/sec) x (MW NH3 = 15/MW exhaust = 28.6) x (3,600 sec/hr) x (ton/2,000 lb) x (annual operating hrs).

[d]NA-control technology not available for this model plant.

[e]NC-data not available to calculate emissions for this control scenario.

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water-to-fuel ratio (WFR), and type of fuel and whether water or steam is injected.

Achievable emission levels from gas turbines using dry low-NO_x combustors were obtained from manufacturers. Controlled NO_x levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, were reported by the various turbine manufacturers, and each of these levels is shown in Table 7-1, where applicable, for each model plant. The percent reduction in NO_x emissions from uncontrolled levels for gas turbines using these combustors ranges from 68 to 98 percent. Virtually all SCR units installed in the United States are used in combination with either wet controls or combustion controls. For this analysis, emission reductions were calculated for SCR in combination with water or steam injection. Using the turbine manufacturers' guaranteed NO_x emissions figures for wet injection and a controlled NO_x emission level of 9 ppmv, referenced to 15 percent oxygen, exiting the SCR, the percent reduction in NO_x emissions for this combination of control techniques ranges from 93 to 99 percent.

Estimated ammonia (NH_3) emissions, in tons per year, corresponding to ammonia slip from the SCR system are also shown in Table 7-1. These estimates are based on an ammonia slip level of 10 ppmv, consistent with information and data presented in Section 5.4. For continuous-duty model plants, the annual NH_3 emissions range from approximately 3 tons for a 3.3 megawatt (MW) (4,425 horsepower [hp]) model plant to 72 tons for a 160 MW (215,000 hp) model plant.

ii. Emissions Trade-Offs

The formation of both thermal and fuel NO_x depends upon combustion conditions. Water/steam injection, lean combustion, and reduced residence time modify combustion conditions to reduce the amount of NO_x formed. These combustion modifications may increase carbon monoxide (CO) and unburned hydrocarbon (HC) emissions. Using SCR to control NO_x emissions produces ammonia emissions. The impacts of these NO_x controls on CO, HC, and ammonia emissions are discussed below.

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(1) Impacts of Wet Controls on CO and HC Emissions. As discussed in Section 5.1.5, wet injection may increase CO and HC emissions. Injecting water or steam into the flame area of a turbine combustor lowers the flame temperature and thereby reduces NO_x emissions. This reduction in temperature to some extent inhibits complete combustion, resulting in increased CO and HC emissions. Figure 5-12 shows the impact of water and steam injection on CO emissions for production gas turbines.[2] The impact of steam injection on CO emissions is less than that of water injection. As seen in Figure 5-12, CO emissions increase with increasing WFR's. Wet injection increases HC emissions to a lesser extent than it increases CO emissions. Figure 5-13 shows the impact of water injection on HC emissions for one turbine. In cases where water and steam injection result in excessive CO and HC emissions, an oxidation catalyst (add-on control) can be installed to reduce these emissions by converting the CO and HC to water (H_2O) and carbon dioxide (CO_2).

(2) Impacts of Combustion Controls on CO and HC Emissions. As discussed in Section 5.2.1, the performance of lean combustion in limiting NO_x emissions relies in part on reduced equivalence ratios. As the equivalence ratio is reduced below the stoichiometric level of 1.0, combustion flame temperatures drop, and as a result NO_x emissions are reduced. Shortening the residence time in the high-temperature flame zone also will reduce the amount of thermal NO_x formed. These lower equivalence ratios and/or reduced residence time, however, may result in incomplete combustion, which may increase CO and HC emissions. The extent of the increase in CO and HC emissions is specific to each turbine manufacturer's combustor designs and therefore varies for each turbine model. As with wet injection, if necessary, an oxidation catalyst can be installed to reduce excessive CO and HC emissions by converting the CO and HC to CO_2 and H_2O.

(3) Ammonia Emissions from SCR. The SCR process reduces NO_x emissions by injecting NH_3 into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form H_2O and nitrogen

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(N_2). The NO_x removal efficiency of this process is partially dependent on the NH_3/NO_x ratio. Increasing this ratio reduces NO_x emissions but increases the probability that unreacted ammonia will pass through the catalyst unit into the atmosphere (known as ammonia "slip"). Some ammonia slip is unavoidable because of ammonia injection control limitations and imperfect distribution of the reacting gases. A properly designed SCR system will limit ammonia slip to less than 10 ppmv (see Section 5.4).

b. SOLID WASTE DISPOSAL

Catalytic materials used in SCR units for gas turbines include precious metals (e.g., platinum), zeolites, and heavy metal oxides (e.g., vanadium, titanium). Vanadium pentoxide, the most commonly used SCR catalyst in the United States, is identified as an acute hazardous waste under RCRA Part 261, Subpart D - Lists of Hazardous Wastes. The Best Demonstrated Available Technology (BDAT) Treatment Standards for Vanadium P119 and P120 states that spent catalysts containing vanadium pentoxide are not classified as hazardous waste.[1] State and local regulatory agencies, however, are authorized to establish their own hazardous waste classification criteria, and spent catalysts containing vanadium pentoxide may be classified as a hazardous waste in some areas. Although the actual amount of vanadium pentoxide contained in the catalyst bed is small, the volume of the catalyst unit containing this material is quite large and disposal can be costly. Where classified by State or local agencies as a hazardous waste, this waste may be subject to the Land Disposal Restrictions in 40 CFR Part 268, which allows land disposal only if the hazardous waste is treated in accordance with Subpart D - Treatment Standards. Such disposal problems are not encountered with other catalyst materials, such as precious metals and zeolites, because these materials are not hazardous wastes.

c. WATER USAGE AND WASTE WATER DISPOSAL

Water availability and waste water disposal are environmental factors to be considered with wet injection. The impact of water usage on the water supply at some remote sites,

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in small communities, or in areas where water resources may be limited is an environmental factor that should be examined when considering wet injection. The volume of water required for wet injection is shown in Table 7-2

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TABLE 7-2. WATER AND ELECTRICITY CONSUMPTION FOR NO_x CONTROL TECHNIQUES

Gas turbine model[a]	Turbine power output, MW	Annual operating hours	Fuel type	Type of emission control	Total water flow, gal/min[a]	Waste water flow, gal/min[b]	Water pump power, kW[c]	Wet injection power consumption, kW-hr/yr[d]	SCR power penalty, kW-hr/yr[e]
Centaur T4500	3.3	8,000	Gas	Water inj.	2.5	0.73	0.40	3,220	132,000
501-KB5	4.0	8,000	Gas	Water inj.	3.94	1.14	0.63	5,070	160,000
LM2500	22.7	8,000	Gas	Water inj.	14.8	4.29	2.38	19,100	908,000
MS5001P	26.8	8,000	Gas	Water inj.	22.2	6.44	3.57	28,600	1,070,000
ABB GT11N	83.3	8,000	Gas	Water inj.	154	44.7	24.8	198,000	3,330,000
MS7001E	84.7	8,000	Gas	Water inj.	69.2	20.1	11.1	89,100	3,390,000
501-KB5	4.0	8,000	Gas	Steam inj.	7.38	2.14	1.19	9,510	160,000
LM2500	22.7	8,000	Gas	Steam inj.	29.5	8.56	4.75	38,000	908,000
MS5001P	26.8	8,000	Gas	Steam inj.	33.3	9.66	5.36	42,900	1,070,000
LM5000	34.4	8,000	Gas	Steam inj.	50.8	14.7	8.18	65,400	1,380,000
ABB GT11N	83.3	8,000	Gas	Steam inj.	178	51.6	28.7	229,000	3,330,000
MS7001E	84.7	8,000	Gas	Steam inj.	104	30.2	16.7	134,000	3,390,000
MS7001F	161	8,000	Gas	Steam inj.	199	57.7	32.0	256,000	6,440,000
Centaur T4500	3.3	8,000	Oil	Water inj.	2.76	0.80	0.44	3,550	132,000
MS5001P	26.3	8,000	Oil	Water inj.	26.7	7.74	4.30	34,400	1,050,000
MS7001E	83.3	8,000	Oil	Water inj.	63.8	18.5	10.3	82,200	833,000
Centaur T4500	3.3	2,000	Gas	Water inj.	2.50	0.73	0.40	3,220	33,000
MS5001P	26.3	2,000	Gas	Water inj.	22.2	6.44	3.57	28,600	263,000
MS7001E	84.7	2,000	Gas	Water inj.	69.2	20.1	11.1	89,100	847,000
Centaur T4500	3.3	2,000	Oil	Water inj.	2.76	0.80	0.44	3,550	33,000
MS5001P	26.3	2,000	Oil	Water inj.	26.7	7.74	4.30	34,400	263,000
MS7001E	84.7	2,000	Oil	Water inj.	63.8	18.5	10.3	82,200	847,000
SATURN T1500	1.1	1,000	Oil	Water inj.	0.81	0.23	0.13	1,040	5,500
TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	21.7	6.29	3.49	27,900	140,000

[a]From Table 6-2.

[b]Calculated as 29 percent of the total water flow.

[c]Power requirement for water pump is calculated as shown in Section 6.1.2.2.

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for each model plant.

Water purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine. Water treatment systems are used to achieve water quality specifications set by gas turbine manufacturers. Table 5-4 summarizes these specifications for six manufacturers.

Discharges from these water treatment systems have a potential impact on water quality. As indicated in Section 6.1, approximately 29 percent of the treated water flow rate (22.5 percent of the raw water flow rate) is considered to be discharged as wastewater. The wastewater flow rates for each of the model plants with a water or steam injection control system are estimated using this factor, and the results are presented in Table 7-2. The wastewater contains increased levels of those pollutants in the raw water (e.g., calcium, silica, sulfur, as listed in Table 5-4) that are removed by the water treatment system, along with any chemicals introduced by the treatment process. Based on a wastewater flowrate equal to 29 percent of the influent raw water, the concentration of pollutants discharged from the water treatment system is approximately three times higher than the pollutant concentrations in the raw water.

The impacts of these pollutants on water quality are site-specific and depend on the type of water supply and on the discharge restrictions. Influent water obtained from a municipality will not contain high concentrations of pollutants. However, surface water or well water used at a remote site might contain high pollutant concentrations and may require additional pretreatment to meet the water quality specifications set by

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manufacturers. This additional pretreatment will increase the pollutant concentrations of the wastewater discharge. Wastewater discharges to publicly-owned treatment works (POTW's) must meet the requirements of applicable Approved POTW Pretreatment Programs.

d. ENERGY CONSUMPTION

Additional fuel and electrical energy is required over baseline for wet injection controls, while additional electrical energy is required for SCR controls. The following paragraphs discuss these energy consumption impacts.

Injecting water or steam into the turbine combustor lowers the net cycle efficiency and increases the power output of the turbine. The thermodynamic efficiency of the combustion process is reduced because energy that could otherwise be available to perform work in the turbine must now be used to heat the water/steam. This lower efficiency is seen as an increase in fuel use. Table 5-10 shows the impacts of wet injection on gas turbine performance for one manufacturer. This table shows a 2 to 4 percent loss in efficiency associated with WFR's required to achieve NO_x emission levels of 25 to 42 ppmv in gas turbines burning natural gas. The actual efficiency loss is specific to each turbine model but generally increases with increasing WFR's and is higher for water injection than for steam injection (additional energy is required to heat and vaporize the water). One exception to this efficiency penalty occurs with steam injection, in which exhaust heat from the gas turbine is used to generate the steam for injection. If the heat recovered in generating the steam would otherwise be exhausted to atmosphere, the result is an increase in net cycle efficiency.

The energy from the increased mass flow and heat capacity of the injected water/steam can be recovered in the turbine, resulting in an increase in power output accompanying the reduced efficiency of the turbine (shown in Table 5-10 for one manufacturer). This increase in power output can be significant and could lessen the impact of the loss in efficiency if the facility has a demand for the available excess power.

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Water and steam injection controls also require additional electrical energy to operate the water injection feed water pumps. The annual electricity usage for each model is the product of the pump power demand, discussed in Section 6.1.2.2, and the annual hours of operation. Table 7-2 summarizes this electricity usage for each of the model plants.

For SCR units, additional electrical energy is required to operate ammonia pumps and ventilation fans. This energy requirement, however, is believed to be small and was not included in this analysis.

The increased back-pressure in the turbine exhaust system resulting from adding an SCR system reduces the power output from the turbine. As discussed in Section 6.3.2.9, the power output is typically reduced by approximately 0.5 percent. This power penalty has been calculated for each model plant and is shown in Table 7-2.

e. REFERENCE FOR CHAPTER 7

1.. 55 FR 22276, June 1, 1990.

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APPENDIX A

Exhaust NO_x emission levels were provided by gas turbine manufacturers in units of parts per million, by volume (ppmv), on a dry basis and corrected to 15 percent oxygen. A method of converting these exhaust concentration levels to a mass flow rate of pounds of NO_x per hour (lb NO_x/hr) was provided by one gas turbine manufacturer.[1] This method uses an emission index ($EINO_x$), in units of lb NO_x/1,000 lb fuel, which is proportional to the exhaust NO_x emission levels in ppmv by a constant, K. The relationship between $EINO_x$ and ppmv for NO_x emissions is stated in Equation 1 below and applies for complete combustion of a hydrocarbon fuel and combustion air having no CO_2 and an O_2 mole percent of 20.95:

$$\frac{NO_x \text{ Ref. } 15\% \ 0_2}{EINO_x} = K \qquad \text{Equation 1}$$

where: NO_x Ref. 15% 0_2 = NO_x, ppmvd @15% O_2 (provided by gas turbine manufacturers);

$EINO_x$ = NO_x emission index, lb NO_x/1,000 lb fuel; and

K = constant, based on the molar hydrocarbon

ratio of the fuel.

The derivation of Equation 1 was provided by the turbine manufacturer and is based on basic thermodynamic laws and supported by test data provided by the manufacturer. According to the manufacturer, this equation can be used to estimate NO_x emissions for operation with or without water/steam injection.

Equation 1 shows that NO_x emissions are dependent only upon the molar hydrocarbon ratio of the fuel and are independent of the air/fuel ratio (A/F). The equation therefore is valid for all gas turbine designs for a given fuel. The validity of this approach to calculate NO_x emissions was supported by a second

turbine manufacturer.[2] Values for K were provided for several fuels and are given below:[1,2]

Pipeline quality natural gas:

K = 12.1

Distillate fuel oil No. 1 (DF-1):

K = 13.1

Distillate fuel oil No. 2 (DF-2):

K = 13.2

Jet propellant No. 4 (JP-4):

K = 13.0

Jet propellant No. 5 (JP-5):

K = 13.1

Methane:

K = 11.6

The following examples are provided for calculating NO_x emissions on a mass basis, given the fuel type and NO_x emission level, in ppmv, dry (ppmvd), and corrected to 15 percent O_2.

Example 1. Natural gas fuel

Gas turbine:
Solar Centaur 'H'
Power output:
4,040 kW
Heat rate:
12,200 Btu/kW-hr
NO_x emissions:
105 ppmvd, corrected to 15 percent O_2
Fuel:

Natural gas

- lower heating value = 20,610 Btu/lb

- K = 12.1

Fuel flow:

$$4{,}040 \text{ kW} \times \frac{12{,}200 \text{ Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{20{,}610 \text{ Btu}} = 2{,}391 \text{ lb/hr}$$

From Equation 1:

$$\frac{105}{EINO_x} = 12.1$$

NO_x emissions, lb/hr:

$$2{,}391 \frac{\text{lb fuel}}{\text{hr}} \times \frac{8.68 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 20.8 \frac{\text{lb } NO_x}{\text{hr}}$$

Example 2. Distillate oil fuel

Gas turbine:

General Electric LM2500

Power output:

22670 kW

Heat rate:

9296 Btu/kW-hr

No_x emissions: 345 ppmvd, corrected to 15 percent O_2

Fuel:

Distillate oil No. 2

-

lower heating value = 18,330 Btu/lb

- K = 13.2

Fuel flow:

$$22{,}670 \text{ kW} \times 9296 \frac{\text{Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{18{,}330 \text{Btu}} = 11{,}500 \text{ lb/hr}$$

From Equation 1:

$$\frac{345}{EINO_x} = 13.2$$

NO_x emissions, lb/hr:

$$11{,}500 \frac{\text{lb fuel}}{\text{hr}} \times \frac{26.1 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 300 \frac{\text{lb } NO_x}{\text{hr}}$$

REFERENCES FOR APPENDIX A:

1. Letter and attachments from Lyon, T.F., General Electric Aircraft Engines, to Snyder, R.B., MRI. December 6, 1991. Calculation of NO_x emissions from gas turbines.

2. Letter and attachments from Hung, W.S., Solar Turbines, Inc., to Snyder, R.B., MRI. December 17, 1991. Calculation of NO_x emissions from gas turbines.

APPENDIX B. COST DATA AND METHODOLOGY USED TO PREPARE COST FIGURES PRESENTED IN CHAPTER 6

APPENDIX B. RAW COST DATA AND COST ALGORITHMS

The maintenance costs for water injection and several of the SCR costs presented in Chapter 5 are based on information from turbine manufacturers and other sources that required interpretation and analysis. Information about additional gas turbine maintenance costs associated with water injection is presented in Section B.1. Information on SCR capital costs, catalyst replacement and disposal costs, and maintenance costs is presented in Section B.2. References are listed in Section B.3.

B.1 WATER INJECTION MAINTENANCE COSTS

Information from each manufacturer and the applicable analysis procedures used to develop maintenance cost impacts for water injection are described in the following sections.

B.1.1 Solar

This manufacturer indicated that the annual maintenance cost for the Centaur is $16,000/year.[1] The cost for the Saturn was estimated to be $8,000.[2] This $8,000 cost was then prorated for operation at 1,000/hr/yr, and was multiplied by 1.3 to account for the additional maintenance required for oil fuel.

B.1.2 Allison

Maintenance costs for water injection were provided by a company that packages Allison gas turbines for stationary applications. This packager stated that for the 501 gas turbine model, a maintenance contract is available which covers all maintenance materials and labor costs associated with the turbine, including all scheduled and unscheduled activities. The cost of this contract for the 501 model is $0.0005 to $0.0010 per KW-hour (KWH) more for water injection than for a turbine not using water injection.[3] For an installation operating 8,000 hours per year at a base-rated output of 4,000 KW, and using an average cost of $0.00075 per KWH, the annual additional maintenance cost is $24,000. By the nature of the contract offered, this figure represents a worst case scenario and to some extent may exceed the actual incremental maintenance costs that would be expected for water injection for this turbine.

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B.1.3 General Electric

General Electric (GE) offers both aero-derivative type (LM-series models) and heavy-duty type (MS-series models) gas turbines. For the aero-derivative turbines, GE states that the incremental maintenance cost associated with water injection is $3.50 per fired hour. This cost is used to calculate the maintenance cost for water injection for GE aeroderivative turbines. No figures were provided for steam injection and no maintenance cost was used for steam injection with these turbines.[4]

Water injection also impacts the maintenance costs for the heavy-duty MS-series models. Costs associated with more frequent maintenance intervals required for models using water injection have been calculated and summarized below. A GE representative stated that the primary components which must be repaired at each maintenance interval are the combustor liner and transition pieces.[5] Approximate costs to repair these pieces were provided by GE.[5] For this analysis, the maximum cost estimates were used to calculate annual costs to accommodate repairs that may be required periodically for injection nozzles, cross-fire tubes, and other miscellaneous hardware. According to GE, a rule of thumb is that if the repair cost exceeds 60 percent of the cost of a new part, the part is replaced.[5] The cost of a replacement part is therefore considered to be 1.67 times the maximum repair cost. If water purity requirements are met, there are no significant adverse impacts on maintenance requirements on other turbine components, and hot gas path inspections and major inspection schedules are not impacted.[5] Combustion repair schedules, material costs, and labor hours are shown in Table B-1. Scheduled maintenance intervals for models with water injection were provided in Reference 6. Corresponding maintenance intervals for models with steam injection were assumed to be the same as models with no wet injection; these scheduled maintenance intervals were provided in Reference 7. Using the information in Table B-1, the total annual cost is

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calculated and shown in Table B-2 for three GE heavy-duty turbine models.

B.1.4 Asea Brown Boveri

This manufacturer states there are no maintenance impacts associated with water injection.[8]

B.2 SCR COSTS

The total capital investment, catalyst replacement, and maintenance costs are estimated based on information from the technical literature. The cost algorithms are described in the following sections.

B.2.1 Total Capital Investment

Total capital investment costs, which include purchased costs and installation costs, were available for SCR systems for combined cycle and cogeneration applications from five sources.[9-13] These costs were scaled to 1990 costs using the Chemical Engineering annual plant cost indexes and are applicable to SCR systems in which the catalyst was placed within the heat recovery steam generator (HRSG). In addition, estimated capital investment costs were available from one source for SCR systems in which a high temperature zeolite catalyst is installed upstream of the HRSG.[14] Both the original data and the scaled costs are presented in Table B-3. The scaled costs were plotted against the turbine size and this plot is shown in Figure B-1. A linear regression analysis was performed to determine the equation for the line that best fits the data. This equation was used to estimate the total capital investment for SCR for the model plants and was extrapolated to estimate the costs for model plants larger than 90 MW.

B.2.2 Maintenance Costs

Maintenance costs for SCR controls were obtained from four literature sources, although 6 of the 14 points were obtained from one article.[9,11-13] These costs were scaled to 1990 costs assuming an inflation rate of five percent per year. All of the data are for turbines that use natural gas fuel. Because there are no data to quantify differences in SCR maintenance costs for oil-fired applications, the available data for operation on

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natural gas were used for both fuels. Both the original data and the scaled costs are presented in Table B-4. The scaled costs were plotted versus the turbine size in Figure B-2. The equation for the line through the data was determined by linear regression, and it was used to estimate the maintenance costs for the model plants.

B.2.3 Catalyst Replacement Costs

Catalyst replacement costs were obtained from three articles for nine gas turbine installations.[9,11,13] Combined catalyst replacement and disposal costs were obtained for another six gas turbine installations from one article.[12] The disposal costs for these six gas turbine installations were estimated based on estimated catalyst volumes and a unit disposal cost of $\$15/ft^3$, given in Reference 15.

The catalyst volumes were estimated assuming there is a direct relationship between the volume and the turbine size; the catalyst volume stated in Reference 16 for one 83 MW turbine is 175 m^3. The resulting disposal costs for these six facilities were subtracted from the combined replacement and disposal costs to estimate the replacement-only costs. All of the replacement costs were scaled to 1990 costs assuming an inflation rate of 5 percent per year. The original data and the scaled costs are presented in Table B-5, and the scaled replacement costs were also plotted versus the turbine size in Figure B-3. Linear regression was used to determine the equation for the line through the data. This equation was used to estimate the catalyst replacement costs for the model plants.

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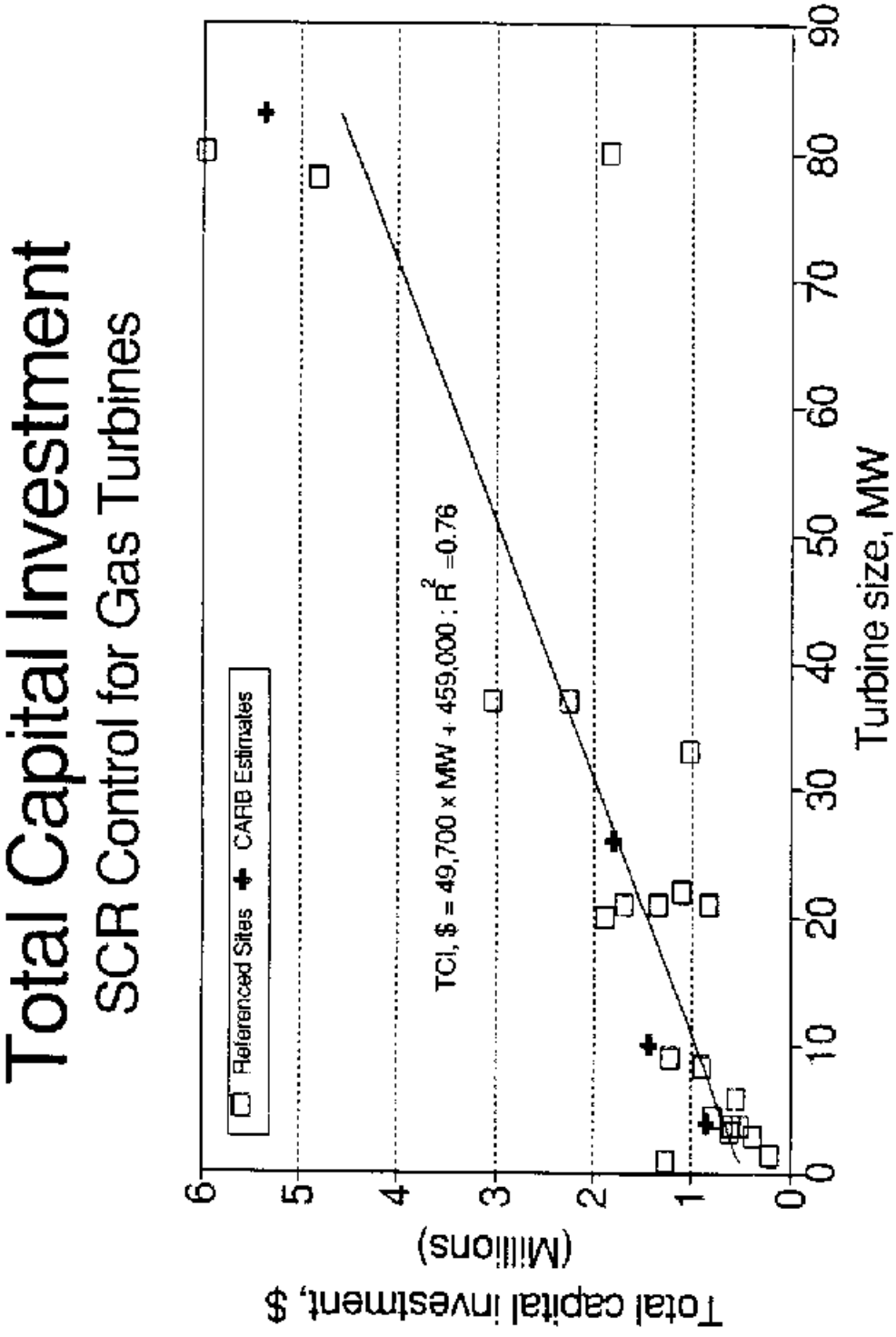


Figure B-1. Total Capital Investment for SCR Control of NO_x Emissions from Gas Turbines

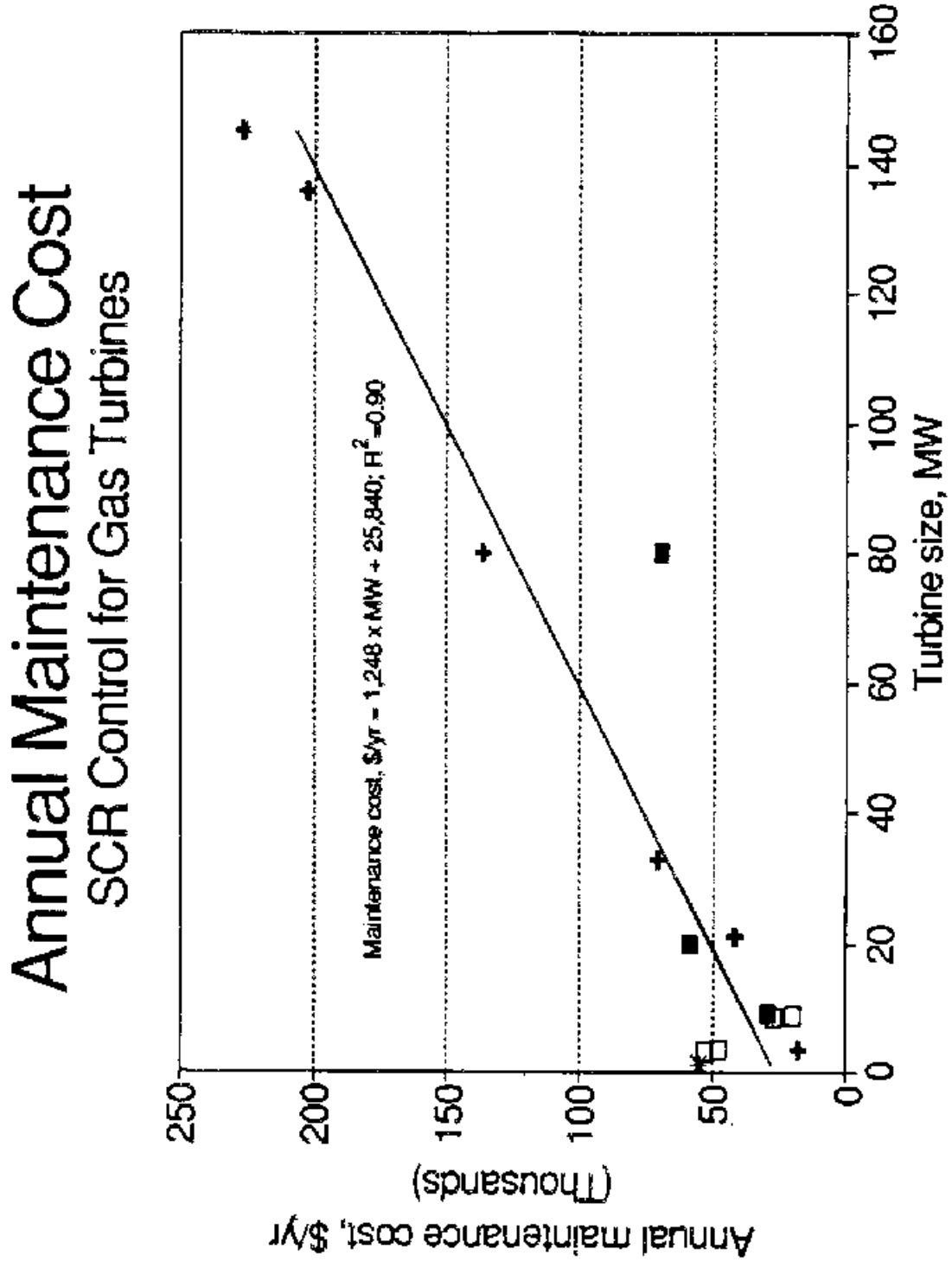


Figure B-2. Annual Maintenance Cost for SCR Control of NO_x Emissions from Gas Turbines

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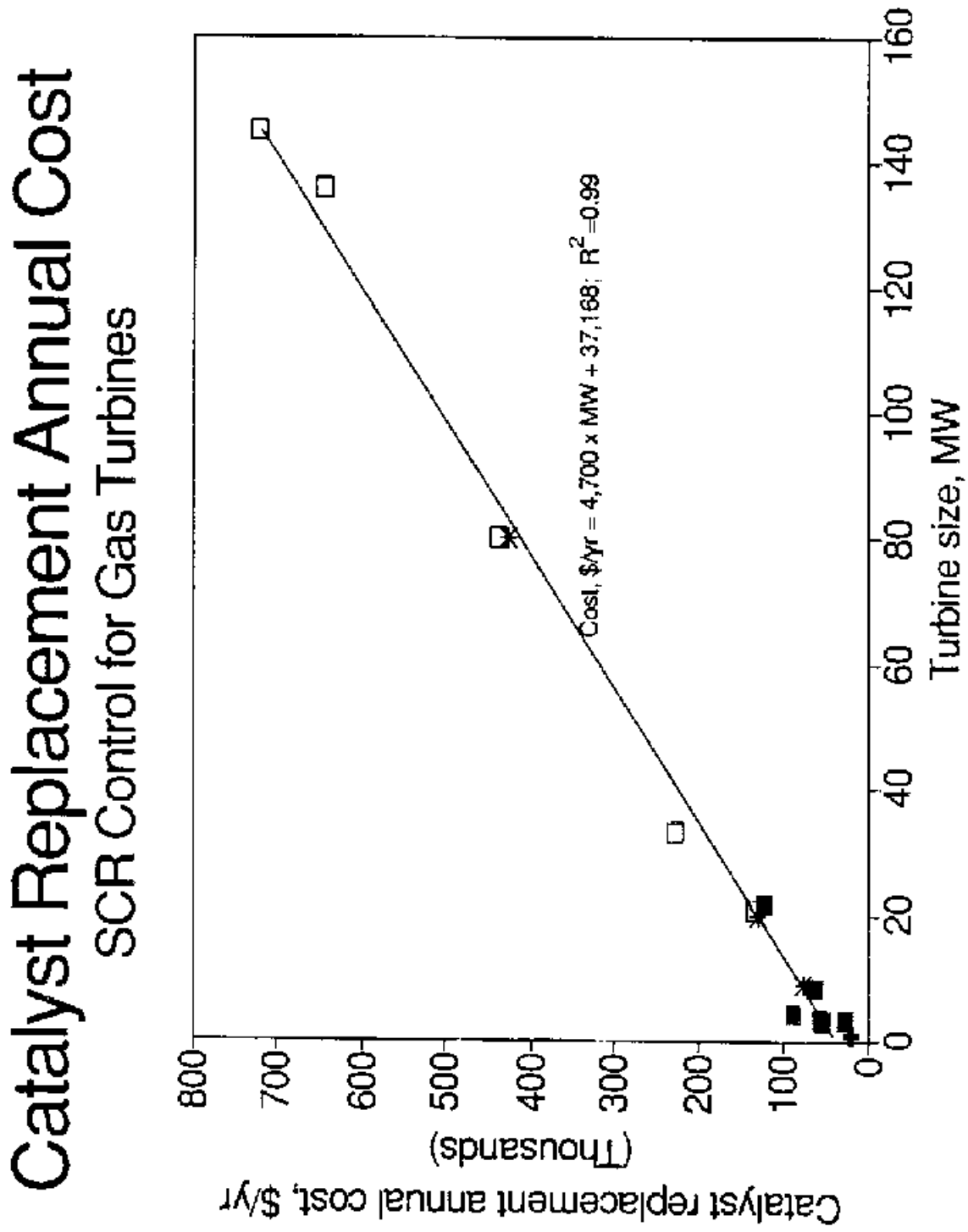


Figure B-3. Catalyst Replacement Annual Cost for SCR Control of Gas Turbines

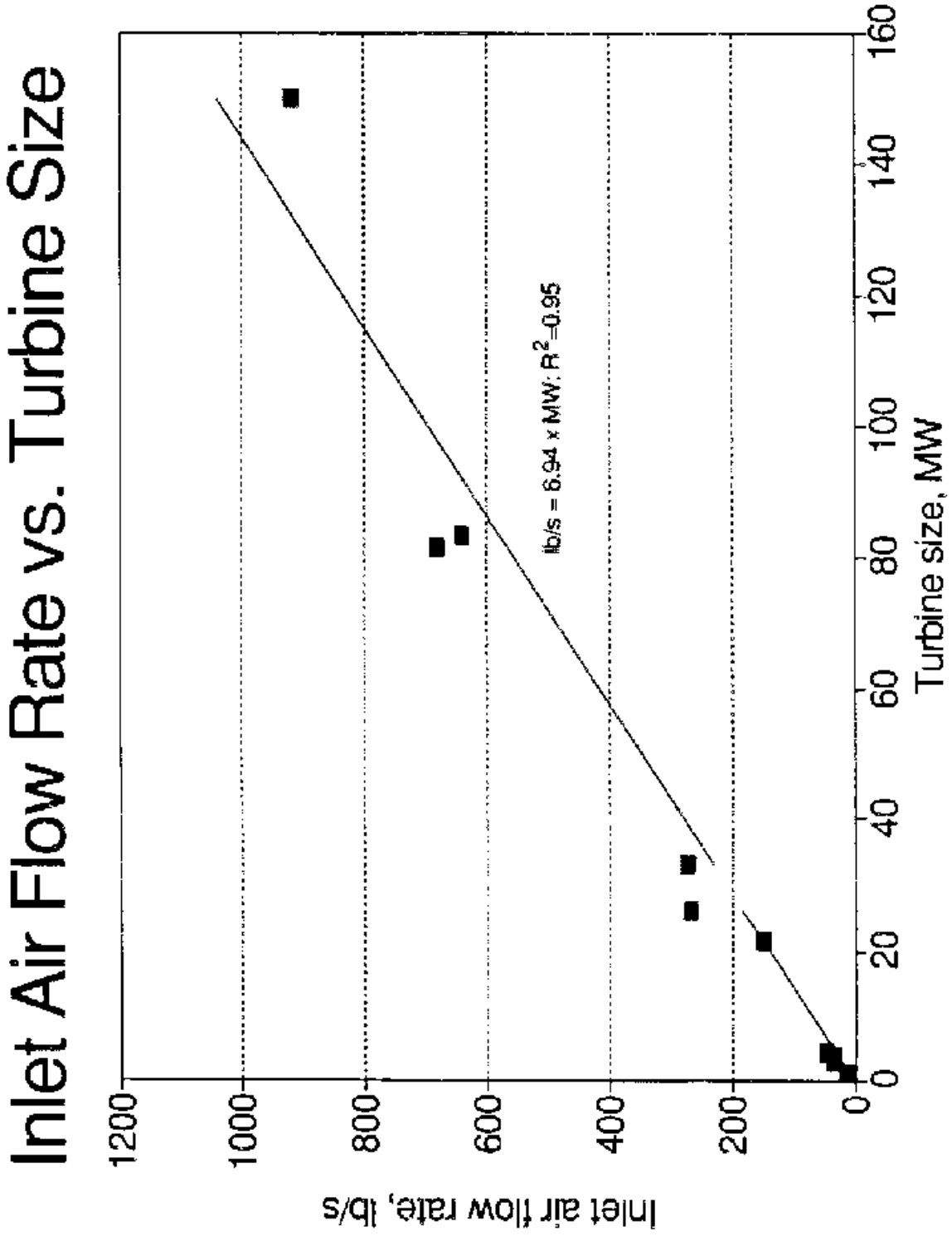


Figure B-4. Inlet Air Flow Rate for Gas Turbines

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TABLE B-1. COMBUSTOR REPAIR INTERVALS, HOURS, AND MATERIAL COST

Gas turbine	Repair interval, hr		Replacement interval, hr		Repair cost, $[d]	Replacement cost, $[d]	Item	Labor hours [a]
	Dry	Wet[b]	Dry[a]	Wet[c]				
MS5001P	12,000	6,000	48,000	24,000	10,000-15,000 15,000-20,000	25,000 42,000	Liners Transition pieces	160
MS7001E	8,000	6,500	48,000	39,000	15,000-30,000 30,000-50,000	50,000 83,000	Liners Transition pieces	576
MS9001E	8,000	6,500	48,000	39,000	31,000-62,000 62,000-124,000	103,000 206,000	Liners Transition pieces	624

[a]Reference 7.
[b]Reference 6.
[c]Scaled from Dry Repair/Replace intervals found in Reference 9.
[d]Reference 5.

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TABLE B-2. ANNUAL COST OF ADDITIONAL MAINTENANCE REQUIRED FOR WATER INJECTION

	Number of inspections over 15 years						Material costs		Labor, each inspection		Total added cost 15 years	Total added annual cost
	Dry		Wet		Added number for wet							
GT Model	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Hours	Cost		
MS5001P [a]												
Combustor liners	8	2	15	5	7	3	15,000	25,000			18,000	
Transition pieces	8	2	15	5	7	3	20,000	42,000	160	4,998	315,980	
											495,980	33,065
MS7001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	30,000	50,000			115,000	
Transition pieces	13	2	15.5	3	2.5	1	50,000	83,000	576	17,994	270,979	
											385,979	25,732
MS9001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	62,000	103,000			237,500	
Transition pieces	13	2	15.5	3	2.5	1	124,000	206,000	624	19,494	584,229	
											821,729	54,782

[a]Based on $31.24/hr. Since parts are normally removed and a spare set is installed at each inspection, the labor cost would be the same for either repair or replacement interval.

[b]Schedule assumes liners and transition pieces are replaced every fourth inspection interval.

[c](7 x $15,000) + (3 x $25,000) = $180,000.

[d](7 x $20,000) + (3 x $42,000) + ($4,998 x 10) = $315,980.

[e]Schedule assumes liners are replaced every fifth interval and transition pieces every sixth interval.

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TABLE B-3. TOTAL CAPITAL INVESTMENT FOR SCR TO CONTROL NO_x EMISSIONS FROM GAS TURBINES

Gas turbine size, MW	SCR capital cost[a]			Scaling factor[c]	1990 SCR capital cost, $
	$	Year	Ref[b]		
1.1	1,250,000	1989	9	357.6/355.4	1,260,000
1.5	180,000	1986	10	357.6/318.4	202,000
3	320,000	1986	10	357.6/318.4	359,000
3.2	600,000	1989	11	357.6/3.554	604,000
3.7	477,000	1988	12	357.6/342.5	498,000
3.7	579,000	1989	11	357.6/355.4	583,000
4	839,000	1991	14	1.0	839,000
4.5	750,000	1988	11	357.6/342.5	783,000
6	480,000	1986	10	357.6/318.4	539,000
8.4	800,000	1986	11	357.6/318.4	898,000
9	1,100,000	1987	13	357.6/323.8	1,210,000
10	1,431,000	1991	14	1.0	1,431,000
20	1,700,000	1987	13	357.6/323.8	1,880,000
21	798,000	1988	12	357.6/342.5	833,000
21	1,500,000	1986	10	357.6/318.4	1,680,000
21	1,200,000	1986	10	357.6/318.4	1,350,000
22	1,000,000	1987	11	357.6/323.8	1,100,000
26	1,800,000	1991	14	1.0	1,800,000
33	990,000	1988	12	357.6/342.5	1,030,000
37	2,000,000	1986	11	357.6/318.4	2,250,000
37	2,700,000	1986	10	357.6/318.4	3,030,000
78	4,300,000	1986	10	357.6/318.4	4,830,000
80	5,400,000	1987	13	357.6/323.8	5,960,000
80	1,760,000	1988	12	357.6/342.5	1,840,000
83	5,360,000	1991	14	1.0	5,360,000

continued

TABLE B-3. (Continued)

[a]Total capital costs were provided by several sources, but it is not clear that they are on the same basis. For example, it is likely that the type of catalyst varies and the target NO_x reduction efficiency may also vary. In addition, some estimates may not include costs for emission monitors; auxiliary equipment like the ammonia storage, handling, and transfer system; taxes and freight; or installation.

[b]Reference 12 also provided costs for SCR used with 136 MW and 145 MW turbines. All of the costs for this reference are lower than the costs from other sources, and the differential increases as the turbine size increases. Because there are no costs from other sources for such large turbines, these two data points would exert undue influence on the analysis; therefore, they have been excluded. Costs for large model plants were estimated by extrapolating with the equation determined by linear regression through the data for turbines with capacities less than 90 MW (see Figure B-1).

[c]Costs for years prior to 1990 are adjusted to 1990 dollars based on the annual CE plant cost indexes. Costs estimated in 1991 dollars were not adjusted.

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TABLE B-4. MAINTENANCE COSTS FOR SCR

Gas turbine size, MW	SCR maintenance cost[a]			Scaling factor[b]	1990 SCR maintenance cost, $
	$/yr	Year	Ref		
1.1	52,200	1989	9	1.050	54,800
3.2	50,000	1989	11	1.050	52,500
3.7	43,000	1988	11	1.103	47,400
3.7	15,500	1988	12	1.103	17,100
8.4	22,000	1986	11	1.216	26,700
8.9	18,000	1988	11	1.103	19,800
9	25,000	1987	13	1.158	28,900
20	50,000	1987	13	1.158	57,900
21	37,900	1988	12	1.103	41,800
33	63,700	1988	12	1.103	70,200
80	124,000	1988	12	1.103	137,000
80	60,000	1987	13	1.158	69,500
136	184,000	1988	12	1.103	203,000
145	205,000	1988	12	1.103	226,000

[a]All of the maintenance costs are for turbines that are fired with natural gas. Although sulfur in diesel fuel can cause maintenance problems, there are no data to quantify the impact. Therefore, the maintenance costs presented in this table were used for both natural gas and diesel fuel applications.
[b]Scaling factors are based on an estimated inflation rate of 5 percent per year.

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TABLE B-5. CATALYST REPLACEMENT AND DISPOSAL COSTS

Gas turbine size, MW	Catalyst replacement cost [a]						Catalyst disposal cost			Catalyst replacement and disposal annual cost, $/yr
	$	Year	Ref.	Scaling factor[b]	1990 catalyst cost, $	Annual cost, $/yr[c]	Catalyst volume, m^3	1990 cost, $[e]	Annual cost, $/yr[c]	
1.1	74,600	1989	9	1.050	78,300	20,700	2.32	1,230	324	21,000
3.2	200,000	1989	11	1.050	210,000	55,400	6.75	3,570	940	56,300
3.7		1988	12	1.103	215,000	56,600	7.80	4,130	1,090	57,700
3.7	100,000	1988	11	1.103	110,000	29,000	7.80	4,130	1,090	30,100
4.5	300,000	1988	11	1.103	331,000	87,300	9.49	5,030	1,330	89,000
8.4	200,000	1986	11	1.216	243,000	64,100	17.7	9,380	2,470	67,000
9	255,000	1987	13	1.158	295,000	77,800	19.0	10,100	2,660	80,000
20	434,000	1987	13	1.158	502,000	132,000	42.2	22,300	5,880	138,000
21		1988	12	1.103	512,000	135,000	44.3	23,500	6,200	141,000
22	400,000	1987	11	1.158	463,000	122,000	46.4	24,600	6,490	128,000
33		1988	12	1.103	864,000	228,000	69.6	36,900	9,700	238,000
80		1988	12	1.103	1,660,000	437,000	169	89,300	23,600	461,000
80	1,400,000	1987	13	1.158	1,620,000	427,000	169	89,300	23,600	451,000
136		1988	12	1.103	2,450,000	645,000	287	152,000	40,100	685,000
145		1988	12	1.103	2,740,000	723,000	306	162,000	42,700	766,000

[a]Reference 12 provided only combined catalyst replacement and disposal costs.

[b]Scaling factors are based on an inflation rate of 5 percent per year.

[c]Annual costs are based on the assumption that the catalyst will be replaced every 5 years. Therefore, the capital recovery factor is 0.2638, assuming an annual interest rate of 10 percent.

[d]In one SCR application, 175 m^3 of catalyst is used with an 83 MW turbine. If the space velocity is the same for any size SCR (assuming the same catalyst), then there is a direct relationship between the amount of catalyst and the exhaust gas flow rate. The exhaust gas flow rate was calculated as equal to the inlet air flow rate, and as Figure B-4 shows, there is nearly a direct relationship between the inlet airflow rate and turbine capacity. Therefore, the catalyst volume for the turbines in this table were estimated assuming there is a direct relationship between the catalyst volume and the turbine output.

[e]Disposal costs are estimated based on a unit cost of $15/$ft^3$.

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B.3 REFERENCES FOR APPENDIX B

I. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Snyder, R., MRI. May 21, 1991. Maintenance considerations for gas turbines.

II. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Neuffer, W.J., EPA/ISB. August 20, 1991. Review of draft gas turbine ACT document.

III. Letter and attachments from Lock, D., U.S. Turbine Corporation, to Neuffer, W.J., U.S EPA/ISB. September 17, 1991. Review of draft gas turbine ACT document.

IV. Letter and attachments from Sailer, E.D., General Electric Marine and Industrial Engines, to Neuffer, W.J., EPA/ISB. August 29, 1991. Review of draft gas turbine ACT document.

V. Telecon. Snyder, R., MRI, with Pasquarelli, L., General Electric Company. April 26, 1991. Maintenance costs for gas turbines.

VI. Letter and attachment from Schorr, M., General Electric Company, to Snyder, R., MRI. April 1, 1991. Response to gas turbine questionnaire.

VII. Walsh, E. Gas Turbine Operating and Maintenance Considerations. General Electric Company. Schenectady, NY. Presented at the 33rd GE Turbine State-of-the-Art Technology Seminar for Industrial, Cogeneration and Independent Power Turbine Users. September, 1989. 20 pp.

VIII. Letter and attachments from Gurmani, A., Asea Brown Boveri, to Snyder, R., MRI. May 30, 1991. Response to gas turbine questionnaire.

IX. Permit application processing and calculations by South Coast Air Quality Management District for proposed SCR control of gas turbine at Saint John's Hospital and Health Center, Santa Monica, California. May 23, 1989.

X. Hull, R., C. Urban, R. Thring, S. Ariga, M. Ingalls, and G. O'Neal. NO_x Control Technology Data Base for Gas-Fueled Prime Movers, Phase I. Prepared by Southwest Research Institute for Gas Research Institute. April 1988.

XI. Shareef, G., and D. Stone. Evaluation of SCR NO_x Controls for Small Natural Gas-Fueled Prime Movers. Phase I. Prepared by Radian Corporation for Gas Research Institute. July 1990.

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XII. Sidebotham, G., and R. Williams. Technology of NO_x Control for Stationary Gas Turbines. Center for Environmental Studies. Princeton University. January 1989.

XIII. Prosl, T., DuPont,and Scrivner, G., Dow. Technical Arguments and Economic Impact of SCR's Use for NO_x Reduction of Combustion Turbine for Cogeneration. Paper presented at EPA Region 6 meeting concerning NO_x abatement of Combustion Turbines. December 17, 1987.

XIV. State of California Air Resources Board. Draft Proposed Determination of Reasonably Available Control Technology And Best Available Retrofit Technology for Stationary Gas Turbines. August, 1991. Appendix C.

XV. Letter and attachments from Henegan, D., Norton Company, to Snyder, R., MRI. March 28, 1991. Response to SCR questionnaire.

XVI. Schorr, M. NO_x Control for Gas Turbines: Regulations and Technology. General Electric Company. Schenectady, New York. Paper presented at the Council of Industrial Boiler Owners NO_x Control IV Conference. Concord, California. February 11-12, 1991. 11 pp.

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OZONE TRANSPORT COMMISSION

OTC Regulatory and Technical Guideline for Control of Nitrogen Oxides (NOx) Emissions from Natural Gas Pipeline Compressor Fuel-Fired Prime Movers

STATIONARY and AREA SOURCES COMMITTEE

Revised May 14, 2019

NMED Exhibit 54

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Table 1 NOx LIMITS* 9

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OTC Regulatory and Technical Guideline for Control of Nitrogen Oxides (NOx) Emissions from Natural Gas Pipeline Compressor Fuel-Fired Prime Movers

This Guideline was developed by the Ozone Transport Commission (OTC) as part of a regional effort to attain and maintain the eight-hour ozone standard, and reduce eight-hour ozone levels.

Notes:

1. *States opting to promulgate rules based on this Guideline must comply with State specific administrative requirements and procedures.*
2. *The term <OTC STATE AGENCY> is a placeholder for individual State Agency names.*
3. *If the owner or operator of a natural gas fueled prime mover subject to this Guideline is unable to comply with the NOx emissions rate limitations or % NOx reduction from uncontrolled shown in specified Section 4 of this Guideline, the owner or operator shall submit an alternative NOx RACT determination, in accordance with Section 5 of this Guideline, for review and approval by the appropriate State Agency which will prepare a revised SIP submittal to the U.S. EPA as required.*

1. Purpose

The purpose of this Guideline is to provide NOx emissions limitations for existing natural gas fueled prime movers powering compressors used for pipeline transportation of natural gas, and to also provide NOx emissions limitations for existing natural gas fueled prime movers powering compressors used for the storage (injection and extraction) of natural gas. Control of NOx emissions from subject sources will help reduce the adverse impact of those emissions on public health, safety, and welfare.

2. Definitions

Note: The definitions used in this section are provided as examples for OTC state agency adoption as needed.

The following words and terms, when used in this Guideline, shall have the following meanings:

2.1 Combustion turbine means a device in which expanding gases from the combustion chamber(s) drive the blades of a turbine to generate mechanical energy in the form of a rotating shaft.

2.2 Compressor means a mechanical device (including, but not limited to reciprocating, axial flow, centrifugal, etc.) designed to increase the pressure of the natural gas in order to facilitate the movement of the natural gas through a pipeline.

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2.3 Existing means the natural gas fueled compressor prime mover was in operation no later than MM-DD-YYYY in any location.

2.4 Field gathering means taking natural gas from the wellhead, and sometimes boosting the natural gas pressure from the wellhead pressure, and injecting the natural gas into field gathering pipelines to transport the natural gas to processing facilities and/or to inject the natural gas into the transport pipelines.

2.5 Four stroke (4S) means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

2.6 Lean burn (LB) means any two-stroke or four-stroke spark ignited reciprocating internal combustion engine that does not meet the definition of a rich burn engine.

2.7 Nameplate rating means: for reciprocating engine natural gas fueled compressor prime movers, the manufacturer's design maximum capacity in horsepower (hp) at the installation site conditions, and for combustion turbine natural gas fuel compressor prime movers, the manufacturer's design maximum capacity at International Organization for Standardization (ISO) 2533 conditions (59^{o} Fahrenheit or 288 Kelvin, 60% relative humidity, and 101.3 kilopascals of pressure). Starting from the completion of any physical change in the prime mover resulting in an increase in the maximum output (in hp) that the prime mover is capable of producing on a steady state basis and during continuous operation, such increased maximum output (at site location conditions for reciprocating prime movers and ISO conditions for combustion turbine prime movers) shall be as specified by the person conducting the physical change.

2.8 Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

2.9 Natural gas fueled means that ≥90% of the prime mover's heat input, excluding recirculated or recuperated exhaust heat, is derived from the combustion of natural gas.

2.10 Operator means any person who operates, controls, or supervises a natural gas fueled prime mover subject to this Guideline and shall include, but not be limited to, any holding company, utility system, or plant manager of such natural gas fueled prime mover.

2.11 Owner means any holder of any portion of the legal or equitable title in a natural gas fueled prime mover subject to this Guideline.

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2.12 Pipeline transportation of natural gas means the movement of natural gas through an interconnected network of compressors and pipeline components, from field gathering networks near wellheads to end users, including:

a. The compressor and pipeline network used for field gathering of natural gas from the wellheads for delivery to either processing facilities or connections to pipelines used for intrastate or interstate transportation of the natural gas.

b. The compressor and pipeline network used to transport the natural gas from field gathering networks or processing facilities over a distance (intrastate or interstate) to and from storage facilities, to large natural gas end-users, and to distribution organizations that provide the natural gas to end-users.

2.13 Prime mover means a spark-ignited reciprocating internal combustion engine or combustion turbine.

2.14 Reasonably available control technology (RACT) means the lowest emission limit for NOx that a particular source is capable of meeting by the application of NOx emissions control technology that is reasonably available considering technological and economic feasibility.

2.15 Reciprocating internal combustion engine means a reciprocating engine in which power, produced by heat and/or pressure that is developed in the engine combustion chambers by the burning of a mixture of air and fuel, is subsequently converted to mechanical work.

2.16 Rich burn (RB) means any four-stroke spark ignited reciprocating internal combustion engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Internal combustion engines originally manufactured as rich burn engines, but modified with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing internal combustion engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

2.17 Spark ignited means a reciprocating internal combustion engine utilizing a spark plug (or other sparking device) to ignite the air/fuel mixture and with operating characteristics significantly similar to the theoretical Otto combustion cycle.

2.18 Shutdown means the period of unit operation between when the compressor prime mover has been unloaded to the minimum load and when the combustion of fuel in the prime mover has ceased.

2.19 Startup means the period of unit operation between when fuel combustion commences in the prime mover and when the compressor prime mover has been loaded to its minimum load.

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2.20 Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

2.21 Two stroke (2S) means a type of reciprocating internal combustion engine which completes the power cycle in a single crankshaft revolution by combining the intake and compression operations into one stroke (one-half revolution) and the power and exhaust operations into a second stroke. This system requires auxiliary exhaust scavenging of the combustion products and inherently runs lean (excess of air) of stoichiometry.

2.22 Uncontrolled means the full load (±25% of nameplate rating) NOx emissions rate of a natural gas fueled compressor prime mover prior to the installation of any NOx controls, including NOx controls installed during prior NOx reduction processes, as documented by Continuous Emission Monitoring Systems (CEMS), stack test, or other method or information approved by the <OTC STATE AGENCY>.

3. Applicability

This Guideline is applicable to existing natural gas fueled prime movers powering compressors used for pipeline transportation of natural gas and the underground storage of natural gas.

3.1 This Rule does not apply to:

3.1.1 Prime movers with nameplate horse-power ratings of <200 hp.

3.1.2 In accordance with the provisions of Section 7 of this Guideline, natural gas fueled compressor prime movers that operate less than 438 hours per year are exempt from the NOx emissions limitations and testing requirements of this Guideline provided they meet the applicable requirements of Section 7 of this Guideline.

4. Emissions Limitations

Except as provided for in Section 5 of this Guideline, no later than MM-DD-YYYY, natural gas compressor prime movers subject to this Guideline shall not exceed the following NOx emissions limits:

4.1 For two-stroke lean burn internal combustion engines, the following NOx emissions limitations are applicable:

4.1.1 Output rating of 200 HP ≤ nameplate rating < 500 HP:

4.1.1.1 2.0 g/BHP-hr, or an emissions rate equivalent to 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.1.1.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions

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rate from Section 4.1.1.1 of this rule times the prime mover's nameplate rating.

4.1.2 Output rating of 500 HP ≤ nameplate rating < 2000 HP:

4.1.2.1 1.5 g/BHP-hr, or an emissions rate equivalent to 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.1.2.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions rate from Section 4.1.2.1 of this rule times the prime mover's nameplate rating.

4.1.3 Nameplate rating of ≥2000 HP:

4.1.3.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.1.3.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions rate from Section 4.1.3.1 of this rule times the prime mover's nameplate rating.

4.2 For four stroke lean burn internal combustion engines, the following NOx emissions limitations are applicable:

4.2.1 Output rating of 200 HP ≤ nameplate rating < 500 HP:

4.2.1.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.2.1.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions rate from Section 4.2.1.1 of this rule times the prime mover's nameplate rating.

4.2.2 Output rating of 500 HP ≤ nameplate rating < 2000 HP:

4.2.2.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.2.2.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions rate from Section 4.2.2.1 of this rule times the prime mover's nameplate rating.

4.2.3 Nameplate rating of 2000 HP or more:

4.2.3.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.2.3.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions

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rate from Section 4.2.3.1 of this rule times the prime mover's nameplate rating.

4.3 For four stroke rich burn internal combustion engines, the following NOx emissions limitations are applicable:

4.3.1 Output rating of 200 HP $\leq$ nameplate rating < 500 HP:

4.3.1.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.3.1.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions rate from Section 4.3.1.1 of this rule times the prime mover's nameplate rating.

4.3.2 Output rating of 500 HP $\leq$ nameplate rating < 2000 HP:

4.3.2.1 1.5 g/BHP-hr, or an emissions rate equivalent to 90% reduction from uncontrolled, whichever emissions rate is greater; or

4.3.2.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions rate from Section 4.3.2.1 of this rule times the prime mover's nameplate rating.

4.3.3 Nameplate rating of ≥2000 HP:

4.3.3.1 1.0 g/BHP-hr, or an emissions rate equivalent to 95% reduction from uncontrolled, whichever emissions rate is greater; or

4.3.3.2 An hourly NOx mass emissions no greater than the mass emissions calculated by multiplying the applicable NOx emissions rate from Section 4.3.3.1 of this rule times the prime mover's nameplate rating.

4.4 For combustion turbines, the following NOx emissions limitations are applicable:

4.4.1 Nameplate rating of less than 2000 HP:

4.4.1.1 150 ppmvd @ 15% O_2, or 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.4.1.2 An hourly NOx mass emissions no greater than the mass emissions equivalent of the combustion turbine operating at its nameplate rating at the applicable NOx emissions rate from Section 4.4.1.1 of this rule.

4.4.2 Output rating of 2000 HP $\leq$ nameplate rating < 5000 HP:

4.4.2.1 50 ppmvd @ 15% O_2, or 80% reduction from uncontrolled, whichever emissions rate is greater; or

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4.4.2.2 An hourly NOx mass emissions no greater than the mass emissions equivalent of the combustion turbine operating at its nameplate rating at the applicable NOx emissions rate from Section 4.4.2.1 of this rule.

4.4.3 Nameplate rating of 5000 HP or more:

4.4.3.1 25 ppmvd @ 15% O_2, or 80% reduction from uncontrolled, whichever emissions rate is greater; or

4.4.3.2 An hourly NOx mass emissions no greater than the mass emissions equivalent of the combustion turbine operating at its nameplate rating at the applicable NOx emissions rate from Section 4.4.3.1 of this rule.

Table 1 NOx LIMITS*

Two-Stroke Lean Burn ICE

Nameplate Rating (HP)	NOx Rate (g/BHP-hr) or (% Reduction)
200 - 499	2.0 (80%)
500 - 1999	1.5 (80%)
≥2000	1.5 (90%)

Four-Stroke Lean Burn ICE

Nameplate Rating (HP)	NOx Rate (g/BHP-hr) or (% Reduction)
200 - 499	1.5 (90%)
500 - 1999	1.5 (90%)
≥2000	1.5 (90%)

Four-Stroke Rich Burn ICE

Nameplate Rating (HP)	NOx Rate (g/BHP-hr) or (% Reduction)
200 - 499	1.5 (90%)
500 - 1999	1.5 (90%)
≥2000	1.0 (95%)

Combustion Turbines**

Nameplate Rating (HP) (MW)	NOx Rate (ppmvd @ 15% O_2)
≤2000 (1.5)	150.0 (6.0 lb/MWhr)
2000 - 4999 (1.5-3.7)	50.0 (2.0 lb/MWhr)
≥5000 (3.7)	25.0 (1.0 lb/MWhr)

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Notes:

*If the owner or operator of a natural gas fueled prime mover subject to this Guideline is unable to comply with the NOx emissions rate limitations or % NOx reduction from uncontrolled shown in Table 1 above and specified Section 4 of this Guideline, the owner or operator shall submit an alternative NOx RACT determination, in accordance with Section 5 of this Guideline, for review and approval by the appropriate State Agency which will prepare a revised SIP submittal to the U.S. EPA as required.

**Combustion Turbine NOx rates are from 40 CFR 60 Subpart KKKK Table 1[1].

4.5 The emissions limitations of Sections 4.1 through 4.4 of this Guideline are applicable during all periods of natural gas fueled compressor prime mover operation, except:

4.5.1 Reserved.

4.5.2 Combustion turbine prime movers operating at ambient temperatures less than 0^{o} F.

4.5.3 Combustion turbine prime movers operating below the effective NOx control range of any installed low-NOx combustion controls.

4.5.4 Natural gas fueled compressor prime movers utilizing post-combustion NOx controls operating at loads below the effective NOx control range of the installed post-combustion controls.

4.4.5 During periods of operation covered by Sections 4.5.1 through 4.5.4 of this Guideline, hourly NOx mass emissions shall not exceed the hourly NOx mass emissions equivalent to the combustion turbine operating at its nameplate rating at the applicable NOx emissions rate from Sections 4.4.1.1, 4.4.2.1, or 4.4.3.1 of this rule.

5. Alternative RACT Emissions Limitation Determination

5.1 If the owner or operator of a natural gas fueled prime mover subject to this Guideline is unable to comply with the emissions rate limitations of Section 4 of this Guideline, the owner or operator shall submit an alternative NOx RACT determination, in accordance with Section 5 of this Guideline, for review and approval by the <OTC STATE AGENCY> and for the <OTC STATE AGENCY> to prepare a revised SIP submittal to the USEPA as required.

5.1.1 An alternative RACT proposal may address the NOx emissions from a specific, single natural gas fueled prime mover, or

5.1.2 An alternative RACT proposal may address NOx emissions averaging of multiple natural gas fueled prime movers under the control of a common

[1] 40 CFR Appendix Table 1 to Subpart KKKK of Part 60, Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines. https://www.gpo.gov/fdsys/pkg/CFR-2014-title40-vol7/pdf/CFR-2014-title40-vol7-part60-subpartKKKK-app1.pdf

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owner or operator at a single facility to achieve the same level of NOx reductions that would be achieved if all of the natural gas fueled prime movers at the location met the applicable NOx emissions limitations of Section 4 of this rule.

5.2 Alternative RACT determinations made pursuant to Section 5.1 of this Guideline shall be submitted to <OTC STATE AGENCY> no later than MM-DD-YYYY for review and approval.

5.3 An alternative NOx RACT determination submitted in accordance with Section 5.1 of this Guideline shall include, as a minimum, the following information:

5.3.1 The name and address of the owner and operator

5.3.2 The address of the subject natural gas compressor prime mover

5.3.3 Latitude and longitude coordinates of the subject natural gas compressor prime mover

5.3.4 Prime mover technical information including

5.3.4.1 Prime mover manufacturer

5.3.4.2 Prime mover model

5.3.4.3 Prime mover serial number

5.3.4.4 Prime mover configuration (combustion turbine, two stroke lean burn, four stoke lean burn, four stroke rich burn)

5.3.4.5 Prime mover original installation/startup date

5.3.4.6 Prime mover nameplate power rating

5.3.4.7 NOx emissions controls

5.3.4.8 Actual, if available, or estimated NOx emissions rate

5.3.5 Identification of the available NO_x control technologies, the projected effectiveness of the technologies considered, and the estimated costs for installation and operation for each of the technologies

5.3.6 If applicable, description and discussion of any previous NOx reduction modifications, changes in operating practices, etc

5.3.7 Identification of equipment or process modifications that are proposed as RACT for implementation on the subject natural gas fueled prime mover, including a technical evaluation and an economic evaluation supporting the selection of the proposed RACT

5.3.8 Expected NOx emission rate(s) for the range of normal operation of the subject natural gas fueled prime mover.

5.3.9 Proposed testing, monitoring, and reporting procedures

5.3.10 The NOx emission rates for the subject existing natural gas fueled prime movers, prior to implementation of the alternative RACT, established with

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approved Continuous Emission Monitoring Systems (CEMS), stack test, or other method approved by the <OTC STATE AGENCY>.

5.3.11 Proposed implementation schedule.

5.3.12 Any other information requested by the <OTC STATE AGENCY>.

6. Testing Requirements

6.1 The owner or operator shall conduct an initial performance test to demonstrate compliance with the applicable NOx emissions limitations of Section 4 of this Guideline no later than MM-DD-YYYY.

6.1.1 The owner or operator shall submit a test protocol to the <OTC STATE AGENCY> at least 30 days prior to emissions testing.

6.2.2 The test methodology shall meet the applicable requirements of 40 CFR Part 60, Appendix A, and the guidance of 40 CFR Part 60 Subpart GG for combustion turbines and the guidance of 40 CFR Part 60 Subpart JJJJ for spark ignited internal combustion engines.

6.2.3 The owner or operator shall submit a compliance test report containing the results of the emissions test to the <OTC STATE AGENCY> no later than 60 days following completion of the emissions test.

6.2 The owner or operator of a natural gas compressor prime mover subject to an alternative RACT emissions limitation in accordance with the provisions of Section 5 of this Guideline shall conduct an initial performance test to demonstrate compliance with the provisions of the approved RACT determination.

6.2.1 The owner or operator shall submit a test protocol to the <OTC STATE AGENCY> at least 30 days prior to emissions testing.

6.2.2 The test methodology shall meet the applicable requirements of 40 CFR Part 60, Appendix A, and the guidance of 40 CFR Part 60 Subpart GG for combustion turbines and the guidance of 40 CFR Part 60 Subpart JJJJ for spark ignited internal combustion engines.

6.2.3 The owner or operator shall submit a compliance test report containing the results of the emissions test to the <OTC STATE AGENCY> no later than 60 days following completion of the emissions test.

6.3 Except as provided in Section 6.4, at least twice per year the owner or operator shall conduct periodic NOx emissions testing of subject natural gas fueled compressor prime movers to demonstrate compliance with the applicable NOx emissions limitations of Section 5 of this Guideline or the applicable alternative RACT NOx emission rate determined in accordance with Section 6 of this Guideline.

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6.3.1 The use of reference method equivalent portable analyzers is acceptable provided the portable analyzer is certified using appropriate reference method procedures in 40 CFR Part 60, Appendix A.

6.3.2 The owner or operator shall submit a test protocol to the <OTC STATE AGENCY> for review and approval prior to the first NOx emission test conducted in compliance with Section 6.3 as follows:

6.3.2.1 Test protocols utilizing reference test methods shall be submitted at least 30 days prior to the conduct of the emissions testing.

6.3.2.2 Test protocols utilizing reference method equivalent analyzers shall be submitted at least 30 days prior to the conduct of the first periodic emissions test under Section 6.3 using the reference method equivalent analyzer.

6.3.2.3 Test protocols utilizing reference method equivalent analyzers for testing subsequent to the first periodic emissions test conducted under Section 6.3 utilizing reference method equivalent analyzers are not required to be submitted to the <OTC STATE AGENCY> provided no changes to the protocol have been made subsequent to the initial <OTC STATE AGENCY> approval of such first period emissions test.

6.3.3 The owner or operator shall submit a test report containing the results of the emissions test to the <OTC STATE AGENCY> no later than 30 days following the completion of the emissions test.

6.3.4 Following the conduct of an initial periodic performance test conducted in accordance with Section 6.3, subsequent period performance rests conducted in accordance with Section 6.3 shall be conducted no less than 90 days following the conduct of the most recent NOx emissions performance test.

6.3.5 NOx emissions testing in compliance with the requirements of Section 6.3 of this Guideline may be conducted at any normal operating load from 40% to 100% of the subject natural gas fueled compressor prime mover's nameplate rating.

6.3.6 Each compliance test must include three test runs where each run lasts at least one hour. Compliance is demonstrated by the average of the three 1-hour or longer test runs.

6.4 If a natural gas fueled compressor prime mover demonstrates compliance with the applicable NOx emission limit of Section 5 or Section 6 of this Guideline for three consecutive tests, the testing frequency requirements of Section 6.3 of this Guideline may be reduced from at least twice per year to at least once per year.

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6.4.1 If a natural gas fueled compressor prime mover that has met the requirements to reduce testing in accordance with Section 6.4 of this Guideline fails to demonstrate compliance with applicable NOx emission limits in any subsequent emissions test, that natural gas compressor prime mover shall meet the testing frequency requirements of Section 6.3 of this Guideline.

6.4.1.1 If the compliance demonstration failure occurs during the first half of a calendar year, the testing frequency requirements of Section 6.3 become effective during that calendar year.

6.4.1.2 If the compliance demonstration failure occurs during the second half of a calendar year, the testing frequency requirements of Section 6.3 become effective during the subsequent calendar year.

6.4.2 All other testing requirements of Section 6.3 remain unchanged.

6.4.3 There are no limits on the number of time a natural gas fueled compressor prime mover may qualify for reduced testing frequency in accordance with Section 6.4 of this Guideline.

7. Exemptions

7.1 Natural gas fueled compressor prime movers that operate 438 or fewer hours per year are exempt from the emissions limitation requirements of Sections 4 and 5 of this Guideline and are exempt from the testing requirements of Section 6 of this Guideline.

7.2 The owner or operator of a natural gas fueled compressor prime mover seeking exemption in accordance with Section 7.1 of this Guideline shall install a non-resettable operating hour metering device on the prime mover. Annual operating hours for the natural gas fueled compressor prime mover shall be monitored, recorded, and reported to <OTC STATE AGENCY> no later than March 31 of each subsequent calendar year in accordance with the reporting requirements of Section 9.3 of this Guideline.

7.3 A natural gas fueled compressor prime mover that was previously exempt in accordance with Section 7.1 of this Guideline shall permanently lose that exemption if the natural gas fueled compressor prime mover exceeds 438 hours per year of operation in any calendar year.

7.3.1 The owner or operator shall submit a plan for the natural gas compressor prime mover's compliance with all applicable requirements of this Guideline no later than March 31 of the year following the calendar year in

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which the natural gas fueled compressor prime mover's exceeded 438 hours of annual operation.

7.3.2 Compliance with all applicable requirements of this Guideline shall be attained no later than December 31 of the year following the calendar year that the natural gas fueled compressor prime mover exceeded 438 hours of annual operation.

7.4 If a natural gas fueled compressor prime mover subject to this Guideline is required by state or federal regulation to monitor and report NOx emissions utilizing <OTC STATE AGENCY> approved CEMS, or the owner or operator of a natural gas fueled compressor prime mover subject to this Guideline elects to monitor and report NOx emissions utilizing <OTC STATE AGENCY> approved CEMS, the owner or operator of the subject natural gas fueled compressor prime mover may petition the <OTC STATE AGENCY> for exemption from the testing requirements of Section 6.3 of this Guideline.

8. Other Requirements

8.1 The owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall follow an inspection and maintenance plan, incorporating appropriate operating and maintenance experience and any applicable prime mover and emission control manufacturer recommendations, to ensure proper maintenance of the natural gas fueled compressor prime mover and related NOx emissions control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Records and documentation supporting the inspection and maintenance plan shall be permanently maintained at the source facility. Records of inspections and maintenance performed shall be maintained as required by Section 9.1 of this Guideline.

8.2 The owner or operator shall follow operating practices and procedures for the natural gas fueled compressor prime mover and related emissions controls consistent with good air pollution control practices for minimizing NOx emissions across the entire load range of the natural gas fueled compressor prime mover, including, as much as practical, periods of startup, shutdown, and malfunction. Records and documentation supporting the subject operating practices and procedures shall be permanently maintained at the source facility.

8.3 If a natural gas fueled compressor prime mover requires major maintenance and natural gas system conditions require the temporary replacement of the natural gas fueled compressor prime mover, a temporary replacement prime mover may be installed as follows:

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8.3.1 The temporary replacement natural gas fueled compressor prime mover shall be similar to the prime mover being temporarily replaced, with similar NOx emissions controls and expected NOx emissions characteristics.

8.3.2 If the temporary replacement natural gas fueled compressor prime mover remains installed for a period exceeding 3 months

8.3.2.1 The temporary replacement natural gas fueled compressor prime mover shall meet the applicable NOx emissions limits specified in Section 4 of this Guideline

8.3.2.2 Compliance with the applicable NOx emissions limitations shall be demonstrated by NOx emissions testing in accordance with the requirements of Section 6.1 of this Guideline, except the testing shall take place within 30 days of exceeding the 3 months temporary replacement period

8.3.3 The owner or operator of a natural gas fueled compressor prime mover shall notify the <OTC STATE AGENCY> of a temporary prime mover replacement within 5 working days of performing the temporary replacement.

8.3.4 The owner or operator of a natural gas fueled compressor prime mover that is being returned to service after temporary replacement shall:

8.3.4.1 Notify the <OTC STATE AGENCY> within 5 working days of the prime movers return to service

8.3.4.2 Demonstrate compliance with the applicable NOx emissions limitations by NOx emissions testing conducted in accordance with Section 6.1 of this Guideline, except the performance test shall be conducted within 30 days of the return to service date.

8.4 If a natural gas fueled compressor prime mover is replaced as part of a routine maintenance prime mover exchange program, a replacement prime mover may be installed as follows:

8.3.1 The replacement natural gas fueled compressor prime mover shall be similar to the prime mover being temporarily replaced, with similar NOx emissions controls and expected NOx emissions characteristics.

8.3.1.1 The replacement natural gas fueled compressor prime mover shall meet the applicable NOx emissions limits specified in Section 4 of this Guideline or alternative NOx RACT plan approved in accordance with Section 5 of this Guideline.

8.3.1.2 Compliance with the applicable NOx emissions limitations shall be demonstrated by NOx emissions testing in accordance with the requirements of Section 6.2 of this Guideline, except the testing

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shall take place within 30 days of the replacement natural gas fueled compressor prime mover's initial startup after installation.

8.3.2 The owner or operator of a natural gas fueled compressor prime mover shall notify the <OTC STATE AGENCY> of a natural gas fueled compressor prime mover replacement within 5 working days of performing the replacement.

9. Recordkeeping and Reporting

9.1 The owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall maintain all records necessary for determining compliance with the provisions of this Guideline at the facility for a period of at least five years, unless otherwise specified in this Guideline.

9.2 No later than MM-DD-YYYY the owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall submit an initial compliance evaluation to the <OTC STATE AGENCY> for review and approval. The initial compliance evaluation shall include, as a minimum, the following information:

9.2.1 The name and address of the owner and operator

9.2.2 The address of the subject natural gas compressor prime mover

9.2.3 Longitude and latitude coordinates of the subject natural gas compressor prime mover

9.2.4 Prime mover technical information including

9.2.4.1 Prime mover manufacturer

9.2.4.2 Prime mover model

9.2.4.3 Prime mover serial number

9.2.4.4 Prime mover configuration (combustion turbine, two stroke lean burn, four stoke lean burn, four stroke rich burn)

9.2.4.5 Prime mover original installation/startup date

9.2.4.6 Prime mover nameplate power rating

9.2.4.7 NOx emissions controls

9.2.4.8 Actual, if available, or estimated NOx emissions rate

9.2.5 Plan for compliance with the requirements of this Guideline

9.2.5.1 Proposed compliance strategy or identification of proposed NOx controls

9.2.5.2 Estimated NOx emissions after installation of controls or strategy

9.2.5.3 Proposed compliance schedule

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9.2.6 Any other information requested by the <OTC STATE AGENCY>.

9.2.7 An alternative RACT emission limitation determination submitted in compliance with the requirements of Section 5 of this Guideline shall fulfill the initial compliance evaluation submittal requirements of Section 9.2 of this Guideline.

9.3 Beginning on MM-DD-YYYY, on March 31 of each calendar year the owner or operator of a natural gas fueled compressor prime mover subject to this Guideline shall submit an annual report to the <OTC STATE AGENCY> containing the following information:

9.3.1 The name and address of the owner and operator

9.3.2 The address of the subject natural gas fueled compressor prime mover

9.3.3 Longitude and latitude coordinates of the subject natural gas compressor prime mover

9.3.4 Identification of the subject natural gas fueled compressor prime mover

9.3.5 Statement of compliance with the applicable emission rate limitations of this Guideline

9.3.6 Statement of compliance regarding the conduct of maintenance and operations in a manner consistent with good air pollution control practices for minimizing emissions, as established in accordance with Section 8 of this Guideline.

9.3.7 For subject natural gas fueled compressor prime movers seeking exemption for prime movers operating less than 438 hours per year in accordance with the requirements of Section 8 of this Guideline, provide applicable hour-meter readings and the calculated prime mover operating hours for the previous calendar year.

9.3.8 If applicable, a statement documenting any change in the operating characteristics of the subject natural gas fueled compressor prime mover.

9.3.9 A statement certifying that the information included in the annual report is complete and accurate.

9.3.10 The annual reports for multiple subject natural gas fueled compressor prime movers at a single source may be combined into a single annual report.

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3.3 Gasoline And Diesel Industrial Engines

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion (IC) engines such as aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The three primary fuels for reciprocating IC engines are gasoline, diesel fuel oil (No.2), and natural gas. Gasoline is used primarily for mobile and portable engines. Diesel fuel oil is the most versatile fuel and is used in IC engines of all sizes. The rated power of these engines covers a rather substantial range, up to 250 horsepower (hp) for gasoline engines and up to 600 hp for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines".) Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating IC engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). This section deals with both types of reciprocating IC engines. All diesel-fueled engines are compression ignited, and all gasoline-fueled engines are spark ignited.

In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

3.3.3 Emissions

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the

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atmosphere from the exhaust. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), total organic compounds (TOC), carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. Nitrogen oxide formation is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The other pollutants, HC, CO, and smoke, are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Sulfur oxides (SO_x) also appear in the exhaust from IC engines. The sulfur compounds, mainly sulfur dioxide (SO_2), are directly related to the sulfur content of the fuel.[2]

3.3.3.1 Nitrogen Oxides -

Nitrogen oxide formation occurs by two fundamentally different mechanisms. The predominant mechanism with internal combustion engines is thermal NO_x which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in the high-temperature region of the flame from dissociated molecular nitrogen in the combustion air. Some NO_x, called prompt NO_x, is formed in the early part of the flame from reaction of nitrogen intermediary species, and HC radicals in the flame. The second mechanism, fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Gasoline, and most distillate oils have no chemically-bound fuel N_2 and essentially all NO_x formed is thermal NO_x.

3.3.3.2 Total Organic Compounds -

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion.

Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.[2]

3.3.3.3 Carbon Monoxide -

Carbon monoxide is a colorless, odorless, relatively inert gas formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.[2-3]

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3.3.3.4 Smoke and Particulate Matter -

White, blue, and black smoke may be emitted from IC engines. Liquid particulates appear as white smoke in the exhaust during an engine cold start, idling, or low load operation. These are formed in the quench layer adjacent to the cylinder walls, where the temperature is not high enough to ignite the fuel. Blue smoke is emitted when lubricating oil leaks, often past worn piston rings, into the combustion chamber and is partially burned. Proper maintenance is the most effective method of preventing blue smoke emissions from all types of IC engines. The primary constituent of black smoke is agglomerated carbon particles (soot) formed in regions of the combustion mixtures that are oxygen deficient.[2]

3.3.3.5 Sulfur Oxides -

Sulfur oxides emissions are a function of only the sulfur content in the fuel rather than any combustion variables. In fact, during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2. The oxidation of SO_2 gives sulfur trioxide (SO_3), which reacts with water to give sulfuric acid (H_2SO_4), a contributor to acid precipitation. Sulfuric acid reacts with basic substances to give sulfates, which are fine particulates that contribute to PM-10 and visibility reduction. Sulfur oxide emissions also contribute to corrosion of the engine parts.[2-3]

3.3.4 Control Technologies

Control measures to date are primarily directed at limiting NO_x and CO emissions since they are the primary pollutants from these engines. From a NO_x control viewpoint, the most important distinction between different engine models and types of reciprocating engines is whether they are rich-burn or lean-burn. Rich-burn engines have an air-to-fuel ratio operating range that is near stoichiometric or fuel-rich of stoichiometric and as a result the exhaust gas has little or no excess oxygen. A lean-burn engine has an air-to-fuel operating range that is fuel-lean of stoichiometric; therefore, the exhaust from these engines is characterized by medium to high levels of O_2. The most common NO_x control technique for diesel and dual-fuel engines focuses on modifying the combustion process. However, selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR) which are post-combustion techniques are becoming available. Controls for CO have been partly adapted from mobile sources.[4]

Combustion modifications include injection timing retard (ITR), preignition chamber combustion (PCC), air-to-fuel ratio adjustments, and derating. Injection of fuel into the cylinder of a CI engine initiates the combustion process. Retarding the timing of the diesel fuel injection causes the combustion process to occur later in the power stroke when the piston is in the downward motion and combustion chamber volume is increasing. By increasing the volume, the combustion temperature and pressure are lowered, thereby lowering NO_x formation. ITR reduces NO_x from all diesel engines; however, the effectiveness is specific to each engine model. The amount of NO_x reduction with ITR diminishes with increasing levels of retard.[4]

Improved swirl patterns promote thorough air and fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC results in improved mixing and complete combustion of the lean air/fuel mixture which lowers combustion temperature, thereby reducing NO_x emissions.[4]

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The air-to-fuel ratio for each cylinder can be adjusted by controlling the amount of fuel that enters each cylinder. At air-to-fuel ratios less than stoichiometric (fuel-rich), combustion occurs under conditions of insufficient oxygen which causes NO_x to decrease because of lower oxygen and lower temperatures. Derating involves restricting the engine operation to lower than normal levels of power production for the given application. Derating reduces cylinder pressures and temperatures, thereby lowering NO_x formation rates.[4]

SCR is an add-on NO_x control placed in the exhaust stream following the engine and involves injecting ammonia (NH_3) into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form water and nitrogen. The effectiveness of SCR depends on fuel quality and engine duty cycle (load fluctuations). Contaminants in the fuel may poison or mask the catalyst surface causing a reduction or termination in catalyst activity. Load fluctuations can cause variations in exhaust temperature and NO_x concentration which can create problems with the effectiveness of the SCR system.[4]

NSCR is often referred to as a three-way conversion catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC and involves placing a catalyst in the exhaust stream of the engine. The reaction requires that the O_2 levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios.[4]

The most accurate method for calculating such emissions is on the basis of "brake-specific" emission factors (pounds per horsepower-hour [lb/hp-hr]). Emissions are the product of the brake-specific emission factor, the usage in hours, the rated power available, and the load factor (the power actually used divided by the power available). However, for emission inventory purposes, it is often easier to assess this activity on the basis of fuel used.

Once reasonable usage and duty cycles for this category were ascertained, emission values were aggregated to arrive at the factors for criteria and organic pollutants presented. Factors in Table 3.3-1 are in pounds per million British thermal unit (lb/MMBtu). Emission data for a specific design type were weighted according to estimated material share for industrial engines. The emission factors in these tables, because of their aggregate nature, are most appropriately applied to a population of industrial engines rather than to an individual power plant. Table 3.3-2 shows unweighted speciated organic compound and air toxic emission factors based upon only 2 engines. Their inclusion in this section is intended for rough order-of-magnitude estimates only.

Table 3.3-3 summarizes whether the various diesel emission reduction technologies (some of which may be applicable to gasoline engines) will generally increase or decrease the selected parameter. These technologies are categorized into fuel modifications, engine modifications, and exhaust after-treatments. Current data are insufficient to quantify the results of the modifications. Table 3.3-3 provides general information on the trends of changes on selected parameters.

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3.3.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section.

Supplement A, February 1996

No changes.

Supplement B, October 1996

- Text was revised concerning emissions and controls.
- The CO_2 emission factor was adjusted to reflect 98.5 percent conversion efficiency.

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Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01)		Diesel Fuel (SCC 2-02-001-02, 2-03-001-01)		EMISSION FACTOR RATING
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	
NO_x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03[d]	0.99[d]	6.68 E-03	0.95	D
SO_x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10[b]	7.21 E-04	0.10	2.20 E-03	0.31	D
CO_2[c]	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

[a] References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

[b] PM-10 = particulate matter less than or equal to 10 μm aerodynamic diameter. All particulate is assumed to be ≤ 1 μm in size.

[c] Assumes 99% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

[d] Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

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Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

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Table 3.3-3. EFFECT OF VARIOUS EMISSION CONTROL TECHNOLOGIES ON DIESEL ENGINES[a]

Technology	Affected Parameter	
	Increase	Decrease
Fuel modifications		
Sulfur content increase	PM, wear	
Aromatic content increase	PM, NO_x	
Cetane number		PM, NO_x
10% and 90% boiling point		PM
Fuel additives		PM, NO_x
Water/Fuel emulsions		NO_x
Engine modifications		
Injection timing retard	PM, BSFC	NO_x, power
Fuel injection pressure	PM, NO_x	
Injection rate control		NO_x, PM
Rapid spill nozzles		PM
Electronic timing & metering		NO_x, PM
Injector nozzle geometry		PM
Combustion chamber modifications		NO_x, PM
Turbocharging	PM, power	NO_x
Charge cooling		NO_x
Exhaust gas recirculation	PM, power, wear	NO_x
Oil consumption control		PM, wear
Exhaust after-treatment		
Particulate traps		PM
Selective catalytic reduction		NO_x
Oxidation catalysts		TOC, CO, PM

[a] Reference 8. PM = particulate matter. BSFC = brake-specific fuel consumption.

NMED Exhibit 55 - 0008

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NMED Exhibit 55 - 0009

Final Technical Support Document (TSD)
for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS
Docket ID No. EPA-HQ-OAR-2015-0500

Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD

U.S. Environmental Protection Agency
Office of Air and Radiation
August 2016

NMED Exhibit 60 - 0001

1 Introduction/Purpose

The purpose of this Technical Support Document (TSD) is to discuss the currently available information on emissions and control measures for sources of NO_X other than electric generating units (EGUs). This information provides more detail about why EGUs are the focus of the final rulemaking, namely the uncertainty that exists regarding whether significant aggregate NO_X mitigation is achievable from non-EGU point sources by the 2017 ozone season, and the fact that the limited available information points to an apparent scarcity of non-EGU reductions that could be accomplished in this timeframe. Notwithstanding these conclusions as regards the 2017 ozone season, the EPA continues to assess the role of NO_X emissions from non-EGU sources to downwind nonattainment problems.

This TSD begins by briefly discussing the non-EGU emissions inventories used in the proposed and final Cross-State Air Pollution Rule (CSAPR) Update analyses, both for the 2011 base year and 2017 future baseline assessed for this rule. The TSD then presents an evaluation of whether non-EGU emissions can be reduced in a cost-effective manner for particular categories. Then, it assesses the available NO_X emission reductions from such categories and presents the category-by-category emissions reduction potential. This assessment considers and presents the annualized costs per ton of these reductions, with a focus on technologies that achieve cost-effective reductions within a range of costs similar to that evaluated for EGUs. The TSD then presents estimates of the time required to install and implement the control measures, both for comparison to the 2017 compliance timeframe, and for discussion of installation time should such measures be required in the future. It should be noted that no changes to these data or estimates have been made for this final TSD compared to the draft version of this TSD provided in the docket for the proposed rule. Finally, the TSD presents a summary of comments received on the proposed rule TSD, along with responses as appropriate.

For the reasons stated in the preamble, the data and discussion in this TSD are intended to focus on the eastern states that are included in the CSAPR Update rule. Information inclusive of western states[1] is presented where available and appropriate.

[1] For the purpose of this action, the western United States (or the West) consists of the 11 western contiguous states of Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington, and Wyoming, and the eastern U.S. (or East) consists of the remaining states in the contiguous U.S.

NMED Exhibit 60 - 0002

2 Background

In this section we present annual and ozone-season NO_X emission inventory totals and the relative percentages for non-EGU source categories statewide and/or nationally. This information is summary in nature and is not meant to replace other, more detailed information available from the EPA, such as the EPA's 2011v6.2 Emissions Modeling Platform TSD[2] as well as the Notice of Data Availability[3] (NODA) and Regulatory Impact Analysis[4] (RIA) for the proposed and final rule.

Table 1 lists 2011 and 2017 projected NO_X emissions by sector, in summary form, for the 48 contiguous states of the United States (CONUS).

Table 1: 2011 Base Year and 2017 Projected NO_X Emissions by Sector (tons), for the 48 CONUS

Sector	2011 NO_X, annual	2017 NO_X, annual	2011 NO_X, ozone season	2017 NO_X, ozone season
EGU-point	2,000,000	1,500,000	942,000	689,000
NonEGU-point	1,200,000	1,200,000	515,000	502,000
Point oil and gas	500,000	410,000	213,000	172,000
Wild and prescribed fires	330,000	330,000	165,000	165,000
Nonpoint oil and gas	650,000	690,000	275,000	293,000
Residential wood combustion	34,000	35,000	3,000	3,000
Other nonpoint	760,000	730,000	204,000	211,000
Nonroad	1,600,000	1,100,000	825,000	582,000
Onroad	5,700,000	3,200,000	2,417,000	1,329,000
C3 commercial marine vessel (CMV)	130,000	130,000	58,000	58,000
Locomotive and C1/C2 CMV	1,100,000	910,000	451,000	384,000
Biogenics	1,000,000	1,000,000	630,000	630,000
TOTAL	**15,000,000**	**11,200,000**	**6,698,000**	**5,018,000**

It is clear from Table 1 that NOx emissions are projected to remain constant or decrease for most sectors in the 48 states between 2011 and 2017, and this is true whether examining annual or ozone season (OS) tons. Emissions from the non-EGU point source sector and the other nonpoint source sector are not projected to change significantly, while emissions

[2] Technical Support Document (TSD), Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform, August 2015, available at: https://www.epa.gov/air-emissions-modeling/2011-version-62-technical-support-document

[3] Notice of Availability of the Environmental Protection Agency's Updated Ozone Transport Modeling Data for the 2008 Ozone National Ambient Air Quality Standard (NAAQS). The official version is available in the docket for this rulemaking.

[4] Regulatory Impact Analysis for the Proposed Cross-State Air Pollution Rule (CSAPR) for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) and Regulatory Impact Analysis for the Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone National Ambient Air Quality Standards (NAAQS). The official versions are available in the docket for this rulemaking.

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from the nonpoint oil and gas source sector are projected to grow (approximately 6%)during this time period. Based on the values in Table 1, Figures 1 and 2 show the relative contributions of the various sectors to overall NOx emissions (left panel) in the CONUS and for the non-EGU sectors (right panel) for 2011 and 2017, respectively.

Figure 1: 2011 NOx emissions by sector, with further non-EGU breakout (48 states)

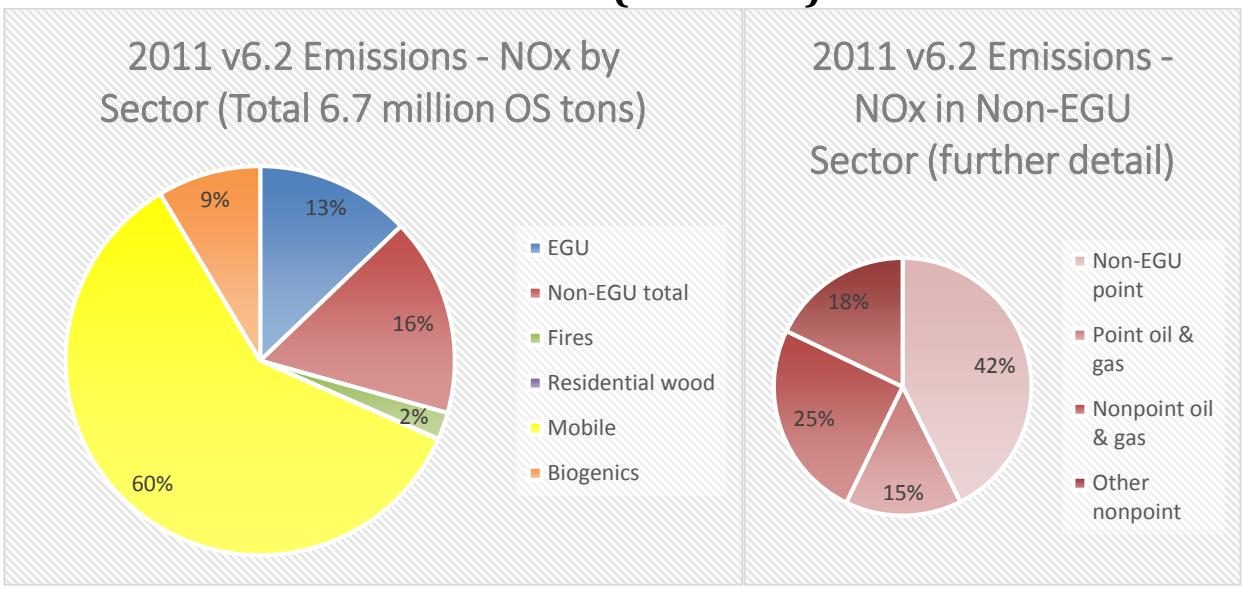


Figure 2: Projected 2017 NOx emissions by sector, with further non-EGU breakout (48 states)

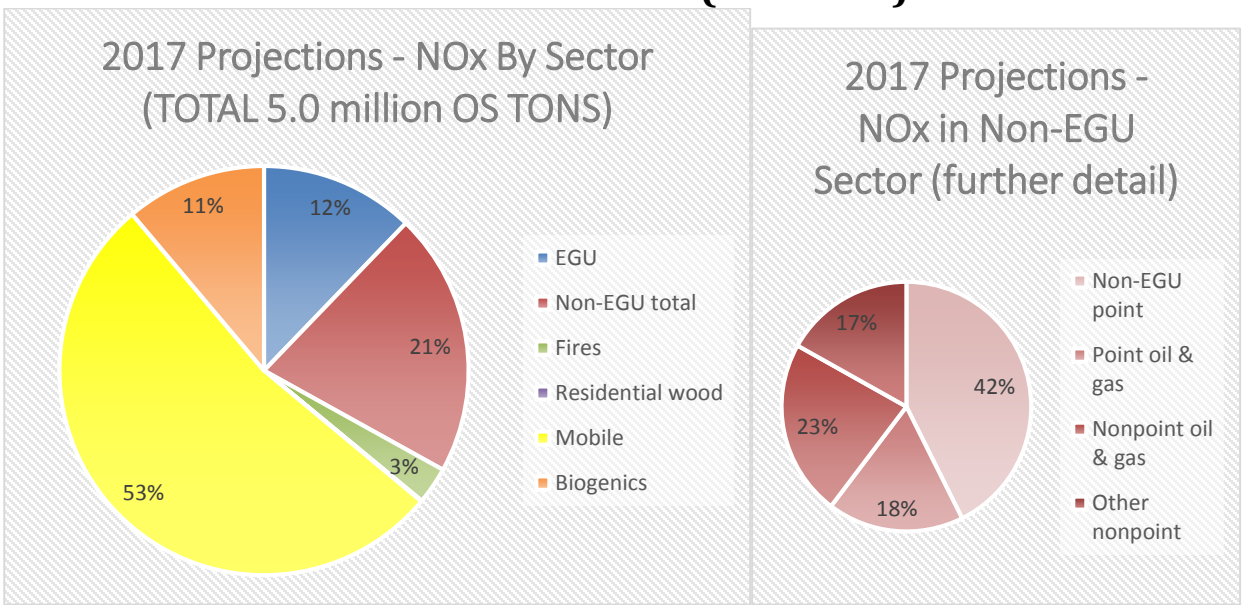


Figure 1 depicts the CONUS total ozone season NOx emissions of 6,698,000 tons in 2011 and Figure 2 depicts the CONUS total ozone season NOx emissions of 5,018,000 tons in 2017. In both 2011 and 2017, the mobile source sector has the largest NOx emissions.[5] Substantial reductions in mobile source NOx emissions are projected to occur by 2017. Mobile source emissions are projected to decrease because of sector-specific standards related to fuels, fuel economy, pollution controls, and repair and replacement of the existing fleet. Because these reductions are already expected to occur, mobile source emission reductions are not included in this analysis of non-EGU emission reductions achievable by the 2017 ozone season.

For the purposes of preliminary analysis in this TSD, "non-EGU total" refers to four separate categories of sources: non-EGU point, point oil and gas, nonpoint oil and gas, and other nonpoint (and does not include mobile sources). The oil and gas point and nonpoint sources are separated from the remaining non-EGU point and nonpoint sources due to the magnitude of their contribution to the inventory and other aspects related to the inventory development, emissions modeling, and future year projections for that industry. The point oil and gas sources are also separated out from the other non-EGU point sources according to the North American Industry Classification System (NAICS) code specified for the various sources. Note that point oil and gas sources include a variety of types of processes, and there is overlap with the processes included in the rest of the non-EGU point inventory. More information on the emissions sectors is available in the 2011v6.2 Emissions Modeling Platform TSD.

Comparing the proportions of the total inventory for non-EGUs (Figures 1 and 2), it becomes clear that, although they are decreasing in the absolute sense, non-EGU NOx emissions are becoming a larger share of overall ozone-season NOx emissions (16% in 2011 compared with 21% in 2017).

Table 2 compares statewide projected total anthropogenic NOx emissions (inclusive of all sectors listed in Table 1 with the exception of fires and biogenics) for the 2017 ozone season to non-EGU NOx emissions for the 2017 ozone season for each of the 48 contiguous United States . Totals are given for the 48 contiguous United States (the 37 eastern states plus the District of Columbia that are addressed in the rule are highlighted below in blue). Non-EGU sources in this table are broken down into two groups (non-EGU point sources, including point oil & gas sources, and other nonpoint and nonpoint oil & gas sources).

[5] The mobile source sector comprises multiple different types of sources (onroad cars & trucks, boats, ships, trains, construction equipment, mining equipment, tractors, etc.).

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Table 2: Projected Total Anthropogenic Ozone-Season NOx Emissions vs. Projected Non-EGU Source Group NOx Emissions, 2017 Projections, Tons[6]

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Alabama	88,805	22,187	25	7,952	9	7,442	8
Arizona	71,906	5,015	7	2,310	3	612	1
Arkansas	69,737	13,400	19	5,308	8	9,164	13
California	236,322	29,342	12	20,220	9	3,105	1
Colorado	90,756	19,594	22	16,899	19	27,284	30
Connecticut	17,672	1,105	6	2,626	15	98	1
Delaware	7,786	628	8	615	8	0	0
District of Columbia	2,252	212	9	312	14	0	0
Florida	177,514	16,293	9	7,543	4	1,112	1
Georgia	103,536	18,816	18	4,559	4	1,495	1
Idaho	27,893	3,752	13	1,989	7	503	2
Illinois	148,178	24,668	17	15,409	10	9,424	6
Indiana	139,133	27,222	20	6,864	5	5,931	4
Iowa	70,467	7,888	11	3,861	5	153	0
Kansas	79,939	6,968	9	12,619	16	10,697	13
Kentucky	106,830	11,456	11	11,905	11	12,251	11
Louisiana	173,330	45,506	26	30,160	17	31,503	18
Maine	17,576	4,639	26	809	5	26	0
Maryland	46,029	6,213	13	3,508	8	522	1
Massachusetts	35,369	4,144	12	4,807	14	105	0
Michigan	131,486	21,867	17	12,245	9	9,398	7
Minnesota	89,328	15,541	17	6,414	7	46	0
Mississippi	54,832	11,684	21	2,122	4	6,557	12
Missouri	101,035	9,238	9	3,594	4	122	0
Montana	38,504	2,948	8	3,630	9	3,390	9
Nebraska	70,005	3,884	6	1,163	2	467	1
Nevada	28,192	4,018	14	1,003	4	115	0
New Hampshire	8,932	680	8	1,028	12	0	0
New Jersey	52,743	4,544	9	5,506	10	173	0
New Mexico	65,263	10,559	16	19,940	31	27,759	43
New York	109,910	13,738	12	14,624	13	904	1
North Carolina	98,064	15,711	16	3,657	4	1,203	1
North Dakota	74,118	4,047	5	18,125	24	19,185	26
Ohio	160,110	21,280	13	11,617	7	2,906	2
Oklahoma	131,763	32,203	24	33,178	25	51,257	39
Oregon	40,507	6,130	15	4,348	11	365	1

[6] EGUs are not provided a separate breakout in Table 2 since state-level emissions are presented in the Preparation of Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform TSD and other TSDs for the proposed and final rules.

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Pennsylvania	174,664	23,735	14	33,508	19	26,713	15
Rhode Island	5,845	544	9	1,370	23	12	0
South Carolina	55,897	10,144	18	3,980	7	348	1
South Dakota	22,192	1,241	6	432	2	75	0
Tennessee	85,759	13,494	16	5,846	7	1,922	2
Texas	467,245	95,671	20	115,180	25	145,285	31
Tribal Data	26,717	3,799	14	0	0	3,700	14
Utah	66,486	8,004	12	9,781	15	9,349	14
Vermont	5,473	163	3	937	17	0	0
Virginia	87,754	14,039	16	7,318	8	4,775	5
Washington	75,833	8,666	11	1,150	2	164	0
West Virginia	64,839	9,678	15	12,642	19	16,723	26
Wisconsin	75,047	11,181	15	5,351	7	178	0
Wyoming	68,864	26,488	38	4,018	6	10,905	16
Eastern States	***3,411,193***	***545,649***	***16***	***418,692***	***12***	***378,171***	***11***
US Total	***4,248,436***	***673,964***	***16***	***503,980***	***12***	***465,421***	***11***

Table 2 indicates that, in the projected 2017 inventory, non-EGU sources comprising non-EGU point and point oil and gas sources are estimated to make up 16% of anthropogenic NOx emissions in the 48 contiguous United States. In individual states, the percentage of anthropogenic emissions contributed by these two non-EGUs categories range from 3% to 26% (eastern states) and from 7% to 38% (western states).

We also note that in the projected 2017 inventory, non-EGU sources comprising nonpoint oil & gas and other nonpoint sources are estimated to make up 12% of anthropogenic NOx emissions in the entire continental U.S. In individual states, the percentage of anthropogenic emissions contributed by these non-EGUs ranges from 2% to 25% (eastern states) and from 4% to 31% (western states).

The EPA's preliminary analysis indicates that NOx emissions from oil and gas sources (inclusive of emissions from the point oil and gas and nonpoint oil and gas sectors) comprise an average of 11% of the total ozone season NOx emissions inventory. For some states, this percentage increases up to 43%, with oil and gas emissions exceeding non-EGU point totals in a number of states. The key sources of NOx emissions in the oil and gas sector are from the combustion of fossil fuel (primarily drilling rigs, internal combustion (IC) engines and pipeline compressors) and flares. Please refer to the EPA's 2011v6.2 Emissions Modeling Platform TSD for more information on emissions from these sectors.

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3 Preliminary Analysis

For the purposes of the proposed rule, the EPA performed a preliminary analysis to characterize whether there are non-EGU source groups with a substantial amount of available cost-effective NOx reductions achievable by the 2017 ozone season. The EPA received no comments that would substantively change this analysis, therefore there was no need to repeat this preliminary analysis for the final CSAPR Update rule.

3.1 Methodology

The EPA's preliminary analysis of potential non-EGU NOx emission reductions was performed using the Control Strategy Tool (CoST). CoST is the software tool the EPA uses to estimate the emission reductions and costs associated with future-year control strategies, and then to generate emission inventories that result from the control strategies applied. CoST tracks information about control measures, their costs, and the types of emissions sources to which they apply. The purpose of CoST is to support national- and regional-scale multi-pollutant analyses, primarily for Regulatory Impact Analyses (RIAs) of the National Ambient Air Quality Standards (NAAQS). CoST is also a component of the Emissions Modeling Framework (EMF) that was used to generate the 2017 non-EGU emissions presented above and in the Emissions Modeling Platform TSD for the proposed CSAPR Update rule. Further discussion and documentation of CoST is available on the EPA's website at http://www.epa.gov/ttnecas1/cost.htm.

Appendices to this TSD discuss recommendations for updates to CoST, including corrections for inapplicable controls, sources already controlled by state rules, sources with permit emissions limits or that have clearly identified controls in place, and sources subject to future NOx emission limits. Appendix A discusses contractor RTI International's work to review estimates for lean burn internal combustion (IC) engines, glass manufacturing, ammonia reformers, and gas turbines.[7] Appendix B discusses contractor SRA International's work on a variety of other categories including many of the others evaluated in this TSD.[8]

EPA has prepared a set of data called the Control Measure Data Base (CMDB) that is used as an important input to CoST. This data includes all control measures utilized by the tool for control strategy analysis. It should be noted that most of the NOx measures included in this report are currently in the Control Measure Data Base used by CoST, and generally do not reflect the updates suggested in these contractor reports. Obstacles to full incorporation of the recommended changes include availability of accurate costs for these measures, and to have cost equations rather than average cost/ton to estimate costs. Control efficiencies are readily available for measures, but costs, particularly those that can be estimated using equations that consider source size or capacity, often are not. In addition, the Pennsylvania

[7] "Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," Revised Draft Report, RTI International, 2014.

[8] "Review of CoST Model Emission Reduction Estimates," SRA International, 2014; "Summary of State NOx Regulations for Selected Stationary Sources," SRA International, 2014.

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Department of Environmental Protection's Additional RACT Requirements for Major Sources of NOx and VOCs rule,[9] which was recently finalized, is not included in these contractor reports. The EPA will consider whether or not to incorporate these recommendations for changes or additions to the NOx controls for non-EGUs to support NOx control efforts for future rules and other efforts. The EPA will also consider updates to reflect state emission control requirements (i.e., Pennsylvania's RACT rule). Nonetheless, the information from these reports helped inform our assessment in terms of uncertainty surrounding non-EGU emission reduction potential. Further details on the CMDB can be found on the CoST web site shown above.

For the purpose of identifying a list of non-EGU NOx source groups with controls available, the EPA ran CoST for non-EGU point sources for the 37 eastern U.S. with NOx emissions of greater than 25 tons/year in 2017. The analysis using CoST was a basis for the review of NOx control measures for non-EGUs undertaken by two different contractors for EPA. Through a contractual agreement with EPA, SRA International and RTI International provided reports within which CoST examined a number of source categories of non-EGUs with annualized control costs up to $10,000 per ton (in 2011 dollars). These reports are included in the Appendices of this TSD. CoST selected particular control technologies based on application of a least-cost criterion for control measures applied as part of the control strategy. Other NOx control measures are available for some of these categories, but on average, annualized costs for these measures were at higher cost.

3.2 Uncertainties and Limitations

The EPA acknowledges several important limitations of the non-EGU cost analysis included in this TSD, which include the following:

Boundary of the cost analysis: In this cost analysis we include only the impacts to the regulated industry, such as the costs for purchase, installation, operation, and maintenance of control equipment over the lifetime of the equipment. Recordkeeping, reporting, testing and monitoring costs are not included. Additional profit or income may be generated by industries supplying the regulated industry, especially for control equipment manufacturers, distributors, or service providers. These types of secondary impacts are not included in this cost analysis.

Cost and effectiveness of control measures: Our application of control measures reflect nationwide average retrofit factors and equipment life. We do not account for regional or local variation in capital and annual cost items such as energy, labor, materials, and others. Our estimates of control measure costs may over- or under-estimate the costs depending on how the difficulty of actual retrofitting and equipment life compares with our control assumptions. In addition, our estimates of control efficiencies for control measures included in our analysis assume that the control devices are properly installed and maintained. There is also variability in scale of application that is difficult to reflect for small area sources of emissions.

[9] Available at: http://www.pabulletin.com/secure/data/vol46/46-17/694.html

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Discount (interest) rate: Because we obtain control cost data from many sources, we are not always able to obtain consistent data across original data sources. If disaggregated control cost data are not available (i.e., where capital, equipment life value, and operation and maintenance [O&M] costs are not shown separately), the EPA assumes that the estimated control costs are annualized using a 7 percent discount rate, which is the discount (interest) rate used in accordance with OMB guidance in Circular A-4. In general, we have some disaggregated data available for non-EGU point source controls. In addition, while these interest rates are consistent with OMB guidance, the actual interest rates may vary regionally or locally.

Accuracy of control costs: We estimate that there is an accuracy range of +/- 30 percent for non-EGU point source control costs. This level of accuracy is described in the EPA Air Pollution Control Cost Manual, which is a basis for the estimation of non-EGU control cost estimates included in this TSD. This level of accuracy is consistent with either the budget or bid/tender level of cost estimation as defined by the American Association for Cost Engineering (AACE) International. In addition, the accuracy of costs is also influenced by the availability of data underlying the cost estimates for individual control measures. For some control measures, we recognize that there is limited data available to generate robust cost estimates. This is reflected in the derivation of costs for some of the non-EGU NOx control measures discussed in Appendix A for this TSD.

3.3 CoST Results

The results of the CoST analysis are displayed in Table 3. In Table 3, we display the source groups selected by CoST, the Source Classification Codes (SCCs) included in those groups[10], the least-cost control technology for a given source group (selected by CoST), the current estimate (in dollars per ton, using 2011 dollars) of the annualized cost per ton NOx reduced of the control technology, the current estimate of the time necessary to install the selected control technology (not including permitting time), the estimated ozone season emissions in the East from the non-EGU source group in 2017 in the absence of the installation of the selected controls, and the estimated potential ozone season reductions in the East from the non-EGU source group in 2017 assuming the CoST selected controls could be fully installed and operational prior to the 2017 ozone season (which as discussed in more detail later, is not the case for many of the categories examined). Note that CoST does not account for installation time or time required for the permitting process. Instead it provides information on the control measures applicable to sources in the inventory, along with the cost of installation and operation and maintenance of the selected measures.

[10] The CoST results do not indicate applicability of the recommended control technology to all sources in the source group but only to the specific SCCs for which control technologies are applicable. For example, for the cement kilns source group, Biosolid Injection Technology (BSI) is applicable only for the types of cement kilns covered by the listed SCCs.

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Table 3: CoST Results: Non-EGU Source Groups with NOx Reductions

Non-EGU Source Group	SCCs	Control Technology Recommended by CoST	Current estimate of NOx $/ton, CoST (2011 $)	Time to install[11] [12](excluding permitting, reporting preparation, programmatic and administrative considerations[13])	2017[14] NOx Emissions (37 States + DC), OS tons, CoST	2017 Potential Reductions [15] (37 States + DC), OS tons, CoST
Cement Kilns	30500622 (preheater kiln), 30500623 (preheater/precalciner); 39000201 (kiln/dryer); 39000288 (kiln in process coal)	Biosolid Injection Technology (BSI)	$410	Uncertain	24,760	4,207

[11] Time to install is not an output of CoST, but are rather estimates determined by the EPA based on research from a variety of sources. See, "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources," Institute of Clean Air Companies, December 2006 (all sources except Cement Kilns and RICE (Reciprocating Internal Combustion Engines)), "Cement Kilns Technical Support Document for the NOx FIP," EPA, January 2001 (cement kilns), and "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," Innovative Environmental Solutions Inc., July 2014 (prepared for the INGAA Foundation).

[12] In general, for control retrofits to non-EGU sectors, it appears that the full sector-wide compliance time is uncertain, but is longer than the installation time shown above for a typical unit. We have insufficient information on capacity and experience within the OEM suppliers and major engineering firms supply chain to offer conclusions on their availability to execute the project work for non-EGU sectors.

[13] Non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 and/or not currently participating in the CSAPR program will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting and/or participating in the current CSAPR program. Installation of NOx monitors for the reporting of NOx mass requires the construction of platforms, CEM shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These added timing considerations for infrastructure on the non-EGU sources combined with the additional programmatic adoption measures necessary make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

[14] Emissions and potential reductions for Gas Turbines ($163/ton grouping), Cement Kiln/Dryer (Bituminous Coal) ($942/ton grouping), Coal Cleaning – Thermal Dryer (2), Spreader Strokers, Petroleum Refinery Process Heaters, Incinerators, Boilers & Process Heaters, Gas-Fired Process Heaters, Coal Boilers, By-Product Coke Manufacturing, ICI Boilers – Residual Oil, Ammonia Production, Glass Manufacturing, ICI Boilers, Iron & Steel - In-Process Combustion - Bituminous Coal, Industrial Processes Miscellaneous, Catalytic Cracking, Process Heaters, & Coke Ovens, Petroleum Refinery Gas-Fired Process Heaters, Glass Manufacturing – Pressed, Glass Manufacturing – Container, Petroleum Refinery Gas-Fired Process Heaters, and RICE source groups were calculated for 2018, however they are likely to be virtually identical to projections for 2017. Non-EGU source groups with projected aggregate 2017 NOx emissions below 100 OS tons are excluded from this table.

[15] Potential reductions assume fully implemented controls by the start of the 2017 ozone season.

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Cement Mfg (dry)	30500606 Industrial Processes, Mineral Products, Cement Manufacturing (Dry Process), Kilns	Selective Non-Catalytic Reduction (SNCR)	$1,255	42-51 weeks	13,006	6,501
Cement Mfg (wet)	30500706 Industrial processes, mineral products, Cement Manufacturing (Wet Process), Kilns	Mid-Kiln Firing	$73	5-7 months	7,971	2,287
Coal Cleaning – Thermal Dryer (1)	30502508 Construction Sand & Gravel, Dryer; 30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	$1,125	6-8 months	503	165
Coal Cleaning – Thermal Dryer (2)	30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	$1,640	6-8 months	154	63
Cement Kiln/Dryer (Bituminous Coal)	39000201 Industrial Processes, In-process Fuel Use, Bituminous Coal, Cement Kiln/Dryer (Bituminous Coal)	SNCR	$942	42-51 weeks	520	260
Iron and Steel Mills - Reheating	30300934 (303015) Primary Metal Production: Steel; 30300933	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$620	6-8 months	1,064	664
Steel Production	30490033 Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Furnaces; 30400704 Industrial Processes, Secondary Metal Production, Steel Foundries, Heat Treating Furnace	Low NOx Burner (LNB)	$928	6-8 months	281	141
Nitric Acid Mfg	30101301 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Pre-1970 Facilities); 30101302 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Post-1970 Facilities)	NSCR	$900	6-14 weeks	1,290	724
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$940-$1101	28-58 weeks	179	177

Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine	Low NOx Burner (LNB)	$163	12 months	945	793
Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine; 20300203 Natural Gas, Turbine: Cogeneration	Low NOx Burner (LNB)	$800	6-8 months	16,036	4,713
Natural Gas RICE Pipeline Compressors	20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	$249	Uncertain	10,099	2,958
Natural Gas RICE Miscellaneous	20100202 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating; 20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating; 20200204, Internal Combustion Engines, Industrial, Natural Gas, Reciprocating: Cogeneration; 20300201, Internal Combustion Engines, Commercial/Institutional, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	$447	Uncertain	27,600	8,085
Natural Gas RICE Pipeline Compressors, Rich Burn	20200253 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Rich Burn	NSCR	$517	Uncertain	11,758	10,571
Natural Gas RICE Pipeline Compressors, Lean Burn / Clean Burn	20200252 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Lean Burn; 20200254 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Lean Burn; 20200255 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Clean Burn; 20200256 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Clean Burn	Low Emission Combustion (LEC)	$649	Uncertain	47,321	41,169
Diesel / Dual Fuel RICE	20200401 Internal Combustion Engines, Industrial, Large Bore Engine, Diesel; 20200402 Internal Combustion Engines, Industrial, Large Bore Engine, Dual Fuel (Oil/Gas)	Ignition Retard	$1,255	Uncertain	865	216

Catalytic Cracking (1)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$1,375	6-8 months	255	140
Spreader Strokers	10100204 External Combustion Boilers, Electric Generation, Bituminous/Subbituminous Coal, Spreader Stroker (Bituminous Coal)	SNCR	$1,390	42-51 weeks	394	158
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$1,406-$1,501	28-58 weeks	161	157
Incinerators	50200102, 50200103, 50200104, 50200504, 30190013, 30190014, 50300101, 50300106, 50300112, 50300113, 50300501, 50300503, 50300504, 50300599, 50100101, 50100102, 50100103, 50100506, 50100515, 50100516, 39990024 Incineration	SNCR	$1,842	42-51 weeks	6,556	2,950
Boilers & Process Heaters	10200203, 10200217, 10300216, 10200204, 10200205, 10300207, 10300209, 10200799 External Combustion Boilers; 30190002, 30600103 Industrial Process Heaters	SCR	$2,235	28-58 weeks	13,146	10,358
Natural Gas RICE Electric Generation	20100206 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating: Evaporative Losses (Fuel Delivery System)	Adjust Air to Fuel Ratio and Ignition Retard	$2,347	Uncertain	107	32
Catalytic Cracking (2)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 30600202 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Catalyst Handling System	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$2,369	6-8 months	274	97
Gas-Fired Process Heaters (1)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired	SCR-95%	$2,376	28-58 weeks	211	204
Coal Boilers	10200206, 10200224, 10200225, 10300102, 10300208, 10300224, 10300225	SNCR	$2,413	42-51 weeks	1099	495

Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas Fired	Ultra-Low NOx Burners	$2,419-$2,638	6-8 months	137	64
By-Product Coke Manufacturing	30300306 Industrial Processes, Primary Metal Production, By-Product Coke Manufacturing, Oven Underfiring	SNCR	$2,673	42-51 weeks	2,366	1,420
ICI Boilers – Residual Oil	10200401, 10200402, 10200404, 10300401, 10300402 External Combustion Boilers, Residual Oil	LNB & SNCR	$2,850	6-8 months	991	689
Ammonia Production	30100306 Industrial Processes, Chemical Manufacturing, Ammonia Production, Primary Reformer: Natural Gas Fired	SCR	$2,896	28-58 weeks	2,508	2,257
Glass Manufacturing - Flat	30501403 Industrial Processes, Mineral Products, Glass Manufacture, Flat Glass: Melting Furnace	OXY-Firing	$3,097	Uncertain	9,721	7,880
ICI Boilers	10200201, 10200202, 10200212, 10300205, 10200501, 10200504, 10200601, 10200602, 10200603, 10200604, 10201401, 10300601, 10300602, 10200701, 10200704, 10200707, 10201402 External Combustion Boilers	Low NOx Burner & SCR	$3,456	6-8 months (LNB) 28-58 weeks (SCR)	31,005	28,204
Iron & Steel - In-Process Combustion - Bituminous Coal	30300819, 30300824, 30300913, 30300914, 30301522 Industrial Processes, Primary Metal Production	SCR	$3,705	28-58 weeks	829	746
Diesel RICE Miscellaneous	20100102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating; 20100107 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating: Exhaust; 20200102 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating; 20200106 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Evaporative Losses (Fuel Storage and Delivery System);	SCR	$3,814	28-58 weeks	1,091	869

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	20200107 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Exhaust; 20300101 Internal Combustion Engines, Commercial/Institutional, Distillate Oil (Diesel), Reciprocating; 20400403 Internal Combustion Engines, Engine Testing, Reciprocating Engine, Distillate Oil					
Catalytic Cracking, Process Heaters, & Coke Ovens	30600201, 30390004, 39000701, 39000702, 39000797	LNB & FGR	$5,199	6-8 months	1,989	1,094
Petroleum Refinery Gas-Fired Process Heaters (3)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$8,885-$9,140	28-58 weeks	370	316
Glass Manufacturing - Pressed	30501404 Industrial Processes, Mineral Products, Glass Manufacture, Pressed and Blown Glass: Melting Furnace	OXY-Firing	$6,356	Uncertain	1,001	851
Petroleum Refinery Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$7,533-$8,120	28-58 weeks	362	304
Industrial Processes Miscellaneous	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 39000701 Industrial Processes, In-process Fuel Use, Process Gas, Coke Oven or Blast Furnace	LNB & FGR	$4,026	6-8 months	871	479
Glass Manufacturing - Container	30501402 Industrial Processes, Mineral Products, Glass Manufacture, Container Glass: Melting Furnace	OXY-Firing	$7,481	Uncertain	3,107	2,628
Petroleum Refinery Gas-	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired; 30600106 Industrial	SCR-95%	$5,609-$5,884	28-58 weeks	372	338

Fired Process Heaters (1)	Processes, Petroleum Industry, Process Heaters, Process Gas-fired					
Taconite Ore Processing	30302351, 30302352, 30302359 Industrial Processes, Primary Metal Production, Taconite Ore Processing, Induration	SCR	$6,449	28-58 weeks	1,188	991
Diesel RICE Electric Generation	20200102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating	SCR	$1,499	28-58 weeks	778	622

3.4 Discussion of Non-EGU Source Groups

The below discussion utilizes the information in Table 3 in order to assess whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season.

It is clear that a number of source categories have been identified by CoST using the least-cost procedure that have the potential for non-EGU stationary source emissions reductions. There are some notable source categories that have the potential for substantial non-EGU stationary source emissions reductions below $10,000 per ton.[16] However, for the purposes of this analysis, the EPA did not further examine control options above $3,400 per ton. This is consistent with the range we analyzed for EGUs in the proposed and final rules, and is also consistent with what the EPA has identified in previous transport rules as highly cost-effective, including the NOx SIP call.[17] Again, this was done because the objective of this analysis is to characterize whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season, so we focused the search on categories with highly cost-effective technologies. This focus excludes several source groups with high emissions reduction potential because reductions from those source groups are not available for $3,400 per ton or less, including: ICI boilers using SCR & LNB; Catalytic Cracking, Process Heaters, & Coke Ovens using LNB & FGR; and Pressed and Container Glass Manufacturing using OXY-Firing.

At a cost level of $3,400 per ton or less, there are a number of source groups with substantial reduction potential. However the table also identifies several source groups whose reduction potential is not significant, and which the EPA did not weigh heavily in assessing the aggregate non-EGU NOx emission reduction potential. This is because the aggregate potential reductions from these "insignificant" source groups is small. These "insignificant" source groups comprise those source groups with many small sources, as well those containing a limited number of larger sources; for either of these types of groups, potential aggregate emission reductions are small relative to reductions available from other source categories. The EPA does not believe that small sources have significant emission reduction potential in the aggregate because most small sources emit less than 100 tons of NOx per year. (It is worth noting that small sources account for a significant percentage of the total number of non-EGU point sources. See Appendix A/B for more information on the number of sources within certain states.) The EPA therefore excludes from the focus of this analysis these insignificant source groups, namely, those with aggregate potential reductions of 1,000 tons per year or less (which represents less than 0.1 percent of the anthropogenic ozone season inventory).

The EPA will now focus on the several source groups with significant cost-effective reductions identified in Table 3. These source groups include cement kilns, two types of cement manufacturing (dry and wet), gas turbines, four separate groups of natural gas reciprocating IC engines (RICE), incinerators, boilers & process heaters, by-product coke

[16] $10,000 per ton represents the cost/ton for Best Available Control Technology (BACT) determinations, which usually do not exceed $10,000/ton in the Eastern U.S.

[17] $3,400 per ton represents the $2,000 per ton value (in 1990 dollars) used in the NOx SIP call, adjusted to the 2011 dollars used throughout this proposal Adjustment of costs was made using the Chemical Engineering Plant Cost Index (CEPCI) annual values for 1990 and 2011.

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manufacturing, ammonia production, and flat glass manufacturing. These source groups are listed below with their control technologies, estimated annualized control costs, and estimated installation time. These groups have been organized into 7 categories for clarity, based on either common control technologies (categories 1 through 6) or similarity of source groups (category 7).

Category 1	**Control Tech.**	**Est. Cost**	**Est. Inst. Time**
-Cement Mfg (dry)	SNCR	$1,255	42-51 weeks
-Incinerators	SNCR	$1,842	42-51 weeks
-By-Product Coke Manufacturing	SNCR	$2,673	42-51 weeks
Category 2			
-Cement Kilns	Biosolid Injection Technology (BSI)	$410	Uncertain
Category 3			
-Gas Turbines	Low NOx Burner (LNB)	$800	6-8 months
Category 4			
-Cement Mfg (wet)	Mid-Kiln Firing	$73	5-7 months
Category 5			
-Boilers & Process Heaters	SCR	$2,235	28-58 weeks
-Ammonia Production	SCR	$2,896	28-58 weeks
Category 6			
-Glass Manufacturing - Flat	OXY-Firing	$3,097	Uncertain
Category 7			
-Gas RICE Pipeline Compressors	Adjust AFR and Ignition Retard	$249	Uncertain
-Gas RICE Miscellaneous	Adjust AFR and Ignition Retard	$447	Uncertain
-Gas RICE Pipeline Compressors, Rich Burn	NSCR	$517	Uncertain
-Gas RICE Pipeline Compressors, Lean/Clean Burn	Low Emission Combustion (LEC)	$649	Uncertain

The EPA makes the following observations about the potential reductions from these significant cost-effective categories.

The source groups listed in Category 1 would utilize SNCR as the recommended control technology. The time necessary to install SNCR equipment is generally well known. A typical installation timeline of 42-51 weeks is generally needed to complete a SNCR project

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going from the bid evaluation through startup, which installation timeline is specific to non-EGUs. Based on this fact alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SNCR technology to be installed and operational in time for the 2017 ozone season seems very unlikely.

The source group listed in Category 2 contains a specific source of uncertainty in regards to biosolid injection technology (BSI). Due in large part to the lack of widespread use of this control technology, research performed by the EPA has been unable to uncover any reliable information on the time required to install the necessary BSI equipment on cement kilns. Compliance timing with regard to biosolid injection technology should therefore be considered extremely uncertain. Based on this fact alone (and aside from additional time likely necessary for permitting or installation of monitoring equipment), the ability for this technology to be installed and operational at all facilities in this category in time for the 2017 ozone season is unknown.

The source group listed in Category 3 would utilize LNB as the recommended control technology, with a necessary installation time of approximately 6-8 months. Some of the LNB combustion control technology identified for non-EGU sources reflects a different technology that may have different timing considerations than that considered for EGU boilers. For instance, LNB at non-EGU combustion turbines in this assessment refers to "dry low-NOx burners" (DLNB) which, in addition to the usual diffusion burner, typically also include provisions to "premix" natural gas and combustion air prior to combustion. In spite of the similarity in naming, this is a different technology than the LNB technology examined and assumed for reductions at EGU boilers. Therefore, the same timing assumptions assumed and demonstrated on the EGU side are not necessarily applicable to combustion control technology for non-EGU sources. Moreover, non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting (such as those EGUs covered under federal transport rulemakings and this one). Installation of NOx monitors for the reporting of NOx mass requires the construction of platforms, Continuous Emissions Monitoring (CEM) shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These timing considerations on the non-EGU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

The source group listed in Category 4 would utilize mid-kiln firing as the recommended control technology. A fairly well-known aspect is the time necessary to install this equipment; typically, 5-7 months is needed to complete a mid-kiln firing project going from the bid evaluation through startup. However, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe of this rule less likely and more uncertain for industrial sources such as those in the cement manufacturing (wet) source group.

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The source groups listed in Category 5 would utilize SCR as the recommended control technology, with an installation time of 28-58 weeks for SCR (dependent on exhaust gas flow rates; larger systems require longer installation times). Based on the installation time frame alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SCR technology to be installed and operational in time for the 2017 ozone season seems unlikely. In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 5 source groups.

The source group listed in Category 6 would utilize OXY-Firing as the recommended control technology, with an uncertain necessary installation. A specific source of uncertainty with regard to the estimated installation time of this control technology is that OXY-Firing is generally installed only at the time of a furnace rebuild, which rebuilds may occur at infrequent intervals of a decade or more.[18] In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 6 source group.

Finally, the source groups listed in Category 7 are all RICE. While some of the recommended control technologies may involve installation timelines that are relatively short on a per-engine basis, there is substantial uncertainty in large-scale installation over numerous sources. References indicate that implementation of NOx controls of any type on a large number of RICE will require significant lead time to train and develop resources to implement emission reduction projects; market demand could significantly exceed the available resource base of skilled professionals.[19] Additionally, in order not to disrupt pipeline capacity, engine outages must be staggered and scheduled during periods of low system demands for those engines involved in natural gas pipelines (as is the case with 3 of the 4 RICE source groups with significant cost-effective reductions). In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as RICE.

4 Summary of Comments Received on Proposed Rule TSD

The EPA received relatively few comments on the draft Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance TSD provided in the docket for this rule. None of these comments changed our conclusions reached in the draft TSD, as commenters generally agreed with the EPA's assessment with respect to the regulation of

[18] See Appendix B.

[19] "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," Innovative Environmental Solutions Inc., July 2014.

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non-EGUs in this rule. Detailed responses to these comments can be found in the response to comments document available in the docket for this final rule. A brief discussion of one comment containing data on control information is presented below.

Commenter Fuel Tech, Inc. (FTI) provided information on the installation time required for SNCR equipment, stating that "FTI has provided SNCR systems in 8-12 months (from contract award to performance guarantee certification)…"[20] This timeframe is largely consistent with the 42-51 week (9.7-11.7 month) timeframe estimate presented by the EPA in the draft TSD.

In addition, FTI provided information on a range of SNCR cost per ton based on installations from 2010 to 2015 on non-EGU sources, stating that "these recent examples show NOx reduction cost effectiveness in the range of $2,200 to $2,900 per ton of NOx removed on an annual basis."[21] FTI's "Figure 1"[22] also provided a chart of cost effectiveness ($/ton) versus unit size (mmBTU/hr) for both annual and ozone season NOx. A log fit of the ozone season curve shows cost effectiveness in the range of approximately $2,000 to approximately $6,500 per ton of ozone season NOx removed, with installations tending to be more expensive for smaller unit sizes. Although FTI's estimates are based on different interest rates and capital investments than our estimates, they are worthwhile to note in comparison to our stated estimate of $1,300 to $2,700 per ton of NOx removed on an ozone season basis.

5 Conclusion

The above preliminary analysis performed by the EPA indicates that uncertainty exists regarding whether significant aggregate NOx mitigation is achievable from non-EGU point sources by the 2017 ozone season. Reducing this uncertainty requires further understanding of potentially available control measures that could have annualized costs of $3,400 per ton or less. In addition, further implementation of the recommendations in the Appendices to this TSD, the extent of which as determined by the EPA to be needed, may also reduce our uncertainty regarding the credibility of data for control measures included in future non-EGU NOx control strategy efforts. Please note that while the information in these Appendices supports our conclusion regarding whether significant aggregate NOx mitigation is achievable from non-EGU point sources by the 2017 ozone season, this final TSD is making no conclusions about the recommendations for further improvements.

While a number of source groups with control options were identified, the EPA did not further examine control options above $3,400 per ton, consistent with the range analyzed for EGUs in the proposed and final rules and with what the EPA has identified in previous transport rules as highly cost-effective. A number of source groups were identified at a cost level of $3,400 per ton or less, however the EPA believes several of these source groups may not be significant. Of the remaining source groups, a variety of factors indicated the ability for control technology to be installed and operational in time for the 2017 ozone

[20] EPA-HQ-OAR-2015-0500-0356, page 3.
[21] EPA-HQ-OAR-2015-0500-0356, page 7.
[22] EPA-HQ-OAR-2015-0500-0356, page 6.

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season seemed unlikely, with an overarching consideration being that non-EGUs of any type that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time for implementation relative to EGUs that are currently equipped with Part 75 monitoring and reporting. These added timing considerations on the non-EGU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

With all of these factors being considered, the limited available information points to an apparent scarcity of non-EGU reductions that could be accomplished by the beginning of the 2017 ozone season. As noted in the proposed and final rule, this conclusion has led the EPA to focus the final FIPs on EGU reductions. Both the proposal and the final rule acknowledge that this may not be the full remedy that is ultimately needed to eliminate an upwind state's significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS (or, for that matter, the 2015 ozone NAAQS) in other states. Emissions reductions from the non-EGU categories discussed above may be necessary, though on a longer timeframe than the 2017 compliance deadline being finalized in this rulemaking. The EPA intends to explore this question further in future ozone transport rulemakings.

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May 2014

Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines

Final Report

Appendix A

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Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines

Revised Draft Report

October 2014

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SECTION 1
INTRODUCTION

The U.S. Environmental Protection Agency (EPA) Health and Environmental Impacts Division (HEID) has developed the Control Strategy Tool (CoST) to support national- and regional-scale multipollutant air quality modeling analyses. CoST allows users to estimate the emissions reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. The tool uses EPA HEID's Control Measures Database (CMDB) to develop control strategies and provides a user interface to that database. The CMDB is a relational database that contains information on an extensive set of control measures for point sources, nonpoint sources, and mobile sources. Information contained in the database includes descriptions of the measures, control efficiencies for the pollutants affected, costs of control, and the types of sources or processes to which the control measures can be applied. The database includes robust cost equations to determine engineering costs for some control measures that take into account how control costs vary with respect to variables for the source such as unit size or flow rate. The database also includes simple cost factors for all source types in terms of dollars per ton of pollutant reduced that can be used to calculate the cost of the control measure if the applicable source variable data are unavailable or no equation has been developed.

This report presents the results of an effort to review and enhance the CMDB with new and/or updated NOx control measure data for the following four industrial source categories: ammonia reformers, combustion turbines (nonEGU), glass manufacturing, and lean burn reciprocating internal combustion engines. Section 2 of this report describes the procedures used to locate more recent data than that currently in the CMDB for control measures applicable to ammonia reformers. Section 2 also identifies the source of the new data, describes any modifications to the assumptions or procedures in the referenced analyses needed to make the results consistent with results for other control measures in the database (such as operating hours for determination of total annual costs), and describes the specific recommended changes or additions to the database. Sections 3 through 5 of this report provide similar details for combustion turbines, glass manufacturing, and lean burn reciprocating internal combustion engines, respectively. Appendix A presents all of the records for ammonia reformer control measures in each of the CMDB tables showing their content after making the recommended revisions described in the report. Appendixes B through D provide comparable tables for the combustion turbine, glass manufacturing, and lean burn reciprocating internal combustion engine (RICE) source categories, respectively. Appendix E provides answers to questions on lean-burn RICE NOx

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emissions and available control measures. It should be noted that these revisions and updates will improve the accuracy and quality of NOx non-EGU control strategy and cost analyses for EPA rulemakings.

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SECTION 2
AMMONIA REFORMERS SECTOR

The control measures database includes the following NO_X emissions control measures for ammonia reformers:

- Oxygen trim and water injection,
- Low NO_X burners and flue gas recirculation,
- Selective non-catalytic reduction (SNCR),
- Selective catalytic reduction (SCR), and
- Low NO_X burners.

In order to update the existing control measures database, a literature search was conducted using the following terms:

- reformer
- cost
- "NO_X" or "nitrogen oxide"
- "Low NO_X burner" or "LNB"
- "Flue gas recirculation" or "FGR"
- oxygen trim
- water injection
- "Selective catalytic reduction" or "SCR"
- "Selective non catalytic reduction" or "SNCR"
- emission reduction
- control efficiency

Due to the use of SCR and SNCR to control NO_X emissions and the fact that ammonia is used in the operation of SCR and SNCR, the literature search resulted in NO_X reductions on processes other than ammonia production.

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In order to focus on ammonia production, a focused internet search for operating permits, BACT analyses, and NO_X controls was conducted using the 22 ammonia production facilities in the United States.

As a result of the following facts, most of the internet search results included NO_X reductions from the production of nitric acid production instead of ammonia production:

- The NO_X emissions from nitric acid production are covered by a New Source Performance Standard (NSPS) codified as Subpart G and Subpart Ga of Part 60.
- Nitric acid facilities covered by the NSPS are required to install NO_X continuous emission monitoring systems (CEMS).
- Many nitric acid facilities use SCR to control NO_X emissions.
- Many ammonia production facilities are co-located with nitric acid production facilities.

The internet search resulted in one new NO_X reduction project, which was the result of a voluntary agreement between Terra Nitrogen and the Indian Nations Council of Governments to install "ultra-low NO_X burner technology to an existing ammonia reformer [and] reduce the unit's NO_X emissions by approximately 60% at a projected capital cost of two million dollars." The existing ammonia reformer is located at Terra Nitrogen, L.P., Verdigris Plant in Claremore, Oklahoma.

Based on information known to EPA and collected for this report, Low NO_X burner technologies are known and demonstrated control techniques for ammonia reformers.

The following sections outline the deletions, additions, changes, and other comments recommended for the CMDB in relation to NO_X emissions from ammonia reformers.

2.1 Recommended Deletions

No deletions are recommended.

2.2 Recommended Additions

The only addition to the CMDB is to add the following reference: *Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O_3 Flex Program*. Prepared by Indian Nations Council of Governments (INCOG), 201 W. 5th Street, Suite 600, Tulsa, OK 74103. March 6, 2008. http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf.

This addition is shown in Appendix A as Table A-1.

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2.3 Recommended Changes

Updates to costs and Efficiencies.

Changes to one record (LNB applied to large source types) are recommended to reflect the new reference dated March 6, 2008.

Using the new reference and a reference already contained in the CMDB, the following assumptions were made:

- NO_X reductions of 425 tons per year[1]
- Capital cost of $2 million[1]
- Maintenance costs are 2.75% of capital costs[2]
- Equipment life of 10 years
- Interest rate of 7%
- Capital recovery factor of 0.1424.

The resulting annual costs are $339,800 and the cost effectiveness is $800 per ton of NO_X reduction (both in 2008 dollars). The capital to annual cost ratio is 5.9.

The previous entry showed a cost effectiveness of $650 per ton of NO_X reduction (in 1990 dollars) and a capital to annual cost ratio is 5.5. The changes are included in Appendix A as Table A-2 and Table A-3. Changes are indicated by red, italic text.

Updates to Source Classification Codes.

The U.S. Environmental Protection Agency (USEPA) developed the Source Classification Code (SCC) system, which assigns an eight digit code to each emission unit based on the general criteria pollutant emission point type, the major industry group, specific industry group, and specific process unit/fuel combination. The system allows similar emission points to be grouped together for analyses.

For ammonia reformers, there are seven applicable SCCs, as shown in Table 2-1.

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[1] Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf.

[2] U.S. Environmental Protection Agency. Alternative Control Techniques Document— NO_X Emissions from Process Heaters (Revised), document EPA-453/R-93-034, dated September 1993.

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Table 2-1. Applicable SCCs for the Ammonia Production Industry

SCC	SCC 1	SCC3	SCC6	SCC8
30100305	Industrial Processes	Chemical Manufacturing	Ammonia Production	Feedstock Desulfurization
30100306	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Natural Gas Fired
30100307	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Oil Fired
30100308	Industrial Processes	Chemical Manufacturing	Ammonia Production	Carbon Dioxide Regenerator
30100309	Industrial Processes	Chemical Manufacturing	Ammonia Production	Condensate Stripper
30100310	Industrial Processes	Chemical Manufacturing	Ammonia Production	Storage and Loading Tanks
30100399	Industrial Processes	Chemical Manufacturing	Ammonia Production	Other Not Classified

In an analysis of NO_X emissions for the Ozone Transport Region in 2011, four of the SCCs in Table 2-1 were identified. These SCCs are 30100306, 30100307, 30100310, and 30100399. Only SCCs 30100306 and 30100307 are associated with ammonia reformer NO_X controls in the current CMDB.

The known control techniques for ammonia reformers are typically used for point emission sources, such as stacks. Emissions from SCC 30100310 are not typically vented, so capture and control of these emissions is likely not feasible. Therefore, no changes related to SCC 30100310 are recommended for the CMDB.

For the purposes of this analysis, SCC 30100399 is assumed to include combustion emissions from gaseous fuels other than natural gas. Therefore, all control techniques that are applicable to natural gas fired ammonia reformers are assumed to also apply to SCC 30100399. Also, the cost to control NO_X emissions from gaseous fuels is assumed to be comparable to the cost to control NO_X emissions from natural gas. Therefore, the costs related to those control techniques are assumed to apply to SCC 30100399.

The applicable SCC from Table 2-1 was added to the Description field for each control technique in Table A-2 of Appendix A. SCC 30100306 was already included in the table; SCCs 30100305, 30100307, and 30100399 were added, where appropriate. Changes are indicated by red text.

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2.4 Other Comments

Control measures used by ICI boilers. Review of NO_X control measures used for boilers was not included in this analysis. However, many of the SCR costs in the CMDB for natural gas fired ammonia reformers are based on SCR costs for Industrial/Commercial/Institutional (ICI) Boilers using Process Gas. No SCR costs specific to ammonia reformers were noted in the CMDB.

At a later time, it may be pertinent to review recent final ICI Boilers regulations or other sources for potential updates to the cost of SCR on ammonia reformers. The final major source NESHAP for ICI Boilers was promulgated on January 31, 2013 and the final area source NESHAP for ICI Boilers was promulgated on February 1, 2013.

Potential NO_X limits for ammonia reformers based on boiler NO_X limits. According to NO_X Reasonably Acceptable Control Technology (RACT), the states of New Jersey and New York have established emission limits for ICI Natural Gas Boilers (greater than 100 million BTU per hour) that could be applicable to natural gas ammonia reformers. These RACT limits are shown in Table 2-2.

Table 2-2. RACT NO_X Limits for ICI Natural Gas Boilers

State	Boiler Size	Limit (lb NO_X/MMBTU)	Effective Date
New Jersey[a]	>100 MMBTU	0.10	Already in effect
New York	>100 MMBTU and ≤ 250 MMBTU	0.06	7/1/14
New York	> 250 MMBTU	0.08	7/1/14

[a] The limit also applies to other indirect heat exchangers.

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SECTION 3
COMBUSTION TURBINES

The CMDB includes the following NO_X emissions control measures for Combustion Turbines:

- Water injection for natural gas-fired turbines (achieves 76 percent reduction)
- Steam injection for natural gas-fired turbines (achieves 80 percent reduction)
- Low NOx Burners for natural gas-fired turbines (achieves 84 percent reduction)
- SCR on natural gas-fired turbines that also have water injection (achieves 95 percent reduction)
- SCR on natural gas-fired turbines that also have steam injection (achieves 95 percent control)
- SCR on natural gas-fired turbines that also have low NOx burners (achieves 94 percent reduction)
- Water injection for oil-fired turbines (achieves 68 percent reduction)
- SCR on oil-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for jet fuel-fired turbines (achieves 68 percent reduction)
- SCR on jet fuel-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for aeroderivative turbines (achieves 40 percent reduction)

All of the cost data are in 1990 dollars, except the costs of water injection for aeroderivative turbines, which are in 2005 dollars. In addition, all of the costs are based on estimated operation for 8,000 hr/yr, except the costs of water injection for aeroderivative turbines, which are for intermittently operated units. The costs in 1990 dollars are based primarily on analyses in EPA's 1993 ACT document for NOx Emissions from Stationary Gas Turbines (EPA, 1993). Capital and annual cost equations are provided for all of the controls except those for jet fuel-fired turbines and water injection for aeroderivative turbines.

Literature search. In order to update the existing CMDB, a literature search was conducted for articles and papers published since 2008. In addition, an internet search was conducted for BACT analysis reports and control technology reports prepared for federal and

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state agencies and RPOs. The literature search did not identify any documents with cost data, but the internet search identified the documents listed in Section 3.5 of this report.

Changes to CMDB. The following sections outline the deletions, additions, and other changes recommended for the CMDB in relation to NO_X emissions from Combustion Turbines. All cost data and calculations are in an Excel Worksheet (RTI, 2014). Copies of the CMDB tables with recommended revisions to the records for combustion turbine controls are provided in Appendix B.

The coefficient of determination (R^2) is 1.0 for many of the regression equations presented in sections 3.2 and 3.3. The R2 value is exactly 1.0 in cases where the analysis was based on only two data points; these cases are noted in the discussions for the particular control measure. In other cases, actual R2 values greater than 0.995 have been rounded to 1.0. These high values likely are due to the fact that available data for most control measures are from a single source, and those sources may have already developed a correlation and then picked specific data points from that correlation for presentation in their documentation.

3.1 Recommended Deletions

RTI recommends deleting the record for water injection for aeroderivative turbines because the estimated costs are for combustion turbines that operate on a limited and intermittent basis (i.e., peaking EGUs). In principle, data for small EGU combustion turbines would be acceptable for estimating costs of control measures for nonEGUs. However, the limited operation of peaking units is inconsistent with the assumed operating time of about 8,000 hr/yr for all of the other nonEGU combustion turbine control measures in the database. For several SCCs that are currently associated with this control measure in the CMDB we are recommending applying other existing control measures, as discussed in Section 3.3.11 of this report.

The CMDB also currently applies several gas turbine control measures to reciprocating internal combustion engine SCCs and to gas turbine SCCs for evaporative losses from fuel storage and delivery systems. We recommend deleting these applications of the gas turbine control measures, as discussed in Section 3.3.11 and Section 5.9 of this report.

3.2 Recommended Additions

There are 3 control technique additions for emerging technologies to be added to the CMDB; these additions include:

- Catalytic Combustion; Gas Turbines—Natural Gas;

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- EMx and Water Injection; Gas Turbines—Natural Gas;
- EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas.

3.2.1 Catalytic Combustion; Gas Turbines—Natural Gas (NCATCGTNG)

Catalytic combustion is a flameless process that allows fuel oxidation to occur at temperatures approximately 1800°F lower than those of conventional combustors (OSEC, 1999). Lower temperatures are desirable because NOx emissions levels are strongly correlated with temperature. One design that has been commercialized is the Xonon™ combustor (now called K-Lean™). In the Xonon combustor, a small amount of fuel is burned in a low temperature pre-combustor. Additional fuel is then mixed with the air and combustion gases from the pre-combustor and passed through a catalyst module. The catalyst promotes a flameless reaction between some of the fuel and oxygen. The gases then enter a burnout zone in which the remaining fuel burns. The maximum temperature in the system is between 2300°F and 2700°F. In addition to low NOx emissions, the catalytic combustor generates very little CO emissions. (Peltier, 2003; CARB, 2004; Leposky, 2004; Kawasaki, 2010; Quackenbush, 2012)

Since 1999 at least six Xonon combustors have been installed; all are 1.4 MW units (CARB, 2004; Kawasaki, 2010; Quackenbush, 2012). Testing of four of the operating Xonon combustors has shown NOx emissions less than 3 parts per million by volume on a dry basis (ppmvd) at 15% oxygen, and permit limits range from 3 ppmvd to 20 ppmvd at 15% oxygen (CARB, 2004; Quackenbush, 2012). Several companies have conducted research into developing larger catalytic combustors and other types of designs, but no information was found indicating that such units have been commercialized (CARB, 2004; Leposky, 2004; Cybulski, 2006).

Although one type of catalytic combustor has been commercialized, we recommend considering catalytic combustion as an emerging technology in the CMDB because so few units are in operation, and they are all only one size. In addition, as of 1999, issues with catalytic combustors include the need for the air-fuel mixture to have completely uniform temperature, composition, and velocity profile to assure effective use of all the catalyst and to prevent damage to the substrate from high temperatures. Also the catalyst durability is uncertain (OSEC, 1999).

The recommended costs are based on costs presented in a report by Onsite Sycom Energy Corporation (OSEC, 1999). The only change we made to the OSEC costs was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent; this change makes the capital recovery costs consistent with guidance in Circular A-4 from the Office of Management and Budget. Table 3-1 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the catalytic combustion NOx control technology. With an outlet

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concentration of 3 ppmvd, catalytic combustion achieves an average reduction of 98 percent relative to uncontrolled conventional diffusion combustion.

Table 3-1. Summary of Cost Effectiveness and Supporting Data for Catalytic Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (5.2)	1999	150	<365	3	920	1.7
Small (26.3)	1999	130	>365	3	670	1.2
Large (170)	1999	210	>365	3	370	0.7

Based on regression of the data in the analysis, the best fit trend lines are represented by the following equations for the uncontrolled scenario:

Total capital investment (1999 dollars) = 20668 x (MMBtu/hr) ^ 0.57 (R^2=1.0)

Total annual cost (1999 dollars) = 4254.2 x (MMBtu/hr) ^ 0.82 (R^2=1.0)

For all but the smallest turbines, the incremental cost of catalytic combustors relative to conventional combustors is less than the incremental cost of DLN combustion versus conventional combustors. Thus, there are no incremental capital costs for catalytic combustion relative to conventional combustion. However, there are incremental annual costs because the cost of catalyst replacement is high. A best fit equation for incremental catalytic combustion total annual costs relative to a RACT baseline of DLN combustion is:

Total annual cost (1999 dollars) = 743.22 x (MMBtu/hr) + 54105 (R^2=1.0)

3.2.2 EMx and Water Injection; Gas Turbines—Natural Gas (NEMXWGTNG)

Like SCR, EMx™ (formerly called SCONOX™) is a post-combustion catalytic NOx reduction technology. EMx uses a precious metal catalyst and a NOx absorption/regeneration process to convert CO and NOx to CO2, H2O, and N2. NOx reacts with the potassium carbonate absorbent coating the surface of the oxidation catalyst in the EMx reactor, forming potassium nitrites and nitrates that are deposited onto the catalyst surface. Each segment, or "can," within the reactor becomes saturated with potassium nitrites and nitrates over time and must be desorbed. Regeneration is accomplished by isolating the can via stainless steel lovers and

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injecting hydrogen diluted with steam. Hydrogen is generated onsite with a small reformer that uses natural gas and steam as input streams. The hydrogen concentration of the reformed gas is typically 5 percent. Hydrogen and carbon dioxide react with the potassium nitrites and nitrates to form N2 and H2O and to regenerate the potassium carbonate for another absorption cycle. (OSEC, 1999; CARB, 2004)

At least 8 EMx systems at 6 facilities have been installed on combustion turbines with capacities up to 45 MW. Permit limits at most of these facilities have been set at 2.5 ppmvd for gas-fired operation. EPA has certified it as "demonstrated in practice" LAER-level technology that reduces NOx to less than 5 ppmvd. The operating range of the catalyst is 300 to 700°F, which means the technology is not applicable for simple cycle turbines. The vendor for the technology has indicated that these systems also reduce carbon monoxide emissions to undetectable levels (essentially 100 percent reduction), reduce volatile organic compound emissions by greater than 90 percent, and reduce fine particulate matter emissions by 30 percent (EmeraChem, 2004). Test data documenting these reductions are not available. For the purposes of the CMDB database, we recommend that this control measure be listed as an emerging technology (rather than known) because its use has been limited to only a few small turbines.

The recommended costs for EMx in the combined EMx/water injection control measure are based on costs presented in a 2008 cost estimate prepared by EmeraChem Power for the Bay Area Air Quality Management District (ECP, 2008). For the purposes of developing 2008 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the ECP analysis:

- Increased the indirect cost for engineering from $200,000 to $255,000 for the 50 MW turbine. ECP's documentation indicated that this cost (as well as most of the other direct installation and indirect costs) would be the same as for an SCR system on the same turbine. The reported cost of $200,000 was inconsistent with this statement.

- Increased the contingencies cost for the 50 MW turbine from $76,486 to $244,101. This change makes the cost consistent with ECP's statement that the cost for contingencies is estimated to be equal to 5 percent of the total purchased equipment cost, excluding the cost of the precious metals in the catalyst, sales taxes, and freight.

- Added a cost for the performance loss due to back pressure from the EMx system for both turbines. ECP estimated the loss to be 0.5 percent, which is consistent with the estimate in the 1993 ACT for SCR and the estimate OSEC used in a cost analysis for SCONOx (EPA, 1993; OSEC, 1999). However, the ECP analysis did not include a corresponding dollar amount for this element.

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- Changed the operating hours from 7,884 hr/yr to 8,000 hr/yr. This change also had a small effect on the annual costs for utilities.

- Added costs for natural gas to generate steam for the 50 MW turbine using the same procedures presented in the ECP analysis for the 180 MW turbine. ECP did not report the basis for the amount of steam needed for the 180 MW turbine. Therefore, we plotted the reported steam consumption versus turbine size for this unit and for two turbines identified in a CARB analysis (CARB, 2004). We calculated the quantity of steam needed for EMx on the 50 MW turbine using the regression equation from this plot. Note that the unit cost for natural gas is $9.75/1000 scf. This was a reasonable annual average cost in 2008, but it would be much too high for an analysis in 2014.

- Deleted the credit for recovery of precious metals in the spent catalyst because the cost for replacement catalyst considers only the difference between the total purchase price minus the value of the recovered material.

- Estimated the annualized cost of replacement catalyst (both the non-precious metal substrate and the precious metal coating) using the future worth factor, whereas the cost in the ECP analysis was the purchased cost divided by the 10-year replacement interval.

- Estimated the cost of annual catalyst cleaning based on the average if data reported by CARB (CARB, 2004) plus the amounts reported by ECP. Although ECP reported a slightly higher cleaning cost for the 180 MW turbine than for the 50 MW turbine, an analysis of all the cleaning data showed no correlation with turbine size. Thus, we used the average of all reported costs for both turbines.

- Revised the indirect annual cost for administrative charges. ECP estimated that these costs are the same as for an SCR system on the same turbines. We factored the cost as 2 percent of the TCI for the applicable EMx systems, which is consistent with the approach for all control devices in the EPA Control Cost Manual. This resulted in slightly higher costs.

- Increased the indirect costs for insurance, property tax, and capital recovery for both turbines because the ECP analysis excluded the precious metal costs from the TCI used in these calculations.

- Calculated capital recovery using an interest rate of 7 percent instead of 10 percent.

The capital costs for water injection in the combined EMx/water injection control measure were estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Total annual costs for water injection were first estimated in 1999 dollars using the regression equation for the water injection control option. On average, 25 percent of these costs were estimated to be for indirect costs that are factored from

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the system capital cost, and the remaining 75 percent is for direct annual costs and overhead. To estimate the total annual costs for water injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-2 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus water injection NOx control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion.

Table 3-2. Summary of Cost Effectiveness and Supporting Data for EMx Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		EMx Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg ppmvd	tpy				
Large (50-180)	2008	160[a]	>365	2.0	2,760	3.1	6,810

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the R^2 =1.0 for both equations because there were only two data points in the analysis):

Total capital investment (2008 dollars) = 196928 x (MMBtu/hr) ^ 0.68

Total annual cost (2008 dollars) = 18747 x (MMBtu/hr) ^ 0.86

Best fit equations for incremental EMx costs relative to a RACT baseline of water injection are:

Total capital investment (2008 dollars) = 156349 x (MMBtu/hr) ^ 0.68

Total annual cost (2008 dollars) = 17252 x (MMBtu/hr) ^ 0.80

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3.2.3 EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NEMXDGTNG)

Table 3-3 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus dry low NOx combustion control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion. For the same reasons noted in Section 3.2.2, we recommend that this control measure be listed as an emerging technology in the CMDB.

Table 3-3. Summary of Cost Effectiveness and Supporting Data for EMx Plus Dry Low NOx Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		EMx Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, $/ton NOx
		Avg ppmvd	tpy				
Small (4.2)	1999	134	<365	2.0	2,860	3.9	14,940
Small (23)	1999	174	>365	2.0	1,720	4.1	10,270
Large (170)	1999	210	>365	2.0	840	3.9	6,600
Large (50-180)	2008	160[a]	>365	2.0	2,050	4.1	12,390

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

The recommended costs for EMx in 2008 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the EMx/water injection control measure described in Section 3.2.2. The recommended costs for EMx in 1999 dollars are based on an analysis prepared by Onsite Sycom Energy Corporation (OSEC, 1999). For this analysis the only changes we made to OSEC's analysis were to reduce the operating hours from 8,400 hr/yr to 8,000 hr/yr, which slightly reduced the energy penalty and utilities costs, and we calculated the capital recovery factor using an interest rate of 7 percent instead of 10 percent. Note that the total annual costs for natural gas (or purchased steam) are considerably lower in this analysis than in the 2008 analysis because the unit cost of natural gas was considerably lower in 1999.

The recommended total capital investment and total annual cost for dry low NOx combustion in 1999 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the dry low NOx combustion control measure alone as described in Section 3.3.3. The recommended total capital investment for dry low NOx combustion in 2008

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dollars was estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the CEPCI. The recommended total annual costs for dry low NOx combustion consist of capital recovery plus the cost for parts and repair; capital recovery costs in 2008 dollars were estimated by escalating the 1999 costs using the CEPCI, and annual parts and repairs costs were assumed to be the same in 2008 as in 1999.

Based on regression of the data in both the 1999 and 2008 cost analyses, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the R^2 =1.0 for the equations in 2008 dollars because there were only two data points in the analysis; R^2 for the equations in 1999 dollars round to 1.0 when only two significant figures are presented):

Total capital investment (1999 dollars) = 58237 x (MMBtu/hr) ^ 0.78

Total annual cost (1999 dollars) = 15004 x (MMBtu/hr) ^ 0.78

Total capital investment (2008 dollars) = 126892 x (MMBtu/hr) ^ 0.74

Total annual cost (2008 dollars) = 20041 x (MMBtu/hr) ^ 0.80

Best fit equations for incremental EMx costs relative to a RACT baseline of DLN combustion are:

Total capital investment (1999 dollars) = 65163 x (MMBtu/hr) ^ 0.72

Total annual cost (1999 dollars) = 13702 x (MMBtu/hr) ^ 0.76

Total capital investment (2008 dollars) = 156349 x (MMBtu/hr) ^ 0.68

Total annual cost (2008 dollars) = 17252 x (MMBtu/hr) ^ 0.80

3.3 Recommended Changes

This section presents updated cost estimates for combustion turbine control measures that are currently in the CMDB, and it describes the basis for such changes. These changes include both more recent costs for some control measures as well as minor revisions to existing estimates for other control measures. The changes affect both cost per ton values and equations.

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This section also identifies applicable SCCs for the new control measures described in Section 3.2, and it identifies additional SCCs for which the control measures in this section are applicable.

3.3.1 Water Injection; Gas Turbines—Natural Gas (NWTINGTNG)

Recommended updates to the costs for water injection are based on analyses in a report prepared by OnSite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the same small turbine model sizes as in EPA's 1993 ACT document (4 MW and 23 MW). OSEC obtained water injection equipment costs in 1999 dollars. They then estimated total capital investment and total annual costs using the same procedures as in the 1993 ACT document, and they concluded that 1999 costs for water injection were essentially the same as the 1990 costs presented in the ACT document. Because the ACT analysis included a greater number of models over a wider range of sizes, RTI recommends continuing to use the cost data from the ACT analysis in the CMDB, except the cost year should be updated from 1990 to 1999. RTI also recommends the four additional changes noted below.

Our second recommendation is to split the record for small sources into two records—one for sources with uncontrolled emissions less than 365 tpy, and the other for emissions greater than 365 tpy. The 2006 AirControlNET Documentation Report indicates that small sources are turbines with design outputs up to 34.4 MW. Four model turbines in the ACT analysis have outputs below this threshold. The two turbines with uncontrolled emissions <365 tpy have an average cost effectiveness of $1,790/ton of NOx. The two turbines with uncontrolled emissions >365 tpy have an average cost effectiveness of $1,000/ton of NOx.

Our third recommendation is to revise the control efficiency for water injection from 76 percent to 72 percent. The 76 percent control level is the average reduction for all 6 model turbines in the 1993 ACT analysis. Five of those models were guaranteed to reduce NOx emissions to less than 42 ppmvd, while the sixth was guaranteed to meet 25 ppmvd. Although water injection may be more effective on some combustion turbines than others, 42 ppmvd is the generally accepted threshold. Thus, we think this threshold should be incorporated in the CMDB. The average reduction of the 5 models in the 1993 ACT analysis with an outlet concentration of 42 ppmvd was 72 percent.

Our fourth recommendation is to use a capital to annual cost ratio of 2.4 in the new record for small sources with uncontrolled emissions >365 tpy; this is the average value for the two turbines in the ACT analysis in this size range. (The capital to annual cost ratio for the small sources with uncontrolled emissions <365 tpy would remain at 3.1 because this is the average

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value for the two turbines in this size range; it is not clear why this value was applied for all small sources in the current version of the CMDB.) The total annual costs in this calculation are based on using a 7 percent interest rate in the calculation of capital recovery, instead of the 10 percent value in the 1993 ACT. Even if capital recovery was estimated using the 10 percent interest rate, it is not clear how the 3.1 value was developed.

Our fifth recommendation is to revise the constants in the CMDB table of equations for estimating capital and annual costs. Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 27665 \times (\text{MMBtu/hr})^{0.69} \quad (R^2 = 0.97)$$

$$\text{Total annual cost (1999 dollars)} = 3700.2 \times (\text{MMBtu/hr})^{0.95} \quad (R^2 = 0.95)$$

3.3.2 Steam Injection; Gas Turbines—Natural Gas (NSTINGTNG)

The only available information on the cost of steam injection was in the 1999 report from Onsite Sycom Energy Corporation (OSEC, 1999). OSEC discussed steam injection only in the context of large GE Frame 7F turbines (170 MW). They noted that only the first such model, operational in 1990 when the ACT analysis was being conducted, was equipped with steam injection. All subsequent units (at least through 1999) were equipped with DLN combustion technology.

Because the limited available information suggests that steam injection costs, like water injection costs, were essentially the same in 1999 as in 1990, we recommend continuing to base the steam injection costs on the results in the 1993 ACT, but update the cost year from 1990 to 1999. In addition, as for water injection, we recommend splitting the one record for small sources into two records—one for sources with uncontrolled NOx emissions <365 tpy, and the other for uncontrolled NOx emissions >365 tpy. This split results in average cost effectiveness values of $1,690/ton of NOx for the small sources with uncontrolled NOx emissions <365 tons/yr and $820/ton of NOx for the small sources with uncontrolled NOx emissions >365 tons/yr. The capital cost to annual cost ratios also are slightly less than the current values in the CMDB.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

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Total capital investment (1999 dollars) = 43092 x (MMBtu/hr) ^ 0.82 (R^2=0.95)

Total annual cost (1999 dollars) = 7282 x (MMBtu/hr) ^ 0.76 (R^2=0.96)

3.3.3 Dry Low NOx Combustion; Gas Turbines—Natural Gas (NDLNCGTNG)

Dry low NOx (DLN) combustion technology premixes air and a lean fuel mixture that significantly reduces peak flame temperature and thermal NOx formation. In some cases, this can be accomplished by using low NOx burners, but in other cases, the combustor design itself differs as well as the burner design. For example, the DLN combustor volume is typically twice that of a conventional combustor (OSEC, 1999). Therefore, we recommend revising the current control technology name in the CMDB from "Low NOx Burners" to "Dry Low NOx Combustion." In addition, the CM abbreviation should be changed from NLNBUGTNG to NDLNCGTNG.

Recommended updates to the costs for DLN Combustion are based on analyses in a report prepared by Onsite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the six turbines with design outputs ranging from 4 MW to 169 MW.

OSEC obtained installed equipment costs and annual repair costs in 1999 dollars from three turbine manufacturers, but there are some uncertainties in the data. Although the reported tabular summary indicates the equipment costs are incremental relative to the cost of a conventional combustor, the text of the report states that the costs for 169 MW turbines are the total cost to replace a conventional combustor (which may explain why the regression equation for the capital costs is linear rather than a power function). Annual costs for parts and repair for some of the turbines were proprietary for two of the small turbines and thus could not be reported. As a result, the annual costs for those turbines are biased low. In addition, because parts and repair costs were unavailable for the 169 MW turbine, OSEC assumed these costs could be represented by the costs for the 23 MW turbine.

The only change we made to the assumptions and data reported by OSEC was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent.

Table 3-4 summarizes the recommended new cost effectiveness and capital to annual cost ratios for implementing the DLN combustion NOx control technology. In addition to changing these costs in the CMDB, we also recommend changing the control efficiency for DLN combustion applied to small sources from 68 percent to 84 percent. The 84 percent level is

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currently used for large sources, and it is consistent with the efficiency for DLN combustion (or low NOx burners) in the 1993 ACT. It appears the 68 percent entry was a data transcription error because that is the control efficiency for water injection applied to oil-fired turbines.

Table 3-4. Summary of Cost Effectiveness and Supporting Data for DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (4-23)	1999	152	<365	25	300	5.0
Large (170)	1999	210	>365	25	130	7.4

Based on regression of the data in both analyses, the best fit trend lines are represented by the following revised equations for both uncontrolled and RACT baseline scenarios:

Total capital investment (1999 dollars) = 2860.6 x (MMBtu/hr) + 25427 (R^2=1.0)

Total annual cost (1999 dollars) = 584.5 x (MMBtu/hr) ^ $^{0.96}$ (R^2=0.95)

3.3.4 SCR and Water Injection; Gas Turbines—Natural Gas (NSCRWGTNG)

Recommended updates to the costs for SCR combined with water injection are based on two sets of cost analyses. One set of costs is in 1999 dollars for three turbines ranging in size from 4.2 MW to 161 MW (OSEC, 1999). The second is in 2008 dollars for two larger turbines with design outputs of 50 MW and 180 MW (ECP, 2008). For SCR, the referenced analyses estimated direct installation costs and indirect costs based on scaling from the purchased equipment costs using standard factors as in the Control Cost Manual. Annual costs were estimated for the same cost elements that were used in the SCR analysis in the 1993 ACT. Water injection costs for the two smallest turbines in the 1999 analysis were estimated as described above for the water injection control option. Water injection costs for the large turbines were not estimated in the referenced analyses.

For the purposes of developing 1999 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the OSEC analysis:

- Increased the engineering cost for SCR for the 161 MW turbine from $100,000 to $228,865. The revised value is equal to 10 percent of the purchased equipment cost, which is consistent with the approach used for the smaller turbines. The report did not explain why $100,000 was used instead of the factor.

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- Estimated performance penalty costs and electricity costs for the blower and pumps in the ammonia injection system using operating hours of 8,000 hr/yr instead of 8,400 hr/yr.

- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.

- Calculated annual catalyst replacement and disposal costs using a future worth factor instead of a capital recovery factor.

- Estimated total capital investment and total annual costs for the 161 MW turbine using the regression equations for the water injection control option. (Maybe it would be better to drop the large model from this analysis and just present 1999 costs for small turbines and 2008 costs for large turbines.)

For the purposes of developing 2008 cost inputs for the CMDB, we started with the ECP analysis for SCR costs and then made the following changes to the data and assumptions:

- Calculated the performance penalty for SCR using an electricity cost of $0.06/kwh instead of $0.1/kwh and 8,000 hr/yr instead of 8,400 hr/yr. In addition, although it appears that the referenced analysis assumed a performance loss equal to 0.5 percent of the turbine's design output, the cited cost was significantly greater than it should be for that percentage loss, even if the cited electricity cost and operating hours were used in the calculation. We changed the cost to be consistent with the calculated amount.

- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.

- Estimated capital costs for water injection in 1999 dollars using the regression equation for the water injection control option, and then scaled the costs to 2008 dollars using the CEPCI.

- Estimated total annual costs for water injection following the same procedure described in Section 3.2.2 for the water injection portion of a combined water injection and EMx control measure. Thus, the total annual costs for water injection are the same in both control measures.

Table 3-5 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on natural gas-fired combustion turbines. Table 3-5 also presents revised incremental costs of SCR relative to a RACT baseline of water injection for the different categories of turbines. Note that the SCR outlet NOx level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC and ACT analyses.

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Table 3-5. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	2,790	3.0	5,840
Small (22.7)	1999	174	>365	9	1,370	2.9	3,130
Large (161)	1999	210	>365	9	1,070	1.5	1,690
Large (50-180)	2008	160[a]	>365	2.5	1,830	2.7	3,170

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in both analyses, the revised best fit trend lines are represented by the following power equations for both uncontrolled scenarios (R^2=1 for the 2008 costs because the analysis was based on only two data points):

Total capital investment (1999 dollars) = 62962 x (MMBtu/hr) ^ 0.66 (R^2=1.0)

Total annual cost (1999 dollars) = 8590 x (MMBtu/hr) ^ 0.87 (R^2=0.99)

Total capital investment (2008 dollars) = 34533 x (MMBtu/hr) ^ 0.85 (R^2=1.0)

Total annual cost (2008 dollars) = 6794 x (MMBtu/hr) ^ 0.94 (R^2=1.0)

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are (R^2=1 for the 2008 costs because the analysis was based on only two data points):

Total capital investment (1999 dollars) = 37193 x (MMBtu/hr) ^ 0.63 (R^2=1.0)

Total annual cost (1999 dollars) = 12065 x (MMBtu/hr) ^ 0.64 (R^2=1.0)

Total capital investment (2008 dollars) = 10323 x (MMBtu/hr) ^ 0.96 (R^2=1.0)

Total annual cost (2008 dollars) = 3106.1 x (MMBtu/hr) ^ 0.94 (R^2=1.0)

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3.3.5 SCR and Steam Injection; Gas Turbines—Natural Gas (NSCTSGTNG)

Combined costs for SCR and steam injection were not presented in any available references. Thus, costs for combined control systems were estimated in 1999 dollars for four model turbines ranging from 4 MW to 161 MW using the procedures described above for steam injection alone and for SCR as part of combined SCR and water injection control systems. Specifically, steam injection costs for each model turbine were assumed to be the same as in the 1993 ACT, consistent with the description above for steam injection control costs. Since OSEC did not estimate SCR costs for the specific turbines in this analysis, we estimated the SCR costs using the trendlines that we developed for incremental SCR costs relative to a RACT baseline of water injection. We then summed the separate SCR and steam injection costs to obtain the combined system costs.

We also estimated costs for a combined steam injection and SCR control measure in 2008 dollars. The SCR portion of the costs are the same as for SCR in the combined water injection plus SCR control measure, as described in Section 3.3.4. Total capital investment for the steam injection portion were estimated in 1999 dollars using the regression equation developed for steam injection alone, as described in Section 3.3.2. These costs were escalated to 2008 costs using the CEPCI. Total annual costs for steam injection were first estimated in 1999 dollars using the regression equation for the steam injection control option (see Section 3.3.2). On average, 40 percent of these costs were estimated to be for indirect costs that are factored from the system capital cost, and the remaining 60 percent is for direct annual costs and overhead. To estimate the total annual costs for steam injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-6 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus steam injection on natural gas-fired combustion turbines. Table 3-6 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the incremental costs are slightly different from the costs in Table 3-5. The costs should be the same for a given turbine category. They differ because the two analyses examined a different number of turbines, and the sizes were not exactly the same. At a later date, the analysis could be improved by combining the SCR costs from both analyses and developing a single set of incremental SCR costs.

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Table 3-6. Summary of Cost Effectiveness and Supporting Data for SCR Plus Steam Injection (SI)

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of SI, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	155	<365	9	2,570	3.3	5,550
Small (26.8)	1999	142	>365	9	1,380	3.1	2,870
Large (83–161)	1999	300	>365	9	570	2.7	1,810
Large (50–180)	2008	160[a]	>365	2.5	1,420	3.9	3,170

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the revised best fit trend lines are represented by the following power equations for the uncontrolled scenario (R^2=1 for the 2008 costs because the analysis was based on only two data points):

Total capital investment (1999 dollars) = 72169 x (MMBtu/hr) ^ 0.66 (R^2=0.99)

Total annual cost (1999 dollars) = 17551 x (MMBtu/hr) ^ 0.72 (R^2=0.98)

Total capital investment (2008 dollars) = 46492 x (MMBtu/hr) ^ 0.82 (R^2=1.0)

Total annual cost (2008 dollars) = 8704 x (MMBtu/hr) ^ 0.86 (R^2=1.0)

Revised best fit equations for incremental SCR costs relative to a RACT baseline of steam injection are assumed to be the same as noted above in the discussion of costs for SCR and water injection.

3.3.6 SCR and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NSCRDGTNG)

Updated costs for combined SCR and DLN combustion control systems were estimated in 1999 dollars for all turbine sizes, 2007 dollars for small turbines, and 2008 dollars for large turbines. The 1999 costs were estimated by combining the separate costs for DLN combustion and SCR provided by Onsite Sycom Energy Systems (OSEC, 1999). The 2007 costs were estimated by combining SCR costs developed by Energy and Environmental Analysis in a report prepared for EPA with the OSEC costs for DLN combustion in 1999 dollars, escalated to 2007 dollars (EEA, 2008). Similarly, costs in 2008 dollars were estimated by combining SCR costs

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developed by EmeraChem Power in an analysis for the Bay Area Air Quality Management District with escalated DLN combustion costs (ECP, 2008). The EEA analysis provided only capital costs; therefore, we estimated annual costs using the same factors provided in ECP's analysis of costs in 2008 dollars. For both the 2007 and 2008 cost estimates, DLN capital costs and capital recovery were escalated from 1999 dollars using the CEPCI, and annual parts and repairs costs were assumed to be the same in all three years.

Table 3-7 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus dry low NOx combustion on natural gas-fired combustion turbines. Table 3-7 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the SCR outlet NOx level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC analyses. We also used an outlet concentration of 2.5 ppmvd to estimate emissions to use with EEA's 2007 costs. The ECP and EEA analyses did not specify inlet NOx emissions concentrations to the SCR; therefore, we assumed 25 ppmvd, as in other DLN analyses. We also assumed an average uncontrolled emissions level of 160 ppmvd for all models so that the overall control efficiency of the DLN combustion plus the SCR was 98 percent. Note that the incremental costs in 1999 dollars are significantly higher than those for SCR following water injection and steam injection; this is due to the inlet concentration being 25 ppmvd for this analysis and 42 ppmvd for water injection and steam injection.

Table 3-7. Summary of Cost Effectiveness and Supporting Data for SCR Plus DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	1,800	2.9	11,900
Small (26.8)	1999	174	>365	9	990	3.6	6,320
Large (161)	1999	210	>365	9	390	4.2	3,340
Small (1–10.2)	2007	160[a]	<365	2.5	2,910	4.3	18,900
Small (25)	2007	160[a]	>365	2.5	1,460	3.8	7,510
Large (50–180)	2008	160[a]	>365	2.5	1,040	4.5	5,560

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

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Based on regression of the data in each analysis, the best fit trend lines are represented by the following power equations for uncontrolled scenarios (R^2=1 for the 2008 costs because the analysis was based on only two data points, and note that the R^2 for the 2007 equations is not meaningful because the DLN portion of the costs are based on a regression equation instead of independent, model-specific data):

Total capital investment (1999 dollars) = 24854 x (MMBtu/hr) ^ $^{0.79}$ (R^2=1.0)

Total annual cost (1999 dollars) = 12725 x (MMBtu/hr) ^ $^{0.69}$ (R^2=1.0)

Total capital investment (2007 dollars) = 187647 x (MMBtu/hr) ^ $^{0.54}$ (R^2=1.0)

Total annual cost (2007 dollars) = 2782 x (MMBtu/hr) + 167494 (R^2=1.0)

Total capital investment (2008 dollars) = 14790 x (MMBtu/hr) ^ $^{0.97}$ (R^2=1.0)

Total annual cost (2008 dollars) = 5263.5 x (MMBtu/hr) ^ $^{0.90}$ (R^2=1.0)

The equations to estimate incremental costs for SCR relative to a RACT baseline of dry low NOx combustion in 1999 dollars and 2008 dollars are assumed to be the same as noted in Section 3.3.4 for incremental costs relative to a RACT baseline of water injection. Incremental costs for SCR relative to a RACT baseline of water injection in 2007 dollars are estimated using the following equations:

Total capital investment (2007 dollars) = 210883 x (MMBtu/hr) ^ $^{0.46}$ (R^2=1.0)

Total annual cost (2007 dollars) = 1894 x (MMBtu/hr) + 185570 (R^2=0.99)

3.3.7 Water Injection; Gas Turbines—Oil (NWTINGTOL)

No new data are available on costs of water injection for oil-fired combustion turbines. However, because the water injection costs for natural gas-fired turbines were determined to be essentially the same in 1999 as in 1990, we assume the same would be true for water injection on oil-fired turbines; the costs for both types of turbines also were the same in the 1993 ACT analysis. Therefore, we recommend continuing to base costs on the results of the 1993 ACT analysis, but to update the cost year from 1990 to 1999. In addition, we changed the size of the large model in the ACT analysis from 83.3 MW to 84.7 MW because it appears the incorrect

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model was used in the ACT analysis. As for the natural gas-fired turbines, we also recommend splitting the single record for small sources into two records—one for source with uncontrolled NOx emissions <365 tpy, and the other for sources with uncontrolled NOx emissions >365 tpy. The resulting cost effectiveness values for the turbines with uncontrolled NOx emissions <365 tpy and >365 tpy are $1,630/ton of NOx and $960/ton of NOx, respectively. The capital to annual cost ratios also change slightly.

As for other control technologies, the constants in the equations to estimate total capital costs and total annual costs differ from those in the regression analyses performed in Excel. In this case, the differences are small, but we recommend revising the constants so that all equations are developed based on the same approach. The revised equations for both the uncontrolled and RACT baseline scenarios are:

$$\text{Total capital investment (1999 dollars)} = 43255 \times (\text{MMBtu/hr})^{0.60} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 6796.8 \times (\text{MMBtu/hr})^{0.80} \quad (R^2=1.0)$$

3.3.8 SCR and Water Injection; Gas Turbines—Oil (NSCRWGTNG)

SCR costs were developed in a BACT analysis for a 48 MW oil-fired combustion turbine (FMPA, 2004). Because water injection costs in 2004 dollars are not available, we calculated costs in 1999 dollars as described above for the water injection option, and then estimated costs in 2004 dollars by scaling up the 1999 capital costs (and capital recovery) using the CEPCI; other annual operating and maintenance costs were assumed to be unchanged. We used the SCR capital cost as presented in the FMPA analysis, but we made several changes to the annual costs. Although the original values may have been appropriate for the specific application evaluated by FMPA, the following changes were made to be consistent with the calculations for other controls in this analysis:

- Estimated O&M costs assuming operation for 8,000 hr/yr instead of 4,422 hr/yr.
- Excluded cost for one week of lost power generation while catalyst is being replaced, assuming that catalyst replacement can be performed during scheduled annual downtime.
- Reduced sales tax and freight cost for catalyst from 12.25 percent of the purchased cost to 8 percent of the purchased cost.
- Deleted capital recovery cost for catalyst because the catalyst is replaced annually.

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- The reported annual cost for ammonia was based on a stoichiometric ratio of 1.4 (possibly because they assumed a significant generation of NO2 relative to NO). They also applied a factor of 1.05, apparently to account for ammonia slip, as in the Control Cost Manual procedures for SCR on boilers. However, both factors should not be needed. For this analysis, we used just the 1.05 factor (also used the reported unit cost of $750/ton of ammonia, which may have been high for 2004).

- Reduced the property tax factor from 2.75 percent of the TCI to 1 percent of the TCI.

Table 3-8 summarizes the recommended cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on oil-fired combustion turbines. Table 3-8 also presents incremental costs of SCR relative to a RACT baseline of water injection. The 1990 costs are essentially the same as the costs currently in the CMDB, except that we recommend splitting the one record for small sources into two records.

Table 3-8. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection (WI) for Oil-Fired Turbines

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg. ppmvd	tpy				
Small (3.3)	1990	179	<365	18	3,200	2.9	7,620
Small (26.3)	1990	211	>365	18	1,320	2.3	2,450
Large (84)	1990	228	>365	18	1,000	2.4	2,210
Large (48)	2004	200[a]	>365	5	1,560	2.3	4,790

aThe referenced analysis did not report an uncontrolled emissions level. The value used in this analysis is the average of the uncontrolled emissions concentrations for oil-fired model turbines in the 1993 ACT.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for the uncontrolled scenario:

$$\text{Total capital investment (1990 dollars)} = 95837 \times (\text{MMBtu/hr})^{0.62} \quad (R^2=0.99)$$

$$\text{Total annual cost (1990 dollars)} = 25990 \times (\text{MMBtu/hr})^{0.70} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are:

$$\text{Total capital investment (1990 dollars)} = 4744 \times (\text{MMBtu/hr}) + 368162 \quad (R^2=1.0)$$

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Total annual cost (1990 dollars) = 1522.5 x (MMBtu/hr) + 142643 (R^2=1.0)

We could not develop equations for this control system in 2004 dollars because 2004 data are available for only one turbine, and thus are insufficient for this purpose.

3.3.9 Water Injection; Gas Turbines—Jet Fuel (NWTINGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.10 SCR and Water Injection; Gas Turbines—Jet Fuel (NSCTWGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.11 Applicable Control Measures for Gas Turbine SCCs

The first column in Table 3-9 lists all of the gas turbine SCCs that are associated with one or more gas turbine control measures in the CMDB table called "Table 03_SCCs." In addition, the last seven SCCs in Table 3-9 are additional gas turbine SCCs that are not currently assigned any NOx control measures in the CMDB. These seven SCCs, as well as many of the others at the top of Table 3-9, were identified with NOx emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100^{o}W longitude). The first 11 control measures in column headings in Table 3-9 are the gas turbine control measures that are currently in the CMDB; the last three column headings are the new control measures identified in this review and described in Section 3.2 of this report.

Each control measure that was determined to be applicable for a specific SCC is identified by either an "E" or an "N" in the cell at the intersection of the applicable SCC row and the control measure column. An "E" means the control measure is already listed in the CMDB for the particular SCC, and we concur with that designation. An "N" means the control measure is not currently linked to a particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for turbines that are fired with relatively uncommon fuels such as landfill gas or gasoline. We have not located any analyses that determined the applicable controls and related costs for gas turbines fired with such fuels. In order to conduct CoST modeling analyses for these turbines, the most representative available control measures

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Table 3-9. Recommended Control Measures for Gas Turbine SCCs

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]												
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
20200101	ICE	Ind	Distillate Oil (Diesel)	Turbine	E	E												
20200103	ICE	Ind	Distillate Oil (Diesel)	Turbine: Cogeneration	E	E												
20200108	ICE	Ind	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D												
20200109	ICE	Ind	Distillate Oil (Diesel)	Turbine: Exhaust	E	E												
20200201	ICE	Ind	Natural Gas	Turbine					E	E	E	E	E	E	D	N	N	N
20200203	ICE	Ind	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	D	N	N	N
20200208	ICE	Ind	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D			
20200209	ICE	Ind	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	D	N	N	N
20200701	ICE	Ind	Process Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200705	ICE	Ind	Process Gas	Refinery Gas: Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200713	ICE	Ind	Process Gas	Turbine: Evap Losses											D			
20200714	ICE	Ind	Process Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200901	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine			E	E										
20200908	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses			D	D										
20200909	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust			E	E										
20201008	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses											D			

(continued)

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Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
20201009	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	N[e]	N[e]									D			
20201011	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine	N[e]	N[e]									D			
20201013	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	N[e]	N[e]									D			
20300102	ICE	C/I	Distillate Oil (Diesel)	Turbine	E	E												
20300108	ICE	C/I	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D												
20300109	ICE	C/I	Distillate Oil (Diesel)	Turbine: Exhaust	E	E												
20300202	ICE	C/I	Natural Gas	Turbine					E	E	E	E	E	E	D	N	N	N
20300203	ICE	C/I	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	D	N	N	N
20300208	ICE	C/I	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D			
20300209	ICE	C/I	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	D	N	N	N
20300701	ICE	C/I	Digester Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300708	ICE	C/I	Digester Gas	Turbine: Evap Losses											D			
20300709	ICE	C/I	Digester Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300801	ICE	C/I	Landfill Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300808	ICE	C/I	Landfill Gas	Turbine: Evap Losses											D			
20300809	ICE	C/I	Landfill Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20400301	ICE	ET	Turbine	Natural Gas					N	N	N	N	N	N	D	N	N	N
20400304	ICE	ET	Turbine	Landfill Gas					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]

(continued)

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Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
50100420	WD	SWD-G	Landfill Dump	Waste Gas Recovery: GT					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20201609	ICE	Ind	Methanol	Turbine: Exhaust	N[e]	N[e]												
20201701	ICE	Ind	Gasoline	Turbine	N[e]	N[e]												
20300901	ICE	C/I	Kerosene/Naphtha (Jet Fuel)	Turbine: JP-4			N	N										
20400302	ICE	ET	Turbine	Diesel/Kerosene	N	N												
20400303	ICE	ET	Turbine	Distillate Oil	N	N												
20400305	ICE	ET	Turbine	Kerosene/Naphtha			N	N										
20400399	ICE	ET	Turbine	Other Not Classified[f]	N[e]	N[e]												

[a]SCCs in regular font are associated with one or more gas turbine control measures in the current CMDB. The SCCs in bold font represent gas turbine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with gas turbine control measures in the current CMDB.

[b]ICE means "Internal Combustion Engines" and WD means "Waste Disposal."

[c]Ind means "Industrial," C/I means "Commercial/Institutional," ET means "Engine Testing," and SWD-G means "Solid Waste Disposal-Government."

[d]An "E" means the control measure is currently associated with the SCC in the CMDB, and no changes are recommended. A "D" means the control measure is currently associated with the SCC, but this control measure should be deleted because it is not appropriate for the SCC. An "N" means the control measure is not currently associated with the SCC in the CMDB, but adding it is recommended.

[e]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

[f]The fuel type is unknown. For the purposes of this analysis it is assumed to be a liquid because most of the emissions identified for the engine testing SCCs in the analysis done in the Ozone Transport Assessment Group Region were from liquid fuel-fired turbines.

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should be assigned. For turbines that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired turbines. Similarly, for turbines that burn miscellaneous liquid fuels, the most representative available control measures are those for oil-fired turbines. The description field in the CMDB table called "Table 02_Efficiencies" could be revised to indicate that the control measures for natural gas units are assumed to be applicable for all gaseous fuel fired units, and the control measures for oil-fired units are assumed to be applicable for all liquid fuel-fired units (note that the separate control measures already in the CMDB for jet fuel-fired turbines are also based on the data for oil-fired units).

Finally, gas turbine SCCs for evaporative losses from turbine fuel storage and delivery systems are associated with NOx control measures in the current CMDB. We recommend deleting these NOx control measure/SCC records from the CMDB table called "Table 03_SCCs" because there should be no NOx emissions from the sources represented by these SCCs. These control measure/SCC combinations are identified with a "D" in the applicable cells in Table 3-9.

3.4 Example Emission Limits for NonEGU Combustion Turbines

NonEGU combustion turbines are subject to several emission regulations, including NSPS in 40 CFR part 60 and various state regulations. Example emission limits in state regulations are presented in Table 3-10.

Table 3-10. NOx Emissions Limits for NonEGU Combustion Turbines in New York

State	Type of Service	Type of Combustion Turbine Operating Cycle	Emission Limit	Effective Date
New York[a]	Any—gaseous fuel	Combined cycle	42 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	50 ppmdv (at 15% O2)	Current
	Any—oil-fired	Combined cycle	65 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	100 ppmdv (at 15% O2)	Current

[a]The requirements apply to combustion turbines with a maximum heat input rate greater than or equal to 10 million Btu per hour at major sources of NOx emissions. The specified limits apply until July 1, 2014; beginning on July 1, 2014, owners/operators must submit a proposal for RACT (NYCRR, 2014).

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SECTION 4
GLASS MANUFACTURING SECTOR

4.1 Introduction

The control cost database separates the glass manufacturing sector into four different types; flat glass, container glass, pressed glass, and general glass manufacturing. The CMDB listed six different control technologies for NOx emissions which were all reviewed in 2006 and included cullet preheat, oxy-firing, electric boost, low NOx burners, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). A literature and internet search was conducted to find any new control technologies for NOx or any updates to existing controls regarding cost and efficiencies. Operating permits for some glass manufacturing plants were reviewed and control system vendors were also contacted for information. A brief summary of data from each reference reviewed in included in the spreadsheet "CoST_Glass Mfg.xlsx."

4.2 Example NOx Regulatory Limits

4.2.1 Wisconsin

Glass manufacturing furnace with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, 2.0 pounds per ton of produced glass.[1]

4.2.2 New Jersey

Commercial container glass, specialty container glass, borosilicate recipe glass, pressed glass, blown glass, and fiberglass manufacturing furnaces: 4.0 lbs/ton glass removed. Flat glass manufacturing furnaces: 9.2 lbs/ton glass removed.

4.2.3 New York

NOx emissions are covered under NY's case-by case RACT regulations.

4.3 Recommended Additions

The following NOx controls are recommended additions for the glass manufacturing industry that are not currently in the control cost database, and a tabular summary of the costs is presented in Table 4-1.

- Electric Boost—Three entries for electric boost controls were in the CMDB for container, flat, and pressed glass manufacturing. A cost estimate for electric boost was found for "general" glass manufacturing (DOE, 2002), since the CMDB did not have a "general" entry for electric boost controls, an entry for "Electric Boost; Glass Manufacturing—General" was added with a new abbreviation of NELBOGMGN. The

[1] http://dnr.wi.gov/About/NRB/2007/January/01-07-3A4.pdf

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reference provided an annualized cost of $7,100 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace operating with an emission rate of 8-lb NOx per ton glass produced and a NOx removal efficiency of 30 percent. Since the reference did not provide capital costs, the capital to annual cost ratio could not be determined, and the capital recovery factor was assumed to be the same as the electric boost entries for container, flat, and pressed glass (i.e., 0.1424, assuming equipment life of 10 years).

- Oxy-firing—Three entries for oxy-firing were in the CMDB for container, flat, and pressed glass manufacturing. Similar to electric boost controls, an updated cost estimate for oxy-firing was found for "general" glass manufacturing (DOE, 2002); since the CMDB did not have a "general" entry for oxy-firing, an entry for "OXY-Firing; Glass Manufacturing—General" was added to the CMDB with a new abbreviation of NOXYFGMGN. The reference provided an annualized cost of $2,352 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 85 percent.[1] Since the capital costs were not provided the capital to annual cost ratio and the capital recovery factor were assumed to be the same as the oxy-firing entries for container, flat, and pressed glass, which all had the same values.

- Catalytic Ceramic Filter—This new control technology for NOx reduction was not previously in the database and was added for flat glass manufacturing with a new abbreviation of CATCFGMFT. A vendor was contacted for information (2013 Vendor Quote). The minimum and maximum cost per ton estimates were based on regenerative gas-fired furnace with pull rates of 600 tons per day and 490 tons per day, respectively. The estimate provided by the vendor included capital cost, annualized capital costs, and annual operational cost in 2013 dollars; it also included NOx reductions based on a 95 percent NOx efficiency.

Table 4-1. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NOx Removal Efficiency (%)	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
Electric Boost (general)	250	2002	30	7,100	N/A[a]
Oxy-firing General	250	2002	85	2,352	2.7
Catalytic Ceramic Filter	490	2013	95	1,045	4.6
	600	2013	95	997	4.6

[a]The ratio cannot be calculated because capital costs are not available.

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4.4 Recommended Changes

Changes to the CMDB are recommended for the following three types of control measures, which are also summarized in Table 4-2.

- Low NOx Burner General—Three entries for Low NOX burners were in the cost database for container, flat, and pressed glass manufacturing. An updated cost estimate for low NOx burners for flat glass and container glass manufacturing (EC, 2013) was found and entries NLNBUGMCN and NLNBUGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NOx removed which was converted to dollars per ton of NOx. For flat glass the minimum cost per ton estimate was based on a 900 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 500 ton per day gas fired furnace. For container glass the minimum cost per ton estimate was based on 450 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 200 ton per day gas fired furnace. The capital recovery factor and the capital to annual cost ratio were also updated. We also recommend changing the equipment life for low NOx burners on flat glass furnaces from 3 years to 10 years (EC, 2013).

  Additionally, equations for low NOx burners were added for entries NLNBUGMCN and NLNBUGMFT to "Table 04_Equations" of the CMDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

  NLNBUGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

  Total capital investment (2007 dollars) = 30,930 x (tons/day)$^{0.45}$ (R^2 = 0.99)

  Total annual cost (2007 dollars) = 9,377 x (tons/day) $^{0.40}$ (R^2 = 0.99)

  NLNBUGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

  Total capital investment (2007 dollars) = 527 x (tons/day) + 664,557 (R^2 = 1.0)

  Total annual cost (2007 dollars) = 132x (tons/day) + 150,105 (R^2 = 1.0)

- Cullet Preheating—Two entries for cullet preheating controls were in the cost database for container and pressed glass manufacturing. An updated annualized cost per ton value and NOx efficiency for pressed and container glass entries (IT, 2002) were found and updated for entries NCLPTGMCN and NCUPHGMPD. The reference provided an annualized cost of $5,000 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 5 percent.[1] Since the reference did not

[1] Annualized cost includes capital and O&M costs and is based on 2002 dollars.

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provide capital costs separately, the capital to annual cost ratio and the capital recovery factor were not updated. Additionally, based on information from EPA's OECA staff, class entries for cullet preheating should be changed from "known" to "emerging" in Table 01_Summary of the CMDB because this control measure is technically feasible but has rarely been implemented.[1]

- Selective Catalytic Reduction—Three entries for selective catalytic reduction were in the CMDB for container, flat, and pressed glass manufacturing. An updated cost estimate for SCR for flat glass and container glass manufacturing (EC, 2013) was found, and entries NSCRGMCN and NSCRGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NOx removed which was converted to dollars per ton of NOx.[2] For flat glass the minimum and maximum cost per ton estimates were based on a 900 and 500 ton per day gas fired furnace, respectively. For container glass the minimum and maximum estimates were based on a 450 and 200 ton per day gas fired furnaces, respectively. The capital to annual cost ratio were also updated.

  Equations for SCR were added for entries NSCRGMCN and NSCRGMFT to Table 4 of the CMDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

  NSCRGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

  Total capital investment (2007 dollars) = 79,415 x (tons/day) $^{0.51}$ (R^2 = 0.99)

  Total annual cost (2007 dollars) = 643 x (tons/day) + 135,302 (R^2 = 1.0)

  NSCRGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

  Total capital investment (2007 dollars) = 3681 x (tons/day) + 1.0E+06 (R^2 = 1.0)

  Total annual cost (2007 dollars) = 842 x (tons/day) + 424,930 (R^2 = 1.0)

1 Personal communication. Katie McClintock, US EPA/OCEA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

[2] Conversion based on 2008 average exchange rate of 0.711. Source: http://www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates

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Table 4-2. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NOx Removed (tons/year)	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
NLNBUGMCN	200	2007	66	1,365	4.2
	450	2007	100	1,072	4.3
NLNBUGMFT	500	2007	371	574	4.2
	900	2007	611	447	4.3
NCLPTGMCN	250	2002	5%	5,000	4.5
NCUPHGMPD	250	2002	5%	5,000	4.5
NSCRGMCN	200	2007	121	2,169	4.5
	450	2007	251	1,684	4.2
NSCRGMFT	500	2007	886	957	3.4
	900	2007	1,383	855	3.7

4.5 Recommended Deletions

- Selective Non-Catalytic Reduction—Three entries for selective non-catalytic reduction were in the cost database for container, flat, and pressed glass manufacturing. Based on conversations between EPA and OECA staff, SNCR entries for glass manufacturing should be removed based on recent NSR settlements that indicate SNCR is not a technically feasible control technology for the removal of NOx.[1]

4.6 Updates to Source Classification Codes

- There are twenty applicable SCCs for glass manufacturing as shown in Table 4-3.

- In an analysis of NO_X emissions for the Ozone Transport Assessment Group Region in 2011, fourteen of the SCCs in Table 4-3 were identified. The six SCCs not included in the Ozone Transport Region are shown at the bottom of Table 4-3. Four of the SCCs, 30501401, 30501402, 30501403, and 30501404 are associated with glass manufacturing NO_X controls in the current CMDB.

- Furnaces are the primary source of NOx emissions in the glass manufacturing industry, therefore NOx emission control techniques are typically for point emission sources associated with furnace emissions. The four SCCs identified in the CMDB pertain to four types of melting furnaces; general, flat, container, and pressed. The

[1] Personal communication. Katie McClintock, US EPA/OCEA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

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remaining sixteen SCCs in Table 4-3 are not associated with furnaces. Therefore, no changes related to SCCs are recommended for the CMDB.

- For new control techniques added to the CMDB for glass manufacturing, the applicable SCC from Table 4-3 was added to the Description field for each control technique in Table 01_Summary in the CMDB (Table C-1of Appendix C of this report). These related control measures and SCCs should also be added to "Table 03_SCCs" in the CMDB.

Table 4-3. Applicable SCCs for the Glass Manufacturing Industry

SCC Code	SCC Level One	SCC Level Two	SCC Level Three	SCC Level Four
30501401[a]	Industrial Processes	Mineral Products	Glass Manufacture	Furnace/General**
30501402[a]	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Melting Furnace
30501403[a]	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Melting Furnace
30501404[a]	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Melting Furnace
30501406	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Forming/Finishing
30501407	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Forming/Finishing
30501408	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Forming/Finishing
30501410	Industrial Processes	Mineral Products	Glass Manufacture	Raw Material Handling (All Types of Glass)
30501411	Industrial Processes	Mineral Products	Glass Manufacture	General **
30501413	Industrial Processes	Mineral Products	Glass Manufacture	Cullet: Crushing/Grinding
30501414	Industrial Processes	Mineral Products	Glass Manufacture	Ground Cullet Beading Furnace
30501416	Industrial Processes	Mineral Products	Glass Manufacture	Glass Manufacturing
30501420	Industrial Processes	Mineral Products	Glass Manufacture	Mirror Plating: General
30501499	Industrial Processes	Mineral Products	Glass Manufacture	See Comment **
SCCs Not Included in the Ozone Transport Assessment Group Region:				
30501405	Industrial Processes	Mineral Products	Glass Manufacture	Presintering
30501412	Industrial Processes	Mineral Products	Glass Manufacture	Hold Tanks **
30501415	Industrial Processes	Mineral Products	Glass Manufacture	Glass Etching with Hydrofluoric Acid Solution
30501417	Industrial Processes	Mineral Products	Glass Manufacture	Briquetting
30501418	Industrial Processes	Mineral Products	Glass Manufacture	Pelletizing
30501421	Industrial Processes	Mineral Products	Glass Manufacture	Demineralizer: General

[a]Denotes SCCs included in the CMDB.

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4.7 References

DOE, 2002. Oxygen Enriched Air Staging a Cost-effective Method For Reducing NOx Emissions. U.S. Department of Energy. Office of Industrial Technologies. April 2002. http://www1.eere.energy.gov/manufacturing/resources/glass/pdfs/airstaging.pdf

EC, 2013. Best Available Techniques (BAT) Reference Document for the Manufacture of Glass. European Commission 2013. http://eippcb.jrc.ec.europa.eu/reference/BREF/GLS_Adopted_03_2012.pdf

Vendor Quote 2013 – Confidential Business Information

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SECTION 5
LEAN BURN ENGINES

The CMDB includes the following NO_X emissions control measures for Lean Burn Engines:

- Air to fuel ratio (AFR) (achieves 20 percent reduction)
- Air to fuel ratio (AFR) and Ignition retard (IR) (achieves 30 percent reduction)
- Ignition retard (IR) (achieves 20 percent reduction)
- Low emission combustion (achieves 87 percent reduction)
- Low emissions combustion, low speed (achieves 87 percent reduction)
- Low emissions combustion, medium speed (achieves 87 percent reduction)
- Nonselective catalytic reduction (NSCR) (achieves 90 percent reduction)
- Selective catalytic reduction (SCR) (achieves 90 percent reduction)
- Selective noncatalytic reduction (SNCR) (achieves 90 percent reduction)

Based on the literature review and the new cost data identified for Lean Burn control technologies, several changes to the CMDB are recommended. No changes to existing records in CMDB are recommended. The following sections outline the additions and other comments recommended for the CMDB in relation to NO_X emissions from Lean Burn Engines.

5.1 Literature Search

In order to update the existing control measures database, a literature search was conducted for articles and papers published since 2008 (to include 2008 through August 2013) using the following terms:

- engine
- lean burn
- cost
- NOx or “nitrogen oxides”
- scr or “selective catalytic reduction”
- turbocharge

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- air/fuel ratio
- layered combustion
- high energy ignition
- high pressure fuel injection
- "low emission control" or LEC
- electronic engine control
- combustion modification
- timing
- exhaust gas recirculation
- lean NOx catalyst
- lean NOx trap
- control efficiency
- emission reduction

The literature search identified a total of 19 references, and the abstracts for these references were reviewed. Three references of potential interest were identified and two of these were obtained for review in the lean burn engine control device study.

5.2 Document Review

A brief summary of data from each reference reviewed in included in the spreadsheet "CoST_leanburn.xlsx," in worksheet "Overall Sum—New Ref Review." The information and data available from each reference is provided in table format, along with indication of whether the data were used or not.

There are 6 control technique additions to be added to the CMDB from 5 references.

The recommended additions include:

- Low Emission Combustion, LEC (for natural gas engines);
- Layered Combustion, LC (for 2 stroke natural gas engines);
- Layered Combustion, LC (for 2 stroke Large Bore natural gas engines);

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- Air to Fuel Ratio Controller, AFRC;
- Selective Catalytic Reduction, SCR (for 4 stroke natural gas engines); and
- SCR (for diesel engines).

Recent cost data for these control techniques were available from reports dated 2001 through 2012.

The references for the added control techniques are included on the "**Table 06 References**" worksheet and are as follows:

OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.

SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003. www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf

CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

PA DEP 2013. Technical Support Document General Permit GP-5. Pennsylvania Department of Environmental Protection, Bureau of Air Quality. January 31, 2013.

5.3 Low Emission Combustion (LEC) (NLECICENG)

The costs and cost effectiveness for applying LEC to natural gas Lean Burn engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2)* (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-1 for LEC along with changes in assumptions for the current analysis.

LEC are described as retrofit kits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) Precombustion chamber (on larger engines), lower cost, simple versions, (3) Turbocharger, (4) High energy ignition system,

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Table 5-1. LEC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 80%	None.
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed $0.	None.

(5) Aftercooler, and (6) Air to fuel ratio controller. (A discussion of individual technologies is provided in Appendix B of the original reference, pp. B-1 to B-28). No detail was provided on the exact combination of combustion modifications included in the example cost analysis; some references indicate that LEC on larger engines often includes a PCC (p.B-10) (CARB 2001). LEC are known or demonstrated control techniques for lean burn engines. An 80 percent NOx emission reduction can be achieved by LEC with little or no fuel penalty (in fact, LEC technologies are expected to decrease fuel consumption because they result in leaner burning engine, though the costs do not account for fuel consumption decrease). The original reference assumed an 80 percent reduction in the cost example.

Capital and annual costs were provided for multiple size ranges of engines. The capital costs ranged from $14,000 to $256,000. Costs for the 1000 to 3000 hp model were given as $40,000 to $256,000, and a mid-range cost of $148,000 was assumed in the current analysis. The total annual costs ranged from $2,000 to $21,000 (these costs are very similar to the costs calculated in the original reference analysis). The original reference assumed there are no annual operation and maintenance costs incurred from the combustion modification technologies, and the only annual cost provided is for annualized capital costs. No emission reductions are provided in the document (however the final cost effectiveness values are provided and the reduction assumed in the original analysis can be back-calculated). In the current analysis, a hp

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rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. An estimate of emissions was made in the current analysis. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were provided as 2000 hr/yr in the original reference, and controlled emissions were estimated based on 80 percent reduction as stated in the reference. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.90 to 27 tpy for the models.

The current analysis shows a cost effectiveness of $2,200/ton of NOx reduction to $780/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is $1,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for LEC on natural gas Lean Burn engines:

$$\text{Capital cost} = 16019\ e^{0.0016 \times (hp)}$$

$$\text{Annual cost} = 2280.8\ e^{0.0016 \times (hp)}$$

The R^2 value for these equations is 0.96. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet "LEC (CARB)-2001" of the Excel file.

5.4 Layered Combustion (LC), 2 Stroke (NLCICE2SNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-2 for LC for 2 stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included in this example are related to (1) Air supply; (2) Fuel supply, (3) Ignition, (4) Electronic controls, and (5) Engine monitoring (a discussion of individual technologies is provided on pp. 17 to 19 for 2 stroke Lean Burn engines). No significant detail was provided on which specific combustion modification technologies were applied. In the example study, 3 of

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the most representative manufacturer and models of 2 stroke Lean Burn engines used for integral compressors were selected for evaluation; these 3 engines were Cooper GMVH-10 2250 hp,

Table 5-2. LC for Natural Gas Lean Burn Engines, 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited ERLE 2009 project (First unit upgrade costs)	Capital costs: used average based on the provided range for each make/model engine.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: $0.

Clark TLA-6 2000 hp, and Cooper GMW-10 2500 hp (cited ERLE 2009 report "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy 0.5 g/bhp-hr NOx"). LC are known or demonstrated control techniques for lean burn, 2 stroke engines. A NOx emissions rate of 0.5 g/bhp-hr was achieved. The OTC 2012 document provided an estimate of the capital cost range for retrofitting technologies to achieve the outlet NOx limit for each engine. An average cost based on the range was estimated for each engine and used in the current analysis. Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NOx emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document).

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Uncontrolled NOx emissions for the 3 similar sized engines ranged from 74 to 93 tpy, and the NOx reductions ranged from 72 to 90 tpy.

Based on the 3 make and model engines, the average cost was estimated to be $2,800,000 for approximately 2250 hp engines (average hp of the 3 units), and the average total annual cost was estimated to be $390,000. The average cost effectiveness is $4,900/ton of NOx reduction for 2000 hr/yr operation.

The cost year is not provided in the reference; we assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010$.

See the cost calculations in worksheet "Overall Sum—New Ref Review" of the Excel file, rows 21 through 25.

5.5 Layered Combustion (LC), Large Bore, 2 Stroke, Low Speed (NLCICE2SLBNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke Large Bore) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Large Bore RICE are those with large piston diameters. The larger the bore (or piston diameter), the larger the volume available for engine combustion, and hence the greater the power delivered by the engine. Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-3 for LC for large bore 2 Stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included (1) High pressure fuel injection; (2) Turbocharging, (3) Precombustion chamber, and (4) Cylinder head modifications (a discussion of individual technologies is provided on pp. 18 to 19 for 2 stroke Lean Burn engines). LC are known or demonstrated control techniques for lean burn, large bore, 2 stroke engines. These modifications achieved a NOx emissions rate of 0.5 g/bhp-hr. The OTC 2012 document provided ranges of capital costs for retrofitting combustion modifications for large bore 2 stroke Lean Burn engines from 200 to 11,000 hp (cited Cameron 2011 presentation "Available Emission Reduction Technology for Existing Large Bore Slow Speed Two Stroke Engines." A copy of this presentation was not found.). Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

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Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NOx

Table 5-3. LC for Natural Gas Lean Burn Engines, Large Bore 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited Cameron 2010 project	None.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2,000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: $0.

emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document). Uncontrolled NOx emissions were estimated to be 410 tpy for the larger 11,000 hp engines and were estimated to be 7.4 tpy for the smaller 200 hp engines.

For the larger 11,000 hp engines, the current analysis shows a cost effectiveness of $1,500/ton of NOx reduction, and for the smaller 200 hp engines, the cost effectiveness is $38,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010$.

See the cost calculations in worksheet “Overall Sum—New Ref Review” of the Excel file, rows 12 and 13.

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5.6 Air to Fuel Ratio Controller (AFRC) (NAFRCICENG)

The costs and cost effectiveness for applying AFRC to natural gas Lean Burn engines are obtained from the document *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines* (CARB 2001). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-4 for AFRC, along with changes in assumptions for the current analysis.

Table 5-4. AFRC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: not provided	Control efficiency: assumed 20%
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed $0.	None.

AFRC are electronic engine controls that typically monitor engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating condition, such as varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. (OTC 2012) (A discussion of individual technologies is provided in Appendix B of the original reference, CARB 2001, pp. B-1 to B-28). AFRC are known or demonstrated control techniques for lean burn engines. An 80 percent NOx emission reduction can be achieved by AFRC in combination with other combustion modifications, however a fuel consumption penalty of up to 3 percent can occur due to AFRC.

Capital were provided for multiple size ranges of engines. The capital costs ranged from $4,200 to $6,500 per engine.

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No annual costs were provided in the document. No emissions reductions were provided in the document. Based on the cost analysis for other combustion technology controls in this document, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (this assumption ignores the fuel penalty issue). The total annual costs ranged from $600 to $930. Because no emission reductions were provided in the document, an estimate of emissions was made in the current analysis. In the current analysis, a hp rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were assumed to be 2000 hr/yr (similar to the operating hours for other control technology analyses provided in the document), and controlled emissions were estimated based on an assumption of 20 percent reduction. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.22 to 6.7 tpy for the models.

The current analysis shows a cost effectiveness of $2,700/ton of NOx reduction to $140/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is $810/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for AFRC on natural gas Lean Burn engines:

$$\text{Capital cost} = 1.3007 \times (\text{hp}) + 4354.5$$

$$\text{Annual cost} = 0.1852 \times (\text{hp}) + 619.99$$

The R^2 value for these equations is 0.87. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet “AFRC (CARB)-2001” of the Excel file.

5.7 SCR (for 4 Stroke Natural Gas Engines) (NSCRICE4SNG)

The costs and cost effectiveness for applying SCR to natural gas engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion*

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Engines—Phase 2) (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-5 for SCR for natural gas engines along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn engines, although multiple references indicate that the feasibility of SCR application for lean burn engines is highly site-specific.

Table 5-5. SCR for Natural Gas Lean Burn Engines, 4-stroke.

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90%	None.
Capital costs: based on RACT/BARCT Determination.	None.
Annual Costs	
Equipment life: 10 years	None.
Interest rate: 10%	Interest rate: 7%
Operating hours rate 1: 2190 hr/yr (equivalent to capacity factor of 0.25)	None.
Operating hours rate 2: 6570 hr/yr (equivalent to capacity factor of 0.75)	None.
Emission rate, uncontrolled: 740 ppmv NOx	None.
Emission rate, controlled: 65 ppmv NOx	None.
Annualized equipment cost: based on RACT/BARCT Determination.	None.
Annual O&M cost: based on RACT/BARCT Determination.	None.

The installed equipment capital cost ranged from $45,000 to $185,000 for 50 hp engines and 1500 hp engines, respectively. The total annual costs ranged from $27,000 for a 50 hp engine to $140,000 for a 1500 hp engine (these costs are very similar to the costs calculated in the original reference analysis; the only difference in annual costs is related to the CRF, i.e., changing the interest rate from 10 percent in the original reference analysis to 7 percent in the current analysis). NOx emissions are provided for two cases: a capacity factor of 0.25 (2190 hr/yr) and a capacity factor of 0.75 (6570 hr/yr). The uncontrolled NOx emissions ranged from 1.2 to 37 tpy for the lower capacity case, and the NOx reductions ranged from 1.1 to 33 tpy. For the higher capacity case, uncontrolled NOx emissions ranged from 3.7 to 110 tpy, and the NOx reductions achieved ranged from 3.3 to 100 tpy. The current analysis shows an average cost

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effectiveness of $8,700/ton of NOx reduction for 2190 hr/yr of operation, and $2,900/ton of NOx reduction for 6570 hr/yr operation (these cost effectiveness values are very similar to the costs shown in the original reference analysis).

Based on the cost calculations for engines of varying hp and annual capacity operating, the following linear equations were developed for the capital cost and annual costs for SCR on natural gas 4-stroke lean burn engines:

$$\text{Capital cost} = 107.1 \times (\text{hp}) + 27186$$

$$\text{Annual cost} = 83.64 \times (\text{hp}) + 14718$$

The R^2 values for these equations are 0.95 for capital cost and 0.98 for annual cost. These equations should be included in the CoST database file under a new equation type for linear equations.

The cost year is not provided in the reference; assumed the cost year is the date of the cost-basis document, 2001$.

See the cost calculations in worksheet "SCR NG (SJVAPCD)-2003" of the Excel file. [Other cost effectiveness values for SCR are available from the PA DEP that are higher than the cost effectiveness values shown for the SJVAPCD SCR analysis, and other analyses. See the summary of SCR costs in worksheet "Other SCR Cost Info" of the Excel file.]

5.8 SCR (for Diesel Engines) (NSCRICEDS)

The costs and cost effectiveness for applying SCR to diesel lean burn engines is provided in *Alternative Control Techniques Document: Stationary Diesel Engines* (EPA 2010). The assumptions for the original reference analysis are provided in Table 5-6 for SCR for diesel engines, along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn, diesel engines.

Approximately 76 percent of the population of stationary diesel engines is less than 300 hp and the remaining 24 percent is greater than 300 hp. Applications for stationary engines under 300 hp include standby power generation, agriculture, and industrial applications, and less than 5 percent are used for continuous power generation. Applications for stationary engines greater than 300 hp are primarily power generation and are almost evenly divided between continuous duty and standby applications.

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The cost analysis provided in the original reference includes an assumption that stationary diesel lean burn engines operate approximately 1000 hr/yr. This assumption is likely appropriate for the majority of those units that are less than 300 hp and for half of the diesel engines greater than 300 hp, i.e., approximately 87 percent of diesel lean burn engines (this ignores the "fewer than 5 percent" used for continuous power generation). For the remaining 13 percent of engines that are greater than 300 hp and used in continuous power generation applications, an assumption for longer operating hours, such as 8000 hr/yr, may be needed to estimate the cost effectiveness.

Table 5-6. SCR for Diesel Lean Burn Engines—Assumptions

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90 %	None.
Equipment life: 15 year	None.
Interest rate: 7%	None.
Capital costs: $98/hp	None.
Annual Costs	
Operating hours: 1000 hr/yr	None.
Annual costs: $40/hp (based on 1000 hr/yr operation; already includes Capital Recovery)	None.

The original reference analysis provided a capital cost of $98/hp, and based on the mid-range hp rating for four model engines, the capital costs ranged from $7,300 to $98,000 for SCR. The original reference analysis provided an annual cost of $40/hp, and the annual costs ranged from $3,000 to $40,000 per year. Uncontrolled NOx emissions factors in the original reference were based on Tier 0 to Tier 3 values[1] and an assumption of 1000 hr/yr operation. Uncontrolled NOx emissions range from 0.25 to 9.2 tpy across the four models, and the NOx reductions ranged from 0.22 to 8.3 tpy.

The current analysis shows an average cost effectiveness of $9,300/ton of NOx reduction for 1000 hr/yr of operation (no weighting to the average based on engine age was applied). The cost effectiveness over the engine size range varied from $4,800/ton to $16,000/ton for diesel engines (and are very similar to the costs shown in the original reference analysis). It is

[1] Federal Standards, from the *Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling—Compression Ignition*. EPA Publication No. EPA420-P-04_009. April 2004.

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important to note that the cost effectiveness is correlated to the manufacturing year of the diesel engine, i.e., the Tier limit for NOx emissions. Older engines manufactured prior to 1998 have the most lenient emissions limit while later model years have more stringent NOx emission limits (lower baseline emissions). The overall magnitude of emission reduction achieved by the SCR is lower for later model years as compared to earlier years, and therefore, the cost effectiveness values are higher for later model years.

[Note: This analysis shows emission reductions and cost effectiveness for existing and new diesel engines through approximately 2011, the last year for phase in of the Tiered emission values. The original reference provided information (circa 2005) on the age of the stationary engine population, with approximately 57 percent of engines at that time being manufactured prior to 1994 and approximately 42 percent manufactured after 1994 (note that the grouping of the age data does not align well with the Tier years, in that the age data shows breaks in 1994 and 2003 while the Tier ranges show breaks in 1996, 1998, 2002, 2003, etc.). As the diesel engine population continues to age and older engines are retired (i.e., those diesel engines subject to the Pre-1998 and the Tier 1 (1998 to 2003) or Tier 1 (1996 to 2001), etc. and are replaced with newer engines achieving lower NOx baseline emissions, the cost effectiveness for new engines would tend to be in the higher end shown for each model and would contribute to a somewhat higher average cost-effectiveness value. The average cost effectiveness will likely move toward the $13,000/ton to $16,000/ton of NOx reduction range.]

See the cost calculations in worksheet "SCR Diesel (EPA Dies ACT)-2010" of the Excel file.

5.9 Applicable SCCs for Lean Burn Engine Control Measures

Table 5-7 lists all of the ICE SCCs that are associated with one or more gas lean burn ICR control measures in the CMDB table called "Table 03_SCCs." These SCCs were identified with NOx emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100oW longitude). The control measures shown in the column headings in Table 5-7 are the ICE control measures that are currently in the CMDB. Each control measure that was determined to be applicable for a specific SCC is identified with an "N" in the cell, meaning the control measure is "new," i.e., not currently linked to this particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for ICE that are fired with relatively uncommon fuels such as process gas, methanol, digester gas, or landfill gas. While we have not

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Table 5-7. Potential Reciprocating Engine SCCs to Add to the CMDB and Applicable Control Measures

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Control Measures for the Reciprocating Engine SCC[d]										
					NAFRICGS	NAFRIICGS	NIRICGD	NIRICGS	NIRICOL	NIRRICOIL	NSCRICGD	NSCRICGS	NSCRICOL	NSCRRICOIL	NSNCRICGS
20200702	ICE	Ind	Process Gas	Reciprocating Engine	N	N		N				N			N
20200712	ICE	Ind	Process Gas	Reciprocating: Exhaust	N	N		N				N			N
20201602	ICE	Ind	Methanol	Reciprocating Engine			N				N				
20201607	ICE	Ind	Methanol	Reciprocating: Exhaust			N				N				
20201702	ICE	Ind	Gasoline	Reciprocating Engine			N				N				
20201707	ICE	Ind	Gasoline	Reciprocating: Exhaust			N				N				
20280001	ICE	Ind	Equipment Leaks	Equipment Leaks											
20282001	ICE	Ind	Wastewater, Aggregate	Process Area Drains											
20300702	ICE	C/I	Digester Gas	Reciprocating: POTW Digester Gas	N	N		N				N			N
20300707	ICE	C/I	Digester Gas	Reciprocating: Exhaust	N	N		N				N			N
20300802	ICE	C/I	Landfill Gas	Reciprocating	N	N		N				N			N
20400401	ICE	ET	Reciprocating Engine	Gasoline			N				N				
20400402	ICE	ET	Reciprocating Engine	Diesel/Kerosene			N		N	N	N		N	N	
20400404	ICE	ET	Reciprocating Engine	Process Gas	N	N		N							N
20400406	ICE	ET	Reciprocating Engine	Kerosene/Naphtha (Jet Fuel)			N				N				
20400409	ICE	ET	Reciprocating Engine	Liquified Petroleum Gas (LPG)			N				N				

[a]SCCs represent reciprocating engine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

[b]ICE means "Internal Combustion Engines."

[c]Ind means "Industrial," C/I means "Commercial/Institutional," and ET means "Engine Testing."

[d]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

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located any analyses that determined the applicable controls and related costs for ICE fired with such fuels, similar control measures can be assigned to these SCCs. In order to conduct CoST modeling analyses for these ICE, the most representative available control measures could be assigned. For ICE that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired ICE. Similarly, for ICE that burn miscellaneous liquid fuels such as methanol, gasoline, kerosene/diesel, and LPG, the most representative available control measures are those for gas- or diesel-fired ICE. Also, for ICE that burn liquid fuels such as diesel/kerosene, the most representative available control measures are those for gas-, diesel-, or oil-fired ICE.

Six new control measures have been added to the CMDB for lean burn engines under this review and these control measures are described in Sections 5.3 through 5.8 of this report. Table 5-8 lists those SCCs that should be associated with the newly added lean burn engine control measures. Each control measure that was determined to be applicable for a specific SCC is identified by a "Y," which means yes.

In Table 5-9, a number of recommendations were made to delete NOx control measure/SCC combinations from the CMDB. ICE SCCs for evaporative losses from fuel storage and delivery systems are incorrectly associated with NOx control measures in the current CMDB, and we recommend deleting these all NOx control measure/SCC records from the CMDB table called "Table 03_SCCs" because there should be no NOx emissions from the sources represented by these SCCs. In addition, multiple ICE control measures are misassigned to turbine SCCs and we recommend deleting these NOx control measure/SCC records. The reverse issue also exists where multiple turbine control measures are misassigned to ICE SCCs, and we recommend deleting these NOx control measure/SCC records, as well. These control measure/SCC combinations are identified in Table 5-9.

5.10 Pennsylvania General Permit 5 (GP-5) for Natural Gas Compression and/or Processing Facilities

Pennsylvania DEP recently released a general permit for Natural Gas Compression and/or Processing Facilities that includes limits on NOx emissions from ICE. NOx emission limits from this general permit, along with other NOx limits for Pennsylvania, are shown in Table 5-10. Typical emission rates and the cost-effectiveness values for applying certain control measures are shown for lean burn and rich burn engines in Table 5-11.

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Table 5-8. Recommended New Control Measures to Associate With Lean Burn Reciprocating Engine SCCs in the CMDB

SCC[a]	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Applicable Control Measures for the Lean Burn Reciprocating Engine SCC					
					NLECICENG	NLCICE2SNG	NLCICE2SLBNG	NAFRCICENG	NSCRICE4SNG	NSCRICEDS
20200102	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating						Y
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Exhaust						Y
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	Y	Y	Y	Y	Y	
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	Y	Y	Y	Y	Y	
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	Y	Y	Y	Y	Y	
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	Y	Y	Y	Y	Y	
20200401[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Diesel			Y			
20200402[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Dual Fuel (Oil/Gas)			Y			
20200403[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Cogeneration: Dual Fuel			Y			

[a]SCCs represent reciprocating engine activities that were identified with NOx emissions in the recent Ozone Transport Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

[b]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

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Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200106	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20200206	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20200306	Internal Combustion Engines	Industrial	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20200406	Internal Combustion Engines	Industrial	Large Bore Engine	Reciprocating: Evap Losses	All NOx control measures
20200506	Internal Combustion Engines	Industrial	Residual/Crude Oil	Reciprocating: Evap Losses	All NOx control measures
20200906	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Evap Losses	All NOx control measures
20201006	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20300106	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20300206	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20300306	Internal Combustion Engines	Commercial/Institutional	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20301006	Internal Combustion Engines	Commercial/Institutional	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20200108	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20200109	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20200208	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Evap Losses	All NOx control measures
20200209	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200908	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses	All NOx control measures
20200909	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust	NNSCRRBGD

(continued)

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Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20201008	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses	All NOx control measures
20201009	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	NNSCRRBGD
20201011	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine	NNSCRRBGD
20201013	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	NNSCRRBGD
20300108	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20300109	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20300208	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Evap Losses	All NOx control measures
20300209	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200105	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20200205	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200207	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200253	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Rich Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

(continued)

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Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200905	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Crankcase Blowby	NSCRWGTJF, NWTINGTJF
20200907	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Exhaust	NSCRWGTJF, NWTINGTJF
20300105	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20300107	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20300205	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20300207	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

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Table 5-10. NOx Control Requirements for RICE in Pennsylvania

State	Source Category Covered	NOx Control Level	Reference
Pennsylvania	153 ton NOx/season	≥2400 hp: 3 g/bhp-hr (220 ppm)	IEPA 2007
Pennsylvania (proposed values) [Assume proposal was 2011Mar26]	General Permit—Natural Gas Production and Processing Facility, SI, ICE	Existing LB or RB, 100 to 1500 hp: 2 g/bhp-hr New, Reconfigured, LB ≤100 hp: 2 g/bhp-hr New, Reconfigured, LB 100 to 637 hp: 1 g/bhp-hr New, Reconfigured, LB >637 hp: 0.5 g/bhp-hr	OTC 2012
Pennsylvania (amended 2013Feb02)	Natural Gas Compression and Processing, NG, SI, ICE, includes facilities with actual or potential emissions <100 tpy NOx, and <25 tpy NOx in 5 counties.	New, Reconfigured LB or RB, ≤100 hp: 2 g/bhp-hr New, Reconfigured LB, 100 to 500 hp: 1 g/bhp-hr New, Reconfigured LB, >500 hp: 0.5 g/bhp-hr New, Reconfigured RB, 100 to 500 hp: 0.25 g/bhp-hr New, Reconfigured RB, >500 hp: 0.2 g/bhp-hr	PA DEP 2013
Pennsylvania	Interstate Pollution Transport Reduction, Emission of NOx from Stationary ICE	LB, >2400 hp: 3.0 g/bhp-hr RICE, RB, >2400 hp: 1.5 g/bhp-hr	DE 2012

Table 5-11. Characteristics of NOx Emissions and Controls for RICE

Engine Type and Size	Uncontrolled Emissions	Emissions	Cost Effectiveness for NOx Reductions	Reference
Lean burn				
LB >500 hp	NA	SCR, stack test, 0.22 to 0.50 g/bhp-hr	SCR: $71,000 to $60,000/ton (for 500 to 4000 hp)	PA DEP 2013, p. 22
LB 100 to 500 hp	1 to 16.4 g/bhp-hr	NA	SCR: >$42,000/ton	PA DEP 2013, p. 20
LB <100 hp	2 g/bhp-hr	2 g/bhp-hr	SCR: >$48,000/ton	PA DEP 2013, p. 17
Rich burn				
RB >500 hp	13 to 16 g/bhp-hr	NSCR: stack test, 0.02 to 0.14 g/bhp-hr	NA	PA DEP 2013, p. 28, 29
RB 100 to 500 hp	13 to 16.4 g/bhp-hr.	NA	NSCR: $177/ton	PA DEP 2013, p. 25, 26
RB <100 hp	11.41 to 21.08 g/bhp-hr	NSCR: <2 g/bhp-hr, at least 90% reduction	NSCR: <$650/ton for 100 hp NSCR: <$1200/ton for 50 hp	PA DEP 2013, p. 17

Appendix A

NMED Exhibit 60 - 0092

APPENDIX A
AMMONIA REFORMERS

Copies of database tables showing all records for ammonia reformer controls, highlighting revisions.

Appendix A

NMED Exhibit 60 - 0093

Table A-1. CMDB Table 06 References (New)

Data Source	Description
AR-1	Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf

Appendix A

Table A-2. CMDB Table 01 Summary

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia—NG-Fired Reformers	NLNBUFRNG	N0561	NOx	Low NOx Burner	Ammonia—NG-Fired Reformers	ptnonipm	Known	10	204|205	*2013*	*AR-1 |186*		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—NG-Fired Reformers	NLNBFFRNG	N0562	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72|172|175|179|186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—Oil-Fired Reformers	NLNBFFROL	N0572	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10		2006	72		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia Prod; Feedstock Desulfurization	NLNBFAPFD	N0622	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Prod; Feedstock Desulfurization	ptnonipm	Known	10		2006	72|172|175|179|185		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton per OSD) feedstock desulfurization processes in ammonia products operations (SCC 30100305) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: It is assumed that the superheated steam needed to regenerate the activated carbon bed used in the desulfurization process is the NOx source. LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Oxygen Trim and Water Injection; Ammonia—NG-Fired Reformers	NOTWIFRNG	N0563	NOx	Oxygen Trim and Water Injection	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72|172|175|179|184|185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. This control is also applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Appendix A

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Catalytic Reduction; Ammonia—NG-Fired Reformers	NSCRFRNG	N0564	NOx	Selective Catalytic Reduction	Ammonia—NG-Fired Reformers	ptnonipm	Known	20	139	2006	72|167|175|179|224|225|226		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.
Selective Catalytic Reduction; Ammonia—Oil-Fired Reformers	NSCRFROL	N0573	NOx	Selective Catalytic Reduction	Ammonia—Oil-Fired Reformers	ptnonipm	Known	20	139	2006	72		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

(continued)

Appendix A

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Non-Catalytic Reduction—Ammonia; NG-Fired Reformers	NSNCRFRNG	N0565	NOx	Selective Non-Catalytic Reduction	Ammonia—NG-Fired Reformers	ptnonipm	Known	20	107	2006	72|172|175|179|185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to small (<1 ton NOx per OSD) ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Low NOx Burner; Ammonia—Oil-Fired Reformers	NLNBUFROL	N0571	NOx	Low NOx Burner	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10	204|205	2006	72		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Oil-Fired Reformers	NSNCRFROL	N0574	NOx	Selective Non-Catalytic Reduction	Ammonia—Oil-Fired Reformers	ptnonipm	Known	20	107	2006	72		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.

(continued)

Appendix A

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia Production; Other Not Classified	NLNBUAONC		NOx	Low NOx Burner	Ammonia Production—Other Not Classified	ptnonipm	Known	10	204|205	2013	AR-1|186		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002)
Low NOx Burner and Flue Gas Recirculation; Ammonia Production; Other Not Classified	NLNBFAONC		NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72|172|175|179|186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Ammonia Production; Other Not Classified	NSNCRAONC		NOx	Selective Non-Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	107	2013	72|172|175|179|185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Oxygen Trim and Water Injection; Ammonia Production; Other Not Classified	NOTWIAONC		NOx	Oxygen Trim and Water Injection	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72|172|175|179|184|185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Appendix A

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Catalytic Reduction; Ammonia Production; Other Not Classified	NSCRAONC		NOx	Selective Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	139	2013	72|167|175|179|224|225|226		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

Appendix A

Table A-3. CMDB Table 02 Efficiencies

cmabbreviation	Pollutant	Locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	Details
NLNBFAPFD	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFAPFD	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFRNG	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFFRNG	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFROL	NOx				0	0	365	60	1990	1120	100	100	cpton	0.1424		5.9	1080	Applied to small source types
NLNBFFROL	NOx				0	365		60	1990	390	100	100	cpton	0.1424		7.5	190	Applied to large source types
NLNBUFROL	NOx				0	0	365	50	1990	400	100	100	cpton	0.1424		5.5		Applied to small source types
NLNBUFROL	NOx				0	365		50	1990	430	100	100	cpton	0.1424		5.5		Applied to large source types
NOTWIFRNG	NOx				0	0	365	65	1990	680	100	100	cpton	0.1424		2.9		Applied to small source types
NOTWIFRNG	NOx				0	365		65	1990	320	100	100	cpton	0.1424		2.9		Applied to large source types
NSCRFRNG	NOx				0	0	365	90	1999	2366	100	100	cpton	0.0944		10		Applied to small source types
NSCRFRNG	NOx				0	365		90	1999	2366	100	100	cpton	0.0944		9.6		Applied to large source types
NSCRFROL	NOx				0	0	365	80	1990	1480	100	100	cpton	0.0944		10	1910	Applied to small source types
NSCRFROL	NOx				0	365		80	1990	810	100	100	cpton	0.0944		9.6	940	Applied to large source types
NSNCRFRNG	NOx				0	0	365	50	1990	3870	100	100	cpton	0.0944		9.4	2900	Applied to small source types
NSNCRFRNG	NOx				0	365		50	1990	1570	100	100	cpton	0.0944		8.2	840	Applied to large source types
NSNCRFROL	NOx				0	0	365	50	1990	2580	100	100	cpton	0.0944		9.4	1940	Applied to small source types
NSNCRFROL	NOx				0	365		50	1990	1050	100	100	cpton	0.0944		8.2	560	Applied to large source types
NLNBUFRNG	NOx				0	0	365	50	1990	820	100	100	cpton	0.1424		5.5		Applied to small source types; *no new information was available for small sources during 2013 update*
NLNBUFRNG	NOx				0	365		50	*2008*	*800*	100	100	cpton	0.1424		*5.9*		Applied to large source types; *equipment life of 10 years and 7% interest*

Approved

APPENDIX B
COMBUSTION TURBINES

Copies of the database tables for showing all records for Combustion Turbines NOx controls are provided. Changes are highlighted in red font.

– Table B-1. CMDB Table 01_Summary

– Table B-2. CMDB Table 02_Efficiencies

– Table B-3. CMDB Table 04_Equations

– Table B-4. Additional CMDB Table 06_References

Appendix A

NMED Exhibit 60 - 0101

Table B-1. CMDB Table 01_Summary

cmname	cmabbreviation	pechanmeascode	majorpoll	controltechnology	sourcegroup	sector	class	equiplife	neidevicecode	datereviewed	datasource	months
Dry Low NOx Combustion; Gas Turbines—Natural Gas	NDLNCGTNG	N0243	NOx	Dry Low NOx Combustion	Gas Turbines—Natural Gas	ptnonipm	Known	15	204|205	2013	72|172|175|179|223|CT-2|CT-6	
SCR + Dry Low NOx Combustion; Gas Turbines—Natural Gas	NSCRDGTNG	N0244	NOx	SCR + DLN Combustion	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-3|CT-4|CT-6|CT-8	
Selective Catalytic Reduction and Steam Injecti; Gas Turbines—Natural Gas	NSCRSGTNG	N0245	NOx	Selective Catalytic Reduction and Steam Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-3	
Selective Catalytic Reduction and Water Injecti; Gas Turbines—Jet Fuel	NSCRWGTJF	N0502	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines—Jet Fuel	ptnonipm	Known	15		2013	72|172|175|179|223|CT-2|CT-7	
Selective Catalytic Reduction and Water Injecti; Gas Turbines—Natural Gas	NSCRWGTNG	N0246	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-3|CT-8	
Selective Catalytic Reduction and Water Injecti; Gas Turbines—Oil	NSCRWGTOL	N0232	NOx	Selective Catalytic Reduction and Water Injection	Gas Turbines—Oil	ptnonipm	Known	15		2013	72|172|175|179|223|224|CT-2|CT-7	
Steam Injection; Gas Turbines—Natural Gas	NSTINGTNG	N0242	NOx	Steam Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Water Injection; Gas Turbines—Jet Fuel	NWTINGTJF	N0501	NOx	Water Injection	Gas Turbines—Jet Fuel	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Water Injection; Gas Turbines—Natural Gas	NWTINGTNG	N0241	NOx	Water Injection	Gas Turbines—Natural Gas	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Water Injection; Gas Turbines—Oil	NWTINGTOL	N0231	NOx	Water Injection	Gas Turbines—Oil	ptnonipm	Known	15		2013	72|172|175|184|223|CT-2	
Catalytic Combustion; Gas Turbine—Natural Gas	NCATCGTNG	N/A	NOx	Catalytic Combustion	Gas Turbines—Natural Gas	ptnonipm	Emerging	15		2013	CT-1|CT-2	
EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas	NEMXDGTNG	N/A	NOx	EMx and Dry Low NOx Combustion	Gas Turbines—Natural Gas	ptnonipm	Emerging	15		2013	CT-1|CT-2|CT-3|CT-4|CT-5	
EMx and Water Injection; Gas Turbines—Natural Gas	NEMXWGTNG	N/A	NOx	EMx and Water Injection	Gas Turbines—Natural Gas	ptnonipm	Emerging	15		2013	CT-1|CT-3	

*For ease in reading this table, the Description field is included on separate pages.

Appendix A

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NDLNCGTNG	Application: This control is the use of dry low NOx combustion (DLN) technology to reduce NOx emissions. DLN combustion reduces the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to large (83.3 MW to 161 MW) natural gas fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NSCRDGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRSGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year.

(continued)

Appendix A

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRSGTNG (cont.)	Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTJF	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

(continued)

Appendix A

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTJF (cont.)	Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTOL	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002).

(continued)

Appendix A

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTOL (cont.)	Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSTINGTNG	Application: This control is the use of steam injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Steam is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The steam can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTJF	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTNG	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTOL	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Appendix A

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NCATCGTNG	Application: This control is the use of catalytic combustion to reduce NOx emissions. Catalytic combustors reduce the amount of NOx created by oxidizing fuel at lower temperatures (and without a flame) than in conventional combustors. Catalytic combustion uses a catalytic bed to oxidize a lean air fuel mixture within a combustor instead of burning with a flame. The fuel and air mixture oxidizes at lower temperatures than in a conventional combustor, producing less NOx. Currently installed only on a few 1.4 MW combustion turbines, and commercially available for turbines rated up to 10 MW (CT-1).
NEMXDGTNG	Application: This control is the use of EMx in combination with dry low NOx combustion. EMx is a post-combustion catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NOx as well as CO, VOC, and optionally SOx. A coated catalyst oxidizes NO to NO2, CO to CO2, and VOC to CO2 and water. The NO2 is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regeneration gas is periodically passed through the catalyst to desorb the NO2 from the catalyst and reduce it to elemental nitrogen (N2). EMx has been successfully demonstrated on several small combustion turbine projects up to 45 MW. The manufacturer has claimed that EMx can be effectively scaled up to larger turbines (CT-1). Cost estimates for DLN combustion in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for DLN combustion that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.
NEMXWGTNG	Application: This control is the use of EMx in combination with water injection. Cost estimates for water injection in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for water injection that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.

Appendix A

Table B-2. CMDB Table 02_Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capamratio	incrementalcpt	details
NWTINGTNG	NOx				0	0	365	72	1999	1790	100	100	cpton	0.1098		3.1		Applied to small source types (<34.4 MW), uncontrolled emissions <365 tpy
NWTINGTNG	NOx				0	365		72	1999	1000	100	100	cpton	0.1098		2.4		Applied to small source types (<34.4 MW), uncontrolled emissions >365 tpy
NWTINGTNG	NOx				0	365		72	1999	730	100	100	cpton	0.1098		1.6		Applied to large source types
NSCRWGTNG	NOx				0	0	365	94	1999	2790	100	100	cpton	0.1098		3	5840	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1370	100	100	cpton	0.1098		2.9	3130	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1070	100	100	cpton	0.1098		1.5	1690	Applied to large source types (~80 to 160 MW)
NSCRWGTNG	NOx				0	365		98	2008	1960	100	100	cpton	0.1098		2.5	3170	Applied to large source types (~50 to 180 MW), 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. 1999 WI capital and indirect annual costs were escalated to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes, direct annual costs for WI were assumed to be the same in 2008 as in 1999, and resulting 2008 costs were added to the 2008 SCR costs from ref CT-3.
NEMXWGTNG	NOx				0	365		99	2008	2960	100	100	cpton	0.1098		2.9	7120	Applied to large source types (50 to 180 MW); WI costs estimated using the same procedure as for NSCRWGTNG applied to large sources.
NSTINGTNG	NOx				0	0	365	80	1999	1690	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	820	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	500	100	100	cpton	0.1098		3.0		Applied to large source types (~80 to 160 MW), 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSCRSGTNG	NOx				0	0	365	95	1999	2570	100	100	cpton	0.1098		3.3	5550	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.

Appendix A

(continued)

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NSCRSGTNG	NOx				0	365		95	1999	1380	100	100	cpton	0.1098		3.1	2870	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRSGTNG	NOx				0	365		95	1999	570	100	100	cpton	0.1098		2.7	1810	Applied to large source types (~80 to 160 MW)
NSCRGYNG	NOx				0	365		95	2008	1420	100	100	cpton	0.1098		3.9	3170	Applied to large source types (50 to 180 MW)
NDLNCGTNG	NOx				0	0	365	84	1999	300	100	100	cpton	0.1098		5	~~540~~	Applied to small source types
NDLNCGTNG	NOx				0	365		84	1999	130	100	100	cpton	0.1098		7.4	~~140~~	Applied to large source types
NSCRDGTNG	NOx				0	0	365	94	1999	1800	100	100	cpton	0.1098		2.9	11900	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	990	100	100	cpton	0.1098		3.6	6320	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	390	100	100	cpton	0.1098		4.2	3340	Applied to large source types (~160 MW)
NSCRDGTNG	NOx				0	365			2007								18900	Applied to small source types (up to 40 MW, uncontrolled emissions <365 tpy)
NSCRDGTNG	NOx				0		365		2007								7510	Applied to small source types (up to 40 MW, uncontrolled emissions >365 tpy)
NSCRDGTNG	NOx				0	365		94	2008	1040	100	100	cpton	0.1098		4.6	5560	Applied to large source types (~50 to 180 MW), 1999 costs for DLN were estimated based on data in ref CT-2. Escalated these costs to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes and added to the 2008 SCR costs from ref CT-3.
NEMXDGTNG	NOx						365		1999	2860							14940	Applied to small source types (<26 MW), uncontrolled emissions <365 tpy
NEMXDGTNG	NOx					365			1999	1720							10270	Applied to small source types (<26 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx					365			1999	840							6600	Applied to large source types (170 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx				0		365											Applied to small source types
NEMXDGTNG	NOx				0	365		99	2008	2040	100	100	cpton	0.1098		4.1	12370	Applied to large source types (50 to 180 MW); DLN costs estimated in 1999 dollars were escalated to 2008 dollars using the CEPCI, except parts and repair costs were assumed to be the same in 2008 as in 1999.
NCATCGTNG	NOx				0		365	98	1999	920	100	100	cpton	0.1098		1.7	4760	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NCATCGTNG	NOx				0		365	98	1999	670	100	100	cpton	0.1098		1.2	2580	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NCATCGTNG	NOx				0	365		98	1999	370	100	100	cpton	0.1098		0.7	2200	Applied to large source types (~170 MW)
NWTINGTOL	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.

Appendix A

(continued)

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NWTINGTOL	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NWTINGTOL	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NSCRWGTOL	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRWGTOL	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRWGTOL	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. Escalated these costs to 2004 dollars using ratio of 2004 to 1999 CEP cost indexes and added to the 2004 SCR costs from ref CT-7. Control efficiency based on data from analysis for one unit (ref CT-7).
NWTINGTJF	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be the same as for oil-fired turbines.
NSCRWGTJF	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be same as for oil-fired turbines).

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Appendix A

Table B-3. CMDB Table 04_Equations[a]

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NWTINGTNG	Type 2	NOx	1999	27665	0.69	3700.2	0.95	27665	0.69	3700.2	0.95		
NSCRWGTNG	Type 2	NOx	1999	62962	0.66	8590	0.87	37193	0.63	12065	0.64		
NSCRWGTNG	Type 2	NOx	2007					210883	0.46				
NSCRWGTNG	Type "L"	NOx	2007							1893.8	185570		
NSCRWGTNG	Type 2	NOx	2008	34533	0.85	7236	0.94	10323	0.96	3106	0.94		
NEMXWGTNG	Type 2	NOx	2008	200894	0.68	19215	0.86	160409	0.67	20174	0.78		
NSTINGTNG	Type 2	NOx	1999	43092	0.66	7282.3	0.76	43092	0.66	7282.3	0.76		
NSCRSGTNG	Type 2	NOx	1999	72169	0.66	17551	0.72	37193	0.63	12065	0.64		
NSCRSGTNG	Type 2	NOx	2008	46492	0.82	9434.1	0.86	10323	0.96	3106	0.94		
NDLNCGTNG	Type 2	NOx	1999			676.37	0.96			676.37	0.96		
NDLNCGTNG	Type "L"	NOx	1999	2860.6	25427			2860.6	25427				
NSCRDGTNG	Type 2	NOx	1999	24854	0.79	12725	0.69	37193	0.63	12065	0.64		
NSCRDGTNG	Type 2	NOx	2007	187647	0.54			210883	0.46				
NSCRDGTNG	Type "L"	NOx	2007			2782	167494			1893.8	185570		
NSCRDGTNG	Type 2	NOx	2008	14785	0.97	5250.8	0.9	10323	0.96	3106.1	0.94		
NEMXDGTNG	Type 2	NOx	1999	58237	0.78	15004	0.78	65163	0.72	13702	0.76		
NEMXDGTNG	Type 2	NOx	2008	129611	0.74	23051	0.78	160409	0.67	20174	0.78		
NCATCGTNG	Type 2	NOx	1999	20668	0.57	4254.2	0.82						
NCATCGTNG	Type "L"	NOx	1999					N/A	N/A	743.2	54105		
NWTINGTOL	Type 2	NOx	1999	42533	0.6	6776.7	0.8	42533	0.6	6776.7	0.8		
NSCRWGTOL	Type 2	NOx	1990	94337	0.63	25914	0.7						
NSCRWGTOL	Type "L"	NOx	1999					4868.5	349694	1546.1	139203		

[a]Type "L" is a linear equation; variables are the slope and intercept. No incremental TCI for NCATCGTNG relative to DLN because the capital costs for catalytic combustion are lower than the capital costs for DLN for all but the smallest turbines. The underlying data for 2008 costs for SCR and EMx are for large turbines (50 MW to 180 MW). The underlying data for 2007 costs are for 1 MW to 40 MW turbines.

Appendix A

Table B-4. Additional CMDB Table 06 References

Data Source	Description
CT-1	Bay Area Air Quality Management District, 2010. Preliminary Determination of Compliance. Marsh Landing Generating Station. March 2010. Available at: http://www.energy.ca.gov/sitingcases/marshlanding/documents/other/2010-03-24_Bay_Area_AQMD_PDOC.pdf
CT-2	Onsite Sycom Energy Corporation, 1999. "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines." Prepared for U.S. Department of Energy. Environmental Programs Chicago Operations Office. November 5, 1999. Available at: https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/gas_turbines_nox_cost_analysis.pdf
CT-3	EmeraChem Power, 2008. Attachment in email from Jeff Valmus, EmeraChem Power, to Weyman Lee, BAAQMD. Request for EMx Cost Information. September 8, 2008. Available at: http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/EMx%20BACT%20economic%20analysis%20final09072008.ashx
CT-4	CH2MHill, 2002. Walnut Energy Center Application for Certification." Prepared for California Energy Commission. November 2002. Available at: www.energy.ca.gov/sitingcases/turlock/documents/applicant_files/volume_2/App_08.01E_Eval_Control.pdf.
CT-5	CARB, 2004. California Environmental Protection Agency. Air Resources Board. Report to the Legislature. Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts. Stationary Source Division. May 2004. Available at: http://www.arb.ca.gov/research/apr/reports/l2069.pdf
CT-6	Resource Dynamics Corporation, 2001. "Assessment of Distributed Generation Technology Applications." Prepared for Maine Public Utilities Commission. February 2001. Available at: http://www.distributed-generation.com/Library/Maine.pdf
CT-7	Florida Municipal Power Agency, 2004. Chapters 3 and 4 of PSD BACT analysis for Stock Island facility in Key West, Florida. Available at http://www.dep.state.fl.us/air/emission/construction/stockisland/BasisofBACT.pdf and http://www.dep.state.fl.us/air/emission/construction/stockisland/NOxBACT.pdf
CT-8	Energy and Environmental Analysis (An ICF International Company), 2008. Technology Characterization: Gas Turbines. Prepared for Environmental Protection Agency Climate Protection Partnership Division. December 2008. Available at: http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

Appendix A

APPENDIX C
GLASS MANUFACTURING

Copies of database tables showing all records for glass manufacturing controls, highlighting revisions.

Appendix A

NMED Exhibit 60 - 0114

Table C-1. CMDB Table 01 Summary

cmname	cmabbreviation	pechanmeascode	major poll	controltechnology	sourcegroup	Sector	Class	equiplife	neidevicecode	datereviewed	datasource	Months	Description
Cullet Preheat; Glass Manufacturing—Container	NCLPTGMCN	N0302	NOx	Cullet Preheat	Glass Manufacturing—Container	ptnonipm	Emerging	10		2013	72|175|182|GM-1		
Cullet Preheat; Glass Manufacturing—Pressed	NCUPHGMPD	N0322	NOx	Cullet Preheat	Glass Manufacturing—Pressed	ptnonipm	Emerging	10		2013	72|175|182|GM-1		
OXY-Firing; Glass Manufacturing—General	NDOXYFGMG	N/A	NOx	OXY-Firing	Glass Manufacturing—General	ptnonipm	Emerging	10			167		
Electric Boost; Glass Manufacturing—General	NELBOGMGN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
Electric Boost; Glass Manufacturing—Container	NELBOGMCN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72|175|182		
Electric Boost; Glass Manufacturing—Flat	NELBOGMFT	N0311	NOx	Electric Boost	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72|175|182		
Electric Boost; Glass Manufacturing—Pressed	NELBOGMPD	N0321	NOx	Electric Boost	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72|175|182		
Low NOx Burner; Glass Manufacturing—Container	NLNBUGMCN	N0303	NOx	Low NOx Burner	Glass Manufacturing—Container	ptnonipm	Known	10	204|205	2013	72|175|179|182|GM-2		
Low NOx Burner; Glass Manufacturing—Flat	NLNBUGMFT	N0312	NOx	Low NOx Burner	Glass Manufacturing—Flat	ptnonipm	Known	10	204|205	2013	72|175|179|182|GM-2		
Low NOx Burner; Glass Manufacturing—Pressed	NLNBUGMPD	N0323	NOx	Low NOx Burner	Glass Manufacturing—Pressed	ptnonipm	Known	10	204|205	2006	175|179|182		
OXY-Firing; Glass Manufacturing—General	NOXYFGMGN	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
OXY-Firing; Glass Manufacturing—Container	NOXYFGMCN	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Flat	NOXYFGMFT	N0315	NOx	OXY-Firing	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Pressed	NOXYFGMPD	N0326	NOx	OXY-Firing	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72		
Selective Catalytic Reduction; Glass Manufacturing—Container	NSCRGMCN	N03403	NOx	Selective Catalytic Reduction	Glass Manufacturing—Container	ptnonipm	Known	10	139	2013	72|172|175|179|182|224|GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Flat	NSCRGMFT	N0314	NOx	Selective Catalytic Reduction	Glass Manufacturing—Flat	ptnonipm	Known	10	139	2013	72|172|175|179|182|186|224|GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Pressed	NSCRGMPD	N0325	NOx	Selective Catalytic Reduction	Glass Manufacturing—Pressed	ptnonipm	Known	10	139	2006	72|172|175|179|182|186|224		
Catalytic Ceramic Filter; Glass Manufacturing—Flat	CATCFGMFT		NOx	Catalytic Ceramic Filter	Glass Manufacturing—Flat	ptnonipm	Known	20		2013	GM-3		

Appendix A

Table C-1. CMDB Table 01 Summary—Description Field

cmabbreviation	description
NCLPTGMCN	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to container glass manufacturing operations classified under 305010402.
NCUPHGMPD	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to pressed glass manufacturing operations classified under 305010404.
NDOXYFGMG	Application: This control is the use of OXY-firing in glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NELBOGMGN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401.
NELBOGMCN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to container glass manufacturing operations classified under SCC 30501402. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998).
NELBOGMFT	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to flat glass manufacturing operations classified under SCC 30501403. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998).
NELBOGMPD	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to pressed glass manufacturing operations classified under SCC 30501403. Discussion: The 50 tons per day plant is assumed to be representative of pressed glass plants (Pechan, 1998).
NLNBUGMCN	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to container glass manufacturing operations classified under 305010402 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998). LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NLNBUGMFT	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to flat glass manufacturing operations classified under 305010404 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998). LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).

(continued)

Appendix A

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NLNBUGMPD	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amo
NOXYFGMGN	Application: This control is the use of OXY-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." This control applies to general manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMCN	Application: This control is the use of OXY-firing in container glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMFT	Application: This control is the use of OXY-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMPD	Application: This control is the use of OXY-firing in pressed glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.

(continued)

Appendix A

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMCN	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to glass-container manufacturing processes, classified under SCC 30501402 and uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRGMFT	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to large(>1 ton NOx per OSD) flat-glass manufacturing operations (SCC 30501403) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

(continued)

Appendix A

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMPD	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to pressed-glass manufacturing operations, classified under SCC 30101404 and uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
CATCFGMFT	Application: Filter tubes have nanobits of proprietary catalyst are embedded throughout the filter walls. The system can achieve excellent NOx removal using liquid ammonia that is injected upstream of the filters, reacting with NOx at the catalyst to form nitrogen gas and water vapor. This control applies to general glass manufacturing operations classified under SCC 30501403

Appendix A

Table C-2. CMDB Table 02 Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existing measure abbr	neiexistingdevcode	minemissions	maxemissions	controleffiiciency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NCLPTGMCN	NOx				0	365	0	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCLPTGMCN	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NCUPHGMPD	NOx				0	365		5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCUPHGMPD	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NELBOGMCN	NOx				0	365		10	1990	7150	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMCN	NOx				0	0	365	10	1990	7150	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMFT	NOx				0	365		10	1990	2320	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMFT	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMPD	NOx				0	365		10	1990	8760	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMPD	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0	8760	Applied to small source types
NELBOGMGN					0	365	0	30	2002	7100	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMGN					0	0	365	30	2002	7100	100	100	cpton	0.1424		0		Applied to small source types
NLNBUGMCN	NOx				0	365		40	2007	1072	100	100	cpton	0.14		4.3	1690	Applied to large source types
NLNBUGMCN	NOx				0	0	365	40	2007	1365	100	100	cpton	0.14		4.2	1690	Applied to small source types
NLNBUGMFT	NOx				0	0	365	40	2007	574	100	100	cpton	0.14		4.2		Applied to small source types
NLNBUGMFT	NOx				0	365		40	2007	447	100	100	cpton	0.14		4.3		Applied to large source types
NLNBUGMPD	NOx				0	365		40	1990	1500	100	100	cpton	0.1424		2.2		Applied to large source types
NLNBUGMPD	NOx				0	0	365	40	1990	1500	100	100	cpton	0.1424		2.2		Applied to small source types
NOxYFGMCN	NOx				0	0	365	85	1990	4590	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMCN	NOx				0	365		85	1990	4590	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	365		85	1990	1900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	0	365	85	1990	1900	100	100	cpton	0.1424		2.7		Applied to small source types
NDOXYFGMG	NOx				0			85	1999	4277	100	100	cpton					
NOxYFGMPD	NOx				0	0	365	85	1990	3900	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMPD	NOx				0	365		85	1990	3900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						365	0	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						0	365	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to small source types
NSCRGMCN	NOx				0	365	0	75	2007	1684	100	100	cpton	0.1424		4.2		Applied to large source types
NSCRGMCN	NOx				0	0	365	75	2007	2169	100	100	cpton	0.1424		4.5		Applied to small source types
NSCRGMFT	NOx				0	365	0	75	2007	855	100	100	cpton	0.1424		3.7	710	Applied to large source types
NSCRGMFT	NOx				0	0	365	75	2007	957	100	100	cpton	0.1424		3.4		Applied to small source types

(continued)

Approved

Table C-2. CMDB Table 02 Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existing measure abbr	neiexistingdevcode	minemissions	maxemissions	controleffiiciency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NSCRGMPD	NOx				0	365		75	1990	2530	100	100	cpton	0.1424		1.3		Applied to large source types
NSCRGMPD	NOx				0	0	365	75	1990	2530	100	100	cpton	0.1424		1.3		Applied to small source types
CATCFGMFT	NOx				0	365	0	95	2013	997	100	100	cpton	0.05		4.6		Applied to large source types
CATCFGMFT	NOx				0	0	365	95	2013	1045	100	100	cpton	0.05		4.6		Applied to small source types

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Table C-3. CMDB Table 06 References (New)

Data Source	Description
GM-1	Oxygen Enriched Air Staging a Cost-effective Method For Reducing NOx Emissions. Industrial Technologies. April 2002. Available at: http://www1.eere.energy.gov/manufacturing/resources/glass/pdfs/airstaging.pdf
GM-2	Best Available Techniques (BAT) Reference Document for the Manufacture of Glass. European Commission 2013. Available at: http://eippcb.jrc.ec.europa.eu/reference/BREF/GLS_Adopted_03_2012.pdf
GM-3	Confidential Vendor Quote

Table C-4. CMDB Table 04_Equations[a]

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NLNBUGMCN	Type 2	NOx	2008	30,930	0.45	9,377	0.40						
NLNBUGMFT	Type "L"	NOx	2008	527	664,557	132	150,105						
NSCRGMCN	Type 2	NOx	2008	79,415	0.51								
NSCRGMCN	Type "L"	NOx	2008			643	135,302						
NSCRGMFT	Type "L"	NOx	2008	3,681	1,000,000	842	424,930						

[a]Type "L" is a linear equation; variables are the slope and intercept.

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APPENDIX D
LEAN BURN ENGINES

Copies of the database tables for showing all records for Lean Burn Engine NOx controls are provided:

– Table D-01_Summary

– Table D-02_Efficiencies

– Table D-03_SCCs

– Table D-04_Equations

– Table D-06_References

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Table D-01_Summary

cmname	cmabbreviation	pechanmeascode	majorpoll	controltechnology	sourcegroup	sector	class	equiplife	neidevicecode	datereviewed	datasource	months	description
Low Emission Combustion; Lean Burn ICE—NG	NLECICENG		NOx	Low Emission Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD3		Low Emission Combustion includes Precombustion chamber head and related equipment on a Lean Burn engine.
Layered Combustion; Lean Burn ICE 2 stroke—NG	NLCICE2SNG		NOx	Layered Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—2 stroke, Lean Burn, NG (Air Supply; Fuel Supply; Ignition; Electronic Controls; Engine Monitoring). Evaluation for 3 most representative made/models of 2 stroke LB compressor engines. All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Layered Combustion; Lean Burn ICE 2 stroke Large Bore—NG	NLCICE2SLBNG		NOx	Layered Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—for Large Bore, 2 stroke, Lean Burn, Slow Speed (High Pressure Fuel Injection achieves 90% reduction; Turbocharging achieves 75% reduction; Precombustion chambers achieves 90% reduction; Cylinder Head Modifications). All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Air to Fuel Ratio Controller; Lean Burn ICE—NG	NAFRCICENG		NOx	Air to Fuel Ratio Controller	Lean Burn ICE—NG	PTNONIPM	Known	10		12/5/2012	ABCD3		
Selective Catalytic Reduction; Lean Burn ICE 4 Stroke—NG	NSCRICE4SNG		NOx	Selective Catalytic Reduction	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1| ABCD2| ABCD3		SCR can be used on Lean Burn, NG engines. Assumed SCR can meet NOx emissions of 0.89 g/bh-hr. This is a Known technology, however there is indication that applicability is engine/unit specific.
Selective Catalytic Reduction; ICE—Diesel	NSCRICEDS		NOx	Selective Catalytic Reduction	ICE—Diesel	PTNONIPM	Known	7		9/15/2013	ABCD4		SCR can be used on Diesel engines.

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Table D-02_Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NLECICENG	NOx	NA	NA	NA	NA	0	365	80	2001	1,000	100	100	cpton	0.1424	7	7.025	NA	
NLCICE2SNG	NOx	NA	NA	NA	NA	0	365	97	2009	4,900	100	100	cpton	0.1424	7	7.024	NA	
NLCICE2SLBNG	NOx	NA	NA	NA	NA	365	0	97	2010	1,500	100	100	cpton	0.1424	7	7.024	NA	Apply to large source types. Assumed Interest Rate of 7 percent (not provided in documentation) to calculate annual costs.
NLCICE2SLBNG	NOx	NA	NA	NA	NA	0	365	97	2010	38,000	100	100	cpton	0.1424	7	7.024	NA	Apply to small source types.
NAFRCICENG	NOx	NA	NA	NA	NA	0	365	80	2001	200	100	100	cpton	0.1424	7	7.023	NA	
NSCRICE4SNG	NOx	NA	NA	NA	NA	0	365	96	2001	2,900	100	100	cpton	0.1424	7	1.401	NA	
NSCRICEDS	NOx	NA	NA	NA	NA	0	365	90	2005	9,300	100	100	cpton	0.1098	7	2.45	NA	

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Table D-03_SCCs

cmabbreviation	Source Classification Code	Status
NLECICENG	20200252	
NLECICENG	20200254	
NLECICENG	20200255	
NLECICENG	20200256	
NLCICE2SNG	20200252	
NLCICE2SNG	20200254	
NLCICE2SNG	20200255	
NLCICE2SNG	20200256	
NLCICE2SLBNG	20200252	
NLCICE2SLBNG	20200254	
NLCICE2SLBNG	20200255	
NLCICE2SLBNG	20200256	
NLCICE2SLBNG	20200401	
NLCICE2SLBNG	20200402	
NLCICE2SLBNG	20200403	
NAFRCICENG	20200252	
NAFRCICENG	20200254	
NAFRCICENG	20200255	
NAFRCICENG	20200256	
NSCRICE4SNG	20200252	
NSCRICE4SNG	20200254	
NSCRICE4SNG	20200255	
NSCRICE4SNG	20200256	
NSCRICEDS	20200102	
NSCRICEDS	20200107	

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Table D-04_Equations

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NSCRICE4SNG	linear capital and annual	NOx	2001	107.1	27186	83.64	14718						
NLECICENG	capital and annual	NOx	2001	16019	0.0016	2280.8	0.0016						
NAFRCICENG	linear capital and annual	NOx	2001	1.0337	4354.5	0.1852	619.99						

Table D-06 References

Data Source	Description
ABCD1	OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.
ABCD2	SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003. www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf
ABCD3	CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.
ABCD4	EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

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APPENDIX E
NOTES PROVIDED HERE TO EPA QUESTIONS ON LEAN BURN RICE

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EPA Question 1: What is the applicability of SCR to RICE, especially Lean Burn?

Notes for Question 1

In addition to the two documents cited in Section 5 of the report with costs for selective catalytic reduction (SCR) for Lean Burn (LB) engines, there are several other references that indicate SCR is feasible for LB engines and several that provide input on technical issues related to SCR use for LB engines. In summary, from the references reviewed, SCR seems to be technically feasible in most instances for LB engines, however, SCR application may not be feasible in all cases due to technical issues at individual sites and individual engines. In addition, SCR costs are higher relative to other NOx control techniques for LB engines. See more detailed discussion below.

SCR can be applied to LB engines, achieving greater than 90 percent NOx reductions (Table 4 on p. 6 provides a slightly different value, greater than 95 percent). The costs [assumed this referred to capital costs] ranged from $50/hp to $125/hp. No annual operating costs were provided. In discussions on p. 8 regarding "catalysts on IC engines" in general (including NSCR, SCR, oxidation, and Lean-NOx), it is noted that "Thousands of stationary IC engine catalyst applications have been effectively used for stationary IC engine gaseous emission control for five years or more. Some installations, however, do experience performance loss over time," however the text goes on to explain remedies for catalyst poisoning issues. Costs [capital] for SCR, LB ranged from $50 to $125/hp (no cost year provided). (MECA 1997)

The literature suggests that SCR is technically feasible for LB engines but there are problems that make SCR installation questionable. Two stroke (2S) LB engines are sensitive to changes in exhaust pressure, which could be problematic for retrofit of SCR on existing engines, but can be alleviated with proper design and sizing of airflow and exhaust components. This reference cited a presentation that indicated the following issues with SCR: applying SCR to pipeline engines is not feasible because the exhaust temperatures (T) are below the operating window for SCR or where SCR effectiveness is reduced; SCR installations are at unmanned facilities; and SCR has not been demonstrated for variable loads. However, the OTC 2012 reference responded to each of these issues, stating that there are several manufacturers and suppliers that offer SCR systems that indicate their catalysts are capable of effectively operating over a wide range of exhaust gas T; modern software based controls and SCADA communication technologies allow operation from a remote location; and SCR can function properly over a broad range of loads given catalysts that are effective over wide T ranges, modern controls regulate fuel and air flows to ensure combustion O_2 and T are at expected levels

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and to regulate reagent flow. A study conducted for retrofitting existing pipeline engines indicates that SCR is a high cost alternative to combustion improvements, primarily due to the high cost of ongoing reagent consumption. (p. 25-26) (There is a similar discussion for SCR for four stroke (4S) LB on p. 39-40; cited presentation at Gas Machinery Conference in October 2011.) (OTC 2012)

Shell indicated they have installed SCR on diesel engines (LB) that they utilize in drilling rig operations. Shell indicated that have been able to achieve greater than 90 percent reduction in NOx emissions while encountering minimal operational issues (see p. 10). (OTC 2012)

The OTC 2012 document indicated that MECA has noted there have been limited examples to date of SCR retrofit on 2S LB engines as demonstration test programs, but the results of these programs have not been published (see p. 27). It appears that SCR for NOx does not appear to be technically infeasible generically but that individual 2S LB engine characteristics and installations may be greatly problematic or not cost effective, although this site-specific issue is not altogether different than other emission reduction technologies (see p.27, 40). (OTC 2012)

The OTC 2012 document indicated that MECA has stated the commercial use of SCR systems for LB stationary engines have been in place since the mid-1980's in Europe and since the early 1990s in the US. One MECA member company has installed over 400 SCR systems worldwide for stationary engines with varying fuel combinations, including dozens of NG compressor engines in the US. These 4S LB engines with urea-SCR achieve >90% NOx reduction (see p.40). (OTC 2012)

EF&EE announced in November 2010 that is received an order from Clean Air Power Inc. for 6 SCR systems, to be installed on large LB NG compressor engines at gas storage sites in TX and MS (see p.40). (OTC 2012)

Clean Air Power cited: 4 SCRs supplied at Pine Prairie Energy Center, Louisiana; 1 SCR supplied at EXTERRAN/TRESPALACIOS, Texas; and 4 SCRs supplied to EXTERRAN/LEAF River, Mississippi (see p.41). (OTC 2012)

A PowerPoint slide presentation from a MARAMA workshop discusses the use of SCR for RICE and LB. Johnson Mathey (JM) included SCR as a feasible control for LB engines in a presentation at a May 2011 MARAMA Workshop. (The SCR systems included Urea and Ethanol as reagents.) SCR operating temperatures range from 700 to 900°F for internal combustion (IC) engines and achieved 90 percent NOx reductions. The budgetary costs

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[assumed this referred to capital costs] ranged from $150/ hp for a 500 hp unit (approximately $75,000) to $42/hp for a 3000 hp unit (approximately $126,000) (cost year not provided). No annual operating costs were provided. JM cited 4 LB engine installations of SCR on gas compressors at 2 locations, including Loudon Compressor Station in Clarksburg, WV and Lodi Compressor/Storage in Kirby Hills, CA. (Chu 2011) These engines are listed in the following table:

SCR for Lean Burn Engines—Johnson Mathey presentation at 2007 MARAMA Workshop

Engine Model	Engine hp	NOx, g/bhp-hr	NOx Reduction, %
CAT G3516	1,340	1.5	90%
CAT G3608	2,370	0.7	90%
CAT G3612	3,550	0.7	90%
CAT G3616	4,735	0.7	90%

References

(MECA 1997). *Emission Control Technology for Stationary Internal Combustion Engines: Status Report*. Manufacturers of Emission Controls Association (MECA). July 1997.

(Chu 2011). *NOx Control for Stationary Gas Engines*. W. Chu, Johnson Mathey. Presented at Advances in Air Pollution Control Technology, MARAMA Workshop. May 19, 2011.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012.

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EPA Question 2: What are credible estimates of the percentage of RICE NOx Emissions that are lean burn versus rich burn when RICE emissions are unspecified?

Notes for Question 2

There does not seem to be much information on NOx emission totals for LB and rich burn (RB) engines. A few references attempted to provide information on the numbers or populations of LB and RB engines. Several of the references highlighted surveys of engine populations and summary information from various engine databases. These data in general tend to point to a large LB engine population, however most of the references noted that RB engines are typically not captured or covered in surveys, databases, or by permits because the RB engines tend to be smaller in size. In general, larger engines tend to be LB and smaller engines tend to be RB. The ERLE 2009 study noted that approximately 73% of the 5,600 engines/horsepower capacity covered in their study of NG pipeline systems are LB, and approximately 6% are RB (the balance is not known). In the KSU 2011 database, approximately 66% of the 4,729 engines used in E&P at major sources are LB and 34% are RB. In addition, the EDF 2008 document cited a 2007 survey conducted for DFW NAA and AA that attempted to identify those engines that did not meet reporting requirement thresholds and were therefore not included in the TCEQ inventory. This reference, which included small engines, indicated that for smaller engines <500 hp, approximately 96% are RB and 4% are LB. The reference also indicated that for larger engines >500 hp, there is approximately a 50-50 split of LB and RB engines and of horsepower capacity. The ETCG 2013 reference also highlights engines in the Barnett Shale region. Data from the TCEQ Barnett Shale Special Inventory (Phase I) survey indicated that the majority of engines in the Barnett Shale are RB (84%). For those engines <240 hp, 95% are RB and 5% are LB, however, in looking at those engines >240 hp, 59% are LB and 41% are RB. More details for each of these references are provided in the discussion that follows.

Note also that the emissions rate in g/bhp-hr for LB engines tend to be higher, and the emissions rate for RB engines tends to be lower. (See the tables under Question 4 of this appendix for relative emission rate values for LB and RB engines in various states and local districts.)

A summary of the information available from various references is provided below.

The CARB 2001 reference indicated that LB engines tend to be larger in size, and smaller engines tend to be RB (p.B-4). (CARB 2001)

EPA received comments from the Interstate Natural Gas Association of America (INGAA) on the 2002 proposed rule, where EPA indicated that 156 of 168 large engines listed in

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the NOx SIP Call Inventory that have SIC codes associated with the NG transmission industry are LB engines (with the exception that the other 12 engines are no longer in service, are owned by a company not included in the industry database, or are duplicates). INGAA recommended that EPA assume all large NG stationary engines in the inventory are LB. (EPA 2003).

One prominent use of large Reciprocating Internal Combustion Engines (RICE) is to drive NG pipeline compressor stations; almost all engines affected by the NOx SIP Call Phase 2 rule in IL (except for 3 engines) are used to compress NG at NG pipeline stations. (IEPA 2007)

A 2009 ERLE study cited in this reference indicated there are 5,600 engines on the NG pipeline systems with a collective rating of 9,150,000 hp. That study further indicated that approximately 80 percent of the rated output was low speed 2S, low speed 4S integral engines and diesel medium speed engines converted to spark ignition (SI). Of these 80 percent of engines, 78 percent were 2S LB, 14 percent were 4S LB, and 8 percent were 4S RB. (On a rated horsepower basis, 80 percent was 2S LB, 15 percent was 4S LB, and 5 percent 4S RB) (p. 16). [On an overall basis, compared to the full 9,150,000 hp collective rating, 2S LB would be roughly 62%, 4S LB would be roughly 11%, and 4S RB would be roughly 6% of the overall rating/engines. So 73% would be LB, 6% would be RB, and the balance is not known.] (OTC 2012)

Engine Type	No. Engines, %	Horsepower, %
2S LB	78	80
4S LB	14	15
4S RB	8	5

The DE 2012 document cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below) (p.19). (DE 2012) [These data may be repeated in OTC 2012, as it looks fairly similar to the 2009 ERLE study data cited above from OTC 2012.]

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S. Total Units (%)	Avg hp
2S LB	2,955 (44%)	2,113
4S LB	1,059 (16%)	1,844
RB	1,672 (25%)	589
Turbine	1,016 (15%)	6,121

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Energy Information Agency (EIA) data cited in the OTC 2012 reference indicated there were 1201 NG mainline compressor stations in the U.S. in 2006, with combined rating of 16,800,000 hp. Between 2007 and 2010, the Federal Energy Regulation Commission (FERC) approved new compressor stations or upgrades to existing compressor facilities that were expected to add 2,600,000 hp (p. 16). (OTC 2012)

The Kansas State University (KSU) 2011 document included a database on 4,729 engines used in Exploration and Production (E&P) at major sources. LB engines accounted for 66 percent of engines (17 percent are 2S and 49 percent are 4S), and RB engines accounted for 34 percent. LB outnumbers RB among engines included in the database; because many engines rating less than 100 hp are not included, and because the majority of the smaller units are 4S RB, RB are actually underrepresented in the database. A listing of the engines (manufacturer and model), air to fuel (A/F) ratio type, cycle, and horsepower are included in Appendix I of the KSU 2011 document. The database was not meant to collect every single engine in use but rather to provide a frequency distribution of engines. The data was pulled from multiple sources, including the State of Wyoming Engine Inventory Database, EPA ICCR Database, GTI/PRCI Engine and Turbine Database, and Database of Colorado and New Mexico Engines (from Universal Compression). The engine database likely includes only permitted engines, and lower-hp engines are underrepresented in the database. (pp. 5-7) (KSU 2011)

The EDF 2008 reference indicated most engines in Barnett Shale area of Texas are 100 to 500 hp but some large engines of 1000+ hp are also used. (EDF 2008)

The EDF 2008 reference indicated that the TCEQ Point Source Emissions Inventory (PSEI) does not include a substantial fraction of compressor engine emissions. Most of the missing engines in the DFW NAA were units with emissions below the reporting thresholds, but the combined emissions from large numbers of these engines can be substantial (pp. 13-14). The 2007 DFW Engine survey indicated there were approximately 680,000 hp of installed engine capacity in DFW NAA not previously reported to the TCEQ PSEI (p. 14). The report also estimated that there is approximately 132,000 hp of engines in Attainment Area (AA) counties within the Barnett Shale that don't report to PSEI (non-PSEI) (p. 14). The LB and RB engine data from the 2007 DFW Engine Survey for the DFW NAA is provided in the table below. In this survey, there seem to be fairly even numbers of LB (51%) and RB (49%) engines in the >500 hp category, and there seems to be fairly even horsepower capacity for the LB and RB engines. For smaller engines that are <500 hp, there are significantly more RB engines (736

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engines, or 96%) than LB engines (27 engines, or 4%). In addition, for the smaller engines <500 hp, the horsepower capacity for RB represents 15% and for LB is <1%. (EDF 2008)

Installed Engine Capacity in 2007 DFW Engine Survey by Engine Type and Size, in DFW NAA (EDF 2008)

Engine Type	Engine Size, hp	Number of Engines	Percent of Engines, %	Typical Size, hp	Installed Capacity, hp	Percent of Installed Capacity, %
RB	<50	12	1.03%	50	585	0.086%
RB	50–500	724	62%	140	101,000	15%
RB	>500	200	17%	1,400	280,000	41%
LB	<500	27	2.3%	185	4,940	0.72%
LB	>500	206	18%	1,425	294,000	44%

The EDF 2008 reference looked at all of the compressor engines in the Barnett Shale region, including both the engines located within the DFW NAA and the engines in the DFW AA (including those larger engines that report to the PSEI and those non-PSEI engines). New TCEQ rules became effective in 2009 to reduce NOx from the subset of engines located in the DFW NAA that typically are not reported to the PSEI (due to their small size) for major sources (p. 25). Engines that are located outside the DFW NAA are not subject to the 2009 rule. As shown in the table below, a 50% reduction of emissions from 2007 to 2009 was estimated in DFW NAA, taking into account the growth, regulation affect, and NSCR installations. For AA engines, emissions will increase from 2007 to 2009 due to growth and the fact that no regulation applies (these engines not subject to 2009 engine regulation) (p. 19). (EDF 2008)

NOx Emissions from Compressor Engines in Barnett Shale of Texas (EDF 2008)

Area	2007 NOx Emissions, tpd	2009 NOx Emissions, tpd
DFW NAA engines	32	16
AA engines	20	31
Barnett Shale engines, total	52	47

The reference then looked at emission reductions for extending the 2009 rule to all engines in the Barnett Shale (including those in the AA). By extending the 2009 engine rule,

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NOx emissions from AA engines would drop by approximately 6.5 tpd (p.25) (this approach reduces emissions from a large number of engines, in particular RB engines between 50 to 500 hp). (EDF 2008)

The ETCG 2013 reference indicated that analysis of test reports at the TCEQ Tyler office showed 68 compressor engines: 9 engines (13%) <240 hp and 59 engines (87%) ≥240 hp (and 69% of all engines ≥500 hp) (p.11). (A graph showing the distribution of the hp for all 68 engines is shown on p.12 of the reference document.) (ETCG 2013)

The ETCG 2013 reference discussed TCEQ Barnett Shale Special Inventory (Phase I) survey data. The table below is a summary of the engine horsepower distribution. (A graph showing the distribution of NG engines in the Barnett Shale region is shown in Figure 5-1 on p. 21 of the reference document.) The majority of engines in the Barnett Shale are RB and are <240 hp, see the two tables below. This data set shows that smaller hp engines are predominantly RB, with 2,089 engines <240 hp are RB (95%) and 104 engines (5%) are LB. For engines >240 hp, 327 engines (59%) are LB and 230 engines (41%) are RB.

2009 Equipment Inventory of Stationary NG Engines by Horsepower for Barnett Shale Region. (ETCG 2013)

Engine Size	Total Engines	Percent of Total Engines	Engine Type, RB or LB	Number of Engines	Percent of Each Size Category
0 to 50 hp	317	12%	RB	302	95%
			LB	15	4.7%
50 to 240 hp	1,876	68%	RB	1,787	95%
			LB	89	4.7%
>240 hp	557	20%	RB	230	41%
			LB	327	59%

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Barnett Shale Special Inventory Phase I Equipment Survey Data on Stationary Gas-Fired Engines for 2009. (ETCG 2013)

Engine counts		
<240 hp	**≥240 hp**	**Total**
RB and LB		
2,193	557	2,750
RB only		
2,089	230	2,319
LB only		
104	327	431

The CO DPHE reference indicates that large NG RICE represent 16% of the statewide point source NOx emissions (16,199 tpy of 101,818 tpy) and 73% of the ICE NOx emissions (16,199 tpy of 22,210 tpy) (p. 1). (CO DPHE)

Example Emissions Estimates: It is difficult to draw conclusions for the emissions from LB versus RB from the data provided. However, some assumptions could be made to help draw conclusions for the defined scenario. If assume that the total capacity between LB and RB in the ERLE study is more representative of the total reporting population than the 50–50 split in the EDF study; assume that operating hours are similarly distributed for both LB and RB; and if the EFs tend to be higher for LB than for RB engines, then it is likely that 90% plus of the total emissions are from LB.

References

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Appendix A

NMED Exhibit 60 - 0138

EPA Question 3: What is the effect of NOx SIP call controls on RICE in NOx SIP call states? That is, what percent reduction and types of controls have gone into place in states affected by the NOx SIP call?

Notes for Question 3

The applicability, reduction achieved, and cost for RICE NOx controls are often engine specific and highly variable. (DE 2012) (OTC 2012)

Common NOx control techniques are provided in the table below, along with NOx emission reductions achievable. (References from other areas outside of the NOx SIP call states also provided details on controls and emissions reductions achieved by these controls and are included in the table.)

Effectiveness of Combustion Control Technologies and Add-On Controls

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB				
Improved combustion air flow, Turbocharger	(p. 18, 31): up to 75%	Up to 90%; 0.5 to 2 g/bhp-hr (increases fuel economy; may increase CO) (p. 9)	—	—
Retard ignition timing	(p. 54): diesel, 10% (reduces engine efficiency; increases PM)	Up to 10% (increase fuel economy; may increase CO) (p. 9)	(p. B-7,8): 15 to 30% (increases fuel consumption; increases VOC, HAP)	20% (pp. 5-7); $310 to $2,000/ton (p. 8)
Improved air fuel mixing, High Pressure Fuel Injection	(p. 18, 31): up to 90%	—	—	—
Advanced In-cylinder mixing	—	30 to 70% (p. 11)	—	—
Precombustion chamber (PCC) ignition system	(p. 19, 31-32): up to 90%	1 g/bhp-hr (p. 10)	—	—
Micro Precombustion chamber (MPCC), hybrid of High energy Ignition system and PCC	—	2 to 4 g/bhp-hr (p. 10)	—	—
Screw-in PCC	—	1 g/bhp-hr (p. 10)	—	—
Autobalance cylinders	(p. 23): not provided	—	—	—

(continued)

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Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB (cont.)				
Air to Fuel Ratio Controller (AFRC)	(p. 19, 32): not provided	Not provided; use in combo with Increased air flow, or postcombustion Catalyst; a few thousand $ for small engine to $30K for larger engines (p. 12).	(p. B-8): not provided (fuel consumption penalty of 3%; may increase CO, VOC)	5 to 30% (pp. 5-7); $320 to $8,300/ton (p. 7)
Combustion modifications, Layered Combustion controls	(p. 25): 60 to 90%; range of 0.5 to 3 g/bhp-hr	—	—	—
4 stroke, LB				
EGR and NSCR	(p. 32): (emissions lower than SCR)[a]	—	—	—
Combustion modifications, Layered Combustion controls	(p. 38): 90%; range of 0.5 to 2 g/bhp-hr	—	—	—
Engines (general) or LB				
High energy ignition system (HEIS)	(p. 18, 31, 44): 10%	2.5 to 3 g/bhp-hr (pp. 9-10)	(p. B-12): 200 ppm NOx	—
Low emission combustion (LEC)/precombustion chamber retrofit (PCC) [also applicable to RB]	—	—	(p. B-10): 80% (may increase VOC, CO)	—
Turbocharging/ supercharging, and Aftercooling	(p. 18): Up to 75%	—	(p. B-13): 3 to 35% for Aftercooling (may reduce VOC, CO; increases engine efficiency, power rating)	—
EGR	(p. 55): diesel, >40% (loss of fuel efficiency; loss of engine output)	Still under development for NG engines; not cost effective at this time (p. 11).	(p. B-14): 30% (reduces engine peak power; reduces fuel efficiency by 2 to 12%)	—
Ignition system improvement	—	—	(p. B-11-2): not provided (may increase VOC, CO)	—

(continued)

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Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Homogeneous charge compression ignition (HCCI), combines best features of SI and CI engines	—	Still in R&D phase, no reduction or cost info available (reduces PM; high efficiency) (p. 11-12).	—	—
Fuel switching, Hydrogen/NG blended fuel	—	40 to 50% (p. 12) Still under development, no cost info available; use of H_2 blend removes need for PCC; H_2 fuel would need to be available in the field.	—	—
Selective Catalytic Reduction (SCR)	(p. 19, 32, 55): 50 to 95% (reduces THC, CO)	80 to 90% (can release NH3) (p. 13)	(p. B-23): >80%	80 to 90% (pp. 5-7); $430 to $4,900/ton (p. 9)
Lean-NOx catalysts	(p. 55): diesel, 10 to 50%	Up to 80% (reduces CO, HC by 60%; reduces fuel economy by 3%) (p. 14)	(p. B-24): diesel, 25 to 50% (increases fuel consumption; may increase VOC, PM)	—
NOxTech	—	—	(p. B-25): 80 to 90%; (decreases CO, VOC, PM by 80%; fuel penalty 5 to 10%)	—
Lean NOx traps	(p. 55): diesel, up to 90%	—	—	—
NOx Adsorber Technology (SCONOx)	—	—	(p. B-27): >90% on diesel engine <100 hp; [2 ppmv on NG turbine]	—
Selective noncatalytic reduction (SNCR) [also applicable to RB]	—	—	—	50 to 95% (pp. 5-7)

(continued)

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Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Fuel switching, methanol	—	—	(p. B-16): 30% for conversion from NG to methanol (can generate formaldehyde emissions)	—
Hybrid system, modification of dual bed NSCR system	—	—	(p. B-22): 3 to 4 ppm NOx	—
Use of electric motors in place of combustion engines	—	—	(p. B-27): >60%	60 to 100% (pp. 5-7); $100 to $4,700/ton [not include full costs] (p. 9)
RB				
Nonselective catalytic reduction (NSCR) plus AFRC	(p. 45, 49-51): 90 to 99% (reduces CO, VOC)	>90%, < 1 g/bhp-hr (reduces CO, HC) (p. 13)	(p. B-19-20): >90% (reduces CO >80%; reduces CO>50%; increases fuel consumption)	80 to 90% (pp. 5-7); Capital cost is $35,000; O&M is $6,000; Annualized capital is $4,851; TAC is $10,851; $571/ton (p. 8)
Convert RB to LB	(p. 45): not provided	—	—	—
EGR	(p. 49): up to 80% (increase power output by 10%; decrease fuel consumption by 7%)	—	—	—
Pre-stratified charge (converts RB to LB)	—	For 4S, RB, 2 g/bhp-hr (may de-rate engine power by 20%; costs significant) (p. 11)	(p. B-15): >80% (improved fuel efficiency)	—

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[a]Some industry literature suggests that some particular 4S RB SI reciprocating engines can be converted to LB configurations with the accompanying LB engine NOx reduction capabilities. One vendor indicates that conversion to a LB configuration and the use of exhaust gas recirculation (EGR) delivers the advantages of a LB engine's efficiency and the RB engine's capability of utilizing NSCR for NOx control. The ability to convert a RB engine to a LB configuration is highly unit specific and does appear to have had widespread application in industry (p. 45). (OTC 2012)

Illinois: IEPA projected 2007 NOx emissions from 28 engines subject to the NOx SIP call to be 6,618 ton/season. NOx emission reductions from these sources were estimated to be 5,422 ton/season, and controlled NOx emissions levels were estimated to be 1,196 ton/season. (So baseline emissions were estimated to be 6,618 ton/season and controlled emissions were estimated to be 1,196 ton/season.) (IEPA 2007)

IEPA 2002 base year emissions inventory was 23,347 tpy NOx emitted from RICE and turbines, or approximately 8.4 percent of total point source NOx emissions (277,899 tpy NOx emissions from all point sources in Illinois) (p. 12). (IEPA 2007)

In addition to the NOx SIP Call requirements, IEPA also included additional units in its NOx regulation. NOx SIP Call units were to comply by May 2007, and additional units in NAA and AA were to comply in 2009, 2011, and 2012 (p. 51). The IL regulation will potentially affect 202 RICE engines and 36 turbines and reduce NOx emissions by 5,422 ton/season in 2007 ozone control season (p. 10). (IEPA 2007) [Full implementation of the IL regulation in 2012, to include additional units in NAA and AA counties down to the 500 hp size [28 NOx SIP Call units plus an additional 246 engines], was projected to reduce NOx emissions statewide by 17,082 tpy and 7,206 ton/season, which is 65 percent reduction on an annual basis and 55 percent reduction in O_3 season emissions (pp. 11 and 56). Uncontrolled NOx emissions in 2012 were projected to be 21,532 tpy and 9,134 ton/season, for those units included under the full implementation of the rule (p. 56). (IEPA 2007)]

Other Available Information

Additional RB control technologies and data are available in the OTC 2012.

Additional Diesel control technologies and data are available in OTC 2012.

References

(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

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EPA Question 4: What are typical or realistic baseline and controlled NOx emissions factors (grams/hp-hr) for RICE in the OTC states?

Notes for Question 4

NOx control requirements for several of the Ozone Transport Commission (OTC) states were provided for Connecticut, New Jersey, New York, and Rhode Island, based on a 1994 STAPPA/ALAPCO document (p. 45). (IEPA 2007) These could potentially be used as maximum EF for RICE units. NOx control requirements are listed in the following table.

NOx Control Requirements for RICE in Some OTC States and Other States

State	Covered	NOx Control Level	Reference
Connecticut	≥3 MMBtu/hr (1175 hp)	Liquid-fired, CI: 8 g/bhp-hr (584 ppm)	IEPA 2007
New York	RACT for Major Facilities of NOx, Severe O_3 NAA ≥200 hp and Rest of state ≥400 hp	▪ Thru March 31, 2005, NG, RICE, LB: 3 g/bhp-hr (220 ppm) ▪ After April 1, 2005, LB: 1.5 g/bhp-hr (110 ppm) ▪ Thru March 31, 2005, Liquid-fired, CI: 9 g/bhp-hr (657 ppm) ▪ After April 1, 2005: 2.3 g/bhp-hr (168 ppm)	OTC 2012, DE 2012, IEPA 2007
New York (RACT)	Major facilities >25 tpy, NYC and Lower Orange Co: ≥200 kW Rest of state, major facilities >100 tpy: ≥400 kW	▪ NG: 1.5 g/bhp-hr ▪ Landfill or digester gas: 2.0 g/bhp-hr	
New Jersey		▪ NG, LB, ≥500 hp: 2.5 g/bhp-hr (182 ppm) ▪ Liquid-fired, CI, ≥500 hp: 8 g/bhp-hr (584 ppm)	IEPA 2007
New Jersey (RACT)	≥148 kW Group of 2 or more engines, each at ≥37 to <148 kW, but total combined power ≥148 kW	▪ Gas, LB: 1.5 g/bhp-hr, or 80% reduction ▪ Gas, RB: 1.5 g/bhp-hr	
New Jersey (RACT)	≥37 kW	▪ Commenced on or after March 7, 2007: 0.9 g/bhp-hr ▪ Modified on or after March 7, 2007: 0.9 g/bhp-hr, or 90% reduction	
Maryland	NG pipeline engines with >15% capacity factor	NA	IEPA 2007
Other States and Areas			
Illinois	NA	▪ 3 g/bhp-hr (210 ppm)	NA

(continued)

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NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
SJVAPCD (amended 2011Aug18)	Rule 4702 ICE, SI and CI, nameplate rating ≥25 hp	▪ 2S, LB, NG, <100 hp: 75 ppmvd ▪ LB limited use or Gas compression: 65 ppmvd ▪ LB, all others: 11 ppmvd	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 2S, SI, LB, ≥500 hp: – Mfg before 9/23/1982: 8 g/bhp-hr – Mfg before 6/18/1992, <825 hp: 8 g/bhp-hr – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010: 1 g/bhp-hr	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S, SI, LB: – Mfg before 9/23/1982, ≥500hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg before 6/18/1992, <825 hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010, ≥500hp: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010, ≥500hp: 1 g/bhp-hr ▪ After 1/1/2030, no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S SI, LB, <500hp: ▪ Mfg before 7/1/2008: 2 g/bhp-hr ▪ After 1/1/2030: no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas (NAA major sources)	RACT, Major ICI, O3 NAA, Beaumont-Port Arthur O_3 NAA Major sources	▪ NG, SI, RICE, LB ≥300 hp: 3 g/bhp-hr ▪ NG, SI, RICE, RB, ≥300 hp: 2 g/bhp-hr	OTC 2012, DE 2012
Texas (NAA minor sources)	Combustion Control at Minor Sources in O_3 NAA, Houston-Galveston-Brazoria	▪ NG, RICE, >50 hp: 0.5 g/bhp-hr	DE 2012, ETCG 2013
Texas	O3 NAA, Dallas Ft. Worth	▪ RB, >50 hp: 0.5 g/hp-hr ▪ LB, >50 hp: – Installed or moved before June 2007: 0.7 g/hp-hr – Installed or moved after June 2007: 0.5 g/hp-hr	EDF 2008; ETCG 2013

(continued)

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NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
Texas	East Texas Combustion Rule (existing engines comply by March 1, 2010; new engines comply at startup.)	▪ RB, NG, RICE, 240 to 500 hp: 1 g/hp-hr ▪ RB, NG, RICE, ≥500 hp: 0.5 g/hp-hr ▪ RB, Landfill gas, RICE, ≥500 hp: 0.6 g/hp-hr	ETCG 2013
Colorado	Regulation 7, RICE, LB, NG, New, modified, relocated	▪ After July 1, 2007, ≥500 hp: 2 g/bhp-hr ▪ After July 1, 2010, ≥500 hp: 1 g/bhp-hr ▪ After January 1, 2008, 100 to 500 hp: 2 g/bhp-hr ▪ After January 1, 2011, 100 to 500 hp: 1 g/bhp-hr	OTC 2012; CO DPHE
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG, SI, ICE	▪ Mfg after 7/1/2008, ≤25 hp, Class I: 11.0 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class I-B: 27.6 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class II: 8.4 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, 25 to 100 hp: 2.8 g/hp-hr of HC + NOx combined	ETGC 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG, 100 to 500 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 1/1/2011: 1 g/bhp-hr	ETCG 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG and LPG, SI, LB, 500 to 1350 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 7/1/2010: 1 g/bhp-hr	OTC 2012
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG (except LB 500 to 1350 hp)	▪ Mfg after 7/1/2007: 2 g/bhp-hr	ETCG 2013

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NOx Control Requirements for RICE in Local Areas.

State or Area	Criteria	NOx control level	Reference
SCAQMD (July 2010)	Rule 1110.2 Emissions from Gaseous and Liquid Fueled Engines	▪ ≥500 hp: 0.5 g/bhp-hr (36 ppmvd) ▪ <500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2010, ≥500 hp: 0.15 g/bhp-hr (11 ppmvd) ▪ After July 1, 2010, <500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2011, All: 0.15 g/bhp-hr (11 ppmvd)	OTC 2012

For engines with unknown pre-rule emissions, NOx emissions were assumed to be 16.4 g/bhp-hr for 2S and 18.9 g/bhp-hr for 4S. (DE 2012)

A list of Stack test results for engines in PA that are >500 hp are given in Appendix A, Table 3 of the PA DEP 2013 reference (p. 53). (PA DEP 2013) [Capital] costs for NSCR, RB ranged from $10 to $12/bhp. (p. 9) NSCR, RB ranged from $10 to $15/bhp (slightly different value given here). (p. 16) (MECA 1997)

IC Engine Typical Emissions Levels (MECA 1997)

Engine Type	Lambda (Actual A/F ratio to Stoichiometric A/F ratio)	Mode	NOx, g/bhp-hr
NG	0.98	Rich	8.3
	0.99	Rich	11.0
	1.06	Lean	18.0
	1.74	Lean	0.7
Diesel	1.6–3.2	Lean	11.6
Dual Fuel	1.6–1.9	Lean	4.1

For RB, CARB 2001 document has Costs for NSCR w/o AFRC achieving 96% reduction. Capital costs ranged from $11,000 to $44,000; Annual costs ranged from $8,200 to $18,000; and cost effectiveness ranged from $2,100/ton to $300/ton NOx reduction (p. V-2 to V-3). (CARB 2001)

For RB, CARB 2001 document has Costs for Pre-stratified Charge, achieving 80% reduction. Capital costs ranged from $10,000 to $47,000; Annual costs ranged from $2,700 to

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$11,000; and cost effectiveness ranged from $800/ton to $200/ton NOx reduction (pp. V-2 to V-3). (CARB 2001)

CARB 2001 document has costs for Ignition Timing Retard (ITR), although the description of the combustion technology indicates it is less popular on Stationary engines than mobile source engines (pp. V-2, B-7 to B-8). (CARB 2001)

The EDF 2008 reference provided NOx EF for engines in the Bartlett Shale region. The document notes that extending the 2009 engine rules in Barnett Shale to counties outside the DFW NAA would likely result in many engine operators installing NSCR on RB engines. NSCR costs were cited as follows: $330/ton (IEPA 2007); $92 to $105/ton (EPA 2006); and $112 to $183/ton (northeast Texas 2005 report). Another control technique reviewed in this report included replacement of compressor engines with electric motors. There are multiple compressors driven by electric motors throughout Texas (p. 26). Use of electric motors instead of gas-fired engines eliminates combustion emissions (p. 27). The costs are time and site specific, based on the cost of electricity, cost of NG, hours of operation per year, number of compressors, size of compressor, etc. (EDF 2008)

NOx Emission Factors for Engines Identified in DFW 2007 Engine Survey (EDF 2008)

2007 EF			2009 EF		
Engine Type	**Engine Size, hp**	**NOx, g/hp-hr**	**Engine Type**	**Engine Size, hp**	**NOx, g/hp-hr**
RB	<50	13.6	RB	<50	13.6
RB	50–500	13.6	RB	50–500	0.5
RB	>500	0.9	RB	>500	0.5
LB	<500	6.2	LB, installed or moved before June 2007	<500	0.62
LB	>500	0.9	LB, installed or moved after June 2007,	<500	0.5
___	___	___	LB, installed or moved before June 2007	>500	0.7
___	___	___	LB, installed or moved after June 2007	>500	0.5

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EPA Question 5: Using FERC data or other data sources, what is the relationship between RICE model and age, and emissions (both for baseline and with controls)? In particular, what is the relationship for RICE built before the imposition of the SI (spark ignition, natural gas-fired) RICE NSPS in 2007?

Notes for Question 5

The DE 2012 reference stated that many of the installed mainline NG compressors are of the age (in excess of 40 years old) to have pre-dated modern original equipment manufacturer (OEM) installed NOx emission controls and otherwise applicable new source performance standards (NSPS). There is little information on the number of units that may have undergone NOx modifications as a result of federal or State rules and regulations. The reference cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below). The average age for each unit type is shown in the following table. [These data are repeated in OTC 2012.] [Based on these data, it is estimated that the LB and RB engines are 37 years old on average (based on dropping the turbine numbers in the table below).] (p. 19) (DE 2012)

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S Total Units (%)	Average Age (as of 2003)	Avg hp
2S LB	2,955 (44%)	42	2,113
4S LB	1,059 (16%)	33	1,844
RB	1,672 (25%)	32	589
Turbine	1,016 (15%)	24	6,121

The OTC 2012 reference indicated that many of the reciprocating engines driving mainline NG compressors are in excess of 40 years old, pre-dating any applicable modern OEM installed NOx emission control and any otherwise applicable NSPS NOx controls (p. 16). (OTC 2012)

The DE 2012 reference discussed a 2005 study conducted for NG field gathering engines in Eastern Texas; the study was able to determine the age only for a very small portion of the engines, and the engine age ranged from 2 to 25 years. The output ratings of engines in the study ranged from 26 to 1478 hp, with the majority rated between 50 and 200 hp (p. 12). (DE 2012)

The DE 2012 reference indicated they reviewed MARAMA's 2007 Point Source Inventory and 2007 FERC data. The 2007 FERC data are provided as Attachment III to the

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reference. The two sets of data did not match: 2007 MARAMA data indicated 107 compressor facilities, and 2007 FERC data indicated 150 compressor facilities. The reviewed databases did not provide any information regarding NOx emission rates (g/bhp-hr, ppmvd). NOx emission rates were obtained for a small number of prime movers, through operating permits: 2SLB range from 1 to 13.3 g/bhp-hr; 4SLB range from 0.5 to 6 g/bhp-hr; and 4SRB were 3 g/bhp-hr. The data are not sufficient to estimate actual NOx emission rates and NOx reductions. Note that the FERC data addresses large entities, and smaller companies may not be required to report data to FERC. The 2007 OTC compressors from FERC are provided in the following table. (DE 2012)

State	No. Compressors	Total Rated hp
CT	10	35,300
MA	15	25,702
MD	17	52,250
ME	4	33,244
NJ	36	129,130
NY	120	359,487
PA	467	1,331,164
RI	6	29,170
VA (OTR area only)	22	49,390

The KSU 2011 reference discussed control technologies testing performed in the laboratory on a 1966 Ajax DP-115 (Lean Burn) that has none of the low emissions controls that are currently OEM standard. The published emission factor (EF) for this engine is 4.4 g/bhp-hr, and the emissions from actual testing were 4.69±0.18 g/bhp-hr (the Lab testing results are discussed on pp. 19-27). There is additional discussion of Field testing conducted on multiple LB engines with NOx emission control techniques, including (1) Increased air flow, and precombustion chamber (PCC) screw-in type, (2) PCC screw-in type and Upgraded turbocharger, (3) Integral PCC and high-output turbocharger (pp. 27-29). Discussion of Field testing conducted on two RB engines with NOx emission control techniques (p. 29). Integrated nonselective catalytic reduction (NSCR) with modeling and enhanced controller is also discussed. (KSU 2011).

References

(KSU 2011). *Final Report: Cost-Effective Reciprocating Engine Emissions Controls and Monitoring for E&P Field and Gathering Engines*. K. Hohn and S. Nuss-Warren, Kansas State University. November 2011.

Appendix A

(DE 2012) *Background Information, Oil and Gas Sector, Significant Sources of NOx Emissions*. Delaware Department of Natural Resources and Environmental Quality.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012.

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EPA Question 6: What is the variability in NOx emissions from RICE within each State, both for baseline and with controls?

Notes for Question 6

No data were found. [Likely a review of RICE SCCs in the NEI across states would be a useful exercise to see the relative levels of baseline and/or controlled NOx emissions, however this exercise was not part of this task.]

Appendix A

NMED Exhibit 60 - 0154

To: US EPA OAQPS

From: SRA International, Inc.

Subject: Review of CoST Model Emission Reduction Estimates

Date: September 30, 2014

EPA uses the Control Strategy Tool (CoST) to estimate the emission reductions and engineering costs associated with control strategies applied to point, area, and mobile sources of air pollutant emissions to support the analyses of air pollution policies and regulations. CoST accomplishes this by matching control measures to emission sources using algorithms such as "maximum emissions reduction", "least cost", and "apply measures in series". There was a concern that the baseline inventory used by CoST did not completely account for emission control requirements already in place, and that the emission reductions were perhaps overestimated.

SRA reviewed the CoST results and made recommendations for changing the CoST control measure assignment and the estimated reductions for oxides of nitrogen (NOx). The recommendations were based on a review of source permits, state regulations, enforcement actions, and other available information. The analysis was conducted for a 24-state area in the eastern two-thirds of the U.S. The focus was on stationary point sources other than electric generating units (non-EGUs). The purpose of this memo is to document the data used and assumptions made in recommending changes to the CoST results, and to summarize the differences between the CoST results and the recommended changes.

The findings in this memo are based on review of CoST results for a 2018 emissions inventory projected from the 2011 National Emission Inventory (NEI). This work was in support of EPA's current Transport Rule efforts for implementing the 75 ppb ozone standard. If EPA considers establishing a tighter ozone standard in the future, it is likely that a more distant future year will be used and that some of the conclusions reached in this memo could change.

CoST DATA PROVIDED BY EPA

EPA provided SRA with the outputs from a CoST scenario that identified sources for which NOx controls were available at a cost-effectiveness level of less than $10,000 per ton. The CoST outputs included source identifiers, control technology, baseline emissions and estimates of NOx emission reductions. The CoST results were divided into two groups. The first group included sources where CoST estimated NOx emission reductions of more than 100 tons per year. There were 547 sources in this group where CoST controls were initially applied. The second group included sources where CoST estimated emission reductions for sources whose 2018 projected emissions were greater than 25 tons/year, excluding those

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with reductions greater than 100 tons/year. There were 1,280 sources in this group where CoST controls were initially applied.

Another contractor reviewed the CoST results for additional source categories, and their recommendations were merged with SRA's recommendations in the summary tables and maps that follow. The data used, assumptions made and results for IC engines are documented elsewhere[1].

REVIEW OF CoST RESULTS FOR THE GREATER THAN 100 TPY GROUP

Table 1 summarizes the source categories included in our analysis, the CoST recommendation for NOx control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 1, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 1 to 4 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that ozone season emissions were equal to 5/12 of the annual emissions. Maps 1A and 1B graphically show the location of sources and the magnitude of the recommended emission reductions.

Table 1 – CoST Controls and Recommended Changes for Greater than 100 TPY Sources

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
By-Product Coke Mfg; Oven Underfiring	Selective Non-Catalytic Reduction	Review of a source-specific NOx RACT permit indicated that NOx controls were technically or economically infeasible.
Cement Kilns	Biosolid Injection Technology	Disagreed with CoST recommendation based on concerns about biosolids availability and information from EPA's ISIS (Industrial Sector Integrated Solutions) Model; recommended SNCR for all sources, except those that already have SNCR due to NOx SIP Call, NSR requirement, Consent Decree, or other state regulation.

[1] Update of NOx Control Measure Data in the CoST Control Measures Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines,Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," prepared by Research Triangle Institute, July 2014.

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Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Cement Manufacturing - Dry	Selective Non-Catalytic Reduction	Agreed with CoST recommendation except when already controlled due to NOx SIP Call, NSR requirement, Consent Decree, or other state regulation.
Cement Manufacturing – Wet	Mid-kiln Firing	Disagreed with CoST recommendation based on information from EPA's ISIS Model; recommended SNCR for all sources, except those that already controlled
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agreed with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Both sources are already controlled with SNCR
External Combustion Boilers, Elec Gen, Solid Waste	Selective Non-Catalytic Reduction	All 6 sources are already controlled with SNCR
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Disagreed with CoST recommendation. OXY-firing is not generally required under recent OECA consent decrees. More common control is oxygen-enriched air staging (OEAS). OXY-firing can only be implemented at the time of furnace rebuild, which is generally done every 10-15 years. Changed recommended control to OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. Assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.
ICI Boilers – Coal/Cyclone	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends SCR
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $2200/ton, which appears

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Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a permit or state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Gas, Natural Gas, Process Gas	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $3456/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a permit or state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a permit or state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR-95%	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies.

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Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Taconite Ore Processing – Induration – Coal or Gas	Selective Catalytic Reduction	Disagree with CoST recommendation of SCR. EPA Region V considers SCR/SNCR to be infeasible. Used Low NOx Burners at 70% reduction instead as reasonable control, except for those sources where a permit or state regulation already required the source to be controlled. .
Utility Boilers* – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Utility Boilers* – Oil/Gas	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.

The utility boilers included in the context of this report are non-IPM utility boilers. In the NEI, these units have an SCC of 1-01—xxx-xx (the SCC series generally used for electric generating units. However, the sources included in this analysis do not sell electricity to the grid.

Ammonia – NG-fired Reformers

There are 15 sources in this category. The CoST control technology was selective catalytic reduction (SCR) with a 90% reduction in NOx emissions. We determined that four of these sources were already controlled by either SCR or ultra-NOx burners and recommended no further control/reductions. For all other sources, we agreed with the CoST control and emission reduction estimate.

By-Product Coke Mfg; Oven Underfiring

There are 14 sources in this category. The CoST control technology was selective non-catalytic reduction (SNCR) with a 60% reduction in NOx emissions. We reviewed a detailed RACT analysis for a facility in Pennsylvania that determined that no controls were feasible. For all sources in this category, we recommended that no controls were feasible and thus no reductions were appropriate.

Cement Preheater/Precalciner Kilns

There are 36 sources in this category. The CoST control technology was biosolid injection technology with a 23% reduction in NOx emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NOx SIP Call requirements that typically required low NOx burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

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EPA expressed a concern whether there was sufficient biosolids availability for use by the uncontrolled kilns. Also, EPA has done considerable research on cement kiln NOx controls as part of its Industrial Sector Integrated Solutions (ISIS) project. EPA uses the ISIS-cement model help analyze policy options for various rulemakings. Based on the ISIS work, we recommended that low-NOx burners and SNCR as the appropriate control for all types of kilns.

For uncontrolled kilns, we applied a 65% reduction in NOx emissions. For kilns already controlled with low-NOx burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing - Dry Process

There are 20 sources in this category. The CoST control technology was SNCR with a 50% reduction in NOx emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NOx SIP Call requirements that typically required low NOx burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

As discussed earlier, we recommended that low-NOx burners and SNCR as the appropriate control for all types of kilns based on the ISIS work. For uncontrolled kilns, we applied a 65% reduction in NOx emissions. For kilns already controlled with low-NOx burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing – Wet Process

There are seven sources in this category. The CoST control technology was mid-kiln firing with a 30% reduction in NOx emissions. We determined that two of these kilns were installing a pilot SCR system as part of a consent decree. One kiln recently went through NSR review and has state-of-the-art control. Another kiln is required to install SNCR as part of a consent decree. No additional reductions were applied for these kilns. For the remaining kilns, we applied low-NOx burners and SNCR as described in the previous sections.

Coal Cleaning – Thermal Dryer

There was one source in this category. The CoST control technology was a low-NOx burner with a 50% reduction in NOx emissions. We could not find any information on this source and accepted the CoST controls.

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Comm/Inst Incinerators

There are two sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. Both of these sources are already controlled by SNCR and we applied no additional emission reductions.

External Combustion Boilers, Elec Gen, Solid Waste

There are six sources in this category. The CoST control technology was SNCR with a 50% reduction in NOx emissions. All six of these sources are already controlled by SNCR and we applied no additional emission reductions.

Fluid Catalytic Cracking Units

There are six sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. Nearly all sources are already controlled or required to install controls as a result of the EPA's global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.

Glass Manufacturing – Container, Flat, Pressed

There are 65 sources in this category. The CoST control technology was oxy-firing with an 85% reduction in NOx emissions. There were several concerns about using oxy-firing for this analysis. First, there is a concern about the timing of installing oxy-firing technology. Oxy-firing is typically installed at the time of a furnace rebuild, which is typically done every 10 to 15 years. Second, oxy-firing is not generally required under recent EPA consent decrees. More common control is oxygen-enriched air staging (OEAS). We recommended that OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. We assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.

ICI Boilers – Coal/Cyclone

There are eight sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. We reviewed the *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD), March, 2011* prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC). LADCO/OTC also recommended SCR for coal-cyclone boilers. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology for five sources which we determined were uncontrolled. Two sources were determined to be already controlled. One source appears to have shut down their coal-fired boilers. No reductions were applied for these three sources since they are already controlled.

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ICI Boilers – Coal/Stoker

There are 45 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency. We determined that most of these sources are currently uncontrolled. Two coal-fired boilers are scheduled to be replaced with gas-fired boilers. Two other boilers recently installed SNCR.

ICI Boilers – Coal/Wall

There are 54 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Gas, Natural Gas, Process Gas

There are 130 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Several of these sources are located in the OTR or ozone nonattainment areas, and as a result already have a RACT control requirement or emission limitation that is consistent with the LADCO/OTC recommendations. A few of these sources are located at petroleum refineries and were assumed to be already controlled due to EPA's refinery enforcement initiative.

Municipal Waste Combustors

There are 55 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We determined that 35 of these sources are already controlled with SNCR and no additional reductions were applied. For the remaining uncontrolled sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are seven sources in this category. The CoST control technology was non-selective catalytic reduction (NSCR) with a 98% reduction in NOx emissions. All but one of these sources is already controlled by NSCR or SCR.

Petroleum Refinery Process Heaters

There are 28 sources in this category. The CoST control technology was SCR with a 95% reduction in NOx emissions. All of the sources in this category are covered sources under EPA's global refinery enforcement initiative. The settlements generally require 40-60% reductions across all boilers/heaters that

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each company operates. Companies have submitted NOx compliance plans to OECA that identify the specific sources that have been controlled or are planned to be controlled, along with the technology used. But it is not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies. No additional reductions were included for this category.

Taconite Ore Processing – Induration – Coal or Gas

There are 10 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. All of the sources in this category are already subject to Best Available Retrofit Technology (BART) requirements under the Regional Haze program. EPA Region V determined that BART is low-NOx burners and agreed that SCR controls are infeasible for indurating furnaces. No additional reductions were included for this category.

Utility Boilers – Coal/Wall, Oil, Gas

There are 11 sources in this category. The CoST control technology was SCR with a 80 to 90% reduction in NOx emissions depending on fuel type. All of the sources in this category appear to be uncontrolled and we agreed with the CoST control and emission reduction estimate.

REVIEW OF CoST RESULTS FOR THE 25 TO 100 TPY GROUP

Due to the large number of sources in this group, we were not able to review individual permits to determine whether the individual source was already controlled. Instead, our recommendations were based on of state regulations, enforcement actions, engineering judgment, and other available information. We generally assumed that sources located in areas with stringent NOx rules are already well controlled and we assumed that no additional reductions were likely from these sources. This assumption was generally applied in New Jersey, New York and sources located in the Houston nonattainment area. Given more time, we would like to have also applied this assumption in other areas with stringent existing regulations, such as Chicago, Milwaukee, and Baton Rouge. In any future analysis, it would be useful to examine the stringency of rules that apply strictly to nonattainment areas.

Table 2 summarizes the source categories included in our analysis, the CoST recommendation for NOx control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 2, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 5 to 8 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that

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ozone season emissions were equal to 5/12 of the annual emissions. Maps 3A and 3B graphically show the location of sources and the magnitude of the recommended emission reductions.

Table 2 – CoST Controls and Recommended Changes for 25 to 100 TPY Sources

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Cement Kilns	Biosolid Injection Technology	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Cement Manufacturing – Wet	Mid-kiln Firing	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Ceramic Clay Mfg; Drying	Low NOx Burner	Questions about technical feasibility for these category, assume zero reductions
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agree with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Agree with CoST recommendation
External Combustion Boilers, Elec Gen, Sub/Bit Coal	Selective Non-Catalytic Reduction	Agree with CoST recommendation, although questions as to whether the source is already controlled or very low usage which would result in a unreasonably high cost-effectiveness
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees.
Gas Turbines	Low NOx Burners	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Because of low emissions, assume that the furnace is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $2200/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be

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Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Distillate Oil or Process Gas	Selective Catalytic Reduction	Because of low emissions, assume that the boiler is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Natural Gas	Low NOx Burner and Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
ICI Boilers – Residual Oil	Low NOx Burner and Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled.
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR or Ultra-Low NOx Burner	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be control due to confidentiality agreements between EPA and companies.
Utility Boilers – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled
Utility Boilers – Oil/Gas	Selective Catalytic Reduction	Because of low emissions, assume unreasonably high cost-effectiveness for SCR; use LNB/FGR as reasonable control.

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Ammonia – NG-fired Reformers

There are seven sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. For all other sources, we agreed with the CoST control and emission reduction estimate.

Cement Kilns

There are six sources in this category. The CoST control technology was either biosolid injection technology with a 23% reduction in NOx emissions or mid-kiln firing with a 30% reduction. Because of the low baseline emissions for these kilns, we assumed that the kilns were already controlled or have low usage which would result in a very high cost-effectiveness. We determined that no reductions be applied for these sources.

Coal Cleaning – Thermal Dryer

There are 10 sources in this category. The CoST control technology was a low-NOx burner with a 50% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Commercial/Institutional Incinerators

There are four sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

External Combustion Boilers, Electric Generation, Coal

There are 14 sources in this category. The CoST control technology was SNCR with a 40% reduction in NOx emissions. It appears that the sources in this category are low usage spreader stokers. Although there may be a concern about the cost-effectiveness for these sources, we agreed with the CoST control and emission reduction estimate.

Fluid Catalytic Cracking Units

There are 21 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. All sources in this category are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative. Additionally, eight of the sources are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions for the FCCUs.

Gas Turbines

There are 438 sources in this category. The CoST control technology was for low-NOx burners with a 68% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Glass Manufacturing – Container, Flat, Pressed

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There are eight sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Because of the low baseline emissions for these furnaces, we assumed that the furnaces were already controlled and determined that no reductions be applied for these sources.

ICI Boilers – Coal/Stoker

There are 133 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency.

ICI Boilers – Coal/Wall

There are 11 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Natural Gas

There are 376 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 50% control efficiency, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

ICI Boilers – Process Gas

There are 57 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

ICI Boilers – Residual Oil

There are 28 sources in this category. The CoST control technology was low-NOx burner and SNCR with a 69.5% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Industrial Incinerators

There are 21 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those

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sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Iron & Steel Mills – Reheating

There are 32 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 77% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Municipal Waste Combustors

There are 25 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. RTI identified the sources are already controlled and no additional reductions were applied for these sources. For the remaining sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are 14 sources in this category. The CoST control technology was NSCR with a 98% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Petroleum Refinery Process Heaters

There are 30 sources in this category. The CoST control technology was SCR with a 90-98% reduction or ultra-low NOx burners with a 30-50% reductions in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

Utility Boilers – Coal/Wall

There are three sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Utility Boilers – Oil/Gas

There are 27 sources in this category. The CoST control technology was SCR with a 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners or flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Appendix B

NMED Exhibit 60 - 0168

Attachment 1 – NOx Emission Reductions by State for Sources in the > 100 Ton per Year Reduction Group

State	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Alabama	24	2,855	2,287	568
Arkansas	6	455	293	162
Delaware	2	206	0	206
Florida	20	2,158	1,370	788
Illinois	21	2,659	1,472	1,187
Indiana	41	5,405	4,510	896
Iowa	10	1,226	999	227
Kansas	7	735	452	283
Kentucky	11	915	838	77
Louisiana	57	7,623	3,622	4,000
Maryland	10	1,933	355	1,578
Michigan	27	2,758	1,768	990
Mississippi	7	1,054	516	538
Missouri	15	1,698	1,562	136
New Jersey	15	417	0	417
New York	30	3,091	281	2,810
Ohio	37	4,098	2,039	2,058
Oklahoma	20	2,949	1,864	1,086
Pennsylvania	52	5,637	2,215	3,422
Tennessee	13	4,741	1,987	2,755
Texas	65	8,860	6,383	2,477
Virginia	28	3,337	3,033	303
West Virginia	9	1,180	793	387
Wisconsin	20	4,092	3,416	676
	547	**70,082**	**42,054**	**28,028**

Appendix B

Attachment 2 – NOx Emission Reductions by Source Group for Sources in the > 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers	15	2,427	1,551	875
By-Product Coke Mfg; Oven Underfiring	14	1,199	0	1,199
Cement Kilns	36	3,932	6,586	-2,654
Cement Manufacturing - Dry	20	3,672	2,234	1,438
Cement Manufacturing - Wet	7	1,294	1,120	174
Coal Cleaning-Thrml Dryer; Fluidized Bed	1	50	50	0
Comm./Inst. Incinerators	2	137	0	137
External Combustion Boilers, Solid Waste	6	472	0	472
Fluid Cat Cracking Units; Cracking Unit	6	607	52	556
Fuel Fired Equip; Process Htrs; Pro Gas	2	143	143	0
Glass Manufacturing - Container	34	2,759	678	2,081
Glass Manufacturing – Flat	23	10,241	6,024	4,217
Glass Manufacturing - Pressed	8	684	402	282
ICI Boilers - Coal/Cyclone	8	2,987	1,840	1,147
ICI Boilers - Coal/FBC	3	233	180	53
ICI Boilers - Coal/Stoker	45	4,688	2,938	1,750
ICI Boilers - Coal/Wall	54	12,041	7,996	4,045
ICI Boilers – Gas	10	1,266	910	356
ICI Boilers - Natural Gas	84	7,578	3,452	4,126
ICI Boilers - Process Gas	36	3,868	1,229	2,639
ICI Boilers - Residual Oil	2	199	82	117
Indust. Incinerators	9	586	124	461
In-Proc;Process Gas;Coke Oven/Blast Furn	3	299	0	299

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Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
In-Process; Bituminous Coal; Cement Kiln	2	290	295	-5
Iron & Steel - In-Process Coal Combustion	4	419	0	419
Iron & Steel Mills – Reheating	2	156	156	0
Municipal Waste Combustors	55	1,591	876	715
Nitric Acid Manufacturing	7	687	82	605
Petroleum Refinery Gas-Fired Process Heaters	28	2,025	0	2,025
Taconite Iron Ore - Induration - Coal or Gas	10	829	451	379
Utility Boiler - Coal/Wall	5	555	555	0
Utility Boiler - Oil-Gas/Tangential	2	526	526	0
Utility Boiler - Oil-Gas/Wall	4	1,645	1,524	121
	547	**70,082**	**42,054**	**28,028**

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Attachment 3 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	1	46	30	16
212 Mining (except Oil and Gas)	11	879	500	379
221 Utilities	10	1,186	853	333
311 Food Mfg	12	1,181	815	366
312 Beverage and Tobacco Product Mfg	7	761	761	0
322 Paper Mfg	70	11,616	7,968	3,648
324 Petroleum and Coal Products Mfg	49	3,942	239	3,703
325 Chemical Mfg	132	19,689	10,753	8,937
3272 Glass and Glass Product Mfg	64	13,588	7,047	6,540
3273 Cement and Concrete Product Mfg	64	9,113	10,183	-1,070
3274 Lime & Gypsum Product Mfg	1	75	52	22
331 Primary Metal Mfg	50	4,908	1,837	3,070
333 Machinery Mfg	1	57	35	21
336 Transportation Equipment Mfg	2	148	103	46
424 Merchant Wholesalers, Nondurable Goods	2	160	0	160
531 Real Estate	1	72	0	72
562 Waste Mgmt and Remediation Services	65	2,366	843	1,523
611 Educational Services	5	295	34	261
	547	**70,082**	**42,054**	**28,028**

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Attachment 4 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Already Controlled	138	12,973	0	12,973
Already Controlled by Glass CD	12	1,034	0	1,034
Already Controlled By Refinery CD	52	4,300	0	4,300
Control Technically or Economically Infeasible	18	1,618	0	1,618
Fuel Switch Already Occurred	4	2,370	0	2,370
Low NOx Burner	7	629	500	129
Low NOx Burner and Flue Gas Recirculation	88	8,792	6,022	2,769
Low NOx Burner and SCR	44	7,996	7,996	0
Low NOx Burner and SNCR	41	5,895	10,236	-4,341
Non-Selective Catalytic Reduction	1	82	82	0
Oxygen Enriched Air Staging	47	12,077	7,104	4,973
Selective Catalytic Reduction (SCR)	27	6,088	6,088	0
Selective Non-Catalytic Reduction (SNCR)	62	5,109	4,026	1,083
Source Already Shutdown	6	1,120	0	1,120
	547	**70,082**	**42,054**	**28,028**

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Attachment 5 – NOx Emission Reductions by State for Sources in the 25 to 100 Ton per Year Reduction Group

State	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Alabama	38	641	517	123
Arkansas	14	277	203	74
Delaware	5	73	58	15
Florida	27	532	399	133
Illinois	91	1,519	845	675
Indiana	44	894	580	314
Iowa	19	422	309	113
Kansas	31	562	421	140
Kentucky	33	619	407	212
Louisiana	101	2,046	1,467	579
Maryland	18	353	209	144
Michigan	67	1,149	844	304
Mississippi	22	366	343	23
Missouri	13	224	179	45
New Jersey	7	72	11	61
New York	41	685	59	625
Ohio	86	1,476	1,075	402
Oklahoma	40	749	669	81
Pennsylvania	79	1,359	423	936
Tennessee	42	742	514	228
Texas	374	6,444	3,311	3,133
Virginia	30	450	350	100
West Virginia	21	421	334	87
Wisconsin	37	697	471	226
	1280	**22,774**	**14,000**	**8,774**

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Attachment 6 – NOx Emission Reductions by Source Group for Sources in the 25 to 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers2	7	200	155	45
Cement Kilns	4	93	0	93
Cement Manufacturing - Wet	2	60	0	60
Ceramic Clay Mfg; Drying	4	29	0	29
Coal Cleaning-Thrml Dryer; Fluidized Bed	10	188	188	0
Comm./Inst. Incinerators	4	47	47	0
Ext Comb Boilers, Elec Gen, Nat Gas (2)	1	28	28	0
Ext Comb Boilers, Elec Gen, Sub/Bit Coal (3)	14	158	158	0
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	2	9	9	0
Fluid Cat Cracking Units; Cracking Unit	21	393	0	393
Fuel Fired Equip; Furnaces; Natural Gas	3	18	18	0
Fuel Fired Equip; Process Htrs; Pro Gas	7	86	86	0
Gas Turbines - Natural Gas	438	7,193	5,749	1,444
Glass Manufacturing - Flat	8	190	0	190
ICI Boilers - Coal/FBC	1	35	22	13
ICI Boilers - Coal/Stoker	133	2,502	1,629	873
ICI Boilers - Coal/Wall	11	246	246	0
ICI Boilers - Distillate Oil	4	75	0	75
ICI Boilers - Gas	26	601	0	601
ICI Boilers - Natural Gas	350	6,814	3,705	3,109
ICI Boilers - Oil	2	41	0	41
ICI Boilers - Process Gas	31	609	0	609
ICI Boilers - Residual Oil	28	484	437	47

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Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Indust. Incinerators	21	230	118	113
In-Proc;Process Gas;Coke Oven/Blast Furn	4	33	8	25
Iron & Steel - In-Process Comb - Coal	1	19	0	19
Iron & Steel Mills - Reheating	32	481	481	0
Municipal Waste Combustors	25	472	228	243
Nitric Acid Manufacturing	14	363	289	74
Petroleum Refinery Gas-Fired Process Heaters	30	456	0	456
Solid Waste Disp;Gov;Other Incin;Sludge	1	6	6	0
Space Heaters - Natural Gas	2	17	13	4
Steel Foundries; Heat Treating Furn	7	122	122	0
Surf Coat Oper;Coating Oven Htr;Nat Gas	2	11	0	11
Utility Boiler - Coal/Wall	2	48	48	0
Utility Boiler - Coal/Wall2	1	13	13	0
Utility Boiler - Oil-Gas/Tangential	8	99	62	37
Utility Boiler - Oil-Gas/Wall	19	307	137	170
	1280	**22,774**	**14,000**	**8,774**

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Attachment 7 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	146	2,674	2,573	100
212 Mining (except Oil and Gas)	12	247	227	20
213 Support Activities for Mining	1	20	20	0
221 Utilities	96	1,575	1,035	540
311 Food Manufacturing	46	715	450	266
312 Beverage and Tobacco Products	9	151	91	60
313 Textile Mills	1	24	15	9
314 Textile Product Mills	1	12	7	4
316 Leather and Allied Product Manufacturing	1	10	7	3
321 Wood Product Manufacturing	6	100	56	44
322 Paper Manufacturing	79	1,662	1,028	634
324 Petroleum and Coal Products	115	2,083	527	1,556
325 Chemical Manufacturing	332	6,480	3,218	3,262
326 Plastics and Rubber Products	13	206	142	65
327 Nonmetallic Mineral Product Manufacturing	24	417	32	385
331 Primary Metal Manufacturing	87	1,380	1,094	285
332 Fabricated Metal Product Manufacturing	4	80	46	33
333 Machinery Manufacturing	2	20	14	6
334 Computer and Electronic Products	1	9	9	0
336 Transportation Equipment Manufacturing	13	261	192	69
337 Furniture and Related Products	2	18	18	0
447 Gasoline Stations	1	7	0	7
454 Nonstore Retailers	1	9	0	9

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3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
482 Rail Transportation	3	37	23	14
486 Pipeline Transportation	156	2,551	2,034	517
488 Support Activities for Transportation	1	18	12	6
531 Real Estate	8	147	0	147
541 Professional Services	6	81	77	4
561 Administrative and Support Services	1	8	0	8
562 Waste Mgmt and Remediation Services	21	376	184	192
611 Educational Services	62	963	617	346
622 Hospitals	7	116	36	80
713 Amusement, Gambling, and Recreation	2	49	45	4
721 Accommodation	2	25	10	15
922 Justice, Public Order, and Safety Activities	4	29	17	12
923 Administration of Human Resources	1	12	8	4
928 National Security and International Affairs	13	201	135	66
	1280	**22,774**	**14,000**	**8,774**

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Attachment 8 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Already Controlled	207	3,380	0	3,380
Already Controlled by Refinery CD	40	704	0	704
Low NOx Burner	362	6,087	6,087	0
Low NOx Burner and Flue Gas Recirculation	361	6,726	4,491	2,235
Low NOx Burner and SCR	11	246	246	0
Low NOx Burner and SNCR	24	437	437	0
Natural Gas Reburn	1	28	28	0
Non-Selective Catalytic Reduction	12	289	289	0
Questions About Feasibility	1	22	0	22
Questions About Feasibility - Cement	6	154	0	154
Questions About Feasibility - Ceramic Clay Mfg	4	29	0	29
Questions about Feasibility - Coating Ovens	2	11	0	11
Questions about Feasibility - Distillate Oil	6	116	0	116
Questions About Feasibility - Glass	7	167	0	167
Questions about Feasibility - Process Gas	50	1,070	0	1,070
Selective Catalytic Reduction	8	216	216	0
Selective Non-Catalytic Reduction	178	3,094	2,207	886
	1280	**22,774**	**14,000**	**8,774**

Appendix D

To: US EPA OAQPS

From: SRA International, Inc.

Subject: Summary of State NOx Regulations for Selected Stationary Sources

Date: September 30, 2014

SRA compiled a summary of state/local NOx emission control regulations pertaining six categories of nonEGUs:

- Cement kilns
- Industrial/Commercial/Institutional (ICI) Boilers – Coal-fired
- ICI Boilers – Gas-fired
- ICI Boilers – Oil-fired
- Gas Turbines
- Internal Combustion (IC) Engines

The analysis included 27 states in the eastern two-thirds of the U.S. For each of these states and source categories, we identified state-specific sub-categories (e.g. fuel type or size threshold), the NOx emission limit or control requirement, averaging time for the emission limit, geographic applicability within the state, testing/monitoring requirements, and rule citation. This information is contained in the attached spreadsheet (Draft State NOx RACT Limits 2014_04_01.xlsx).

Attachment 1 is an overall summary of the relative stringency of the NOx requirements by geographic area and source category. We also prepared a 2-page summary for each of the six categories to concisely compare state NOx emission limits or control requirements. These are shown in Attachments 2 to 7, along with notes highlighting the major differences between the state regulations.

Please let us know should you have questions or comments about any of the data presented in this memorandum.

Appendix B

NMED Exhibit 60 - 0180

Attachment 1 – Relative Stringency of NOx Requirements

Source Category	States/Areas with Most Stringent Regulations	States/Areas with Less Stringent Regulations	States with No Regulations or Sources
Cement Kilns[1]	*States*: IL, MD, NY, PA, TX *Areas*: Ellis County, TX	*States*: AL (NOx SIP area), IN, KY, MO, MI, OH, SC, TN, VA, WV	*States*: AR, FL, GA, MS, OK *States with no cement kilns*: CT, DE, LA, MA, NC, NJ, WI
Coal-fired ICI Boilers[2]	*States*: NY *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Houston-Galveston (coke-fired), Milwaukee,	*States*: FL, GA, IN, MA, MD, MI, PA, TN, VA *Areas*: Chicago, St. Louis (MO portion), Baton Rouge, Charlotte, Cleveland	*States*: AL, AR, KY, MS, OK, SC, TX (except Houston-Galveston) WV *NE States with no coal-fired ICI boilers*: CT, DE, NJ
Gas-fired ICI Boilers	*States*: NJ, NY, PA *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Beaumont-Port Arthur, Cleveland, Dallas, Houston, Milwaukee	*States*: CT, DE, FL,GA, MA, MD, MI, MO, TN, VA *Areas*: Clark/Floyd Counties, St. Louis (MO portion), Charlotte	*States*: AL, AR, KY, MS, OK, SC, WV
Oil-fired ICI Boilers	*States*: NJ, NY, PA *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Cleveland, Dallas, Houston, Milwaukee	*States*: CT, DE, FL, GA, MA, MD, MI, TN, VA *Areas*: Clark/Floyd Counties, St. Louis (MO portion), Charlotte	*States*: AL, AR, KY, MS, OK, SC, WV
Gas Turbines	*States*: NJ *Areas*: GA 45-county area, Dallas, Houston, Milwaukee	*States*: CT, DE, FL, LA, MA, MD, NY, PA, TN, VA *Areas*: Chicago, St. Louis (IL portion), St. Louis (MO portion), Charlotte, Cleveland,	*States*: AL, AR, IN, KY, MI, MS, OK, SC, WV
IC Engines > about 500 hp	*States*: MD, NJ, NY *Areas*: Chicago, St. Louis (IL portion), Dallas, Houston	*States*: CT, DE, MA, MI, PA, TN, VA *Areas*: Baton Rouge, St. Louis (MO portion), Charlotte, Cleveland, Milwaukee	*States*: AL, AR, IN, KY, MS, OK, SC, WV

1) Cement kiln emission limits imposed by recent EPA enforcement settlements tend to be more stringent than the emission control requirements in state rules.

2) CT, DE and NJ have no active coal-fired boilers, so the stringency of their regulations for coal-fired ICI boilers is difficult to evaluate

Appendix B

Attachment 2 - Cement Kilns

	NOx Limit (lbs/ton clinker)			
State	**Long Dry**	**Long Wet**	**Pre-heater**	**Pre-calciner**
AL	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
AR	No Limits	No Limits	No Limits	No Limits
CT	No Cement Kilns in State			
DE	No Cement Kilns in State			
FL	No Limits	No Limits	No Limits	No Limits
GA	No Limits	No Limits	No Limits	No Limits
IL	5.1	5.1	3.8	2.8
IN	6.0	5.1	3.8	2.8
IN (Clark/Floyd)	10.8 (op day)/ 6 (30 day)	No Limits	5.9 (op day)/ 4.4 (30 day)	No Limits
KY	6.6	6.6	6.6	6.6
LA	No Cement Kilns in State			
MA	No Cement Kilns in State			
MD	5.1	6.0	2.8	2.8
MI	6.0	5.1	3.8	2.8
MO	6.0	6.8	4.1	2.7
MS	No Limits	No Limits	No Limits	No Limits
NC	No Cement Kilns in State			
NJ	No Cement Kilns in State			
NY	Case-by-case RACT Determination			
OH	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
OK	No Limits	No Limits	No Limits	No Limits
PA	3.44*	3.88*	2.36*	2.36*
SC	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TN	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TX	5.1	4	3.8	2.8
TX (Ellis County)	No Limits	3.4	No Limits	1.7
VA	Case-by-case RACT Determination			
WI	No Cement Kilns in State			
WV	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			

ACT = Alternative Control Technology

* Pennsylvania has proposed “RACT 2” presumptive RACT limits

APPENDIX B

Observations Regarding State NOx Rules for Cement Kilns:

- ❖ Geographic Applicability
  - All NOx SIP Call states with cement kilns have NOx rules in place
  - Since only portions of Alabama, Michigan, and Missouri were affected by NOx SIP Call, the NOx rules only apply in the affected counties.
  - States not included in the NOx SIP Call do not have NOx RACT for cement kilns, except for Texas. The Texas NOx requirements only apply in in Bexar, Comal, Ellis, Hays, and McLennan Counties.
- ❖ Form of NOx Limitation or Control Requirement
  - A few states express the requirement as "at least one of the following: low-NOx burners, mid-kiln system firing, alternative control techniques or reasonably available control technology approved by the Director and the EPA as achieving at least the same emissions decreases as with low-NOX burners or mid-kiln system firing."
  - A few states specify presumptive emission limits in terms of pounds of NOx per ton of clinker.
  - Three states do not set presumptive emission limits but rather require facilities to submit a case-by-case RACT determination. Pennsylvania has a proposed regulation that will specify presumptive RACT limits; current rules require sources to hold 1 trading allowance per ton of NOx calculated by multiplying tons clinker by the presumptive NOx limit.
- ❖ Stringency of NOx Limitation or Control Requirement
  - For states requiring "low-NOX burners, mid-kiln system firing, or ACT", it is generally assumed that this will result in a 30% reduction from uncontrolled levels.
  - For states with numerical emission limits, the limits generally represent a 20 – 40 % reduction from uncontrolled levels, depending on the type of kiln.
  - Texas has very stringent limits for kilns in Ellis County.
  - Pennsylvania has proposed presumptive RACT emission limitations in April 2014 that are more stringent than existing presumptive RACT limits in other states.

Appendix B

Attachment 3 – Coal-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.29 to 0.43	0.29 to 0.43	0.29 to 0.43
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
FL	Broward, Dade, Palm Beach Counties	0.9	0.9	0.9
GA	45 county area	No limits	30 ppmvd @ 3% O2	0.7
IL	Chicago & St Louis areas	Tune-up	0.12 CFB 0.25 Other	0.12 CFB 0.18 Other
IN	Clark and Floyd Counties	No limits	0.4 to 0.5	0.4 to 0.5
KY	Statewide	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	0.2	0.1	0.1
MA	Statewide	0.43	0.33 to 0.45	0.33 to 0.45
MD	Select counties	No limits	0.38 to 1.0	0.38 to 1.0
MI	Fine grid zone	No limits	No limits	0.4
MO	St Louis area	No limits	0.45 to 0.86	0.45 to 0.86
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	No limits	0.4 to 0.5	1.8
NJ	Statewide	0.43 to 1.0	0.38 to 1.0	0.38 to 1.0
NY	Statewide	No limits	0.08 to 0.20	0.08 to 0.20
OH	Cleveland 8 county area	0.3	0.3	0.3
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.45	0.45	0.20 to 0.35
SC	Statewide	No limits	No limits	NOx SIP Call
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Houston area	0.057 coke-fired	0.057 coke-fired	0.057 coke-fired
VA	Northern VA	No limits	0.38 to 1.0	0.38 to 1.0
WI	Milwaukee 7 county area	0.10 to 0.25	0.10 to 0.25	0.10 to 0.20
WV	Statewide	No limits	No limits	No limits

Appendix B

Observations Regarding State NOx Rules for Coal-fired Boilers:

- ❖ Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
  - Texas only has emission limitations for coke-fired boilers in the Houston-Galveston nonattainment area.
- ❖ Size Applicability
  - Most of the states do not have NOx emission requirements for boilers less than 100 mmBtu/hour.
  - 10 states do regulation boilers in the 50-100 mmBtu size range.
- ❖ Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- ❖ Stringency of NOx Limitation or Control Requirement
  - Most states specify different emission limits for different types of boilers and firing types (e.g., dry bottom tangential-fired) vs. dry bottom wall-fired)
  - A few states in the Northeast have very few or no coal-fired ICI boilers, so the stringency of the regulations in those states is difficult to evaluate. These states are CT, DE, NJ and MA.
  - For boilers greater than 100 mmBtu/hour, the LADCO/OTC[1] Phase I recommended limits are in the 0.2-0.3 lbs/mmBtu range (depending on boiler/firing configuration). The LADCO/OTC Phase II recommended limits are in the 0.1-0.2 lbs/mmBtu range. Four areas have limits that generally meet the LADCO/OTC recommendations (Chicago, Baton Rouge, New York State, and Milwaukee.
  - Texas has a very stringent limit (0.057 lbs/mmBtu) for coke-fired boilers in the Houston-Galveston area.

[1] *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD), March, 2011* prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC).

Appendix B

Attachment 4 – Gas-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No Limits	No Limits	No Limits
AR	Statewide	No Limits	No Limits	No Limits
CT	Statewide	0.2 to 0.43	0.2 to 0.43	0.2 to 0.43
DE	Statewide	LEA, low NOx, FGR	0.2	0.2
FL	Broward, Dade, Palm Beach Counties	0.2 to 0.5	0.2 to 0.5	0.2 to 0.5
GA	45 county area	30 ppmvd @ 3% O2	30 ppmvd @ 3% O2	0.2
IL	Chicago & St. Louis Areas	Tune-up	0.08	0.08
IN	Clark and Floyd Counties	No Limits	0.2	0.2
KY	Statewide	No Limits	No Limits	No Limits
LA	Baton Rouge 5 counties & Region of Influence	0.1 to 0.2	0.1	0.1
MA	Statewide	0.1	0.2	0.2 to 0.28
MD	Select counties	Tune-up	0.2	0.2
MI	Fine grid zone	No limits	Source specific RACT	0.2
MO	St Louis area	No limits	0.2 to 0.5	0.2 to 0.5
MS	Statewide	No limits	No limits	No Limits
NC	Charlotte 6 county area	0.3	0.3	0.3
NJ	Statewide	0.1 to 0.5	0.1	0.1
NY	Statewide	0.05	0.06	0.08
OH	Cleveland 8 county area	0.1	0.1	0.1
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.08	0.08	0.08
SC	Statewide	No limits	No limits	No Limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston areas	0.03 or 90% reduction	0.03 or 90% reduction	0.03 or 90% reduction
TX	Beaumont area	0.10	0.10	0.10
VA	Northern VA	0.2	0.2	0.2
WI	Milwaukee 7 county area	No limits	0.08	0.08
WV	Statewide	No limits	No limits	No Limits

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Observations Regarding State NOx Rules for Gas-fired Boilers:

- ❖ Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX,VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- ❖ Size Applicability
  - About half of the states have NOx emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.05 lbs/mmBtu.
- ❖ Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- ❖ Stringency of NOx Limitation or Control Requirement
  - The LADCO/OTC Phase I recommendations are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr.
  - The LADCO/OTC Phase II recommendations are either 0.05-0.1 lbs/mmBtu or 60% reduction.
  - New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations.
  - Five areas (Chicago, Baton Rouge, Beaumont-Port Arthur, Cleveland, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations.
  - Dallas and Houston have the most stringent emission limitations – 0.02 lbs/mmBtu for greater that 100 mmBtu/hr units.

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Attachment 5 – Oil-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
GA	45 county area	30 ppmvd	30 ppmvd	0.3
IL	Chicago & St Louis areas	Tune-up	0.1 Distillate 0.15 Resid.	0.1 Distillate 0.15 Resid.
IN	Clark and Floyd Counties	No limits	0.2 Distillate 0.3 Resid.	0.2 Distillate 0.3 Resid.
KY	Statewide	No limits	No limits	NOx SIP Call
LA	Baton Rouge	0.2	0.1	0.1
MA	Statewide	Tune-up	0.3 Distillate 0.4 Resid.	0.25 to 0.28
MD	Select counties	No limits	0.25	0.25
MI	Fine grid zone	No limits	No limits	0.3 Distillate 0.4 Residual
MO	St Louis area	No limits	0.3	0.3
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	0.2	0.2	0.2
NJ	Statewide	Tune-up	0.1 Distillate 0.2 Resid.	0.1 Distillate 0.2 Resid.
NY	Statewide	0.08 to 0.2	0.15	0.15 to 0.2
OH	Cleveland 8 county area	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.
OK	Statewide	New only	New only	New only
PA	Statewide	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.
SC	Statewide	No limits	No limits	No limits
TN	5 Counties	Case-by-Case RACT	Case-by-Case RACT	Case-by-Case RACT
TX	Dallas and Houston areas	No limits	~0.01	~0.01
VA	Northern VA	0.25 to 0.43	0.25 to 0.43	0.25 to 0.43
WI	Milwaukee 7 county area	No limits	0.10 Distillate 0.15 Resid.	0.10 Distillate 0.15 Resid.
WV	Statewide	No limits	No limits	No limits

Appendix B

Observations Regarding State NOx Rules for Oil-fired Boilers:

- ❖ Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- ❖ Size Applicability
  - About half of the states have NOx emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.08 lbs/mmBtu.
- ❖ Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- ❖ Stringency of NOx Limitation or Control Requirement
  - The LADCO/OTC Phase I recommendations for distillate oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for distillate oil are either 0.08-0.1 lbs/mmBtu or 60% reduction.
  - Only New Jersey has state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
  - Three areas (Chicago, Baton Rouge, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
  - The LADCO/OTC Phase I recommendations for residual oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.2 lbs/mmBtu or 60% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for residual oil are either 0.2 lbs/mmBtu or 50-70% reduction.
  - New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil.
  - Four areas (Chicago, Baton Rouge, Charlotte, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil
  - Dallas and Houston have the most stringent emission limitations – 0.01 lbs/mmBtu for greater that 100 mmBtu/hr units.

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Attachment 6 – Gas Turbines

		NOx Limit (ppmvd @15% O2)			
State	**Geographic Area**	**Simple Cycle >25 MW Gas-fired**	**Simple Cycle >25 MW Oil-fired**	**Combined Cycle > 25 MW Gas-fired**	**Combined Cycle > 25 MW Oil-fired**
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	55	258 (0.9 lb/mmBtu)	55	258 (0.9 lb/mmBtu)
DE	Statewide	42	88	42	88
GA	45 county area	6	6	6	6
IL	Chicago & St Louis areas	42	96	42	96
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)
MA	Statewide	65	100	42	65
MD	Select counties	42	65	42	65
MI	Fine grid zone	No limits	No limits	No limits	No limits
MO	St Louis area	75	100	75	100
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte 6 county area	75	95	75	95
NJ	Statewide	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)
NY	Statewide	50	100	42	65
OH	Cleveland 8 county area	42	96	42	96
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	42	75	42	75
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	source specific RACT	source specific RACT	source specific RACT	source specific RACT
TX	Dallas and Houston areas	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)
VA	Northern VA	42	65/77	42	65/77
WI	Milwaukee 7 county area	25 to 42	65 to 96	9	9
WV	Statewide	No limits	No limits	No limits	No limits

Appendix B

Appendix B

Observations Regarding State NOx Rules for Gas Turbines:

- ❖ Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Nine states (AL, AR, IN, KY, MI, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (GA, IL, LA, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- ❖ Other Applicability Criteria
  - States use a variety size thresholds. For example, Ohio's rules differentiate between units < 3.5 MW and > 3.5 MW. Wisconsin has requirements for three size ranges: 10-25 MW, 25-50 MW, and >50 MW.
  - State limits generally differ by type of fuel – gas or oil. Wisconsin also includes limits for biologically derived fuel.
  - Some states have different limits for simple-cycle and combined-cycle units. Other states have a single limit that applies to both types of units.
- ❖ Form of NOx Limitation or Control Requirement
  - States do not specify specific types of control techniques, but rather set a numerical emission limit.
  - Most states express limits in terms of "ppmv at 15% oxygen". Some states use lbs/mmBtu, and the equivalent limits shown in the table above were calculated using based on Part 75 Eq-F5 and F-factors. New Jersey's limits are in terms of lbs/MHr.
- ❖ Stringency of NOx Limitation or Control Requirement
  - Three areas have very low limits compared to other states/areas: the 45 county area in Georgia, Dallas and Houston-Galveston

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Attachment 7 – IC Engines Greater than ~500 hp

		NOx Limit (g/hp-hr)			
State	**Geographic Area**	**Gas-fired, Lean Burn**	**Gas-fired, Rich Burn**	**Diesel**	**Dual Fuel**
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	2.5	2.5	8.0	8.0
DE	Statewide	Technology Stds.	Technology Stds.	Technology Stds.	Technology Stds.
GA	45 county area	?	?	?	?
IL	Chicago & St Louis areas	210 ppmvd @ 15% O2 (2.9 g/hp-hr)	150 ppmvd @ 15% O2 (2.2 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & ROI	4.0	2.0	?	?
MA	Statewide	3.0	1.5	9.0	9.0
MD	Select counties	150 ppmvd @ 15% O2 (1.7 g/hp-hr)	110 ppmvd @ 15% O2 (1.6 g/hp-hr)	175 ppmvd @ 15% O2 (2.0 g/hp-hr)	125 ppmvd @ 15% O2 (1.4 g/hp-hr)
MI	Fine grid zone	3.0	1.5	2.3	1.5
MO	St Louis area	3.0 10.0	2.5 to 9.5	2.5 - 8.5	2.5 - 6.0
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte Area	2.5	2.5	8.0	8.0
NJ	Statewide	2.5	1.5	8.0	8.0
NY	Statewide	1.5	1.5	2.3	2.3
OH	Cleveland	3.0	3.0	3.0	3.0
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	3.0	2.0	8.0	8.0
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston area	0.5	0.5	2.8 to 6.9	0.5
VA	Northern VA	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
WI	Milwaukee 7 county area	3.0	3.0	3.0	3.0
WV	Statewide	No limits	No limits	No limits	No limits

Appendix D

Observations Regarding State NOx Rules for IC Engines:

- ❖ Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Eight states (AL, AR, IN, KY, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (GA, IL, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- ❖ Other Applicability Criteria
  - States use a variety size thresholds. For example, Louisiana's rules have separate limits for IC engines that are 150-300 hp, >300 hp, and >1500 hp. New York uses > 200 hp and > 400 hp. Delaware uses > 450 hp, while North Carolina uses > 650 hp.
  - State limits generally differ by type of fuel – gas, oil, dual-fuel or landfill/digester gas.
  - A few states have different limits lean-burn and rich-burn engines. Other states have a single limit that applies to both types of units.
- ❖ Form of NOx Limitation or Control Requirement
  - Most states express limits in terms of "gram per brake horsepower hour".
  - Some states use "ppmvd @ 15% O2", and the equivalent limits shown in the table above were calculated using conversion factors from ppmv @ 15% O2 to g/hp-hr from EPA ACT, July 1993 EPA453-R-93-032.
  - Delaware specifies control technology standards rather than numerical emission limits.
- ❖ Stringency of NOx Limitation or Control Requirement
  - Maryland, New Jersey, New York and the Dallas/Houston areas of Texas have limits that are more stringent than other states/areas.

Appendix B

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The INGAA Foundation, Inc.

Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry

Prepared for:
The INGAA Foundation, Inc.

By:
Innovative Environmental Solutions, Inc. &
Optimized Technical Solutions

July 2014

INGAA Foundation Final
Report No. 2014.03

Innovative
Environmental
Solutions, Inc.

Optimized Technical Solutions
Producing prime results for a complicated world

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Executive Summary

New and proposed changes in air emission regulations are likely to impact the interstate natural gas transportation industry. Regulations that are expected to impact the industry include the ozone National Ambient Air Quality Standards (NAAQS) and the nitrogen dioxide (NO_2) one hour NAAQS. Since nitrogen oxides (NOx) react in the atmosphere to form ozone, it is regulated as a precursor to ozone. As emission control rules are developed and permitting actions implemented in response to these federal standards, there will be ongoing pressure to reduce emissions of NOx from existing equipment that has not yet been impacted by NOx control rules, or has been minimally impacted. For example, EPA and states have not yet implemented permitting requirements related to a recent revision to the NO_2 NAAQS. In addition, due to lawsuits and evolving EPA policy, states have been passive in recent years regarding the next set of rules to reduce NOx to address ozone NAAQS concerns. In response to a new ozone NAAQS planned for 2015, there is a potential for broad NOx controls in the eastern half of the U.S. to address NOx transport. Along with the revised ozone NAAQS and implementation of the NO_2 NAAQS, upcoming court decisions, including a Supreme Court decision on EPA authority to institute regional NOx rules, will likely break the regulatory logjam.

Based on these expected air regulation changes that result in new requirements to reduce NOx from existing equipment, a significant number of stationary engines that drive natural gas compressors in interstate natural gas transmission service will likely require modification to meet new federal or state NOx rules or permitting requirements. **Based on current technical resources, the projected time to implement retrofit NOx control (or replacement) is far in excess of typical regulatory schedules.**

The focus of the research for this report was to evaluate the resources required of the operating companies, emission reduction suppliers, engineering service providers, and contractors to implement NOx control regulations for low speed reciprocating engines used in the interstate natural gas transportation industry. The information gathered in developing this report included input solicited from both operating companies and vendors who provide emission reduction retrofit equipment. The assessment included an evaluation of an industry database to estimate the number and type of engines that would be impacted by changes to the emission regulations. Resource and schedule requirements assessed in this report are based on the actual fleet (i.e., make, model, NOx control status) from that database. This study found:

- The special technical expertise to design, construct, and commission emission reduction projects is not widely available to the industry for the slow speed integral engines prevalent in natural gas transmission. Regulations that require installation of NOx control on a large number of reciprocating engines will require a significant lead time to train and develop employees and service provider resources to implement emission reduction projects on a timely basis.
  - Availability of this special technical expertise and building this capability is the primary resource constraint that will affect the ability to meet regulatory obligations, if those regulations affect a large percentage of the existing fleet. Based on current capabilities and a scenario where NOx regulations broadly affect the existing fleet of uncontrolled reciprocating engines, the estimated time to complete upgrades to over 2600 engines is

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nearly forty years. Although strategies to comply may result in many engines (e.g., lower horsepower, lower use engines) being retired or replaced, scheduling implications due to the lack of available expertise would still extend far beyond the expected regulatory timelines. In addition, even if a smaller percentage of the fleet requires control, the required time (e.g., 15 years for 1000 engines) would likely exceed any expected regulatory schedule. Building this technical expertise to address regulatory implementation timelines are significant concerns.

- Engine NOx control projects are generally much less costly than engine replacement. If the anticipated regulations are implemented, capital costs to modify currently uncontrolled reciprocating engines used in the interstate natural gas transmission industry are estimated at approximately $4 billion to achieve NOx emission rates of 3 grams per horsepower hour (g/hp-hr) and over $6 billion to achieve 1 g/hp-hr.
- The age of the impacted equipment (most of the engines are over 40 years old) requires additional time to engineer and construct reliable emission reduction modifications due to inaccurate or missing engineering records that reflect the current equipment configuration.
- Some engines with low specific power output will require extra time to properly design and construct emission reduction modifications and maintain the same power operating range.
- Based on previous experience, the timeline of obtaining air permits is a key parameter defining the overall schedule for completing a specific emission reduction project – i.e., permitting can slow the project timeline.
- Equipment outages that last several weeks to over a month to implement emission reduction modifications may have significant impact on available pipeline capacity and could cause significant capacity disruption, especially if the schedule overlaps with implementation of other regulations such as pipeline integrity testing.

1.0 Introduction

As shown below, air emissions from a natural gas compressor station are regulated by a complex web of federal and state regulation. This report focuses on the potential availability of resources – equipment, people, and expenditures – needed to modify these compressor stations to meet possible NOx emission requirements.

Air emissions continue to be a major regulatory issue, and air quality regulations pose a risk to normal operations of existing natural gas transmission infrastructure. NOx emissions are the primary air pollutant of interest from natural gas-fired combustion sources. NOx can react in the atmosphere to form ozone, so NOx is regulated as a precursor to ozone. NOx can also react to form nitrates, and ammonium nitrate is an aerosol that comprises a portion of atmospheric fine particulate ($PM_{2.5}$). The U.S. Environmental Protection Agency (EPA) establishes NAAQS for six criteria pollutants, including ozone, NO_2, and $PM_{2.5}$. NOx emissions are comprised of NO and NO_2, but all NOx emissions are generally considered NO_2 under the NO_2 NAAQS.

Based on ambient air monitoring, if the air quality in a particular location does not meet (i.e., "attain") the NAAQS, that geographical area will be designated as a "nonattainment" area. Then, state or local agencies are required to develop regulations that decrease emissions from *existing sources* to reduce ambient pollutant levels and attain the NAAQS. In addition, NOx emissions may be evaluated by regulatory agencies using a model that simulates the behavior of the exhaust plume (i.e., a "dispersion model") to assess whether NO_2 impacts beyond the compressor station fence line exceed the NO_2 NAAQS. If so, mitigation would likely be required.

For example, NOx Reasonably Achievable Control Technology (RACT) regulations may be adopted by a state to address ozone nonattainment within the state. These rules may apply to limited in-state areas (e.g., urban nonattainment areas) or statewide. In addition, many urban and eastern U.S. areas have already reduced NOx emissions, but NOx transported from upwind states contributes to nonattainment. This phenomenon is referred to as "NOx transport," and EPA may adopt multi-state regional rules to reduce NOx across the eastern U.S. and mitigate NOx transport. For natural gas-fired combustion sources, NOx is the primary pollutant that may be regulated by these rules. Emissions of other pollutants such as formaldehyde, which is regulated as a hazardous air pollutant (HAP), may also trigger emission controls. However, it is generally expected that existing catalyst control providers can meet demands to address new regulatory requirements.

Thus, this report focuses on potential resource constraints associated with regulations that require retrofit installation of NOx emission control technologies. More specifically, the report focuses on combustion-based technologies – i.e., low emissions combustion (LEC) – for lean burn reciprocating engines commonly used in interstate transmission and most likely subject to retrofit NOx control in the future (i.e., this older equipment is typically "grandfathered" and many units have not been subject to NOx regulations to date). The reciprocating engines of interest are low speed "integral" engines uniquely used for gas compression, where the compressor and its driver – i.e., the reciprocating engine used to power the compressor – are integrated into a single piece of equipment with a common crankshaft. These legacy integral engines comprise a large portion of the horsepower capacity in interstate natural gas compression and can also be found in gas processing and, to a lesser extent, in gathering compression. Although these engines have been

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in service for many years, because they were designed specifically to compress natural gas, natural gas-fired integral engines remain the most efficient option for gas compression.

LEC is the preferred approach to reduce lean burn engine NOx emissions, but EPA or states may consider additional controls such as selective catalytic reduction (SCR). Rich burn reciprocating engines may require non-selective catalytic reduction (NSCR) to reduce NOx and formaldehyde, but rich burn engines are a smaller percentage of interstate transmission prime movers and many rich burns already use NSCR emissions control in response to the federal HAP standard or state requirements.

The focus of this report is to assess the availability of resources to implement air emission modifications on the reciprocating engines used to transport natural gas on the interstate pipeline system. For example, there are currently a handful (or less) of service providers that provide LEC control for reciprocating engines. Thus, depending upon the breadth and timing of emission control requirements, there is a concern that resource constraints may impact timely compliance or the reliability of gas delivery.

This report will identify potential constraints, including potential bottlenecks in the supply chain, regarding availability of capital equipment and technology service providers to address retrofit NOx control of the existing fleet of equipment. Scheduling issues will be discussed, including constraints that may point to the need for phasing regulatory compliance.

The regulatory context is based on an expectation that existing reciprocating engines that do not include NOx control technology will eventually be required to retrofit NOx control technology in response to recent or upcoming revisions to the federal ozone or NO_2 NAAQS. NOx control resource availability for reciprocating engines is the most probable resource constraint due to the limited service providers and trained labor in this field, so this report focuses on potential resource limitations and the time required to control these engines, especially lean burn engines.

In addition to this Introduction, the report includes:

- An Executive Summary.
- Section 2 discusses the study approach.
- Section 3 provides an overview of reciprocating engine NOx control technologies,
- Section 4 discusses engine demographics (population and type) for interstate transmission prime movers.
- Section 5 presents NOx related air quality regulatory concerns and analysis assumptions and methodology.
- Section 6 presents methodology and results related to costs and schedule.
- Section 7 presents the analysis and discussion of limitation by project phase, and Section 8 provides conclusions.
- Appendices provide a list of acronyms and the survey questions used for discussions with operators, equipment manufacturers, and service providers.

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2.0 Study Approach

The information in this report was gathered confidentially by Innovative Environmental Solutions (IES) and Optimized Technical Solutions (OTS) and the information has been consolidated in a manner that the individual responses cannot be broken out by the vendor or operator supplying the information. This is done to prevent business strategies or other competitive information from reaching competitors. All efforts were made to prevent the communication of information that could result in anticompetitive practices.

Interviews were performed with multiple emission reduction vendors and operating companies. In addition, a literature review was performed, and relevant information is cited. There is significant uncertainty regarding the requirements (e.g., required emission levels), geographical breadth, and timing of NOx regulations. Since there are many possible regulatory outcomes, specific dates and regulations are not a focus, but a general discussion of the NOx control regulatory threat is provided in Section 5. Instead of considering a specific regulation, the analysis in this report focuses on identifying potential resource constraints based on an assumption that many legacy prime movers without NOx control will eventually require upgrade (or replacement). To consider technology needs, costs, and scheduling, the analysis considers the engine types (i.e., model) based on an available database. Two NOx targets are considered (i.e., 3 g/bhp-hr or 1 g/bhp-hr) based on previous experience for likely regulatory endpoints and guidance from advisors, and a general ranking of regulatory risk for three geographical areas is used when assessing implications. States were categorized as high risk/stringency (where regulations may already be in place in some cases – e.g., northeast state where much of the fleet is already controlled), moderate risk (e.g., midwest and eastern states where compressor stations may be implicated as contributors to eastern U.S. NOx transport), and lower risk states, where regulation is less likely (e.g., northern plains states, where control is less likely unless EPA initiates broad national requirements for existing equipment). In addition, costs were considered under the premise that NOx control would be widely required for uncontrolled units either due to NOx regulations (e.g., in response to ozone nonattainment) or permitting actions to address conformance with the NO_2 NAAQS.

This effort began with interviews of multiple interstate gas pipeline operating companies that had previous experience with NOx reduction projects. In addition, independent interviews were conducted with six different suppliers of equipment and services that modify reciprocating engines used in the interstate natural gas transportation industry. Interviews covered all aspects of the execution of NOx reduction projects from start to finish. Specific topics in project execution included:

- **Permitting** – Permitting is the process of obtaining air emission permits from the regulating agency – typically a state agency. This phase requires an initial engineering analysis to determine the modifications required and the expected air emissions for each emission source at a facility for the permit application. Defined technologies must be settled upon prior to completing the permit.
- **Initial design** – This portion of the project assesses: (1) which emission reduction technologies are suitable for a facility and the associated suppliers for the emission reduction equipment, (2) the reduction in air emissions that can be expected with the applicable emission reduction equipment, and (3) the initial design for the equipment changes. Input from the suppliers of

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emission reduction equipment is usually required during this portion of the project. Initial design information is also necessary to provide information for the permitting process, but other, more detailed design considerations are also addressed under this topic.

- **Cost estimating and scheduling** – This part of the project establishes the expected timeframe and financial costs expected to modify the equipment for emissions control. Personnel resource availability and allocations are also typically performed in this portion of the project execution.
- **Contracting and procurement** – In this portion of the project, detailed cost and schedule information to implement an emission control project is solicited from suppliers and contractors. This requires the creation of design specifications, evaluation criteria, and contractual terms and conditions.
- **Detailed design** – This phase involves developing detailed designs based on specific emission control equipment selected. Detailed design includes but is not limited to the development of material lists, drawings, engine control system modifications, and commission plans.
- **Construction** – This portion of the emission control project is where physical modifications are made to the engine and ancillary equipment.
- **Commissioning** – This is the phase of the emission control project where calibration, configuration, and tuning of the engine is performed to ready the engine for continuous operation. Training of the operating and maintenance personnel is also often performed during this phase.
- **Operation and maintenance** – This is the post-conversion and commissioning portion of the project. Proper operation and maintenance of the engine and emission control equipment is required to ensure compliance with the emission limits.

This report discusses resource constraints for each of these phases for reciprocating engine NOx control projects, as described by the operators and suppliers of emission reduction equipment. For NSCR application to rich burn engines, a higher level review was conducted because it is likely that there are an adequate number of vendors to address market demand and fewer engines are likely to be affected.

Cost and schedule estimates are based on the number and size of engines to be converted, information provided by pipeline operators and suppliers of emission reduction equipment, and reference publications. Factors that influence technology requirements and costs for reciprocating engines include:

- Combustion cycle (two-stroke, four-stroke),
- The engine make and model,
- Brake mean effective pressure (BMEP) of the engine,
- Engine aspiration type (natural, turbocharged), and
- The number of power cylinders.

Based on engines identified in an industry database, this information was used to determine the most probable type of modifications needed to achieve the target NOx emission level.

3.0 Reciprocating Engine NOx Emission Reduction Technology Overview

NOx control technologies for reciprocating engines are discussed below. LEC technologies for lean burn engines are discussed in Section 3.1, and NSCR for rich burn engines is discussed in section 3.2. Section 3.3 discusses SCR. Although SCR has not been applied to existing integral engines, it could be considered by regulatory agencies, especially for lean burn engines where LEC is not available or cannot achieve the target NOx level.

3.1 Reciprocating Internal Combustion Engines – LEC for Lean Burn Engines

An overview of LEC NOx control technologies for lean burn reciprocating engines is described in this section. [1] [2] [3]

NOx emissions from natural gas combustion are formed from nitrogen and oxygen in the combustion air, and NOx emissions increase significantly at higher combustion temperatures. LEC achieves lower NOx by providing sufficient excess air to reduce the maximum combustion temperature and minimize NOx formation. The use of LEC to control NOx is possible on fuel-injected two-stroke cycle engines and many four-stroke cycle engines. Since the excess air may hinder combustion or light-off of the air-fuel charge in the cylinder, LEC-equipped engines generally require a high energy ignition source. This is most commonly implemented by the use of pre-chamber combustion systems that ignite a smaller charge that then ignites the in-cylinder air-fuel mixture. The power operating range may decrease on two-stroke cycle engines when converted to LEC.

Since peak combustion temperatures are influenced by the amount of excess air and air-fuel mixing, there are several methods that can be used to minimize peak temperatures and NOx formation during lean combustion. Regulatory agencies use the term "LEC" broadly and a number of technology approaches can be used depending on the engine and NOx emission limit. In many cases, multiple LEC related technologies may be required – e.g., additional air through new or upgraded turbocharging, higher energy ignition /precombustion chambers, and enhanced mixing. Several primary technologies are described below. For the engine types in the fleet, the analysis considered the proper technology approach to achieve target NOx emissions of 3 g/hp-hr or 1 g/hp-hr.

3.1.1 Enhanced Mixing

Pockets of rich fuel can exist in engines equipped with direct fuel injection. The resulting locally rich fuel mixtures result in localized higher combustion temperatures with an associated increase in NOx formation. Engine modifications to produce enhanced air/fuel mixing can counteract this effect. For example, "high pressure" fuel injection systems have been developed that take advantage of the higher pressure gas available from the pipeline to greatly improve air-fuel mixing. On some engines, enhanced mixing modifications may also require high energy ignition modifications to prevent engine misfires.

3.1.2 Mechanical Modifications

Modifications that can be used to reduce NOx emissions include upgrading or conversion to turbocharging, adding additional turbocharger after-cooling, installing different cam shafts, installing different (e.g., electronic) fuel injection valves, etc. These are not discussed in detail

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here as they usually result in minor reductions as an independent action, but are typical technologies that may be included as part of the emissions reduction project. Since dispersion modeling may be required to ensure that modeled offsite impacts do not exceed the NO_2 NAAQS, stack height extensions are a modification that can reduce modeled ground level concentrations. In general, a stack height that is at least 1.5 times the height of the compressor building peak height is desired to avoid building-induced "downwash" that brings the plume to ground level sooner and results in higher modeled impacts.

3.1.3 Operational Control – Ignition Timing

The peak combustion pressure (and thereby the peak combustion temperature) can be lowered by retarding (or delaying) the ignition timing of the engine. The lower combustion temperature results in lower NOx emissions. Only nominal NOx reductions are achieved when used in isolation and fuel consumption increases. This may also reduce the maximum power the engine can produce, and typically increases carbon monoxide (CO), volatile organic compounds (VOCs), and total unburned hydrocarbons (THC) emissions. VOCs are regulated as an ozone precursor and are a subset of THC (the methane and ethane components of THC are excluded from VOCs because these two hydrocarbons are minimally reactive in ozone producing atmospheric reactions).

3.1.4 Operational Control – Air/Fuel Ratio

Altering engine control methods can reduce the formation of NOx and improve the reliability of maintaining emissions at the prescribed level. On engines that utilize air/fuel controls, some NOx reductions may be possible by changing the control curve to operate the engine leaner without other engine modifications. This control change is limited by the amount of air available from the turbocharger and the ability of the ignition system to ignite the leaner mixture without misfires.

3.1.5 Other (non-LEC) Technologies

The technologies described above are not intended to be a comprehensive list. There are other control methods such as exhaust gas recirculation that are not covered here due to their limited effectiveness and limited use on the types of engines typically utilized in interstate natural gas transmission.

3.2 Rich Burn Reciprocating Internal Combustion Engines – Nonselective Catalytic Reduction

Rich burn engines are designed to operate with minimal excess air – i.e., with combustion air approximately equal to the amount required to completely combust the fuel with minimal excess air. The "stoichiometric" amount of air is the exact amount required to burn the fuel with no excess. For reciprocating engines that operate near stoichiometric conditions (excess oxygen in the exhaust <0.5%), NSCR is the accepted emissions control option. This type of exhaust control technology is commonly used on automobiles and also referred to as a 3-way catalyst because emissions of NOx, CO, and VOCs can be reduced. For this control technology to work effectively for all three pollutants, an air to fuel ratio controller (AFRC) is required that maintains the AFR over a very narrow operating band. With too little air, NOx will be low, but CO and VOCs may significantly increase. With too much air (and thus too much oxygen available), CO and VOCs will be reduced (i.e., NSCR operates as an oxidation catalyst), but

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NOx reduction across the catalyst will be impacted and post-catalyst NOx will significantly increase.

Catalytic elements used in NSCR can be contaminated by engine oil carryover and other operating factors. Cleaning and replacement is required on a periodic basis. Unburned hydrocarbons in the exhaust stream reduce the life of the catalyst. This is the common technology of choice for rich burn four-stroke cycle engines.

3.3 Selective Catalytic Reduction for Lean Burn Engines

For NOx control from lean burn engines, this report focuses on LEC. SCR is discussed here because it is often considered by regulators when assessing NOx controls for combustion equipment and future control rules may require SCR in some cases (e.g., if LEC is not effective on a particular engine model). SCR is an exhaust control for lean combustion (i.e., excess air is available) that reduces NOx by reaction with ammonia or urea over a catalyst. [4] [5] Ammonia or urea injection is required with precise reagent feedrate control based on the NOx concentration and the NO/NO_2 ratio of the NOx. The reagent and NOx "selectively" react on the catalyst to (ideally) form water and molecular nitrogen (N_2). To date, SCR application to U.S. gas transmission sources has been very limited, and SCR has not been applied to an existing integral engine. Technical concerns about the SCR performance for gas transmission engines include exhaust temperature requirements, reagent control (and sophistication of current systems), and treatment of potential variations in the reciprocating engine exhaust NO/NO_2 ratio.

SCR has been more commonly applied to larger utility scale turbines and boilers, with very limited gas transmission applications to date. Recently, some new 4-stroke cycle lean burn engines have been sited with SCR, but retrofit application to lean burn prime movers has not occurred. While NSCR for rich burn engines exploits the chemical processes available at stoichiometric combustion to reduce multiple pollutants, SCR "selectively" reduces NOx. The use of SCR is most effective when operating in the exhaust temperature range of 480 to 800 °F. The minimum operating temperature of the catalyst is dependent on the composition of the exhaust gases and the type of catalyst materials used, and the typical exhaust temperature range for some lean burn engines may present challenges. Engines that have variable power loads require more sophisticated controls to inject the proper amount of reagent, and it is not evident that robust control schemes have been developed for transmission applications. The installation of a continuous emissions monitor could be required to effectively control the amount of reagent necessary to achieve the desired NOx emission rate.

SCR catalytic elements can be contaminated by byproducts of combustion (such as oil ash) and engine oil carryover. Cleaning and replacement is required on a periodic basis, and extra management is required to ensure adequate inventories of reagent are maintained.

Due to the issues described above and the desire to prevent NOx formation rather than controlling NOx in the exhaust, LEC is preferred over SCR for existing lean burn engines.

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4.0 Reciprocating Engine Demographics (Population and Type)

An INGAA engine database (originally developed by PRCI and GRI over 10 years ago) includes 3665 *low speed* reciprocating engines used in the interstate natural gas industry. It should be noted that the number of engines in the tables below reflect large bore, low speed reciprocating engines. There are other engines used in the natural gas transportation industry. Most of the other engines are newer high-speed four-stroke cycle engines that are already equipped with low NOx emissions (typically LEC or NSCR) technology, such as best achievable control technology (BACT) required during permitting of new units or technology to meet New Source Performance Standards (NSPS) and National Emission Standard for Hazardous Air Pollutants (NESHAP) regulations.

Although this database is not complete (e.g., it was estimated to include over 80% of interstate transmission facilities when it was compiled), and changes in the fleet have occurred since the database was last updated, the information from this source still provides a reasonable basis to assess counts of existing engines and technology requirements for NOx control. Of the 3665 low speed engines, 35 are known to have been abandoned or replaced leaving a net of 3630 engines. These engines were categorized by engine type and geographical region as described in Section 5, where regulatory risk (i.e., likelihood and level of control) was used to categorize states into three regulatory risk categories depending on the state where the engine is located. Table 4-1 shows engine counts for each category for the three primary engine types. (The states in each risk category are identified in section 5.)

Table 4-1. Engine Type by Geographical Regulatory Risk Category.

Engine type	Category 1	Category 2	Category 3	Total
2-stroke cycle	321	1975	344	2640
4-stroke cycle lean	82	320	51	453
4-stroke cycle (rich)	50	405	82	537
Total	453	2700	477	3630

The average engine size is 2145 brake horsepower with an average of 12 power cylinders per engine. To assess technology requirements and potential resource issues, these engines have been grouped or classified based on different engine types/subtypes and current emission control capabilities. Each group type requires a different approach to NOx reduction with an associated impact on costs and schedules. The two-stroke cycle and four-stroke cycle lean engines are candidates for LEC and the four-stroke cycle rich burn engines are candidates for NSCR NOx control technologies. For the purposes of this discussion, the "rich burn" engines include older, horizontal engines that do not include air to fuel ratio control and may operate near stoichiometric conditions (i.e., "rich") or leaner (i.e., with excess air). The term "stoichiometric" refers to the condition where the amount of oxygen available from the combustion air is equivalent to the amount required to completely combust all of the fuel without any excess oxygen. Rich burn engines operate near stoichiometric conditions, while lean burn engines have excess air. Regulatory definitions, such as the federal NSPS and NESHAP standards, typically

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use ten percent excess air (which is equivalent to two percent excess oxygen in the exhaust) as the threshold between rich and lean operation.

To estimate the number of engines that would require NOx emissions control, and assess associated capital costs and timeline, the INGAA database of engines was analyzed by current emission levels as shown in Table 4-2. Note that this table excludes 417 low BMEP four-stroke rich burn engines that are assumed to have NSCR catalysts as described in Section 4-2.

Table 4-2. Engine Counts by NOx Emission Levels.

Emission capability	Category 1	Category 2	Category 3	Total
NOx $\leq$ 1 g/hp-hr	64	0	0	64
1 < NOx $\leq$ 3 g/hp-hr	339	162	36	537
NOx > 3 g/hp-hr	0	2238	374	2612
Total	403	2400	410	3213

The majority of reciprocating engines used in the interstate natural gas transportation industry were installed before 1960. Most have been exempt from clean air regulations issued after they were installed since existing units are "grandfathered" – i.e., exempt from regulations that affect new sources. A common exception is engines that have been controlled in response to NOx RACT or similar rules adopted to decrease the NOx inventory from existing sources as a strategy to address ozone nonattainment. A discussion follows on each of the primary engine categories, related engine counts, and NOx control technology available.

4.1 Horizontal engines

Horizontal engines are four-stroke cycle naturally aspirated engines with four double acting power pistons. These engines were manufactured by Cooper-Bessemer (Type 22 through Type 26) and Worthington (24X36 and 26X36). These engines are the first type of reciprocating engines widely used to compress natural gas for transportation. They are a derivative of horizontal steam engines. The double acting power cylinders (combustion occurs on both sides of the piston) have very large cylinder bores (22" to 26") and strokes (typically 36"). It is difficult to control the air/fuel mixture for these units – e.g., for use with post-combustion catalytic control. Likewise, they are not suited to LEC conversion. Per the INGAA database, there are 120 engines in this group, where a retrofit NOx control technology is not available, with an average power rating of 1530 hp.

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Figure 4-1. Horizontal Engine

Because these engines have higher operating and maintenance costs, they are generally operated on a last on, first off basis in response to demand. Therefore, their annual operating hours tend to be lower than newer engines operating at the same facility.

Since technology upgrades are not available, the assumed "NOx control" option for these engines is replacement. For cost estimating purposes, the assumed replacement equipment is 3000-4000 hp gas turbines equipped with dry low NOx (lean premixed) combustors. Although larger gas turbines would reduce the capital replacement costs, smaller gas turbines are a better match (although still larger) to the engines being replaced. Larger engines do not have the necessary turndown capability to match the horizontal engines. Gas turbines were selected over other engine types due to the lower capital costs. Where minimizing fuel is a major consideration, high speed four-stroke cycle reciprocating engines would be selected as the replacement engine. All of these engines are located in geographical regulatory risk Categories 2 and 3 as shown in Table 4-3. These engines are a subset of the four-stroke rich burn engines found in Table 4-1. All horizontal engines are assumed to have NOx emission rates greater than 3 g/hp-hr.

Table 4-3. Number of horizontal engines.

Engine Type	Category 1	Category 2	Category 3	Total
4-stroke – horizontal	0	105	15	120

4.2 Low BMEP four-stroke cycle naturally aspirated engines

Like the horizontal engines, the low BMEP four-stroke cycle engines (see Figure 4-2) used in natural gas transmission sometimes operate near stoichiometric conditions and other times operate lean. These engines differ from horizontal engines in that they can generally be fitted

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with air-fuel controls to enable operation with NSCR. However, depending on the units, operation with NSCR sometimes requires higher exhaust temperatures than the unit was initially designed. Alternatives technologies include converting to LEC (with the addition of a turbocharger) [6] or installing SCR. SCR has had very limited application to existing reciprocating engines, and installation of SCR may limit the ability of the engine to operate at rated power.



Figure 4-2. Ingersoll-Rand KVG

The analysis in this report assumes that NOx reductions would be achieved with installation of NSCR, with engine modifications completed as necessary to accommodate higher exhaust temperatures. However, existing rich burn engines at "major sources" (i.e., larger facilities such as compressor stations with multiple reciprocating engines) were required to install NSCR to comply with an EPA regulation, with compliance required by 2007 for the 2004 RICE NESHAP rule. Therefore, resource limitation were not assessed and costs to modify these engines are not estimated here because any incremental costs (e.g., to better tune the air to fuel ratio controller (AFRC) for NOx reduction) should be minimal. It is likely that some of these engines will require control or additional modifications to achieve required NOx reductions. The number of these engines in each geographical regulatory risk category can be found in Table 4-4. This is a subset of the four-stroke cycle rich burn engines in Table 4-1.

Table 4-4. Number of low BMEP four-stroke cycle engines.

Engine Type	Category 1	Category 2	Category 3	Total
4-stroke cycle low BMEP	50	300	67	417

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4.3 Opposed piston two-stroke cycle engines

The gas pipeline transportation industry employs about 14 two-stroke cycle opposed piston engines such as the Fairbanks-Morse engine shown in Figure 4-3. These engines typically use superchargers to provide scavenging air.

The engines utilize two power pistons per power cylinder with intake and exhaust ports at opposite ends of the cylinder liner. The two pistons are connected to separate crankshafts which are synchronized through a vertical driveshaft and bevel gears. Because of the higher number of moving parts on these engines, they tend to have higher maintenance costs than other engines used in this industry.

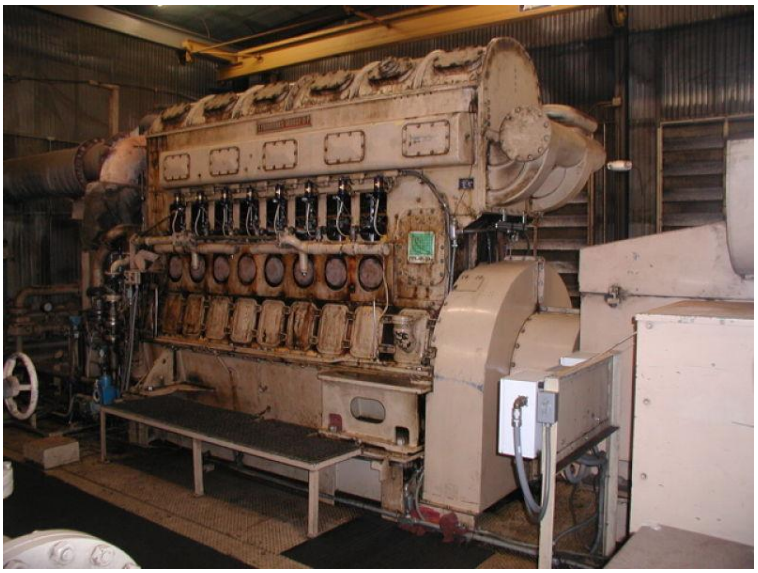


Figure 4-3. Fairbanks-Morse MEP-8

The engines can be converted to lean burn combustion or controlled using post-combustion catalytic reduction. NOx emission rates below 3 g/hp-hr are difficult to achieve at full load and speed on these engines through lean combustion alone. Based on the operating cost of these engines and emission characteristics, the analysis in this report assumes emission reduction is achieved with lean burn conversion and an emission rate of 3 g/hp-hr. Replacement is assumed if lower emission rates are required. The location of these engines by geographical regulatory risk category is in Table 4-5. This is a subset of the two-stroke cycle engines in Table 4-1.

Table 4-5. Number of opposed piston two-stroke cycle engines.

Engine type	Category 1	Category 2	Category 3	Total
2-stroke cycle opposed piston	1	13	0	14

4.4 Medium and higher BMEP four-stroke cycle turbocharged engines

Medium and higher BMEP four-stroke cycle turbocharged engines (see example in Figure 4-4) operate too lean to utilize NSCR for NOx reduction, and these engines are generally suited to

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NOx control through lean burn combustion and enhanced mixing methods – i.e., LEC technologies.



Figure 4-4. Ingersoll-Rand 616KVT

For cost estimating and resource availability assessment purposes in this study, reducing emissions to 3 g/hp-hr is assumed to be achieved through lean combustion. To lower NOx emissions to 1 g/hp-hr requires the addition of enhanced fuel mixing. The assumed emissions and location of these engines by geographical regulatory risk category can be found in Table 4-6. This table is a subset of four-stroke cycle rich and four-stroke cycle lean engines in Table 4-1.

Table 4-6. Number of medium and higher BMEP four-stroke cycle turbocharged engines.

Emission type	Category 1	Category 2	Category 3	Total
NOx $\leq$ 1 g/hp-hr	36	0	0	36
1 < NOx $\leq$ 3 g/hp-hr	46	26	5	77
NOx > 3 g/hp-hr	0	308	46	354
Total	82	334	51	467

4.5 Low BMEP two-stroke cycle engines

Low BMEP two-stroke cycle engines are generally older engines (i.e., the "first generation" of pipeline integral 2-stroke engines) that utilize low volume pumps or blowers to provide engine scavenging (Figure 4-5). To reduce NOx emissions, LEC is applied through the removal of the mechanically driven scavenging and installation of turbochargers with after-cooling and precombustion chambers. Because of the low BMEP of these engines, there is typically less exhaust energy to support turbocharger operation. As a result, the power turndown range of converted units is limited. The addition of enhanced fuel mixing technologies would extend the power operating range for these engines.

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Figure 4-5. Clark HBA Low BMEP Engine

Therefore, conversion to 3 g/hp-hr of NOx is assumed to require both conversion to leaner combustion and the installation of enhanced fuel mixing. With these modifications, the engines are capable of achieving 1 g/hp-hr of NOx in a narrower range near rated speed and power.

Adding a turbocharger sometimes allow these engines to operate at a higher rated power. This can increase the available turndown range of these engines as more heat energy is available to drive the turbocharger. Power increases of 5-40% are possible. The ability to increase the rated power of the engines is dependent on the design of the mechanical, structural, and auxiliary components (crankshaft, connecting rods, pistons, foundation, jacket water cooling, etc.) to handle the higher loads on the engine. The gas compressor cylinders may also require modifications to be able to utilize the additional power. This is usually achieved by installing larger compressor pistons and additional unloaders.

An increase of the engine power rating usually requires modifications to the air permit and filing with the Federal Energy Regulatory Commission. In some cases, the update of several engines could allow the abandonment of another engine thereby eliminating the need (and associated costs) to control emissions for that engine.

On a per horsepower basis, the costs of NOx control conversion for these units are generally more than the costs for higher BMEP two-stroke cycle engines (discussed below). This is due to additional intake/exhaust manifold modifications and the installation (versus an upgrade) of a turbocharger/after-cooler system. The assumed emission limits and location of these engines by geographical regulatory risk category is shown in Table 4-7. This is a subset of the two-stroke cycle engines in Table 4-1.

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Table 4-7. Number of low BMEP two-stroke cycle engines.

Emission type	Category 1	Category 2	Category 3	Total
NOx $\leq$ 1 g/hp-hr	5	0	0	5
1 < NOx $\leq$ 3 g/hp-hr	72	0	0	72
NOx > 3 g/hp-hr	0	461	44	505
Total	77	461	44	582

4.6 Medium and higher BMEP two-stroke cycle engines

Medium and high BMEP two-stroke cycle engines are engines that utilize centrifugal blowers and/or turbochargers to provide engine scavenging (Figure 6). These engines are generally larger than the first generation low BMEP 2-cycle engines discussed above. They are well suited to lean burn combustion to reduce NOx formation. A reduction in the power operating range can be expected on some of these engines in order to maintain very low NOx emissions. The addition of enhanced fuel mixing technologies extends the operating range of these engines and/or further reduces NOx emissions.

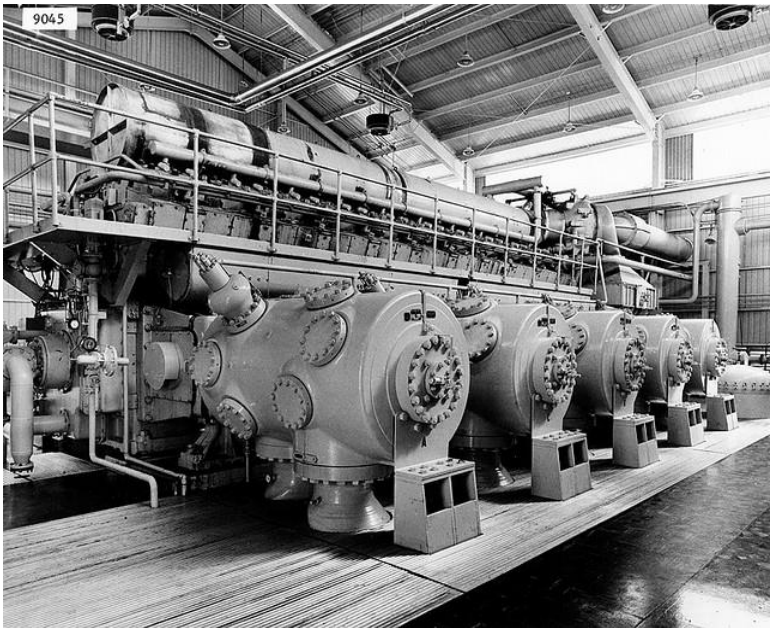


Figure 4-6. Cooper-Bessemer Z330

For the cost estimating purposes of this study, reducing emissions to 3 g/hp-hr is assumed to be achieved through lean combustion. This emission level is consistent with NOx limits for retrofit control of lean burn engines in federal and status rules, and is an expected upper bound target in upcoming rules. However, it is possible that lower NOx emission levels, such as 1 g/hp-hr limits, will be pursued in some jurisdictions. Lower emission limits also require the addition of enhanced fuel mixing. The assumed emission limits and location of these engines by geographical regulatory risk category is shown in Table 4-8. This is a subset of the two-stroke cycle engines in Table 4-1. Note that this group includes many engines, and often these engines are more highly utilized than smaller, older low BMEP engines discussed in the previous section.

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Thus, the medium to high BMEP two-stroke cycle engines are a prime candidate for regulation when states or EPA consider NOx control regulations.

Table 4-8. Number of medium and high BMEP two-stroke cycle engines.

Emission type	Category 1	Category 2	Category 3	Total
NOx $\leq$ 1 g/hp-hr	23	0	0	23
1 < NOx $\leq$ 3 g/hp-hr	221	134	31	386
NOx > 3 g/hp-hr	0	1372	269	1641
Total	244	1506	300	2050

5.0 Regulatory Background and Analysis Assumptions and Methodology

NOx emission regulations continue to evolve and are not fully defined at this time. However, as EPA and the states implement regulations in response to ozone NAAQS nonattainment and the NO_2 NAAQS, it is expected that new regulations and permitting actions over the next 5 to 15 years will impact the status of many engines that are currently uncontrolled. The following section provides an overview of NOx regulations and regulatory risk, and section 5.2 discusses assumptions used to assess implications.

5.1 NOx Regulations – Background and Regulatory Risk

For existing equipment, NOx regulations are generally in response to concerns with ozone NAAQS nonattainment because NOx is an ozone precursor – i.e., it reacts in the atmosphere to form ozone. In addition, 2010 revisions to the NO_2 NAAQS increased the stringency of that rule. If offsite impacts (i.e., beyond the facility fence line) of NO_2 determined using a dispersion model exceed the NAAQS, then mitigation may be required. At this time, the most likely triggers for retrofit NOx control for natural gas transmission prime movers are:

- NOx RACT Rules: Revisions to the ozone NAAQS planned for 2014 – 2015 will likely increase the number of nonattainment areas, and result in new state-level NOx RACT rules later this decade. Such rules are highly likely to occur unless EPA provides a different regional solution, and state rules could result in different requirements and applicability (e.g., statewide or county-specific rule) from state to state. States tend to rely on rules developed by other states, so states that are early actors in the next few years could provide "model rules" that would be broadly implemented.
- Regional Rule: EPA may implement a broad (e.g., eastern half of U.S.) regional rule similar to the 2004 NOx SIP Call Phase 2 Rule that required NOx reductions from large sources. Over 200 natural gas-fired prime movers were controlled in response to the 2004 SIP Call Rule. A similar new regional rule could supplant or supplement state NOx RACT Rules (see previous bullet), could quicken the schedule, and would likely affect many eastern U.S. engines. EPA may be hesitant to pursue this (and instead defer to the states) due to legal issues that remain to be resolved with a regional rule for electric utilities.
- NO_2 NAAQS mitigation: To date, there have been minimal regulatory actions in response to the 2010 NO_2 NAAQS revision. However, example modeling has shown that the relatively short stacks common for reciprocating engines and conservatism in AERMOD (the regulatory

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dispersion model) may result in offsite impacts that exceed the 100 ppbv 1-hour NO_2 NAAQS for uncontrolled reciprocating engines. Although there has been limited action to date, this could result in state or federal requirements to mitigate these impacts, and agency actions could be prompted by litigation or pressure from third parties. For existing facilities, EPA or the state could require modeling at any time, such as when the operating permit undergoes its five year renewal. Third party challenges could also force states or EPA to act regardless of the permit renewal schedule. This issue has the potential to impact many existing, uncontrolled reciprocating engine prime movers. Mitigation may require multiple measures, including NOx control, increasing stack height, and/or increasing the property buffer (e.g., land purchase, moving the fence to the property line).

Regarding the ozone NAAQS, EPA planned to revise the NAAQS in 2011 in response to legal challenges. This was delayed and it was decided to complete the next revision under the schedule that requires NAAQS review every 5 years. That schedule currently plans for a proposed rule in the spring of 2014 and a final rule by mid-2015. That rulemaking will likely result in more nonattainment areas than under the current 75 ppbv NAAQS. This is illustrated in Figure 5-1 and Figure 5-2.

Nonattainment is determined by assessing whether the 3-year average value (from ozone monitoring) exceeds the NAAQS. Projected nonattainment areas from EPA maps in 2010 for an ozone NAAQS of 60, 65 or 70 ppbv are shown in the left map in Figure 5-1. Those ozone levels were being considered for the 2011 rule that was deferred. The right map shows actual ozone nonattainment areas determined in 2012 for the current 75 ppbv standard. The projections for 60 to 70 ppbv were based on 2006 – 2008 data. The nonattainment areas defined in 2012 are based on a 3-year average from 2008 – 2010 or 2009 – 2011. The eastern U.S. had a cool and wet summer in 2009, and hot, sunny weather is more conducive to ozone formation. Thus, states and third parties are challenging EPA and would like to plan for broader nonattainment and address NOx transport from upwind states. Figure 5-2 shows an analysis completed by the Ozone Transport Commission, a group of 12 northeastern states that collaboratively assess air quality in that area. If 2009 data is excluded and the 3-year average is based on 2010 – 2012 data, the figure shows significantly more areas above 75 ppbv and also shows areas that would not achieve a lower, 70 ppbv standard.

Thus, if upcoming summers are not cool (like 2009), and EPA fulfills expectations to lower the ozone NAAQQS to a level between 60 and 70 ppbv in 2015, nonattainment areas will more likely resemble the 60 – 70 ppbv map on the left in Figure 5-1; or, for the northeast, the map in Figure 5-2. This would result in either a broad regional NOx control rule or requirements for many states to develop or update NOx RACT regulations for existing sources.

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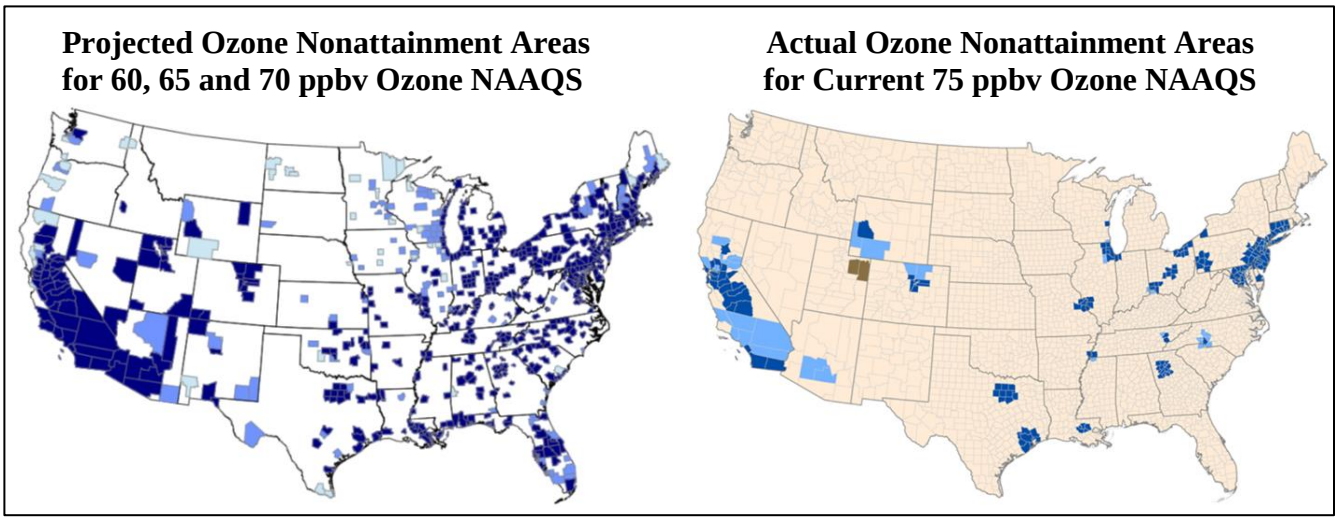


Figure 5-1. Projected ozone nonattainment areas (left map) for ozone NAAQS of 60 ppbv (light blue), 65 ppbv (blue) or 70 ppbv (dark blue) and actual ozone nonattainment areas (right map) for the 75 ppbv ozone NAAQS (dark blue – whole county; light blue – partial county; green – unclassifiable).

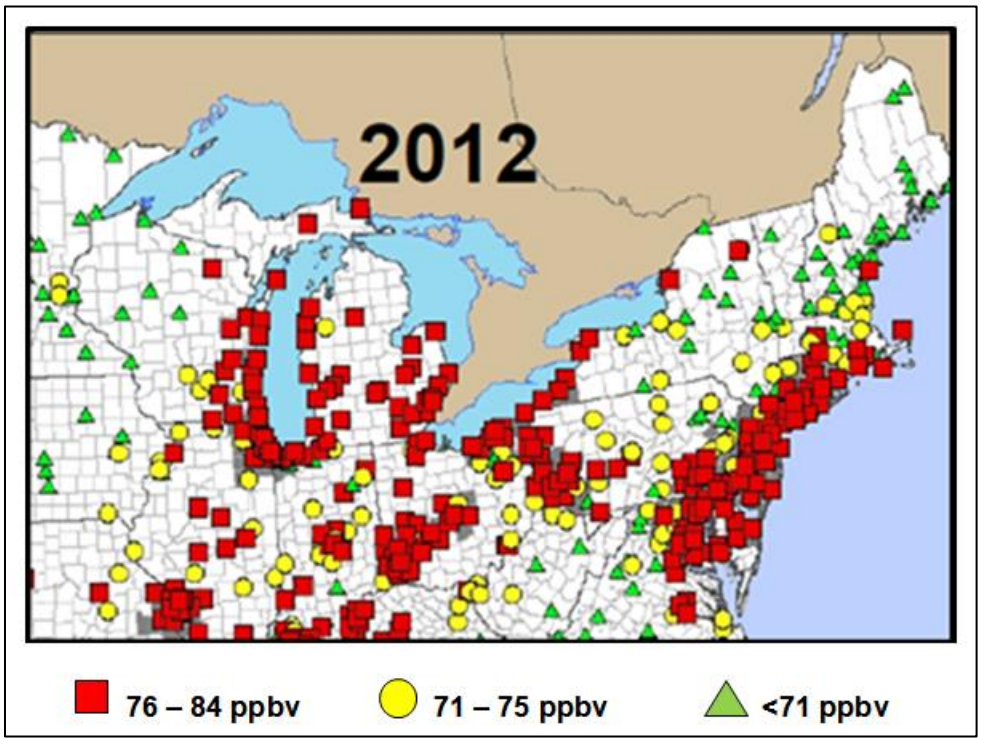


Figure 5-2. Updated northeast U.S. ozone air quality projections from the Ozone Transport Commission based on 2010 – 2012 ozone data (3-year average).

Regarding the NO_2 NAAQS, a committee of state and federal modelers has published example modeling results that show "typical" compression facilities with offsite impacts well above the NAAQS. [7] In Pennsylvania, a third party has requested that the state require modeling for all

compressor facilities based on an independent report presenting modeling results with impacts above the NAAQS. [8] To date, the state has provided analysis and data to justify not requiring such modeling, but additional third party challenges are likely. Thus, although requirements in response to the 2010 NO_2 NAAQS have not yet been common, the 2010 NO_2 NAAQS provides a platform for requirements that could broadly affect reciprocating engines that are not equipped with low NOx technology.

Thus, although schedules and mandates are highly uncertain, implementation of current and pending regulations will likely require retrofit NOx control (or replacement) for many existing natural gas-fired reciprocating engines. For this report, the specific timing and count of affected units was not defined. The analysis conducted, based on the actual engines in the fleet discussed in Section 4, focused on available resources and the cost and schedule to install controls based on NOx endpoints of 3 g/bhp-hr or 1 g/hp-hr. These emission levels are based on anticipated emission limits for typical NOx rules, with the lower limit based on potential requirements in more aggressive states.

In judging the likelihood of control and target NOx level (i.e., 3 or 1 g/bhp-hr), states were divided into three categories based on a judgment of the risk of NOx control and stringency over the next 5 to 15 years. This assessment was based on experiences with different states, proximity to areas that have previously failed to attain the ozone NAAQS or are expected to not attain if the ozone NAAQS is lowered in 2015, or within an area that has been targeted by eastern U.S. nonattainment areas as a "NOx transport" area. When considering the time required to install NOx controls, engine location and this ranking were considered (e.g., likelihood that a NOx level of 1 g/hp-hr NOx would be required). For assessing the likelihood of control and the NOx endpoint (3 g/hp-hr or 1 g/hp-hr), states were placed into one of three regulatory risk categories:

- Category 1 (high risk and stringency) – geographical region (i.e., states) where stringent NOx emissions limits are already in place (e.g., northeast states, California, Colorado); if NOx control is not in place, there is a high probability engine modifications will be required;
- Category 2 – geographical region where there is a moderate probability that lower NOx emission limits will be required (e.g., Midwest and southeast states implicated as contributors to NOx transport); and,
- Category 3 – geographical region with a lower probability that lower NOx emission limits will be required.

The INGAA database includes engines in forty-one states, and the list of states and their ranking is shown in Table 5-1.

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Table 5-1. Regulatory Risk Category for States with Engines in the Database.

State	Risk Category
Alabama	2
Arizona	2
Arkansas	2
California	1
Colorado	1
Connecticut	1
Florida	2
Georgia	2
Idaho	3
Illinois	2
Indiana	2
Iowa	3
Kansas	2
Kentucky	3
Louisiana	2
Maryland	1
Michigan	2
Minnesota	3
Mississippi	2
Missouri	3
Montana	3
Nebraska	3
New Jersey	1
New Mexico	2
New York	1
North Carolina	2
Ohio	2
Oklahoma	2
Oregon	3
Pennsylvania	1
Rhode Island	1
South Carolina	3
Tennessee	2
Texas	2
Utah	3
Virginia	2
Washington	3
West Virginia	2
Wisconsin	3
Wyoming	3

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5.2 Assumptions and Methodology for Reciprocating Internal Combustion Engines (NOx)

The following assumptions and methods were used when assessing technology and resource requirements, schedules, and costs.

- Many rich burn engines employed in interstate natural gas transmission have been modified to reduce HAP emissions under the 2004 RICE NESHAP. Typically these four-stroke cycle rich burn engines added NSCR technology, including the associated engine air-to-fuel ratio control (AFRC). This technology also reduces NOx emissions. As such, four-stroke cycle rich burn engines were excluded from this analysis. It is believed that this is a reasonable assumption with the following caveats:
  - Some of the smaller four-stroke cycle rich burn engines or engines at small facilities may not have installed NSCR.
  - Some engines may require additional modifications or more attention to AFRC to meet NOx limits. This may be achieved by installing a larger catalyst or an upgraded AFRC.
- Some engines (i.e., horizontals) do not have suitable control technologies to reduce NOx emissions as they sometimes operate near stoichiometric conditions (rich) at full load and lean conditions at reduced load. These engines lack the ability to control the air to fuel ratio across the load range. In addition, the engines are of older designs that have limited parts availability and higher operating costs. For the purposes of this study, it is assumed these engines are replaced with new engines and the associated compressor and ancillary equipment. Specific engine types include:
  - Cooper-Bessemer four-stroke cycle horizontal engines, and
  - Worthington four-stroke cycle horizontal engines.
- Some of the engines in the INGAA database have been removed from service since the database was last updated. Those units were removed from the analysis where information was provided by the operator or the author had personal knowledge regarding those units.
- For cost estimating purposes, the following scope of work was assumed for NOx control:
  - 3 g/hp-hr NOx emission rate limit:
    - NOx control through low emissions combustion,
    - High energy ignition system is assumed to be precombustion chamber, either:
      - Screw-in, or
      - Head replacement;
    - Turbocharger modifications are required for lean combustion,
    - Turbocharger after-cooling enhancements are required, and
    - May or may not require (depending on engine model):
      - Fin fan after-cooler upgrades,
      - Coolant surge tank modifications,
      - Auxiliary generator upgrades,
      - Air inlet piping and filter modifications, and/or
      - Exhaust manifold, silencer, and exhaust stack modifications.

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        - Alternate or additive approaches (depending on the engine and emission target) include:
            - Enhanced mixing with or without high energy ignition system modifications, and
            - Post-combustion treatment utilizing SCR in select cases.
    - 1.0 g/hp-hr NOx emission rate limit:
        - Modifications for 3 g/hp-hr NOx as outlined above plus enhanced mixing and/or post-combustion treatment utilizing SCR.
- To identify those engines already controlled, existing emission capabilities were assumed based on descriptions and attributes in the INGAA engine database. Specifically, engines were assumed to be controlled to:
    - 3 g/hp-hr NOx or lower if:
        - The engine was identified as having low NOx emission controls,
        - The engine was identified as having post-combustion catalytic treatment (i.e., this implies that permitting closely scrutinized emissions),
        - The engine make and model number is known to be a low NOx emissions unit,
        - The engine is located in a state where control is already required for reasonably available control technology (RACT), or
        - The operating company and/or emission reduction vendor identified specific engines that have been modified to achieve low NOx emissions.
    - 1 g/hp-hr NOx or lower if the operating company and/or emission reduction vendor identified specific engines that were modified to be capable of this emission level.
- As discussed in Section 5-1 and shown in Table 5-1, U.S. locations were divided into three areas based on a judgment of the risk of NOx control requirements and stringency over the next 5 to 15 years.
- New air emission regulations or permitting requirements are expected to eliminate the grandfather provision in many cases and institute NOx control requirements for existing engines that currently are not controlled. The timing that the States (or other agencies) will implement NOx reduction rules and the level of NOx reduction cannot be defined at this time. For assessing the likelihood (and stringency) of control, States were categorized into three geographical regulatory risk categories as discussed above and shown in Table 5-1.
- To understand worst case scenarios in regards to the number of affected engines and a conservative cost projection, it was generally assumed that some level of control would be required for uncontrolled units. For example, engines in northern plains states that may not be affected by a regulation to address nonattainment could still require control to address NO_2 modeled impacts. In general, with the exception of the rich burn engines in Table 4-4, engine counts without controls (e.g., horizontal engines; engines >3 g/hp-hr) from Section 4 tables were included in the cost estimate and scheduling assessment, and additional engines (i.e., units currently controlled but with emissions between 1 and 3 g/hp-hr) are considered for the 1 g/hp-hr NOx limit, depending on location. These total over 2600 uncontrolled engines and over 500 engines that may require additional control if NOx requirements are reduced to 1 g/hp-hr. At this time, it is not expected that the lower NOx level would be

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broadly required. So, while costs are estimated for the 1 g/hp-hr endpoint to provide that estimate in the report, the schedule to complete all retrofits judges the engine location when assessing the likelihood of a 1 g/hp-hr NOx requirement.

6.0 Cost and Schedule Estimates

The primary purpose of this report is to assess resource constraints associated with retrofit NOx control. In assessing technology requirements and resource constraints, costs were also determined. Cost and schedules are discussed in this section, and Section 7 discusses resource availability (i.e., skill sets and staffing) for each project phase. Information is tabulated for:

- Capital cost for NOx control to achieve NOx emissions of either 3 or 1 g/hp-hr (see Tables 6-1 and 6-2). Separate costs are shows for each emission level, and these costs are not incremental.
- Annual engine retrofits (or replacements) that can be completed based on *current* staffing levels for key technology and engineering service providers (see Table 6-3).
- Time required to complete retrofits (or replacements) for the projected engine counts, based on an emission level of 3 or 1 g/hp-hr and current staffing levels.
  - Table 6-2 shows the number of years required to control engines to 3 g/hp-hr.
  - Marginally longer time is required to achieve 1 g/hp-hr for some engine types. Table 6-5 shows the *incremental time required* to achieve the lower NOx limit.
- The regulatory risk "categories" shown in the tables are based geographical assignment of regulatory risk by state as discussed in Section 5.1 and shown in Table 5-1.

6.1 Capital costs

The costs to modify or replace engines to reduce NOx emissions were gathered through interviews with operating companies, other published sources, and the author's experience.

As described above, unit (engine and compressor) replacement was assumed for horizontal and in some cases opposed piston two-stroke cycle engines. Replacement units were assumed to be dry low NOx gas turbines. Replacement costs were estimated at a fixed cost per unit ($1,800,000) plus a variable cost proportional to engine size ($895/hp). In the case of horizontal and opposed piston two-stroke cycle units, one new turbine unit was assumed for every two units that were replaced.

In select cases where SCR was considered, costs were estimated at a fixed cost per unit ($250,000) plus a variable cost proportional to engine size ($375/hp). Lean burn combustion modifications were estimated at a fixed cost per unit ($152,000) plus a variable cost proportional to engine size ($725/hp). Because of additional turbocharger and after-cooling requirements for two-stroke cycle engines, multipliers for the variable costs (for lean combustion conversion only) are 1.22 and 1.08 for low BMEP and medium/high BMEP two-stroke cycle engines respectively.

Enhanced mixing modifications were estimated at a fixed cost per unit ($235,000) plus a variable cost proportional to engine size ($85/hp). When both lean combustion and enhanced mixing modifications are implemented at the same time (e.g., converting from > 3 g/hp-hr to <1 g/hp-hr)

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costs were estimated at a fixed cost per unit ($427,000) plus a variable cost proportional to engine size ($785/hp).

Costs were assessed for affected engines to reduce emissions to 3 g/hp-hr. For reducing to less than 1 g/hp-hr, the additional costs were determined for further reducing emissions from these engines. In addition, costs were determined for additional engines that are already controlled to 3g/hp-hr that require additional reductions to achieve 1 g/hp-hr. Note that the costs to modify engines for NOx control are significantly lower than the replacement costs. This is due in large part to the fact that both the engine and the gas compressor must be replaced if the engine is replaced. As a general rule, the replacement equipment has a lower overall unit efficiency[1] and therefore uses more fuel (and by correlation has higher CO_2 emissions) than the units they are replacing.

The total estimated NOx control capital costs to modify reciprocating engines used in the natural gas transportation industry are summarized below. Table 6-1 represents the costs to reduce emission rates to less than 3 g/hp-hr, and Table 6-2 represents the costs to reduce emission rates to less than 1 g/hp-hr. For 3 g/hp-hr, total costs are nearly $4 billion and "average" costs per unit for the different engine types were about $1 to $1.5 million for 2-stroke engines and $2 million for 4-stroke engines. Replacement costs exceeded $2 million per unit.

Note that these two tables are exclusive, i.e., the tables present costs to achieve either 3 or 1 g/hp-hr and are not to be added together. In addition, while many units may need to achieve NOx limits on the order of 3 g/hp-hr, it is currently not expected that a large percentage of the fleet will need to achieve 1 g/hp-hr. For example, engines in higher risk areas (Category 1) are more likely to face the more stringent emission limit, while engines in lower risk Category 3 would be far less likely to require a 1g/hp-hr emission limit. Thus, costs to achieve 1 g/hp-hr NOx are a conservative upper bound (i.e., broad NOx regulations are more stringent than expected) for the engine fleet in the INGAA database.

Table 6-1. Costs to achieve 3 g/hp-hr ($ in thousands).

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	$0	$236,308	$36,054	$272,362
Opposed piston	$756	$14,311	$0	$15,067
Med & high BMEP 4-stroke	$0	$660,355	$89,798	$750,153
Low BMEP 2-stroke	$0	$685,751	$65,811	$751,562
Med & high BMEP 2-stroke	$0	$1,770,389	$330,588	$2,100,977
Total	$ 756	$3,367,114	$522,251	$3,890,121

[1] Generally reciprocating engines drive reciprocating compressors while gas turbine engines drive centrifugal compressors. As a general rule, reciprocating engines are more fuel efficient than gas turbines. Likewise, reciprocating compressors are generally more efficient than the centrifugal compressors. There are exceptions where the gas turbine unit is the more efficient option. An example would be a high speed, low BMEP reciprocating engine driving a reciprocating compressor with small valve flow area replaced with a gas turbine/centrifugal compressor.

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Table 6-2. Costs to achieve 1 g/hp-hr ($ in thousands).

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	$0	$236,308	$36,054	$272,362
Opposed piston	$2,108	$38,100	$0	$40,208
Med & high BMEP 4-stroke	$18,235	$807,287	$111,779	$937,301
Low BMEP 2-stroke	$24,290	$629,647	$60,415	$714,352
Med & high BMEP 2-stroke	$94,840	$3,645,435	$680,204	$4,420,479
Total	$ 139,473	$5,356,777	$888,452	$6,384,702

6.2 Schedule

Starting in 1999 as part of the NOx State Implementation Plan (SIP) Call (an eastern U.S. regional NOx rule for large existing sources), approximately 200 natural gas transmission engines were converted to LEC. From interviews with the operators and the emission reduction equipment suppliers, the conversion process took six years in total to fully implement. Additional engines were controlled in the late-1990's through about 2009 in response to state RACT rules.

Based on interviews with pipeline operations and emission reduction equipment suppliers having experience with previous conversion projects, NOx control for each engine requires between 1 and 2 ½ years to complete (from inception to completion of commissioning). The longer duration projects are those that require more infrastructure modifications (such as cooling equipment and auxiliary generators), on-engine modifications (after-coolers, turbochargers, lubrication systems, cooling systems, fuel systems, pre-chambers, intake/exhaust systems, and controls), and engine overhaul. Generally, older engines require more time to design the conversion. This is due to inaccurate or missing engineering records on the current configuration of and ancillary equipment used on the engine.

Taking into account both the lead time and conversion time and based on *currently available resources* (i.e., trained personnel), the average number of units that can be modified to lean combustion on a sustained basis is ***approximately 75 engines per year***. This is the key resource constraint that will affect NOx control requirements that affect these engines, even if only a subset of engines (e.g., a quarter of the current total capacity) is affected by new NOx control rules. Note that this projection is somewhat higher than the approximately 50 units per year converted under the NOx SIP Call even though additional technical resources are not in place at this time. The higher number of units converted per year assumes some efficiency of scale will be achieved based on processes and standards developed from previous efforts. A relatively optimistic projection for the annual number of conversions was selected so that the analysis reflects an "optimistic" scenario without considering how staffing and training will respond to market demand.

The estimated number of engines that can be retrofit per year is based on *current* resource availability. While a dramatic increase in market demand would likely result in hiring and training of additional resources, the special skills associated with this niche market would require time to build that resource. In addition, until new regulations are adopted the market and timing is not clear, thus this resource base will not grow until the market is clear.

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Based on the engine counts in Section 4 and the regional location of the engines, an estimate of the number of engines that can be modified per year is shown in Table 6-3, and the resulting number of years necessary to address NOx controls for the reciprocating engines used in natural gas transmission is presented in Tables 6-4 and 6-5.

The number of engines that can be modified per year depends on differences in scope related to the engine type (e.g., some engines are configured for lean combustion while others are not). The estimated number of engines that can be modified per year by engine type and emission level is shown in Table 6-3. The count varies for different engine types and emission level due to the complexity of the retrofit (e.g., need for additional equipment such as turbochargers, need to upgrade ancillary support such as cooling, etc.). It is not anticipated that the number of annual engine conversions can be significantly improved upon within a short timeframe (e.g., if demand for NOx control significantly and quickly increases) because specific skills and specialized training are necessary to serve this market.

Table 6-3. Estimated number of engines that can be modified/replaced per year.

	Modified to achieve NOx emission levels of:	
Engine type & initial emissions	**≤ 3 g/hp-hr**	**≤ 1g/hp-hr**
Horizontal engines	40	40
Opposed piston	40	40
Med & high BMEP 4-stroke > 3 g/hp-hr	75	64
Med & high BMEP 4-stroke ≤ 3 g/hp-hr	N/A	82
Low BMEP 2-stroke > 3 g/hp-hr	60	50
Low BMEP 2-stroke ≤ 3 g/hp-hr	N/A	75
Med & high BMEP 2-stroke > 3 g/hp-hr	75	64
Med & high BMEP 2-stroke ≤ 3 g/hp-hr	N/A	80

Based on the number of engines to be controlled (engine counts from the INGAA database as shown in Section 4) and the estimated number of engines that can be modified per year, the estimated time required to implement modifications to achieve 3 g/hp-hr is shown in Table 6-4.[2]

For NOx levels of 1 g/hp-hr, far fewer engines will be affected. To provide an upper bound on capital costs for control, , costs in Table 6-2 were estimated assuming that all of the affected units would need to achieve the low NOx level. The schedule to achieve the lower NOx level and timing presented in Table 6-5 considers a much smaller subset of engines, such as engines in a high risk location such as the northeast (Category 1). While Table 6-2 shows the costs to control all engines to 1 g/hp-hr, Table 6-5 shows the nominal *incremental time* required for this smaller subset of "high regulatory risk" engines to achieve 1 g/hp-hr.

[2] While the elapsed time for an engine retrofit or replacement from inception to completion may take 1-2 calendar years, the work can be performed by multiple engineering firms and construction companies resulting in an average resource time of less than one year per project.

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Based on current technical resources, the projected time to implement retrofit NOx control (or replacement) is far in excess of typical regulatory schedules. Primarily due to the large number of engines in Category 2 (units primarily in southeast and midwest states), *Table 6-4 shows that it would take **decades** to address NOx controls for a large number of engines*, even if the annual rate of retrofit conversions is doubled. Since the retrofit market is currently very limited (i.e., rules are not currently requiring installation of retrofit NOx controls), *there is no incentive to increase capacity* at this time. So, this limitation will not be addressed until indicated by market demand and confirmed regulations. Section 7 includes additional discussion of manpower and other resource constraints on a project level basis.

Table 6-4. Time required to modify engines to achieve 3 g/hp-hr (in years) [3]

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	0.00	2.6	0.4	3.0
Opposed piston	0.03	0.3	0.00	0.3
Med & high BMEP 4-stroke	0.00	4.1	0.6	4.7
Low BMEP 2-stroke	0.00	7.7	0.7	8.4
Med & high BMEP 2-stroke	0.00	18.2	3.6	21.8
Total	0.03	32.9	5.3	38.2

A small number of engines (e.g., in Category 1) may require control to the more stringent 1 g/hp-hr NOx level. Table 6-5 shows the *incremental* time required to address that more stringent mandate and shows minimal impact on schedule to achieve the lower NOx level. However, considering capital costs in Tables 6-1 and 6-2, a lower NOx limit will have a significant cost impact, with engine-specific costs on average about 65% higher to achieve 1 g/hp-hr.

Table 6-5. Incremental time required to modify a subset of high risk engines to 1 g/hp-hr rather than 3 g/hp-hr (in years).

Emission type	Category 1	Category 2	Category 3	Total
Horizontal engines	0.00	0.07	0.01	0.08
Opposed piston	0.00	0.01	0.00	0.01
Med & high BMEP 4-stroke	0.00	0.06	0.01	0.07
Low BMEP 2-stroke	0.00	0.15	0.01	0.16
Med & high BMEP 2-stroke	0.00	0.28	0.06	0.34
Total	0.00	0.57	0.09	0.66

[3] Unless resource constraints are addressed via staffing and training, the overall timeline cannot be shortened by executing the projects for multiple regions/engine types simultaneously. For example, replacing all of the horizontal engines in Categories 2 and 3 will take about 3 years even if the work for both categories is performed at the same time. This is because executing projects in Category 3 states concurrently with projects in Category 2 states will require the reallocation of resources away from Category 2 states.

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7.0 Resource Analysis and Limitations by Project Phase

This section discusses resource requirements and constraints chronologically by project phase. The resource considered in this section is available manpower – i.e., staffing and expertise by topical area. All phases of project planning and execution are discussed even though several have minimal impact on schedule or cost. The information gathered identified several constraints and concerns associated with the available resources to implement NOx emission reduction projects. Constraints are due to the availability of skilled or expert staff necessary to complete key project tasks, and the requirements and limitations are discussed qualitatively by project task.

Interview subjects included multiple operating companies and six different suppliers of equipment and services to modify natural gas transmission reciprocating engines.

7.1 Permitting

The permitting portion of the project typically involves evaluating many different cases. Design iterations are made to determine technology requirements to reduce emissions to required levels within the required timeframe. Secondary factors include the impact the proposed retrofit NOx control technology has on equipment efficiency and operational turndown. Due to the workload of the permitting agencies, the permitting process typically takes a long time to complete (months to years in some cases). Because of the long lead time involved, air quality permit applications are often filed before design optimization for the NOx control equipment can be completed.

Complicating factors may include other regulatory limits. For example, implementing significant modifications to a piece of equipment to reduce air emissions may require modifications to reduce noise emissions to conform to local noise regulations. In addition, special care must be made to ensure retrofitting NOx control technology does not adversely impact emissions of other pollutants such as THC and CO, or additional controls (i.e., oxidation catalyst for CO or hydrocarbons) are considered to address this situation.

The operators expressed concern that regulations to reduce NOx emissions will result in constraints at the state regulating agencies (e.g., timing to process permits and potential backlog due to state budget and staffing issues). The result could include:

- Slow response time in issuing air permits. This can result in delays to the project execution schedule, and can make it difficult to comply with new regulations with a hard deadline for implementation.
- Limited flexibility in approving new emission reduction technologies (i.e., time constraints due to agency staffing).
- Limited ability to modify the design for optimization after the permit application has been submitted without causing further delays.

These concerns could be mitigated somewhat if longer or phased implementation schedules are allowed. States generally propose a short compliance schedule (e.g., 18 months to two years from the rule date). It is incumbent upon the affected industry to try to convince the state during rule development to allow longer schedules, including phased schedules. Thus, operators need to

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be proactive in working with states (or EPA) to achieve "reasonable" schedules. However, it is highly unlikely that a decades long implementation scenario indicated by Table 6-4 will be achievable.

7.2 Initial design

Based on the expected number of engines to be modified, pipeline operating companies will require additional engineering staff to perform initial design of NOx reduction modifications. Some of this will be achieved through the hiring of additional staff. However, based on the current trends and practices, most of this resource will be provided by firms that provide contract engineering services or turnkey solutions from LEC technology providers. Examples include: Black & Veatch, E-N Engineering, Mustang Engineering, Cameron, Dresser Rand, Hoerbiger, GE Oil and Gas, and many others. The experience and knowledge of these engineering firms for retrofit NOx control projects is varied and in most cases is limited. This is due in part to high turnover that occurs in these firms and the wide variability of equipment to be modified. The use of engineering staff additions and/or engineering services will require a significant learning curve and training. This will require more time to execute initial engine modification designs. As experience improves over time, the project execution duration should be reduced.

During this phase of project execution, providers of emission reduction equipment such as Cameron, Dresser Rand, and Hoerbiger will receive numerous requests for potential options for emission reduction technologies. This is especially likely where:

- Very low emission rates are required,
- Few engines of the make/model have previously been modified for low NOx technology,
- The engine has a unique design and configuration that requires specialized engineering analysis, and/or
- The engine is required to operate in special modes (e.g., requires a wide power range).

This demand for quotes is a potential resource constraint for the emission reduction equipment providers, especially when demand initially increases. In general, the unique attributes associated with legacy integral reciprocating engines provide a common theme regarding personnel / expertise based constraints. If regulatory timelines can be extended for projects that are unique in design or configuration, this can be mitigated.

Some emission reduction equipment providers will provide turnkey services (design, procure, construct, commission). However, there are currently only a handful of companies that provide this service for NOx control of legacy integral units. The number of engines modified using turnkey services will be limited to what emission reduction equipment providers can provide with moderate increases in qualified technical staff through using contract employees, part time staff, subcontractors, and retirees.

7.3 Procurement

Provided adequate personnel resources and experience exist in the initial design phase to produce procurement specifications, the actual procurement process should have minimal resource constraints. Qualified procurement personnel are available on a contract basis. In many cases,

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the pipeline operating company will use the same contract engineering services to perform the procurement process.

Discussions with NOx emission control equipment suppliers indicated that manufacturing production can be increased to provide the equipment within a reasonable time period (assumed to be *at least 3 years*). As such, the procurement of the hardware required for NOx emission reduction projects is not expected to be a constraint as long as reasonable regulatory schedules are negotiated, trends for increased demand are understood, and production responds accordingly.

7.4 Cost estimating and scheduling

The cost estimating and scheduling phase typically use the same resources used in the initial design. This phase is not expected to have a significant resource constraint.

7.5 Detailed design

Detailed design for emission reduction projects will encounter much of the same resource constraints as described under initial design. The difference in this phase is more resources will be required to produce engineering drawings and project specification documents. Like the initial design phase, this will be achieved through a mix of additional employees for the pipeline operating company, contract services, and turnkey providers, with turnkey LEC technology companies the predominant resource – unless rapid growth in market demand prompts an alternative in the future.

At this phase of the project, the pipeline operating company will require additional resources to provide detailed project management oversight for the life of the project. Again, this will likely be achieved through the use of a mix of new employees and contract services with an associated training and learning curve period.

7.6 Construction

Pipeline operating companies and turnkey emission reduction vendors typically use contract construction services to implement the physical modifications to engines. These resources are generally available and should not be a constraint unless there are a number of major pipeline construction projects that would overlap with the timing of the engine emission reduction projects. Review of the potential for competing infrastructure projects is beyond the scope of this report, but other studies are available, such as the INGAA Foundation Report on midstream infrastructure projections through 2035. [9]

There is one exception; there is currently a shortage of welders qualified for natural gas piping. Modifying a large number of engines to reduce NOx emissions (e.g., 25%, 50%, or possibly the vast majority of over 2600 engines identified in Section 4) would further constrain this resource. Increasing the timeline available to implement engine modifications and avoiding an overlap in the execution of those projects with major pipeline expansion projects would help mitigate this constraint.

During the construction period, the equipment is not available for the transportation of natural gas. To minimize the impact on pipeline capacity and associated disruption for shippers, outages are optimized by:

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- Scheduling the construction during periods of low system demands (such as during the summer for pipeline systems that have peak demands during the winter heating season),[4]
- Scheduling outages such that only one or two engines are out of service at any one station during any period of time, and
- Scheduling outages such that outages at compressor stations are staggered (e.g., start with outages at Stations A, C, E, & G, and when the modifications at those stations are completed, then Stations B, D, F, & H)

Future PHMSA regulations [10] may require pipeline operators to complete hydrostatic testing of pipelines (e.g., those installed prior to 1970). If the schedule to install NOx controls overlaps with other pipeline regulations, a reduction in available pipeline capacity may occur. This is exasperated by the overlapping vintage of the pipe that may be affected by PHMSA rules and the compressor engines likely to require NOx control. The result could result in shortages of natural gas in some areas of the country. To mitigate this possibility, it is important to understand not only air quality (or safety) regulatory schedules, but possible implications from different compliance activities across all regulations that occur in the same timeframe. Possible implications from overlapping requirements need to be communicated to regulators to try to avoid impacts on pipeline capacity and natural gas delivery.

7.7 Commissioning and Start-up

Proper commissioning of NOx reduction equipment is critical to assure the modified engine reliably meets air emission limits. The process of commissioning and safely placing into service an engine with new NOx control technology requires many different skills and specialized equipment, including:

- Engine mechanical specialist to tune the operation of the engine and equipment to measure the developed engine power,
- Control technicians to calibrate additional measurement points, verify pump rotations, etc.,
- Control system specialists to modify control software (to accommodate additional measurement points and control algorithms) and tune control loops,
- Qualified operating personnel to safely introduce fluids and energize systems,
- Subsystem specialists with specific expertise in control valves, gas measurement, and communications,
- Air emissions testing equipment and analysts, and
- Specialists to train the equipment operators on the operation and maintenance of the new equipment.

Due to the specialized skills required during this phase and expectations that demand will exceed the currently available resources, *these are personnel resources that are likely to be constrained*

[4] With the increase in the number of natural gas fueled power plants installed over the last decade, many interstate pipelines that historically had peak loads during the winter heating season now also have peak demand periods in the summer. Off peak periods for these pipelines are now during the spring and fall.

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for NOx control projects. Mitigation measures include utilizing available temporary resources (such as qualified contractors and retired employees), hiring and training new staff, and extending the timeline for modifications.

7.8 Operation and Maintenance

Within the first year after commissioning an engine, additional adjustments are commonly required after break-in and to address changes to seasonal ambient conditions. This typically requires the same technical personnel and equipment used to commission the engine as discussed above. The same mitigation measures described above would apply to operation and maintenance of the equipment.

If adequate operating spares for the newly installed equipment are purchased as part of the project, material resources should not be a constraint.

8.0 Conclusions

There is a great deal of uncertainty about the breadth (i.e., how geographically broad), depth (i.e., stringency of the rule), and schedule for new NOx regulations that will affect existing natural gas-fired reciprocating engines. Litigation and scheduling delays have slowed the regulatory process. Although the timing and breadth of new NOx control regulations remains uncertain, it is likely that many of the natural gas-fired reciprocating engines in the existing prime mover fleet will require NOx control by 2025. There are several thousand legacy natural gas-fired reciprocating engines driving compressors in interstate transmission, and their location (i.e., in rural areas where emission rules are more rare) and history (i.e., operating prior to rulemakings that affect new equipment) make these engines candidates for future regulation.

Based on previous projects and interviews with industry experts, modifying these engines will require significant time and capital. The capital required to address the fleet of engines without low NOx technology is significant. In addition, the lack of available expertise is likely to be a primary constraint in addressing broad, new regulations on a timely basis.

Based on interviews with operators, equipment vendors, and service providers, the primary conclusions from this study include:

- The special technical expertise to design, construct, and commission emission reduction projects for the low speed integral engines prevalent in natural gas transmission is available from a handful of companies, and with few NOx rules being adopted in recent years, this expertise may be migrating to other markets. Regulations that require installation of NOx control on a large number of reciprocating engines will require a significant lead time to train and develop resources to implement emission reduction projects. For example, if upcoming NOx regulations impact 25% of the current fleet of legacy reciprocating engines, the number of units requiring NOx control (over 600) would exceed the total number of units that have been controlled over the last 20 years. A higher percentage could be impacted (e.g., 50% of units affected is over 1300 units; even high impacts are possible), and market demand could significantly exceed the available resource base of skilled professionals.
- **Availability of this special technical expertise and building this resource is the primary resource constraint that will affect the ability to meet regulatory obligations that affect**

a large percentage of the fleet. Based on current capabilities and a scenario where NOx regulations broadly affect the existing fleet of uncontrolled reciprocating engines, *the estimated time to complete upgrades to over 2600 engines is nearly forty years.*

  - Although regulations may affect a smaller subset of engines or compliance strategies may result in many engines (e.g., lower horsepower, lower use engines) being retired or replaced, schedule implications due to the lack of available expertise will likely extend far beyond the required regulatory timeline (e.g., 1000 engines would require 15 years).
  - There is no incentive to begin to build this resource base until it is clear that a market will exist – i.e., the regulations and associated schedule are in place. Since lawsuits and EPA priorities have slowed the next cycle of NOx regulations, it is not possible to project the timing, stringency, number of affected units, or schedule for implementing new NOx rules.
  - In addition to regulatory risk associated with NOx rules in response to nonattainment with the ozone NAAQS, revisions that increased the stringency of the NO_2 NAAQS in 2010 could trigger new NOx control requirements for existing facilities through the permitting process – e.g., during permit renewal. This issue has the potential to trigger NOx control requirements *sooner* than the current ozone NAAQS timeline.

- Due to this resource constraint, it is imperative that companies engage state and federal regulators when NOx rulemakings commence. Emission regulations typically allow only one to two years to implement controls, and additional time and phased implementation will be needed to provide a more reasonable schedule. However, once the next round of NOx rules are initiated, it is unlikely that a decade(s) long schedule will be allowed. The schedule conflicts associated with regulatory timelines, market demand, current supply (i.e., available resources), and service provider growth will likely present a significant challenge over the next 5 to 10 years.
- Engine NOx control projects are generally much less costly than engine replacement. Capital costs to modify the fleet of currently uncontrolled reciprocating engines used in the interstate natural gas transmission industry are estimated at $3,890 million and $6,385 million to achieve NOx emission rates of 3 g/hp-hr and 1 g/hp-hr respectively.
- The age of the impacted equipment (most of the engines are over 40 years old) requires additional time to engineer and construct reliable emission reduction modifications due to inaccurate or missing engineering records that reflect the current equipment configuration.
- Some engines with low specific power output will require extra time to properly design and construct emission reduction modifications and maintain the same power operating range.
- Based on previous experience, the timeline to obtain air permits is a key parameter defining the overall schedule for completing a specific emission reduction project – i.e., permitting can slow the project timeline.
- Equipment outages to implement emission reduction modifications may have a significant impact on available pipeline capacity, especially if the timeline overlaps with implementation of other regulations, such as pipeline integrity assessments that may be required by PHMSA.

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Appendix A: Acronyms

AFRC	Air to Fuel Ratio Controller
BACT	Best available control technology
BHP	Brake horsepower
BMEP	Brake mean effective pressure
CO	Carbon monoxide
EPA	Environmental Protection Agency
g	Grams
hp	Horsepower
Hr	Hour
INGAA	Interstate Natural Gas Association of America
LEC	Low emission combustion
MACT	Maximum achievable control technology
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO_2	Nitrogen dioxide
NOx	Nitrogen oxides
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standard
O_2	Oxygen
PHMSA	U.S. Dept. of Transportation Pipeline and Hazardous Materials Safety Administration
RACT	Reasonably available control technology
RICE	Reciprocating internal combustion engine
SCR	Selective catalytic reduction
SIP	State implementation plan (Dresser-Rand and others also use "SIP" for screw-in pre-chamber.)
THC	Total unburned hydrocarbons
VOC	Volatile organic compounds (For gas-fired combustion, VOCs are THC excluding methane and ethane, which are the two most prevalent exhaust hydrocarbons). Formaldehyde is also a VOC but is excluded from some regulations (e.g., it is more difficult to measure than THC and may not be included in data used to establish a VOC standard or emission limit).

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Appendix B: Survey Questions for Operator and Service Provider Interviews

1. Over the last three years, approximately how many engines has your company modified (as prime contractor) to meet emission levels of 3 g/hp-hr or less?

2. How many of those modifications were achieved through lean emission reduction?

3. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to operating companies so they could modify their engines to meet emission levels of 3 g/hp-hr or less?

4. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to other vendors or contractors so they could modify their engines to meet emission levels of 3 g/hp-hr or less (acting as a subcontractor)?

5. Over the last three years, approximately how many engines has your company modified (as prime contractor) to meet emission levels of 1 g/hp-hr or less (this should be a subset of (1) above)?

6. How many of those modifications were achieved through lean emission reduction (this should be a subset of (2) above)?

7. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to operating companies so they could modify their engines to meet emission levels of 1 g/hp-hr or less (this should be a subset of (3) above)?

8. Over the last three years, approximately how many engines has your company supplied parts, equipment, material, start-up support, or training to other vendors or contractors so they could modify their engines to meet emission levels of 1 g/hp-hr or less (acting as a subcontractor) (this should be a subset of (4) above)?

9. Estimate average number of employees and subcontract staff (i.e. full time equivalent positions) utilized to support the emissions reduction projects over the last three years.

10. Over the last three years, the qualified staffing to support emission reduction projects has:
    a. Increased significantly
    b. Increased some
    c. Stayed about the same
    d. Decreased some
    e. Decreased significantly

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11. Based on current staffing, estimate the number of projects per year your company can support acting as the prime contractor.

12. Based on current staffing, estimate the number of projects per year your company can support acting as a subcontractor/parts provider.

13. Based on the technical skills required, estimate the time required to hire and fully train new staff to support emission reductions projects:
    a. Up to six months
    b. Six months to one year
    c. One to two years
    d. More than two years

14. Please describe any issues or concerns associated with implementing a large number of emission reduction modifications over a three year time span.

ALPHA-GAMMA TECHNOLOGIES, INC.

MEMORANDUM

DATE: April 28, 2006

SUBJECT: Control Costs for Reciprocating Internal Combustion Engines at Major and Area Sources

FROM: Bradley Nelson, Alpha-Gamma Technologies, Inc.

TO: Jaime Pagán, EPA Energy Strategies Group

The purpose of this memorandum is to present information on the costs of control technology options for reducing hazardous air pollutants (HAP) emissions from stationary reciprocating internal combustion engines (RICE).

Introduction

The EPA has determined that oxidation catalysts, catalyzed diesel particulate filters (CDPF), and non-selective catalytic reduction (NSCR) are applicable controls for HAP reduction from stationary RICE. Equipment cost information from a vendor was obtained and used to calculate cost equations for oxidation catalysts and NSCR. The cost equations were used to estimate the national impacts of controlling emissions from existing and new engines. Cost information developed by the California Air Resources Board (ARB) for the Airborne Toxic Control Measure for stationary compression ignition (CI) engines and costs developed for the proposed new source performance standards (NSPS) for stationary CI engines were used to estimate costs for installation of CDPF on existing and new engines, respectively.

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Methodology for Determining Cost Equations

The EPA determined that CDPF, oxidation catalysts, and NSCR are applicable controls for the reduction of HAP emissions from RICE. This is based on the theory that HAP reduction will only occur if an oxidation process occurs. At the time of this memorandum, these are the only known add-on control technologies that utilize oxidation. The following sections describe how the capital and annual costs for these control technologies were derived.

The capital and annual costs were determined using the Office of Air Quality Planning and Standards (OAQPS) Control Cost Methodology described below:

Determine:

1 - Total Capital Costs
2 - Total Annual Costs

1 - Total Capital Cost Components and Factors:

Total Capital Cost (TCC) = Direct Costs (DC) + Indirect Costs (IC)

1.1 - Direct Costs (DC): DC = PEC + DIC

1.1.1 - Purchased Equipment Costs (PEC):

- Control Device and Auxiliary Equipment (EC)
- Instrumentation (10% of EC)
- Sales Tax (3% of EC)
- Freight (5% of EC)

PEC = 118% EC

1.1.2 - Direct Installation Costs (DIC)

- Foundations and Supports (8% of PEC)
- Handling and Erection (14% of PEC)
- Electrical (4% of PEC)
- Piping (2% of PEC)
- Insulation for Ductwork (1% of PEC)
- Painting (1% of PEC)

DIC = 30% PEC

DC = PEC + 0.3 PEC = 1.3 PEC

1.2 - Indirect Costs (IC): IC = ICC + C

1.2.1 - Indirect Installation Costs (IIC)

- Engineering (10% of PEC)
- Construction and Field Expenses (5% of PEC)
- Contractor Fees (10% of PEC)
- Startup (2% of PEC)
- Performance Test (1% of PEC)

IIC = 28% PEC = 0.28 PEC

1.2.2 - Contingencies (C) (3% of PEC)

- Equipment Redesign and Modifications
- Cost Escalations
- Delays in Startup

C = 3% PEC = 0.03 PEC

IC = 0.28 PEC + 0.03 PEC = 0.31 PEC

TCC = 1.3 PEC + 0.31 PEC = 1.61 PEC = 1.61 (1.18 EC) = 1.9 EC

2 - Total Annual Cost Elements and Factors

Total Annual Cost (TAC) = Direct Annual Costs (DC) + Indirect Annual Costs (IC)

2.1 - Direct Annual Costs (DC):

- Utilities
- Operating Labor
- Maintenance
- Annual Compliance Test
- Catalyst Cleaning
- Catalyst Replacement
- Catalyst Disposal

2.2 - Indirect Annual Costs (IC)

- Overhead (60% of operating labor and maintenance costs)

- Fuel Penalty
- Property Tax (1% of TCC)
- Insurance (1% of TCC)
- Administrative Charges (2% of TCC)
- Capital Recovery = $[I*(1+I)^n/((1+I)^n-1)*TCC]$ where I is the interest rate, and n is the equipment life.

Oxidation Catalysts

The cost of adding an oxidation catalyst to a new or existing lean burn spark ignition (SI) engine was estimated based on information obtained from a manufacturer of oxidation catalysts for RICE[1]. The vendor provided equipment cost estimates for six generic sized engines ranging from 500 to 8,000 horsepower (HP). The data obtained from the vendor were used to calculate capital and annual cost equations for oxidation catalyst control for RICE at major and area sources. Based on vendor information, EPA assumed there would be no difference between installing oxidation catalyst control on an existing source versus on a new source.

The equipment cost from the oxidation catalyst manufacturer and the OAQPS control cost methodology were used to calculate capital and annualized costs. The capital cost includes the direct, indirect, and contingency costs of installation of the oxidation catalyst. The total annual cost includes the direct and indirect annual costs of operating and maintaining the oxidation catalyst. Maintenance costs were estimated based on maintenance information for CDPF presented in Table 6.2-30 of the nonroad diesel engine regulatory impact analysis (RIA)[2]. The nonroad diesel RIA did not provide any maintenance costs for oxidation catalysts. The EPA would expect that similar maintenance costs would be associated with CDPF and oxidation catalysts, and therefore felt it was appropriate to use the maintenance cost information from the nonroad diesel RIA. Table 6.2-30 of the nonroad diesel RIA indicated that a maintenance interval of 3,000 hours for engines below 175 HP and 4,500 hours for engines above 175 HP was appropriate. Table 6.2-30 estimates the cost for maintenance is $65 for engines up to 600 HP and $260 per event for engines above 600 HP. The EPA has used the assumption that SI engines operate 2,800 hours per year. To provide a conservative estimate of annual maintenance costs for an oxidation catalyst, it was assumed that maintenance is required for all oxidation catalysts every year and the cost for maintenance would be $260. An equipment life of 20 years and an interest rate of 7 percent were used to estimate the indirect annual costs. The fuel penalty associated with operating an oxidation catalyst was assumed to be negligible.

A summary of the costs and linear regression statistical results is provided in Appendix A. The annualized cost equation for oxidation catalyst on lean burn SI engines was estimated at:

Oxidation Catalyst Annual Cost = 1.52 * HP + 393

where;

HP = engine size in HP.

The capital cost equation for installing an oxidation catalyst on a lean burn SI engine was calculated to be:

Oxidation Catalyst Capital Cost = 11.3 * HP - 170

where;

HP = engine size in HP.

The linear equations have a correlation coefficient of 0.9907, which shows the data fit the equations very closely. Therefore, the equations were used to estimate annualized and capital cost for oxidation catalysts for stationary RICE. A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

Non-Selective Catalytic Reduction

Non-selective catalytic reduction, also referred to as a "three way catalyst," is the only available control technology for rich burn RICE that can effectively reduce the emissions of HAP. This is because rich burn engines operate at stoichiometric air-to-fuel ratios and therefore do not have sufficient oxygen available for oxidation catalysts. The catalyst is formulated to enhance both reduction and oxidation reactions, which reduces the emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). Cost data were obtained from a manufacturer of NSCR[3,4]. The cost data contained information for three Caterpillar engine models and five generic sized rich burn engines. Again, based on vendor information, EPA assumed there would be no difference between installing NSCR on an existing source versus a on new source.

The capital cost includes the direct, indirect, and contingency costs of installation of NSCR. The total annual cost includes the direct and indirect annual costs of operating and maintaining the catalyst. Maintenance costs were estimated using the maintenance cost information for CDPF presented in Table 6.2-30 of the nonroad diesel RIA, referenced earlier. The catalyst manufacturer that provided the NSCR cost information recommends a maintenance interval of 3,000 hours. The EPA would expect that similar maintenance costs would be associated with CDPF and NSCR, and therefore felt it was appropriate to use the maintenance cost information from the

nonroad diesel RIA. Table 6.2-30 of the nonroad diesel RIA estimates the cost for maintenance was $65 for engines up to 600 HP and $260 per event for engines above 600 HP. The EPA has used the assumption that SI engines operate 2,800 hours per year. To provide a conservative estimate of annual maintenance costs for the NSCR, it was assumed that maintenance is required every year at a cost of $260. An equipment life of 20 years and an interest rate of 7 percent were used to estimate the indirect annual costs. The fuel penalty associated with operating the NSCR was assumed to be negligible.

A linear regression analysis was done on the data set for NSCR on rich burn engines and the linear equation for annualized cost was;

NSCR Annual Cost = 2.65 * HP + 657

where;

HP = engine size in HP.

The capital cost equation for installing a NSCR on a rich burn SI engine was calculated to be:

NSCR Capital Cost = 19.7 * HP + 1799

where;

HP = engine size in HP.

The linear equations have a correlation coefficient of 0.9887, which shows the equations are a good estimation of the cost data. Therefore, this equation was used to estimate annualized and capital cost for NSCR for stationary RICE. A summary of the costs, linear regression statistics, and a graph of the data are presented in Appendix A.

Catalyzed Diesel Particulate Filters

Catalyzed diesel particulate filters is a control technology that reduces the emissions of HAP from diesel CI engines. It is primarily installed on engines for the reduction of particulate matter (PM) from diesel exhaust. The catalyst element in the CDPF is also effective in reducing the emissions of CO, VOC, and HAP. Costs for CI engines will be calculated for existing and for new engines. This is because installation costs and compliance costs will be different for new and existing CI engines and therefore will be estimated separately in this analysis. Using equipment cost data and the OAQPS cost methodology, a cost equation was developed for prime and emergency CI RICE.

Existing CI Engines

Cost data for retrofitting CDPF on existing engines were obtained from the California ARB presentation entitled "Methods and Key Assumptions for Estimating the Costs for In-Use Stationary Engines[5]." The data set included annualized cost data for 11 engines. The cost data available for CDPF include a passive or active catalyst element. The passive CDPF use a catalyzed coating to reduce emissions of CO, VOC, and HAP emissions, and reduce the ignition temperature necessary for oxidation of PM. The active filters use heat from the engine or from a secondary source to regenerate the catalyst media.

A linear regression analysis was done on the data set and the linear equation for annualized cost was;

$$\text{CDPF Annual Cost} = 6.27 * HP + 1094$$

where;

HP = engine size in HP.

The capital cost equation for installing a CDPF on a CI engine was calculated to be:

$$\text{CDPF Capital Cost} = 7.48 * HP + 1304$$

where;

HP = engine size in HP.

The linear equations have a correlation coefficient of 0.8038, which shows the equation is a good approximation of the data. Therefore, this equation was used to estimate annualized cost and capital cost for retrofitting CDPF for stationary CI prime and emergency engines. A graphical representation of the cost data is shown in Appendix A.

New CI Engines

For the cost of installing CDPF on new engines, EPA used the cost information that was developed for the proposed NSPS for stationary CI engines[6]. These costs were presented in the memorandum entitled "Control Costs for NO_x Adsorbers and CDPF for CI engines," which can be found in the rulemaking docket for the CI NSPS (Docket ID Number EPA-HQ-OAR-2005-0029). The costs for CDPF in that memorandum were based on information obtained from the nonroad diesel RIA. For the stationary CI NSPS, EPA estimated that annualized costs for installing CDPF on new stationary CI engines varied from $130 to $3,100 depending on engine size. Based on these costs, EPA estimated the average annualized cost to be $1/HP for both prime and emergency stationary CI engines. The average cost per HP was used to

estimate annualized cost for CDPF for new CI prime and emergency engines at major and area sources. The capital cost was estimated using the same data points and was calculated to be $1.5/HP.

Summary

The following table presents a summary of the costs for control devices to reduce HAP emissions from engines located at area and major sources. The equations can be used to estimate regulatory costs for existing and new engines, as applicable.

Table 1. Summary of Control Costs for HAP Controls

Engine Type	HAP Control Device	Annualized Costs	Capital Costs
2SLB SI	Oxidation Catalyst	1.52 * HP + 393	11.3 * HP - 170
4SLB SI	Oxidation Catalyst	1.52 * HP + 393	11.3 * HP - 170
4SRB SI	NSCR	2.65 * HP + 657	19.7 * HP + 1799
CI – retrofit	CDPF	6.27 * HP + 1094	7.48 * HP + 1304
CI – new	CDPF	$1/HP	$1.5/HP

References

1. Email from Mike Leonard, Miratech to Brenda Riddle, Alpha-Gamma Technologies. July 20, 2005.

2. Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. May 2004. EPA/420-04-007.

3. Email from Mike Leonard, Miratech to Brad Nelson, Alpha-Gamma Technologies. July 21, 2005.

4. Email from Nick Huff, Miratech to Jennifer Snyder, Alpha-Gamma Technologies. September 15, 2003.

5. Presentation by CARB for Public Consultation Meeting to Discuss Regulatory Approaches to Reduce Emissions from Stationary Diesel Fueled Engines. March 6, 2003. Presentation of the Methods and Key Assumptions for Estimating the Costs for In-Use Stationary Engines.

6. Memorandum from Tanya Parise, Alpha-Gamma Technologies Inc. to Sims Roy, U.S. Environmental Protection Agency, OAQPS ESD Combustion Group. May 31, 2005. Control Costs for NO_x adsorbers and CDPF for CI Engines.

Appendix A

Control Cost Summary and Linear Regression Statistics

Oxidation Catalyst Cost

Data obtained from Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines.

Additional Data from Final Regulatory Support Document: Control of Emissions from Unregulated Nonroad Engines.

		Direct Costs		Indirect Costs									
Engine Size (HP)	**Equipment Cost**	**PEC**	**DIC**	**IIC**	**C**	**Total Capital Cost**	**Regression Capital Cost**		**Direct Annual Cost**	**Indirect Annual Cost**	**Total Annual Cost**	**Regression Annual Cost**	**Annual Cost/Hp**
500	$5,390	$6,360.20	$1,908.06	$1,780.86	$190.81	$10,240	5,503		$260	$1,532	$1,792	1,156	$3.58
1000	$6,930	$8,177.40	$2,453.22	$2,289.67	$245.32	$13,166	11,177		$260	$1,925	$2,185	1,918	$2.19
2000	$11,180	$13,192.40	$3,957.72	$3,693.87	$395.77	$21,240	22,524		$260	$3,010	$3,270	3,443	$1.64
3000	$14,210	$16,767.80	$5,030.34	$4,694.98	$503.03	$26,996	33,871		$260	$3,784	$4,044	4,968	$1.35
5000	$28,480	$33,606.40	$10,081.92	$9,409.79	$1,008.19	$54,106	56,565		$260	$7,428	$7,688	8,018	$1.54
8000	$49,740	$58,693.20	$17,607.96	$16,434.10	$1,760.80	$94,496	90,605		$260	$12,856	$13,116	12,593	$1.64
													$1.99

Assumptions:

PEC = 118% of purchased equipment cost (PEC).

DIC = 30% of purchased equipment cost (PEC).

IIC = 28% of purchased equipment cost (PEC).

C = 3% of purchased equipment cost (PEC).

Direct Annual Cost = ($5 x Hp) + (14.26 x 5).

Indirect Annual Cost = 60% of direct annual cost + 4% of total capital cost + capital recovery.

Capital Recovery assumes equipment 0.09439293

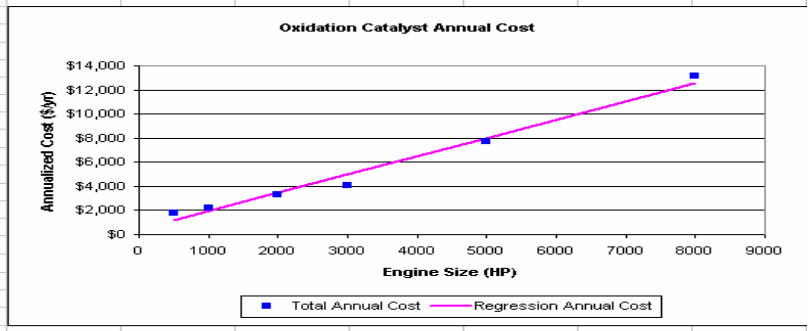
SUMMARY OUTPUT - Annual Cost

Regression Statistics	
Multiple R	0.99073446
R Square	0.98155477
Adjusted R S	0.97694346
Standard Err	660.027964
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	92728904.4	92728904.4	212.858235	0.00012838
Residual	4	1742547.65	435636.913		
Total	5	94471452.1			

	Coefficients	*Standard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	393.098586	433.592132	0.90660913	0.41588915	-810.74866	1596.94583
Engine Size	1.52495566	0.10452303	14.5896619	0.00012838	1.23475261	1.81515871



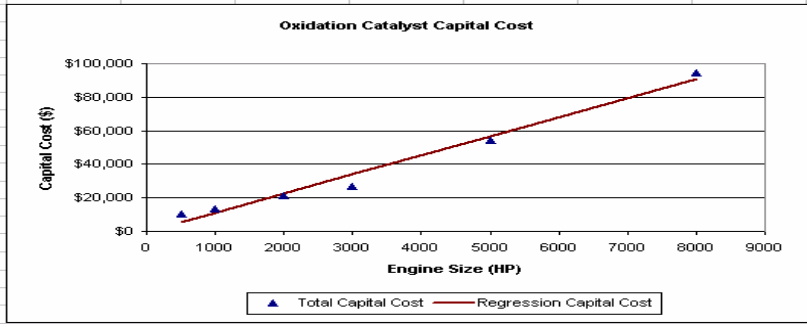
SUMMARY OUTPUT - Capital Cost

Regression Statistics	
Multiple R	0.99073446
R Square	0.98155477
Adjusted R S	0.97694346
Standard Err	4911.17814
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5134070542	5134070542	212.858235	0.00012838
Residual	4	96478683	24119670.8		
Total	5	5230549225			

	Coefficients	*Standard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-170.4063	3226.29997	-0.0528179	0.9604096	-9128.0696	8787.25702
Engine Size	11.3469873	0.77774162	14.5896619	0.00012838	9.18762589	13.5063487



Three Way Catalyst Cost
Generic rich-burn three-way catalyst data from Miratech 7/21/2005.
Additional Data from Miratech in response to 9/15/2003 letter from Jennifer Snyder

			Direct Costs		Indirect Costs					Direct	Indirect	Total	Regression	
Model Engine	Size (HP)	Equipment Cost	PEC	DIC	IIC	C	Total Capital Cost	Regression Capital Cost		Annual Cost	Annual Cost	Annual Cost	Annual Cost	Annual Cost/Hp
CATERPILLAR G3306	167	$1,980	$2,336.40	$700.92	$654.19	$70.09	$3,762	$5,096		$260	$662	$922	1,101	$5.52
CATERPILLAR G3408	255	$4,660	$5,498.80	$1,649.64	$1,539.66	$164.96	$8,853	$6,833		$260	$1,346	$1,606	1,334	$6.30
CATERPILLAR G3408	300	$4,620	$5,451.60	$1,635.48	$1,526.45	$163.55	$8,777	$7,721		$260	$1,336	$1,596	1,454	$5.32
Generic Rich-Burn Engine	300	$5,180	$6,112.40	$1,833.72	$1,711.47	$183.37	$9,841	$7,721		$260	$1,479	$1,739	1,454	$5.80
Generic Rich-Burn Engine	500	$6,610	$7,799.80	$2,339.94	$2,183.94	$233.99	$12,558	$11,669		$260	$1,844	$2,104	1,984	$4.21
Generic Rich-Burn Engine	800	$8,410	$9,923.80	$2,977.14	$2,778.66	$297.71	$15,977	$17,591		$260	$2,303	$2,563	2,780	$3.20
Generic Rich-Burn Engine	1500	$13,370	$15,776.60	$4,732.98	$4,417.45	$473.30	$25,400	$31,409		$260	$3,570	$3,830	4,637	$2.55
Generic Rich-Burn Engine	3000	$33,630	$39,683.40	$11,905.02	$11,111.35	$1,190.50	$63,890	$61,019		$260	$8,742	$9,002	8,617	$3.00
														$4.49

Assumptions:
PEC = 118% of purchased equipment cost (PEC).
DIC = 30% of purchased equipment cost (PEC).
IIC = 28% of purchased equipment cost (PEC).
C = 3% of purchased equipment cost (PEC).
Direct Annual Cost = ($5 x Hp) + (14.26 x 5).
Indirect Annual Cost = 60% of direct annual cost + 4% of total capital cost + capital recovery.
Capital Recovery assumes equipment life of 20 years and 7% 0.09439293

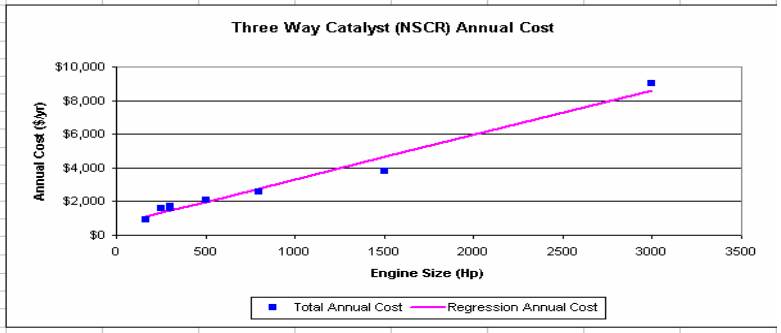
SUMMARY OUTPUT - Annual Cost

Regression Statistics	
Multiple R	0.98867533
R Square	0.9774789
Adjusted R Square	0.97372539
Standard Error	422.191634
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	46418204.4	46418204.4	260.416855	3.6002E-06
Residual	6	1069474.66	178245.776		
Total	7	47487679			

	Coefficients	*Standard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	657.783688	204.776055	3.21220998	0.01831596	156.714366	1158.85301
Size (HP)	2.65290585	0.1643945	16.1374364	3.6002E-06	2.25064669	3.055165



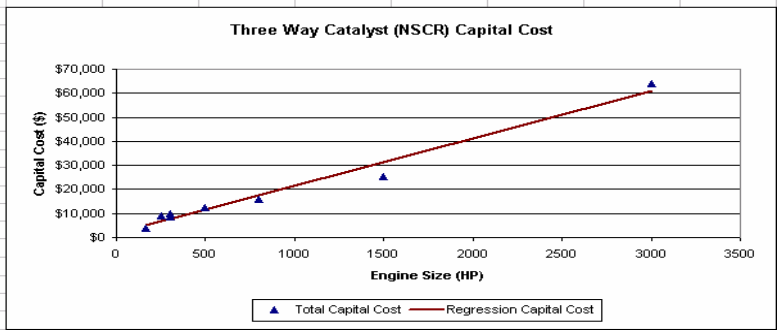
SUMMARY OUTPUT - Capital Cost

Regression Statistics	
Multiple R	0.98867533
R Square	0.9774789
Adjusted R Square	0.97372539
Standard Error	3141.47042
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2570011337	2570011337	260.416855	3.6002E-06
Residual	6	59213018.5	9868836.41		
Total	7	2629224355			

	Coefficients	*Standard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1799.07948	1523.71072	1.18072246	0.28239336	-1929.3091	5527.46802
Size (HP)	19.7399109	1.2232371	16.1374364	3.6002E-06	16.7467554	22.7330664



Catalyzed Diesel Particulate Filter Cost Data Analysis - Retrofit

Cost data for retrofitting CDPF were obtained from the California ARB presentation entitled "Methods and Key Assumptions for Estimating the Costs for In-Use Stationary Engines."

Model Engine	Engine Size (Hp)	DPF Total Annualized Costs	Annual Cost ($/HP)	Regression Annual Cost		Calculated Capital Cost	Capital Cost ($/HP)	Regression Capital Cost
Caterpillar 3516B	2848	14,609	5.1	18,959		17,413	6.1	22,599
Caterpillar	2680	25,882	9.7	17,905		30,851	11.5	21,343
Caterpillar 3516B	2680	20,863	7.8	17,905		24,869	9.3	21,343
Cummins KTTA50-G2	2220	6,370	2.9	15,020		7,593	3.4	17,903
Caterpillar 3412 DISTA	1100	4,311	3.9	7,994		5,138	4.7	9,529
Caterpillar	1072	14,240	13.3	7,819		16,974	15.8	9,320
Caterpillar 3412C	896	5,463	6.1	6,715		6,512	7.3	8,004
Caterpillar	536	5,696	10.6	4,456		6,790	12.7	5,312
Caterpillar 3406	519	4,392	8.5	4,350		5,235	10.1	5,185
Caterpillar 3406	449	3,957	8.8	3,911		4,717	10.5	4,662
Caterpillar	175	1,443	8.2	2,192		1,720	9.8	2,613
Average			7.7				9.2	

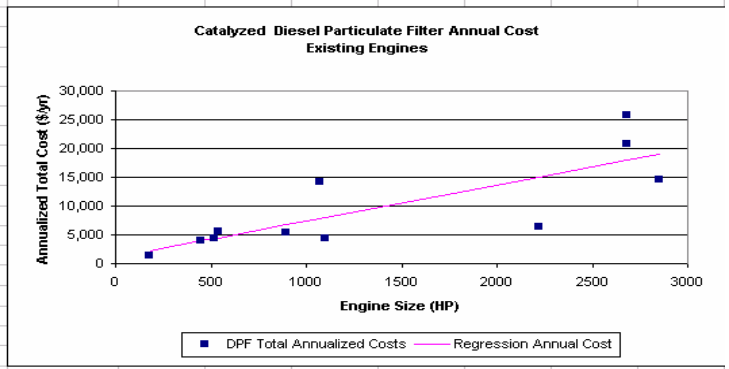
SUMMARY OUTPUT - Annual Cost

Regression Statistics	
Multiple R	0.803791559
R Square	0.646080871
Adjusted R Square	0.606756523
Standard Error	4995.552821
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	410008127.6	410008127.6	16.42953815	0.00287051
Residual	9	224599931.9	24955547.99		
Total	10	634608059.5			

	Coefficients	*Standard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1094.360085	2612.738025	0.418855651	0.685140777	-4816.06846	7004.788627
X Variable 1	6.272637475	1.54752442	4.053336668	0.00287051	2.771891357	9.773383594



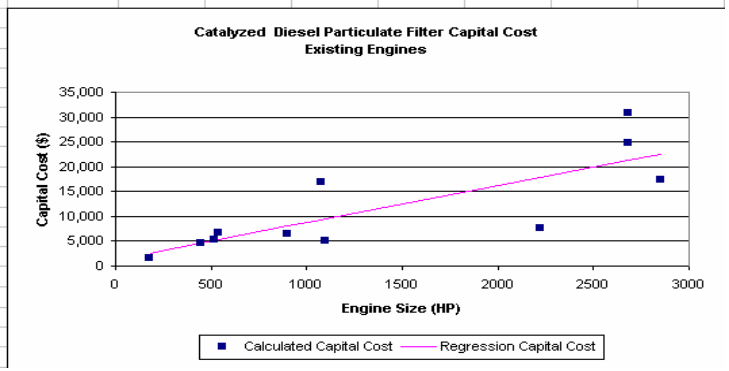
SUMMARY OUTPUT - Capital Cost

Regression Statistics	
Multiple R	0.803791559
R Square	0.646080871
Adjusted R Square	0.606756523
Standard Error	5954.698962
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	582565788.2	582565788.2	16.42953815	0.00287051
Residual	9	319125957.6	35458439.73		
Total	10	901691745.8			

	Coefficients	*Standard Erro*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	1304.477222	3114.383725	0.418855651	0.685140777	-5740.7536	8349.708044
Engine Size (Hp)	7.47698387	1.844649108	4.053336668	0.00287051	3.304094497	11.64987324



MEMORANDUM

DATE: June 29, 2010

SUBJECT: Control Costs for Existing Stationary SI RICE

FROM: Bradley Nelson, EC/R, Inc.

TO: Melanie King, EPA OAQPS/SPPD/ESG

1.0 PURPOSE

The purpose of this memorandum is to present information on the costs of control technology options for reducing hazardous air pollutants (HAP) emissions from existing stationary spark ignition (SI) reciprocating internal combustion engines (RICE). The memorandum will look at the cost of retrofitting control technology on existing engines. This information will be used to determine national impacts associated with the final rule.

2.0 INTRODUCTION

EPA has determined that oxidation catalysts for two-stroke lean burn (2SLB) and four-stroke lean burn (4SLB) engines, and non-selective catalytic reduction (NSCR) for four-stroke rich burn (4SRB) engines are applicable controls for HAP reduction from existing stationary SI RICE. To determine the capital and annual costs for these control technologies, equipment cost information was obtained from industry groups[1] and vendors and manufacturers of SI engine control technology. In some cases, the industry groups provided a breakdown of the capital and annual cost components for each of the retrofit options. Using this cost data, annualized cost and capital cost equations for oxidation catalysts and NSCR were developed.

[1] Reciprocating Internal Combustion Engine National Emission Standards for Hazardous Air Pollutants (RICE NESHAP) Proposed Revisions – Emission Control Costs Analysis Background for "Above the Floor" Emission Controls for Natural Gas-Fired RICE, Innovative Environmental Solutions Inc., October 2009. (EPA-HQ-OAR-2008-0708-0279) .

3.0 CONTROL COST METHODOLOGY

The following sections describe the methodology used to derive the total capital and total annual costs for each of the control technology options. These methodologies were used to calculate total capital and total annual costs when only purchased equipment costs were available (e.g., vendor equipment costs). The methodologies were not used for cost data provided by industry groups because they included a breakdown of the actual total capital and total annual costs. A summary of the methodologies, equations, and assumptions used to estimate the total capital and total annual costs for some of the costs data are described in the following sections.

3.1 Total Capital Costs

The total capital cost includes the direct and indirect costs of purchasing and installing the control equipment. The direct cost includes the cost of purchasing the equipment and instrumentation, cost of shipping, and the cost of installing the control equipment. The indirect cost includes the costs for engineering, contractor fees, testing costs, and also includes costs for contingencies, such as additional modifications, or delays in startup. The total capital cost equation can be summarized as follows:

Total Capital Cost (TCC) = Direct Costs (DC) + Indirect Costs (IC)

The direct costs include the costs of purchasing and installing the control equipment and can be summarized using the following equation;

DC = Purchased Equipment Cost (PEC) + Direct Installation Costs (DIC).

A summary of the cost assumptions for PEC includes the following:

- Control Device and Auxiliary Equipment (EC);
- Instrumentation (10% of EC);
- Sales Tax (3% of EC);
- Freight (5% of EC);

and can be summarized as:

PEC = 118% EC.

A summary of the cost assumptions for DIC includes the following:

- Foundations and Supports (8% of PEC);
- Handling and Erection (14% of PEC);
- Electrical (4% of PEC);
- Piping (2% of PEC);
- Insulation for Ductwork (1% of PEC);

NMED Exhibit 63 - 0002

- Painting (1% of PEC);

and can be summarized as:

DIC = 30% PEC = 0.3 PEC.

Therefore, the direct costs can be simplified using the following equation:

DC = PEC + 0.3 PEC = 1.3 PEC.

The indirect costs include the costs of engineering and contractor fees and contingencies and can be summarized using the following equation:

IC = Indirect Installation Costs (ICC) + Contingencies (C).

A summary of the cost assumptions for ICC includes the following:

- Engineering (10% of PEC);
- Construction and Field Expenses (5% of PEC);
- Contractor Fees (10% of PEC);
- Startup (2% of PEC);
- Performance Test (1% of PEC);

and can be summarized as:

IIC = 28% PEC = 0.28 PEC.

A summary of the cost assumptions for C includes the following:

- Equipment Redesign and Modifications;
- Cost Escalations;
- Delays in Startup;

and is assumed to be:

C = 3% PEC = 0.03 PEC.

Therefore, the IC can be summarized using the following equation:

IC = 0.28 PEC + 0.03 PEC = 0.31 PEC,

and the simplified TCC equation can be expressed as:

TCC = 1.3 PEC + 0.31 PEC = 1.61 PEC = 1.61 (1.18 EC) = 1.9 EC

NMED Exhibit 63 - 0003

3.2 Total Annual Costs

The total annual cost includes the direct and indirect annual costs of operating and maintaining the control equipment. The direct annual cost includes the cost of the utilities, operating labor, and control device cleaning and maintenance. The indirect annual cost includes the overhead costs such as spare parts for the control equipment, administrative charges, and the capital recovery of the control technology. The total annual cost equation can be summarized as follows:

Total Annual Cost (TAC) = Direct Annual Costs (DAC) + Indirect Annual Costs (IAC).

The DAC includes the following parameters:

- Utilities;
- Operating Labor;
- Maintenance;
- Annual Compliance Test;
- Catalyst Cleaning;
- Catalyst Replacement;
- Catalyst Disposal.

The IAC includes the following parameters:

- Overhead;
- Fuel Penalty;
- Property Tax;
- Insurance;
- Administrative Charges;
- Capital Recovery = $\{I(1+I)^n/((1+I)^n-1)*TCC\}$ where I is the interest rate, and n is the equipment life.

To calculate DAC, the costs were broken up into three separate costs: operation and maintenance materials cost, operation and maintenance labor cost, and the cost for annual performance testing or downtime or allowance for catalyst washing. Actual annual cost data from the industry groups were used to estimate the DAC for each of the control technologies. The IAC was broken up into three separate costs: administrative, fuel penalty, and capital recovery. Again, cost data from the industry groups was used to estimate these costs for each of the control technologies. No fuel penalty was estimated for the oxidation catalyst control technologies, because this control technology does not increase the fuel usage of the SI engine.

NMED Exhibit 63 - 0004

4.0 CONTROL COST EQUATIONS

Control cost equations were developed for 2SLB oxidation catalyst, 4SLB oxidation catalyst, and a NSCR for 4SRB engines using the total capital cost and total annual cost data for each control technology. Control cost equations for 2SLB and 4SLB oxidation catalysts were developed separately because the 2SLB oxidation catalyst requires a premium catalyst to reduce the HAP compounds because of the low exhaust temperature of 2SLB engines.

4.1 2SLB Oxidation Catalyst

The 2SLB oxidation catalyst is an effective control technology that reduces HAP emissions from a 2SLB SI engine by oxidizing organic compounds using a catalyst. The oxidation catalyst unit contains a honeycomb-like structure or substrate with a large surface area that is coated with a premium active catalyst layer, such as, platinum or palladium. The oxidation catalyst works by oxidizing carbon monoxide (CO) and gaseous hydrocarbons (HAP) in the exhaust gas to carbon dioxide (CO_2) and water. The reduction of CO and HAP varies depending on the type of catalyst used and the exhaust temperature of the pollutant stream.

The cost of retrofitting an oxidation catalyst to an existing 2SLB engine was estimated using cost data obtained from vendors and industry groups covering engines ranging from 58 horsepower (HP) to 4,670 HP. An equipment life of 10 years and an interest rate of 7 percent were used to estimate the capital recovery of the control technology and the fuel penalty was assumed to be negligible. The cost equations are presented in 2009 dollars.

The total annualized cost equation for retrofitting an oxidation catalyst on a 2SLB engine was estimated to be:

$$\text{2SLB Oxidation Catalyst Total Annual Cost} = \$11.4 \times HP + \$13{,}928$$

where;

HP = engine size in HP.

The linear equation has a correlation coefficient of 0.8046, which shows the data fits the equation closely. Therefore, this equation was used to estimate annualized cost for an oxidation catalyst on a 2SLB engine.

The total capital cost equation for retrofitting an oxidation catalyst on a 2SLB engine was estimated to be:

$$\text{2SLB Oxidation Catalyst Total Capital Cost} = \$47.1 \times HP + \$41{,}603$$

where;

HP = engine size in HP.

NMED Exhibit 63 - 0005

A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

4.2 4SLB Oxidation Catalyst

The 4SLB oxidation catalyst is an effective control technology that reduces HAP emissions from a 4SLB SI engine by oxidizing organic compounds using a catalyst. The oxidation catalyst unit contains a honeycomb-like structure or substrate with a large surface area that is coated with a premium active catalyst layer, such as, platinum or palladium. The oxidation catalyst works by oxidizing CO and gaseous hydrocarbons (HAP) in the exhaust gas to CO_2 and water. The reductions of CO and HAP vary depending on the type of catalyst used and the exhaust temperature of the pollutant stream.

The cost of retrofitting an oxidation catalyst to an existing 4SLB engine was estimated using cost data obtained from vendors and industry groups covering engines ranging from 400 HP to 8,000 HP. Again, an equipment life of 10 years and an interest rate of 7 percent were used to estimate the capital recovery of the control technology and the fuel penalty was assumed to be negligible. The cost equations are presented in 2009 dollars.

The total annualized cost equation for retrofitting an oxidation catalyst on a 4SLB engine was estimated to be:

4SLB Oxidation Catalyst Total Annual Cost = $1.81 x HP + $3,442

where;

HP = engine size in HP.

The linear equation has a correlation coefficient of 0.9779, which shows the data fits the equation very closely. Therefore, this equation was used to estimate annualized cost for an oxidation catalyst on a 4SLB engine.

The total capital cost equation for retrofitting an oxidation catalyst on a 4SLB SI engine was estimated to be:

4SLB Oxidation Catalyst Total Capital Cost = $12.8 x HP + $3,069

where;

HP = engine size in HP.

A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

NMED Exhibit 63 - 0006

4.3 Non-Selective Catalytic Reduction

The NSCR or three-way catalyst is used to control HAP emissions from 4SRB engines. In addition to HAP reductions, NSCR also reduces the emissions of nitrogen oxides (NO_x), CO, and other hydrocarbons (HC). The reduction of HAP and CO takes place through an oxidation reaction that converts HAP to CO_2 and water and converts CO to CO_2. The conversion of NO_x takes place through a reduction of the NO_x to nitrogen gas and oxygen.

The cost of retrofitting an NSCR on an existing 4SRB engine was estimated based on cost data received from vendors and industry groups. A linear regression analysis was done on the data set and the linear equation for annualized cost was;

$$\text{NSCR Annual Cost} = \$4.77 \times HP + \$5{,}679$$

where;

HP = engine size in HP.

The linear equation has a correlation coefficient of 0.7987, which shows an acceptable representation of the cost data. Therefore, this equation was used to estimate annualized cost for retrofitting the NSCR control technology on 4SRB engines.

The capital cost equation for retrofitting an air-to-fuel ratio (AFR) controller and NSCR on a 4SRB engine was estimated to be:

$$\text{NSCR Capital Cost} = \$24.9 \times HP + \$13{,}118$$

where;

HP = engine size in HP.

A summary of the cost calculations, regression analyses, and graphical representations of the annual and capital cost data are presented in Appendix A.

NMED Exhibit 63 - 0007

5.0 SUMMARY

The following table presents a summary of the annual and capital control costs as a function of engine size for the control technologies applicable to existing stationary SI engines, as discussed in this memorandum.

Table 1. Summary of Annual and Capital Costs Equations for Existing Stationary SI Engines

HAP Control Device	Annual Cost ($2009)	Capital Cost ($2009)
2SLB Oxidation Catalyst	$11.4 x HP + $13,928	$47.1 x HP + $41,603
4SLB Oxidation Catalyst	$1.81 x HP + $3,442	$12.8 x HP + $3,069
NSCR	$4.77 x HP + $5,679	$24.9 x HP + $13,118

NMED Exhibit 63 - 0008

6.0 References

Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279).

Email from Bruce Chrisman, Cameron's Compression Systems to Tanya Parise, EC/R, Subject: Existing RICE NESHAP - Information for EPA for 2SLB Engines, October 16, 2009.

Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009.

Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186).

Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086).

Email from Antonio Santos, MECA to Tanya Parise, EC/R, Subject: EPA Proposed Existing RICE NESHAP - Cost of Aftertreatment, October 2, 2009. Response #2.

Price quote from Charles Ball, Emissions & Silencer Technology for an oxidation catalyst for a 500 HP 4SLB engine.

Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls, April 19, 2010.

Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279).

Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038).

Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087).

Four Corners Air Quality Task Force Report of Mitigation Options, November 1, 2007. Mitigation Option: Use of NSCR/3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines (EPA-HQ-OAR-2008-0708-0009).

NMED Exhibit 63 - 0009

Appendix A

Control Cost Summary and Linear Regression Statistics

NMED Exhibit 63 - 0010

2SLB Oxidation Catalyst Cost ($2009)

Engine Size (HP)	Equipment Cost	Direct Costs		Indirect Costs		Total Capital Cost	Direct Annual Costs			Indirect Annual Costs				Total Annual Cost	Data Source
		PEC	DIC	IIC	C		O&M Materials	O&M Labor	Total Direct Annual Cost (TDAC)	Administrative Charges (ADMC)	Fuel Penalty (FPC)	Capital Recovery (CRC)	Total Indirect Annual Cost (TIAC)		
296	$24,987	$29,485	$8,845	$8,256	$885	$47,470	$7,958	$875	$8,833	$225	$0	$6,759	$6,984	$15,817	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
192	$24,987	$29,485	$8,845	$8,256	$885	$47,470	$7,958	$875	$8,833	$225	$0	$6,759	$6,759	$15,592	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
384	$30,409	$35,883	$10,765	$10,047	$1,076	$57,771	$7,958	$875	$8,833	$225	$0	$8,225	$8,225	$17,058	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
800	$50,901	$60,063	$18,019	$16,818	$1,802	$96,702	$7,958	$875	$8,833	$225	$0	$13,768	$13,768	$22,601	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)
58	$12,191	$14,385	$4,316	$4,028	$432	$23,160	$7,958	$875	$8,833	$225	$0	$3,298	$3,298	$12,131	Email from Bruce Chrisman, Cameron's Compression Systems to Tanya Parise, EC/R, Subject: Existing RICE NESHAP - Information for EPA for 2SLB Engines, October 16, 2009
600	$51,378	$60,626	$18,188	$16,975	$1,819	$97,608	$7,958	$875	$8,833	$225	$0	$13,897	$14,122	$22,955	Email from Bruce Chrisman, Cameron's Compression Systems to Tanya Parise, EC/R, Subject: Existing RICE NESHAP - Information for EPA for 2SLB Engines, October 16, 2009
148	$14,589	$17,215	$5,165	$4,820	$516	$27,716	$7,958	$875	$8,833	$225	$0	$3,946	$4,171	$13,004	Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
296	$22,123	$26,105	$7,832	$7,309	$783	$42,029	$7,958	$875	$8,833	$225	$0	$5,984	$6,209	$15,042	Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
192	$14,589	$17,215	$5,165	$4,820	$516	$27,716	$7,958	$875	$8,833	$225	$0	$3,946	$4,171	$13,004	Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
384	$22,123	$26,105	$7,832	$7,309	$783	$42,029	$7,958	$875	$8,833	$225	$0	$5,984	$6,209	$15,042	Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
600	$30,409	$35,883	$10,765	$10,047	$1,076	$57,771	$7,958	$875	$8,833	$225	$0	$8,225	$8,450	$17,283	Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
800	$37,871	$44,688	$13,406	$12,513	$1,341	$71,947	$7,958	$875	$8,833	$225	$0	$10,244	$10,469	$19,302	Email from James Harrison, Exterran to Melanie King, EPA, Subject: 2SLB - Cameron oxidation catalyst pricing, October 20, 2009
3850						$210,000			$25,000	$225	$0	$29,899	$30,124	$55,124	Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a Clark TLAD-8 2SLB gas compressor engine.
4670						$210,000			$25,000	$225	$0	$29,899	$30,124	$55,124	Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a Cooper Bessemer 2SLB gas compressor engine.
2166						$210,000			$25,000	$225	$0	$29,899	$30,124	$55,124	Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a MEP 2SLB gas compressor engine.
1859						$210,000			$25,000	$225	$0	$29,899	$30,124	$55,124	Anadarko Petroleum Corporation Comments on the Proposed Revisions to the National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, June 2, 2009, Case Study (EPA-HQ-OAR-2008-0708-0186). Cost is for installation on a MEP 2SLB gas compressor engine.

Assumptions:

PEC = 118% of purchased equipment cost (PEC).

DIC = 30% of purchased equipment cost (PEC).

IIC = 28% of purchased equipment cost (PEC).

C = 3% of purchased equipment cost (PEC).

Capital Recovery assumes equipment life of 10 years and 7% interest rate. 0.142377503

O&M Materials cost covers the annualized equipment cost to replace the catalyst (every 3 years), thermocouples (every 7.5 years), crankcase filters (3 months), and annual catalyst rotation for cleaning. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)]

O&M Labor cost covers the annualized labor cost to replace and rotate (for cleaning) catalyst, thermocouples, and crankcase filter. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment N (EPA-HQ-OAR-2008-0708-0279)]

2SLB Oxidation Catalyst Cost ($2009)

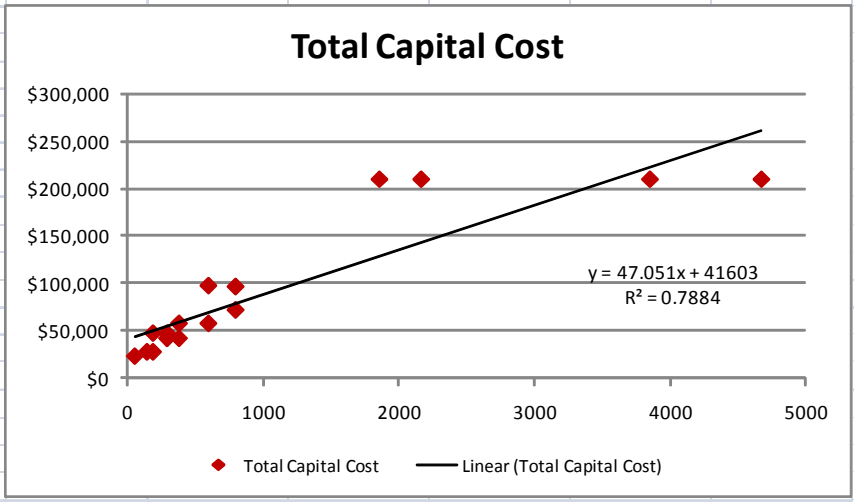
SUMMARY OUTPUT - Capital Cost

Regression Statistics	
Multiple R	0.887931512
R Square	0.788422369
Adjusted R Squa	0.773309682
Standard Error	34869.66159
Observations	16

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	63432625775	63432625775	52.16956604	4.40556E-06
Residual	14	17022506190	1215893299		
Total	15	80455131965			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	41602.60574	11206.04006	3.712516244	0.002319141	17568.04028	65637.1712
X Variable 1	47.0511302	6.514205394	7.222850271	4.40556E-06	33.07954923	61.02271117



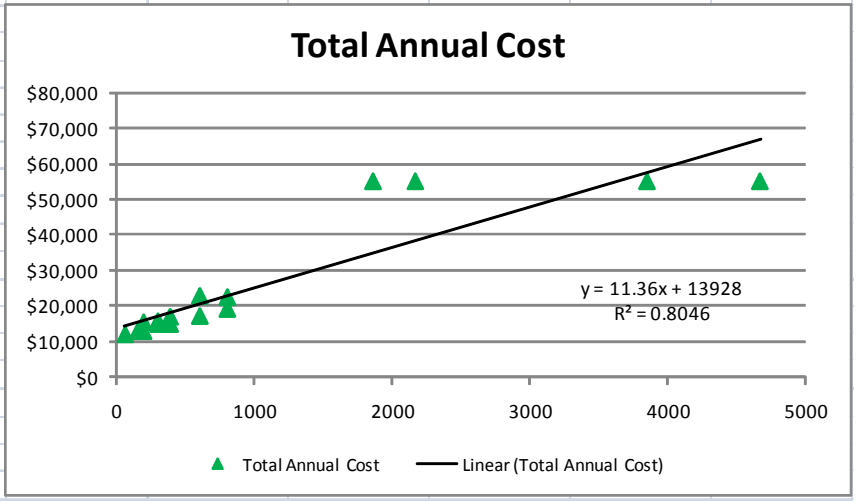
SUMMARY OUTPUT - Annual Cost

Regression Statistics	
Multiple R	0.896978958
R Square	0.804571251
Adjusted R Squa	0.790612055
Standard Error	8009.912446
Observations	16

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3697938056	3697938056	57.63736182	2.5054E-06
Residual	14	898221763.5	64158697.39		
Total	15	4596159819			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	13928.11988	2574.140259	5.410785147	9.1811E-05	8407.138137	19449.10162
X Variable 1	11.3603976	1.496378585	7.591927411	2.5054E-06	8.150984738	14.56981046



4SLB Oxidation Catalyst Cost ($2009)

Engine Size (HP)	Equipment Cost	Direct Costs		Indirect Costs		Total Capital Cost	Direct Annual Costs			Indirect Annual Costs				Total Annual Cost	Data Source
		PEC	DIC	IIC	C		O&M Materials	O&M Labor	Total Direct Annual Cost (TDAC)	Administrative Charges (ADMC)	Fuel Penalty (FPC)	Capital Recovery (CRC)	Total Indirect Annual Cost (TIAC)		
500	$6,361	$7,505	$2,252	$2,102	$225	$12,084	$1,891	$1,053	$2,944	$225	$0	$1,720	$1,945	$4,889	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from $2005 to $2009 using the Marshall and Swift Equipment Cost Index.
1000	$8,178	$9,650	$2,895	$2,702	$289	$15,536	$1,891	$1,053	$2,944	$225	$0	$2,212	$2,212	$5,156	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from $2005 to $2009 using the Marshall and Swift Equipment Cost Index.
2000	$13,193	$15,568	$4,670	$4,359	$467	$25,064	$1,891	$1,053	$2,944	$225	$0	$3,569	$3,569	$6,513	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from $2005 to $2009 using the Marshall and Swift Equipment Cost Index.
3000	$16,769	$19,787	$5,936	$5,540	$594	$31,857	$1,891	$1,053	$2,944	$225	$0	$4,536	$4,536	$7,480	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from $2005 to $2009 using the Marshall and Swift Equipment Cost Index.
5000	$33,608	$39,658	$11,897	$11,104	$1,190	$63,849	$1,891	$1,053	$2,944	$225	$0	$9,091	$9,091	$12,035	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from $2005 to $2009 using the Marshall and Swift Equipment Cost Index.
8000	$58,697	$69,262	$20,779	$19,393	$2,078	$111,512	$1,891	$1,053	$2,944	$225	$0	$15,877	$15,877	$18,821	Email from Mike Leonard, Miratech Corporation to Brenda Riddle, AGTI, RE: Clarification of SCR Cost Information for EPA, July 20, 2005. (EPA-HQ-OAR-2005-0030-0086). Costs converted from $2005 to $2009 using the Marshall and Swift Equipment Cost Index.
1000	$8,500	$10,030	$3,009	$2,808	$301	$16,148	$1,891	$1,053	$2,944	$225	$0	$2,299	$2,524	$5,468	Email from Antonio Santos, MECA to Tanya Parise, EC/R, Subject: EPA Proposed Existing RICE NESHAP - Cost of Aftertreatment, October 2, 2009. Response #2
500	$3,700	$4,366	$1,310	$1,222	$131	$7,029	$1,891	$1,053	$2,944	$225	$0	$1,001	$1,001	$3,945	Price quote from Charles Ball, Emissions & Silencer Technology for an oxidation catalyst for a 500 HP 4SLB engine.
400		$6,575	$2,961	$2,005		$11,541	$1,958	$1,143	$3,101	$225	$0	$1,643	$1,643	$4,744	Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls
400		$6,575	$2,961	$2,005		$11,541	$1,958	$1,143	$3,101	$225	$0	$1,643	$1,643	$4,744	Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls
425		$7,149	$3,025	$2,005		$12,179	$1,756	$875	$2,631	$225	$0	$1,734	$1,734	$4,365	Memorandum from Tom McGrath, IES to Brad Nelson, EC/R, Request for Additional Cost Detail for Gas-Fired Engines Emission Controls

Assumptions:

PEC = 118% of purchased equipment cost (PEC).

DIC = 30% of purchased equipment cost (PEC).

IIC = 28% of purchased equipment cost (PEC).

C = 3% of purchased equipment cost (PEC).

Capital Recovery assumes equipment life of 10 years and 7% interest rate. 0.142377503

O&M Materials cost covers the annualized equipment cost to replace the catalyst (every 3 years), thermocouples (every 7.5 years), crankcase filters (3 months), and annual catalyst rotation for cleaning. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment L (EPA-HQ-OAR-2008-0708-0279)]

O&M Labor cost covers the annualized labor cost to replace and rotate (for cleaning) catalyst, thermocouples, and crankcase filter. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment L (EPA-HQ-OAR-2008-0708-0279)]

4SLB Oxidation Catalyst Cost ($2009)

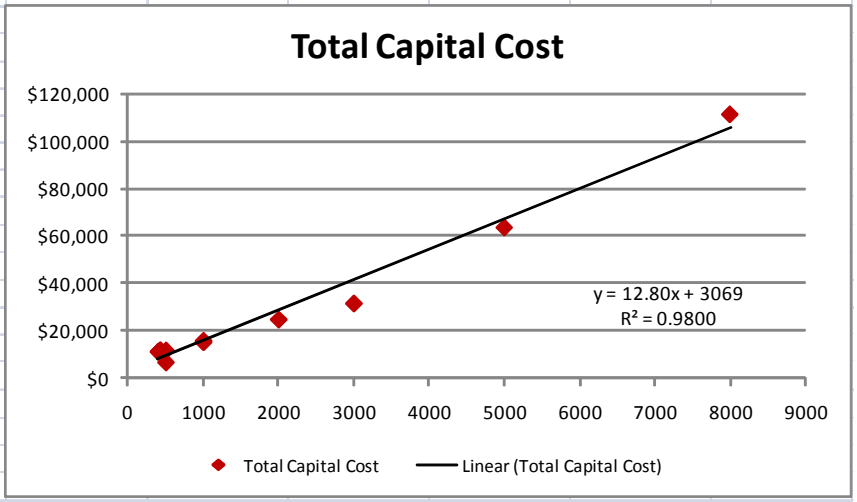
SUMMARY OUTPUT - Total Capital Cost

Regression Statistics	
Multiple R	0.989944875
R Square	0.979990856
Adjusted R Squa	0.977767618
Standard Error	4727.892942
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	9853063606	9853063606	440.7943494	5.91417E-09
Residual	9	201176745.1	22352971.68		
Total	10	10054240351			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	3069.26319	1884.275356	1.62888252	0.137778178	-1193.263795	7331.790175
Engine Size (HP)	12.80450452	0.609880529	20.99510299	5.91417E-09	11.42485892	14.18415013



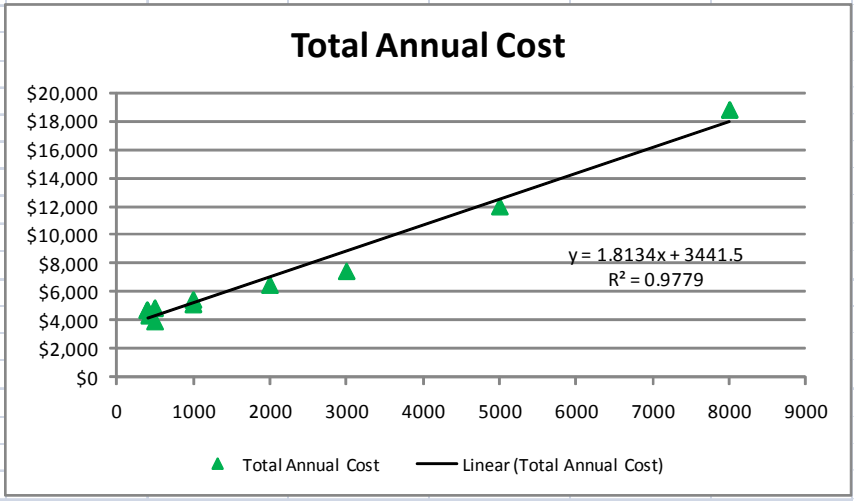
SUMMARY OUTPUT - Total Annual Cost

Regression Statistics	
Multiple R	0.988903698
R Square	0.977930524
Adjusted R Squa	0.97547836
Standard Error	703.9457563
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	197622721.6	197622721.6	398.8030634	9.20031E-09
Residual	9	4459856.651	495539.6279		
Total	10	202082578.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	3441.504829	280.553654	12.26683303	6.38308E-07	2806.848372	4076.161285
X Variable 1	1.81340819	0.090806373	19.97005417	9.20031E-09	1.607989903	2.018826477



4SRB NSCR Costs ($2009)

Engine Size (HP)	Equipment Cost	AFRC Cost	Direct Costs		Indirect Costs		Total Capital Cost	Direct Annual Costs			Indirect Annual Costs				Total Annual Cost	Data Source
			PEC	DIC	IIC	C		O&M Materials	O&M Labor	Total Direct Annual Cost (TDAC)	Administrative Charges (ADMC)	Fuel Penalty (FPC)	Capital Recovery (CRC)	Total Indirect Annual Cost (TIAC)		
50			$8,935				$11,945	$664	$1,275	$1,939	$225	$379	$1,701	$2,305	$4,244	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
100			$10,099				$13,363	$664	$1,275	$1,939	$225	$379	$1,903	$2,507	$4,446	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
100			$10,827				$15,139	$1,071	$1,320	$2,391	$225	$695	$2,155	$3,075	$5,466	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
175			$12,284				$17,132	$1,071	$1,320	$2,391	$225	$695	$2,439	$3,359	$5,750	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
175			$10,667				$16,165	$1,706	$1,360	$3,066	$225	$1,200	$2,302	$3,727	$6,793	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
300			$16,119				$22,117	$1,706	$1,360	$3,066	$225	$1,200	$3,149	$4,574	$7,640	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
300			$11,777				$17,240	$2,384	$1,380	$3,764	$225	$2,021	$2,455	$4,701	$8,465	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
500			$16,689				$24,502	$2,384	$1,380	$3,764	$225	$2,021	$3,489	$5,735	$9,499	Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)
167	$2,588	$7,017	$11,334	$3,400	$3,173	$340	$18,247	$1,071	$1,320	$2,391	$225	$695	$2,598	$3,518	$5,909	Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038). Cost for NSCR/AFRC on a Caterpillar G3306 adjusted from $2003 to $2009.
255	$6,091	$7,017	$15,467	$4,640	$4,331	$464	$24,902	$1,706	$1,360	$3,066	$225	$1,200	$3,545	$4,970	$8,036	Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038). Cost for NSCR/AFRC on a Caterpillar G3408 adjusted from $2003 to $2009.
300	$6,039	$7,017	$15,405	$4,622	$4,314	$462	$24,803	$2,384	$1,380	$3,764	$225	$2,021	$3,531	$5,777	$9,541	Email from Nick Huff, Miratech to Jennifer Synder, AGTI, SCR Questions for RICE MACT, October 23, 2003 (EPA-HQ-OAR-2005-0029-0038). Cost for NSCR/AFRC on a Caterpillar G3408 adjusted from $2003 to $2009.
300	$6,113	$7,500	$16,063	$4,819	$4,498	$482	$25,862	$2,384	$1,380	$3,764	$225	$2,021	$3,682	$5,928	$9,692	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 300 HP rich-burn engine adjusted from $2005 to $2009.
500	$7,800	$7,500	$18,054	$5,416	$5,055	$542	$29,067	$2,384	$1,380	$3,764	$225	$2,021	$4,139	$6,385	$10,149	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from $2005 to $2009.
800	$9,924	$7,500	$20,561	$6,168	$5,757	$617	$33,103	$2,384	$1,380	$3,764	$225	$2,021	$4,713	$6,959	$10,723	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from $2005 to $2009.
1500	$15,778	$7,500	$27,468	$8,240	$7,691	$824	$44,223	$2,384	$1,380	$3,764	$225	$2,021	$6,296	$8,542	$12,306	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from $2005 to $2009.
3000	$39,686	$7,500	$55,679	$16,704	$15,590	$1,670	$89,644	$2,384	$1,380	$3,764	$225	$2,021	$12,763	$15,009	$18,773	Email from Mike Leonard, Miratech to Brad Nelson, AGTI, Information Request, July 21, 2005 (EPA-HQ-OAR-2005-0030-0087). Cost for NSCR/AFRC on a generic 500 HP rich-burn engine adjusted from $2005 to $2008.
48	$3,735	$2,950	$7,762	$4,080			$11,842	$480	$540	$1,020	$225	$0	$1,686	$1,911	$2,931	Four Corners Air Quality Task Force Report of Mitigation Options, November 1, 2007. Mitigation Option: Use of NSCR/3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines (EPA-HQ-OAR-2008-0708-0009). TCC includes cost of catalyst housing ($2,385), catalyst element ($1,000), AFRC ($2,950), installation of catalyst housing and support ($1,380), installation and setup of AFRC ($2,160), solar panel electricity for AFRC control ($350), installation of solar panel electricity to AFRC ($540), and taxes/freight ($1,077). TDAC includes annual cost for quarterly change of O2 sensor and emissions monitoring ($320), labor and travel to site ($540), and annualized cost of catalyst replacement 5 year life ($160). Cost quoted for a Compressco Ford 460.
23	$2,925	$2,950	$6,952	$4,080			$11,032	$480	$540	$1,020	$225	$0	$1,571	$1,796	$2,816	Four Corners Air Quality Task Force Report of Mitigation Options, November 1, 2007. Mitigation Option: Use of NSCR/3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines (EPA-HQ-OAR-2008-0708-0009). TCC includes cost of catalyst housing ($1,775), catalyst element ($800), AFRC ($2,950), installation of catalyst housing and support ($1,380), installation and setup of AFRC ($2,160), solar panel electricity for AFRC control ($350), installation of solar panel electricity to AFRC ($540), and taxes/freight ($1,077). TDAC includes annual cost for quarterly change of O2 sensor and emissions monitoring ($320), labor and travel to site ($540), and annualized cost of catalyst replacement 5 year life ($160). Cost quoted for a Waukesha 220/330.

Assumptions:
PEC = 118% of purchased equipment cost (PEC).
DIC = 30% of purchased equipment cost (PEC).
IIC = 28% of purchased equipment cost (PEC).
C = 3% of purchased equipment cost (PEC).
Direct Annual Cost = ($5 x Hp) + (14.26 x 5).
Indirect Annual Cost = 60% of direct annual cost + 4% of total capital cost + capital recovery.
Capital Recovery assumes equipment life of 10 y 0.142377503
O&M Materials cost covers the annualized equipment cost to replace the catalyst (every 3 years), thermocouples (every 7.5 years), crankcase filters (3 months), and annual catalyst rotation for cleaning. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)]
O&M Labor cost covers the annualized labor cost to replace and rotate (for cleaning) catalyst, thermocouples, and crankcase filter. [Source: Technical Report: RICE NESHAP Control Costs Background for "Above the Floor Analysis", October 2009, Attachment D (EPA-HQ-OAR-2008-0708-0279)]

4SRB NSCR Costs ($2009)

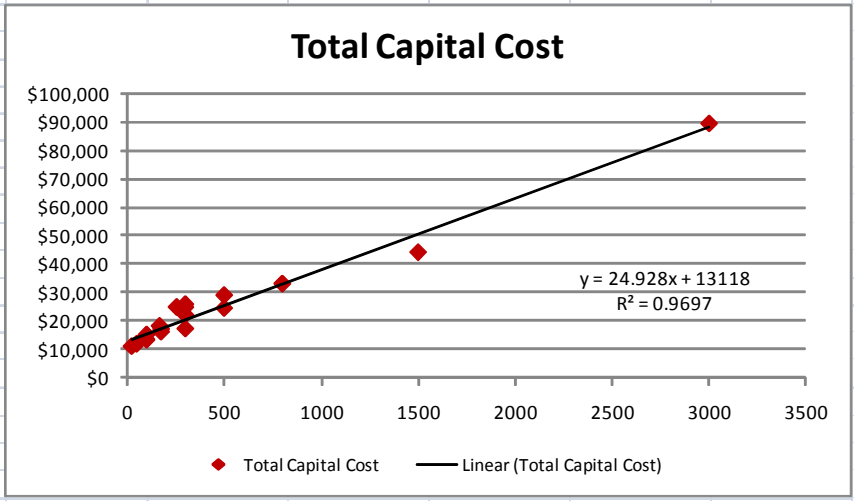
SUMMARY OUTPUT - Total Capital Cost

Regression Statistics	
Multiple R	0.984731321
R Square	0.969695774
Adjusted R Squa	0.96780176
Standard Error	3273.282484
Observations	18

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5485538418	5485538418	511.9791654	1.41597E-13
Residual	16	171430051.5	10714378.22		
Total	17	5656968469			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	13117.61245	933.7363075	14.0485192	2.03296E-10	11138.17991	15097.04498
Engine Size (HP)	24.92848169	1.101716069	22.62695661	1.41597E-13	22.59294798	27.26401541



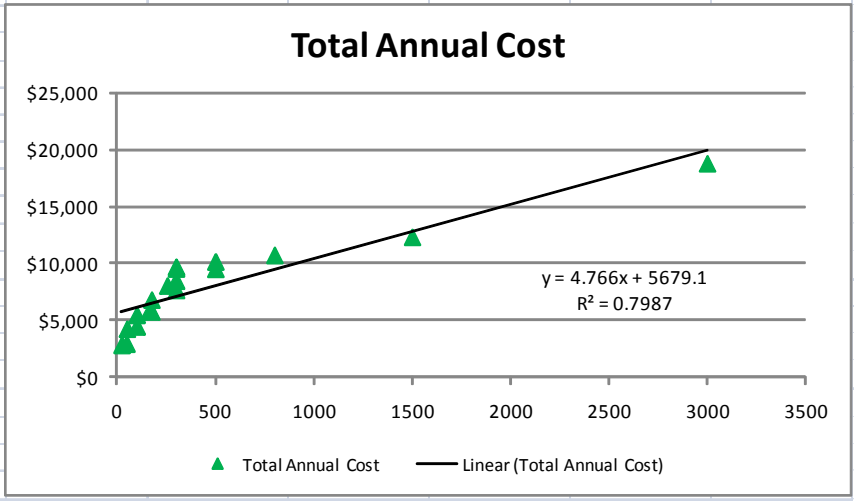
SUMMARY OUTPUT - Total Annual Cost

Regression Statistics	
Multiple R	0.893674092
R Square	0.798653382
Adjusted R Squa	0.786069219
Standard Error	1777.457825
Observations	18

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	200508408.1	200508408.1	63.46495544	5.85557E-07
Residual	16	50549701.12	3159356.32		
Total	17	251058109.2			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	5679.133777	507.0374813	11.20061926	5.54849E-09	4604.262341	6754.005214
X Variable 1	4.765983033	0.59825385	7.96648953	5.85557E-07	3.497741535	6.034224532



Wet Seal Degassing Recovery System for Centrifugal Compressors



Technology/Practice Overview

Description

Centrifugal compressors are used throughout the natural gas industry to compress gas for processing, movement through pipelines, and other needs. These compressors require seals around the rotating shaft to prevent high pressure gases from escaping where the shaft exits the compressor casing. Seals may be either wet seals using oil as a barrier or dry seals that use a mechanical barrier with most new compressors equipped with dry seal. However, there are a large number of centrifugal compressors with wet seals in operation. Wet seals use specialty oil which is circulated under higher pressure than the gas in the adjacent compressor case, between rings around the compressor shaft, forming a barrier against the compressed gas leakage. In the wet seal design shown in Exhibit 1, the center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. "O-ring" rubber seals prevent leakage around the stationary rings. Very little gas escapes through the oil barrier; considerably more gas is entrained in the oil that comes in direct contact with the high pressures gas at the "inboard" (compressor side) interface, thus contaminating the seal oil. Prior to recirculation, seal oil must be purged of natural gas (which is primarily methane) in a process called seal oil "degassing." Methane released during degassing is commonly vented to the atmosphere with vent outlets usually located in elevated areas that are not easily accessible to operators for inspection or maintenance (e.g., roof vent stacks). As a result, the majority of methane emissions from a centrifugal compressor often go undetected by operators.

- ■ Compressors/Engines
- □ Dehydrators
- □ Directed Inspection & Maintenance
- □ Pipelines
- □ Pneumatics/Controls
- □ Tanks
- □ Valves
- □ Wells
- □ Other

Applicable Sector(s)

- ■ Production
- ■ Processing
- ■ Transmission
- ■ Distribution

Economic and Environmental Benefits

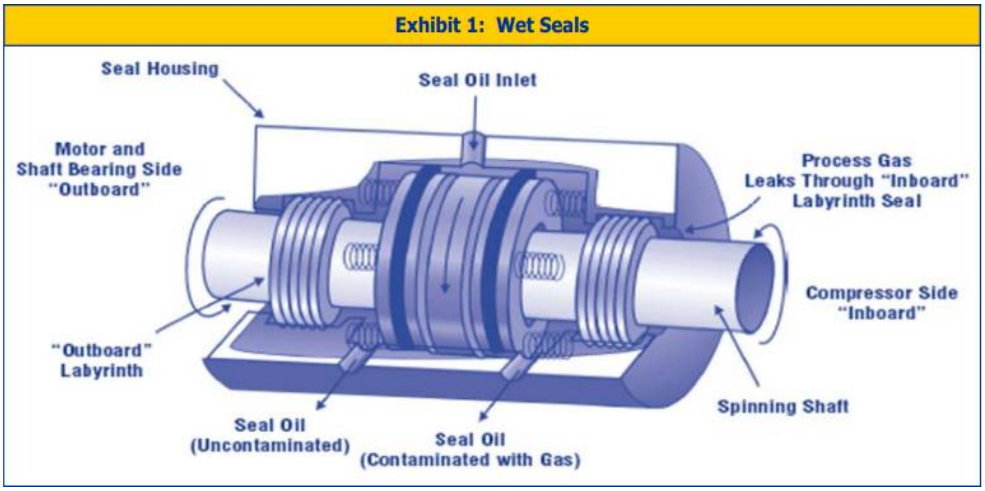
Economics Evaluation

Estimated Gas Price	Annual Methane Savings[1]	Value of Annual Gas Savings	Estimated Implementation Cost	Incremental Operating Cost	Payback
$3.00/Mcf	30,000 Mcf 120,000 Mcf	$90,000 $360,000	$33,000 $90,000	Minimal	5 months 3 months
$5.00/Mcf	30,000 Mcf 120,000 Mcf	$150,000 $600,000	$33,000 $90,000	Minimal	3 months 2 months
$7.00/Mcf	30,000 Mcf 120,000 Mcf	$210,000 $840,000	$33,000 $90,000	Minimal	2 months 1 months

[1] *At each gas price, the costs and savings are for one and four compressors at a station.*

Wet Seal Degassing Recovery System for Centrifugal Compressors

Exhibit 1: A typical wet seal setup, the seal oil enters through the inlet (top) and provides a barrier to gas attempting to escape by forming two thin films under higher pressure between the center rotating ring and the two stationary rings (seen with surrounding o-rings).



One Partner has reduced methane emissions from centrifugal compressor seal oil degassing by separating gas from seal oil in a small separator/disengagement vessel and routing it back into the compressor suction, to high pressure turbine fuel gas, or to low pressure fuel gas for heaters/burners. A diagram illustrating this partner's approach is shown in Exhibit 2. Seal oil with entrained gas is typically routed directly to an atmospheric pressure degassing tank from which disengaged gas is vented to the atmosphere. In the capture system, the contaminated seal oil is instead separated from entrained gas in a separator operating at seal oil pressure with gas flow control by a critical orifice. The entrained gas captured from the seal oil is

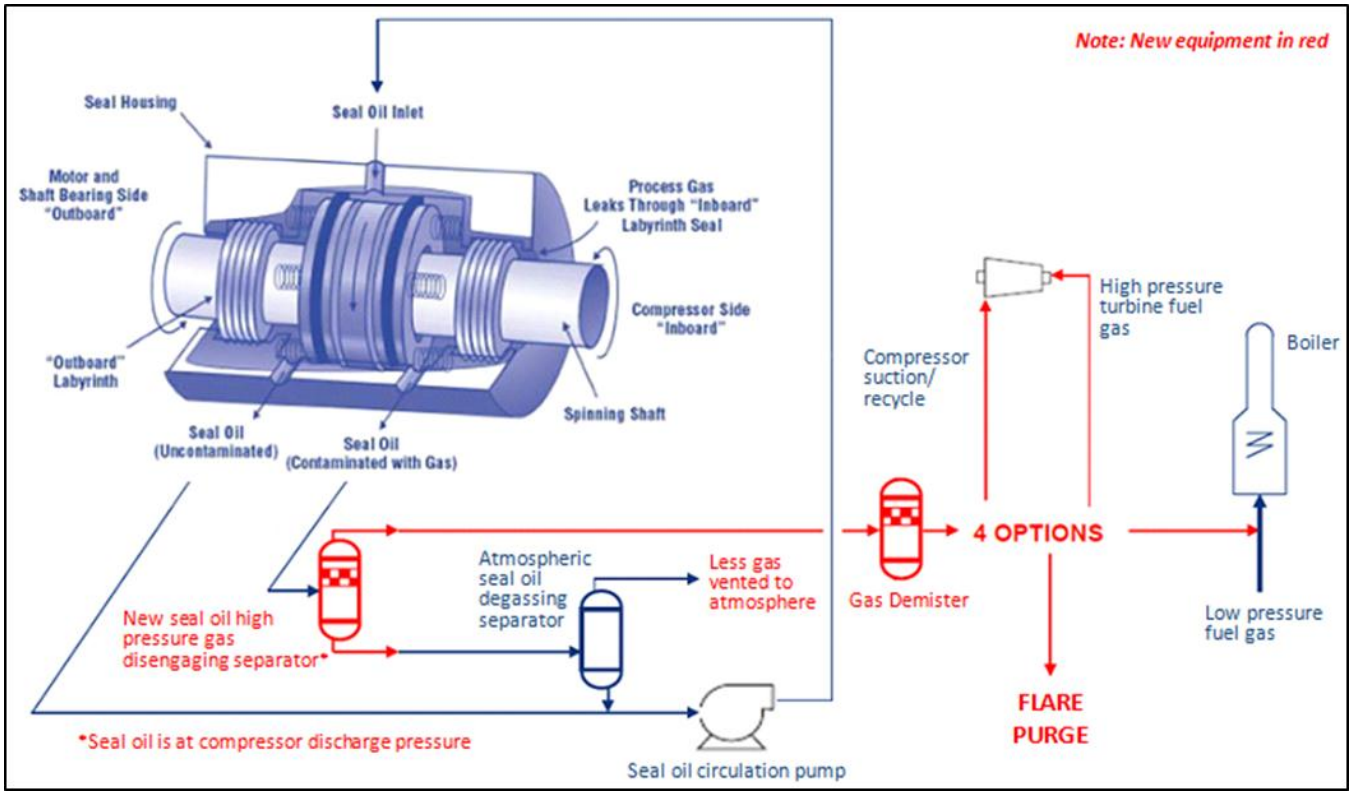


Exhibit 2: General process flow of wet seal degassing recovery system. Existing equipment is shown in blue or black and new equipment for seal oil degassing recovery is shown in red.

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routed to a seal oil demister to remove entrained seal oil before routing to beneficial use. The seal oil then flows from the bottom of the seal oil degassing separator to the atmospheric degassing separator where the remaining minimal volume of entrained/dissolved gas is removed and vented to the atmosphere. The regenerated seal oil is then recirculated back to the compressor seal oil system.

Operating Requirements

In order to implement this recovery and use of gas separated from seal oil there must be a use for the recovered gas. Operators may configure the wet seal degassing recovery system to route the recovered gas as low pressure heater/boiler fuel (approximately 50 pounds per square inch gauge [psig]), high pressure turbine fuel (approximately 250 psig), to compressor suction, flare sweep gas, or any combination of the four options. One Partner has configured their wet seal degassing recovery systems to route recovered gas from multiple centrifugal compressors to all four of these choices. If routed to fuel gas use, the small amount of entrained seal oil mist in the gas stream from the new seal oil high pressure gas disengagement separator (shown in red in Exhibit 2 above) requires a demister/filter knock-out vessel (s) be installed to remove residual oil.

Applicability

Wet seal degassing recovery systems could be installed at most locations with wet seal centrifugal compressors, particularly in lieu of retrofitting compressors with dry seals. Retrofitting wet seal centrifugal compressors with dry seals is not always feasible due to operating conditions/requirements, substantial costs, and compressor downtime. Wet seal degassing recovery systems offer an economic alternative to installing dry seals to mitigate methane emissions from wet seal degassing with very little downtime.

Methane Emissions

According to previous measurements of seal oil degassing reported in Bylin, et al. (2009), emissions from degassing centrifugal compressor seal oil can be as high as 185 standard cubic feet per minute (scfm) (5.2 cubic meters (m3) per minute) of gas per compressor, with an average value of 63 scfm (1.8 m3 per minute) of gas per compressor. Gas volume from degassing centrifugal compressor seal oil varies primarily due to: the number of seals per centrifugal compressor, the rate of seal oil circulation, the size of the compressor, and the compressor discharge pressure. One Partner currently operates wet seal degassing recovery systems that recover 99 percent of the degassing emissions from fifteen centrifugal compressors – four low pressure compressors, nine high pressure compressors, and two tandem compressors at one facility. Based on a study conducted at this particular facility, the wet seal gas recovery system captures 3,300 scfm of gas; that equates to 1.6 billion cubic feet (Bcf) of gas per year (8,500 hours of operation per year as indicated by the Partner). This Partner reports another approximately 85 wet seal centrifugal compressors with the same or similar seal oil gas recovery systems in this particular operation.

Economic Analysis

The analysis for installing a wet seal degassing recovery system should consider the capital and operational costs along with the revenue generated by recovered gas. As shown in the overview table (Economic and Environmental Benefits) above, the economics for recovering wet seal degassing losses are compelling at even low gas prices. The detailed economic analysis in Exhibit 3 below presents two scenarios. The first scenario depicts the wet seal degassing recovery system installed for one centrifugal compressor, and the second scenario illustrates a wet seal degassing recovery system installed at a centrifugal compressor station with four centrifugal compressors. These examples are based on one Partner's emissions measurements, savings, and installed equipment costs which have high pressure gas disengagement separators on each seal of 15 compressors, with one recovered gas two stage filter/demister system.

Capital Costs

The investment per compressor to recover seal oil degassing emissions using this technology includes the cost of a high pressure seal oil gas disengagement separator for each compressor seal or pair of seals operating at the same seal oil pressure, new piping, the appropriate pressure and flow controls, and the labor to design and install the equipment. Operating and maintenance (O&M) costs are expected to be minimal. The investment per station to condition the recovered degassing emissions for injection into a low pressure fuel system would include the cost of a gas demister to remove residual seal oil from the recovered gas. If the recovered gas is routed to a higher pressure turbine fuel system, a second seal oil high efficiency filter/separator

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is likely required to ensure all remaining seal oil mist is removed.

The capital cost (estimated) for each separator includes the purchase cost of the process vessel, piping, instrumentation, structural support, electrical, painting, shipping, insurance, and installation. Exhibit 3 summarizes the estimated capital costs for each piece of equipment installed in a wet seal degassing recovery system.

design pressure of 720 psig. The cost for a seal oil single-stage demister/filter system designed for a single centrifugal compressor or a compressor station with four centrifugal compressors is $9,000.

If any of the recovered gas is being used as high pressure turbine fuel, the recovery system may include a second seal oil gas high-efficiency filter to ensure trace amounts of seal oil do not foul the turbine fuel injectors. This economic analysis assumes the seal oil gas filter

Exhibit 3: Wet Seal Degassing Recovery System Installation and Equipment Costs

Equipment	One Centrifugal Compressor Capital Cost ($2011)	Centrifugal Compressor Station Capital Cost ($2011)
Seal-Oil/Gas Separator [1]	$19,000	$76,000
Seal Oil Gas Demister – Low Quality Gas	$9,000	$9,000
Seal Oil Gas Demister – High Quality Gas	$5,000	$5,000
Total	**$33,000**	**$90,000**

[1] *Assuming two seals per centrifugal compressor and four centrifugal compressors at the station. An individual high pressure seal oil gas separator costs $9,500 per seal.*

High Pressure Seal Oil Gas Disengagement Separators

For each centrifugal compressor connected to the wet seal degassing recovery system, a seal oil gas separator will be installed for each seal or pair of seals if operating at the same seal oil pressure. The seal oil gas separators can be designed to operate at the same pressure as the seal oil exiting the seal housing. Based on a Partner's installation, the size of these separators assumes 1-foot diameter, 3-foot height seal oil gas separators with a 1,125 psig design pressure and made of carbon steel. The total cost of each seal oil gas separator is $9,500; assuming two seal-oil/gas separators per compressor, the total cost per compressor is $19,000.

Seal Oil Recovered Gas Demister/Filter

Before the recovered gas can be sent to a fuel line it must pass through at least one high-efficiency demister to remove entrained seal oil that may foul burners and potentially clog fuel injectors. The seal oil gas demister can be designed to receive recovered gas from multiple centrifugal compressors with wet seals. Therefore, the design characteristics of this vessel will vary depending on the number of centrifugal compressors connected to the vessel. Based on a Partner's installation, this economic analysis assumes, for a single centrifugal compressor, the seal oil gas demister will be vertical and have a 1-foot diameter and 4-foot height with a

for turbine fuel quality gas will be vertical and have a 1-foot diameter and 3-foot height with a design pressure of 300 psig and be made of carbon steel. The cost for the second seal oil high-efficiency filter for a single centrifugal compressor or a compressor station is $5,000.

Piping and Instrumentation

Operators will need to route seal oil exiting the compressor seal to the new seal-oil/gas separator and then to the degassing tank which will require piping modifications. Additionally, pipes and valves to transport the recovered gas from the seal oil gas disengagement separators to the seal oil gas demister/filters and further to the fuel gas, compressor suction or flare line(s) will be required. Pressure and flow controls will also need to be installed to regulate the pressure and flow of the recovered gas from each high pressure seal oil degassing separator. In this Partner's installations this is accomplished with a critical orifice (1/16 inch/1.59 mm) on the gas outlet from each seal-oil/gas separator which restricts gas flow using choke flow effects. For example, this Partner has set up the wet seal degassing recovery system to route captured gas to a high pressure turbine fuel line, low pressure process heater fuel line, and flare purge which requires additional instrumentation and flow control. The majority of the gas is routed to the high pressure

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turbine fuel line with excess gas routed to the low pressure process heater fuel line or flare, depending on fuel requirements. The piping and instrumentation costs are included in the installation and capital costs for each individual piece of equipment listed in Exhibit 3.

Estimated Savings

The savings for capturing seal oil degassing emissions are realized by generating additional gas sales and revenue through using recovered gas for site fuel gas or recycling directly to suction and sales or processing. Based on the measurement studies discussed in Bylin, et al. (2009), the average methane emissions from centrifugal compressor wet seal degassing is 63 scfm (1.8 m3 per minute) of gas per compressor. Assuming 8,000 hours of operation per year, the total gas emissions per year is 30 million cubic feet (MMcf) per compressor. Based on one Partner's experience, over 99 percent of the entrained gas in the seal oil was captured and used as fuel – proving this technology performs as well as dry seal systems from an emission perspective. This analysis assumes 99 percent of the potential degassing emissions are captured and 1 percent is vented. Therefore, 30 MMcf of gas is recovered per centrifugal compressor and displaces the same volume in fuel gas or is routed to compressor suction and sales. At $3.00 per thousand cubic feet (Mcf), savings from reduced fuel gas consumption is estimated to be $90,000 per year per centrifugal compressor connected to a wet seal degassing recovery system. A station with four centrifugal compressors connected to a wet seal degassing recovery system could potentially generate $360,000 per year of additional revenue.

Comparing Costs to Savings

The economics of implementing a wet seal degassing recovery system is shown below using a five-year cash flow table. This analysis presented in Exhibit 4 and Exhibit 5 considers capital costs and methane emissions savings. The capital and installation costs in this economic analysis assume the operator installs both the seal oil gas demister/filter separator for low pressure fuel gas and seal oil gas high efficiency filter for high pressure turbine fuel gas, which will allow the operator to route to a flare, low pressure burner, or turbine fuel line. Exhibit 3 shows the detailed breakdown of the equipment and capital cost used in this economic analysis. It is important to note that all analyses will be highly site-specific, but the economics of installing a wet

Exhibit 4: Wet Seal Degassing Recovery System Costs and Savings for One Compressor

Costs and Savings ($)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Wet seal recovery system capital & installation costs	($33,000)					
Annual natural gas savings ($3.00/Mcf of Methane)		$90,000	$90,000	$90,000	$90,000	$90,000
						NPV (Net Present Value) = $280,000
						IRR (Internal Rate of Return) = 270%
						Payback Period = 5 months

Exhibit 5: Wet Seal Degassing Recovery System Costs and Savings for Four Compressors at a Station

Costs and Savings ($)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Wet seal recovery system capital & installation costs	($90,000)					
Annual natural gas savings ($3.00/Mcf of Methane)		$360,000	$360,000	$360,000	$360,000	$360,000
						NPV (Net Present Value) = $1,200,000
						IRR (Internal Rate of Return) = 400%
						Payback Period = 3 months

seal gas recovery system are so attractive that companies should consider implementing this technology at any and all facilities with at least one centrifugal compressor with wet seals.

Exhibit 4 presents the economics of installing a wet seal degassing recovery system for a single centrifugal compressor. Exhibit 5 presents the economics of installing a wet seal degassing recovery system at a station with four centrifugal compressors. The net present value and payback period are calculated using a 10 percent discount rate.

Operational Reliability

The Partner reporting the seal oil degassing systems reports them being in place with constant use since 1977 and no failures due to the degassing systems. With about 100 such systems installed and operating from very low pressures to very high pressures across a range of gas compositions, the operational reliability of seal oil degassing systems has been clearly demonstrated.

Discussion

A wet seal oil degassing recovery system is likely to provide the lowest cost for retrofit with the quickest payback for compressor stations, offshore production platforms or gas processing plants with single or multiple wet seal centrifugal compressors. All options pay back in less than a year. The economics are compelling, but the installation may require a brief shut-down of each compressor to tie the seal oil circulation piping into the new gas disengagement vessels. New facilities requiring the installation of wet seal centrifugal compressors can also integrate wet seal degassing recovery systems into their process design at the same costs. As demonstrated by a Partner facility, wet seal degassing recovery systems are highly effective at capturing degassing emissions from wet seal centrifugal compressors and subsequently reducing fuel gas purchases and/or increasing gas sales with a high rate of return.

References

Biegler, et al. "4.3.1 Guthrie's Modular Method." *Systematic Methods of Chemical Process Design*. Ed. Neal R. Amundson. Saddlewood: Pearson, pages 133 to 135. 1997.

Bylin, C., et al. *Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry*. 24th World Gas Conference Paper. Buenos Aires, Argentina. 5-9 October 2009. www.epa.gov/gasstar/documents/best_paper_award.pdf.

EPA. *Natural Gas STAR Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006. www.epa.gov/gasstar/documents/ll_wetseals.pdf.

Turton, et al. "7.3.2 Module Costing Technique." *Analysis, Synthesis, and Design of Chemical Processes*. 3rd edition. Pearson Education, Inc., pages 192 to 209. 2008.

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While we have taken steps to ensure the accuracy of this Internet version of the document, it is not the official version. To see a complete version including any recent edits, visit: https://www.ecfr.gov/cgi-bin/ECFR?page=browse and search under Title 40, Protection of Environment.

METHOD 22—VISUAL DETERMINATION OF FUGITIVE EMISSIONS FROM MATERIAL SOURCES AND SMOKE EMISSIONS FROM FLARES

NOTE: This method is not inclusive with respect to observer certification. Some material is incorporated by reference from Method 9.

1.0 Scope and Application

This method is applicable for the determination of the frequency of fugitive emissions from stationary sources, only as specified in an applicable subpart of the regulations. This method also is applicable for the determination of the frequency of visible smoke emissions from flares.

2.0 Summary of Method

2.1 Fugitive emissions produced during material processing, handling, and transfer operations or smoke emissions from flares are visually determined by an observer without the aid of instruments.

2.2 This method is used also to determine visible smoke emissions from flares used for combustion of waste process materials.

2.3 This method determines the amount of time that visible emissions occur during the observation period (*i.e.*, the accumulated emission time). This method does not require that the opacity of emissions be determined. Since this procedure requires only the determination of whether visible emissions occur and does not require the determination of opacity levels, observer certification according to the procedures of Method 9 is not required. However, it is necessary that the observer is knowledgeable with respect to the general procedures for determining the presence of visible emissions. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. This training is to be obtained from written materials found in References 1 and 2 or from the lecture portion of the Method 9 certification course.

3.0 Definitions

3.1 *Emission frequency* means the percentage of time that emissions are visible during the observation period.

3.2 *Emission time* means the accumulated amount of time that emissions are visible during the observation period.

3.3 *Fugitive emissions* means emissions generated by an affected facility which is not collected by a capture system and is released to the atmosphere. This includes emissions that (1) escape capture by process equipment exhaust hoods; (2) are emitted during material transfer; (3) are emitted from buildings housing material processing or handling equipment; or (4) are emitted directly from process equipment.

3.4 *Observation period* means the accumulated time period during which observations are conducted, not to be less than the period specified in the applicable regulation.

3.5 *Smoke emissions* means a pollutant generated by combustion in a flare and occurring immediately downstream of the flame. Smoke occurring within the flame, but not downstream of the flame, is not considered a smoke emission.

4.0 Interferences

4.1 Occasionally, fugitive emissions from sources other than the affected facility (*e.g.*, road dust) may prevent a clear view of the affected facility. This may particularly be a problem during periods of high wind. If the view of the potential emission points is obscured to such a degree that the observer questions the validity of continuing observations, then the observations shall be terminated, and the observer shall clearly note this fact on the data form.

5.0 Safety

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

6.0 Equipment

6.1 Stopwatches (two). Accumulative type with unit divisions of at least 0.5 seconds.

6.2 Light Meter. Light meter capable of measuring illuminance in the 50 to 200 lux range, required for indoor observations only.

7.0 Reagents and Supplies [Reserved]

8.0 Sample Collection, Preservation, Storage, and Transfer [Reserved]

9.0 Quality Control [Reserved]

10.0 Calibration and Standardization [Reserved]

11.0 Analytical Procedure

11.1 Selection of Observation Location. Survey the affected facility, or the building or structure housing the process to be observed, and determine the locations of potential emissions. If the

affected facility is located inside a building, determine an observation location that is consistent with the requirements of the applicable regulation (*i.e.,* outside observation of emissions escaping the building/structure or inside observation of emissions directly emitted from the affected facility process unit). Then select a position that enables a clear view of the potential emission point(s) of the affected facility or of the building or structure housing the affected facility, as appropriate for the applicable subpart. A position at least 4.6 m (15 feet), but not more than 400 m (0.25 miles), from the emission source is recommended. For outdoor locations, select a position where the sunlight is not shining directly in the observer's eyes.

11.2 Field Records.

11.2.1 Outdoor Location. Record the following information on the field data sheet (Figure 22-1): Company name, industry, process unit, observer's name, observer's affiliation, and date. Record also the estimated wind speed, wind direction, and sky condition. Sketch the process unit being observed, and note the observer location relative to the source and the sun. Indicate the potential and actual emission points on the sketch. Alternatively, digital photography as described in section 11.2.3 may be used for a subset of the recordkeeping requirements of this section.

11.2.2 Indoor Location. Record the following information on the field data sheet (Figure 22-2): Company name, industry, process unit, observer's name, observer's affiliation, and date. Record as appropriate the type, location, and intensity of lighting on the data sheet. Sketch the process unit being observed, and note the observer location relative to the source. Indicate the potential and actual fugitive emission points on the sketch. Alternatively, digital photography as described in section 11.2.3 may be used for a subset of the recordkeeping requirements of this section.

11.2.3 Digital Photographic Records. Digital photographs, annotated or unaltered, may be used to record and report sky conditions, observer's location relative to the source, observer's location relative to the sun, process unit being observed, potential emission points and actual emission points for the requirements in sections 11.2.1 and 11.2.2. The image must have the proper lighting, field of view and depth of field to properly distinguish the sky condition (if applicable), process unit, potential emission point and actual emission point. At least one digital photograph must be from the point of the view of the observer. The photograph(s) representing the environmental conditions including the sky conditions and the position of the sun relative to the observer and the emission point must be taken within a reasonable time of the observation (*i.e.,* 15 minutes). When observations are taken from exactly the same observation point on a routine basis (*i.e.,* daily) and as long as there are no modifications to the units depicted, only a single photograph each is necessary to document the observer's location relative to the emissions source, the process unit being observed, and the location of potential and actual emission points. Any photographs altered or annotated must be retained in an unaltered format for recordkeeping purposes.

11.3 Indoor Lighting Requirements. For indoor locations, use a light meter to measure the level of illumination at a location as close to the emission source(s) as is feasible. An illumination of greater than 100 lux (10 foot candles) is considered necessary for proper application of this method.

11.4 Observations.

11.4.1 Procedure. Record the clock time when observations begin. Use one stopwatch to monitor the duration of the observation period. Start this stopwatch when the observation period begins. If the observation period is divided into two or more segments by process shutdowns or observer rest breaks (see section 11.4.3), stop the stopwatch when a break begins and restart the stopwatch without resetting it when the break ends. Stop the stopwatch at the end of the observation period. The accumulated time indicated by this stopwatch is the duration of observation period. When the observation period is completed, record the clock time. During the observation period, continuously watch the emission source. Upon observing an emission (condensed water vapor is not considered an emission), start the second accumulative stopwatch; stop the watch when the emission stops. Continue this procedure for the entire observation period. The accumulated elapsed time on this stopwatch is the total time emissions were visible during the observation period (*i.e.*, the emission time.)

11.4.2 Observation Period. Choose an observation period of sufficient length to meet the requirements for determining compliance with the emission standard in the applicable subpart of the regulations. When the length of the observation period is specifically stated in the applicable subpart, it may not be necessary to observe the source for this entire period if the emission time required to indicate noncompliance (based on the specified observation period) is observed in a shorter time period. In other words, if the regulation prohibits emissions for more than 6 minutes in any hour, then observations may (optional) be stopped after an emission time of 6 minutes is exceeded. Similarly, when the regulation is expressed as an emission frequency and the regulation prohibits emissions for greater than 10 percent of the time in any hour, then observations may (optional) be terminated after 6 minutes of emission are observed since 6 minutes is 10 percent of an hour. In any case, the observation period shall not be less than 6 minutes in duration. In some cases, the process operation may be intermittent or cyclic. In such cases, it may be convenient for the observation period to coincide with the length of the process cycle.

11.4.3 Observer Rest Breaks. Do not observe emissions continuously for a period of more than 15 to 20 minutes without taking a rest break. For sources requiring observation periods of greater than 20 minutes, the observer shall take a break of not less than 5 minutes and not more than 10 minutes after every 15 to 20 minutes of observation. If continuous observations are desired for extended time periods, two observers can alternate between making observations and taking breaks.

11.5 Recording Observations. Record the accumulated time of the observation period on the data sheet as the observation period duration. Record the accumulated time emissions were observed on the data sheet as the emission time. Record the clock time the observation period began and ended, as well as the clock time any observer breaks began and ended.

12.0 Data Analysis and Calculations

If the applicable subpart requires that the emission rate be expressed as an emission frequency (in percent), determine this value as follows: Divide the accumulated emission time (in seconds)

by the duration of the observation period (in seconds) or by any minimum observation period required in the applicable subpart, if the actual observation period is less than the required period, and multiply this quotient by 100.

13.0 Method Performance [Reserved]

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 References

1. Missan, R., and A. Stein. Guidelines for Evaluation of Visible Emissions Certification, Field Procedures, Legal Aspects, and Background Material. EPA Publication No. EPA-340/1-75-007. April 1975.

2. Wohlschlegel, P., and D.E. Wagoner. Guideline for Development of a Quality Assurance Program: Volume IX—Visual Determination of Opacity Emissions from Stationary Sources. EPA Publication No. EPA-650/4-74-005i. November 1975.

17.0 Tables, Diagrams, Flowcharts, and Validation Data

FUGITIVE OR SMOKE EMISSION INSPECTION
OUTDOOR LOCATION

Company Location Company Rep.	Observer Affiliation Date
Sky Conditions Precipitation	Wind Direction Wind Speed
Industry	Process Unit

Sketch process unit: indicate observer position relative to source; indicate potential emission points and/or actual emission points.

OBSERVATIONS	Clock Time	Observation period duration, min:sec	Accumulated emission time, min:sec
Begin Observation			
End Observation			

Figure 22-1

FUGITIVE OR SMOKE EMISSION INSPECTION
INDOOR LOCATION

Company Location Company Rep.	Observer Affiliation Date
Industry	Process Unit

Light type (fluorescent, incandescent, natural)
Light location (overhead, behind observer, etc.)
Illuminance (lux or footcandles)
Sketch process unit: indicate observer position relative to source; indicate potential emission points and/or actual emission points.

OBSERVATIONS	Clock Time	Observation period duration, min:sec	Accumulated emission time, min:sec
Begin			
End Observation			

Figure 22-2

Prepared for:

Western Regional Air Partnership
Oil and Gas Working Group

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June 2019

Baseline 2014-2016 Oil and Gas Emission Inventory for the WESTAR-WRAP Region

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Baseline 2014-2016 Oil and Gas Emission Inventory for the WESTAR-WRAP Region

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EXECUTIVE SUMMARY

This study provides estimates of criteria air pollutant and greenhouse gas emissions for oil and gas (O&G) exploration and production operations in the Western States Air Resources Council-Western Regional Air Partnership (WESTAR-WRAP) region for a 2014-2016 baseline period. This analysis was sponsored by the Western Regional Air Partnership Oil and Gas Working Group (WRAP OGWG).

The WESTAR-WRAP region consists of 15 states in the Western US, several of which have substantial O&G exploration and production activities. Accurate O&G emission inventories are critical for air quality, including regional haze planning. In 2014, O&G activity in the WESTAR-WRAP Region included close to 12,000 spuds, over 225,000 active O&G wells, over 9 trillion cubic feet of natural gas production, and over 1 billion barrels of oil production. Over 70% of active wells in the WESTAR-WRAP region in 2014 were vertical wells and over 75% of spuds were horizontal or directional wells, indicating a shift from development of vertical to horizontal and directional wells.

To develop the baseline 2014-2016 WESTAR-WRAP region emission inventory base year 2014 emissions were compiled from existing emission inventory sources (described in Section 2.1). Subsequent to compilation of the base year 2014 emission inventory, outreach was conducted to gather additional data from regulatory agencies and upstream O&G operators to enhance the emissions inventory and, to the extent that data was provided, make the inventory applicable to the 2014-2016 baseline period (described in Section 2.2). A survey data collection effort was used to collect new information to enhance emission inventory accuracy as part of the outreach effort. Survey data collection targeted specific equipment types, production areas, and operators that could substantially enhance the WESTAR-WRAP O&G emission inventory. The survey was first distributed to state agencies so that in-house agency data could be leveraged prior to asking O&G operators to provide survey data. After state agencies filled out the survey, it was distributed to O&G operators to fill remaining data gaps. O&G emissions from California are excluded from this analysis since California Air Resources Board is developing O&G emissions independently and results were not available for inclusion in this report.

Integrating the data collected as part of survey outreach into the 2014-2016 baseline emission inventory resulted in NOx emissions increases of 8% over the WESTAR-WRAP region compared the base year 2014 WRAP emission inventory. Hydraulic fracturing engine emissions accounted for 47% of nitrogen oxides (NOx) emission increases and emissions from artificial lift engines accounted for 38% of NOx emissions increases. Volatile organic compound (VOC) emissions decreased by 22% over the WESTAR-WRAP region based on integration of operator survey data into the inventory, primarily as a result of increases to oil tank control prevalence.

State-level WESTAR-WRAP region O&G emissions by state are presented in Table ES-1.

Table ES-1. WESTAR-WRAP region O&G emissions by state.

Pollutant	Criteria Air Pollutant Emissions (tons/yr) and Greenhouse Gas Emissions (1000 tons/yr)												
	AK	AZ	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY
NOx	43,291	1,960	65,985	889	9,265	57,706	78,940	156	454	693	16,379	444	46,171
VOC	27,449	280	189,113	34	35,714	197,658	185,088	269	73	3,090	112,485	36	264,821
CO	13,607	439	56,710	272	7,955	52,690	113,550	111	263	496	14,145	301	21,384
SOx	2,156	33	710	4	946	9,574	23,155	15	13	13	586	14	6,888
PM_{10}	1,166	51	1,929	10	170	1,336	2,393	11	20	77	706	14	1,276
$PM_{2.5}$	1,098	51	1,929	10	170	1,336	2,393	11	20	77	706	14	1,276

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Pollutant	Criteria Air Pollutant Emissions (tons/yr) and Greenhouse Gas Emissions (1000 tons/yr)												
	AK	AZ	CO	ID	MT	ND	NM	NV	OR	SD	UT	WA	WY
CO_2	N/A	1,183	11,101	245	2,254	18,303	19,954	99	210	584	5,777	201	11,096
CH_4	N/A	1	225	<1	138	247	705	<1	<1	4	529	<1	365
N_2O	N/A	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1
$CO_2(e)$	N/A	1,209	18,583	248	5,712	24,541	37,677	108	216	699	19,034	203	20,304

The contents of the report by Chapter are summarized as follows:

- Chapter 1.0 provides introductory information on study methodology, scope, and O&G activity in the WESTAR-WRAP region;
- Chapter 2.0 describes the steps taken to compile the emission inventory based on reference inventories, agency submitted data, and survey responses;
- Chapter 3.0 presents summaries of baseline 2014-2016 emissions.

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1.0 INTRODUCTION

The WRAP OGWG is sponsoring the development of O&G emission inventories as part of efforts to support regional haze planning in the Western States Air Resources Council-Western Regional Air Partnership (WESTAR-WRAP) region. The O&G emission inventories developed under WRAP OGWG sponsorship will also facilitate other types of air quality planning (e.g., photochemical ozone modeling). More information about WRAP OGWG emission inventory development efforts may be found at the project webpage: https://www.wrapair2.org/ogwg.aspx.

This report describes the development of a criteria air pollutant and greenhouse gas (GHG) emissions inventory for O&G field operations in the WESTAR-WRAP region for a baseline 2014-2016 period, including point (midstream) and nonpoint (wellsite) sources. The baseline emissions inventory was compiled based on existing emission inventory sources and improvements based on collected survey data.

1.1 Scope

1.1.1 Sources

The emission inventory documented herein includes emissions from upstream and midstream O&G sources, consistent with the OGWG Road Map Scope of Work[1] and the OGWG Roadmap Phase I Report (Grant et al., 2018b). Downstream O&G emissions are not included. The baseline O&G emission inventory includes wellsite, gathering, and processing subsectors (items 1, 5, and 6 in Figure 1-1). Item 1) On-shore Petroleum and Natural Gas Production is referred to as "wellsite" sources; emissions from wellsite sources are typically classified as nonpoint sources[2]. Items 5) Gathering and Boosting and 6) Gas Processing Plant are collectively referred to as "midstream" sources; emissions from midstream sources are typically classified as point sources. The classification of well-site emissions as nonpoint and midstream emissions as point sources is consistent with O&G emission inventory classifications used in the WRAP Phase III study[3], West-wide Jumpstart Air Quality Modeling Study (WestJUMP AQMS)[4], 2011 Western Air Quality Study[5], and 2014 NEI methodology[6].

[1] https://www.wrapair2.org/pdf/11162017_WRAPO&GWorkgroup_RoadMapSOW.pdf

[2] There are exceptions; for example, several wellsite sources in the Uinta Basin are available by facility and will be included in emission inventories as point source emissions.

[3] https://www.wrapair2.org/PhaseIII.aspx

[4] https://www.wrapair2.org/WestJumpAQMS.aspx

[5] http://vibe.cira.colostate.edu/wiki/wiki/1018/3saqs-2011a-modeling-platform

[6] https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-technical-support-document-tsd

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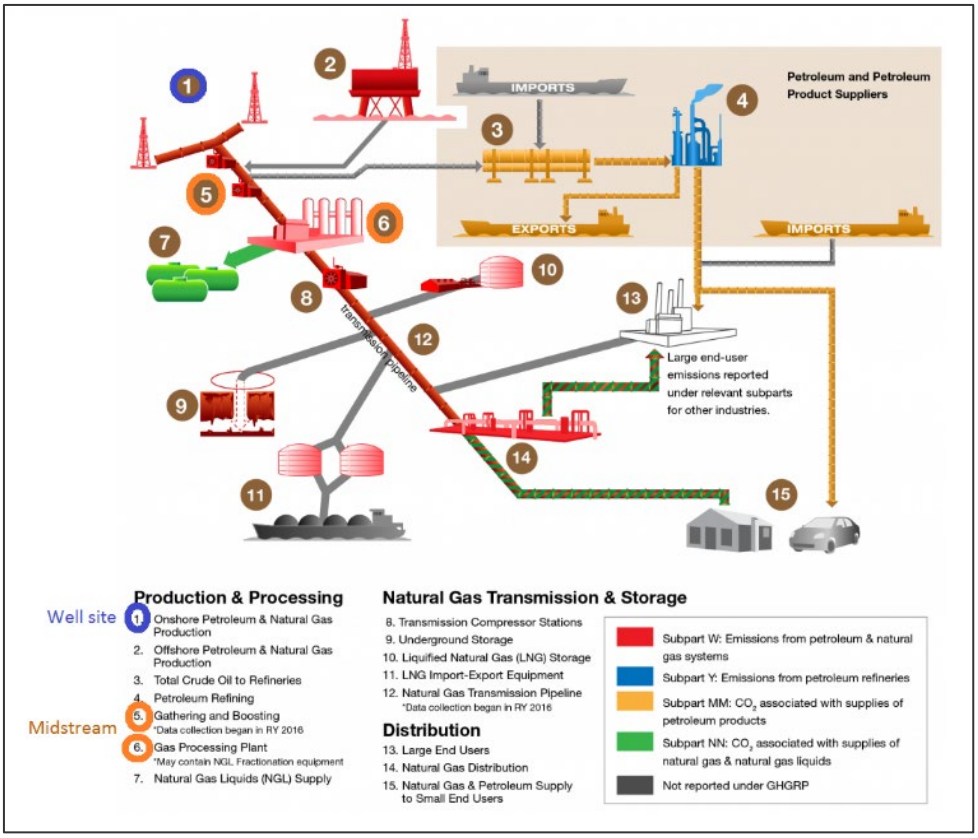


Figure 1-1. Example Petroleum and Natural Gas Industry schematic[7,8].

1.1.2 Geographical Scope

The WESTAR-WRAP region includes 15 states, several of which have substantial O&G production and generate substantial O&G emissions. Figure 1-2 shows major basins in the WESTAR-WRAP region. California O&G emissions are estimated by the California Air Resources Board and are not included herein. Several states have limited or zero O&G production and O&G sector emissions: Arizona, Hawaii, Idaho, Nevada, Oregon, South Dakota, and Washington. Emissions were estimated by county, distinguishing between tribal and non-tribal sources.

[7] Source: https://www.epa.gov/ghgreporting/ghgrp-and-oil-and-gas-industry

[8] This figure shows O&G subsectors for which emissions have been developed in this study. It is important to consider that Petroleum and Natural Gas Industry equipment is typically tailored to meet field, basin, and/or region-specific infrastructure requirements.

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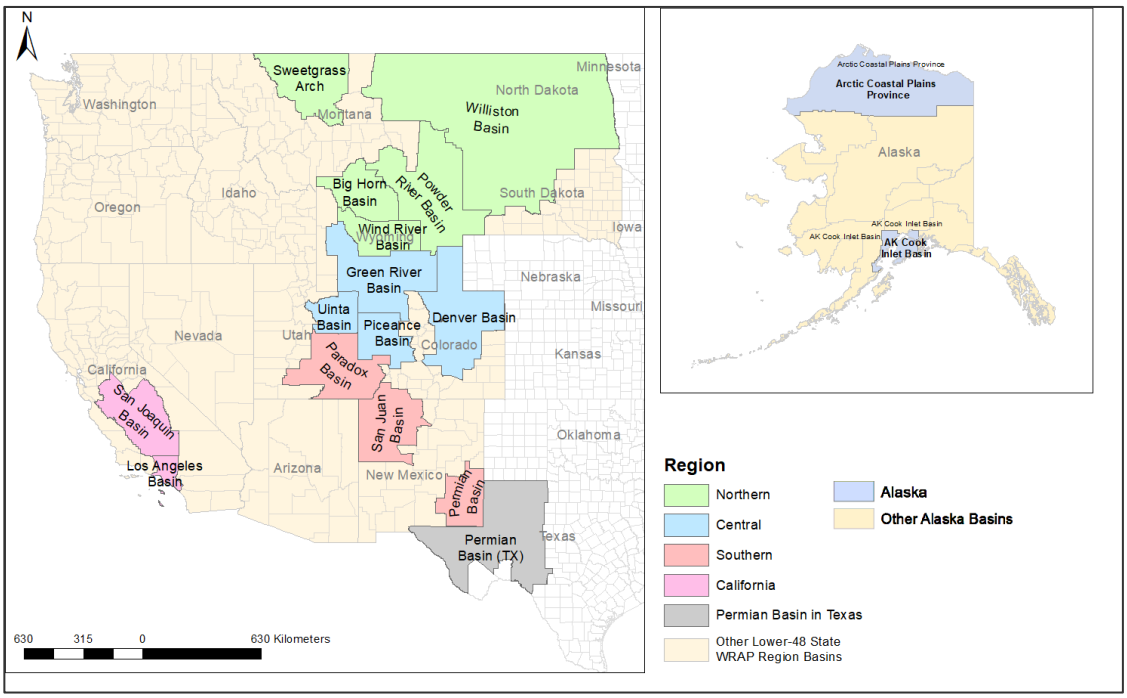


Figure 1-2. WESTAR-WRAP region, including major O&G basins.

1.1.3 Temporal Scope

The baseline emission inventory was developed with annual emissions for the baseline period 2014-2016. Base year 2014 emission inventories that were the basis of the emission inventory compilation were updated, to the extent that data was made available, to include updated 2014-2016 emission inventory inputs provided by regulatory agencies and O&G operators. In general, midstream facility emissions are derived from state and federal agency data for calendar year 2014. Wellsite input factors were developed for activities in calendar year 2014, with updates to input factors as described in Section 2.2. All well count and production data used to develop the emission inventory were obtained from the IHS Enerdeq database for calendar year 2014.

1.1.4 Pollutants

Emissions were estimated for the following pollutants;

- Nitrogen oxide (NOx)
- Volatile organic compounds (VOC)
- Carbon monoxide (CO)
- Particular matter less than 10 microns (PM_{10})
- Particulate matter less than 2.5 microns ($PM_{2.5}$)
- Sulfur oxides (SOx)
- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)

1.2 Well Count and Production Data

Oil and gas related activity data were obtained from the IHS Enerdeq database[9] queried via online interface. The IHS Enerdeq database uses data from each state's Oil and Gas Conservation Commission (OGCC or equivalent) as sources of information for oil and gas activity. This data is also available directly through database querying tools maintained by the respective agencies. It was determined that the IHS database is more accurate and complete than the state databases. The IHS database was also used to develop emission inventories in the WRAP Phase III, WestJump AQMS, and IWDW studies. Therefore, the IHS database was chosen as the basis for O&G activity statistics for this analysis. Two types of data were queried from the Enerdeq database: production data and well data. Production data includes information relevant to producing wells while well data includes information relevant to drilling activity ("spuds") and completions.

Production data were obtained for all counties in the WRAP region as IHS "298" format data files. The "298" well data contain information regarding historical O&G production. The "298"well data were processed with a PERL script to develop a database by American Petroleum Institute (API)-number, well type (oil, gas, or coalbed methane; CBM), spud type (directional, horizontal, or vertical), annual gas production, oil production, and water production with latitude and longitude information.

The API number in the IHS database consists of 14 digits as follows:

- Digits 1 to 2: state identifier
- Digits 3 to 5: county identifier
- Digits 6 to 10: borehole identifier
- Digits 11 to 12: sidetracks
- Digits 13 to 14: event sequence code (recompletions)

Based on the expectation that the first 10 digits, which include geographic and borehole identifiers, would predict unique sets of well head equipment, the unique wells were identified by the first 10 digits of the API number.

Well data were also obtained from the IHS Enerdeq database for all WRAP region states as IHS "297" well data. The "297" well data contain information on spuds and completions. The "297" well data were processed with a PERL script to arrive at a database of by-API-number and spud type, spud and completion dates with latitude and longitude information. Drilling events in 2014 were identified by indication that the spud occurred within 2014. If the well API number indicated the well was a recompletion, it was not counted as a drilling event, but if the API number indicated the well was a sidetrack, it was counted as a drilling event.

O&G activity for the WRAP Region states is summarized in Table 1-1; details by basin, spud type and well types are available in the 2014 O&G activity spreadsheet[10].

[9] All data queried from IHS Enerdeq is subject to copyright protections

[10] https://www.wrapair2.org/pdf/WESTAR_OG_Activity_10Aug2018_distributed.xlsm

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Table 1-1. WESTAR-WRAP region 2014 O&G activity by state.

State	Spud Count	Active Well Count	Gas Production (BCF/yr)	Condensate and Oil Production (MMbbl/yr)
AK	115	2,079	3,157	168
AZ	0	64	<1	<1
CO	2,017	47,756	1,642	95
ID	3	1	<1	0
MT	174	10,515	66	30
ND	2,623	12,706	464	395
NM	1,358	51,140	1,244	125
NV	2	73	<1	<1
OR	0	16	1	0
SD	7	244	15	2
UT	839	13,021	450	41
WA	0	0	0	0
WY	1,044	35,615	1,998	76
Total	**8,182**	**173,230**	**9,038**	**932**

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2.0 METHODOLOGY

To develop the baseline 2014-2016 WESTAR-WRAP region emission inventory, first, base year 2014 emissions were compiled from existing emission inventory sources (described in Section 2.1). Subsequent to compilation of the base year 2014 emission inventory, outreach was conducted to gather additional data from regulatory agencies and upstream O&G operators to enhance the emissions inventory and, to the extent that data was provided, make the inventory applicable to the 2014-2016 baseline period (described in Section 2.2).

2.1 2014 WRAP OGWG Baseline O&G Emission Inventory version 1

Ramboll compiled a WESTAR-WRAP region 2014 base year O&G emission inventory version 1 (also referred to herein as the WRAP OGWG v1 emission inventory)[11] from the following emission inventories:

- 2014 Greater San Juan and Permian Basin Emission Inventory (Grant et al., 2018a)
- 2014 Intermountain West O&G Basin Emission Inventory (Parikh et al., 2017)
- Uinta Basin 2014 Air Agencies Oil and Gas Emissions Inventory (Utah Division of Air Quality [UDAQ], 2017)
- Colorado Department of Health and Environment (CDPHE) Denver Basin Emission Inventory (CDPHE, 2018)
- US Environmental Protection Agency (EPA) 2014 NEI O&G Inventory, version 2 (EPA, 2018)[12]

O&G emissions on tribal land in the above studies included nonpoint emissions which were based on tribe specific emissions only if they were provided directly by a tribe (e.g., Southern Ute Indian Tribe in Grant et al. [2018a]); otherwise, tribal nonpoint emissions were typically estimated by apportioning county-level emissions to tribal and non-tribal land based on O&G activity. For inventories that did not fully distinguish tribal from non-tribal sources, tribal and non-tribal splits were added by allocating emissions according to the fraction of O&G activity surrogates on and off tribal land in each county. Point source emissions on tribal lands consist of Part 71 sources and other minor sources (e.g., sources reported under the Tribal Minor New Source Rule) to the extent that each inventory included those emission sources.

Table 2-1 shows data sources by basin used to compile the version 1 emission inventory.

Table 2-1. Inventory data source by basin.

Basin	State	Reference
Greater San Juan	CO and NM	Grant et al. (2018a)
Permian	NM	Grant et al. (2018a)
Denver	CO	Parikh et al. (2017) and CDPHE (2018)
Uinta	UT	Parikh et al. (2017) and UDAQ (2017)
Piceance	CO	Parikh et al. (2017)
Paradox	CO	

[11] https://www.wrapair2.org/pdf/WESTAR_OGWG_Emissions_Inventory_2014_Webdistribution_081018.xlsx

[12] To extract emissions from the NEI, nonpoint emissions were extracted for all source classification (SCC) codes beginning with "2310". For point sources, O&G emissions were extracted for North American Industry Classification System (NAICS) codes: 2111, 4862, 21111, 48611, 48621, 211111,211112, 213111,213112, 486110, 486210.

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Basin	State	Reference
Raton	CO	
Big Horn	WY and MT	
Powder River	WY and MT	
Green River	WY	
Central Western Overthrust	WY	
Wind River	WY	
Williston	MT, ND and SD	
Sweetgrass Arch	MT	
Central Montana Uplift	MT	
Other Basins	All	EPA (2018)

Emission inventory data gaps were filled to ensure completeness, to the extent feasible according to the following:

- $PM_{2.5}$ emissions were not included in Grant et al. (2018a) and Parikh et al. (2017). $PM_{2.5}$ emissions were assumed equivalent to PM_{10} emissions taken from these reference sources.
- GHG emissions were not available in Parikh et al. (2017). GHG emissions were estimated by multiplying criteria air pollutant emissions for a given source category by a source category specific GHG to criteria air pollutant emissions mass ratio. For venting, fugitive, and tank sources, basin and well type specific GHG to VOC mass ratios available from the EPA O&G Tool were used. AP-42 process specific emission factors from the Greater San Juan and Permian Basin Inventory Study were used to estimate GHG to NOx emission ratios for combustion sources.

2.2 Survey Updates for 2014-2016 baseline inventory

As part of technical improvements to the WESTAR-WRAP O&G emission inventory, a survey data collection effort was used to collect new information to enhance emission inventory accuracy. Survey data collection targeted specific equipment types, production areas, and operators that could substantially enhance the WESTAR-WRAP O&G emission inventory. First, the survey was distributed to state agencies so that in-house agency data could be leveraged prior to asking O&G operators to provide survey data. After state agencies filled out the survey, it was distributed to O&G operators to fill remaining data gaps.

In this section survey results are applicable to baseline emission inventory updates are reported and integration into the baseline year inventory (also referred to herein as the WRAP OGWG v2 emission inventory) is described.

2.2.1 Survey Content

Survey content was decided upon in collaboration with the WRAP OGWG and focused on gathering information on several key O&G emissions source categories. Two surveys were developed, one survey requesting a complete set of inputs for each source category, and a second survey focused only on emission controls practices and technology related inputs. Each

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agency decided whether to distribute the survey to operators and if the operators would fill out the complete or controls-focused survey.

Table 2-2 shows the source categories and associated data requested in the survey. Several tabs in the survey request *representative* O&G equipment configuration and operation data. Survey respondents were instructed to provide *representative* data that, as accurately as feasible, reflects configuration(s) that represent a vast majority of activity in a given basin. The request for representative inputs is consistent with the estimation of upstream O&G emissions as nonpoint sources. Surveyed agencies and operators were also given the option to provide data files with individual configurations, in addition to, or in place of representative data. The O&G survey is available online: complete survey[13] and controls-focused survey[14].

Table 2-2. Survey Content

Source Category	Survey Data Fields
Upstream Exploration	
Drill Rigs	Spud type, well type, representative engine configuration (number, hours per spud, horsepower), engine age distribution, fleet turnover frequency
Hydraulic Fracturing Engines	Spud type, well type, representative engine configuration (number, hours per spud, horsepower), engine age distribution, fleet turnover frequency
Upstream Production	
Condensate Tanks	Spud type, VOC flashing emission rate, control type and prevalence, capture efficiency and basis, inspection type and frequency
Oil Tanks	Spud type, VOC flashing emission rate, control type and prevalence, capture efficiency and basis, inspection type and frequency
Wellhead Engines	Spud type, well type, number of engines per well by function (compressor, artificial lift, etc.), representative engine configuration (number, hours per spud, horsepower), engine age distribution
Gas Composition	
Produced Gas	Extended gas composition by spud type and/or well type.
Flash Gas Composition	Extended gas composition by spud type and/or well type

2.2.2 Survey Distribution and Collection

The survey was first provided to WRAP OGWG member state agencies. State agencies reviewed the survey and, if available, provided in-house agency data responses. State agencies determined whether they would distribute the survey to operators, and if so, whether to distribute the complete or controls-focused survey. Subsequently, the survey was distributed by agencies to select operators. Operators were responsible for contacting their drilling, hydraulic fracturing, etc. contractors to obtain relevant survey data.

[13] https://www.wrapair2.org/pdf/WRAP_OGWG_Survey_SelectSrc_08Jan2019.xlsx

[14] https://www.wrapair2.org/pdf/WRAP_OGWG_Survey_ControlsOnly_08Jan2019.xlsx

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Survey distribution to operators, including supplemental outreach and operator activity data is described below.

1. Ramboll distributed the following materials to each WRAP OGWG state agency member:
    a. Survey form
    b. High priority operator list ranked by oil and gas (O&G) activity/ownership for each basin
    c. Recommendations for survey collection and distribution
    d. Survey cover letter template for agency survey distribution
2. Member state agency gathered survey data. Ramboll staff answered technical questions about the survey.
    a. Each agency gathered survey data from internal agency sources and/or external sources such as O&G exploration and production companies.
    b. If the agency chose to distribute the survey to O&G companies, the survey was distributed to the high priority operators chosen by the agency.
    c. Each agency performed follow-up with operators the agency designated to fill out the survey to ensure that surveys were completed and submitted prior to the survey due date.

The type of survey distributed and the basins for which surveys were distributed is shown in Table 2-3.

Table 2-3. Operator survey distribution

State	Distributing Agency	Basin	Survey Type
Montana	MTDEQ	Big Horn	Complete
		Central Montana Uplift	Complete
		Powder River	Complete
		Sweetgrass Arch	Complete
		Williston	Complete
New Mexico	NMED	Permian	Complete
		San Juan	Complete
North Dakota	NDDOH	Williston	Complete
Wyoming	WYDEQ	Denver	Controls-focused
		Green River	Controls-focused
		Powder River	Controls-focused

2.2.3 Survey Collection

Several agencies provided data for specific O&G basins in response to the survey as indicated below.

- **Alaska** (Arctic Coastal Plains Province and Cook Inlet Basin): Baseline emission inventory updates.
- **Colorado** (Denver Basin): 2017 emission inventory. A*pplicable to future year emission inventory controls.*

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- **Montana** (Central Montana Uplift, Sweetgrass Arch, and Williston Basin): Gas compositions.
- **Wyoming** (Denver Basin, Green River Basin, and Powder River Basin): 2014 and 2017 detailed operator submissions to be used in the estimation of future year control factors. A*pplicable to future year emission inventory controls.*
- **Utah** (Uinta Basin): Engine age distributions to be used in the estimation of future year control factors. A*pplicable to future year emission inventory controls*

A total of 42 operators surveys were collected, with the largest number of surveys (17) collected in the Williston Basin in North Dakota (see Table 2-4). Operator survey results are documented below.

Table 2-4. Returned operator surveys.

State	Basin	No. of Returned Surveys	Percent of 2014 Basin-wide Activity Represented by Returned Surveys		
			Well Count	Oil Production	Gas Production
Montana	Big Horn	1	5%	0%	6%
	Central Montana Uplift	2	62%	5%	85%
	Powder River	1	23%	91%	90%
	Sweetgrass Arch	2	23%	19%	53%
	Williston	6	25%	64%	31%
New Mexico	Permian	4	66%	80%	86%
	San Juan	0	-	-	-
North Dakota	Williston	17	11%	25%	26%
Wyoming [a]	Denver	1	18%	46%	52%
	Green River	4	46%	51%	53%
	Powder River	4	4%	34%	13%

[a] Control-focused survey, not applicable to baseline emission inventory improvements.

2.2.4 Operator Survey-Based Emission Inventory Updates

In this section operator survey results applicable to baseline emission inventory updates are reported and integration into the baseline year inventory is described. Table 2-5 shows, by basin, the categories for which operators submitted survey data. Emission inventory updates based on operator survey data are limited to the basins and source categories listed in Table 2-5.

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Table 2-5. Categories for which survey data applicable to baseline inventory updates was submitted.

Source Category	Big Horn Basin	Central Montana Uplift	Sweetgrass Arch	Powder River Basin	Permian Basin	Williston Basin	
	MT	MT	MT	MT	NM	MT	ND
Drilling	-	-	-	-	×	×	×
Hydraulic Fracturing	-	-	-	-	×	×	×
Tanks	×	×	×	×	×	×	×
Wellhead Engines	×	×	×	×	×	×	×
Gas Compositions	×	×	×	×	×	×	×

For basins in which survey-based operator data was available for only one operator, if the operator represented greater than 10% of the O&G activity metric associated with a given source category, representative input factors were developed by assuming that the remaining O&G activity in the basin would have input factors equivalent to those used in the development of the WRAP OGWG v1 emission inventory. If the operator represented less than 10% of the O&G activity metric, a representative factor was not developed to preserve the confidentiality of a single operator's data.

2.2.4.1 Drill Rigs

Updated drill rig inputs were developed for the Permian Basin, Williston Basin in Montana, and Williston Basin in North Dakota (see Table A1). Rig activity per spud, estimated as total horsepower-hours (i.e., the product of number of engines, rated horsepower per engine, and hours per spud) decreased for each basin by 20%-53% relative to current inventory estimates. Permian Basin drill rigs were comprised of a substantial fraction of Tier 4 engines and Williston Basin drill rigs were comprised almost exclusively of Tier 2 engines. For operators that indicated use of Tier 4 engines, those engines were described as "generators". Therefore, Tier 4 drill rig engines were assumed to meet stringent generator-set emission standards. The baseline emission inventory was updated to be based on the drill rig configuration inputs in Table A1 for the indicated basins.

Table 2-6 shows the basis of drill rig emissions for basins in which survey-based input factors were developed. Survey-based emission rates per spud were developed based on survey-based factors in Table A1 and multiplied by the number of horizontal spuds in each county in applicable basins to estimate emissions. These emissions replaced estimates of drill rig emissions from horizontal spuds in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of spuds in each county on non-tribal and tribal land.

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Table 2-6. Emission inventory basis for basins with drill rig survey data.

Basin	Horizontal [b]		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Permian	Survey-based factors	[a]	OGWG v1	[a]
Williston (MT)	Survey-based factors		OGWG v1	
Williston (ND)	Survey-based factors		OGWG v1	

[a] not applicable, no tribal activity

[b] horizontal input factors were applied to directional wells

2.2.4.2 Hydraulic Fracturing Engines

Updated hydraulic fracturing engine inputs were developed for the Permian Basin and Williston Basin in North Dakota (see Table A2). Fracturing engine activity per spud, estimated as total horsepower-hours (i.e., the product of number of engines, rated horsepower per engine, and hours per spud) increased substantially compared to current inventory estimates; Permian Basin total horsepower-hours increased by approximately 8 times and Williston Basin increased by approximately 27 times. Horsepower-hour increases are being driven by more intensive hydraulic fracturing activities at horizontal wells than assumed for previous inventories. Emission rates also changed substantially from previous estimates, with substantial use of Tier 4 engines in both the Williston and Basin Permian Basin and use of both natural gas turbine and electrified engine configurations in addition to diesel engine configurations in the Permian Basin. Based on input from several operators, hydraulic fracturing pump arrays that use Tier 4 diesel engines are configured to use generator-sets. Therefore, Tier 4 engines in hydraulic fracturing pump arrays were assumed to meet stringent Tier 4 generator-set standards. Other, less prevalent engines with smaller rated-power per engine such as light plants or blenders were assumed to meet Tier 4 interim standards.

Table 2-7 shows the basis of hydraulic fracturing engine emissions for basins in which survey-based input factors were developed. Survey-based emission rates per fracturing event were developed based on survey-based factors in Table A2 and multiplied by the number of horizontal spuds in each county in applicable basins to estimate emissions; one hydraulic fracturing event was assumed per spud. These emissions replaced estimates of hydraulic fracturing engine emissions from horizontal wells in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of spuds in each county on non-tribal and tribal land.

Table 2-7. Emission inventory basis for basins with hydraulic fracturing engine survey data.

Basin	Horizontal [b]		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Permian	Survey-based factors	[a]	OGWG v1	[a]
Williston (ND & MT)	Survey-based factors		OGWG v1	

[a] not applicable, no tribal activity

[b] horizontal input factors were applied to directional wells

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2.2.4.3 Tanks

Oil Tanks

Updated oil tank inputs were developed for several O&G basins (see Table A3). There are substantial differences in oil tank input factors compared to input factors in the current inventory. For example, the fraction of uncontrolled tanks changed from 73% to 19% for the Permian Basin, from 14% to 1% for the Powder River Basin, from 17% to < 1% for horizontal and vertical wells in the Williston Basin. Decreases in the prevalence of uncontrolled tanks indicates that a higher fraction of tanks are being controlled to comply with regulations such as EPA New Source Performance Standard (NSPS) Subpart OOOO. Uncontrolled VOC flash emission factors decreased for several basins. For example, uncontrolled VOC flash emission factors decreased by 16% and 61% for oil tanks in the Williston Basin, in Montana and North Dakota, respectively. Flash emission factor decreases may result from factors such as better sampling and/or the use of more site specific information in E&P Tank model runs and/or process simulation software in the submitted surveys compared to previously compiled emission inventory inputs.

Table 2-8 shows the basis of oil tank emissions for basins in which survey-based input factors were developed. Survey-based emission rates per barrel of oil produced were developed based on survey-based factors in Table A3 and multiplied by the amount oil production from horizontal or vertical wells in each county in applicable basins to estimate emissions. These emissions replaced estimates of oil tank emissions from horizontal wells and vertical wells in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of oil production in each county from wells on non-tribal and tribal land.

Table 2-8. Emission inventory basis for basins with oil tank survey data.

Basin	Horizontal [b]		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Central Montana Uplift	OGWG v1		Survey-based factors	
Permian	Survey-based factors	[a]	OGWG v1	[a]
Powder River (MT)	OGWG v1		Survey-based factors	
Sweetgrass Arch	OGWG v1		Survey-based factors	
Williston (MT)	Survey-based factors			
Williston (ND)	Survey-based factors			

[a] not applicable, no tribal activity

[b] horizontal input factors were applied to directional wells

Condensate Tanks

Updated condensate tank inputs were developed for the Sweetgrass Arch and Williston Basin in North Dakota and Montana (see Table A4). The fraction of uncontrolled tanks increased from 31% to 100% in the Sweetgrass Arch Basin and decreased from 8% to 4% and 8% to 1% in the Williston Basin, in Montana and North Dakota, respectively.

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Table 2-9 shows the basis of condensate tank emissions for basins in which survey-based input factors were developed. Survey-based emission rates per barrel of condensate produced were developed based on survey-based factors in Table A4 and multiplied by the amount oil production from horizontal or vertical wells in each county in applicable basins to estimate emissions. These emissions replaced estimates of condensate tank emissions from horizontal wells and vertical wells in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of condensate production in each county from wells on non-tribal and tribal land.

Table 2-9. Emission inventory basis for basins with condensate tank survey data.

Basin	Horizontal [b]		Vertical	
	Non-tribal	Tribal	Non-tribal	Tribal
Sweetgrass Arch	OGWG v1		Survey-based factors	
Williston (MT)	Survey-based factors		OGWG v1	
Williston (ND)	Survey-based factors		OGWG v1	

[a] not applicable, no tribal activity

[b] horizontal input factors were applied to directional wells

Capture Efficiency

For tanks with emission controls, capture efficiency represents the percent of uncontrolled emissions that are controlled by the control device. Open thief hatches result in uncontrolled fugitive tank emissions. Across all returned operator surveys, 20 condensate tank configurations and 51 oil tank configurations were submitted. 75% of condensate tank configuration and 57% of oil tank configuration responses included a response to the thief hatch status (summarized in Table 2-10). The overall average percent of thief hatches open was 2.8% for condensate tanks and 3.0% for oil tanks.

Table 2-10. Open thief hatch survey response summary.

Operator Response	Survey Field: Percentage of Tanks Observed with Thief Hatches Open	Average Percentage of Tanks Observed with Thief Hatches Open
	Number of Responses	
Condensate Tanks		
No Response / Not available	5	2.8%
Zero	7	
Minimal	3	
Non-zero Value	5	
Oil Tanks		
No Response / Not tracked	29	3.0%
Zero	9	
Minimal	1	
Non-zero Value	12	

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Assuming that a tank with an open thief hatch emits VOCs at the uncontrolled tank VOC emission rate, a capture efficiency of 97% (i.e., 3% of tank emissions are not routed to the flare) would result in emissions that are 2.5 times higher for a 98% efficient control device and 1.6 times higher for 95% efficient control device (see Figure 2-1).

More study is needed to (1) develop robust capture efficiency estimates and (2) estimate VOC emission magnitude when a thief hatch is open; the increases in emissions estimated in Figure 2-1 are screening level estimates.

At this time, sufficient information is not available to extrapolate the average capture efficiency shown in Table 2-10 across the WESTAR-WRAP region. Variation in capture efficiency by production type and geography is not available. Therefore, capture efficiency is assumed to be 100%, consistent with previous inventories.

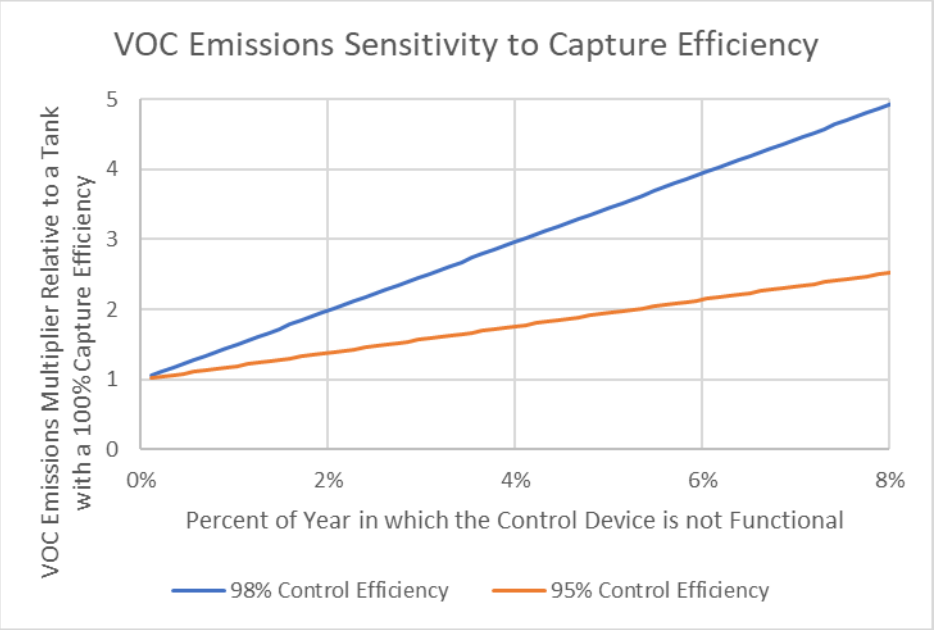


Figure 2-1. Tank VOC emissions sensitivity to capture efficiency.

2.2.4.4 Wellhead Engines

Updated wellhead configurations were developed for the basin and engine types listed below and are included in Table A5.

- **Sweetgrass Arch Wellhead Compressors Engines:** WRAP OGWG v1 input factors indicated zero activity from this source category. Operator submitted survey data indicated substantial use of wellhead compressors in this basin.
- **Bighorn Basin Lateral Compressor Engines:** Survey-based input factors are similar to WRAP OGWG v1 input factors.
- **Central Montana Uplift Lateral Compressor Engines:** Survey-based input factors include lower annual activity and higher prevalence compared to WRAP OGWG v1 input factors.

- **Williston Basin Artificial Lift Engines:** Survey-based input factors were developed by horizontal and vertical spud types for Montana and North Dakota. For each spud type and state, the survey-based input factors showed substantially higher electrification compared to the WRAP OGWG v1 input factors.
- **Permian Basin Artificial Lift Engines:** Survey-based input factors were developed by horizontal spud type for New Mexico. Survey-based input factors showed lower prevalence and electrification and higher average engine rated-power compared to the WRAP OGWG v1 input factors.
- **Williston Basin Generators**: Survey-based input factors were developed for generators operating at horizontal oil wells. Wellhead generators were not included in the WRAP OGWG v1 emission inventory. 11% of horizontal oil wells are estimated to have a generator.

Table 2-11 shows the basis of wellhead engine emissions for basins in which survey-based input factors were developed. Survey-based emission rates per active well were developed based on survey-based factors in Table A5 and multiplied by the number of active horizontal oil, horizontal gas, vertical oil, or vertical gas wells in each county in applicable basins to estimate emissions. These emissions replaced estimates of wellhead engine emissions in the WRAP OGWG v1 emission inventory. County-level emissions were apportioned to non-tribal and tribal land according the fraction of active wells in each county from wells on non-tribal and tribal land.

Table 2-11. Emission inventory basis for basins with wellhead engine survey data.

Basin	Engine Type	Well Type	Horizontal [b]		Vertical	
			Non-tribal	Tribal	Non-tribal	Tribal
Sweetgrass Arch	Wellhead Compressors	Gas	OGWG v1		Survey-based factors	
Bighorn Basin	Lateral Compressor	Gas	OGWG v1		Survey-based factors	
Central Montana Uplift	Lateral Compressor	Gas	OGWG v1		Survey-based factors	
Williston Basin (ND & MT)	Artificial Lift	Oil	Survey-based factors			
Permian Basin	Artificial Lift	Oil	Survey-based factors		OGWG v1	
Williston Basin (ND & MT)	Generators	Oil	Survey-based factors		[c]	

[a] not applicable, no tribal activity

[b] horizontal input factors were applied to directional wells

[c] not applicable, generator engine inputs are not available for vertical wells in the survey or WRAP OGWG v1. No emissions are estimated for this engine type at vertical wells.

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2.2.4.5 Emission Changes Resulting from Integration of Operator Survey Data

NOx emissions increased by 8% over the WESTAR-WRAP region based on integration of operator survey data into the inventory (see Table 2-12). Hydraulic fracturing engine emissions accounted for 47% of NOx emission increases. Operator surveys indicated the use of pump engine arrays with more engines and more operational hours than previous inventories. Emissions from artificial lift engines accounted for 38% of NOx emissions increases. Operator surveys indicated the use of artificial life engines with higher rated power than assumed in previous inventories. Emissions from drill rig emissions accounted for close to 100% of NOx emission decreases as a result of lower overall combined activity in horsepower-hours relative to previous inventories.

Table 2-12. NOx Emission Changes Resulting from Integration of Operator Survey Data.

Basin	Source Category	NOx (tpy)
Williston , ND	Hydraulic Fracturing Engines	18,369
Williston , ND	Artificial Lift Engines	11,894
Williston , ND	Generator Engines	2,848
Permian , NM	Artificial Lift Engines	2,800
Sweetgrass , MT	Nonpoint Compressor Engines	1,789
Williston , MT	Artificial Lift Engines	1,404
Williston , ND	Oil Tanks	823
Williston , MT	Hydraulic Fracturing Engines	743
Permian , NM	Hydraulic Fracturing Engines	742
Williston , MT	Generator Engines	437
Central Montana Uplift , MT	Nonpoint Compressor Engines	226
Permian , NM	Oil Tank Flaring	54
Williston , ND	Condensate Tanks	17
Big Horn , MT	Nonpoint Compressor Engines	9
Williston , MT	Condensate Tanks	1
Williston , ND	Drill Rigs	-15,610
Williston , MT	Drill Rigs	-1,258
Permian , NM	Drill Rigs	-943
Williston , MT	Oil Tanks	-18
Powder River , MT	Oil Tanks	-1
Sweetgrass , MT	Oil Tanks	0
Central Montana Uplift , MT	Oil Tanks	0
Sweetgrass , MT	Condensate Tanks	0
Total Change		**24,325**
Percent Change		**8%**

VOC emissions decreased by 22% over the WESTAR-WRAP region based on integration of operator survey data into the inventory (see Table 2-13). VOC emission increases were small compared to VOC emission decreases. Emissions from oil tanks accounted for close to 100% of VOC emission decreases as a results of higher emission control prevalence.

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Table 2-13. VOC Emission Changes Resulting from Integration of Operator Survey Data.

Basin	Source Category	VOC (tpy)
Permian , NM	Artificial Lift Engines	2,224
Williston , ND	Hydraulic Fracturing Engines	1,450
Williston , ND	Artificial Lift Engines	957
Sweetgrass , MT	Oil Tanks	535
Williston , ND	Condensate Tanks	485
Williston , ND	Generator Engines	417
Permian , NM	Drill Rigs	325
Permian , NM	Hydraulic Fracturing Engines	175
Williston , MT	Artificial Lift Engines	139
Central Montana Uplift , MT	Oil Tanks	104
Williston , MT	Generator Engines	64
Williston , MT	Hydraulic Fracturing Engines	58
Sweetgrass , MT	Nonpoint Compressor Engines	33
Sweetgrass , MT	Condensate Tanks	32
Williston , MT	Condensate Tanks	20
Powder River , MT	Oil Tanks	5
Big Horn , MT	Nonpoint Compressor Engines	0
Williston , ND	Oil Tanks	-282,784
Permian , NM	Oil Tank	-28,623
Williston , MT	Oil Tanks	-16,190
Williston , ND	Drill Rigs	-1,033
Williston , MT	Drill Rigs	-81
Central Montana Uplift , MT	Nonpoint Compressor Engines	-2
Total Change		**-321,690**
Percent Change		**-22%**

2.2.5 Agency Survey-Based Emission Inventory Updates

The 2014 NEI v2 was the sole basis of Alaska O&G emissions in the WRAP OGWG v1 emission inventory. Alaska Department of Environmental Conservation (ADEC) noted that emissions from several facilities emitting below Title V thresholds were not included in the 2014 NEI v2. ADEC provided emissions for these sources (see Table 2-14) were added to the WRAP OGWG v2 emission inventory.

Table 2-14. Alaska O&G emissions from small nonpoint sources.

Facility	Emissions (tons/year)					
	NOx	VOC	CO	SO_2	PM_{10}	$PM_{2.5}$
Greater Prudhoe Bay Skid 50 Pad Transfer Station	39	[a]	[a]	39	[a]	[a]
Peak Base Shop, Peak Wellex, and Nabors Base Camp Facilities	56	18	44	5.3	11	[a]
Milne Point S Pad (CHOPS)	37	<1	14	11	<1	[a]
Alpine Satellite Drill Pad CD5	93	88	60	23	5	[a]
Arctic Wolf Camp	39	[a]	[a]	[a]	[a]	[a]
24 Man Skid Camp	41	[a]	[a]	[a]	[a]	[a]
Mustang Oil Field Development	186	110	216	9	7	7
Paxton Production Facility	57	29	50	<1	1	1
Gudenrath Compressor Station	76	<1	26	1	2	2
Baker Platform	88	10	28	11	6	[a]
NNA Grind and Inject Operation	86	[a]	[a]	[a]	[a]	[a]
Kenai Gas Field Pad 41-18	42	[a]	44	53	[a]	[a]
Cook Inlet Exploratory Drilling Program- Bluecrest / Buccaneer	17	8	49	5	4	[a]
Cosmopolitan Project - Bluecrest	64	62	94	35	12	[a]
Cosmopolitan Project - Buccaneer	21	25	59	12	4	[a]

[a] Emissions not included in reference dataset and were set to zero in WRAP OGWG v2 inventory

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3.0 SUMMARY RESULTS

O&G emissions results for the baseline 2014-2016 WRAP OGWG v2 emission inventory for the WESTAR-WRAP region are presented below as a series of tables and charts. Additional summaries and fully detailed emission inventory data are available in spreadsheets that accompany this report which are posted on the WRAP OGWG website (https://www.wrapair2.org/OGWG.aspx).

3.1 2014-2016 WRAP OGWG v2 emission inventory

2014-2016 WRAP OGWG v2 NOx and VOC emissions for all WRAP region basins are summarized in Table 3-1 and Table 3-2 respectively. Across the WESTAR-WRAP region, most nonpoint O&G emissions are emitted from wellsite sources and point O&G emission are emitted from midstream sources. Approximately 58% of 2014 NOx emissions and over 85% of 2014 VOC emissions were from nonpoint sources. Basin specific nonpoint and point source contributions result from basin specific equipment and operational characteristics and infrastructure, and in some cases basin specific accounting. For example, the Uinta Basin includes several wellsite source categories in the point source emission inventory. The top-seven emitting bases account for approximately 75% of NOx emissions and the top-five basin and state combinations account for over 80% of VOC emissions.

Table 3-1. Summary of nonpoint and point NOx emissions (tons/yr) by basin.

Basin and State	NOx Emissions (tons/yr)		
	Nonpoint	Point	Total
Williston, ND	55,003	2,703	57,706
San Juan, NM	33,436	11,294	44,730
Arctic Coastal Plains Province, AK	1,384	34,348	35,732
Permian, NM	14,442	18,561	33,004
Powder River, WY	24,508	5,017	29,525
Denver, CO	16,750	8,155	24,905
Piceance, CO	5,824	9,571	15,395
San Juan, CO	11,842	3,417	15,259
Uinta, UT	886	14,161	15,047
Green River, WY	5,430	5,408	10,838
Raton, CO	79	6,881	6,959
AK Cook Inlet Basin, AK	1,853	4,664	6,517
Williston, MT	4,930	482	5,412
Big Horn, WY	972	1,501	2,473
Sweetgrass Arch, MT	2,128	313	2,441
Denver Basin noCO, WY	1,733	33	1,766
Las Animas Arch, CO	420	1,252	1,671
Wind River, WY	235	1,334	1,569
Plateau Sedimentary Prov, AZ	-	1,468	1,468
Paradox, UT	923	300	1,123
Other WRAP Basins	1,218	7,474	8,692
Total	**183,995**	**138,337**	**322,333**

Table 3-2. Summary of nonpoint and point VOC emissions (tons/yr) by Basin.

Basin and State	VOC Emissions (tons/yr)		
	Nonpoint	Point	Total
Williston, ND	196,696	962	197,658
Powder River, WY	172,453	4,658	177,112
Denver, CO	159,112	6,704	165,817
Permian, NM	86,633	11,164	97,796
Uinta, UT	9,212	85,077	94,290
San Juan, NM	79,743	6,824	86,567
Green River, WY	62,626	11,306	73,932
Williston, MT	26,977	705	27,682
Arctic Coastal Plains Province, AK	21,278	672	21,949
Paradox, UT	17,422	48	17,471
Piceance, CO	3,114	11,620	14,734
Wind River, WY	6,601	1,424	8,025
Sweetgrass Arch, MT	5,277	103	5,380
AK Cook Inlet Basin, AK	4,712	650	5,362
Big Horn, WY	3,523	513	4,036
San Juan, CO	2,176	1,701	3,877
Other WRAP Basins	9,763	4,659	14,421
Total	**867,318**	**148,791**	**1,016,110**

Figure 3-1 and Figure 3-2 show NOx and VOC nonpoint emissions contributions, respectively, for basin and state combinations with the largest nonpoint emission contributions.

The largest source of nonpoint NOx emissions are hydraulic fracturing engines, wellhead engines, process heaters, and drill rigs. Wellhead engines (including artificial lift engines, wellhead and lateral compressor engines, generators and other miscellaneous engines) are the largest contributor to nonpoint NOx emissions in the San Juan Basin (NM; 90%), San Juan Basin (CO; 95%), and Permian Basin (NM; 52%). Hydraulic fracturing engines are the largest contributor to NOx emissions for the Williston Basin (ND; 43%) and Powder River Basin (WY; 81%). Drill rigs are the largest contributor to NOx emissions for the Denver Basin (CO; 32%) and Piceance Basin (CO; 40%).

The largest nonpoint VOC emissions sources vary by basin. In the Williston Basin (ND), casinghead gas accounts for 50% of VOC emissions. In the Powder River Basin (WY), hydraulic fracturing and completion activities account for 91% of VOC emissions. In the Denver Basin (CO), condensate tanks account for 76% of VOC emissions. In the Permian Basin (NM), oil tanks account for 45% of VOC emissions. In the San Juan Basin (NM), pneumatic devices account for 32% of VOC emissions.

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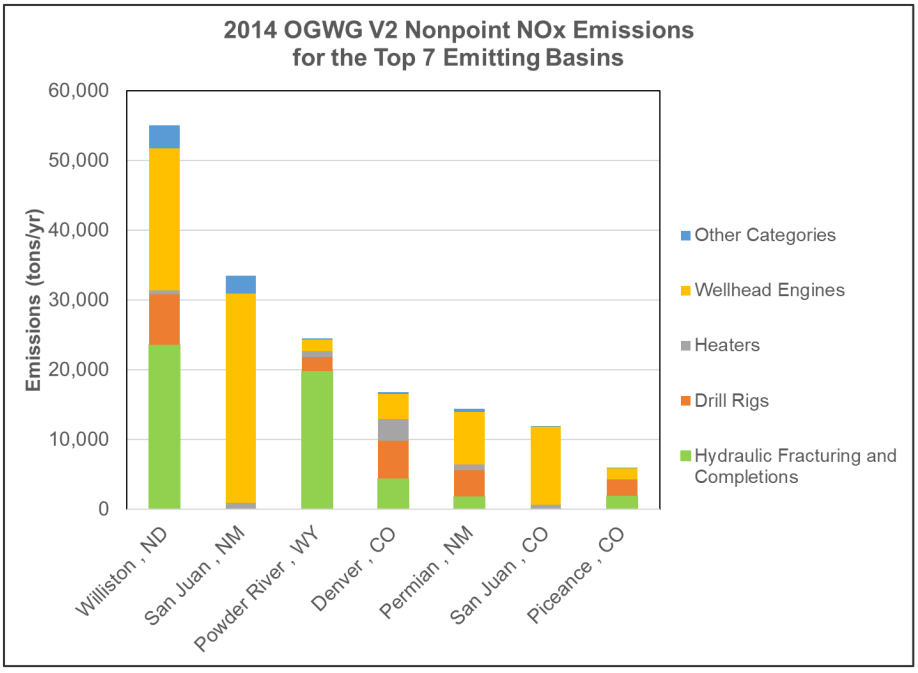


Figure 3-1. 2014 OGWG V2 nonpoint NOx emissions (tons/yr) contribution by source category for top 7 highest emitting basins.

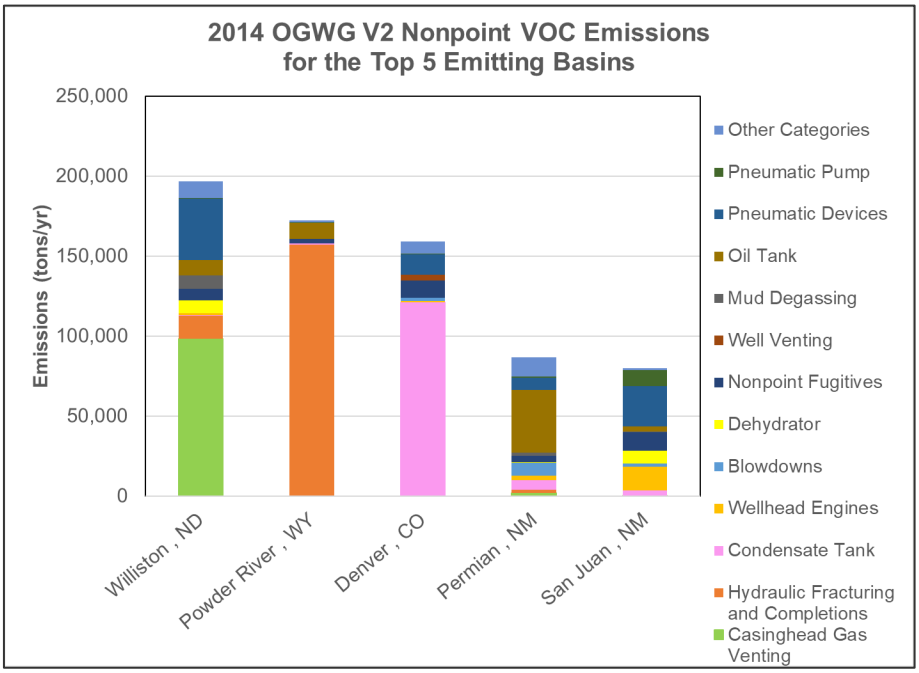


Figure 3-2. 2014 OGWG V2 nonpoint VOC emissions (tons/yr) contribution by source category for top 5 highest emitting basins.

3.1.1 2014-2016 Baseline Comparison to 2014 Emission Inventories

Changes from the 2014 NEI v2 to the 2014 base year WRAP OGWG v1 to the 2014-2016 baseline WRAP OGWG v2 are shown below for NOx (Figure 3-3) and VOC (Figure 3-4).

Changes from 2014 NEI v2 to the WRAP OGWG v1 inventory are based on state supplied emission inventory updates (e.g., Colorado condensate tanks and Uinta Basin 2014 Air Agencies Oil and Gas Emissions Inventory); differences between NEI v2 emissions and the 2014 IWDW emission inventory that was the basis of WRAP OGWG v1 emission inventory for several states (e.g., Wyoming, Colorado); and for the Greater San Juan (Colorado and New Mexico) and Permian Basin (New Mexico), differences between Grant et al. (2018a) and the EPA NEI v2. WESTAR-WRAP region-wide emission increased by 16% for NOx and 14% for VOC from 2014 NEI v2 to 2014 base year WRAP OGWG v2.

Changes from the WRAP OGWG v1 to the WRAP OGWG v2 emission inventory are based on updates per agency and operator survey responses. WESTAR-WRAP region-wide NOx emissions increased by 9% and VOC decreased by 22%. NOx emission increases for North Dakota, Montana, and New Mexico resulting from survey-based updates were the primary cause of WESTAR-WRAP region-wide NOx emission increases. VOC emission decreases for North Dakota, Montana, and New Mexico resulting from survey-based updates were the primary cause of WESTAR-WRAP region-wide VOC emission decreases.

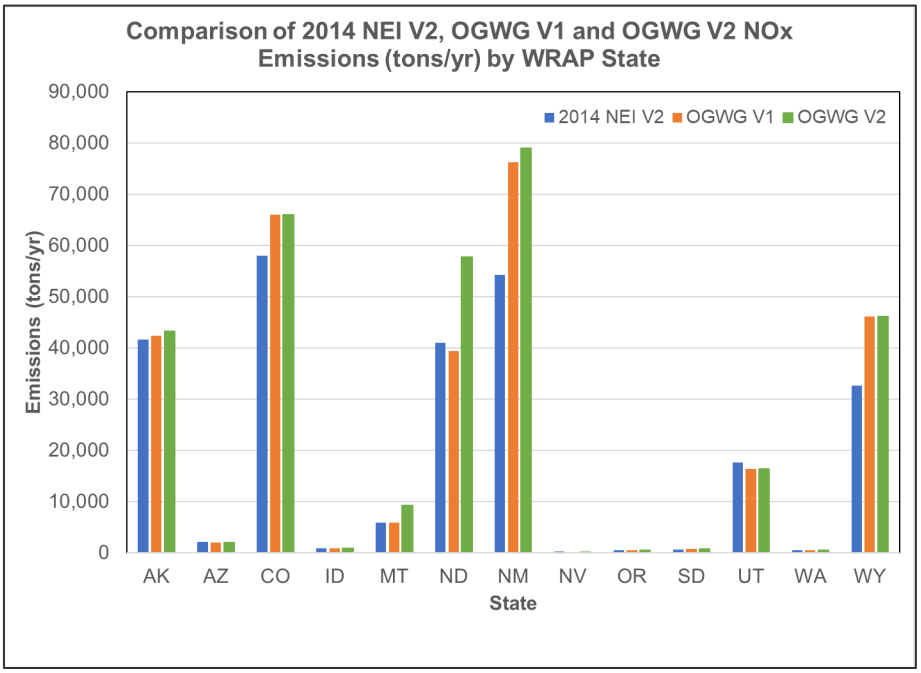


Figure 3-3. Comparison of 2014 NEI, OGWG V1 and OGWG V2 NOx emissions by WRAP region State.

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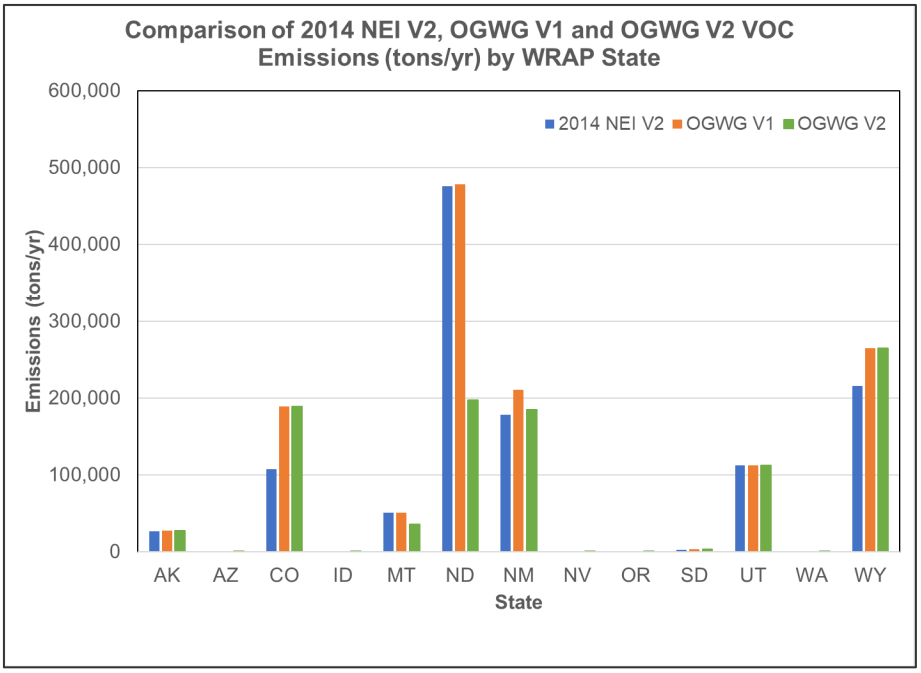


Figure 3-4. Comparison of 2014 NEI, OGWG V1 and OGWG V2 VOC emissions by WRAP region State.

3.1.2 2008, 2011, 2014-2016 baseline summaries

Figure 3-5 and Figure 3-6 show emission trends for WESTAR-WRAP basins which were included in the WestJUMP AQMS [15] and/or WAQS [16]. The geographical extent of each basin is not always the same across these inventories, however, core O&G activity counties in each basin generally did not change across inventories.

Substantial NOx emission increases from the 2008 to 2014-2016 inventory are noted for several basins, although emission increases appear to be moderated for several basins by lower emissions per unit of production based on regulatory controls and/or infrastructure configurations. Denver Basin NOx emission increases of 20% and VOC increases of 66% from 2008 to 2014-2016 are substantially less than the Colorado-wide 287% oil production increase from 2008 to 2016. Permian Basin NOx emission increases of 34% and VOC decreases of 24% from 2008 to 2014-2016 are substantially less than the New Mexico-wide 143% oil production increase from 2008 to 2016. Williston Basin NOx emission increases of 117% and VOC decreases of 23% from 2011 to 2014-2016 are less than the North Dakota-wide oil production increases of 148% from 2011 to 2016. Increases in San Juan Basin NOx (25%) and VOC (60%) emissions from 2011 to 2014-2016 are due primarily to updated emission inventory inputs and methodology in the 2014 Greater San Juan Basin emission inventory study (Grant et al. [2018a]). Changes in Uinta Basin emissions are expected to result from both oil and gas production changes and changes to emission inventory compilation methodology in the most recent Utah Agencies Uinta Basin emission inventory.

[15] https://www.wrapair2.org/westjumpaqms.aspx
[16] http://views.cira.colostate.edu/wiki/#WAQS

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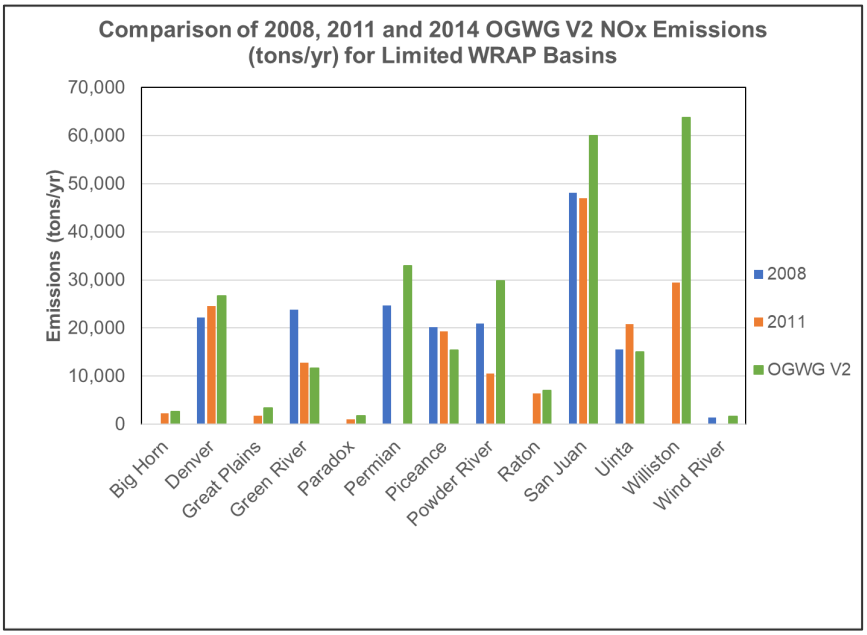


Figure 3-5. Comparison of 2008, 2011 and 2014 OGWG V2 NOx emissions (tons/yr) for limited WRAP Basins[17,18,19].

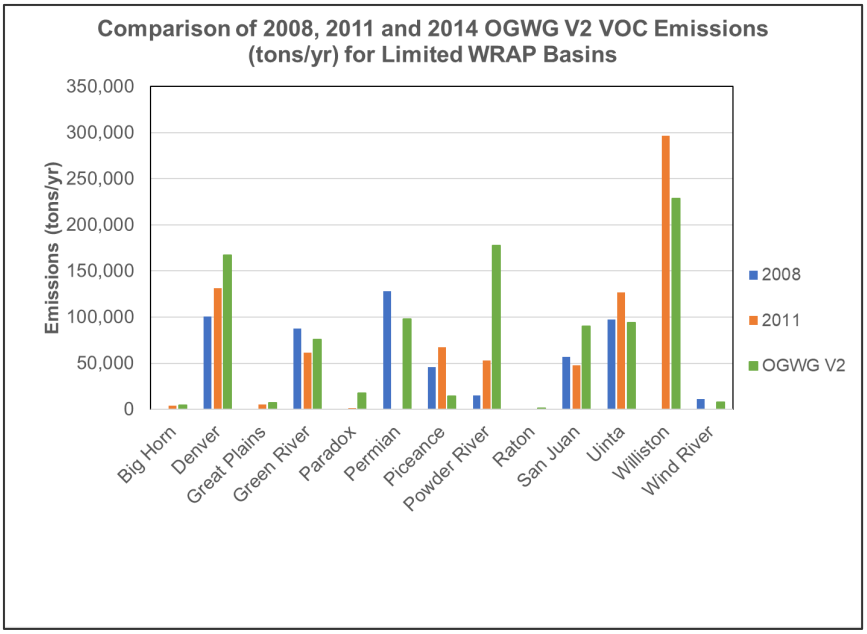


Figure 3-6. Comparison of 2008, 2011 and 2014 OGWG V2 VOC emissions (tons/yr) for limited WRAP Basins[17,18,19].

[17] Emissions for some basins are not available for 2008 or 2011.

[18] Paradox and Raton 2011 emissions are limited to permitted sources.

[19] Great Plains includes emissions for Sweetgrass arch and Central Montana Uplift basins.

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4.0 REFERENCES

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Appendix A

Survey-based Input Factors Updates for the Baseline Emission Inventory

Table A1. Baseline Emission Inventory Inputs: Drill Rigs.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Permian Basin (NM)		
Fraction of Spuds Represented	21%	not applicable
Spud Type	Horizontal	Horizontal
Well Type	Oil	Oil
Fuel Type	Diesel	Diesel
Number of Engine Per Rig (number/rig)	5	8
Rated Horsepower (hp/engine)	1477	825
Hours of Operation (hours/spud)	546	768
Percent of Engines Electrified (%)	0%	25%
Percent of Engines - Uncontrolled	0%	EPA 2014a MOVES Defaults
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	21%	
Percent of Engines - Tier 3	0%	
Percent of Engines - Tier 4	79%	
Average Engine Turnover Frequency (years)	[a]	
Williston Basin (MT)		
Fraction of Spuds Represented	43%	not applicable
Spud Type	Horizontal	Horizontal
Well Type	Oil	Oil
Fuel Type	Diesel	Diesel
Number of Engine Per Rig (number/rig)	2	2
Rated Horsepower (hp/engine)	2193	2293
Hours of Operation (hours/spud)	236	481
Percent of Engines Electrified (%)	0%	0%
Percent of Engines - Uncontrolled	0%	Emission factors indicated a mix of engines up to Tier 4 certification
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	100%	
Percent of Engines - Tier 3	0%	
Percent of Engines - Tier 4	0%	
Average Engine Turnover Frequency (years)	[a]	
Williston Basin (ND)		
Fraction of Spuds Represented	47%	not applicable
Spud Type	Horizontal	Horizontal
Well Type	Oil	Oil
Fuel Type	Diesel	Diesel

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Number of Engine Per Rig (number/rig)	4	2
Rated Horsepower (hp/engine)	1445	2206
Hours of Operation (hours/spud)	259	507
Percent of Engines Electrified (%)	23%	0%
Percent of Engines - Uncontrolled	0%	Emission factors indicated a mix of engines up to Tier 4 certification
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	99%	
Percent of Engines - Tier 3	1%	
Percent of Engines - Tier 4	0%	
Average Engine Turnover Frequency (years)	5	

[a] Not enough information is available to populate this field

Table A2. Baseline Emission Inventory Inputs: Hydraulic Fracturing Engines.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Permian Basin (NM)		
Fraction of Spuds Represented	19%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	All
Configuration Type	Diesel Engine	Diesel Engine
Fraction of ICE Engine Configurations	95%	100%
Number of Engines Per Frac Job (number/frac)	22	10
Rated Horsepower (hp/engine)	1697	2313
Hours of Operation (hours/frac job)	109	23
Percent of Engines Electrified (%)	5%	0%
Percent of Engines - Uncontrolled	0%	EPA 2014a MOVES Defaults
Percent of Engines - Tier 1	0%	
Percent of Engines - Tier 2	11%	
Percent of Engines - Tier 3	0%	
Percent of Engines - Tier 4	84%	
Average Engine Turnover Frequency (years)	4	
Configuration Type	Turbine	Turbine

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Fraction of Natural Gas Engine Configurations	5%	0%
Rated Horsepower (hp/turbine)	49,000	-
Hours of Operation (hours/frac job)	70	-
Percent of Turbines - Uncontrolled	100%	-
Average Engine Turnover Frequency (years)	10	-
Williston Basin (ND)		
Fraction of Spuds Represented	39%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	All
Fuel Type	Diesel	Diesel
Number of Engines Per Frac Job (number/frac)	29	5
Rated Horsepower (hp/engine)	1356	1823
Hours of Operation (hours/frac job)	156	26
Percent of Engines Electrified (%)	0%	0%
Percent of Engines - Uncontrolled	0%	Emission factors indicated a mix of engines up to Tier 4 certification
Percent of Engines - Tier 1	5%	
Percent of Engines - Tier 2	35%	
Percent of Engines - Tier 3	3%	
Percent of Engines - Tier 4	56%	
Average Engine Turnover Frequency (years)	3	
Powder River Basin (MT)		
Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.		
Williston Basin (MT)		
Survey response was limited to two operators comprising 2% of exploration activity. Recommend assuming that Willison Basin, Montana hydraulic fracturing inputs are equivalent to Williston Basin, North Dakota.		

[a] Not enough information is available to populate this field

Table A3. Baseline Emission Inventory Inputs: Oil Tanks.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Central Montana Uplift (MT)		
Fraction of Oil Production Represented	8%	not applicable
Spud Type	Vertical	All

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.01	0.01
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.40	1.75
Percent of Tanks - Uncontrolled	100%	47%
Percent of Tanks - Flares	0%	53%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	Visual	a
Frequency of Inspection (number/tank/year)	189	
Percent of Tanks - Open Thief Hatch	3%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	a	
Annual Average Hours Controls are Offline - Other		
Other - Description		
Permian (NM)		
Fraction of Oil Production Represented	3%	not applicable
Spud Type	Horizontal	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.03	0.01
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.93	1.60
Percent of Tanks - Uncontrolled	19%	73%
Percent of Tanks - Flares	47%	27%
Percent of Tanks - Vapor Recovery Unit (VRU)	1%	0%
Percent of Tanks - Other Device	33%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/IR Camera	a
Frequency of Inspection (number/tank/year)	32	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	36	
Annual Average Hours Controls are Offline - Other	0	

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Other - Description	-	
Powder River Basin (MT)		
Fraction of Oil Production Represented	93%	not applicable
Spud Type	vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.02	0.04
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.88	2.84
Percent of Tanks - Uncontrolled	1%	14%
Percent of Tanks - Flares	6%	86%
Percent of Tanks - Vapor Recovery Unit (VRU)	93%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	Routine	a
Frequency of Inspection (number/tank/year)	12	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	24	
Annual Average Hours Controls are Offline - Other	8	
Other - Description	Flare failures, site upsets, equipment failures, power losses	
Sweetgrass Arch (MT)		
Fraction of Oil Production Represented	20%	not applicable
Spud Type	vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.01	0.01
Uncontrolled Flash VOC EF (lb VOC/bbl)	2.07	1.94
Percent of Tanks - Uncontrolled	100%	47%
Percent of Tanks - Flares	0%	53%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	visual	a
Frequency of Inspection (number/tank/year)	0	

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	A	
Annual Average Hours Controls are Offline - Other		
Other – Description		
Williston Basin (MT)		
Fraction of Oil Production Represented	44%	not applicable
Spud Type	Horizontal	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.04	0.06
Uncontrolled Flash VOC EF (lb VOC/bbl)	3.75	5.33
Percent of Tanks - Uncontrolled	1%	17%
Percent of Tanks - Flares	99%	83%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/Visual/FLIR/AVO/site sound smell	a
Frequency of Inspection (number/tank/year)	11	
Percent of Tanks - Open Thief Hatch	4%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	13	
Annual Average Hours Controls are Offline - Other	132	
Other - Description	Equipment failure or repair needed	
Williston Basin (MT)		
Fraction of Oil Production Represented	41%	not applicable
Spud Type	Vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.05	0.06
Uncontrolled Flash VOC EF (lb VOC/bbl)	4.50	5.33
Percent of Tanks - Uncontrolled	26%	17%
Percent of Tanks - Flares	74%	83%

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	Routine	a
Frequency of Inspection (number/tank/year)	12	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	24	
Annual Average Hours Controls are Offline - Other	8	
Other - Description	Equipment failure or repair needed	
Williston Basin (ND)		
Fraction of Oil Production Represented	51%	not applicable
Spud Type	Horizontal	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.08	0.07
Uncontrolled Flash VOC EF (lb VOC/bbl)	2.18	5.64
Percent of Tanks - Uncontrolled	0%	17%
Percent of Tanks - Flares	98%	83%
Percent of Tanks - Vapor Recovery Unit (VRU)	1%	0%
Percent of Tanks - Other Device	1%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/Visual/FLIR/AVO	a
Frequency of Inspection (number/tank/year)	7	
Percent of Tanks - Open Thief Hatch	9%	
Percent of Tanks - Open Dump Valves	5%	
Annual Average Hours Controls are Offline - Maintenance	23	
Annual Average Hours Controls are Offline - Other	492	
Other - Description	Equipment failure or repair need	
Williston Basin (ND)		
Fraction of Oil Production Represented	24%	not applicable

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Spud Type	Vertical	All
Tank Type	Oil Tank	Oil Tank
Gas Venting Rate (MCF/bbl)	0.02	0.07
Uncontrolled Flash VOC EF (lb VOC/bbl)	1.33	5.64
Percent of Tanks - Uncontrolled	1%	17%
Percent of Tanks - Flares	99%	83%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR/OGI/Visual/ AVO	a
Frequency of Inspection (number/tank/year)	4	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	1%	
Annual Average Hours Controls are Offline - Maintenance	A	
Annual Average Hours Controls are Offline - Other		
Other – Description		

[a] Not enough information is available to populate this field

Table A4. Baseline Emission Inventory Inputs: Condensate Tanks.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Sweetgrass Arch (MT)		
Fraction of Condensate Production Represented	14%	not applicable
Spud Type	Vertical	All
Tank Type	Condensate Tank	Condensate Tank
Gas Venting Rate (MCF/bbl)	0.13	0.15
Uncontrolled Flash VOC EF (lb VOC/bbl)	6.40	7.00
Percent of Tanks - Uncontrolled	100%	31%
Percent of Tanks - Flares	0%	69%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	0%	0%
Other Device Control Type Description	-	-
Inspection Type	visual	a

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Frequency of Inspection (number/tank/year)	12	
Percent of Tanks - Open Thief Hatch	0%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	A	
Annual Average Hours Controls are Offline – Other		
Other – Description		
Williston Basin (MT)		
Fraction of Condensate Production Represented	65%	not applicable
Spud Type	Horizontal	All
Tank Type	Condensate Tank	Condensate Tank
Gas Venting Rate (MCF/bbl)	0.17	0.30
Uncontrolled Flash VOC EF (lb VOC/bbl)	11.36	14.08
Percent of Tanks - Uncontrolled	4%	8%
Percent of Tanks - Flares	95%	91%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	1%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	LDAR	a
Frequency of Inspection (number/tank/year)	2	
Percent of Tanks - Open Thief Hatch	14%	
Percent of Tanks - Open Dump Valves	0%	
Annual Average Hours Controls are Offline - Maintenance	48	
Annual Average Hours Controls are Offline - Other	480	
Other - Description	Equipment failure or repair needed	
Williston Basin (ND)		
Fraction of Condensate Production Represented	<1%	not applicable
Spud Type	Horizontal	All
Tank Type	Condensate Tank	Condensate Tank
Gas Venting Rate (MCF/bbl)	0.09	0.31
Uncontrolled Flash VOC EF (lb VOC/bbl)	10.53	14.72
Percent of Tanks - Uncontrolled	1%	8%
Percent of Tanks - Flares	99%	92%
Percent of Tanks - Vapor Recovery Unit (VRU)	0%	0%
Percent of Tanks - Other Device	1%	0%
Other Device Control Type Description	Combustor	-
Inspection Type	A	a
Frequency of Inspection (number/tank/year)		

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Tanks - Open Thief Hatch		
Percent of Tanks - Open Dump Valves		
Annual Average Hours Controls are Offline – Maintenance		
Annual Average Hours Controls are Offline – Other		
Other – Description		
Big Horn Basin (MT)		
Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.		
Central Montana Uplift (MT)		
Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.		

[a] Not enough information is available to populate this field

Table A5. Baseline Emission Inventory Inputs: Wellsite Engines.

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Sweetgrass Arch (MT) - Wellhead Compressor Engines		
Fraction of Well Count Represented	30%	not applicable
Spud Type	Vertical	All
Well Type	Gas	Gas
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	1.0	0
Rated Horsepower (hp/engine)	121	135
Hours of Operation (hours/engine)	740	0
Percent of Engines Electrified (%)	0%	0%
Average Engine Turnover Frequency (years)	a	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	21%	30%
If NG - Percent of Engines - Rich Burn	79%	70%
Percent of Engines Meeting NSPS subpart JJJJ Standards	a	a
Big Horn Basin (MT) - Lateral Compressor Engines		
Fraction of Well Count Represented	14%	not applicable
Spud Type	Vertical	All
Well Type	Gas	Gas
Fuel Type	Natural Gas	Natural Gas
Number of Wells per Engine	31	35

Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Rated Horsepower (hp/engine)	237	271
Hours of Operation (hours/engine)	8760	8760
Percent of Engines Electrified (%)	0%	0%
Average Engine Turnover Frequency (years)	40	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	20%	20%
If NG - Percent of Engines - Rich Burn	80%	80%
Percent of Engines Meeting NSPS subpart JJJJ Standards	a	a
Central Montana Uplift (MT) - Lateral Compressor Engines		
Fraction of Well Count Represented	82%	not applicable
Spud Type	Vertical	All
Well Type	Gas	Gas
Fuel Type	Natural Gas	Natural Gas
Number of Wells per Engine	28	129
Rated Horsepower (hp/engine)	277	443
Hours of Operation (hours/engine)	4576	8559
Percent of Engines Electrified (%)	0%	0%
Average Engine Turnover Frequency (years)	a	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	11%	61%
If NG - Percent of Engines - Rich Burn	89%	39%
Percent of Engines Meeting NSPS subpart JJJJ Standards	a	a
Sweetgrass Arch (MT) - Artificial Lift Engines		
Survey response was limited to one operator, comprising a very small fraction of activity, therefore, no input factors were developed.		
Williston Basin (MT) - Artificial Lift Engines		
Fraction of Well Count Represented	48%	not applicable
Spud Type	Vertical	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.78	0.23
Rated Horsepower (hp/engine)	96	65
Hours of Operation (hours/engine)	6841	7930
Percent of Engines Electrified (%)	95%	21%
Average Engine Turnover Frequency (years)	a	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	0%	0%
If NG - Percent of Engines - Rich Burn	100%	100%

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Percent of Engines Meeting NSPS subpart JJJJ Standards	0%	a
Williston Basin (ND and MT) - Artificial Lift Engines		
Fraction of Well Count Represented	49%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.51	0.22
Rated Horsepower (hp/engine)	242	70
Hours of Operation (hours/engine)	8322	8538
Percent of Engines Electrified (%)	76%	17%
Average Engine Turnover Frequency (years)	6	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	76%	0%
If NG - Percent of Engines - Rich Burn	24%	100%
Percent of Engines Meeting NSPS subpart JJJJ Standards	42%	a
Williston Basin (ND) - Artificial Lift Engines		
Fraction of Well Count Represented	10%	not applicable
Spud Type	Vertical	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.33	0.22
Rated Horsepower (hp/engine)	66	70
Hours of Operation (hours/engine)	8384	8538
Percent of Engines Electrified (%)	52%	17%
Average Engine Turnover Frequency (years)	18	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	48%	0%
If NG - Percent of Engines - Rich Burn	52%	100%
Percent of Engines Meeting NSPS subpart JJJJ Standards	a	a
Permian Basin (MT) - Artificial Lift Engines		
Fraction of Well Count Represented	19%	not applicable
Spud Type	Horizontal	All
Well Type	Oil	Oil
Fuel Type	Natural Gas	Natural Gas
Number of engines per well	0.42	0.97
Rated Horsepower (hp/engine)	373	21
Hours of Operation (hours/engine)	8760	4380
Percent of Engines Electrified (%)	14%	70%

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Basin / Parameter	Survey - Based Factors	WRAP OGWG 2014 V2 Emission Inventory Input Factors
Average Engine Turnover Frequency (years)	a	a
If Other - Fuel Type	-	-
If NG - Percent of Engines - Lean Burn	26%	0%
If NG - Percent of Engines - Rich Burn	74%	100%
Percent of Engines Meeting NSPS subpart JJJJ Standards	99%	a
Williston Basin (MT and ND) – Generators		
Fraction of Well Count Represented	65%	A
Spud Type	Horizontal	
Well Type	Oil	
Fuel Type	Natural Gas	
Number of engines per well	0.03	
Rated Horsepower (hp/engine)	327	
Hours of Operation (hours/engine)	6094	
Percent of Engines Electrified (%)	16%	
Average Engine Turnover Frequency (years)	5.6	
If NG - Percent of Engines - Lean Burn	10%	
If NG - Percent of Engines - Rich Burn	90%	
Percent of Engines Meeting NSPS subpart JJJJ Standards	97%	
Fuel Type	Diesel	
Number of engines per well	0.02	
Rated Horsepower (hp/engine)	222	
Hours of Operation (hours/engine)	8760	
Percent of Engines Electrified (%)	0%	
Average Engine Turnover Frequency (years)	3	
Percent of Engines Meeting NSPS subpart JJJJ Standards	a	
Permian Basin – Generators		
Survey response was limited to one operator. Since this source category is not included in the WRAP OGWG v2 emission inventory, it was not possible to develop input factors due to confidentiality considerations.		
Permian Basin – Vapor Recovery Unit Engines		
Survey response was limited to one operator. Since this source category is not included in the WRAP OGWG v2 emission inventory, it was not possible to develop input factors due to confidentiality considerations.		

[a] Not enough information is available to populate this field

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Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

Background Technical Support Document for the

Final New Source Performance Standards

40 CFR Part 60, subpart OOOOa

May, 2016

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
µg/L	micrograms per liter
AEO	Annual Energy Outlook
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
bbl	barrels
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
CAA	Clean Air Act
CAGR	compound annual growth rate
CD	combustion device
CETAC-WEST	Canadian Environmental Technology Advancement Corporation-WEST
cfm	cubic foot per minute
CFR	U.S. Code of Federal Regulations
CH_4	methane
CIPs	chemical injection pumps
CO	carbon monoxide
CO_2	carbon dioxide
CO_2Eq.	carbon dioxide equivalents
COOGCC	Colorado Oil and Gas Conservation Commission
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FR	Federal Register
GE	General Electric
GHG	greenhouse gas
GOR	gas to oil ratio
GRI	Gas Research Institute
H_2S	hydrogen sulfide
HAP	hazardous air pollutants
Inj/With	injection/withdrawal
IR	infrared
kg/hr/comp	kilograms per hour per component
kg/hr/source	kilograms per hour per source
kW	kilowatt
lbs	pounds
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf	million cubic feet
MMT	million metric tons

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Acronyms/Abbreviations	**Description**
$MMtCO_2e$	million metric tons of CO_2-equivalents
Mscf	thousand standard cubic feet
Mscf/cyl	thousand standard cubic feet per cylinder
Mscf/yr	thousand standard cubic feet per cylinder per year
NEMS	National Energy Modeling System
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations & maintenance
OAQPS	Office of Air Quality and Standards
OAR	Office of Air and Radiation
OEL	open-ended line
OGI	optical gas imaging
OVA	organic vapor analyzers
PES	Preliminary Environmental Study
PG&E	Pacific Gas & Electric
PM	particulate matter
PNAS	Proceedings of the National Academy of Sciences
ppmv	parts per million by volume
PRV	pressure relief valve
psig	pounds per square inch gage
REC	renewable energy certificate
scf	standard cubic feet
scf/hr-cylinder	standard cubic feet per hour-cylinder
scf/minute or scfm	standard cubic feet per minute
scfh	standard cubic feet per hour
SO_2	sulfur dioxide
THC	total hydrocarbon
TOC	total organic compounds
tpy	tons per year
TSD	Technical Support Document
TVA	toxic vapor analyzers
U.S.	United States
U.S.C.	United States Code
URS Corporation	United Research Services Corporation
UT Austin	University of Texas, Austin
VOC	volatile organic compounds
VRU	Vapor recovery unit
WAQD	Wyoming's Air Quality Division

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1.0 INTRODUCTION

This background technical support document (TSD) provides information relevant to the development of the final rule Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. The final rule establishes GHG standards, in the form of limitations on methane, for certain sources that are currently regulated for VOC but not GHG. It also establishes both VOC and GHG standards certain sources that are currently unregulated for either emissions.

Chapter 2 presents an overview of the oil and natural gas sector and source category. This chapter is intended to provide introductory material on the oil and natural gas source category, as listed under section 111(b)(1)(A).

The remainder of the TSD is presented in two volumes; Volume 1 provides the unit-level analysis supporting the determination of the best system of emission reduction (BSER); and Volume 2 presents the national impacts of the regulatory decisions for the final rule.

1.1 Volume 1 - Unit-Level BSER Analysis

Chapters 3 through Chapter 7 present detailed information and analyses pertaining to each emissions source that was considered in this regulatory action. They include emission data and discussions of available control options and their costs that are considered in the development of standards reflecting the BSER for these emission sources.

1.2 Volume 2 - National Level Impacts

Chapters 8 through Chapter 15 present the estimates of national level impacts needed to inform the Preamble of the final rule and the Regulatory Impact Analysis (RIA) for the rule, as required under Executive Order 12866. Specifically, each chapter summarizes the national baseline, nationwide emission reductions and cost impacts for use in the Preamble and RIA. It is important to note that that national impacts estimates incorporate in to the baseline the fact that some states already have requirements of emissions sources addressed by this final rule. Further, this analysis is separate and apart from the analyses required to identify the BSER based on which standards are to be established under section 111(b) of the CAA. Chapter 13 summarizes the natural gas savings from the application of emissions controls.

Finally, the Appendix to the TSD provides technical information on the background and development of the low pressure well equation.

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1.3 Supporting Documentation

This action follows the development of several prior oil and gas NSPS related actions. This review references several documents that were published as a consequence of these prior actions. For ease of presentation, the following documents are consistently cited in the following sections:

- The TSD for the 2011 NSPS proposal, published in July, 2011, will be referred to in this document as "2011 NSPS TSD".[1]
- The supplemental TSD for the 2012 final NSPS standards, published April, 2012, will be referred to in this document as "2012 NSPS STSD".[2]
- The gas composition memo that was developed during the NSPS process which characterizes and analysis of data to determine the gas composition and develop ratios for natural gas composition to be used for the various segments in the development of regulations for the oil and natural gas sector. This document will be referred to as "2011 Gas Composition Memorandum".[3]
- Emissions information and counts for various emission sources were developed from facility-level data submitted to the Greenhouse Gas Reporting Program (GHGRP) and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks. The most recent available data from the GHG Inventory at the time of the development of this analysis was for 2013, and was used for various portions of the analysis. For the purposes of this document these data sources are referred to as "GHGRP" and “GHG Inventory”. Currently available GHGRP reported data cover 2011 through 2014 and the most recent available GHG Inventory covers data from 1990-2014.[4] These new activity data have been reviewed for the final rule and incorporated into this analysis appropriate
- The TSD for the 2015 NSPS proposal, published in August, 2015, will be referred to in this document as "2015 NSPS Proposal TSD". Note that this TSD includes all information from the proposal TSD that did not change and that continues to support the decisions of final rule, as well

[1] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards.* July 2011. EPA-453/R-11002.
[2] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for Proposed Standards*. April 2012. Docket ID EPA-HQ-OAR-2010-0505-4550.
[3] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for use in the Oil and Natural gas Sector Rulemaking". July 2011. Docket ID EPA-HQ-OAR-2010-0505-0084.
[4] U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC

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any revisions to relevant data or information that supports the provisions of the final rule.[5]

All of the calculations supporting the analyses in this document are included in the docket in the form of spreadsheets that are labeled corresponding to the section of the TSD.

[5] See EPA-HQ-OAR-2010_0505-5021

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2.0 OIL AND NATURAL GAS SOURCE CATEGORY OVERVIEW

The final rule covers emission sources within the oil and natural gas source category, which includes onshore crude oil production and natural gas production, processing, transmission and storage.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treatment of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the "pads" where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production segment also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants.

There are two basic types of wells: oil wells and gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids,

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sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

The pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment. Pipelines in the natural gas transmission and storage segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

Emissions can occur from a variety of processes and points throughout the oil and natural gas source category. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic HAP. The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas.[6]

The analysis in this document addresses only emission sources in the oil and natural gas source category. Unless otherwise noted, use of the term "gas" refers to natural gas.

[6] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4 parts per million by volume (ppmv)) along with the presence of CO_2.

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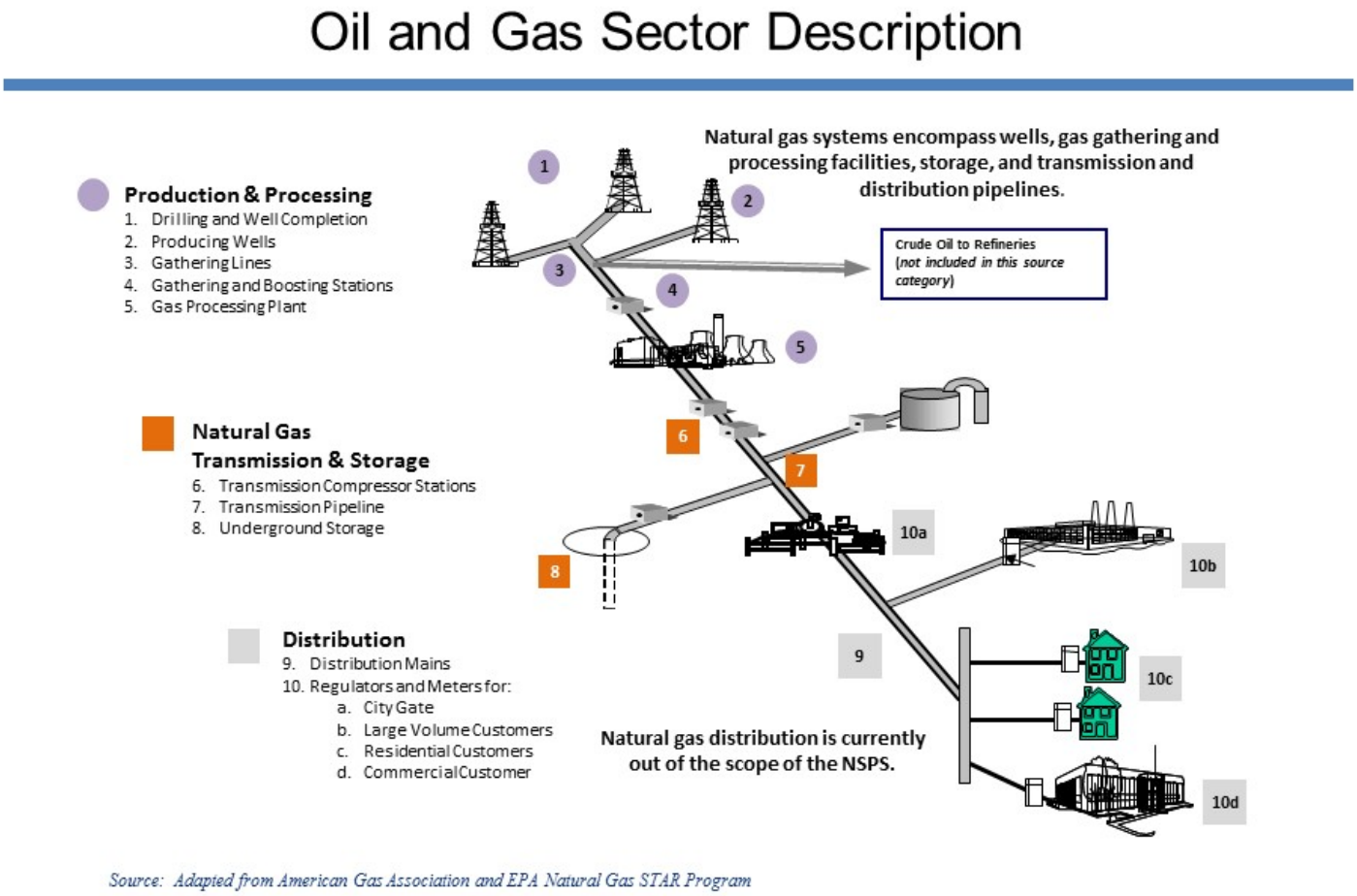


Figure 1. Oil and Natural Gas Sector Operations

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3.0 HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS AND RECOMPLETIONS

During development of the 2012 NSPS amendments, methane and VOC emissions from hydraulically fractured oil and natural gas well completions and recompletions were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD. The 2012 NSPS promulgated requirements for control of emissions from hydraulically fractured natural gas well completions and recompletions.

The EPA has reevaluated hydraulically fractured oil well completion emissions based on more recent data and information as discussed below. As was determined with respect to gas wells, oil well completions and recompletions use multi-phase processes with various sources of emissions where the highest emissions result from the venting of natural gas to the atmosphere during flowback. The flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes hydraulically fractured oil well completions and recompletions, and provides estimates for representative oil wells and nationwide emissions. With respect to control technology, the same control technology can be employed to control emissions from oil well completions as were found to be appropriate for gas well completions. In this chapter, the EPA evaluated costs, emission reductions, and secondary impacts for oil well completions and recompletions based on the revised emissions profile.

Because oil well completions and recompletions were included in the proposed NSPS amendments in 2011 (76 FR 52738), for the sake of convenience the EPA repeat below the process description and control technology discussions from the 2012 NSPS TSD with minimal edits.

3.1 Process Description

3.1.1 Oil Well Completions

All oil wells must be “completed” after initial drilling in preparation for production.

Well completion activities include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and

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gathering lines are installed as necessary for production to begin.[7]

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rates of various phases (oil, gas, and water), oil API gravity, and pressure and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as "wildcat") wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving oil production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Natural gas emissions are a result of the flowback of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion flowback escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the flowback eventually contains a higher volume of natural gas from the formation. Due to the specific additional equipment and resources involved and the nature of the flowback of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

3.1.2 Oil Well Recompletions Recompletions are remedial operations conducted to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere

[7] U.S. EPA. Lessons Learned: Reduced Emissions Completions. Office of Air and Radiation (OAR): Natural Gas Star Program, Washington, DC, 2011.

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unless the flowback gas is captured.

When hydraulic re-fracturing (recompletions) is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The flowback velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Flowback emissions are a result of free gas being produced by the well following hydraulic fracturing during a well completion and recompletion activity. The high rate flowback, with intermittent slugs of water and sand along with free gas, is directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the flowback emissions originate from the recompletion process but may be vented as the flowback enters the impoundment or vessels.

3.2 Emission Data and Emission Factors

3.2.1 Summary of Major Studies and Emission Factors

Together with the sources of information and data reviewed during the development of the 2012 NSPS, the EPA reviewed recent data and information as was discussed in the white paper titled “Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production" published by the EPA in April, 2014.[8] Table 3-1 presents a list of the studies and information sources consulted for development of the NSPS and the 2014 white paper. The list below includes sources with information on hydraulically fractured gas and oil well completions and workovers.

Table 3-1. Major Studies Reviewed Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Drilling Info database	HPDI	2015	Nationwide	X	
GHG Mandatory Reporting Rule and Technical Supporting Documents[a]	EPA	2013	Nationwide	X	

[8] Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.

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Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Inventory of GHG Emissions and Sinks: 1990-2013[b, c]	EPA	2015	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry (Draft)[d]	Radian	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry[e]	ICF	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[f]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories[g]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[h]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Oil and Natural Gas Production Facilities[i]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[j]	U.S. Energy Information Administration (EIA)	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations[k]	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program[l]	New York State Department of Environmental Conservation	2009	Regional	X	X
Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards[m]	EPA	2012	Nationwide	X	X
Fort Berthold Federal Implementation Plan[n]	EPA	2012	Regional	X	X
ERG/EC/R Contractor Analysis of HPDI® Data[o]	EPA	2012	Nationwide	X	X
Environmental Defense Fund Analysis of HPDI Data[p]	EDF	2014	Nationwide	X	X

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Measurement of Methane Emissions at Natural Gas Production Sites in the United States[q]	Allen et al.	2014	Nationwide	X	X
Methane Leaks from North American Natural Gas Systems[r]	Brandt et al.	2014	Nationwide	X	X

a. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010. 84-89 pp.
b. U.S. EPA. Annex 3.5: Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. Inventory of GHG Emissions and Sinks: 1990-2013. Washington, DC. 2015.
c. U.S. EPA. Annex 3.6: Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems. Inventory of GHG Emissions and Sinks: 1990-2013. . Washington, DC. 2015.
d. Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. EPA, June 14, 1996.
e. ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. EPA. 1999.
f. ENVIRON International Corporation. Oil and Gas Emission Inventories for the WRAP. Prepared for Western Governors' Association. December 27, 2005.
g. ENVIRON International Corporation. Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories Prepared for Central States Regional Air Partnership. November 2008.
h. Independent Petroleum Association of America. Oil and Gas Producing Industry in Your State. 2008.
i. Eastern Research Group, Inc. Emissions from Oil and Gas Production Facilities. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.
j. U.S. EIA. Annual U.S. Natural Gas Wellhead Price. EIA. Natural Gas Navigator. Retrieved December 12, 2010. http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm.
k. ERG, Inc. Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations. Prepared for the U.S. EPA. September 1999.
l. New York State Department of Environmental Conservation. Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (DRAFT). September 2009.
m. *See footnote* 2.
n. Fort Berthold Indian Reservation Federal Implementation Plan (78 FR 17836). U.S. Environmental Protection Agency (U.S. EPA). 2012a. *Technical Support Document, Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), North Dakota.* Docket Number: EPA-R08-OAR-2012-0479.U.S. EPA.
o. Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production. Washington, CD. 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.
p. Environmental Defense Fund (EDF). 2014. *Co-Producing Wells as a Major Source of Methane Emissions: A Review of Recent Analyses, March, 2014.* Available at http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf. Supplemental materials available at https://www.dropbox.com/s/osrom4w6ewow4ua/EDF-Initial-Production-Cost-Effectiveness-Analysis.xlsx.
q. Proceeding of the National Academy of Sciences of the United States of America (PNAS). 2013. *Measurement of Methane Emissions at Natural Gas Production Sites in the United States*. August 19, 2013. Available at http://www.pnas.org/content/early/2013/09/10/1304880110.abstract.
r. Brandt, A.R., et al. 2014a. *Methane Leaks from North American Natural Gas Systems.* Science 343, 733 (2014). February 14, 2014. Available at http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.

3.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion

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and recompletion emissions are estimated as the venting of emissions from the well following hydraulic fracturing during a well completion or recompletion activity.

This analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. The basic approach for this analysis was to use natural gas production data to approximate natural gas emissions from representative oil well completions and recompletions and then estimate methane and VOC emissions using the representative gas composition values developed in the 2011 Gas Composition Memorandum for the 2012 NSPS.[9]

Based on the comments received during the development of the NSPS, the EPA recognized that there are instances where gas produced by a well is incidental to oil production and that the gas flow would not support operation of a separator if low levels of gas produced. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field. EIA data show that the number of "oil only" wells drilled from 2007-2012 was less than 20 percent.[10] Therefore, the EPA evaluated available information to determine a minimum threshold of gas produced.

Non-volatile "black oils" (oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900.[11] Therefore, oil wells with GORs less than 300 are at the lower end of this range, and likely will not have enough associated gas that can be separated.[12] Based on this consideration, the EPA concludes that a separator will not function at a well with a of GOR of less than 300 scf/barrel and, therefore, well completion of such well would not be reasonably capable of capturing and controlling emissions. Consequently, removed these oil wells from our analysis conducted to determine emissions from hydraulically fractured oil wells.

The following methodology was used to estimate the potential methane and VOC emissions from hydraulically fractured oil well completions.

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[9] See U.S. EPA Docket ID Number EPA-HQ-OAR-2010-0505-0084.
[10] http://www.eia.gov/todayinenergy/detail.cfm?id=13571#
[11] http://petrowiki.org/Oil_fluid_characteristics
[12] The reason for the proposed threshold GOR of 300 was that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though in theory any amount of free gas could be separated from the liquid, in reality this is not practical given the design and operating parameters of separation units operating in the field. On February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137.

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1. The EPA obtained well production data from the DrillingInfo database dated February, 2014.[13] The DrillingInfo database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. DrillingInfo collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. The data extract from the DrillingInfo database included the population of all wells with gas or hydrocarbon liquid production during 2010 to 2012 and with a recorded completion year of 2010 to the date of the extract (February, 2014).
2. The data was then processed to identify oil wells that were hydraulically fractured using a methodology based on a crosswalk of formation types and other information. See the ERG memorandum titled "*2013 GHGRP Subpart W and NSPS/NESHAP DrillingInfo Processing Methodology*" available in the docket, for a detailed description of the process to identify hydraulically fractured oil wells from the total oil well population.
3. From the dataset of hydraulically fractured oil wells, the EPA identified the wells completed in 2012 using the "completion year" record or the year of the "first month of production". Wells with a completion year of 2012 could have been completed for the first time in 2012 or could have been re-completed (i.e., re-fractured in 2012). The EPA also removed from the dataset all wells not characterized in the DrillingInfo database as “oil,” “gas” or “oil and gas”.
4. For the above identified hydraulically fractured oil well population, the EPA calculated the gas to oil ratio (GOR) by dividing the standard cubic feet (scf) of gas produced during the first month of production by the barrels (bbl) of petroleum liquid produced during the first month. The EPA then used the GOR to categorize the wells into oil and gas wells. Oil wells were defined to be those wells with a GOR of less than 100,000 scf/bbl. This threshold was chosen because it is consistent with the threshold used in the EPA National Emissions Inventory Oil and Gas Emission Estimation Tool and the threshold used in several states, including Texas[14] and New Mexico[15].
5. Based on the calculated GOR for the wells identified above, the EPA eliminated from the

[13] DrillingInfo is a private organization specializing in compiling primarily publically available oil and gas data, conducting statistical analysis, and providing analysis platforms for customers. The DrillingInfo database is particularly focused on historical oil and gas production data and drilling permit data.

[14] Available at http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=79.

[15] Available at http://164.64.110.239/nmac/parts/title19/19.015.0002.htm.

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evaluation wells with a GOR of less than 300 scf of gas per barrel produced.

6. The EPA then calculated the following average daily gas production values for each oil well;
    - Average daily gas production over the first month of operation by dividing the total gas production in the first month of operation by the average number of days in a month (30.42);
    - Average daily gas production over the first 6 months of operation by dividing the total gas production in the first six months of operation by the average number of days in 6 months (182.5); and
    - Average daily gas production over the first year of operation by dividing the total gas production in the first year of operation by the total days in one year (365).
7. The EPA assumed that the average daily gas production during the first month was representative of the daily potential emissions during a hydraulically fractured oil well completion. Therefore, the estimated gas production from a representative oil well completion was determined by taking the average of the average daily natural gas production during the first month of operation for each of the above identified oil wells (i.e., hydraulically fractured, and completed in 2012).
8. To determine the potential methane and VOC emissions for a representative oil well completion or recompletion, the EPA converted the average natural gas potential emissions per day to short tons of potential methane and VOC emissions. The conversion factors used are those developed for the NSPS and outlined in the memorandum titled "*Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking"*, available in the docket.[16] Specifically, the EPA assumes natural gas is 46.71% methane by volume, the density of methane is 0.0208 tons per Mcf, and that there is 0.8374 lbs of VOC per pound of methane.

The EPA then calculated the potential VOC and methane emissions during a hydraulically fractured oil well flowback by multiplying potential methane and VOC emissions per day by the number of days in the average flowback event. The data sources referenced in the white papers noted a range of flowback duration from 1-10 days. Some of the values in the ranges were based on study observation and some based on assumptions. Comments on the oil well completion white paper supported a flowback duration on the low end of the range. Our analysis assumes an oil well flowback duration is toward the low end of that range, 3 days.

[16] *See footnote* 3.

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Table 3-2 presents the estimated potential (i.e., uncontrolled) emissions from a representative oil well completion or recompletion. The data sources in the white papers and comments received on the white papers showed a broad range of potential emission estimates (8 to around 200 tons methane per completion or workover) for hydraulically fractured oil well completions. Some of the values were developed using data on gas production and assumptions about flowback; others used measurement data. As described above, the estimates presented in the table below were developed using flowback characteristics and gas production data and include the effect of a GOR threshold of 300 that excludes oil wells with very little gas production. The estimates in the table below represent emissions from that population of wells, in the absence of controls. To calculate emissions to the atmosphere using these values, additional information on gas that is not emitted (e.g., through use of RECs or flaring) is needed.

Table 3-2. Uncontrolled Emission Estimates from Representative Oil Well Completion or Recompletion

	Average Daily Production Natural Gas (Mcf/event)	Potential Emissions Methane [a] (tons/event)	Potential Emissions VOC [b] (tons/event)
3-Day Completion or Recompletion Event	999	9.72	8.14

a. It is assumed methane comprises 46.732 percent by volume of natural gas. The factor used to convert methane from volume to weight is 0.0208 tons methane per thousand cubic feet (Mcf) of methane.[17]
b. Assumes 0.8374 lb. VOC/lb. methane.

3.3 Control Techniques

3.3.1 Potential Control Techniques

The techniques that have been proven to reduce emissions from oil well completions and recompletions are the same as those that were evaluated for development of the 2012 NSPS for gas well completions and recompletions; specifically RECs and completion combustion. As with natural gas wells, the use of a REC not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. Completion combustion destroys the organic compounds. Based on our research as published in the oil completions white paper, these technologies have been found to be technically feasible for oil well completions and recompletions, and are in use in the industry to control emissions from oil wells. The EPA identified no other potential control options for oil well completions. For the sake of convenience, the description sections included below are from the 2012 NSPS TSD with limited edits. The

[17] U.S EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC. 2010. Appendix B, Pgs. 87-89.

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following sections describe the cost impact of these technologies with respect to oil well completions based on our current analysis of emissions.

3.3.2 Reduce Emission Completions and Recompletions

3.3.2.1 Description

Reduced emission completions, also referred to as "green" completions, use specially designed equipment at the well site to capture and treat gas during well completion activities. This process prevents some natural gas from venting and results in additional revenues for producers from the sale or use of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.[18]

In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[19] In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.
- Pressure of produced gas. During the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the gathering line backpressure. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another potential

[18] U.S. EPA Fact Sheet No. 703: Green Completions. OAR: Natural Gas Star Program. Washington, DC. September 2004.
[19] Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. API Meeting Minutes. July 2010.

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compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or CO_2, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

3.3.2.1 Emission Reduction Potential

RECs are an effective emission reductions method for oil well completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 2.2. The emission reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on information presented in the white papers, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[20] Any amount of gas that cannot be recovered can be directed to a combustion device in order to achieve a minimum 95 percent reduction in emissions.

3.3.2.2 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs. The EPA received information and comment from multiple technical experts that the equipment necessary to perform a REC for an oil well completion is the same as that for a gas well completion.

Therefore, as was determined in the 2011 NSPS TSD[21], the annual cost of performing a REC

[20] Memorandum to Bruce Moore, U.S. EPA from ICF Consulting. Percent of Emissions Recovered by Reduced Emission Completions. May 2011.
[21] *See footnote 1*.

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was estimated to be $12,735 for a representative well completion lasting 3 days[22]. For our analysis, the cost is adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator.[23] The resulting cost for performing a REC for a well completion or recompletion lasting 3 days is estimated to be $13,459.

Monetary savings associated with additional gas captured to the sales line is estimated based on a natural gas price of $4.00 per Mcf.[24] It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates to a total recovery of 899 Mcf of natural gas per completion or recompletion. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately $3,597. When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net cost on the order of $9,862 per completion.

RECs are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. The cost per ton of emissions reduced was then calculated in two ways, both of which reflect that REC is a multi-pollutant control measure (VOC and GHG (in the form of limitations on methane)). The first method, the single-pollutant method, allocates all of the costs to one pollutant and zero to the other. The second method, the multi-pollutant method, allocates costs among the pollutants that a given technology reduced. This proration was based on estimates of the percentage reduction expected for each pollutant.

Based on expected emission reductions from the use of a REC, the cost of control for methane is $1,539 per ton and $1,837 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the other. The cost is $769 per ton of methane and $919 per ton of VOC when the total cost is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

Because a REC accomplishes gas savings, the cost of control for methane is $1,127 per ton and $1,346 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the

[22] This cost was based on state of the industry in 2006 and adjusted to 2008 US Dollars. For the 2012 NSPS the EPA determined a cost per day value, however, the 2012 NSPS applied this per day cost to a 7-day event duration. Here the EPA use the same cost per day and a 3-day event duration.
[23] Available at http://research.stlouisfed.org/fred2/series/GDPDEF/.
[24] When including the additional natural gas recovery in the cost analysis, the EPA assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The Energy Information Administration's 2014 Annual Energy Outlook forecasted wellhead prices paid to lower 48 state producers to be $4.46/Mcf in 2020 and $5.06/Mcf in 2025. The $4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low.

other, and the monetary gas savings is considered. Likewise, the cost is $564 per ton of methane and $673 per ton of VOC when the total cost is reduced by the gas savings and is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

As mentioned earlier, during a well completion, gas that cannot be recovered with REC can be combusted. For the purposes of this analysis, the EPA also analyzed costs for the a REC combined with the cost of a combustion device as described below in section 2.3.3.1. For the combined REC and combustion scenario, the cost of control for methane is $1,861 per ton and $2,222 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero to the other. The cost is $930 per ton of methane and $1,111 per ton of VOC when the total cost is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC).

When gas savings is considered, for the combined REC and combustion, the cost of control for methane is $1,471 per ton and $1,757 per ton of VOC when 100 percent of the cost is attributed to one pollutant and zero cost to the other, and the monetary gas savings is considered. Likewise, the cost is $736 per ton of methane and $879 per ton of VOC when the total cost is reduced by the gas savings and is allocated equally between methane and VOC (i.e., 50 percent to methane and 50 percent to VOC). Table 2-3 provides a summary of REC cost per ton of emission reduction.

3.3.2.3 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., NO_x, PM, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

3.3.3 Combustion Devices

3.3.3.1 Description

As mentioned earlier, during a well completion, gas that cannot be recovered with REC can be combusted. Combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[25] Combustion devices are used to control VOC in many industrial settings, since these devices can normally handle fluctuations in concentration, flow rate,

[25] U.S. EPA. AP-42, Fifth Edition, Volume I, Chapter 13.5 Industrial Flares. OAQPS. 1991.

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heating value, and inert species content.[26] Combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These devices can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead (i.e., a pit flare). The flow directed to a combustion device during a well completion may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. On the other end of the spectrum is the enclosed combustor that is specifically designed for completions that is an integral part of a completion equipment package. For the purpose of this analysis, the term combustion device represents any types of combustion devices used in the industry for control of hydrocarbon emissions.

3.3.3.2 Emission Reduction Potential

It is difficult to measure precisely the destruction efficiency of a combustion device during a well completion activity. The actual destruction efficiency achieved in practice can be expected to vary with the amount of noncombustible gas and liquids in the gas flow. For the purposes of this analysis, a destruction efficiency of 95 percent, consistent with the expected destruction efficiency of a properly designed and operated flare, was assumed for completion combustion devices over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes the use of a continuous ignition source with an independent external fuel supply to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a completion combustion device or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences). As a result, the design and nature of combustion devices used for completions must handle multiphase flow and stream compositions well site conditions that vary during the flowback period and not all unrecoverable gas can be safely combusted in every case.

[26] U.S. EPA. Air Pollution Control Technology Fact Sheet: FLARES. Clean Air Technology Center.

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3.3.3.3 Cost Potential

An analysis estimating the cost for wells including combustion devices was conducted for the 2012 NSPS, resulting in an estimated average completion combustion device cost of approximately $3,523 (2008 dollars).[27] For our analysis, this cost was adjusted to 2012 dollars using the Gross Domestic Product: Implicit Price Deflator [28] resulting in an estimated annual cost of $3,723 per well completion. As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimate. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost per ton of emissions reduced was then calculated in two ways. The first method (the single-pollutant approach) allocated all of the costs to one pollutant and zero cost to the other. The second method (the multi-pollutant approach) allocated costs among the pollutants that a given technology reduced (i.e., in this case GHG in the form of limitations on methane, and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. Completion combustion devices have a cost of control of $403 per ton of methane or $481 per ton of VOC for oil well completions and recompletions when 100 percent of the cost is attributed to one pollutant and zero to the other. Under the multipollutant approach where the cost is prorated to both pollutants equally (i.e., a 50 percent to methane and 50 percent to VOC), the cost of control is $202 per ton of methane and $241 per ton of VOC. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 3-3.

3.3.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including NO_x, CO, sulfur oxides (SO_x), CO_2, and smoke/particulates. The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the

[27] The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals the 2009 average value for the combustion device is $3,195.
[28] Available at http://research.stlouisfed.org/fred2/series/GDPDEF/.

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flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.[29] The high methane content of the gas stream routed to the completion combustion device suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.[30]

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.[31] These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided in Table 3-5.

[29] *See footnote 25*.
[30] Ibid.
[31] Ibid.

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Table 3-3. Reduced Emission Completion and Combustion Emission Reductions and Cost Impacts Summary

Control Technology	Emissions Reduced Per Completion[a] (short tons)		Volume of Whole Gas Captured (Mcf/completion)	Value of Whole Gas Captured ($/completion)	Annual Cost ($)	Cost of Control Per Completion (excluding gas savings) ($/short ton)		Cost of Control Per Completion (including gas savings) ($/short ton)	
	Methane	VOC				Methane	VOC	Methane	VOC
REC (100)[b]	8.75	7.33	899	$3,597	$13,459	$1,539	$1,837	$1,127	$1,346
REC (50/50)[c]	8.75	7.33	899	$3,597	$13,459	$769	$919	$564	$673
REC and Combustion device (100)[b,d]	9.23	7.73	899	$3,597	$17,183	$1,861	$2,222	$1,471	$1,757
REC and Combustion device (50/50)[c,d]	9.23	7.73	899	$3,597	$17,183	$930	$1,111	$736	$879
Completion Combustion (100)[b]	9.23	7.73	0	$0	$3,723	$403	$481	$403	$481
Completion Combustion (50/50)[c]	9.23	7.73	0	$0	$3,723	$202	$241	$202	$241

a. Assumes 95% control.
b. Scenario where 100 percent of the cost of control is attributed to methane and VOC.
c. Scenario where 50 percent of the cost of control is attributed to methane and 50 percent is attributed to VOC.
d. Control option that combines use of a REC and a combustion device to attain 95 percent control.

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Table 3-4. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1[a]

Pollutant	Emission Factor (lb/MMBtu)
THC[b]	0.14
CO	0.31
NO_x	0.068
PM[c]	0-274
Pollutant	**Emission Factor (kg CO_2/MMBtu)**
CO_2[d]	60

a. Based on combustion efficiency of 98 percent.
b. Measured as methane-equivalent.
c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
d. Carbon dioxide factor is derived from the CO_2 emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

3.4 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and particulate matter (PM) from the combustion of the completion gases in the completion combustion device. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1. Require combustion for all hydraulically fractured oil well completions and recompletions;
- Regulatory Option 2. Require REC for all hydraulically fractured oil well completions and recompletions;
- Regulatory Option 3. Require REC and combustion for hydraulically fractured oil well completions and recompletions where gas can be recovered with REC; and
- Regulatory Option 4. Require combustion where gas cannot be recovered with REC.

The following sections discuss these regulatory options.

3.4.1 Evaluation of Regulatory Options

Under Regulatory Option 1, nearly all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., NO_x, CO). Therefore, EPA rejected Regulatory

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Option 1.

The second regulatory option would require RECs for all completions and recompletions of hydraulically fractured oil wells. As stated previously, RECs are not technically feasible for all well completions, such as exploratory wells due to their distance from sales lines. Further, RECs are also not always technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas or inert gas concentrations.

The third regulatory option consists of a combination of REC and combustion for hydraulically fractured oil well completions. As discussed for Regulatory Option 2, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure or inert gas concentrations. In order to allow for owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g., wellhead pressure or inert gas concentrations), or infrastructure issues (e.g., absence of pipelines or processes on-site which can be used to route captured gas) Regulatory Option 3 also allows for the use of a completion combustion device in combination with RECs.

Under this option, some venting must be allowed in lieu of combustion for situations in which combustion would present safety hazards, other concerns.

Regulatory Option 4 reduces emissions through combustion in situation where gas cannot re recovered through REC (for exploratory and delineation wells due to their distance from sales lines, low pressure wells).

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4.0 FUGITIVE EMISSIONS STANDARDS

In the TSD for the proposed rule, monitoring options for reducing fugitive emissions from well sites and compressor stations were analyzed. The monitoring options that were analyzed included optical gas imaging (OGI) and Method 21 at monitoring frequencies of annual, semiannual and quarterly. For Method 21 repair thresholds of 10,000 ppm, 2,500 ppm and 500 ppm were also analyzed for each of the monitoring frequencies. Based on the analysis in the proposed rule TSD, the semiannual OGI monitoring option was selected as BSER for well sites and compressor stations. Comments on the proposed BSER analysis were received during the proposed rule comment period, and the BSER analysis for the OGI option was re-evaluated to take into account these comments. In response to comments, Method 21 was also re-evaluated as an alternative option for fugitive emission monitoring.

4.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as pressure release valves (PRVs), pump seals, valves or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as gas driven pneumatic controllers or gas driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

For the purposes of the analysis and regulatory evaluation of fugitive emissions from components and equipment, the EPA differentiated between the current definition of "equipment" in the rule[32] and the intended definition for the purposes of addressing fugitive emissions. Therefore in the final rule, the EPA have defined a new term, "fugitive emissions component" as the focus of the

[32] The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

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requirements for fugitive emissions. The proposed definition for fugitive emissions component is as follows:

> Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a gas-driven pneumatic controller or a gas-driven pump, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from sites other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

The EPA received comment that this proposed fugitive emissions component definition was too broad and vague and may include equipment such as separators, pressure vessels, and dehydrators instead of the components (i.e., valves, connectors) on the equipment. The commenters also asserted that the "included but not limited to" description adds uncertainty to what should be included in the collection of fugitive emissions components. Based on these comments, the EPA has revised the definition of fugitive emissions component in the final rule to read:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vesselnot subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

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In April of 2014, the EPA published a white paper[33] which summarized the EPA's current understanding of methane and VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities. The white paper also outlined the EPA's understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

4.2 Fugitive Emissions Data and Emissions Factors

4.2.1 Model Plants

For the proposed rule, model plants were developed to estimate fugitive emissions from well sites and compressor stations. Data from the 2016 draft GHG Inventory[34], developed with the most recently published GHGRP reported data, were used to determine the equipment counts for well sites and compressor stations. Component counts per piece of equipment were those used in the GHG Inventory and GHGRP, which were derived the EPA/GRI study and 40 CFR, part 98, subpart W tables, were then used to determine the total number of fugitive components (valves, connectors, OELs, and PRVs) at each of these sites. A description of the data and methodology for determining fugitive emissions for these model plants are discussed in the following sections.

4.2.2 Oil and Gas Production Well Sites

Oil and natural gas production practices and equipment vary from site-to-site. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well pad. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Baseline model plant emissions for the natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from GHG Inventory, derived from GHGRP, EPA/GRI,

[33] U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

[34] The draft 2016 GHG Inventory was the most recent data available at the time of this analysis. The 2016 GHG Inventory was finalized April 15, 2016 with the same data that was used in the public review draft. Therefore, this analysis is consistent with the most recent final GHG Inventory.

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and 40 CFR part 98, subpart W tables as described above, and the component oil and natural gas production emission factors from AP-42[35]. Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the emissions from the production segment (e.g., oil production well sites and natural gas production well sites) are presented in Table 4-1. The emission factors in Table 4-1 are also used to calculate fugitive emissions from gathering and boosting stations.

Table 4-1. Oil and Gas Production Operations Average TOC Emissions Factors

Component Type	Component Service	Emission Factor[a] (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

4.2.2.1 Proposed Rule Well Site Model Plant

A model plant for natural gas and oil well sites was developed using the average number of wells associated with a well site using data from the DrillingInfo HPDI® database[36]. The analysis, described in the TSD for the proposed rule, determined that the national average of wells per well site was 1.81, and was rounded to 2.0 wells per well site for the model plant fugitive analysis for both natural gas production and oil production well sites.

For the proposed rule, average equipment count per well data from the EPA/GRI document for natural gas production well sites and GHG Inventory for oil production well sites were used to determine the number of production equipment located at a well site. The average equipment count per well for each of the equipment types were multiplied by the average number of wells at a well site (2) and then rounded up to the nearest integer.

The types of production equipment located at a natural gas well site includes: gas wellheads, separators, meters/piping, in-line heaters, and dehydrators. The types of components that are associated

[35] U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)
[36] Drilling Information, Inc. 2011. *DI Desktop.* 2011 Production Information Database.

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with this production equipment include: valves, connectors, OELs, and PRVs. Component counts for each of the production equipment items were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI report. Fractions of components were rounded up to the nearest integer.

Baseline fugitive emissions for the proposed rule were calculated using the estimated component counts for the natural gas well site and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS[37]. For the proposed rule, the fugitive emissions for the natural gas production well site model plant were determined to be 4.54 tons per year of methane and 1.26 tons per year of VOC.

For oil well sites, data from the GHG Inventory, derived from GHGRP reported data, were used to estimate equipment counts for these sources. The types of oil well site equipment include: oil well heads, separators, headers and heater/treaters. Fugitive emissions components counts for these equipment types were estimated using component count data from Table W-1C of 40 CFR part 98, subpart W.

The estimated baseline fugitive emissions from oil well sites were calculated using the estimated component counts and the total organic compound (TOC) emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. For the proposed rule, the fugitive emissions for the oil well site model plant were determined to be 1.09 tons per year of methane and 0.30 tons per year of VOC.

4.2.2.2 Final Rule Natural Gas Well Site Model Plant

During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016[38] GHG Inventory, and was used to revise the equipment

[37] Memorandum to Bruce Moore. U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking". July 28, 2011.
[38] In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

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counts for the natural gas well sites. The average equipment count per well was multiplied by the average number of wells per well site (2) and rounded to the next highest integer. The updated equipment counts per natural gas well site were 2 separators, 3 meters/piping, 1 in-line heaters, and 1 dehydrators per well. In comparison to the model plant in the proposed rule TSD, the only change in equipment counts was for meters/piping which increased from 1 to 3. Average component counts for each piece of equipment were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for natural gas production well sites is presented in Table 4-2.

The baseline fugitive emissions for the natural gas well site model plant were calculated using the revised component counts for the natural gas well site model plant and the oil and natural gas production AP-42 TOC emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the natural gas well site model plant were determined to be 5.50 tons per year of methane and 1.53 tons per year of VOC and are provided in Table 4-3.

4.2.2.3 Final Rule Oil Well Site Model Plant

Comments on the proposed rules stated that methane emissions from oil well site model plants were underestimated. While some oil wells produce very little natural gas (oil wells with a gas-to-oil-ratio less than 300 standard cubic feet of gas per stock barrel of oil), other oil wells produce significant volumes of natural gas (oil wells with a gas-to-oil-ratio greater than 300 standard cubic feet of gas per stock barrel of oil). To address these types of oil wells, two model plants were developed to estimate fugitive emissions from oil well sites. The oil well site model plant developed for the proposed rule was used to define the oils wells with a gas-to-oil ratio less than 300 standard cubic feet of gas per stock barrel of oil (< 300 GOR). During the comment period for the proposed rule, updated data on equipment counts per well (derived from GHGRP reported data) became available for 2013 (the most recent year of data available in the public review draft) from the draft 2016[39] GHG Inventory, and was used to revise

[39] In the final 2016 GHG Inventory, the equipment counts per well are the same as those in the draft GHG inventory used in this analysis.

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the equipment counts for the oil well sites. The equipment count for this model plant consists of 2 oil wellheads, 1 separator, 1 header, and 1 heater/treater. To develop the model plant for oil well sites with a gas-to-oil ratio greater than 300 standard cubic feet of gas per stock barrel of oil (> 300 GOR), three meters/piping were added to the equipment counts included for the < 300 GOR model plant to account for the handling of the natural gas from the well. Component counts for the oil well equipment (wellhead, separator, header, heater/treater) were obtained from Table W-1C of subpart W The component counts for meters/piping were obtained from the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per production equipment and rounding to the nearest integer. A summary of the fugitive emissions component counts for oil well site model plants are presented in Table 4-4.

Baseline model plant emissions for the oil well site model plants were calculated using the fugitive emissions component counts and the component oil and natural gas production emission factors from AP-42. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight ratios in the gas composition memorandum. The fugitive emissions for the < 300 GOR model plant were determined to be 1.23 tons per year of methane and 0.33 tons per year of VOC. The fugitive emissions for the > 300 GOR model plant were determined to be 2.75 tons per year of methane and 0.75 tons per year of VOC. A summary of the emissions are provided in Table 4-5.

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Table 4-2. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Equipment[a]				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
					Total	138.9	509.4	14.3	6.9
					Rounded Total	139	510	15	7

a. Data Source: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 4-3. Estimated Fugitive Emission Estimate for Natural Gas Well Site Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled Emission Factor[b] (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane[c]	VOC[d]
Valves	139	0.0045	4.196	1.166
Connectors	510	0.0002	0.684	0.190
OELs	15	0.002	0.201	0.056
PRVs	7	0.0088	0.413	0.115
		Total	5.50	1.53

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.
b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
c. Methane emissions calculated using 0.695 weight ratio for Methane/TOC obtained from gas composition memorandum.
d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

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Table 4-4. Average Fugitive Emissions Component Count for Oil Well Site Model Plant

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment[a]					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR)[a]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
						Total	29	54	42	0	2
Oil Well Model Plant (> 300 GOR)[b]											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
						Total	68	54	186	2	4

a. Oil well (<300 GOR) component counts obtained from Table W-1C pf 40 CFR part 98, subpart W.
b. Oil well (>300 GOR) component counts from 40 CFR Part 98, subpart W, Table W-1C.

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Table 4-5. Estimated Fugitive Emission Estimate for Oil Well Site Model Plant

Oil Well Site Model Plant Component	Model Plant Component Count[a]	Uncontrolled Emission Factor[b] (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane[c]	VOC[d]
Oil Well Model Plant (< 300 GOR)				
Valves	29	0.0045	0.876	0.243
Flanges	54	0.00039	0.185	0.039
Connectors	42	0.0002	0.056	0.016
OELs	0	0.002	0	0
PRVs	2	0.0088	0.118	0.033
		Total	1.23	0.33
Oil Well Model Plant (> 300 GOR)				
Valves	68	0.0045	2.053	0.571
Flanges	54	0.00039	0.185	0.039
Connectors	186	0.0002	0.250	0.069
OELs	2	0.002	0.027	0.007
PRVs	4	0.0088	0.236	0.066
		Total	2.75	0.75

a. Fugitive emissions component count values for model plant are based on a 2 wellhead pad and are rounded to the nearest integer.
b. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
c. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.
d. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

4.2.3 Compressor Stations

The proposed rule TSD evaluated fugitive monitoring at three types of compressor stations; gathering and boosting stations, transmission stations and storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas, such as the removal of water or hydrocarbons occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components (e.g., valves, connectors) that may be sources of fugitive emissions associated with these operations.

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4.2.3.1 Proposed Rule Compressor Station Model Plant

For the proposed rule TSD, baseline model plant emissions for compressor stations were calculated using the fugitive emissions component counts from the EPA/GRI document and the component oil and natural gas production emission factors from AP-42 for gathering and boosting stations and EPA/GRI emission factors for transmission and storage stations. Annual emissions were calculated assuming 8,760 hours of operation each year. The AP-42 emission factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors used to estimate the new source emissions from the gathering and boosting stations are presented in Table 4-1. In the proposed rule TSD, the fugitive emissions from gathering and boosting stations were estimated to be 35.1 tons per year of methane and 9.77 tons per year of VOC. The model plant fugitive emissions for transmission stations were estimated to be 62.4 tons per year of methane and 1.73 tons per year of VOC, and 164.4 tons per year of methane and 4.55 tons per year of VOC for storage stations.

4.2.3.2 Final Rule Compressor Station Model Plant

Gathering and boosting stations are sites that collect oil and natural gas from well sites and direct them to the natural gas processing plants. These stations have similar production equipment (including separators, meters, piping, compressors, in-line heaters, dehydrators and other equipment) to well sites; however, they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in Chapter 8 of this document. A summary of the fugitive emissions component counts for oil and gas gathering and boosting stations are presented in Table 4-6.

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The proposed gathering and boosting model plant did not change from proposal. Therefore, the baseline emissions that are discussed in Section 4.2.3.1 remain the same for the final TSD and are summarized in Table 4-7. The emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

4.2.3.3 Final Rule Natural Gas Transmission and Storage Model Plant

Natural gas transmission and storage stations are facilities that use compressors to move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include production equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compressors operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. The segments include fugitive emissions from components related to inlet and outlet pipelines, meter runs, dehydrators, and other piping located at the compressor building for transmission and storage stations, and injection/withdrawal components associated with the injection/withdrawal well piping at storage stations. This industry segment also includes emissions from compressor related components, but does not include emissions from compressor seals or site blowdown open-ended lines. The blowdown open-ended lines were included in the proposed rule TSD, but were determined, based on comments, to be a vent rather than a fugitive emission source. Therefore in this analysis, emissions from blowdown open-ended lines were removed from the component list and the associated emissions were not included in the total fugitive emissions from transmission and storage stations. For the other components at these facilities, fugitive emissions component counts and methane emission factors were obtained from the EPA/GRI study. A summary of the fugitive emissions component counts, component emission factors and baseline methane and VOC emissions for transmission and storage model plants are presented in Table 4-8. The average fugitive emissions for transmission stations were determined to be 40.4 tons per year of methane and 1.12 tons per year of VOC and 142.4 tons per year of methane and 3.94 tons per year of VOC for storage facilities. These emissions were used to estimate the potential emission reductions and cost of control of a fugitive emissions reduction program.

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Table 4-6. Average Fugitive Emissions Component Count for Gathering and Boosting Station Model Plant

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment[a]				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
					Total	906	2,864	83	48
					Rounded Total	906	2,864	83	48

a. Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 4-7. Estimated Fugitive Emissions for Gathering and Boosting Station Model Plant

Gathering and Boosting Station Model Plant Component	Model Plant Component Count	Uncontrolled Emission Factor[a] (kg/hr/comp)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Valves	906	0.0045	27.35	7.603
Connectors	2,864	0.0002	3.84	1.068
OELs	83	0.002	1.11	0.310
PRVs	48	0.0088	2.83	0.788
		Total	35.1	9.77

a. TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.
b. Methane emissions calculated using 0.695 weight ratio for methane/TOC obtained from gas composition memorandum.
c. VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from gas composition memorandum.

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Table 4-8. Estimated Fugitive Emissions for Natural Gas Transmission and Storage Model Plant

Component	Model Plant Component Count[a]	Component Methane Emission Factor[a] (Mscf/year/component)	Methane Emissions[b] (tpy)	VOC Emissions[c] (tpy)
Transmission Facility				
Valve	673	0.867	12.1	0.336
Control Valve	31	8	5.2	0.143
Connectors	3,068	0.147	9.4	0.260
OEL	51	11.2	11.9	0.329
PRV	14	6.2	1.8	0.050
		Total	40.4	1.12
Storage Facility				
Valve	1,868	0.867	33.7	0.933
Connector	5,571	0.147	17.0	0.472
OEL	353	11.2	82.3	2.77
PRV	66	6.2	8.52	0.236
Valve (Inj/With)	30	0.918	0.57	0.016
Connector (Inj/With)	89	0.125	0.23	0.006
OEL (Inj/With)	7	0.237	0.03	0.001
PRV (Inj/With)	1	1.464	0.03	0.001
		Total	142.4	3.94

a. Component counts and methane emission factors for non-compressor related components obtained from EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)
b. Methane emissions calculated by multiplying the model plant component count by the component methane emission factor and converting to tons using the conversion factor 0.02082 tons methane/Mscf methane.
c. VOC emissions calculated using 0.0277 weight ratio for VOC/methane obtained from Gas Composition memorandum.

4.3 Control Techniques

4.3.1 Potential Control Techniques

The use of OGI and Method 21 to monitor and reduce fugitive emissions from well sites and compressor stations was evaluated in the TSD for the proposed rule. Based on this analysis, it was determined that semiannual monitoring using OGI was BSER for both well sites and compressor stations. The EPA received numerous comments on this BSER determination and re-evaluated the OGI option using updated information received during the comment period. The re-evaluation for the final rule is provided in the following sections.

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4.3.2 Fugitive Emissions Detection and Repair with OGI

4.3.2.1 Description

The reduction of fugitive emissions from well sites and compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities) involves the development of a fugitive emissions monitoring plan. Under this option, the final rule states that monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company defined area. The monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

In order to estimate the cost of implementation of a monitoring and repair plan, the EPA needed to estimate the cost of repair, which is based on the number of components found to have fugitive emissions. Since OGI visualizes gaseous emissions using active or passive infrared imaging, the OGI the operator would not be able to determine the exact concentration or emission rate of the fugitive emissions; however, all visualized fugitive emissions would be required to be repaired. If a fugitive emissions component cannot be immediately repaired during the monitoring survey, the operator must repair or replace the component as soon as practicable, but no later than 30 days after detection of the fugitive emissions. For this resurvey, the operator may use OGI, Method 21 or the alternative screening procedures specified in section 8.3.3 of Method 21 to confirm that the component is no longer emitting fugitive emissions. When OGI is used for the resurvey, no visible emissions indicate that the fugitive emissions component has been repaired. When Method 21 is used for the resurvey, no detectable emissions (e.g., a concentration of less than 500 ppm above background) indicate that the fugitive emissions component has been repaired.

4.3.2.2 Emission Reduction Potential

Information in the white paper related to the potential emission reductions from OGI monitoring and repair varied from 40 to 99 percent. The data from these studies are based on the gathering of individual OGI surveys at various oil and natural gas segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found during the OGI survey and assumptions made by the authors. However, these studies in the white paper did not

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provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program. A report was found after the publication of the white paper from the Colorado Air Quality Control Commission[40] which estimated 40 percent reduction for annual OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy (≥ 6 to ≤ 12 tpy), 60 percent reduction for quarterly OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy (> 12 to ≤ 50 tpy), and 80 percent reduction for monthly OGI monitoring at well production tank batteries with an uncontrolled VOC emission greater than 50 tpy (> 50 tpy).

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, the EPA expects the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on the information in the studies and EPA's engineering judgement, the potential emission reduction percentages for the proposed rule were estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emissions reductions for annual, semiannual, and quarterly monitoring frequencies[41] were calculated using the data from the EPA Protocol document. For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500

[40] Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to Regulation Number 3 and 7 (5 CCR 1001-5 and 5 CCR 1001-9).* February 7, 2014.
[41] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program, April 25, 2016.

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ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF[42] using data from Subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semi-annual and quarterly monitoring, respectively.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emissions reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emissions reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.[43]

4.3.2.3 Cost Impacts

Costs for preparing an OGI fugitive emission monitoring and repair plan for a company defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

[42] ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, Revised May 2, 2016.
[43] See Emission Reduction Comparison - Well Sites.xls and Emission Reduction Comparison – Compressor Stations.xls in the docket for more information.

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- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be $57.80 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $231.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of $3,468.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Cost for annual monitoring was estimated to be $925 semiannual monitoring was estimated to be $1,850 and quarterly monitoring $3,699.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $58 for compressor stations (i.e., gathering and boosting stations, transmission stations, and storage facilities). For companies that own and operate well sites, the cost notification of compliance status was estimated to be $58 per well site for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of $1,272.
- Cost of a Method 21 Monitoring Device of $10,800.
- Costs for implementing a fugitive emission monitoring plan for a company defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:
- Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of $925 per monitoring event. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be $42 per monitoring event.
- The cost for OGI monitoring using an outside contractor was assumed to be $600 for a well site and $2,300 for a compressor station.[44]
- Annual repair costs were estimated to be $299 per monitoring event for well sites, $3,436 per monitoring event for gathering and boosting stations, $3,361 per monitoring event for transmission stations, and $6,946 per monitoring event for storage facilities. These costs were estimated assuming that 1.18 percent of the components are found to leak[45] during monitoring and 75 percent are repaired online and 25 percent are repaired offline.

[44] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

[45] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (e.g., pumps LL, valve LL, agitators LL). There is no information

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- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of $58 per hour. This assumes the company is able to perform the resurvey without retaining contractors. The capital costs include the cost of Method 21 instrumentation (estimated to be $10,800[46]). For compressor stations, the cost to resurvey repaired components was estimated to be $2.00 per component.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, notification of initial compliance status, and purchase of a Method 21 instrumentation. The total capital cost of these activities was calculated to be $17,620 per company defined areas for semiannual monitoring and $19,470 per company define areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company defined area[47], the capital cost per well site was estimated to be $759 for annual monitoring, $801 for semiannual monitoring and $885 for quarterly monitoring. For compressor stations (gathering and boosting stations, transmission stations and storage facilities) the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation was calculated to be $16,407 per facility. For gathering and boosting stations, this capital cost was assumed to be shared with other gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated 7 gathering and boosting stations, and the capital cost of each of these stations was estimated to be $2,393.

For all oil and natural gas segments, the annual cost includes; subsequent activities planning, OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and

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on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[46] Average of subsequent monitoring costs in Table 13 from the Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180

[47] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

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submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, semiannual and quarterly OGI surveys. The OGI monitoring cost memorandum[48] present the analyses for other costing methodologies, including a company-based OGI monitoring program and an OGI program using cost methodologies developed for the Colorado fugitive leak program to estimate the annual cost of implementing an OGI monitoring and repair program for oil and natural gas well sites, gathering and boosting, transmission and storage compressor stations for the respective OGI monitoring frequencies.

The cost per ton of emissions reduced was calculated using two separate methods. The first method allocated all of the costs to one pollutant and zero to the other (single-pollutant approach) using representative unit costs for each control option. The second method allocates the annual cost among the pollutants (multi-pollutant approach) that a given technology reduced (i.e., GHG (in the form of limiting methane emissions) and VOC). This proration was based on estimates of the percentage reduction expected for each pollutant. In the case of fugitives, the percent reductions for methane and VOC emissions are equal; and therefore the proration of the annual cost was divided equally and applied to the methane and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (i.e., gathering and boosting, transmission and storage). Table 4-9, 4-10 and 4-11 presents a summary of the cost of control for methane and VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly, respectively) based on the single-pollutant method. Tables 4-12, 4-13 and 4-14 present a summary of the capital and annual costs, and the cost of control for methane and VOC using the multi-pollutant method (i.e., 50 percent of the cost attributed to methane and 50 percent of the cost attributed to VOC).

[48] Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA, Evaluation of Cost methodologies for OGI Monitoring, April 6, 2016.

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4.3.2.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP-42 mobile emission factors[49] and assuming a distance of 70 miles to the well site or compressor station, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 pounds per year (lb/yr) of hydrocarbons, 6.0 lb/yr of carbon monoxide (CO) and 0.40 lb/yr of nitrogen dioxides (NO_X). The emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_X.

[49] AP-42: Compilation of Air Pollutant Emission Factors. Highway Vehicles, Light-Duty Gasoline Truck I, Model Year 1998+, 50,000 miles. https://www3.epa.gov/otaq/ap42.htm#highway

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Table 4-9. Summary of the Model Plant Cost of Control for Annual OGI Monitoring Option – Single Pollutant[50]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Well Site[d]	2.20	0.61	$759	$1,318	$809	$600	$2,158	$368	$1,324
Oil Well Site (GOR < 300)[d]	0.49	0.13	$759	$1,318	$1,204	$2,670	$9,953	$2,438	$9,089
Oil Well Site (GOR > 300 GOR)[d]	1.10	0.30	$759	$1,318	$1,063	$1,198	$4,380	$967	$3,533
Well Site Program Weighted Average[h]						**$1,224**	**$4,464**	**$993**	**$3,619**
Gathering & Boosting Station[e]	14.1	3.91	$2,393	$7,777	$7,777	$553	$1,990	$553	$1,990
Transmission Station[f]	16.2	0.45	$16,407	$10,117	$10,117	$626	$22,626	$626	$22,626
Storage Facility[g]	57.0	1.58	$16,407	$13,798	$13,798	$242	$8,751	$242	$8,751
Compressor Stations Program Weighted Average[h]						**$541**	**$3,098**	**$541**	**$3,098**

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

[50] As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

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Table 4-10. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option – Single Pollutant[51]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	3.3	0.917	$801	$2,285	$1,521	$693	$2,494	$461	$1,660
Oil Well Sites (GOR < 300) [d]	0.74	0.199	$801	$2,285	$2,114	$3,085	$11,503	$2,854	$10,639
Oil Well Site (GOR > 300 GOR)[d]	1.65	0.451	$801	$2,285	$1,903	$1,385	$5,062	$1,153	$4,215
Well Site Program Weighted Average[h]						**$1,415**	**$5,160**	**$1,183**	**$4,314**
Gathering & Boosting Station[e]	21.1	5.86	$2,393	$13,534	$13,534	$642	$2,309	$642	$2,309
Transmission Station[f]	24.2	0.67	$16,407	$15,868	$15,868	$655	$23,659	$655	$23,659
Storage Facility[g]	85.5	2.37	$16,407	$23,230	$23,230	$272	$9,822	$272	$9,822
Compressor Stations Program Weighted Average[h]						**$625**	**$3,480**	**$625**	**$3,480**

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for transmission and storage segments includes the cost of implementing the monitoring program.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $13,120 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $20,482 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

[51] *Ibid*.

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Table 4-11. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option -Single-Pollutant[52]

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	4.4	1.222	$885	$4,220	$3,201	$960	$3,453	$728	$2,619
Oil Well Sites (GOR < 300) [d]	0.99	0.265	$885	$4,220	$3,991	$4,272	$15,929	$4,041	$15,064
Oil Well Site (GOR > 300 GOR)[d]	2.20	0.602	$885	$4,220	$3,710	$1,918	$7,010	$1,686	$6,163
Well Site Program Weighted Average[h]						**$1,960**	**$7,145**	**$1,728**	**$6,299**
Gathering & Boosting Station[e]	28.1	7.81	$2,393	$25,049	$25,049	$891	$3,205	$891	$3,205
Transmission Station[f]	32.3	0.89	$16,407	$27,369	$27,369	$847	$30,606	$847	$30,606
Storage Facility[g]	114.0	3.15	$16,407	$42,093	$42,093	$369	$13,348	$369	$13,348
Compressor Stations Program Weighted Average[h]						**$864**	**$4,732**	**$864**	**$4,732**

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.
b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $24,622 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $39,345 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

[52] *Ibid*.

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Table 4-12. Summary of the Model Plant Cost of Control for the Annual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	2.20	0.61	$759	$1,318	$809	$300	$1,079	$184	$662
Oil Well Sites (GOR < 300) [d]	0.49	0.13	$759	$1,318	$1,204	$1,335	$4,977	$1,219	$4,545
Oil Well Site (GOR > 300 GOR)[d]	1.10	0.30	$759	$1,318	$1,063	$599	$2,190	$483	$1,767
Well Site Program Weighted Average[h]						**$612**	**$2,232**	**$496**	**$1,810**
Gathering & Boosting Station[e]	14.1	3.91	$2,393	$7,777	$7,777	$277	$995	$277	$995
Transmission Station[f]	16.2	0.45	$16,407	$10,117	$10,117	$313	$11,313	$313	$11,313
Storage Facility[g]	57.0	1.58	$16,407	$13,798	$13,798	$121	$4,375	$121	$4,375
Compressor Stations Program Weighted Average[h]						**$271**	**$1,549**	**$271**	**$1,549**

a. Assumes 40% reduction with the implementation of annual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $16,696 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $1,191 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $7,376 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $7,369 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $11,050 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 4-13. Summary of the Model Plant Cost of Control for the Semiannual OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Site[d]	3.3	0.917	$801	$2,285	$1,521	$347	$1,247	$231	$830
Oil Well Sites (GOR < 300) [d]	0.74	0.199	$801	$2,285	$2,114	$1,543	$5,752	$1,427	$5,319
Oil Well Site (GOR > 300 GOR)[d]	1.65	0.451	$801	$2,285	$1,903	$693	$2,531	$577	$2,108
Well Site Program Weighted Average[h]						**$708**	**$2,580**	**$592**	**$2,157**
Gathering & Boosting Station[e]	21.1	5.86	$2,393	$13,534	$13,534	$321	$1,155	$321	$1,155
Transmission Station[f]	24.2	0.67	$16,407	$15,868	$15,868	$327	$11,829	$327	$11,829
Storage Facility[g]	85.5	2.37	$16,407	$23,230	$23,230	$136	$4,911	$136	$4,911
Compressor Stations Program Weighted Average[h]						**$312**	**$1,740**	**$312**	**$1,740**

a. Assumes 60% reduction with the implementation of semiannual IR camera monitoring.
b. The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $17,620 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $2,151 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $13,133 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $13,120 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $20,482 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 4-14. Summary of the Model Plant Cost of Control for the Quarterly OGI Monitoring Option - Multi-Pollutant Method

Model Plant	Annual Emission Reductions[a] (tpy)		Capital Cost[b] ($)	Annual Cost ($/year)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[c] ($/ton)	
	CH_4	VOC		without savings	with savings	CH_4	VOC	CH_4	VOC
Natural Gas Production Well Sites[d]	4.40	1.222	$885	$4,220	$3,201	$480	$1,726	$364	$1,310
Oil Well Sites (GOR < 300) [d]	0.99	0.265	$885	$4,220	$3,991	$2,136	$7,964	$2,020	$7,532
Oil Well Sites (GOR > 300 GOR)[d]	2.20	0.602	$885	$4,220	$3,710	$959	$3,505	$843	$3,081
Well Site Program Weighted Average[h]						**$980**	**$3,572**	**$864**	**$3,150**
Gathering & Boosting Station[e]	28.1	7.8	$2,393	$25,049	$25,049	$445	$1,603	$445	$1,603
Transmission Station[f]	32.3	0.9	$16,407	$27,369	$27,369	$424	$15,303	$424	$15,303
Storage Facility[g]	114.0	3.2	$16,407	$42,093	$42,093	$185	$6,674	$185	$6,674
Compressor Stations Program Weighted Average[h]						**$432**	**$2,366**	**$432**	**$2,366**

a. Assumes 80% reduction with the implementation of quarterly IR camera monitoring.
b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of $19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was estimated to be $16,753 divided between 7 stations within a company defined area. The capital cost for the transmission and storage segments includes the cost of implementing the monitoring program of $16,407.
c. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $4 Mcf.
d. Annual cost for well sites includes annual monitoring and repair cost of $4,071 and amortization of the capital cost over 8 years at 7% interest.
e. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of $24,649 and amortization of the capital cost over 8 years at 7% interest.
f. Annual cost for transmission station includes annual monitoring and repair cost of $24,622 and amortization of the capital cost over 8 years at 7% interest.
g. Annual cost for storage facilities includes annual monitoring and repair cost of $39,345 and amortization of the capital cost over 8 years at 7% interest.
h. The weighted average for the segments were calculated using the 2012 activity counts of 3,346 gas well sites, 6,812 oil well sites (GOR<300), 9,330 oil well sites (GOR>300), 96 G&B stations, 4 transmission stations and 5 storage facilities.
Note: Gathering and boosting, transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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4.4 Regulatory Options

Monitoring of fugitive emissions was evaluated using OGI and Method 21 in the TSD for the proposed rule. For OGI, monitoring frequencies of annual, semiannual and quarterly were evaluated for well sites and compressor stations. Annual, semiannual and quartering monitoring was also evaluated for Method 21 at three different leak definitions; 500 ppm, 2,500 ppm and 10,000 ppm. Based on the results of these evaluations, semiannual monitoring using OGI was selected as BSER for well sites and compressor stations.

For this analysis, the OGI monitoring options were updated for the final rule using information received since proposal for the proposed rule. The OGI monitoring options include;

- Regulatory Option 1 – The implementation of an annual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 2 - The implementation of a semiannual OGI fugitive emissions monitoring and repair program.
- Regulatory Option 3 - The implementation of a quarterly OGI fugitive emissions monitoring and repair program.

4.4.1 OGI Monitoring Options

As noted above, the EPA calculated a weighted average cost of control for well sites (which includes oil wells, oil wells with associated gas, and natural gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review the EPA has summarized the cost of control for the options for well sites and compressor stations in Table 4-15.

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Table 4-15. Summary of the Cost of Control for the OGI Monitoring Options[53]

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Well Sites								
1 - Annual	$1,224	$4,464	$612	$2,232	$993	$3,619	$496	$1,810
2 - Semiannual	$1,415	$5,160	$708	$2,580	$1,183	$4,314	$592	$2,157
3 - Quarterly	$1,960	$7,145	$980	$3,572	$1,728	$6,299	$864	$3,150
Compressor Stations								
1 - Annual	$504	$2,225	$252	$1,112	$272	$1,201	$136	$601
2 - Semiannual	$580	$2,562	$290	$1,281	$396	$1,749	$198	$875
3 - Quarterly	$802	$3,540	$401	$1,770	$618	$2,728	$309	$1,364

4.4.2 EPA Method 21 as an Alternative to OGI Monitoring

4.4.2.1 Description

As an alternative to OGI monitoring, the EPA evaluated allowing the use of Method 21 to detect fugitive emissions from the collection of the fugitive emissions components at well sites and compressor stations to determine if the emissions reductions were equal to or greater than the emissions reductions achieved using OGI monitoring. As with OGI monitoring, emissions reductions vary based on the frequency of the monitoring of the components as well as the repair threshold. Based on comments received on the proposed rule, the EPA evaluated repair thresholds of 500 ppm and 10,000 for Method 21fugitive emissions monitoring.

4.4.2.2 Emission Reduction Potential

The EPA based the emission reduction analysis on the method for estimating leak detection and repair (LDAR) control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). Under this method, the control effectiveness is calculated using a stepwise approach that starts from the initial leak frequency and adds monitoring cycles until the leak frequency after monitoring reaches steady state. The difference between the initial leak rate and the final leak rate provides the control effectiveness for the fugitive emissions monitoring program. Other parameters included in the monitoring cycle calculations are the percentage of successfully repair

[53] *Ibid.*

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components, the percentage of new leaks and the percentage of leaks that were repaired but have reoccurred. The EPA Protocol does not provide these data for oil and natural gas production; only for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and refineries. The refinery emissions data are provided in non-methane organic compound (NMOC) units, which would require assumed TOC and methane weight fractions to determine the TOC emission factors, whereas the SOCMI emissions data is already based on TOC. The assumed TOC and methane weight fractions would add another level of uncertainty to the emission reduction percentage calculations if the refinery data were used. Therefore, we determined that using the SOCMI data would provide the best estimate of potential fugitive emission reduction percentages for a typical Method 21 monitoring program, and would be comparable to the potential fugitive emission reductions for oil and gas production, if the other parameters were available for this segment. The potential emission reduction from the implementation of a Method 21 program was calculated using this SOCMI data. Table 4-16 provides a summary of the parameters used to calculate the monitoring cycles. An example of the methodology is provided in Chapter 5.3.2 of the EPA Protocol document. The SOCMI data in the EPA Protocol document only included occurrence rates for monthly and quarterly monitoring. To calculate annual and semiannual occurrence rates, a logarithmic equation was derived from the data points. Initial leak frequencies were calculated using the EPA Protocol average leak rate equations for 500 and 10,000 ppm gas valves (see Table 5-4) and the average SOCMI emission factor for gas valves of 0.00597 kilograms per hour per source (see Table 2-1) and solving for leak fraction. The initial leak frequencies can also extrapolated using the lines in Figure 5-1 in the EPA Protocol document. The average leak fraction equation and calculated initial leak frequency are provided in Table 4-16.

Using the parameters in Table 4-16, the estimated emission reductions were calculated using the monitoring cycle approach in the EPA Protocol document. The leak frequency after monitoring reached steady state on the sixth monitoring cycle and the percent reduction was calculated. The results of the emission reductions are presented in Table 4-17.

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Table 4-16. Parameters and Assumptions Used to Calculate Monitoring Cycles

Parameter	Parameter Value (500 ppm)	Parameter Value (10,000 ppm)
Occurrence Rate	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly	5.46% Annual, 4.21% Semiannual, 2.97% Quarterly
Recurrence Rate	14%	14%
Unsuccessful Repair Rate	10%	10%
Initial Leak Frequency	13.53%	7.49%
Average Leak Rate Equation	ALR = 0.044*LF + 0.000017	ALR = 0.078*LF + 0.00013

Table 4-17. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair

Monitoring Frequency	Fugitive Percent Reduction		
	Method 21 Repair Threshold		OGI
	10,000 ppm	500 ppm	
Annual	42	68	40
Semiannual	55	75	60
Quarterly	67	83	80

As noted in Table 4-17 above, in all cases the percent reduction for the 500 parts per million Method 21 alternative is equal to or greater than the estimated OGI monitoring and repair percent reduction. The percent reduction for the 10,000 parts per million leak threshold was only greater than the OGI option for annual monitoring. Based on the estimated OGI monitoring model plant emission reductions (see Tables 4-9 through 4-14), Table 4-18 summarizes the estimated model plant emission reductions for the alternative Method 21 monitoring and repair option for 500 and 10,000 parts per million leak thresholds. For annual monitoring, both the Method 21 leak thresholds had higher emission reductions then the OGI monitoring option. Only the 500 parts per million leak threshold had emission reductions that were equal to or greater than the OGI monitoring option for semiannual and quarterly monitoring.

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Table 4-18. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gas Well Sites	2.20	0.61	2.32	0.65	3.75	1.04
Oil Well Sites (GOR < 300)	0.49	0.13	0.52	0.14	0.84	0.23
Oil Well Sites (GOR > 300)	1.10	0.30	1.16	0.32	1.88	0.51
Gathering & Boosting	14.1	3.91	14.8	4.12	24.0	6.67
Transmission	16.2	0.45	17.0	0.47	27.6	0.76
Storage	57.0	1.58	60.1	1.66	97.3	2.69
Semiannual Monitoring						
Gas Well Sites	3.30	0.92	3.01	0.84	4.14	1.15
Oil Well Sites (GOR < 300)	0.74	0.20	0.68	0.18	0.93	0.25
Oil Well Sites (GOR > 300)	1.65	0.45	1.51	0.41	2.07	0.57
Gathering & Boosting	21.1	5.86	19.3	5.35	26.5	7.37
Transmission	24.2	0.67	22.1	0.61	30.5	0.84
Storage	85.5	2.37	78.1	2.16	107.4	2.97
Quarterly Monitoring						
Gas Well Sites	4.40	1.22	3.70	1.03	4.53	1.26
Oil Well Sites (GOR < 300)	0.99	0.26	0.83	0.22	1.02	0.27
Oil Well Sites (GOR > 300)	2.20	0.60	1.85	0.51	2.27	0.62
Gathering & Boosting	28.1	7.81	23.7	6.58	29.0	8.06
Transmission	32.3	0.89	27.2	0.75	33.3	0.92
Storage	114.0	3.15	96.0	2.66	117.5	3.25

a. Assumes baseline emissions shown in Tables 4-5 and 4-8 and percent reduction shown in Table 4-21.

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5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves.

The 2012 NSPS promulgated requirements for control of emissions from pneumatic controllers in the production and processing segments. During development of the 2012 NSPS amendments, methane and VOC emissions for these sources were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD.

This chapter describes pneumatic controllers in the transmission and storage segment, including their function and associated emissions. Options available to reduce emissions from pneumatic controllers in the transmission and storage segment are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic controllers.

5.1 Process Description

5.1.1 Pneumatic Controllers

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the transmission and storage segment, an estimated 84,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[54]

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to

[54] U.S. EPA. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. OAR: Natural Gas Star. Washington, DC. February 2004.

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operate or control a valve. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) intermittent controllers release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized that "closed loop" systems are applicable only in instances with very low pressure[55] and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the controller's bleed stream. Since actuation emissions serve the controller's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation. Intermittent controllers are assumed to have zero bleed emissions.[56] For most applications (but not all), intermittent controllers serve functionally different purposes than bleed devices. Therefore, because intermittent controllers are inherently low emitting sources and the total emissions are dependent on the applications in which they are used, the EPA did not include intermittent controllers in this analysis. This is consistent with the treatment of these controllers under the 2012 NSPS.

In addition, not all pneumatic controllers are gas driven. At sites with electrical service sufficient

[55] Memorandum to Bruce Moore, U.S. EPA from Denise Grubert, EC/R. Meeting Minutes from EPA Meeting with the API. October 2011.

[56] The EPA received comments indicating that in some cases intermittent controllers had continuous emissions, and low-bleed pneumatic controllers were observed to have emission rates that were 270 percent higher than the EPA's emission factor for these devices, in some cases approaching the emission rate of high-bleed controllers. The EPA believes this is the result of malfunctioning controllers. The data the EPA have does not indicate that emissions from intermittent controllers are significant under normal operating conditions. The EPA are continuing to research this issue; however, the EPA do not believe additional requirements are warranted for such controllers based on the incidental, non-standard operation observed during these studies.

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to power an instrument air compressor electrically powered pneumatic devices can be used. In addition, it may be possible to use electrically powered pneumatic devices at sites with electrical service. These "non-gas driven" pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not gas driven, they do not directly release natural gas. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas source category likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas-driven devices.[57]

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emission

In the evaluation of the emissions from pneumatic controllers in the transmission and storage segment and the potential options available to reduce the emissions, the EPA consulted numerous studies and sources of information. Table 5-1 presents these studies and sources of information with an indication of the type of relevant information contained in each resource.

Table 5-1. Major Studies and Sources of Information Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
GHG Mandatory Reporting Rule and Technical Supporting Document[a]	EPA	2014	Nationwide	X	
Draft Inventory of GHG Emissions and Sinks: 1990-2014[b]	EPA	2016	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry[c]	GRI/EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft)[d]	EPA	1996	Nationwide	X	

[57] Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the GRI and EPA. EPA-600/R-96-080k. June 1996.

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Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Methane Emissions from the Petroleum Industry[e]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States[f]	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program[g]	EPA	2000-2010	Other	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the U.S.[h]	Multiple Affiliations, Academic and Private	2013	Nationwide	X	
Determining Bleed Rates for Pneumatic Devices in British Columbia[i]	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas[j]	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[k]	ICF International	2014	Nationwide	X	X

a. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.
b U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC.
c. Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report. Prepared for the GRI and EPA. EPA-600/R-96-080b. June 1996, Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology. Prepared for the GRI and EPA. EPA-600/R-96-080c. June 1996, Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors. Prepared for the GRI and EPA. EPA-600/R-96-080e. June 1996, and Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the GRI and EPA. EPA-600/R-96-080k. June 1996.
d. Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. EPA, June 14, 1996.
e. ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. EPA. 1999.
f. ENVIRON International Corporation. Oil and Gas Emission Inventories for the WRAP. Prepared for Western Governors' Association. December 27, 2005.
g. U.S. EPA. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. OAR: Natural Gas Star. Washington, DC. February 2004.
h. Allen, David, T., et al. 2013. *Measurements of methane emissions at natural gas production sites in the United States.* Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs. (http://www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html).
i. U.S. EPA. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. OAR: Natural Gas Star. Washington, DC. February 2004.
j. U.S. EPA. PRO Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. OAR: Natural Gas Star. Washington, DC. September 2004.
k. Canadian Environmental Technology Advancement Corporation (CETAC)-WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

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5.2.2 Representative Pneumatic Device Emissions

Continuous bleed pneumatic controllers can be classified into two types based on their emission rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.[58]

For this analysis, the EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the GHG Reporting rule[59], the Inventory of GHG Emissions and Sinks, new studies, as well as pneumatic controller vendor information obtained during the development of the NSPS rulemaking. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold. Since publication of the white paper, additional data have become available on emissions from pneumatic controllers, including reporting year 2014 data from GHGRP, and new measurement data from Subramanian et al. 2015, and Allen et al. 2014. GHGRP reported methane emissions for 2014 are 197,387 tons CO_2 Eq.in transmission, and 111,354 tons CO_2 Eq.in storage. The 2016 GHG Inventory, with emissions data for 1990-2014, calculates that national methane emissions for pneumatic controllers are 694,801 tons CO_2Eq. in transmission and 734,112 tons CO_2Eq. in storage. In the Subramanian et al. 2015 data set, the average emission rate for pneumatic controllers in the transmission segment was 12.9 scfh, and the average emission rate for pneumatic controllers in the storage segment was 21.2 scfh. Information was not available on the fraction of high bleed versus low and intermittent bleed controllers in each population.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have

[58] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the GRI in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed' rates of 0.1 to 0.5 cubic feet per minute are considered to be "high-bleed" types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[59] Available at http://www.epa.gov/ghgreporting/reporters/subpart/w.html.

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emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[60,61] While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. For this analysis, the EPA determined that best available emissions rate estimates for pneumatic controllers are presented in Table W-3 of the GHG Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W).

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from the average pneumatic controller type in the transmission and storage segment then estimate methane and VOC using a representative gas composition.[62]

The specific ratios from the representative gas composition were 0.908 lbs of methane per pound of natural gas and 0.0277 lbs VOC per pound methane. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

Table 5-2. Average Bleed Emission Estimates per Pneumatic Controller in the Natural Gas Transmission and Storage Segment[a, b]

High-Bleed (tpy)		Low-Bleed (tpy)	
Methane	**VOC**	**Methane**	**VOC**
3.013	0.083	0.227	0.00628

a. The conversion factor used in this analysis is 1,000 cubic feet (Mcf) of methane is equal to 0.0208 tons methane.
b. Natural gas transmission and storage emission factors for continuous bleed controllers were derived from Table W-1A of Subpart W.

5.3 Control Techniques

Several options to reduce emissions from pneumatic controllers were identified. Table 5-3 provides a summary of these options for reducing emissions from pneumatic controllers including: instrument air, non-gas driven controls, and enhanced maintenance. The use of instrument air systems, as discussed in the 2012 NSPS TSD[63], requires a constant source of electric power. Because electric power is not necessarily available at all transmission and storage affected facilities, the use of instrument air systems would not be practically feasible as a control for emissions from pneumatic controllers in this

[60] U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2010.
[61] All rates are listed at an assumed supply gas pressure of 20 psig.
[62] *See footnote* 3.
[63] *See footnote 2*.

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industry segment. Likewise, because the mechanical systems identified for use in this industry would require, at minimum, a backup source of electric power, this option is also not considered to be practically feasible for use in controlling these pneumatic controller emissions. The enhanced maintenance option is considered to be too variable and costly as a viable option for control pneumatic controller emissions. Based on these concerns, further analyses of these options were not conducted.

Given the various applicability, cost of emission reductions and cost issues with the control options, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic controllers. This conclusion is consistent with and supported by requirements of States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed controllers are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis.

As noted above, intermittent controllers are assumed to have zero bleed emissions. In addition, these controllers are assumed to not always be used in the same functional application as continuous bleed controllers. Therefore, intermittent controllers are not an appropriate option for control for all continuous bleed controllers. It is assumed intermittent, or no-bleed, controllers meet the definition of a low-bleed.

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Table 5-3. Alternative Control Options for Pneumatic Controllers

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around $165 more than high bleed versions.
Convert to Instrument Air[a]	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. These systems can achieve 100 percent reduction in emissions. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back- up natural gas pneumatic device.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed Device[b]	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems.

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Option	Description	Applicability/Effectiveness	Estimated Cost Range
Enhanced Maintenance[c]	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or lose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

a. U.S. EPA. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. OAR: Natural Gas Star. Washington, DC. February 2004.
b. U.S. EPA. PRO Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. OAR: Natural Gas Star. Washington, DC. September 2004.
c**.** CETAC-WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

5.3.1 Low-Bleed Controller Emission Reduction Potential

As discussed in the above sections, low-bleed controllers provide the same operational function as high-bleed controllers, but have lower continuous bleed emissions. As summarized in Table 5-4, the average achievable reduction in emissions per controller is estimated to be approximately 2.79 tons of methane and 0.077 tons of VOC. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device currently available on the market.

Table 5-4. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Controller with a Representative Low-Bleed Pneumatic Controller in the Natural Gas Transmission and Storage Segment

Baseline Emission reductions - High-Bleed Replaced with Low-Bleed[a] (tpy)	
Methane	**VOC**
2.79	0.077

a. Average emission reductions based on the typical emission rate from high-bleed and low-bleed controllers as listed in Table 5-2.

5.3.2 Emission Reduction Potential

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the transmission and storage segment.[64] This corresponds to 96 new high-bleed devices in the production segment (out of 120) that can be replaced with a new low-bleed alternative.

Applicability may depend on the function of instrumentation for an individual device such as whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and

[64] *See footnote* 54 .

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precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

5.3.3 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.[65] As Table 5-5 indicates, the average cost for a low bleed pneumatic is $2,471, while the average cost for a high bleed is $2,698.[66] Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of $227 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was annualized for a 15-year period using a 7 percent interest rate. This equated to an annualized cost of around $25 per low-bleed controller.

Table 5-5. Cost Projections for Representative Pneumatic Controllers[a]

Controller Type	Minimum Cost ($)	Maximum Cost ($)	Average Cost ($)	Low-Bleed Incremental Cost ($)
High-Bleed Controller	$387	$7,398	$2,471	$227
Low-Bleed Controller	$554	$9,356	$2,698	

a. Cost data from the 2012 NSPS was converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator. During the development of the 2012 NSPS major pneumatic controller vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

Although monetary savings associated with additional gas captured exist, these savings were not estimated for the transmission and storage segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. The cost per ton of emissions reduced was then calculated in two ways. The first method, the single pollutant approach, allocated all of the costs to one pollutant and zero to the other(s). The second method, the multipollutant approach, prorated costs among the pollutants that a given technology reduced (in this case GHG in the form or limiting methane emissions, and VOC). This proration was based on estimates of the percentage reduction expected for

[65] Ibid.
[66] Costs are estimated in 2012 U.S. Dollars.

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each pollutant. Table 5-6 provides a summary of low-bleed pneumatic cost of control.

Table 5-6. Cost-of Control for Low-Bleed Pneumatic Controllers versus High Bleed Pneumatics for the Transmission and Storage Segment[67]

Method	Incremental Capital Cost Per Unit[a] ($)	Total Annual Cost Per Unit[b] ($/year)	Emission reductions (tpy)		Cost of Control ($/ton)	
			Methane	VOC	Methane	VOC
Single Pollutant Approach 100%	$227	$25	2.79	0.077	$9	$323
Multipollutant Approach 50/50	$227	$25	2.79	0.077	$4	$162

a. Incremental cost of a low bleed controller versus a high bleed controller as summarized in Table 6-7.
b. Annualized cost assumes a 7 percent interest rate over a 15-year equipment lifetime.

5.3.4 Secondary Impacts

Low-bleed pneumatic controllers are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes would be created, no wastewater generated, and no electricity required. Therefore, there are no secondary impacts expected from the use of low-bleed pneumatic devices.

5.4 Regulatory Options

EPA evaluated the following Regulatory alternatives for pneumatic controllers:

- Regulatory Option 1. Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2. Establish an emissions limit equal to 6 scfh.

5.4.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely need to install instrument air systems to meet the threshold limit. Because facilities located in the transmission and storage segment might not always have sufficient electrical service to install an instrument air systems, this option would not be practically feasible in all situations. In addition, the cost of supplying electric power (which is highly variable) would need to be considered, which would likely render the cost of this control option unreasonable. Therefore, EPA rejected Regulatory Option 1 for facilities in the transmission and storage segment.

[67] As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the columns for the single pollutant approach present the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the transmission and storage segment. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria would be required to ensure the device function dictates the precision of a high bleed device. Therefore, EPA is utilizing Regulatory Option 2 for facilities in the transmission and storage segment.

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6.0 PNEUMATIC PUMPS

The natural gas industry uses a variety of pneumatic gas-powered pumps where there is no reliable electrical power to "control processing problems and protect equipment".[68] Pneumatic pumps are "small positive displacement, reciprocating units used throughout the oil and natural gas production sector to inject precise amounts of chemicals into process streams [or for freeze protection glycol circulation]."[69] Most chemical injection pumps (CIPs) fall into two main types: diaphragm, generally for heat tracing or plunger/piston, generally for chemical and methanol injection. This chapter describes pneumatic pumps including their function and associated emissions. Options available to reduce emissions from pneumatic pumps are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic pumps.

6.1 Process Description

In many situations across all segments of the oil and gas industry, pneumatic pumps make "use of gas pressure where electricity is not readily available."[70] In the production segment, the supply gas is mostly produced natural gas, whereas in processing, the supply gas may be compressed air. In these gas-driven pneumatic pumps, characteristics that affect methane emissions include "the frequency of operation, the size of the unit, the supply gas pressure, and the inlet methane composition."[71]

Pneumatic pumps are generally used for one of three purposes: glycol circulation in dehydrators, hot oil circulation for heat tracing/freeze protection, or chemical injection. Glycol dehydrator pumps "recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber."[72] Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks. CIPs, i.e. piston/plunger pumps or small diaphragm pumps, inject small desired amounts of chemicals such as methanol to prevent hydrate formation or corrosion inhibitors into process streams to regulate operations of a plant and protect the equipment.

[68] Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps. Prepared for the GRI and EPA. EPA-600/R-96-080b. June 1996.
[69] Ibid.
[70] Ibid.
[71] Ibid.
[72] U.S. EPA OAQPS. Oil and Natural Gas Sector Pneumatic Devices. April 2014.

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The piston and diaphragm pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas."[73]

Chemical injection pumps work by allowing a fluid to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged. This complete movement represents one full stroke.[74]

Typical chemicals injected in an oil or gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H_2S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Since the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.[75]

Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid.[76]

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[73] Ibid.
[74] Ibid.
[75] Ibid.
[76] GlobalSpec. Diaphragm Pumps Information. Available at http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

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In addition, not all pneumatic pumps are gas-driven. These "non-natural-gas driven" pneumatic pumps can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Because these devices are not natural gas-driven, they do not directly release natural gas or VOC emissions. However, these systems have other energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power an air control system. This analysis assumed that natural gas processing plants and natural gas transmission stations are the only facilities in the oil and natural gas source category highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas-driven devices.[77] The application of electrical controls is further elaborated in Section 6.2.

6.1.1 Emissions Data and Information

In the evaluation of the emissions from pneumatic pumps and the potential options available to reduce these emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each study.

Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
GHG Mandatory Reporting Rule	EPA	2012	Nationwide	X	
Inventory of U.S. GHG Emissions and Sinks: 1990-2014	EPA	2016	Nationwide/ Regional	X	
Methane emissions from the Natural Gas Industry	GRI/EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry	EPA	1999	Nationwide	X	
Natural Gas STAR Program	EPA	2012	Study Specific	X	X

[77] Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080k. June 1996.

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6.1.1.1 Representative Pneumatic Pump Emissions

For this analysis, the EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic pumps[78,79], Subpart W of the GHG Reporting rule[80], U.S. GHG Natural Gas and Petroleum Inventories (GHG Inventory)[81], and U.S. EPA GRI Report[82]. Subpart W and GHG Inventory use the emission factors form the U.S. EPA GRI Report. Similarly, EPA determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA GRI Report. For the activity factor, EPA determined the best available data is the GHG Inventory. Since publication of the white paper, additional data have become available on emissions from pumps, including GHGRP 2014 reporting year data. In 2014, reported methane emissions from chemical injection pumps in the production segment were 3,037,798 tons of CO_2 Eq. In the Inventory of Greenhouse Gas Emissions and Sinks: 1990-2014, national methane emissions from chemical injection pumps for 2014 are around 8,034,400 tons of CO_2Eq.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in each industry segment and then estimate VOC and HAP using the gas composition as was determined for the NSPS.[83] The specific ratios from the gas composition used for this analysis were 0.278 lbs VOC per pound methane in the production and processing segments. Table 6-2 summarizes the estimated bleed emission factors for a representative pneumatic pump by industry segment.

[78] U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004.
[79] U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.
[80] U.S. Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases from Petroleum and Natural Gas Systems – Subpart W. Washington, DC. November 2010.
[81] U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2012. Available at http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html.
[82] Gas Research Institute (GRI)/U.S. Environmental Protection Agency. Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R -96-080m).
[83] *See footnote* 3.

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Table 6-2. Average Bleed Emission Estimates per Pneumatic Pump

Segment/Pump Type	Emission Factor (scf/hr)[a]	Emission factor (Mcf/year)[b]	Emission Factor (tpy)[c]	Emission Factor (tpy)[d]
	Natural Gas	Methane	Methane	VOC
Production				
Diaphragm	22.45	163	3.46	0.96
Piston	2.48	18	0.38	0.11
Processing				
Small Diaphragm	22.45	163	3.46	0.96
Medium Diaphragm	22.45	163	3.46	0.96
Large Diaphragm	22.45	163	3.46	0.96
Small Piston	2.48	18	0.38	0.11
Medium Piston	2.48	18	0.38	0.11
Large Piston	2.48	18	0.38	0.11

a. Data Source: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA-600/R -96-080m), Sections 6.1 – Diaphragm Pumps and 6.2 – Piston Pumps. In the development of the emission factor, the GRI study incorporated a usage factor of 44% for diaphragm pumps and 40% for piston pumps.
b. Assumes 8760 hrs/yr and volumetric fraction of methane is 82.9% of natural gas in natural gas production and processing.
c. Assumes density of methane is 19.26 g/scf.
d. Assumes 0.27797 VOC content per pound of methane in natural gas production and processing.

6.2 Control Techniques

Gas-driven chemical pumps emit methane during normal operations. Depending on the type of pump, and the constraints of the location, companies can utilize a variety of technologies to reduce emissions. Table 6-3 provides a summary of these options for reducing emissions from gas-driven chemical pumps including: instrument air, solar, electricity, or routing emissions to a gas capture system or flare.

In situations where the replacement of gas-driven pumps with electric, solar and instrument air pumps is not possible, emissions can be captured via a vapor recovery unit (VRU), or sent to a combustion device. Emission control options for gas-driven pumps are described in the following section.

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Table 6-3. Alternative Control Options for Gas-Driven Pumps

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Convert to Solar Pumps	Solar power cells can generate electricity to power the pump. Solar cells can utilize a back-up power system to ensure reliability.	Solar powered pumps are only reliable in areas where the sun can power the pump reliably. These devices can result in 100 percent reduction in emissions where applicable.	Capital costs for converting to solar pumps is approximately $2,300 per device
Convert to Electric Pumps	Electric pumps can be used where a reliable source of electricity is available at the facility.	Electric powered pumps are only reliable with a constant supply of electricity. Overall, this option is applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Capital costs range between $1,807 to $5,352 plus electricity costs and an average annual maintenance cost of $263 per device.
Convert to Instrument Air**Error! Bookmark not efined.**	Instrument air systems can be used by replacing compressed air for the gas in pumps. These systems include a compressor, electrical power source, air dehydrator (depending on the type of pump), and volume tank.	Instrument air systems reduce emissions by 100 percent by replacing natural gas with instrument air. This technology offers economies of scale, where it is more economical at facilities with more pneumatic pumps. The system requires a reliable source of electrical power.	A complete cost analysis is provided in Section 6.3.3 System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Route Natural Gas to an Existing Control Device	Routing natural gas from a gas-driven pump entails piping to a control device inlet stream.	Routing natural gas pumps to a combustion device reduces VOC and methane emissions by 95 percent. Routing natural gas to a control device is an option when a control device with available capacity is present on site.	Capital costs will vary depending on the distance of pipeline necessary, but are approximately $5,433 per device.
Route Natural Gas to Newly Installed Control Device	Routing natural gas from a gas-driven pump to a control device requires installation of a control device and piping between the pump and the control device.	Routing natural gas-driven pumps to a combustion control device typically reduces VOC and methane emissions by 95 percent. Routing natural gas to a control device is an option when utilities (i.e., electricity, water) needed to run the device are readily available.	Capital costs will be approximately $48,500 with annual costs around $104,000.
Route Natural Gas to Existing Gas Capture System	Routing natural gas from a gas-driven pump entails piping to a VRU.	Routing natural gas-driven pumps to a VRU reduces VOC and methane emissions through gas capture where emission reduction efficiencies are typically 95 percent. Routing natural gas	Capital costs will vary depending on the distance of pipeline necessary, but are estimated to be approximately $5, 433 per device.

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Option	Description	Applicability/Effectiveness	Estimated Cost Range
		to a VRU is applicable when an existing VRU with available capacity is present on site.	
Route Natural Gas to Newly Installed Gas Capture System	Routing natural gas from a gas-driven pump to a gas capture system requires the installation of a gas capture system such as a VRU and piping between the pump and the capture system. There must also be an onsite use for the captured gas such as a combustion engine; otherwise, a control device would be required.	Installing a VRU and sending natural gas from pumps results in emission reductions of approximately 95percent. This option is most effective at facilities with a large number of pumps, and other emission sources that can also be sent to the VRU.	Capital costs will be approximately $36,000 with annual costs around $7,500.

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6.2.1 Solar Pumps

6.*2.1.1 Emissions Reduction Potential*

Solar pumps provide the same functionality as gas-driven pumps, and can be utilized at remote sites where a reliable source of electricity is not available. Solar-charged direct current (DC) pumps can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 pounds per square inch gage (psig) and have zero natural gas emissions. Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in methane and VOC emissions. Therefore, based on the emissions from Table 6-2 above, the EPA estimates converting natural gas-driven chemical pumps to solar-powered pumps can reduce methane emissions by 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump for all segments. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a natural gas-driven pump with a solar-powered pump will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year per piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a natural gas-driven pump with a solar-powered pump will reduce methane emissions by 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

6.2.1.2 Effectiveness

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in methane and VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Solar-powered pumps are typically low volume pumps that inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

6.2.1.3 Cost Impacts

The primary costs associated with conversion to solar pumps are the initial capital expenditures and annual maintenance costs which are typically lower than gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar powered pumps includes the capital cost of replacing the pump with a solar powered pump and operating cost. The operating costs are estimated to be 10 percent of the capital costs. Based on Natural Gas STAR document, “PRO Fact Sheet:

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Convert Natural Gas-Driven Chemical Pumps"[84], the cost for solar-powered electric pumps are approximately $2,000 with solar panels having a lifespan of 15 years and electric motors lasting 5 years. The total capital cost, including installation and labor are $2,227 (2012 dollars). The EPA estimates there would be no additional annual operating cost for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a natural gas-driven pump with a solar pump is $317. In addition, the use of electric pumps will have savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on $4.00 per Mcf would be $786 per year for diaphragm pumps and $87 per year per piston pump.

6.2.1.4 Secondary Impacts

No secondary impacts from conversion to solar powered pumps are expected.

6.2.2 Electric Pumps

6.2.2.1 Emission Reduction Potential

Electric pumps also provide the same functionality as gas-driven pumps, and are only restricted by availability of a reliable source of electricity. Electric pumps have zero natural gas emissions, as summarized in Table 6-4, and converting gas-driven chemical pumps to an electric pump can reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a pneumatic pump with an electric pump will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year for a piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a pneumatic pump with an electric pump will reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump and VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

[84] U.S. EPA. PRO Fact Sheet No. 202. Convert Natural Gas-Driven Chemical Pumps. Available at http://www.epa.gov/gasstar/documents/convertgasdrivenchemicalpumpstoinstrumentair.pdf.

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6.2.2.2 Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at processing plants or large dehydration facilities that have access to reliable power.

6.2.2.3 Cost Impacts

The primary costs associated with converting natural gas-driven pumps to electric pumps are the initial capital expenditures, installation and ongoing operation and maintenance. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"[85] the cost of electric pumps to replace diaphragm pumps is $4,647 and to replace a piston pump is $1,819 in 2012 dollars depending on the horsepower of the unit.[86] The annual operating costs for the electric pumps is estimated to be $293. Annualizing the capital cost over the life expectancy of the pump at a 7 percent discount rate, the annual cost for replacing a natural gas-driven pump with an electric pump is $954 for diaphragm pump, and $552 for a piston. In addition, the use of electric pumps will have savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year. The value of the natural gas saved based on $4.00 per Mcf would be $786 per year for diaphragm pumps and $87 per year per piston pump.

6.2.2.4 Secondary Impacts

The secondary impacts from electric pumps are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

6.2.3 Instrument Air System

6.2.3.1 Process Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same natural gas-driven pumps can be used for natural gas and compressed air, without altering any of the parts of the pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to a reliable source of electricity can install an instrument air system. A description of each of the

[85] Ibid.

[86] U.S. EPA. Lessons Learned. Replacing Gas-Assisted Glycol Pumps with Electric Pumps. Available online - http://www.epa.gov/gasstar/documents/ll_glycol_pumps3.pdf.

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components as described in the Natural Gas STAR document, "PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air":[87]

- Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.
- A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.
- Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, without affecting the process control functions.

6.2.3.2 Emission Reduction Potential and Effectiveness

Instrument air eliminates all emissions from natural gas-driven pumps, but can only be used in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more

[87] *See footnote 78.*

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economical and therefore more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning.[88] Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that replacement of a pneumatic pump converted to instrument air will reduce VOC emissions by 0.96 tons per year per diaphragm pump and 0.11 tons per year for a piston pump. Likewise, for the transmission and storage segment, the EPA estimates that replacement of a pneumatic pump converted to instrument air will reduce methane emissions by an estimated 3.46 tons per year per diaphragm pump and 0.38 tons per year per piston pump and VOC emissions by 0.1 tons per year per diaphragm pump and 0.01 tons per year for a piston pump.

6.2.3.3 Cost Impacts

As stated earlier, instrument air conversions require a compressor with a capacity based on the number of control loops at the location. The compressor size is equivalent to the volume of natural gas used by the control loops after adjusting for gas losses during drying, plus any utility air necessary at the facility. This volume can either be calculated via a meter or utilizing a rule of thumb of one cubic foot per minute (cfm) of instrument air per control loop.[89]

For natural gas processing, the cost of emission reductions of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because the EPA assumes new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. As was discussed in the 2011 NSPS TSD, the EPA assumes that existing processing plants have an instrument air system in place, including backup systems, and that the cost of adding additional air load to the system would be confined to the incremental cost of upgrading or replacing the compressor and connecting the natural gas-driven pumps to the system. Therefore, for this analysis, the cost being attributed to the replacement of natural gas-driven pumps with air-driven pumps includes the annualized cost of replacing or adding a compressor and installation of the associated piping to connect the pumps to the existing system, and the associated energy costs for operating the new

[88] U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004.
[89] Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080b. June 1996.

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compressor. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps.

Because the EPA has no data to characterize the number and types of gas-driven pumps at natural gas processing plants, the EPA developed several model plant scenarios that would likely cover a reasonable range of the numbers and types of pumps that might be found at natural gas processing plants. The model plants represented processing plants with 4, 10, 20, 50 and 100 total pumps. Because there is a significant variation in emission profiles between natural gas-driven diaphragm and piston pumps, the EPA also evaluated, within each model plant, three distribution scenarios for the pumps (i.e., 50 percent diaphragm and 50 percent piston, 25 percent diaphragm and 75 percent piston, and 75 percent diaphragm and 25 percent piston.). In our analysis, the EPA determined the total additional air capacity needed based on the estimated natural gas emission rate for the two types of natural gas-driven pumps, and based on the model plant scenarios, determined the volume of additional air capacity that would need to be addressed by the compressor. The EPA then based the analysis on the use of 90 percent of available capacity of the system. The EPA determined that there were basically three sizes (small, medium and large) compressors that would address the range of model plants. Table 6-4 summarizes the model plant analysis of required system capacity and potential emission reductions. The compressor costs used in our analysis were drawn from the costing analysis conducted for the 2011 NSPS proposal for instrument air systems for pneumatic controllers (See Section 5 of the 2011 TSD). The EPA estimated costs, including operating costs, at three size levels; small, medium and large. Table 6-5 summarizes the cost replacement of the various size compressors into an existing instrument air system.

Because gas emissions are avoided, the use of an instrument air system to control natural gas-driven pumps will have natural gas savings realized from the gas not released. The EPA estimates that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will save of 22 Mcf per year. The value of the natural gas saved based on $4.00 per Mcf would be $786 per year per diaphragm pumps and $87 per year per piston pump.

6.2.3.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

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Table 6-4. Model Plant Characterization for Replacing Gas-Driven Pumps with Instrument Air System

Model Plant Size	Annual Compressor Cost[a]	Pump Distribution Scenario[b]	Total Number of Pumps	Number of Diaphragm Pumps	Number of Piston Pumps	Total Additional Air Capacity Required (scf/hour)	Gas Saved[c] (Mcf)	Emission reductions[d] (tpy)	
								Methane	VOC
Small	10,051	50/50	4	2	2	50	49.8	7.7	2.1
		75/25	4	3	1	70	69.8	10.8	3.0
		25/75	4	1	3	30	29.9	4.6	1.3
Medium Small	10,051	50/50	10	5	5	125	124.6	19.2	5.3
		75/25	10	7.5	2.5	175	174.5	26.9	7.5
		25/75	10	2.5	7.5	75	74.7	11.5	3.2
Medium	32,271	50/50	20	10	10	249	249.2	38.4	10.7
		75/25	20	15	5	349	349.1	53.8	15.0
		25/75	20	5	15	149	149.4	23.0	6.4
Medium Large	72,394	50/50	50	25	25	623	623.1	96.0	26.7
		75/25	50	37.5	12.5	873	872.7	134.5	37.4
		25/75	50	12.5	37.5	374	373.5	57.5	16.0
Large	72,394	50/50	100	50	50	1,246	1246.2	192.0	53.4
		75/25	100	75	25	1,745	1745.4	269.0	74.8
		25/75	100	25	75	747	747.0	115.0	32.0

a. See Table 6-5 for the compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in $786 savings per diaphragm pump and $87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

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Table 6-5. Cost of Compressor Replacement for Existing Instrument Air System

Compressor Size	Air Capacity (scf/hour)	Capital Cost ($)	Capital Cost + Installation[a] (2008)	Total Capital Cost[b] ($2012)	Annualized Cost[c] ($)	Labor Cost ($2008)	Power Cost ($2008)	Total O&M[d] ($2008)	Total O&M[d] ($2012)	Annual Cost[e] ($)
Small	135	$3,772	$5,658	$5,999	$854	$1,334	$7,340	$8,674	$9,197	$10,051
Medium	562	$18,855	$28,282	$29,989	$4,270	$4,333	$22,075	$26,408	$28,002	$32,271
Large	1,350	$33,183	$49,775	$52,779	$7,515	$5,999	$55,188	$61,187	$64,880	$72,394

a. Installation cost is estimated to be 50 percent of capital cost.
b. Cost was escalated to 2012 using the FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (http://research.stlouisfed.org/fred2/series/GDPDEF/#).
c. Annualized capital cost using a 7% interest rate and an equipment life of 10 years.
d. The total O&M includes both the annual labor cost and the annual power cost.
e. The total annual cost includes the annualized capital cost and the total O&M.

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6.2.4 Install or Route Gas to Combustion Device

6.2.4.1 Emission Reduction Potential

Routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas emitted, but rather combusts the gas volume. Costs for routing the natural gas to a combustion device are further described in Table 6-3. The EPA estimates capture and combustion device efficiency to be 95 percent reduction. Therefore, methane reductions are estimated to be 3.29 tons per year for a diaphragm pump and 0.36 tons per year for a piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that routing emissions to a combustion device will reduce VOC emissions by 0.91 tons per year per diaphragm pump and 0.1 tons per year for a piston pump.

6.2.4.2 Effectiveness

Capture systems combined with combustion devices are considered a reliable mechanism to reduce approximately 95 percent of emissions. Each combustion device requires a reliable ignition source where the average gas consumption per pilot burner is 70 scf per hour.[90] Most processing plants or large dehydration facilities already have at least one existing combustion device.

6.2.4.3 Cost Impacts

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital costs and operating costs. Based on the analysis conducted for the 2012 NSPS for a combustion device to control emissions from storage vessels,[91] the capital cost for installing a new combustion device is $32,301 in 2008 dollars. The EPA estimates that the capital cost for installing a new combustion device is $34,250 and the annual operating costs are $17,001 in 2012 dollars. Based on the life expectancy for a combustion device, the EPA estimate the annualized cost of installing a new combustion device to be $21,877 using a 7 percent discount rate. For the proposal, the estimated annualized cost of routing emissions to an existing combustion device was $285 using a 7 percent discount rate. Because the gas captured is combusted there is no gas savings associated with use of a combustion device.

Based on comments received from the proposal, the EPA revised our estimated cost for routing emissions to an existing control device. EPA received cost estimates from two commenters that claimed

[90] Ibid.
[91] U.S. EPA docket ID: EPA-HQ-OAR-2010-0505-0045.

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that the proposed cost estimate for routing emissions to an existing control device or process was too low. One commenter[92] claimed that there were engineering costs in addition to the cost to pipe emissions in a closed vent system (CVS) to a control device and that the total capital cost would be $5,800. Another commenter[93] provided detailed cost with respect to installing a CVS that considers that there could be a significant distance between the pump location and the control device on a site. This commenter suggested that the cost would be $8,500 to route emissions through a CVS to an existing control device.

The cost estimates the EPA received from the commenters were not directly comparable to each other, nor were they directly comparable to the proposal cost estimate. Therefore, in order to consider the additional costs provided by the commenters in our analysis, the EPA treated the costs as individual, all-inclusive cost estimates for routing emissions to an existing control device. The EPA calculated the average of the capital cost from proposal and the two commenter estimates and found the estimated capital cost to be $5,433. Using the 7 percent discount rate, the EPA calculated the annualized cost for each of the commenter estimates to be $826 (from the $5,800 estimate) and $1,210 (from the $8,500 estimate). The EPA averaged these annualized costs with the proposed annualized cost of $285 which resulted in a revised annualized cost of $774.

6.2.4.4 Secondary Impacts

There are secondary impacts from combustion of emissions routed from natural gas-driven pumps. The combustion of the recovered natural gas creates secondary emissions of hydrocarbons, NO_X, CO_2, and CO. A summary of the estimated secondary emission are presented in Table 6-6. No other wastes should be created or wastewater generated.

[92] EPA-HQ-OAR-2010-0505-6884-A1.
[93] EPA-HQ-OAR-2010-0505-6881.

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Table 6-6. Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device

Pump Type	Secondary Impacts (tpy)				
	THC[a]	CO[b]	CO_2[c]	NO_x[d]	PM[e]
Diaphragm	0.02	0.03	14	0.01	0
Piston	0.002	0.004	2	0.001	0

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.
b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.
c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.
d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.
e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a "lightly smoking" flare.

6.2.5 Install or Route Gas to VRU

6.2.5.1 Emission Reduction Potential

Use of a vapor recovery technology has the potential to reduce the emissions from natural gas-drive pumps by 100 percent if all vapor is recovered. However, the effectiveness of the gas capture system and downtime for maintenance would reduce capture efficiency and therefore, the EPA estimates that routing emissions from a natural gas-driven pump to an existing VRU, or a newly installed VRU can reduce the gas emitted by approximately 95 percent, while at the same time, capturing the gas for beneficial use. The EPA estimates that methane emission reductions for routing gas to a VRU to be 3.29 tons per year for a diaphragm pump and 0.36 tons per year for a piston pump. Based on the gas composition for natural gas in the production segment, the EPA estimates that routing emissions to a VRU will reduce VOC emissions by 0.91 tons per year per diaphragm pump and 0.1 tons per year for a piston pump.

6.2.5.2 Effectiveness

VRUs are reliable, typically with a backup compressor system to allow for shutdowns and repairs. VRUs are more economical for facilities with multiple gas emission sources that can be routed to the VRU. Some of these other emission sources can include tanks, dehydrators, and compressors and as a result, VRUs are more common at natural gas processing plants and large dehydration facilities.

6.2.5.3 Cost Impacts

Routing natural gas to an existing VRU or installing a new VRU, have both capital costs and maintenance costs. Based on the analysis conducted for the 2012 NSPS for control of emissions from

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storage vessels[94], the capital cost and installation costs for a VRU is estimated to be $98,186 in 2008 dollars. The EPA estimates the capital cost of installation of a VRU to be $104,111 and the annual operation and maintenance cost to be $9,932 in 2012 dollars. If a VRU is already on site, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. The total annualized cost of a new VRU is estimated to be $24,755 based on a 7 percent discount rate.

As discussed above, for the proposal the EPA estimated the cost of routing emissions to an existing VRU to be $2,000 in 2012 dollars. The annualized cost of routing gas to an existing VRU is estimated to be $285 based on a 7 percent discount rate. In addition, because there is potential for beneficial use of gas recovered through the VRU, the EPA estimates an annual gas recovered as 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The gas savings realized is estimated to be $749 per diaphragm pump and $84 per piston pump, per year based on $4.00 value per Mcf of gas recovered.

As discussed above in section 6.2.4.3 with respect to routing emissions to an existing combustion control device, the EPA considered additional cost estimates submitted during the proposed rule public comment period and have revised the estimated cost for routing emissions to an existing VRU to be the same as the cost of routing to an existing combustion device, or $774 annualized cost.

6.2.5.4 Secondary Impacts

The secondary impacts from use of a VRU are indirect, variable and dependent on the electrical supply used to power the VRU. No other secondary impacts are expected.

6.3 Regulatory Options

The control technologies evaluated for natural gas-driven pumps included options that provided 100 percent emission reductions. These options included replacing the pumps with solar-powered pumps or electric pumps or use of instrument air systems to eliminate natural gas emissions. The EPA also evaluated gas recovery and gas combustion technologies that would result in 95 percent emission reductions.

The use of instrument air systems and electric pumps requires a consistent supply of electric power and the use of solar-powered pumps and routing emissions to a VRU requires a reliable supply of backup electric power. Because reliable electric power is not universally available for production, gathering and boosting and transmission and storage locations these control technologies were

[94] Ibid.

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determined to not be technically viable options for those segments. Because electric power is typically available at natural gas processing plants, those technologies are considered technically viable for the processing segment.

For the final rule, we have revaluated our best available emissions and usage data for piston pumps. Based on our emissions data these pumps have inherently low emissions primarily due to size. In addition, available information indicates that these pumps are typically used intermittently which further limits their emission potential. Therefore, we determined that based on their low emissions, control of piston pumps is not warranted at this time and we have excluded piston pumps from further evaluation.

Based on the costs and estimated emission reductions for each of the viable emission control alternatives, the EPA further evaluated the cost per ton of emissions reduced for methane and VOC. The cost per ton of emissions reduced was calculated in two ways. The first method, or single-pollutant approach, allocated all of the costs to one pollutant and zero cost to the other. The second method, or the multipollutant approach, allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). This multipollutant approach is based on estimates of the percentage reduction expected for each pollutant.

Based on the above considerations, for the proposal the EPA evaluated the following regulatory alternatives:

- Regulatory Option 1. Require a zero emission standard for diaphragm pumps at natural gas processing plants.
- Regulatory Option 2. Require a 95 percent emissions reduction standard for diaphragm pumps production facilities.
- Regulatory Option 3. Require a 95 percent emissions reduction standard for diaphragm pumps production facilities only where an existing control device or process is available.

6.3.1 Evaluation of Regulatory Options

Regulatory Option 1 would require zero emissions of methane and VOC from gas-driven, diaphragm pumps at natural gas processing plants. To attain this emission reduction, the facility would need to either replace the natural gas-driven diaphragm pumps with solar-powered or electric pumps or use instrument air systems to replace natural gas-driven function with air-driven function. The EPA evaluated the cost of control for each of these options based on the estimated emission reductions as detailed above.

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Using the single-pollutant (allocate all of the costs to one pollutant and zero to the other) for calculating cost of control, for the use of an instrument air system at natural gas processing plants the EPA estimates the cost per ton of methane reduced to be between $374 and $2,185 and the cost per ton of VOC reduced to be between $1,344 and $7,861 without considering gas savings. With gas savings, for the use of an instrument air system at natural gas processing plants, the cost per ton of methane reduced was $146 and $1,957, and the cost per ton of VOC reduced was between $527 and $7,042. Using the multi-pollutant method of allocating cost between methane and VOC, the EPA estimates the cost of control, without considering gas savings, ranged from $187 to 1,093 per ton of methane reduced and $672 and $3,930 per ton of VOC reduced. When considering gas savings, the EPA found the cost of control to range from $73 to $979 per ton of methane reduced and $263 to $3,521 per ton of VOC reduced. The range of cost per ton is dependent on the size of the system/compressor needed for the facility.

Under the single pollutant approach, the EPA estimates the cost of control for installation of either an electric pump or solar-powered pumps to be between ($136) and $1,223 per ton of methane reduced or between ($489) and $4,235 per ton of VOC reduced, considering gas savings.[95] Under the multi-pollutant approach and considering savings, the EPA estimates the cost of control for installation of either an electric pump or solar-powered pump to be between ($68) and $1,337 per ton of methane reduced and between ($244) and $2,112 per ton of VOC reduced, considering gas savings. The EPA considers these costs to be reasonable. Based on these cost of control values for methane and VOC, EPA determined that Regulatory Option 1 is appropriate for the natural gas processing segment. Tables 6-7 through 6-10 summarize the cost of control for each of these options for the natural gas processing segment. For the final rule, the EPA had no changes to this analysis for natural gas processing plants.

The control technologies that produce zero emissions (or 100 percent reduction in emissions) (i.e., solar-powered and electric pumps and instrument air systems) are not technically viable alternatives for the production and transmission and storage segments where reliable electric power is not universally available. Instead, the available control technologies for those segments produce a 95 percent emission reduction. Therefore, the second regulatory option would require a 95 percent reduction in emissions at production sites, transmission stations and storage facilities. To attain this emission reduction, the facility could route emissions to a VRU or a combustion device.

[95] Negative cost reflects a net savings considering gas saved.

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For the proposal, the EPA calculated the cost of control for this option for each control technology by the single-pollutant and multi-pollutant methods described above. For the installation of a new VRU or combustion device, the cost of control for methane and VOC emission reductions ranged from $3,652 to over $1 million per ton. The cost of control for a new combustion device ranged between $3,328 to over $1 million per ton. Based on these cost of control values for methane and VOC, Regulatory Option 2 was rejected for all segments. For the final rule, the EPA had no changes to this analysis. Tables 6-11 through 6-14 summarize the cost of control for Option 2 for all segments.

For the proposal, EPA evaluated Regulatory Option 3 to require 95 percent control of emissions in all segments only where an existing control device or process was available. The sole cost associated with this option that would be attributed to the emission reduction would be the cost of routing the diaphragm pump emissions to the control device. As discussed above, for the final rule, the EPA has revised the estimated cost to route emissions to either an existing VRU or an existing combustion device based on commenter provided cost estimates. Under the new analysis the capital cost is approximately $5,433, which when annualized at a 7 percent discount rate, resulted in an annualized cost of $774. Based on this annualized cost, using the single-pollutant approach of calculating cost of control, the cost of control for methane emission reductions with an existing VRU or an existing combustion device is $235 per ton for all segments. The cost of control for VOC reductions is $847 per ton for the production and processing segments and $8,496 per ton for the transmission and storage segment. Considering natural gas savings when an existing VRU is used, the cost of control for methane emission reductions is $8 per ton for all segments. The cost of control for VOC emission reductions is $27 per ton for the production and processing segments and $274 per ton for the transmission and storage segment.

Using the multi-pollutant approach of calculating cost of control, the cost of control for methane emission reductions with an existing VRU or an existing combustion device is $118 per ton for all segments. The cost of control for VOC reductions is $423 per ton for the production and processing segments and $4,248 per ton for the transmission and storage segment. Considering natural gas savings when an existing VRU is used, the cost of control for methane emission reductions is $4 per ton for all segments. The cost of control for VOC emission reductions is $14 per ton for the production and processing segments and $137 per ton for the transmission and storage segment... EPA found these methane costs to be reasonable and selected Option 3 for control of natural gas-driven diaphragm pump emissions for all segments. Tables 6-15 through 6-16 summarize results of our cost of control analyses.

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Table 6-7. Cost of Control for Use of Instrument Air Systems at Natural Gas Processing Plants - Single-Pollutant[96]

Plant Size	Compressor Cost[a]	Scenario[b]	Total Number of Pumps	Total Gas Saved[c] (Mcf)	Emission reductions[d] (tpy)		Cost of control (without savings) ($/ton)		Cost of control (with savings)[c] ($/ton)	
					Methane	VOC	Methane	VOC	Methane	VOC
Small	$10,051	50/50	4	49.8	7.7	2.1	$1,309	$4,708	$1,081	$3,890
		75/25	4	69.8	10.8	3.0	$934	$3,360	$707	$2,543
		25/75	4	29.9	4.6	1.3	$2,185	$7,861	$1,957	$7,042
Medium Small	$10,051	50/50	10	124.6	19.2	5.3	$523	$1,883	$296	$1,065
		75/25	10	174.5	26.9	7.5	$374	$1,344	$146	$527
		25/75	10	74.7	11.5	3.2	$874	$3,144	$646	$2,325
Medium	$32,271	50/50	20	249.2	38.4	10.7	$840	$3,023	$613	$2,205
		75/25	20	349.1	53.8	15.0	$600	$2,158	$373	$1,340
		25/75	20	149.4	23.0	6.4	$1,403	$5,048	$1,175	$4,229
Medium Large	$72,394	50/50	50	623.1	96.0	26.7	$837	$3,011	$527	$1,895
		75/25	50	872.7	134.5	37.4	$558	$2,007	$311	$1,119
		25/75	50	373.5	57.5	16.0	$1,674	$6,022	$1,031	$3,711
Large	$72,394	50/50	100	1246.2	192.0	53.4	$418	$1,505	$150	$539
		75/25	100	1745.4	269.0	74.8	NA - Beyond Capacity			
		25/75	100	747.0	115.0	32.0	$837	$3,011	$402	$1,446

a. See Table 6-5 for compressor cost analysis.
b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).
c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in $786 savings per diaphragm pump and $87 savings per piston pump.
d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

[96] As explained earlier, this control option simultaneously reduces both methane (which is being evaluated for controlling the pollutant GHG) and VOC. Under the single pollutant approach, all costs are attributed to one pollutant and zero to the other. For simplicity, the table presents the cost per ton of the assigned pollutant; the table does not present the cost per ton of the one that is assigned zero cost because it is always zero.

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Table 6-8. Cost of Control for Use of Instrument Air Systems at Natural Gas Processing Plants - Multi-Pollutant Method

Plant Size	Compressor Cost[a]	Scenario[b]	Total Number of Pumps	Total Gas Saved[c] (Mcf)	Emission reductions[d] (tpy)		Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[c] ($/ton)	
					Methane	VOC	Methane	VOC	Methane	VOC
Small	$10,051	50/50	4	49.8	7.7	2.1	$654	$2,354	$541	$1,945
		75/25	4	69.8	10.8	3.0	$467	$1,680	$353	$1,271
		25/75	4	29.9	4.6	1.3	$1,093	$3,930	$979	$3,521
Medium Small	$10,051	50/50	10	124.6	19.2	5.3	$262	$942	$148	$533
		75/25	10	174.5	26.9	7.5	$187	$672	$73	$263
		25/75	10	74.7	11.5	3.2	$437	$1,572	$323	$1,163
Medium	$32,271	50/50	20	249.2	38.4	10.7	$420	$1,512	$307	$1,103
		75/25	20	349.1	53.8	15.0	$300	$1,079	$186	$670
		25/75	20	149.4	23.0	6.4	$702	$2,524	$588	$2,114
Medium Large	$72,394	50/50	50	623.1	96.0	26.7	$418	$1,505	$263	$948
		75/25	50	872.7	134.5	37.4	$279	$1,004	$156	$559
		25/75	50	373.5	57.5	16.0	$837	$3,011	$516	$1,855
Large	$72,394	50/50	100	1246.2	192.0	53.4	$209	$753	$75	$269
		75/25	100	1745.4	269.0	74.8	NA - Beyond Capacity			
		25/75	100	747.0	115.0	32.0	$418	$1,505	$201	$723

a. See Table 6-5 for compressor cost analysis.

b. Allocation of type of pumps (i.e., 50/50 is half the pumps are diaphragm and half are piston, 75/25 is 75% of the pumps are diaphragm and 25% are piston, etc.).

c. Based on raw gas emissions of 22.45 scf/hr for a diaphragm pump and 2.48 scf/hr for a piston pump, resulting in $786 savings per diaphragm pump and $87 savings per piston pump.

d. Based on 3.36 tons per year of methane and 0.96 tons per year of VOC per diaphragm pump and 0.36 tons per year of methane and 0.11 tons per year of VOC per piston pump.

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Table 6-9. Cost of Control for Replacement with Solar-Powered or Electric Pumps at Natural Gas Processing Plants - Single-Pollutant[97]

Type of Pump	Control Option	Emission Factor (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
					Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	without savings		with savings	
		Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm	Electric[a]	3.46	0.96	4,175	22.45	197	$786	$276	$994	$49	$175
Diaphragm	Solar	3.46	0.96	$2,000	22.45	197	$786	$92	$330	($136)	($489)

a. For electric pumps, annual cost assumes a 5.0 BHP electric pump as reported in NGS LL "Replacing Gas-Assisted Glycol Pumps with Electric Pumps". Assumes installation is 10% of the capital cost.

Table 6-10. Cost of Control for Replacement with Solar-Powered or Electric Pumps at Natural Gas Processing Plants - Multi-Pollutant Method

Type of Pump	Control Option	Emission Factor (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
					Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	without savings		with savings	
		Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm	Electric[a]	3.46	0.96	$4,175	22.45	197	$786	$138	$497	$24	$88
Diaphragm	Solar	3.46	0.96	$2,000	22.45	197	$786	$46	$165	($68)	($244)

a. For electric pumps, annual cost assumes a 5.0 BHP electric pump as reported in NGS LL "Replacing Gas-Assisted Glycol Pumps with Electric Pumps". Assumes installation is 10% of the capital cost.

[97] *See footnote 50.*

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Table 6-11. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to a New VRU - Single-Pollutant Method

Pump Type/ Segment	Emission Reductions (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
				Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	without savings		with savings	
	Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	$24,755	22.45	187	$749	$7,531	$27,094	$7,304	$26,275
Processing	3.29	0.91	$24,755	22.45	187	$749	$7,531	$27,094	$7,304	$26,275
Transmission	3.29	0.09	$24,755	22.45	187	$749	$7,531	$271,888	$7,304	$263,666
Storage	3.29	0.09	$24,755	22.45	187	$749	$7,531	$271,888	$7,304	$263,666

Note: No gas savings is attributed to transmission and storage.

Table 6-12. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to a New VRU - Multi-Pollutant Method

Segment	Emission Reductions (tpy/pump)		Annualized Cost ($)	Natural Gas			Cost of Control ($/ton)			
				Emission Factor (scf/h)	Saved (Mcf/yr)	Value ($)	without savings		with savings	
	Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	$24,755	22.45	187	$749	$3,766	$13,547	$3,652	$13,137
Processing	3.29	0.91	$24,755	22.45	187	$749	$3,766	$13,547	$3,652	$13,137
Transmission	3.29	0.09	$24,755	22.45	187	$749	$3,766	$135,944	$3,652	$131,833
Storage	3.29	0.09	$24,755	22.45	187	$749	$3,766	$135,944	$3,652	$131,833

Note: No gas savings is attributed to transmission and storage.

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Table 6-13. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Diaphragm Pump Emissions to a New Combustion Device - Single-Pollutant Method

Segment	Type of Pump	Emission reductions (tons/yr-pump)		Annualized Cost ($2012)	Cost of Control ($/ton)	
		Methane	VOC		Methane	VOC
Production	Diaphragm	3.287	0.914	$21,877	$6,656	$23,944
Processing	Diaphragm	3.287	0.914	$21,877	$6,656	$23,944
Transmission	Diaphragm	3.287	0.091	$21,877	$6,656	$240,279
Storage	Diaphragm	3.287	0.091	$21,877	$6,656	$240,279

Table 6-14. Estimated Cost of Control for Emission Reductions from Routing Gas-Drive Diaphragm Pump Emissions to a New Combustion Device - Multi-Pollutant Method

Segment	Type of Pump	Individual Pneumatic Pump Emission Reductions (tons/yr-pump)		Annualized Cost ($2012)	Cost of Control ($/ton)	
		Methane	VOC		Methane	VOC
Production	Diaphragm	3.287	0.914	$21,877	$3,328	$11,972
Processing	Diaphragm	3.287	0.914	$21,877	$3,328	$11,972
Transmission	Diaphragm	3.287	0.091	$21,877	$3,328	$120,140
Storage	Diaphragm	3.287	0.091	$21,877	$3,328	$120,140

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Table 6-15. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to an Existing Combustion Device or VRU - Single-Pollutant Method

Pump Type/ Segment	Emission Reductions[a] (tpy/pump)		Annualized Cost[b] ($)	Natural Gas			Cost of Control ($/ton)			
				Emission Factor (scf/h)	Saved (Mcf/ yr)	Value[c] ($)	without savings		with savings[d]	
	Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	$774	22.45	187	$749	$235	$847	$8	$27
Processing	3.29	0.91	$774	22.45	187	$749	$235	$847	$8	$27
Transmission	3.29	0.09	$774	22.45	187	$749	$235	$8,496	$8	$274
Storage	3.29	0.09	$774	22.45	187	$749	$235	$8,496	$8	$274

a. Based on 95 percent control.
b. Based on capital cost of $5,433 annualized using a 7 percent discount rate.
c. Based on $4.00 per Mcf average price for natural gas.
d. Applies to VRU only. There is no gas savings with a combustion device.

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Table 6-16. Cost of Control for Routing Gas-Driven Diaphragm Pump Emissions to an Existing Combustion Device or VRU - Multi-Pollutant Method

Pump Type/ Segment	Emission Reductions[a] (tpy/pump)		Annualized Cost[b] ($)	Natural Gas			Cost of Control ($/ton)			
				Emission Factor (scf/h)	Saved (Mcf/yr)	Value[c] ($)	without savings		with savings[d]	
	Methane	VOC					Methane	VOC	Methane	VOC
Diaphragm Pumps										
Production	3.29	0.91	$774	22.45	187	$749	$118	$423	$4	$14
Processing	3.29	0.91	$774	22.45	187	$749	$118	$423	$4	$14
Transmission	3.29	0.09	$774	22.45	187	$749	$118	$4,248	$4	$137
Storage	3.29	0.09	$774	22.45	187	$749	$118	$4,248	$4	$137

a. Based on 95 percent control.
b. Based on capital cost of $5,433 annualized using a 7 percent discount rate.
c. Based on $4.00 per Mcf average price for natural gas.
d. Applies to VRU only. There is no gas savings with a combustion device.

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7.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry as prime movers are reciprocating and centrifugal compressors.

The 2012 NSPS promulgated requirements for control of emissions from wet seal centrifugal compressors and reciprocating compressors in the production and processing segments. During development of the 2012 NSPS amendments, methane and VOC emissions for these sources were estimated and included in the cost and impact analysis. See the 2011 NSPS TSD for information on the production and processing segments.

This chapter discusses the emissions from these compressors in the transmission and storage segment and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

7.1 Process Description

7.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

7.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy.

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These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic groves and springs. The opposing forces create a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are typically lower for dry seals in comparison to wet seals.

7.2 Emissions Data and Emissions Factors

7.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide emission estimates from reciprocating and centrifugal compressors. These studies are provided in Table 7-1, along with the type of information contained in the study.

Table 7-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Public review draft Inventory of U.S. GHG Emissions and Sinks: 1990-2014[a]	EPA	2016	Nationwide	X	
GHG Mandatory Reporting Rule and TSD[b]	EPA	2013	Nationwide	X	
Methane Emissions from the Natural Gas Industry[c]	GRI/EPA	1996	Nationwide	X	
Natural Gas STAR Program[d,e]	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry Methane Emission Factor Improvement Study[f]	URS Corporation, UT Austin, and U.S. EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and	API/ANGA	2012	Regional	X[h]	

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Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Analysis of API and ANGA Survey Responses[g, h]					
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries[i]	ICF International (Prepared for the Environmental Defense Fund)	2014	Regional	X	X

a. U.S. EPA. Public review draft of Inventory of U.S. Greenhouse Gas Emission and Sinks 1990-2014. Washington, DC.
b. U.S. EPA. GHG Emissions Reporting From the Petroleum and Natural Gas Industry: Background TSD. Climate Change Division. Washington, DC. November 2014.
c. National Risk Management Research Laboratory. GRI/EPA Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks. Prepared for the U.S. Department of Energy, EIA. EPA-600/R-96-080h. June 1996.
d. U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. EPA. 2006.
e. U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals In Centrifugal Compressors. *Natural Gas STAR. EPA.* 2006.
f. URS Corporation/University of Texas at Austin. 2011. Natural Gas Industry Methane Emission Factor Improvement Study, Final Report. December 2011.
http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.
g. API and America's Natural Gas Alliance (ANGA). 2012. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses. Final Report. September 21, 2012.
h. The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emissions information was included.
i. ICF International. 2014. Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries. Prepared for the Environmental Defense Fund. March 2014.

7.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study[98] and the methane-to-VOC ratio developed in the gas composition memorandum.[99] The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 lbs of methane per Mcf. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 7-2. Once the methane emissions were calculated, the ratio of VOC-to-methane

[98] National Risk Management Research Laboratory. GRI/EPA Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.
[99] See footnote *3*.

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was used to estimate VOC emissions. The specific VOC-to-methane ratios used for this analysis were 0.278 lbs VOC per pound of methane for the production and processing segments, and 0.0277 lbs VOC per pound of methane for the transmission and storage segment. A summary of the reciprocating compressor emissions are presented in Table 7-3.

The centrifugal compressor emission factors for wet seals and dry seals are based on data used in the GHG Inventory[100]. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.[101]

Since publication of the white paper, additional data have become available on compressor emissions in transmission and storage, including reporting year 2014 data from GHGRP, and new measurement data from Subramanian et al. 2015. These data confirm the significant emissions from these sources, but indicate that emissions levels differ from those assumed in this analysis. In the 2013 GHGRP transmission and storage data set, reported emissions from reciprocating compressors are 2,100,647 tons CO_2 Eq. of methane, and reported emissions from centrifugal compressors are 697,643 tons CO_2 Eq. of methane. The Subramanian study, compared total average methane emissions per compressor in transmission and storage for both reciprocating and centrifugal compressors to those in the 2015 GHG Inventory, and found that the 2015 GHG Inventory had higher average emissions. The 2016 GHGI inventory includes updated estimates for reciprocating and centrifugal compressors, based on data from the Subramanian study and GHGRP.

[100] U.S. EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014.
[101] Ibid.

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Table 7-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Compressor Station	Reciprocating Compressors			Centrifugal Compressors		
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor[a]	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)	Pressurized Factor[a]
Transmission	57[b]	3.3	79.1%	47.7[d]	6[d]	30.0[d]
Storage	51[c]	4.5	67.5%	47.7[d]	6[d]	22.4[d]

a. Percent of hours per year that a compressor is pressurized.
b. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-17.
c. EPA/GRI. (1996). "Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks." Table 4-24.
d. U.S. EPA. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems. GHG Inventory: Emission and Sinks: 1990-2012. Washington, DC. 2014. Annex 3.5 Table A-129.

Table 7-3. Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Compressor Location	Baseline Emission Estimates (tpy)	
	Methane	VOC
Reciprocating Compressors		
Transmission	27.1	0.75
Storage	28.2	0.78
Centrifugal Compressors (Wet Seals)		
Transmission	157	4.34
Storage	117	3.24
Centrifugal Compressors (Dry Seals)		
Transmission	19.7	0.546
Storage	14.7	0.407

7.3 Control Techniques

7.3.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas across the piston rod packing. This includes replacement of the compressor rod packing or replacement of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas across the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings

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reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate option for reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[102] Rods wear "out-of-round" or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a combustion device. A summary of these techniques are presented in the following sections.

One control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a combustion device was considered to be a viable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. "Beam" type compressors have two seals, one on each end of the compressor, while "over-hung" compressors have a seal on only the "inboard" (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes "O-

[102] U.S. EPA. Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR. Washington DC. 2006.

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ring" rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the "inboard" (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a combustion device.

7.3.2 Reciprocating Compressor Rod Packing Replacement

7.3.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the "nose gasket" around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the rod packing ensures the correct fit is maintained between packing rings and the rod.

7.3.2.2 Emissions Reduction Potential

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The emission reductions for the transmission and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors (as presented in Table 6-2) and the average emission factor for newly installed rod packing. This calculation, shown in the Equation 1 below, was performed for the transmission and storage segment.

Equation 1

$$R_{PTS} = \frac{Comp_{New}^{PTS}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6}$$

where:

R_{PTS} = Potential methane emission reductions from transmission or storage compressors replacing rod packing, in million cubic feet per year (MMcf/year).

$Comp_{New}^{PTS}$ = Number of new transmission or storage compressors.

$E_{G\&B}$ = Methane emission factor for transmission or storage compressors in Table 7-2, in cubic feet per hour per cylinder.

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E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[103] for this analysis.
C = Average number of cylinders for transmission or storage compressors in Table 7-2.
O = Percent of time during the calendar year the average transmission or storage compressor is in the operating and standby pressurized modes, 79.1%, 67.5% respectively.
8760 = Number of days in a year.
10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating compressor rod packing replacement in the transmission and storage segment is presented in Table 7-4. The emissions of VOC were estimated using the methane emissions calculated above and the methane-to-VOC- ratio developed for each of the segments in the gas composition analysis conducted for the NSPS.[104]

Table 7-4. Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing for a Typical Year

Compressor Location	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Typical Year					
Transmission	15	21.7	0.601	325	9
Storage	17	21.8	0.605	109	10

7.3.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas STAR Lessons Learned document[105] which estimated the cost to replace the rod packing rings to be $1,712 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing placement is based on number of hours that the compressor operates, or the time since the last replacement. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program.[106] The

[103] Ibid.
[104] *See footnote* 3.
[105] *See footnote 102*.
[106] Ibid.

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cost impacts are based on the replacement of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

For the 2012 NSPS, the number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This percentage of hours is, on average, the number of hours per year a reciprocating compressor is pressurized and was used as the basis for the cost evaluation as it was determined to be the best available industry-wide percent pressurized value. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3.8 years for transmission compressors and 4.4 years for storage compressors using the operating factors in Table 7-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3122 for transmission compressors and 0.2720 for storage compressors. The capital costs were calculated using the average rod packing cost of $1,712 and the average number of cylinders per segment as presented in Table 7-2. The annual costs were calculated using the capital cost and the capital recovery factors.

The cost per ton of emissions reduced was then calculated in two ways. The first method, or single-pollutant approach, allocated all of the costs to each pollutant separately. The second method, or multi-pollutant approach, allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). The multi-pollutant approach was based on estimates of the percentage reduction expected for each pollutant. A summary of the capital and annual costs for the transmission and storage segment is shown in Table 7-5.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement, however, these savings were not included in the cost estimates for the transmission and storage segment because it is assumed that the owner/operator of the compressor generally is not the owner of the natural gas that is compressed at their compressor stations.

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Table 7-5. Cost of Control for Reciprocating Compressor Rod Packing Replacement ($2012)

Compressor Location	Capital Cost ($)	Annual Cost ($/yr)	Cost of Control Single-Pollutant Approach ($/ton)		Cost of Control Multi-Pollutant Approach ($/ton)	
			Methane	VOC	Methane	VOC
Transmission	$5,650	$1,748	$81	$2,910	$40	$1,455
Storage	$7,705	$2,077	$95	$3,434	$48	$1,717

7.3.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no maintenance of electrical systems and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing is replaced based on operating hours or time since the last replacement.

7.3.3 Centrifugal Compressor Dry Seals

7.3.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce gas emissions compared to wet seals. At the same time, they significantly reduce operating costs and enhance compressor efficiency compared to wet seals. Economic and environmental advantages of using dry seals include:

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- Gas Leak Rates. During normal operation, dry seals leak at a rate of less than 6 scfm methane per compressor.[107] While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[108, 109]
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.
- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid "parasitic" equipment power losses. Wet seal systems require 50 to 100 kilowatt (kW) per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

6.3.3.2 Emissions Reduction Potential

The emission reduction of the dry seal compressor was calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 7-2 were used in combination with an operating factor of 30 percent for transmission centrifugal compressors and 22.4 percent for storage centrifugal

[107] U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. October 2006. Available at http://epa.gov/gasstar/documents/ll_wetseals.pdf.
[108] "Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry". US EPA, ICF International, PEMEX, EnCana Oil & Gas, Hy-Bon Engineering, Pluspetrol, Gazprom, VNIIGAZ. World Gas Conference 10/2009. Available at http://www.epa.gov/gasstar/documents/best_paper_award.pdf.
[109] U.S. Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2009. Washington, DC. April, 2011. Annex 3. Page A-153.

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compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors are based on data from the GHG Inventory.[110] The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.[111] A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 7-6.

Table 7-6. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Compressor Location	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Transmission	0	137	3.79	0	0
Storage	1	102	2.83	102	2.83

7.3.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. From the Natural Gas STAR Program, General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between $50,000 and $100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3 percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between $2 million to $5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is $75,000 ($79,268 in 2012 dollars). The annual cost was calculated as the capital recovery of this capital cost assuming a 20-year equipment life and 7 percent interest which came to $7,482 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of dry seal compressor is $88,300 in comparison to wet seal compressor. The cost per ton of emissions reduced was then

[110] *See footnote* 4.
[111] U.S. EPA. Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. Natural Gas STAR. 2006.

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calculated in two ways. The single-pollutant method allocated all of the costs to each pollutant separately. The multi-pollutant method prorated costs among the pollutants that a given technology reduced (i.e., methane and VOC). The multi-pollutant method was based on estimates of the percentage reduction expected for each pollutant. A summary of the capital and annual costs for dry seals is presented in Table 7-7 along with the methane and VOC cost of control for the dry seal compressor option. We do not consider revenues from gas savings for transmission and storage facilities because it is assumed the owners of the compressor station do not own the natural gas that is compressed at the station.

Table 7-7. Cost of Reductions for Centrifugal Compressor Using Dry Seal Compressors ($2012)

Compressor Location	Capital Cost ($)	Annual Cost Per Compressor ($/compressor-year)		Methane Cost of Control ($/ton)		VOC Cost of Control ($/ton)	
		without savings	with O&M savings	without savings	with O&M savings	without savings	with O&M savings
Single-Pollutant							
Transmission	$79,268	$7,482	-$85,843	$55	-$627	$1,974	-$22,642
Storage	$79,268	$7,482	-$85,843	$73	-$840	$2,643	-$30,324
Multi-Pollutant Method							
Transmission	$79,268	$7,482	-$85,843	$27	-$314	$987	-$11,321
Storage	$79,268	$7,482	-$85,843	$37	-$420	$1,322	-$15,162

7.3.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

7.3.4 Centrifugal Compressor Wet Seals Routed to a Combustion Device

7.3.4.1 Description

Another control option used to reduce emissions from centrifugal compressors equipped with wet seals is to route the emissions to a combustion device or capture the emissions and route them to a process (e.g., a fuel system). A wet seal system uses oil that is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas. The

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center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to a combustion device or to a process.

7.3.4.2 Emissions Reduction Potential

Combustion devices have been used in the oil and natural gas industry to combust gas streams that have VOC and organic HAP. A combustion device typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves 95 percent reduction of methane, VOC, and organic HAP. The wet seal emissions in Table 7-2 were used along with the control efficiency to calculate the emission reductions from this option. A summary of the emission reductions is presented in Table 7-8.

Table 7-8. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Combustion Device

Compressor Station	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)		Nationwide Emission Reductions (tpy)	
		Methane	VOC	Methane	VOC
Transmission	0	149	4.12	0	0
Storage	1	111	3.08	111	3.08

7.3.4.3 Cost Impacts

The capital and annual cost of the combustion device (an enclosed flare for the analysis) was calculated using the methodology in the EPA Control Cost Manual.[112] The heat content of the gas stream was calculated using information from the gas composition memorandum.[113] A summary of

[112] EPA Air Pollution Control Cost Manual - Sixth Edition, (EPA 452/B-02-001).
[113] See footnote 3.

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the capital and annual costs for wet seals routed to a flare is presented in Table 7-9. The cost per ton of emissions reduced was then calculated in two ways. The single-pollutant approach allocated all of the costs to each pollutant separately. The multi-pollutant approach allocated costs among the pollutants that a given technology reduced (i.e., methane and VOC). This allocation was based on estimates of the percentage reduction expected for each pollutant. The methane and VOC cost of control for the wet seals routed to a combustion device option is also shown in Table 7-9. There is no cost savings estimated for this option because the recovered gas is combusted.

Table 7-9. Cost of Control for Centrifugal Compressor Wet Seal Emission Routed to a Combustion Device

Compressor Location	Capital Cost ($)		Annual Cost per Compressor ($/compressor-year)		Cost of Control New CD ($/ton)		Cost of Control Existing CD ($/ton)	
	New CD	Existing CD	New CD	Existing CD	Methane	VOC	Methane	VOC
Single-Pollutant								
Transmission	$71,783	$23,252	$114,146	$3,311	$767	$27,705	$22	$804
Storage	$71,783	$23,252	$114,146	$3,311	$1,028	$37,105	$30	$1,076
Multi-Pollutant Method								
Transmission	$71,783	$23,252	$114,146	$3,311	$384	$13,853	$11	$402
Storage	$71,783	$23,252	$114,146	$3,311	$514	$18,553	$15	$538

CD = Control Device

7.3.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a combustion device. The combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_X, CO_2, and CO emissions). A summary of the estimated secondary emission are presented in Table 7-10. No other wastes should be created or wastewater generated.

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Table 7-10. Secondary Impacts from Wet Seal Emissions Routed to a Combustion Device

Compressor Location	Secondary Impacts from Wet Seals Routed to a Combustion Device (tpy)				
	THC[a]	CO[b]	CO_2[c]	NO_x[d]	PM[e]
Transmission	0	0	0	0	0
Storage	0.58	1.29	550	0.28	0.01

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.
b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.
c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.
d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.
e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a "lightly smoking" flare.

7.4 Regulatory Options

EPA evaluated the following regulatory options:

- Regulatory Option 1. Require replacement of the reciprocating compressor rod packing based on 26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2. Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3. Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

7.4.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 7.3.1. The methane and VOC cost of control for reciprocating compressors at transmission stations is $81 and $2,910 per ton, respectively. The methane and VOC cost of control for reciprocating compressors at storage facilities is $95 and $3,434 per ton, respectively. Based on these cost of control values for methane, EPA selected Regulatory Option 1 for the transmission and storage segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 7.3.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in

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comparison to wet seals. Under the single pollutant approach, the methane and VOC cost of emission reductions for dry seals compressors was calculated to be $55 per ton and $1,974 per ton respectively for centrifugal compressors located at transmission facilities, not including the savings from operation and maintenance costs. When those savings were considered the methane and VOC cost of control was calculated to be ($627) per ton and ($22,642) per ton. Also under the single pollutant approach, the methane and VOC cost of control for dry seal compressors was calculated to be $73 per ton and $2,643 per ton respectively for centrifugal compressors located at storage facilities, not including the savings from operation and maintenance costs.[114] When those savings were considered, the methane and VOC cost of control was calculated to be ($840) per ton and ($30,324) per ton. However, commenters on the 2011 Oil and Natural Gas NSPS noted that are certain situations where installing a dry seal system is not feasible, such as where gas composition is inadequate and in retrofits of some existing compressors due to housing design or operational requirements. Therefore, EPA rejected Regulatory Option 2 as a regulatory option for centrifugal compressors located at transmission or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a combustion device or process. Under the single pollutant approach, the methane and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be $767 per ton and $27,705 per ton respectively for centrifugal compressors located at transmission facilities. Also under the single pollutant approach, the methane and VOC cost of control for routing emissions from a wet seal system to a combustion device was calculated to be $1,028 per ton and $37,105 per ton respectively for centrifugal compressors located at transmission facilities. However, facilities may already have a combustion device operating at the facility or would route the captured gas back to a useful process rather than flaring it. Those facilities would not incur the additional capital cost and operation and maintenance costs of the flare. Under the single pollutant approach for those facilities the methane and VOC cost of control were calculated to be $22 per ton and $804 per ton respectively for transmission facilities and $30 per ton and $1,076 per ton respectively for storage facilities. Based on these cost of control values, EPA is selecting Regulatory Option 3 for the transmission and storage segment.

[114] Negative cost is the result of operation and maintenance savings for dry seals.

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VOLUME 2: NATIONAL LEVEL IMPACTS

8.0 NATIONWIDE IMPACTS FOR HYDRAULICALLY FRACTURED OIL WELL COMPLETIONS AND RECOMPLETIONS

8.1 Nationwide Emissions

8.1.1 Determination of Number of Completions and Recompletions

The first step in this analysis is to estimate nationwide baseline emissions in 2012, the year selected as the baseline year. In order to develop the baseline emissions, the EPA estimate the average number of wells that would be affected using the number of completions and recompletions performed in a typical year derived from the DrillingInfo database extract as described above. This value was then multiplied by the potential uncontrolled emissions per well completion listed in Table 3-2.

The DrillingInfo database includes the most recent completion date for all reported wells in the US. Therefore, the methodology described above for calculating the number of hydraulically fractured oil well completions from the HPDI® database in 2012 identifies wells initially fractured in 2012 and wells that were refractured (recompletions) in 2012. Because these recompletions are included in the database and resulting extracted dataset, it is not necessary to calculate a refracture frequency.

To more accurately estimate baseline emissions for this analysis, and to ensure no emission reductions were calculated for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. The number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing state regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., the number of wells impacted by local (as opposed to state level) regulations could not be determined because data for wells subject to county or local ordinance level regulations are not available. Therefore, the calculated percentage of wells subject to state regulation based on the identified state regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under state regulations, the DrillingInfo database extract well count data (described

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above) was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the states identified as having existing controls. In our proposal, the EPA identified Colorado, and Wyoming as the only states requiring controls on completions comparable to the NSPS requirements prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared.[115] The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to Wyoming, the Colorado Oil and Gas Conservation Commission (COOGCC) requires a renewable energy certificate (REC) for both oil and natural gas wells.[116] It was assumed for proposal that the ratio of wells in Colorado and Wyoming to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in Wyoming to the number of total nationwide wells was assumed to represent the percentage of controlled well recompletions as it was the only state identified as having regulations directly related to recompletions. The EPA used the referenced GOR of less than (<) 100,000 scf/bbl for oil wells to identify the oil wells located in Wyoming and Colorado. From this review it was estimated that 8.81 percent of oil well completions are controlled in absence of federal regulation.

The EPA received significant comment that the proposal did not consider the existing control requirements for a then-proposed, now-final requirements in North Dakota that requires flaring of all emissions during the flowback stage of completions. In particular, the North Dakota Air Pollution Control Rules require that all organic gases and vapors be burned by flares and the North Dakota Industrial Commission requires that all vented casinghead gas be burned, pending arrangements for disposition for some useful purpose.[117] Considering the comments, for the final

[115] Wyoming BACT permitting guidance. Available at http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf.
[116] COGCC 805 Series Rules (805.b.(3)A). Available at http://cogcc.state.co.us/ and the Colorado Code of Regulations at: http://www.sos.state.co.us/CCR/Welcome.do.
[117] N.D. Admin. Code§ 33-15-07-02(1) and§ 43-02-03-45

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rule, the EPA determined that the percentage of completions and recompletions conducted in North Dakota for oil wells greater than or equal to 300 GOR was 9.4 percent.

Finally, the EPA determined the number of exploratory oil well completions based on the percentage breakdown between exploratory and development wells in the National Energy Modeling System (NEMS). NEMS is a model of the U.S. energy economy developed and maintained by the EIA. NEMS is used to produce the Annual Energy Outlook (AEO), a reference publication that provides detailed forecasts of the energy economy from the current year to 2040. The NEMS source code is publicly available and fully documented. The source code and accompanying documentation is released annually when a new AEO is produced. Because of the availability of NEMS, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues. NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. Based on the NEMS AEO 2014 Reference Case, 3.8 percent of oil wells are exploratory and 96.2 percent are development wells.

In addition, as for the development of the 2012 NSPS for gas well completions, the EPA is aware that some oil well completions and workovers are controlled voluntarily using RECs or combustion devices. However, the EPA could not identify a national level data source on this practice from which the EPA could estimate the numbers of voluntarily controlled oil well completions. Therefore, due to lack of data and a reliable benchmark for estimating the number of voluntarily controlled completions, the EPA assumed zero for our analysis of baseline emissions.

In order to determine nationwide impacts of the number of new oil well completions and recompletions, the EPA used the base year of 2012 activity data (see the 2015 Proposal TSD for details on the 2012 base year projection) as described above and projected activity numbers for the years 2020 and 2025 based on predictions from the NEMS Oil and Gas Supply Model. The EPA calculated the compound annual growth rate (CAGR) between 2012 and 2015 for development and exploratory oil wells based on the AEO 2015 Reference Case. The CAGR for development wells was found to be -0.1 percent and the CAGR for exploratory wells was found to be 6.2 percent. These factors were used to calculate the number of exploratory and development oil well completion for the years 2020 and 2025.

Table 8-1 summarizes the estimated number of hydraulically fractured oil well completions derived from our analysis detailed above.

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Table 8-1. Estimated Number of Hydraulically Fractured Oil Well Completions and Recompletions - 2020 and 2025

Hydraulically Fractured Oil Well Completions	**2020**	**2025**
Total Oil Well Completions and Recompletions	19,703	20,988
Total with < 300 GOR		
Development	4,481	4,774
Exploratory/Delineation	177	188
Total with ≥ 300 GOR		
Development	13,862	14,730
Exploratory/Delineation	1,183	1,296
Total with ≥ 300 GOR and Regulated by States (CO and WY) (Comparable to NSPS)		
Development	1,100	1,168
Exploratory/Delineation	92	101
Total with ≥ 300 GOR and Regulated by States (ND) (Flaring only)		
Development	1,200	1,275
Exploratory/Delineation	103	112
Total with ≥ 300 GOR, Not Regulated by States (CO and WY)		
Development	12,762	13,562
Exploratory/Delineation	1,091	1,195

Because the proposed and final rule requirements affect oil well completions and recompletions differently, particularly where activities are currently controlled under a state regulation, the EPA estimated the number of projected well completions and recompletions which would be affected under different control scenarios under the NSPS. Specifically, the EPA calculated activity numbers for the following control scenarios:

- Development oil wells that are greater than or equal to 300 GOR which are currently venting and are capable of conducting a REC combined with combustion. This number is the number of new development oil well completions and recompletions that are not covered by a state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2015) and not located in ND and that are capable of conducting a REC. The EPA estimate that 50 percent of these oil wells are capable of conducting a REC.
- Development oil wells that are greater than or equal to 300 GOR and are currently venting, however, it is technically infeasible for them to conduct a REC, therefore combust emissions. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and

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13,562 in 2025) and are not located in ND and that are not capable of conducting a REC due to technical infeasibility reasons (other than low pressure). See the discussion in 3.3.2.1 with respect to technical infeasibility as being reasons for not being required to conduct a REC. The EPA estimates that 10 percent of these oil wells are not capable of conducting a REC.

- Development oil wells that are greater than or equal to 300 GOR and are currently venting, however, due to low pressure cannot conduct a REC, and therefore combust emissions. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2025) and are not located in ND and that are not capable of conducting a REC due to low pressure. As discussed in section 8.2.1 below, the EPA estimate that 40 percent of these oil wells are not capable of conducting a REC.
- Development oil wells that are greater than or equal to 300 GOR and are currently flaring based on state requirements that are capable of conducting a REC combined with combustion. This number is the number of new development oil well completions and recompletions that are not covered by state regulation in CO or WY (i.e., 12,762 in 2020 and 13,562 in 2025) and are located in ND and that are capable of conducting a REC. As discussed in section 8.2.1 below the EPA estimate that 50 percent of these oil wells are capable of conducting a REC.
- All other development oil wells. This number is the development oil wells that are less than 300 GOR plus the greater than or equal to 300 GOR oil wells that are located in ND that are currently flaring and incapable of conducting a REC, plus the greater than or equal to 300 GOR oil wells that are controlled based on state regulation. This scenario results in no change in control status based on the NSPS.
- Exploratory and delineation oil wells that are greater than or equal to 300 GOR and are currently venting which would now be required to combust emissions. This is the number of exploratory and delineation oil wells that are not covered by state regulation in CO or WY and that are not located in ND. The EPA assumes that 100 percent of these wells are venting.
- All other exploratory and delineation oil wells. This number is the exploratory/delineation oil wells that are less than 300 GOR plus the greater than or equal to 300 GOR oil wells that are located in ND that are currently flaring and incapable of conducting a REC plus the

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greater than or equal to 300 GOR oil wells that are controlled based on state regulation. This scenario results in no change in control status based on the NSPS.

Table 8-2 summarizes the estimates of the numbers of oil well completions and recompletions based on these control scenarios above.

Table 8-2. Estimated Number of Total Oil Well Completions and Recompletions by Control Scenario under the NSPS for 2020 and 2025

Estimated Control Scenario Under NSPS	2020	2025
Development Oil Wells (Venting/REC with Combustion)	5,781	6,144
Development Oil Wells (Venting/TI for REC, Combustion)	1,156	1,229
Development Oil Wells (Venting, LP/Combustion)	4,625	4,915
Development Oil Wells (Flaring/REC)	600	637
Development Oil Wells (No change)	6,181	6,580
Exploratory/Delineation Oil Wells (Venting/Combustion)	988	1,083
Exploratory/Delineation Oil Wells (No change)	372	401

REC = Reduced Emissions Completion, TI for REC, Combustion = Technical infeasibility for a REC, combustion required, LP = Low pressure well

8.1.2 Nationwide Emission Estimates

Using the estimated emissions per source as shown in Table 3-2, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil well completions and recompletions in the base year 2012 and projected completions and recompletions for the projected years 2020 and 2025 were calculated and are summarized in Table 8-3. All values have been rounded to the nearest ton for estimation purposes.

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Table 8-3. Nationwide Baseline Emissions for 2020 and 2025 from Hydraulically Fractured Oil Well Completions and Recompletions

Well Source Subcategory	Emissions Per Event (tpy)		Number of Uncontrolled Wells[a]	Baseline Nationwide Emissions (tpy)	
	Methane	VOC		Methane[b]	VOC[b]
Projected Year 2020					
All Oil Wells	9.72	8.14	13,853	122,279	102,396
1. Developmental Oil Wells	9.72	8.14	12,162	112,672	94,351
2. Exploratory/Delineation Oil Wells	9.72	8.14	988	9,607	8,045
Projected Year 2025					
All Oil Wells	9.72	8.14	14,007	130,257	109,078
1. Developmental Oil Wells	9.72	8.14	12,925	119,734	100,266
2. Exploratory/Delineation Oil Wells	9.72	8.14	1,083	10,523	8,812

a. The number of controlled wells is equal to all wells less wells controlled based on state regulations in ND, CO and WY.
b. Based on the assumption that VOC content is 0.8374 lbs VOC per pound methane. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. These values do not account for secondary emissions from portion of gas that is directed to a combustion device.

8.2 Nationwide Impacts of the Final Rule (for purposes of Regulatory Impact Analysis)

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to final standards for oil well completions and recompletions. See the rule package for details of the final standards.

8.2.1 Primary Environmental Impacts of Regulatory Options

The selected standards for oil well completions and recompletions are as follows:

- Subcategory 1 - Development (i.e., wells which do not meet the definition of exploratory or delineation wells) Oil Well Completions and Recompletions: Operational standard for completions and recompletions with hydraulic fracturing which requires a combination of REC with combustion, but allows for combustion alone or venting during specified situations.
- Subcategory 2 - Exploratory and Delineation Oil Well Completions and Recompletions: An operational standard for completions and recompletions with hydraulic fracturing which requires completion combustion devices with an allowance for venting during specified situations.

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As noted in section 3.3.1 above, there are several control scenarios under which an oil well might be affected under the NSPS. The number of completions and recompletions that would be subject to the various regulatory requirements under the NSPS is listed in Table 8-3.

Table 8-4 summarizes the nationwide emission reduction estimates for each of the estimated control scenarios for the projected years 2020 and 2025. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion or recompletion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Additionally, were it is technically infeasible to conduct a REC, the EPA estimated a 95 percent emission reduction as the result of combustion where required. As discussed in section 3.3.2.1 above, there are several instances where conducting a REC is not feasible. The EPA estimate, for the purposes of estimating impacts that 50 percent of oil wells will be capable of conducting a REC and that 40 percent of the oil wells will not be able to conduct a REC due to low pressure in the well. Another 10 percent of the oil wells are estimated to not be able to conduct a REC due to other technical infeasibility such as access to gas lines, inert gas concentration, safety or other hazards where the separator cannot be operated. Nationwide emission reductions were estimated by applying this 95 percent reduction to the uncontrolled baseline emissions presented in Table 3-2.

8.2.2 Nationwide Cost Impacts

The operational standards for development wells that can conduct a REC include both REC and a completion combustion device, therefore the total incremental cost of the operational standard for developmental oil well completions and for recompletions is estimated at around $17,183, which includes the costs in Table 3-3 for the REC equipment and transportation in addition to the cost for the completion combustion device. The cost for a completion combustion device alone is estimated to be $3,723. The cost for addition of REC equipment to a site that is already combusting emissions is estimated to be $13,459.

For the projected year 2020, applying the cost for the combined REC with completion combustion device to the estimated 5,781 oil wells that are estimated to be capable of conducting a REC, the total nationwide cost was estimated to be approximately $78.5 million, which includes an estimated annual savings of approximately $20.8 million when natural gas savings are considered. Likewise, for projected year 2025, the cost for RECs with combustion device applied to 6,144

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development oil well completions and recompletions, the total nationwide cost was estimated to be approximately $83.5 million, including annual savings estimated at around $22.1 million when natural gas savings are considered.

For development oil wells not capable of conducting a REC due to technical infeasibility, the cost of a REC and combustion control device applied to the 1,156 completions in 2020 and the 1,229 completions in 2025, the nationwide cost was estimated to be approximately $19.9 million and $21 million respectively. These completions have no gas savings because the separator is estimated to not able to function and therefore no gas will be able to be recovered. Finally, for wells that are currently flaring emissions, the EPA estimate 600 wells in 2020 and 637 wells in 2025. The nationwide costs for addition of REC to these completions are approximately $5.9 million in 2020 and $6.3 million in 2025 which includes gas savings of approximately $2.2 million and $2.3 million, respectively.

For development oil wells that meet the definition of low pressure wells, the standard requires combustion of emissions and a separator is not required to be onsite.[118] Therefore, the EPA apply the cost of a combustion control device to the estimated 4,625 low pressure oils wells estimated for the year 2020 and the estimated 4,915 for the year 2025, the nationwide cost was estimated to be approximately $17.2 million and $18.3 million respectively. The total nationwide cost estimated for development oil well completions is approximately $121.7 million for the year 2020 (including $23 million in gas savings) and $129.2 million for the year 2025 (including $24.4 million in gas savings).

For exploratory and delineation oil well completions, the EPA apply the cost of a combustion control device to the 988 oil well completions estimated for the year 2020 and the 1,083 oil wells estimated for the year 2025, and the nationwide costs associated with exploratory and delineation oil well completions is approximately $3.7 million for 2020 and $4 million for 2025. Table 8-4 summarizes the estimated nationwide emission reductions and costs for each of these control scenarios.

[118] Note that for the final rule the low pressure well definition has been revised. See Appendix A for a full discussion of the revised low pressure well definition.

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Table 8-4. Nationwide Emission and Cost for Control Scenarios under the Final Subpart OOOOa

Well Completion Category (Current status/Rule Requirement)	Number of Sources Subject to NSPS[a]	Annual Cost Per Completion Event[b]	Nationwide Emission Reductions[c] (tpy)				Total Nationwide Costs ($/year)	
		($)	Methane	VOC	HAP	CO2e[d]	without savings	with savings[e]
Projected Year 2020								
Development Oil Wells (Venting/REC with Combustion)	5,781	$17,183	53,379	44,699	5.3	1,210,611	$99,333,820	$78,539,011
Development Oil Wells (Venting/TI for REC, Combustion)	1,156	$17,183	10,674	8,938	1.1	242,080	$19,863,327	$19,863,327
Development Oil Wells (Venting, LP/Combustion)	4,625	$3,723	42,705	35,761	4.3	968,531	$17,221,179	$17,221,179
Development Oil Wells (Flaring/REC)	600	$13,459	0	0	0	0	$8,075,587	$5,917,329
Development Oil Wells (No change)	6,181	$0	0	0	0	0	0	0
Exploratory/Delineation Oil Wells (Venting/Combustion)	988	$3,723	9,123	7,639	0.9	206,899	$3,678,816	$3,678,816
Exploratory/Delineation Oil Wells (No change)	372	$0	0	0	0	0	0	0
Total	**19,703**	**N/A**	**115,880**	**97,038**	**12**	**2,628,121**	**148,172,729**	**125,219,662**

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Well Completion Category (Current status/Rule Requirement)	Number of Sources Subject to NSPS[a]	Annual Cost Per Completion Event[b]	Nationwide Emission Reductions[c] (tpy)				Total Nationwide Costs ($/year)	
		($)	Methane	VOC	HAP	CO2e[d]	without savings	with savings[e]
Projected Year 2025								
Development Oil Wells (Venting/REC with Combustion)	6,144	$17,183	56,731	47,506	5.7	1,286,627	$105,571,180	$83,470,625
Development Oil Wells (Venting/ TI for REC, Combustion)	1,229	$17,183	11,348	9,503	1.1	257,367	$21,117,672	$21,117,672
Development Oil Wells (Venting, LP/Combustion)	4,915	$3,723	45,383	38,003	4.5	1,029,260	$18,300,993	$18,300,993
Development Oil Wells (Flaring/REC)	637	$13,459	0	0	0	0	$8,573,581	$6,282,231
Development Oil Wells (No change)	6,580	$0	0	0	0	0	0	0
Exploratory/Delineation Oil Wells (Venting/Combustion)	1,083	$3,723	10,000	8,374	1.0	226,793	$4,032,548	$4,032,548
Exploratory/Delineation Oil Wells (No change)	401	$0	0	0	0	0	0	0
Total	**20,989**	**N/A**	**123,461**	**103,386**	**12**	**2,800,048**	**157,595,975**	**133,204,070**

REC = Reduced Emissions Completion, TI for REC, Combustion = Technically infeasible to conduct REC, combustion required, LP = Low pressure wells

a. As presented in Table 4-43.

b. From Table 4-6.

c. Assumes no emission reductions for wells controlled by state regulation in CO, WY, and ND.

d. Assumes 0.90718474 metric tonnes per short ton and global warming potential of methane = 25.

e. Assumes savings only for scenarios where REC is performed.

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8.3 Nationwide Secondary Impacts

Regulatory Options 3 and 4 require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although it is understood that the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 3 and 4, it was assumed that 90 percent of flowback is captured and an additional 5 percent of the remaining gas is combusted. For Subcategory 1 oil well completions and recompletions with hydraulic fracturing, it is assumed around 50 Mcf (5 percent of 999 Mcf) of natural gas is combusted on a per well basis when a REC is performed. For Regulatory Option 3 for Subcategory 1 oil wells where combustion is used for control and for Regulatory Option 4 for Subcategory 2 oil well completions and recompletions with hydraulic fracturing, it is assumed that 949 Mcf (95 percent of 999 Mcf) of flowback emissions are combusted by the combustion device. The impacts of pollutant emissions per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 3-5.

For the projected year 2020, for Subcategory 1 well completions and recompletions controlled by a REC combined with a combustion device, it is estimated 0.002 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. For subcategory 1 and subcategory 2 well completions controlled with a combustion device alone, it is estimated 0.37 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions for projected year 2020, the proposed regulatory options are estimated to produce around 300 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 8-5 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2020 and Table 8-6 summarizes the estimated secondary emissions of the selected regulatory options for projected year 2025.

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Table 8-5. Nationwide Secondary Impacts of Selected Regulatory Options for Projected Year 2020[a]

Pollutant	Regulatory Option 3[b,c]				Regulatory Option 4[d]		Combined Options
	1. Developmental Oil Well - REC		1. Developmental Oil Well - Combustion		2. Exploratory/Delineation Oil Well		
	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Nationwide Secondary Emissions (tpy)
THC	0.004	24	0.076	440	0.076	75	540
CO	0.008	54	0.169	975	0.169	167	1,196
NO_x	0.002	12	0.037	214	0.037	37	262
PM	0.000	0	0.001	7	0.001	1	9
CO_2	3.599	22,967	71.987	416,155	71.987	71,123	510,246

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The REC operational standard (Regulatory Option 3 – REC) combines REC and combustion is assumed to capture 90 percent of flowback gas. 5 percent of the flowback is assumed to be combusted by the combustion device. Therefore, it is estimated 50 Mcf is combusted per completion event. This analysis assumes there are 6,381 developmental oil well completions and recompletions using this control scenario.

c. The REC operational standard (Regulatory Option 3 – Combustion) Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 5,781development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 988 exploratory wells fall into this category.

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Table 8-6. Nationwide Secondary Impacts of Selected Regulatory Options for Projected Year 2025[a]

Pollutant	Regulatory Option 3[b,c]				Regulatory Option 4[d]		Combined Options
	1. Developmental Oil Well - REC		1. Developmental Oil Well - Combustion		2. Exploratory/Delineation Oil Well		
	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Emissions per Completion Event (tons)	Nationwide Secondary Emissions (tpy)	Nationwide Secondary Emissions (tpy)
THC	0.004	26	0.076	468	0.076	83	576
CO	0.008	57	0.169	1,037	0.169	183	1,2763
NO_x	0.002	13	0.037	227	0.037	40	280
PM	0.000	0	0.001	8	0.001	1	9
CO_2	3.599	24,407	71.987	442,287	71.987	77,962	544,655

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The REC operational standard (Regulatory Options 3 REC) combines REC and combustion is assumed to capture 90 percent of flowback gas. 95 percent of the remaining flowback is assumed to be combusted by the combustion device. Therefore, it is estimated 50 Mcf is combusted per completion event. This analysis assumes there are 6,781 developmental oil well completions and recompletions using this control scenario.

c. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 6,144 development oil well completions and recompletions exploratory wells fall into this category.

d. Assumes 949 Mcf of natural gas is combusted per completion. This analysis assumes 1,083 exploratory wells fall into this category.

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9.0 NATIONWIDE IMPACTS FOR FUGITIVE EMISSIONS STANDARDS

9.1 Nationwide Emissions from New Sources

9.1.1 Overview of Approach

Similar to the approach used to calculate emissions from well site and compressor station model plants, nationwide emissions were calculated by using the model plant emissions that were calculated for the oil and natural well sites and compressor stations. These model plant emissions were used for estimating the baseline emissions and emission reductions for the new sources.

9.1.2 Activity Data

Data from oil and natural gas technical documents and inventories were used to estimate the number of new sources for each of the oil and natural gas segments. Information from the DrillingInfo HPDI® database and GHG Inventory were used to estimate the number of new well sites, gathering and boosting stations, and transmission and storage facilities in 2012. A summary of the steps used to estimate the new sources for each of the oil and gas segments is presented in the following sections.

9.1.2.1 Well Sites

The DrillingInfo database provided the information on the number of oil and natural gas wells completed or recompleted in the 2012 in the U.S. The total number of new natural gas well completions, both conventional and fractured was determined to be 8,456. From this number of wells, the EPA subtracted wells that were assumed to be covered by state leak regulations as of the effective date of the revised NSPS. Based on our research, four states have recently enacted leak regulations; Colorado, Ohio, Wyoming and Utah. Below is a brief discussion of these state regulations:

- Colorado: Effective on April 14, 2014, requires well production facilities and natural gas compression station owners/operators to inspect components for leaks using an approved instrument monitoring method (AIMM). This LDAR program began as early as January 1, 2015 with inspection frequency varying based on the amount of fugitive VOC emissions identified (i.e., 0-6 tpy - one-time, 6-12 tpy -annually, 12-50 tpy -quarterly, or >50 tpy -monthly). Monitoring inspections of well production facility and compressor station components must be conducted using Method 21, an infra-red camera, or other Division approved instrument based monitoring devices or methods. In addition, monthly audio, visual, and olfactory inspections must be

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conducted to identify leaks. When OGI is used for leak detection, a leak is defined as any detectable emissions that are not associated with normal equipment operation (e.g. pneumatic device actuation)[119]. For compressor station facilities constructed prior to May 1, 2014, a leak is defined as any concentration of hydrocarbon above 2,000 ppm when Method 21 is used to conduct monitoring inspections. For well sites and compressor stations that were constructed on or after May 1, 2014, a leaks is defined as any concentration of hydrocarbon above 500 ppm when Method 21 is used.

- Ohio: On May 19, 2014 Ohio EPA approved two types of oil and gas well-site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing general permits for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT HH). Operators are required to develop and implement a site-specific LDAR program for ancillary equipment (e.g., vent, compressor, PRD, flange, etc.) that requires monitoring using a FLIR camera or Method 21. Quarterly monitoring is required for the first year and varies after that depending on performance.[120] Ohio has also proposed a package of general permits that have been designed around a natural gas compressor station that has the potential to leak greater than 10 tons per year of VOC. The general permit requirements include quarterly monitoring of ancillary equipment, including each pump, compressor, pressure relief device, connector, valve, flange, vent, cover, any bypass in the closed vent system, and each storage vessel using either an OGI or an analyzer meeting U.S. EPA Method 21 of 40 CFR Part 60, Appendix A.

- Utah: On June 5, 2014, Utah Department of Environmental Quality approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014. This GAO requires LDAR for equipment (e.g., valves, pumps, etc.) at least annually, and initial quarterly surveying of sources with projected annual throughput of crude oil and condensate combined that is greater than 25,000 barrels. The monitoring can be performed using Method 21 (leak definition of 500 ppm), a tunable diode laser absorption spectroscopy or an IR camera.[121]

[119] Colorado regulations available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.
[120] Ohio regulations available at http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits.
[121] Utah regulations are available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.

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- Wyoming: On June 30, 2015, Wyoming Department of environmental Quality issued regulations for existing (as of January 1, 2014) PAD and single-well oil and gas production facilities that are located in the Upper Green River Basin. The rule regulates fugitive emissions from PAD and single-well facilities or sources, and compressor stations with fugitive emissions greater than or equal to 4 tons per year of VOC and requires owner/operators to develop and implement an LDAR protocol by January 1, 2017. Fugitive emissions monitoring can be conducted using a combination of Method 21, OGI, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule - at least one quarterly evaluation must be done using Method 21, OGI, or other instrument based technology. The rule requires quarterly monitoring of control equipment, systems, and devices (e.g. reboiler overhead condensers, storage tanks, vent lines, valves, connectors, etc.).[122]

9.1.3 Emission Estimates

The nationwide emissions were calculated using the model plant data and the estimated number of new and modified sources for each of the segments. The nationwide emission estimates for the total number of oil and natural gas production well sites, gathering and boosting stations, and transmission and storage facilities incrementally affected by the fugitive emission requirements in the NSPS for are summarized in Table 9-1. The summary includes baseline emissions for each of these segments for projected years 2020 and 2025.

Table 9-1. Nationwide Baseline Emissions for Sources Subject to NSPS Monitoring and Repair Plans in 2020 and 2025

Oil and Gas Segment	Number of Sources Subject to NSPS[a]	Methane Emissions (tpy)	VOC Emissions (tpy)
Projected Year 2020			
Natural Gas Well Sites	16,819	92,425	25,692
Oil Well Sites (GOR < 300)	32,392	39,989	10,726
Oil Well Sites (GOR > 300)	44,367	122,013	33,382
Gathering & Boosting Stations	480	16,868	4,689
Transmission Stations	20	808	22
Storage Stations	25	3,561	99

[122] Wyoming regulations are available at http://soswy.state.wy.us/Rules/RULES/9868.pdf.

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Oil and Gas Segment	Number of Sources Subject to NSPS[a]	Methane Emissions (tpy)	VOC Emissions (tpy)
Projected Year 2025			
Natural Gas Well Sites	34,487	189,515	52,680
Oil Well Sites (GOR < 300)	66,173	81,693	21,912
Oil Well Sites (GOR > 300)	90,636	249,256	68,196
Gathering & Boosting Stations	960	33,737	9,378
Transmission Stations	40	1,616	45
Storage Stations	50	7,122	197

a. Affected facilities in 2020 include new facilities in 2016 through 2020 which are assumed to still be operating in 2020. Affected facilities in 2025 includes new affected facilities in 2016 through 2025 which are assumed to still be operating in 2025.

According to our analysis, 20.87 percent of the total number of new natural gas well completions, both conventional and fractured, were covered by leak regulations in these four states. Therefore the number of new natural gas wells covered by federal regulations was estimated to be 6,691. Assuming an average of two natural gas wells per well site, the number of new well sites in 2012 was estimated to be 3,346. Projections from the NEMS data were used to estimate the total number of new natural gas completions, both conventional and hydraulically fractured in the years 2020 and 2025. The percentage of wells covered by state leak regulations, and the 2 natural gas wells per well site assumptions were applied to these totals to estimate the number of new natural gas production well sites. Our projected activity for year 2020 was developed to reflect the total number of affected facilities in 2020 which is the accumulation of newly affected facilities from 2016 through and including 2020. Likewise, our projected year 2025 reflects total accumulated newly affected facilities from 2016 through and including 2025. These activity estimates assume all newly affected facilities continue to be operating in the projected years. The number of natural gas well sites was estimated to be 16,819 well sites in 2020 and 34,487 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 30 percent of the total natural gas well sites based on a sensitivity analysis of the well site data.

For oil wells, the same approach used for natural gas wells was used to estimate the number of new oil wells in the U.S. The number of new oil well completions in 2012, both conventional and hydraulically fractured, was determined to be 35,404. It was assumed that 8.81 percent of these oil wells are covered by state regulations in 2012 based on information in the HPDI database, which includes: Colorado, Ohio, Wyoming and Utah. Therefore 32,285 new oil wells were not covered by state leak regulations in 2012. Assuming an average of two oil production wells per well site, the number of new oil production well sites

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was determined to be 16,142 in 2012. Projections from the NEMS data were used to estimate the total number of new oil well completions in the years 2020 and 2025. The percentage of wells covered by State leak regulations, and the two oil wells per well site assumptions was applied to these totals to estimate the number of new oil well production sites. Because the requirements have impacts annually, our projected activity for years 2020 and 2025 were developed to reflect the facilities newly affected by the rule from 2016 through 2020 and 2016 through 2025, respectively, and assumed to still be in operation in the analysis years. The number of oil well sites were estimated to be 76,759 well sites in 2020 and 156,809 in 2025. These estimated well site values were used to calculate the national fugitive emissions from natural gas well sites in 2012, 2020 and 2025. Low production wells were assumed to be 43 percent of the total oil well sites based on a sensitivity analysis of the well site data. Oil well sites with a gas-to-oil ratio of greater than 300 were assumed to account for 57.8 percent of the total oil well sites based on data from the HPDI database as summarized in Table 9-1.

9.1.3.1 Gathering and Boosting Stations

The number of new gathering and boosting stations was estimated using the current number of gathering compressors estimated in the GHG Inventory. The total number of small and large gathering compressors was listed as 36,066 in the inventory. The EPA/GRI document does not include a separate list of individual compressors for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the total number of compressors in the GHG Inventory, the number of gathering and boosting stations was estimated to be 8,015. To estimate the number of new gathering and boosting stations, the EPA used an annual growth rate of 1.2 percent, which is based on the gas well CAGR for new gas wells divided by the average wells per well site. This provided an estimate of 96 new gathering and boosting stations each year that would be affected sources under the proposed NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

9.1.3.2 Transmission and Storage Facilities

The number of new transmission and storage facilities was estimated by reviewing the annual number of facilities from the year 1990 to 2013 estimated in the GHG Inventory published in 2015 and determining

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the rate of change in the number of these facilities over this period. The average change for the last 10 years was reviewed and the annual number of new transmission stations was determined to be 4 and the annual number of storage facilities was determined to be 5. The values were used to estimate the number of affected sources under the NSPS in each of the years 2012 through 2025. Because the requirements have impacts annually, our projected activity for year 2025 was developed to reflect the impacts of the rule from 2020 through 2025 as summarized in Table 9-1. This approach was used to support the regulatory impacts assessment process to reflect rule impacts from the effective date through 2025.

9.1.4 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to the regulatory options which were selected as a viable options for reducing fugitive emissions from fugitive emissions components located at production well sites and compressor stations.

9.1.4.1 Primary Environmental Impacts of Regulatory Options

Based on the discussion above, the EPA reconsidered Regulatory Options 1 and 2 for well sites and Regulatory Options 1, 2 and 3 for compressor stations. A summary of the options are provided below;

- Regulatory Option 1. Require the implementation of a fugitive emissions monitoring and repair program which includes annual monitoring of fugitive emissions components using OGI.
- Regulatory Option 2. Require the implementation of a fugitive emissions monitoring and repair program which includes semiannual monitoring of fugitive emissions and components using OGI.
- Regulatory Option 3. Require the implementation of a fugitive emissions monitoring and repair program which includes quarterly monitoring of fugitive emissions components using OGI.

The number of oil and natural gas well sites, gathering and boosting stations, transmission stations, and storage facilities that would be subject to the regulatory options listed above were estimated using data from the HPDI database. In 2020, which include all new and modified sources since 2016, it was estimated that there would be 76,759 oil well sites, 16,819 gas well sites, 480 gathering and boosting stations, 20 transmission stations, and 25 storage facilities subject to these options. In 2025, which include all new and modified sources since 2016, it was estimated that there would be 156,809 oil well sites, 34,487 gas well sites, 960 gathering and boosting stations, 40 transmission stations, and 50 storage facilities subject to these options.

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It was estimated that OGI monitoring and repair can achieve an overall 40 percent VOC and methane reduction for annual monitoring, 60 percent VOC and methane reduction for semiannual monitoring, and 80 percent VOC and methane reduction for quarterly monitoring over the life span of the facility. These percent reduction values were estimated based on information from the EPA white paper and an analysis by the Colorado Air Quality Control Commission as described previously. Nationwide emission reductions were estimated by applying this 40, 60 and 80 percent VOC and methane reduction to the uncontrolled baseline emissions for well sites and compressor stations. In considering the three frequency options, the EPA considered the implementation issues with respect to the monitoring and repair plan and the EPA determined that, based on input from industry and regulatory agencies, that the program frequency should be consistent across the segments in the oil and natural gas source category. Therefore, nationwide impacts were estimated for these options as presented in Tables 9-2, 9-3 and 9-4.

9.1.4.2 Cost Impacts

OGI Monitoring and Repair Plans (Options 1, 2 and 3)

Regulatory Option 1 include annual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-2) include the costs for having a contractor perform the annual OGI survey, activities planning, repair costs, resurvey of repaired components using a Method 21 device, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of an annual OGI monitoring and repair program at well sites was calculated to be 127 thousand standard cubic feet per year (Mscf/yr) for a natural gas production well site, 64 Mscf/yr for an oil well site with a GOR > 300, and 29 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas saved was calculated to be 815 Mscf/yr for gathering and boosting stations, 836 Mscf/yr for transmission stations, and 2,950 Mscf/yr for storage facilities.[123]

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue

[123] Natural gas savings calculated using the CH_4 reductions and assuming a methane to natural gas volume ration of 82.9% for upstream facilities (well sites, gathering & boosting) and a methane to natural gas volume ratio of 92.8% for downstream facilities (transmission, storage).

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from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA. Table 9-2 also summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 1.

Regulatory Option 2 include semiannual monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-3) include the costs for having a contractor perform the semiannual OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas savings from the implementation of a semiannual OGI monitoring and repair program were calculated to be 191 Mscf/yr for a natural gas production well site, 96 Mscf/yr for an oil production well site with a GOR > 300, and 43 Mscf/yr for an oil production well site with a GOR < 300. For the compressor stations, the potential natural gas savings were calculated to be 1,222 Mscf/yr for gathering and boosting stations, 1,255 Mscf/yr for transmission stations, and 4,424 Mscf/yr for storage facilities.[124] Table 9-3 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 2.

Regulatory Option 3 for well sites and compressor stations include quarterly monitoring of fugitive emissions components using OGI and repair of fugitive emissions components that are found to be leaking during the survey. The annual costs for these surveys (as summarized in Table 9-4) include the costs for having a contractor perform the quarterly OGI survey, activities planning, repair costs, preparation and submittal of an annual report and the amortization of the capital costs over 8 years at 7 percent interest. The potential natural gas saved from the implementation of a quarterly OGI monitoring and repair

[124] Ibid.

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program at well sites was calculated to be 255 Mscf/yr for a natural gas production well site, 127 Mscf/yr for an oil well site with a GOR > 300, and 57 Mscf/yr for an oil production well site with a GOR < 300. The potential natural gas savings at compressor stations were calculated to be 1,629 Mscf/yr for gathering and boosting stations, 1,673 Mscf/yr for transmission stations, and 5,899 Mscf/yr for storage facilities.[125] Table 9-4 summarizes the nationwide cost impacts for the projected years 2020 and 2025 for implementation of regulatory Option 3.

9.1.4.3 Low Producing Natural Gas and Oil Wells

For the proposed rule, the EPA evaluated an alternative nationwide impact scenario that accounts for well sites that produce relatively little crude oil and/or natural gas. The EPA had proposed that low producing wells not be subject to fugitive emissions monitoring provisions. While there were several criteria for defining a low-producing well, the EPA believed the definition of a "stripper well" in Internal Revenue Services (IRS) regulations, was consistent with the type of well which would be considered low-producing under that scenario. Under the IRS regulations, a stripper well property “means, with respect to any calendar year, any property with respect to which the amount determined by dividing—(i) the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year, by (ii) the number of such wells, is 15 barrel equivalents or less". [126] This proposal was based on our belief at the time that low production wells have inherently low emissions from well completions and that many are owned and operated by small businesses. The EPA was concerned about the burden of the well completion requirement on small businesses, in particular if there is little emission reduction to be achieved.

However, based on information provided in the comments for the proposed rule, the EPA determined that fugitive emissions from low production wells may be comparable to fugitive emissions from other production wells. The low production well sites have the same type of equipment (e.g., separators, storage vessels) and components (e.g., valves, flanges, connectors) as production well sites with production greater than 15 boe per day. This indicates that the component counts for low production well sites are similar to that of non-low production well sites, and hence the potential fugitive emissions from both types of well sites are comparable. The comments on the proposed rule stated that many of these well sites are developed for leasing purposes and are typically unmanned and not visited as often as

[125] Ibid.
[126] 26 U.S.C. 613A(c)(6)(E).

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other well sites. This may potentially allow fugitive emissions to go unnoticed longer. No data were provided in the comments on the proposed rule that shows low production well sites have lower GHG (principally as methane) or VOC emissions than normal production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites since the type of equipment and the well pressures are more than likely the same. In addition, discussions with the industry indicated that well site fugitive emissions are not based on production, but rather on the number of equipment and components. Therefore, the EPA believes that the emissions from low production and non-low production well sites are likely comparable and are included as affected sources for fugitive emissions.

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Table 9-2. Nationwide Emission and Cost Analysis for Regulatory Option 1 – Annual OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility ($)	Annual Cost Per Facility ($)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million $/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	$1,318	$809	36,970	10,277	$22.2	$13.6
Oil Well Sites (GOR < 300)	32,392	$1,318	$1,204	15,996	4,290	$42.7	$38.9
Oil Well Sites (GOR > 300)	44,367	$1,318	$1,063	48,805	13,353	$58.5	$47.2
Well Sites Total	**93,578**	**NA**	**NA**	**101,771**	**27,920**	**$123.4**	**$99.7**
Gathering & Boosting	480	$7,777	$4,518	6,747	1,876	$3.7	$2.2
Transmission	20	$10,117	$6,372	323	9	$0.2	$0.1
Storage	25	$13,798	$590	1,424	39	$0.3	$0.01
Compressor Stations Total	**525**	**NA**	**NA**	**8,494**	**1,924**	**$4.2**	**$2.3**
Projected Year 2025							
Gas Well Sites	34,487	$1,318	$809	75,806	21,072	$45.5	$27.9
Oil Well Sites (GOR < 300)	66,173	$1,318	$1,204	32,677	8,765	$87.2	$79.7
Oil Well Sites (GOR > 300)	90,636	$1,318	$1,063	99,702	27,278	$119.5	$96.4
Well Sites Total	**191,296**	**NA**	**NA**	**208,185**	**57,115**	**$252.2**	**$204**
Gathering & Boosting	960	$7,777	$4,518	13,495	3,751	$7.5	$4.3
Transmission	40	$10,117	$6,372	646	18	$0.4	$0.3
Storage	50	$13,798	$590	2,849	79	$0.7	$0.02
Compressor Stations Total	**1,050**	**NA**	**NA**	**16,990**	**3,848**	**$8.6**	**$4.6**

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Table 9-3. Nationwide Emission and Cost Analysis for Regulatory Option 2 – Semiannual OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility ($)	Annual Cost Per Facility ($)	Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million $/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	$2,285	$1,521	55,455	15,415	$38.4	$25.6
Oil Well Sites (GOR < 300)	32,392	$2,285	$2,114	23,993	6,436	$74.0	$68.5
Oil Well Sites (GOR > 300)	44,367	$2,285	$1,903	73,208	20,029	$101.4	$84.4
Well Sites Total	**93,578**	**NA**	**NA**	**152,656**	**41,880**	**$213.8**	**$178.5**
Gathering & Boosting	480	$13,534	$8,646	10,121	2,813	$6.5	$4.2
Transmission	20	$15,868	$10,250	485	13	$0.3	$0.2
Storage	25	$23,230	$3,418	2,137	59	$0.6	$0.1
Compressor Stations Total	**525**	**NA**	**NA**	**12,743**	**2,885**	**$7.4**	**$4.5**
Projected Year 2025							
Gas Well Sites	34,487	$2,285	$1,521	113,709	31,608	$78.8	$52.5
Oil Well Sites (GOR < 300)	66,173	$2,285	$2,114	49,016	13,147	$151.2	$139.9
Oil Well Sites (GOR > 300)	90,636	$2,285	$1,903	149,554	40,917	$207.1	$172.5
Well Sites Total	**191,296**	**NA**	**NA**	**312,279**	**85,672**	**$437.1**	**$364.9**
Gathering & Boosting	960	$13,534	$8,646	20,242	5,627	$13.0	$8.3
Transmission	40	$15,868	$10,250	969	27	$0.6	$0.4
Storage	50	$23,230	$3,418	4,273	118	$1.2	$0.2
Compressor Stations Total	**1,050**	**NA**	**NA**	**25,484**	**5,772**	**$14.8**	**$8.9**

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Table 9-4. Nationwide Emission and Cost Analysis for Regulatory Option 3 – Quarterly OGI Monitoring and Repair

Fugitive Emission Component Location	Number of Sources Subject to NSPS	Annual Cost Per Facility ($)		Nationwide Emission Reductions (tpy)		Total Nationwide Costs (million $/year)	
		without savings	with savings	Methane	VOC	without savings	with savings
Projected Year 2020							
Gas Well Sites	16,819	$4,220	$3,201	73,940	20,553	$70.9	$53.8
Oil Well Sites (GOR < 300)	32,392	$4,220	$3,991	31,991	8,581	$136.7	$129.3
Oil Well Sites (GOR > 300)	44,367	$4,220	$3,710	97,610	26,706	$187.2	$164.6
Well Sites Total	**93,578**	**NA**	**NA**	**203,541**	**55,840**	**$394.8**	**$347.7**
Gathering & Boosting	480	$25,049	$18,532	13,495	3,751	$12.0	$8.9
Transmission	20	$27,369	$19,879	646	18	$0.5	$0.4
Storage	25	$42,093	$15,678	2,849	79	$1.1	$0.4
Compressor Stations Total	**525**	**NA**	**NA**	**16,990**	**3,848**	**$13.6**	**$9.7**
Projected Year 2025							
Gas Well Sites	34,487	$4,220	$3,201	151,612	42,144	$145.5	$110.4
Oil Well Sites (GOR < 300)	66,173	$4,220	$3,991	65,354	17,530	$279.2	$264.0
Oil Well Sites (GOR > 300)	90,636	$4,220	$3,710	199,405	54,557	$382.4	$336.2
Well Sites Total	**191,296**	**NA**	**NA**	**416,371**	**114,231**	**$807.1**	**$710.6**
Gathering & Boosting	960	$25,049	$18,532	26,989	7,502	$24.0	$17.8
Transmission	40	$27,369	$19,879	1,293	36	$1.1	$0.8
Storage	50	$42,093	$15,678	5,698	158	$2.1	$0.8
Compressor Stations Total	**1,050**	**NA**	**NA**	**33,980**	**7,696**	**$27.2**	**$19.4**

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10.0 NATIONWIDE IMPACTS FOR PNEUMATIC CONTROLLERS

10.1 Nationwide Emissions from New Sources

10.1.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined using the methodologies described in section 10.1.2 of this chapter.

10.1.2 Population of Controllers Installed Annually

The number of pneumatic controllers installed in the transmission and storage segment was approximated using the Inventory of U.S. GHG Emissions and Sinks: 1990-2012. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g., 2011) from the given years total (e.g., 2012). This difference was assumed to be the number of new devices installed in the latter year (e.g., Number of new devices installed during 2012 equals pneumatics in 2012 minus pneumatics in 2011). A 10-year average was calculated based on the number of new controllers installed in 2003 through 2012 in order to determine the average number of new devices installed in a typical year. An average was taken of all years. Where the year change was negative, the average calculation treated it as zero.

The number of facilities estimated to be subject to regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low-bleed controllers, such as in Wyoming and Colorado. Therefore, the EPA considered all facilities to be unregulated for this analysis.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of intermittent controllers that would be installed versus a bleed controller. This estimate of the percent of intermittent and bleed controllers was based on data from the GRI study, where 32 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission and

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storage segment.[127] The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 10-1 summarizes the estimated number of new devices installed per year.

Table 10-1. Estimated Number of Pneumatic Controllers Installed in a Typical Year in the Natural Gas Transmission and Storage Segment

Number of New Controllers Estimated for a Typical Year[a, b]		
Intermittent	**Bleed-Devices**	**Total**
256	120	376

a. National averages of population counts from the Inventory were refined to include the difference in intermittent and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 32 percent of the pneumatic controllers are bleed devices in the transmission and storage segment.
b. The number of pneumatics controllers estimated for the transmission and storage segment was approximated from comparing a 10 year average of new controllers installed in 2003 through 2012 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. GHG Emissions and Sinks: 1990-2012.

10.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 10-2. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table W-3 of the GHG Reporting Rule, Subpart W since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

Table 10-2. Nationwide Baseline Emissions from Representative Pneumatic Controller Installed in a Typical Year in Natural Gas Transmission and Storage Segment[a, b]

Baseline Emissions from Representative New Continuous Bleed Controller (tpy)		Number of New Continuous Bleed Controllers Expected Per Year	Nationwide Baseline Emissions from New Continuous Bleed Controller (tpy)	
Methane	**VOC**		**Methane**	**VOC**
3.013	0.083	120	362	10

a. Baseline emissions were based on the bleed rates for a high-bleed controllers.
b. To estimate VOC emissions, the weight ratio of 0.0277 lbs VOC per pound methane was used.

10.2 Nationwide Cost Impacts of Regulatory Options

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective,

[127] *See footnote 57.*

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however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Table 10-3 summarizes the nationwide emission reductions and nationwide costs impacts of the selected regulatory option for the natural gas transmission and storage segment. It is estimated to affect 96 new transmission and storage pneumatic controllers per year and 480 new affected sources through 2020 and 960 affected sources through 2025. The nationwide capital cost for projected year 2020 is estimated to be $109,073 and annual costs of $11,976 without considering value of gas saved. With consideration of gas savings from recovered gas, the annual cost for projected year 2020 is a net savings of $270,264. The nationwide capital cost for projected year 2025 is estimated to be $218,146 and annual costs of $23,951 without considering savings from gas saved. With consideration of gas savings from recovered gas, the annual cost for projected year 2025 is a net savings of $540,529.

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Table 10-3. Nationwide Cost and Emission Reduction Impacts for Pneumatic Controllers for Transmission and Storage for the Projected Years 2020 and 2025

Number of Affected Facilities[a]	Capital Cost Per Controller[b]	Annual Costs		Nationwide Emission Reductions				Total Nationwide Costs ($/year)		
		w/o savings	w/savings	(tpy)			(metric tonnes)	Capital Cost	Annualized Cost	
	(2012)	($/year)		Methane	VOC	HAP	CO2e		w/o savings	w/savings
Projected Year 2020										
480	$227	$25	($563)	1,338	37	1	30,335	$109,073	$11,976	($270,264)
Projected Year 2025										
960	$227	$25	($563)	2,675	74	2	60,671	$218,146	$23,951	($540,529)

a. The number of sources subject to NSPS for the natural gas transmission and storage segment represent the number of new controllers expected per year (120) reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed controllers can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments.
b. The capital cost is equal to the incremental cost of a low bleed device versus a new high bleed device.
c. Based on the global potential warming of methane equal to 25.
Note: Negative numbers reflect a net savings.

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11.0 NATIONWIDE IMPACTS FOR PNEUMATIC PUMPS

11.1 Nationwide Emissions from New Sources

11.1.1 Approach

Nationwide emissions from newly installed natural gas pneumatic pumps for a typical year were calculated by estimating the count of pneumatic pumps installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 6-2. The count of new pneumatic pumps installed for a typical year was determined for each natural gas production and natural gas processing. The methodologies that determined the estimated count of new pneumatic pumps installed in a typical year is provided below.

11.1.2 Population of Pneumatic Pumps Installed Annually

For the natural gas production segment the count of new pneumatic pumps installed in a typical year was estimated by reviewing the annual count of pneumatic pumps from the year 1990 to 2012 reported in the GHG Inventory for the natural gas and oil production facilities and determining the rate of change in the count of pneumatic pumps in each inventory over this period. For all the years, the annual counts of new pneumatic pumps installed between two years were not consistent. The average change for the entire period was estimated to be 877 for natural gas facilities and (-161) for oil facilities. Additionally, the average change over the last 10 years was estimated to be 1,480 for natural gas facilities and 803 for oil facilities. Because of the fluctuation in the count of new pneumatic pumps from the years 1990 to 2012, it was assumed that the 10-year average change represented a better estimate of the current growth of pneumatic pumps. For proposal the EPA calculated the average change excluding years where there was a negative change in the number of pneumatic pumps IPs. Based on comments received, the EPA changed the methodology to include the years where there was a negative change as zero in the averaging calculation. Based on this methodology, the counts of new pneumatic pumps that would be affected sources under the proposed NSPS for a typical year was estimated to be 1,184 for natural gas facilities and 241 for oil facilities.

To forecast the count of pneumatic pumps replaced in a *typical* year, age and count of gas and oil wells for 2012 were extracted from DI Desktop®. The age of the pneumatic pump was assumed to be the age of the well. The average lifetime of a pneumatic pump was assumed to be 10 years. Therefore, a portion of CIPs that reached 10 years in a particular year were assumed to be replaced that year. For a typical year for this analysis, the replacement count for pneumatic pumps was estimated to be 340

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diaphragm pumps and 340 piston pumps for gas wells with the same replacement pump counts for oil wells.

The GHG Inventory[128] does not estimate any emissions from pneumatic pumps for the natural gas processing, natural gas transmission and storage segments. Pneumatic pump data are not reported in GHGRP for these segments. For this analysis, the EPA assumed that pneumatic pumps are not used in these segments.

Once the population counts of pneumatic pumps in each segment were established, the count of pneumatic pumps was split into diaphragm and piston. Similar to the assumption used in the EPA/GRI Report,[129] for new and replaced pumps for each segment the EPA assumed 50 percent of the pumps to be diaphragm and 50 percent of the pumps to be piston pumps. Table 11-1 below summarizes the estimated count of new pumps installed per year.

Table 11-1. Estimated Count of Pneumatic Pumps Installed in a Typical Year

Segment/Pump Type	Number of New Pumps
Production/Diaphragm	1,052
Production/Piston	1,052
Processing/Diaphragm and Piston	0
Transmission/Diaphragm and Piston	0
Storage/Diaphragm and Piston	0

11.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for pneumatic pumps for new sources in a typical year are summarized in Table 11-2 by industry segment and pump type.

[128] *See footnote 81.*
[129] *See footnote 82.*

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Table 11-2. Nationwide Baseline Emissions from Representative Pneumatic Pumps Installed in a Typical Year for the Oil and Natural Gas Industry

Segment/Pump Type	Number of New Pumps[a]	Emission Factor (tpy)[b]		Nationwide Emissions (tpy)	
		Methane	VOC	Methane	VOC
Production/Diaphragm	1,052	3.46	0.96	3,641	1,012
Production/Piston	1,052	0.38	0.11	400	111
Processing/Diaphragm	0	3.46	0.96	0	0
Processing/Piston	0	0.38	0.11	0	0
Totals				4,040	1,123
Total Production				4,040	1,123
Total Processing				0	0
Total Transmission				0	0
Total Storage				0	0

a. From Table 7-3.
b. From Table 7-2.

11.2 Nationwide Emission Reductions and Cost Impacts of Selected Regulatory Options

The EPA calculated the nationwide impacts of the selected options by considering the estimated affected population for each of the target years, the estimated emission reductions per pneumatic pump controlled by the regulatory option and the annualized cost associated with that control option for that pump in that segment.

For Option 1, based on the activity analysis presented above, the EPA estimated there will be no new pneumatic pumps installed in the natural gas processing segment in either of the projected years 2020 or 2025. Therefore, there will be zero nationwide emission reductions and costs associated with Option 1.

For Option 3 for the final rule, the EPA estimated that there will be 1,052 new, modified, or reconstructed diaphragm pumps installed in a typical year. As noted above, due to inherently low emissions, piston pumps were removed from coverage under the final rule. In addition, for the final rule, the EPA included a provision that allowed for an exemption from control where it is determined to be technically infeasible to connect the pump to an existing control device or process at a non-greenfield site or where the a pump is limited use. The EPA has no data that provides information on the number of pumps located at sites where a control device or process is available. Further, the EPA have no data that indicates how often conditions with respect to the pump and/or the control device would be such that it would be technically infeasible to connect the pump to an existing control device or process or where a pump is limited use. In order to estimate impacts that account for these circumstances that would remove

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control requirements for the pumps under the NSPS, the EPA has estimated that 75 percent of the new pumps will be able to be connect to an existing control device or process. Based on this estimate, 789 pumps in a typical year would be subject to control requirements under the rule.

For nationwide impacts, the EPA estimated that a total of 3,946 new or replaced diaphragm pumps will be installed in the production segment from 2016 through and including the projected year 2020, assumed to still be in operation in 2020. For the projected year 2025, the EPA determined the affected population as those affected facilities from the years 2016 through and including 2025, assumed to still be in operation in 2025. Therefore, the EPA estimated that 7,892 new diaphragm pumps will be installed in the production segment by 2025. Table 12-3 summarizes the estimated number of pumps that would be subject to the final rule provisions for the projected years 2020 and 2025.

Table 11-3. Estimated Count of Pneumatic Pumps Installed Subject to NSPS for 2020 and 2025

Segment/Pump Type	Estimated Number of New Pumps			
	Pumps Per Year[a]	Controlled Per Year Under NSPS	Controlled Under NSPS 2020	Controlled Under NSPS 2025
Production/Diaphragm	1,052	789	3,946	7,892
Production/Piston	1,052	0	0	0
Processing/Diaphragm and Piston	0	0	0	0

a. This number includes all newly installed, modified, and reconstructed pumps.

Based on these activity numbers, the nationwide emission reductions in 2020 are estimated to be 12,970 tons per year of methane and 3,605 tons per year of VOC from diaphragm pumps. The total nationwide emission reductions, for the projected year 2025, are estimated to be 25,940 tons per year of methane and 7,210 tons per year of VOC from diaphragm pumps.

The nationwide costs are based only on the Option 3 costs related to routing pump emissions to an existing combustion device or a VRU. The EPA estimated that the annualized cost for routing pump emissions either to a combustion device or a VRU would be $774. Based on the estimated affected population of 3,946 pneumatic pumps in 2020, the EPA estimated the nationwide cost to be approximately $3.1 million in 2020. The nationwide costs are estimated to be approximately $6.1 million in 2025. Table 11-4 summarizes the nationwide emission reduction and cost impacts for projected years 2020 and 2025.

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Secondary emissions impacts for Option 3 would include emissions resulting from the combustion of the recovered gas. Table 11-5 summarizes the nationwide secondary emissions for the projected year 2020 and 2025 for Option 3.

Table 11-4. Nationwide Impacts for Gas-Driven Diaphragm Pumps for Projected Years 2020 and 2025

Segment/ Affected Facility	Number of Pumps Subject to NSPS[a]	Annualized Cost[b]	Nationwide Emission Reductions[c] (tpy)			(metric (tonnes)[d]	Nationwide Costs
		($)	Methane	VOC	HAP	CO_2e	(million $)
Projected Year 2020							
Natural Gas Processing	0	$10,051 - $72,394	0	0	0	0	$0
Production	3,946	$774	12,970	3,605	136	294,149	$3.1
Projected Year 2025							
Natural Gas Processing	0	$10,051 - $72,394	0	0	0	0	$0
Production	7,892	$774	25,940	7,210	272	588,299	$6.1

a. From Table 7-19.
b. From Table 7-18.
c. Based on 95 percent control.
d. Assumes 0.90718474metric tonnes per short ton and global warming potential of methane = 25.

Table 11-5. Nationwide Secondary Impacts from Pneumatic Pumps Routed to a Combustion Device for Projected Years 2020 and 2025

Segment	Secondary Impacts (tpy)				
	THC[a]	CO[b]	CO_2[c]	NO_x[d]	PM[e]
Projected Year 2020					
Production	60	133	56,699	292	1
Projected Year 2025					
Production	120	266	113,397	58	0

a. Total hydrocarbons - based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.
b. Carbon monoxide - based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.
c. Carbon Dioxide - based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.
d. Nitrous Oxides - based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.
e. Particulate Matter - based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a "lightly smoking" flare.

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12.0 NATIONWIDE IMPACTS FOR COMPRESSORS

12.1 Nationwide Emissions from New Sources

12.1.1 Overview of Approach

The number of new affected facilities in the oil and natural gas source category was estimated using data from the GHG Inventory.[130] The nationwide emissions estimates for new sources were then determined by multiplying the number of new sources for each oil and natural gas segment by the expected emissions per compressor based on the emission factor data presented in Table 7-3. A summary of the number of new, modified, and reconstructed reciprocating and centrifugal compressors for transmission and storage segment is presented in Table 7-4.

12.1.2 Nationwide Activity Data for Compressors in Transmission and Storage

The number of reciprocating compressors and wet seal centrifugal compressors installed in the transmission and storage segment was estimated using the GHG Inventory. The number of new reciprocating compressors, wet seal centrifugal compressors, and dry seal centrifugal compressors installed in a given year was estimated by subtracting the prior year (e.g., 2011) from the given year's (e.g., 2012) total as represented in the Inventory. This difference was assumed to be the number of new compressors installed in the latter year (e.g., number of new compressors installed during 2012 equals the compressors reported in 2012 minus the compressors reported in 2011). A 10-year average was calculated based on the number of new compressors installed in 2003 through 2012 in order to determine the average number of new compressors installed in a typical year. Where the data indicated a decrease in new compressors, the average calculation counted those years as zero. An average was taken of all years and rounded to the nearest whole number. The results of this analysis are shown in Table 12-1.

Table 12-1. Approximate Number of New Compressors in the Transmission and Storage Segment in a Typical Year[a]

Compressor Location	Number of New Reciprocating Compressors	Number of New Centrifugal Compressors	
		Wet Seal	Dry Seal
Transmission	15	0	2
Storage	17	1	5

[130] See footnote 4.

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a. Estimates of the number of new compressors were rounded to the nearest whole number.

12.1.3 Nationwide Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 12-2 by industry segment.

Table 12-2. Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors for Projected Years 202 and 2025

Compressor Location/Compressor Type	Nationwide Baseline Emissions (tpy)	
	Methane	VOC
Projected Year 2020		
Transmission		
Reciprocating Compressors	2,035	56
Wet Seal Centrifugal Compressors	0	0
Storage		
Reciprocating Compressors	2,401	675
Wet Seal Centrifugal Compressors	585	16
Projected Year 2025		
Transmission		
Reciprocating Compressors	4,070	113
Wet Seal Centrifugal Compressors	0	0
Storage		
Reciprocating Compressors	,4802	133
Wet Seal Centrifugal Compressors	1,169	32

12.2 Nationwide Emission Reductions and Cost Impacts of Selected Regulatory Options

Tables 12-3 and 12-4 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 15 reciprocating compressors at transmission facilities and 17 reciprocating compressors at underground storage facilities in a typical year. The nationwide impacts for projected year 2020 are based on a typical year. The projected affected number of compressors for projected year 2020 is calculated as all compressors affected from 2016 through and including 2020 and for 2025 as all compressors affected from 2016 through and including 2025, assumed to still be in operation in the analysis years. A summary of the capital and annual costs and emission reductions for this option is presented in Table 12-3.

Operators in the gathering and boosting and transmission and storage parts of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation

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service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

Regulatory Option 3 is expected to affect 1 new wet-seal centrifugal compressor in the transmission and storage segment (specifically at a storage facility) each year. The number of affected centrifugal compressors is low because the historical rate of growth in the overall number of wet seal centrifugal compressors in the segment has been low, indicating few new compressors are being installed. In addition, most new centrifugal compressors are expected to use dry seals, which would not be affected facilities. EPA did not change these activity numbers for the final rule. A summary of the capital and annual costs and emission reductions for this option is presented in Table 12-4. A summary of the nationwide secondary combustion-related emissions from Option 2 are summarized in Table 12-5.

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Table 12-3. Nationwide Cost Impacts for Regulatory Option 1

Compressor Location	Number of New Sources	Nationwide Emission Reductions (tpy)		Total Nationwide Costs	Annualized Cost ($/year)	
		Methane	VOC	Capital Cost ($)	Without Savings	With Savings
Projected Year 2020						
Transmission	75	1,626	45	$423,769	$131,066	($205,534)
Storage	85	1,856	51	$654,915	$159,594	($207,676)
Projected Year 2025						
Transmission	150	3,252	90	$847,537	$262,132	($411,068)
Storage	170	3,712	103	$1,309,830	$353,049	($415,351)

Note: Negative number indicates net savings.

Table 12-4. Nationwide Cost Impacts for Regulatory Option 3

Compressor Location	Number of New Sources	Nationwide Emission Reductions (tpy)		Nationwide Costs			
		Methane	VOC	Capital Cost New CD[a] ($)	Capital Cost Existing CD[b] ($)	Annual Cost New CD[a] ($/year)	Annual Cost Existing CD[b] ($/year)
Projected Year 2020							
Transmission	0	0	0	$0	$0	$0	$0
Storage	5	555	21	$358,914	$116,260	$570,728	$16,553
Projected Year 2025							
Transmission	0	0	0	$0	$0	$0	$0
Storage	10	1,111	41	$717,829	$232,520	$1,141,456	$33,106

a. CD = Combustion Device Cost is based installation of a full system of control using a combustion device.
b. Cost is based on routing compressor to an existing combustion device.

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Table 12-5. Nationwide Secondary Impacts from Compressor Emissions Routed to a Combustion Device

Compressor Location	Secondary Impacts (tpy)				
	THC[a]	CO[b]	CO_2[c]	NO_x[d]	PM[e]
Projected Year 2020					
Storage	2.9	6.4	2,748	1.4	0.05
Projected Year 2025					
Storage	5.8	13	5,496	2.8	0.10

a. Based on combustion of natural gas stream and AP-42 Total Hydrocarbons emission factors for industrial flares.
b. Based on combustion of natural gas stream and AP-42 Carbon Monoxide emission factors for industrial flares.
c. Based on combustion of natural gas stream and 40 CFR Part 98, subpart Y, Equation Y-2.
d. Based on combustion of natural gas stream and AP-42 Nitrogen Oxides emission factors for industrial flares.
e. Based on combustion of natural gas stream and AP-42 Particulate Matter emission factors for industrial flares. Assumes a "lightly smoking" flare.

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13.0 NATURAL GAS SAVINGS

Affected facilities under the NSPS may recover natural that would have otherwise been vented or combusted as a result of controlling emissions. This section presents the value of recovered gas nationally.[131] With respect to the regulatory options presented above, there are several opportunities for gas savings to be realized, as noted below:

- For oil well completions, with implementation of a REC, the EPA estimated that 899 Mcf of natural gas is recovered during the average 3-day completion event.
- For equipment leaks, with implementation of the semiannual OGI monitoring and repair of leaks found, the EPA estimate that the average annual gas saved would be 43 Mcf for oil wells with GOR < 300, 96 Mcf for oil wells with GOR > 300, 191 Mcf for gas wells, 1,222 Mcf for gathering and boosting stations, 1,255 Mcf for transmission stations, and 4,424 for storage facilities. For quarterly monitoring and repair, the EPA estimate for average annual gas saved would be 57 Mcf for oil wells with GOR < 300, 127 Mcf for oil wells with GOR > 300, 255 Mcf for gas wells, 1,629 Mcf for gathering and boosting stations, 1,673 Mcf for transmission stations, and 5,899 for storage facilities.
- For pneumatic controllers, the EPA estimate the use of low-bleed controllers instead of high-bleed controllers will save 147 Mcf of natural gas per year.
- For reciprocating compressors, the EPA estimate that the replacement of rod packing every 26,000 hours of operations (or every three years) will avoid the loss of, for each reciprocating compressor, 1,122 Mcf per year for transmission facilities and 1,130 Mcf per year for storage facilities.[132]
- For centrifugal compressors, the EPA estimates that the replacement of one wet seal compressor with a dry seal compressor will save 5,290 Mcf per year.[133]

Based on the above per unit natural gas savings and the new source activity counts anticipated for the projected years 2020 and 2025 for the affected facilities, the EPA calculated

[131] Note that operators in the gathering and boosting and transmission and storage segments of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost supporting BSER decisions in the preamble (and is presented in Volume 1 of this TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. This section addresses all gas savings regardless of presumed ownership.
[132] See footnote 2.
[133] See footnote 2.

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the nationwide gas savings for each of the regulatory options discussed in the sections above for the projected years 2020 and 2025. Table 13-1 presents the estimated gas savings for these affected facilities.

Table 13-1. Estimated Nationwide Natural Gas Savings for Selected Regulatory Options

Affected Facility	Number of Affected Facilities Subject to NSPS[a]	Volume of Gas Saved (MMcf)	Value of Gas Saved ($ million)
Projected Year 2020			
Well Completions			
Development Oil Wells	19,703	5,738	$23
Equipment Leaks			
Oil Well Site[b]	76,759	5,633	$22.5
Gas Well Site[b]	16,819	3,214	$12.9
Gathering[c]	480	782	$3.1
Transmission[c]	20	33	$0.13
Storage[c]	25	147	$0.59
Pneumatic Controllers	480	70.6	$0.28
Pneumatic Pumps	3,946	0	$0.00
Reciprocating Compressors - Transmission	75	84	$0.34
Reciprocating Compressors - Storage	85	96	$0.38
Centrifugal Compressors - Storage	5	26	$0.10
Total Projected Year 2020	122,343	15,824	$63
Projected Year 2025			
Well Completions			
Development Oil Wells	20,988	6,098	$24.4
Equipment Leaks			
Oil Well Site	156,809	11,508	$46
Gas Well Site	34,487	6,590	$26.4
Gathering	960	1,564	$6.3
Transmission	40	67	$0.27
Storage	50	295	$1.8
Pneumatic Controllers	960	141	$0.56
Pneumatic Pumps	7,892	0	$0
Reciprocating Compressors - Transmission	150	168	$0.67
Reciprocating Compressors - Storage	170	192	$0.77
Centrifugal Compressors - Storage	10	53	$0.21
Total Projected Year 2025	230,407	26,676	$107

a. Reflects only the number of affected facilities subject to the NSPS that will have potential gas savings (not all sources will have potential for gas savings).
b. For oil wells, the activity number reflects both oil well sites with GOR < 300 and oil well sites with GOR > 300. The gas savings for well sites are based on semiannual monitoring and repair.
c. The gas savings for compressor stations are based on quarterly monitoring and repair.

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14.0 POTENTIAL NATIONWIDE CO_2 Eq. and HAP IMPACTS

Because methane is of concern for global warming effects, the EPA also calculated the global warming potential expressed as CO_2 Eq. for the methane reductions from the proposed regulatory options. For the purposes of this analysis, one ton of methane is equal to 25 tons of CO_2 Eq. The EPA have converted the CO_2 Eq. values to metric tonnes consistent with the presentation of CO_2 Eq.in the GHG Inventory.

In addition, there may be important HAP emission co-reductions a resulting from the application of emission controls under the NSPS. For the purposes of the NSPS, the EPA estimate HAP emissions by applying a ratio to the methane emissions. The ratio used is based on the gas composition analysis conducted for the NSPS.[134] Because gas composition was determined to vary between industry segments and between the various affected facilities, different ratios were used accordingly. Table 14-1 summarizes the HAP-to-methane ratios used for the various affected facilities in the various segments. Based on the methane emission reductions estimated in the above sections for the respective affected facilities and regulatory options, the EPA estimated the HAP emissions.

Table 14-2 summarizes the CO_2 Eq. and HAP emission reductions calculated for the affected facilities based on the finalized regulatory options.

Table 14-1. HAP-to-Methane Ratios Used to Estimate HAP Emissions

Segment	Affected Facility	HAP-to-Methane Ratio
Production	HF Oil Well Completions	0.0001
	Equipment Leaks:	
	Oil Well sites	0.0105
	Gas Well Sites	0.0105
	Gathering and Boosting	0.0105
	Pneumatic Pumps	0.0105
Transmission	Equipment Leaks	0.000822
	Pneumatic Pumps	0.000822
	Pneumatic Controllers	0.000822
	Reciprocating Compressors	0.000822
Storage	Equipment Leaks	0.000822
	Pneumatic Pumps	0.000822
	Pneumatic Controllers	0.000822
	Reciprocating Compressors	0.000822
	Centrifugal Compressor	0.000822

[134] See footnote 3.

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Table 14-2. HAP and CO_2 Eq. Reductions for Selected Regulatory Options

Affected Facility	Number of Sources Subject to NSPS	Nationwide Emission Reductions			
		Methane (tpy)	VOC (tpy)	HAP (tpy)	CO_2e (MT/year)
Projected Year 2020					
HF Oil Well Completions					
All Oil Wells	19,703	115,880	97,038	12	2,628,121
Development Oil Wells	18,955	106,758	89,399	11	2,421,222
Exploratory/Delineation Oil Wells	748	9,123	7,639	1	206,899
Equipment Leaks					
Oil Well Site	76,759	97,201	26,465	997	2,204,483
Gas Well Site	16,819	55,455	15,415	581	1,257,695
Gathering & Boosting	480	13,495	3,751	141	306,056
Transmission	20	646	18	0.5	14,657
Storage	25	2,849	79	2.3	64,609
Pneumatic Controllers	480	1,338	37	1	30,335
Pneumatic Pumps	3,946	12,970	3,605	136	294,149
Reciprocating Compressors					
Transmission	75	1,626	45	1.3	36,881
Storage	85	1,856	51	1.5	42,094
Centrifugal Compressors – Storage	5	555	15	0.4	23,178
Total Projected Year 2020	118,397	303,871	146,519	1,874	6,902,258
Projected Year 2025					
HF Oil Well Completions					
All Oil Wells	20,988	123,461	103,386	12	2,800,048
Development Oil Wells	20,191	113,461	95,012	11	2,573,255
Exploratory/Delineation Oil Wells	797	10,000	8,374	1	226,793
Equipment Leaks					
Oil Well Site	156,809	198,569	54,065	2,037	4,503,477
Gas Well Site	34,487	113,709	31,608	1,191	2,578,877
Gathering	960	26,989	7,502	283	612,111

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Affected Facility	Number of Sources Subject to NSPS	Nationwide Emission Reductions			
		Methane (tpy)	VOC (tpy)	HAP (tpy)	CO_2e (MT/year)
Transmission	40	1,293	36	1.1	29,314
Storage	50	5,698	158	4.7	129,218
Pneumatic Controllers	960	2,675	74	2	60,671
Pneumatic Pumps	7,892	25,940	7,210	272	588,299
Reciprocating Compressors					
Transmission	150	3,252	90	2.6	73,762
Storage	170	3,712	103	3.0	84,187
Centrifugal Compressors					
Storage	10	1,111	31	1	25,187
Total Projected Year 2025	222,516	506,409	204,263	3,810	11,485,151

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15.0 COMPARISON OF TOTAL COST IMPACTS TO OVERALL INDUSTRY CAPITAL EXPENDITURES AND RECEIPTS

In order to provide another perspective on the reasonableness of the estimated cost of control as determined in our evaluation of BSER for the final standards as presented in Volume 1 of this TSD, we analyzed the total cost of the rule for each type of affected facility (as presented in Volume 2 of this TSD) under two additional approaches using industry economic data.

First, we compared the total nationwide capitals costs that would be incurred for each type of affected facility to comply with the final standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the final standards to the level of new capital expenditures that the industry is incurring in the absence of the final standards. Capital expenditure data for relevant NAICS codes covered by the rule were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey[135]. For the capital expenditures analysis, we determined the estimated nationwide capital costs estimated to be incurred by each type of affected facility to comply with the final standards[136], then divided the nationwide capital costs by the new capital expenditures (census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. For example, we used the total estimated capital cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total capital expenditures the NAICs codes that correspond to oil and natural gas production segment. Table 15-1 below summarizes the capital expenditure data used for our analysis.

For fugitive emissions standards at well sites and compressor stations, there are no actual capital cost identified in the TSD. Instead, for the purposes of this portion of the analysis, we used the first-year corporate-based costs for these standards.

[135] Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2013, Table 4a. See http://www.census.gov/econ/aces/xls/2013/full_report.html

[136] The total capital cost estimate is based on the number of estimated affected facilities within the year and the capital cost per facility, however, the capital expenditure may not actually be incurred in that year.

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In the second approach, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us determine whether the annualized costs appears reasonable as a percentage of the revenues being generated by the industry. The annualized cost, as calculated for the rule, includes capital cost annualized using a seven percent discount rate plus any annually incurred cost for implementation of a control technology. We included, where applicable, the cost savings realized from recovered natural gas. The annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census[137]. For the annual revenues analysis, we determined the estimated nationwide annualize costs incurred by each type of affected facility to comply with the final standards[138], then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. For example, we used the total annual cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total receipts for the NAICs codes that correspond to oil and natural gas production segment. Table 15-2 below summarizes the revenue data used for our analysis.

For the capital expenditures, the production segment was represented with the NAICS codes 21111 " Crude Petroleum and Natural Gas Extraction" and 213111 and 213112 " Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 4862 "Pipeline transportation of natural gas". For revenue, the production segment was represented with the NAICS codes 21111 " Crude Petroleum and Natural Gas Extraction" and 213112 " Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 486210 "Pipeline transportation of natural gas". Although there is not a one-to-one correspondence between NAICS codes and the

[137] Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Employment Size for the United States, All Industries: 2012. Release date: 6/22/2015. 2012 County Business Patterns and 2012 Economic Census. For information on confidentiality protection, sampling error, and nonsampling error, see http://www.census.gov/econ/susb/methodology.html. For definitions of estimated receipts and other definitions, see http://www.census.gov/econ/susb/definitions.html.

[138] The estimated nationwide annualized costs were determined based on the estimated number of affected facilities in that year, however, these annualized costs are not necessarily incurred within that same year.

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industry segments we used in the development of the analysis, we believe there is enough similarity to draw accurate conclusions.

Because we are aware the different owners or operators are generally involved in the different industry segments, we conducted the analysis at the affected facility level to ensure proper characterization of the impact. We also conducted the analysis for all sources in the production segment and in the transmission and storage segment. Table 15-3 summarizes the result of our analysis. In all cases we found that the rule impacts in comparison to either capital expenditures or revenues represent a fraction of one percent.

Table 15-1. NAICS-Based Capital Expenditure Data

Capital Expenditures Data (millions $, current$)			
Oil and Natural Gas Segment	**NAICS code**	**NAICS DESCRIPTION**	**Total New Expenditures**
Production	2111	Crude Petroleum and Natural Gas Extraction	$158,911
	213111 213112	Support activities for oil and gas operations	$19,966
Transmission and Storage	4862	Pipeline transportation of natural gas	$12,891

Table 15-2. NAICS-Based Revenue Data

Revenue Data (millions $, 2012$)				
Oil and Natural Gas Segment	**NAICS CODE**	**NAICS DESCRIPTION**	**ESTIMATED RECEIPTS ($1,000)**	**ESTIMATED RECEIPTS (millions 2012$)**
Production	211111	Crude Petroleum and Natural Gas Extraction	$276,076,578	$276,077
	213112	Support Activities for Oil and Gas Operations	$90,645,566	$90,646
Processing	211112	Natural Gas Liquid Extraction	$49,236,136	$49,236
Transmission and Storage	486210	Pipeline Transportation of Natural Gas	$26,587,330	$26,587

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Table 15-3. Comparison of Final NSPS OOOOa Nationwide Cost in 2025, by Affected Facility Cost to Industry Wide Capital Expenditures and Revenues

Oil and Natural Gas Segment/ Affected Facility	Number of Sources Subject to NSPS	Total Nationwide Capital Costs	Total Nationwide Annual Cost	Nationwide Capital Cost/ Capital Expenditures	Nationwide Annual Cost/Receipts
	Units	(million 2012$)	(million $)	(%)	(%)
Production					
Hydraulically Fractured Oil Well Completions and Recompletions	21,000	160	130	0.09	0.04
Pneumatic Pumps	8,000	43	6.1	0.02	0.00
Fugitives - Well Sites	190,000	150	365	0.09	0.10
Total Production Segment	219,000	353	501	0.20	0.14
Transmission and Storage					
Compressors					
- Reciprocating	320	2	1	0.02	0.00
- Centrifugal	10	$1.1	1	0.06	0.04
Pneumatic Controllers	960	0	0	0.00	0.00
Fugitives - Compressor Stations	1,100	4	27	0.03	0.10
Total Transmission and Storage Segment	2,400	7	29	0.11	0.14

Source : All cost information is from the "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR Part 60, subpart OOOOa" available in the docket. For Hydraulically Fractured Oil Well Completions and Recompletions from Table 8-4, for Gas Driven Pumps from Table 11-4, for Fugitives - Well sites from Table 9-3, for Compressors, Reciprocating from Table 12-3, for Centrifugal from Table 12-4, for Pneumatic controllers from- Table 10-3, and for Fugitives - Compressor Stations from Table 9-4. The analysis results are rounded to two significant digits for this presentation. Capital costs reflect capital costs associated with affected facilities in 2025, including expenditures made prior to 2025.

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APPENDIX A

MEMORANDUM

Development of the Low Pressure Well Equation for Determining REC Requirements at Hydraulically Fractured Oil and Gas Wells

MEMORANDUM

FROM: ICF International

THRU: Graham Fitzsimons, EC/R

TO: Ravi Srivastava, U.S. EPA

DATE: April 29, 2016

SUBJECT: Technical Development of the Low Pressure Well Equation for Assessing REC Feasibility at Hydraulically Fractured Oil and Gas Wells

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This memorandum documents the method for estimating flowback pressure during completion for a hydraulically fractured petroleum well to assess whether a Reduced Emissions Completion (REC) can be implemented. If the well does not have adequate pressure to push the produced natural gas into the flow line then the well is deemed a low pressure well. The memo provides background on low pressure wells, the technical development of the low pressure well equation (LPWE) and related correlations, comparison of LPWE predictions with those from an established well flow model, and an example calculation using the LPWE. A brief summary then follows the main body of this memo.

1. Background on Low Pressure Well Equation

REC is a practice in which the natural gas produced during a well completion is captured and routed through the flow line, following hydraulic fracturing. To successfully perform an REC, the pressure of the gas needs to be sufficiently high to push the gas into the flow line. If a well does not have adequate pressure to push the gas into the flow line then the well is deemed a low pressure well.

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In the March 2015 New Source Performance Standards (NSPS) proposal, EPA proposed to use the definition for low pressure gas well provided in the 2012 final NSPS rule for all wells (i.e. oil and/or gas). According to this definition, the pressure of the flowback fluid, immediately before it enters the flow line, is calculated by the following equation:

$$P_L\ (psia) = 0.445 \cdot P_R - 0.038 \cdot L + 67.578 \quad (1)$$

Where P_L (psia) is predicted flow line pressure (sales line pressure is sometimes used interchangeably with flow line pressure), P_R (psia) is reservoir pressure (synonymous with formation pressure), and L (ft) is true vertical depth of the well.

If the P_L calculated using the above equation is less than the available actual flow line pressure, the well would be considered to be a low pressure well. Such a well cannot implement an REC during completion flowback.

The above equation is not appropriate for application to oil wells. This effort was undertaken to develop an equation for predicting pressure of the flowback fluid just before the fluid enters the flow line and essentially modifies equation (1) to account for additional pressure drop due to flows of oil and water.

While detailed models are available for calculating multiphase flow in oil and gas wells, these models typically require many inputs, often complex, from an experienced user, the values of some of which may not be readily available before well completion activity is undertaken. The LPWE described in this memorandum uses only those inputs for which estimates are understood to be available before well completion activity starts including:

- Wellhead production rates (gas, oil, and water);
- Wellhead oil gravity;
- Reservoir pressure and bottomhole temperature; and
- True vertical well depth.

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The three flow regimes typically encountered during the flowback event include:

a. **Fracture fluid flow.** After hydraulic fracture (frack) of a new or existing well, the well tubing is filled with large quantities of frack fluid which consists of injected liquid (i.e., water plus additives) and proppant (typically sand). This material must be evacuated to prepare the well for production.

   During the initial flowback, virtually all of the flow output from the well consists of the frack material itself, rather than hydrocarbons from the formation, given that the well tubing is filled with the frack fluid. As the frack fluid reaches the surface, it is typically directed to atmospheric pressure storage, typically a tank.

b. **Slug flow.** As the column of frack fluid flows to the surface, it is followed by hydrocarbons (gas and oil) and water from the formation and any inert gas introduced during the frack. Because of the differences in density and viscosity of the various flowback components (oil, water, gas, and frack fluid), at this point the flowing fluid typically has multi-phase slugs of gas and liquid. As the slug flow reaches the surface, it is directed to temporary storage where the liquids portion of the slug flow is contained while the gas portion of the slug flow is typically vented to the atmosphere or sent to a completion combustion device.

c. **Steady flow.** Over time (on the order of hours to days), the slug flow transitions to a steady flow condition where the frack fluid slugs in the tubing have been largely evacuated and there is a reasonably steady flow of hydrocarbons (oil and gas) and water. For energized fracks, this steady flow of vapor may, for a time, contain a significant percentage of the inert gas introduced into the formation during the frack, and over time, (on the order of hours) the steady flow transitions to primarily hydrocarbons and water from the formation. Depending upon the pressure of the fluid (oil, gas, and water) downstream of the wellhead, the steady flow of fluid can be directed to surface equipment and then to the flow line or a completion combustion device.

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The LPWE developed in this document applies to the steady flow of hydrocarbons encountered during the separation flowback stage[1]. Under this flow regime, gas may be separated and routed to the flow line.

2. Development of the Low Pressure Well Equation

Prior to developing the LPWE, research was performed to identify flow correlation models that adequately estimate the pressure drop across the well depth. In literature, a multitude of flow correlation models exist, ranging from simple pressure gradient models to complex mechanistic models. No flow correlation model is perfect and there is no model that can be applied to every situation. The hydrostatic pressure drop is typically the dominant component of pressure drop in wells. This component varies significantly with the gas-to-oil ratio, with higher volumes of oil significantly increasing the pressure drop due to oil having a higher density than gas. The frictional losses in wells constitute a small fraction of the total pressure drop across the entire well. Therefore, even for wells with horizontal section(s), it is the vertical section that determines the overall pressure drop characteristics. Hence for characterizing pressure drop in a well, it was important to focus on models that perform adequately for vertical wells. In general, the Hagedorn and Brown model[2] performs well for vertical wells, and is typically a good choice for such wells[3].

All flow correlation models, including Hagedorn and Brown, typically require many inputs, often complex, from an experienced user, the values of some of which may not be readily available before well completion activity is undertaken. Therefore use of such models for determining REC requirements

[1] Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.
[2] Hagedorn, A.R. and Brown, K.E., "Experimental study of pressure gradients occurring during continuous two-phase flow in small diameter vertical conduits," JPT, April 1965, 475. https://www.onepetro.org/journal-paper/SPE-940-PA
[3] Rao, B., "Multiphase Flow Models Range of Applicability", May, 1998, http://ctes.nov.com/documentation/technotes/Tech%20Note%20Multiphase%20Flow%20Models.pdf.

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could pose practical limitations. Consequently, a need was identified to develop a simpler model that could be used to determine whether an REC can be performed. The LPWE developed in this work uses only those inputs for which estimates are understood to be available before well completion activity starts.

The development of the LPWE starts from an energy balance that takes into account the two main components of pressure drop for oil and gas wells – hydrostatic and frictional. As such, the LPWE developed in this work modifies equation (1) to account for these components of pressure drop resulting from flow of oil and water in a well.

Under steady flow conditions during flow back, the flow of oil, gas, water, and proppant in well tubing can be visualized as a column of fluid[4] experiencing[5]:

- The hydrostatic pressure drop due to the weight of the fluid column in the well tubing;
- Frictional pressure drop due to friction at the tubing walls opposing the flow to the surface;
- The pressure of the hydrocarbons and water at bottom hole conditions; and
- The pressure of the hydrocarbons and water at the well head.

Consequently[6],

$$P_{WH} = P_{BH} - \left(\Delta P_g\right)_h - (\Delta P_o)_h - (\Delta P_w)_h - \Delta P_f \quad (2)$$

[4] Pressure drop from horizontal sections of a well is assumed to be negligible compared to the vertical sections of the same well due to the hydrostatic pressure drop being the dominant component of total pressure drop compared to the frictional component in the lateral sections.
[5] An additional force due to fluid acceleration is also present. Since this force contributes a negligible amount to total pressure drop across the well tubing, the impact of this force is ignored.
[6] Hydrostatic pressure drop due to small amounts of proppant during separation flowback is implicit in the hydrostatic drop due to water.

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Where P_{WH} is well-head pressure, P_{BH} is bottomhole pressure, $(\Delta P_g)_h$ is total hydrostatic pressure drop due to the gas phase, $(\Delta P_o)_h$ is total hydrostatic pressure drop due to the oil phase, $(\Delta P_w)_h$ is total hydrostatic pressure drop due to the water phase, and ΔP_f is total frictional pressure drop.

The pressure drop due to friction typically contributes a small amount to the overall total pressure drop, and it can be expressed as a percentage, x(%), of the total pressure drop:

$$\Delta P_f = x(\%).\left[\left(\Delta P_g\right)_h + (\Delta P_o)_h + (\Delta P_w)_h + \Delta P_f\right]$$

Simplifying and solving for pressure drop due to frictional losses:

$$\Delta P_f = \frac{x(\%).\left[\left(\Delta P_g\right)_h + (\Delta P_o)_h + (\Delta P_w)_h\right]}{[100 - x(\%)]} \quad (3)$$

Substituting equation (3) into equation (2) yields:

$$P_{WH} = P_{BH} - \left(\Delta P_g\right)_h - (\Delta P_o)_h - (\Delta P_w)_h - \frac{x(\%).\left[\left(\Delta P_g\right)_h + (\Delta P_o)_h + (\Delta P_w)_h\right]}{[100 - x(\%)]}$$

Simplifying further yields:

$$P_{WH} = P_{BH} - \left[\frac{100}{100 - x(\%)}\right]\left[\left(\Delta P_g\right)_h + (\Delta P_o)_h + (\Delta P_w)_h\right] \quad (4)$$

Now the pressure drops due to flow of gas, oil, and water can be expressed in terms of respective pressure gradients across the well. Then equation (4) can be written as,

$$P_{WH}\,(psia) = P_{BH}(psia) - \left[\frac{100}{100 - x(\%)}\right]\left[\left(\frac{\Delta P_g}{L}\right)_h + \left(\frac{\Delta P_o}{L}\right)_h + \left(\frac{\Delta P_w}{L}\right)_h\right]\left(\frac{psi}{ft}\right) \cdot L(ft) \quad (5)$$

Where L is the true vertical depth of the well, expressed in feet.

In the previous evaluation conducted for the 2012 NSPS, the flow line and bottom hole pressures for a gas well were expressed as:

$$P_L\,(psia) = \frac{P_{WH}}{1.01}(psia) \quad (6)$$

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and

$$P_{BH}\ (psia) = \frac{P_R}{2}(psia) \quad (7)$$

These relationships are assumed to be generally applicable to flow in petroleum wells. Then, using these equations in equation (5) yields:

$$P_L\ (psia) = 0.495 \cdot P_R(psia) - 0.99\left[\frac{100}{100-x(\%)}\right]\left[\left(\frac{\Delta P_g}{L}\right)_h + \left(\frac{\Delta P_o}{L}\right)_h + \left(\frac{\Delta P_w}{L}\right)_h\right](\frac{psi}{ft}) \cdot L(ft) \quad (8)$$

Rewriting (8) in terms of densities (pounds/cubic foot) and the related volume fractions,

$$P_L\ (psia) = 0.495 \cdot P_R(psia) - \frac{0.99}{144}^{7} \cdot \left[\frac{100}{100-x(\%)}\right]\left[\frac{q_g}{q_g+q_o+q_w}\rho_g + \frac{q_o}{q_g+q_o+q_w}\rho_o + \frac{q_w}{q_g+q_o+q_w}\rho_w\right](\frac{psi}{ft}) \cdot L(ft) \quad (9)$$

Where q_g, q_o, and q_w are the volumetric flowrates of gas, oil, and water in the well, respectively, expressed in cubic feet per second, and ρ_g, ρ_o, ρ_w, are the densities for the gas, oil, and water phases in the well, respectively, expressed in pounds per cubic feet.

2.1 Determination of hydrostatic and frictional pressure gradient due to gas flow

Under conditions of gas flow only, equation (9) becomes

$$P_L\ (psia) = 0.495 \cdot P_R(psia) - \frac{0.99}{144} \cdot \left[\frac{100}{100-x(\%)}\right]\rho_g(\frac{psi}{ft}) \cdot L(ft) \quad (10)$$

Comparing equations (1) and (10), we get,

$$0.445 \cdot P_R(psia) - 0.038 \cdot L(ft) + 67.578 = 0.495 \cdot P_R(psia) - \frac{0.99}{144} \cdot \left[\frac{100}{100-x(\%)}\right]\rho_g(\frac{psi}{ft}) \cdot L(ft)$$

Simplifying,

[7] 144 inches squared per foot squared.

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$$\frac{0.99}{144}\cdot\left[\frac{100}{100-x(\%)}\right]\rho_g\cdot L = 0.05\cdot P_R + 0.038\cdot L(ft) - 67.578\ (psi) \quad (11)$$

Substituting equation (11) into equation (9),

$$P_L\ (psia) = 0.495\cdot P_R(psia) - \frac{q_g}{q_g+q_o+q_w}[0.05\cdot P_R + 0.038\cdot L(ft) - 67.578] - \frac{0.99}{144}\cdot$$

$$\left[\frac{100}{100-x(\%)}\right]\left[\frac{q_o}{q_g+q_o+q_w}\rho_o + \frac{q_w}{q_g+q_o+q_w}\rho_w\right](\frac{psi}{ft})\cdot L(ft) \quad (12)$$

2.2 Determination of hydrostatic pressure gradient due to water flow

Generally a well can produce significant amounts of water while producing oil and gas. Therefore, it was important to take the water pressure gradient (psi/ft) into consideration when developing the LPWE. In the development of the LPWE the fresh water gradient of 0.433 psi/foot is used for calculating the hydrostatic pressure drop due to water[8].

Then,

$$\frac{1}{144}\left[\frac{q_w}{q_g+q_o+q_w}\rho_w\right]\left(\frac{psi}{ft}\right) = \left[\frac{q_w}{q_g+q_o+q_w}0.433\right](\frac{psi}{ft}) \quad (13)$$

Substituting (13) in (12) yields:

$$P_L\ (psia) = 0.495\cdot P_R(psia) - \frac{q_g}{q_g+q_o+q_w}[0.05\cdot P_R + 0.038\cdot L(ft) - 67.578] - 0.99\cdot$$

$$\left[\frac{100}{100-x(\%)}\right]\left[\frac{q_o}{q_g+q_o+q_w}\cdot\frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w}0.433\right](\frac{psi}{ft})\cdot L(ft) \quad (14)$$

2.3 Determination of Estimated Frictional Pressure Drop (%)

As mentioned above, the Hagedorn and Brown flow model performs well for vertical wells and predicts both hydrostatic and frictional components of pressure drop based on the input conditions provided to

[8] American Association of Petroleum Geologists: http://wiki.aapg.org/Hydrostatic_pressure-depth_plot_construction.

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the model[9]. This model, henceforth referred to as the Hagedorn and Brown model, was coded in Excel by EPA and provided to ICFI. ICF checked the model and used it for validating the results of the LPWE. To evaluate the relative contribution of pressure drop due to frictional losses, an experimental matrix of model runs was created using known ranges of data from the DI Desktop™ commercial well database. These ranges are understood to cover the spectrum of oil and gas well characteristics relevant to the U.S[10]. The experimental matrix is summarized in Table 1 below.

Table 1: Experimental Matrix of Input Variables for All Model Runs

Input Variable	**Units**	**Values Used for All Model Runs**
Oil Production Rate	Standard barrel per day	100, 200, 400, 800, 1000, 2000
Gas Production Rate	Million standard cubic feet per day	0.1, 0.3, 0.5, 1, 2, 3, 5, 10
Pressure Gradient[11]	psi per foot of well depth	0.35, 0.433, 0.5, 0.6, 0.75
Well Depth	Feet	500, 1000, 2500, 5000, 7000, 9000, 13000, 17000, 20000
Oil Wellhead Gravity	API	20, 30, 40, 50

Hagedorn and Brown model runs were completed and the pressure drop due to frictional losses was calculated as a percent of total pressure drop (hydrostatic and frictional). After evaluating over 7,560

[9] The Hagedorn and Brown model used in this work calculates pressure drop gradient in psi/ft and multiplies the gradient by the well depth.

[10] For purposes of this work, wells with Gas to Oil Ratios of 300 or less were excluded from the model runs. Additionally, few model runs with negative predicted values from either Hagedorn and Brown or the LPWE were considered infeasible and removed from the results.

[11] Increments of pressure gradient were multiplied against values of well depth to produce values of bottomhole pressure for each model run.

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dynamic model runs[12], it was found that pressure drop due to frictional losses was close to 0.64% on average with a median value of 0.24%. As a conservative estimate, a value of 1% (i.e., x% = 1%) was assumed in this work to adequately characterize frictional pressure drop for operations typically encountered in U.S. oil production.

2.4 The Final Low Pressure Well equation

Assuming an average frictional component to total pressure drop ratio of 1% (i.e., x% = 1%) and substituting the value into (14), the final form of the LPWE becomes:

$$P_L\,(psia) = 0.495 * P_R(psia) - \frac{q_g}{q_g+q_o+q_w}[0.05 \cdot P_R + 0.038 \cdot L(ft) - 67.578] -$$

$$\left[\frac{q_o}{q_g+q_o+q_w} \cdot \frac{\rho_o}{144} + \frac{q_w}{q_g+q_o+q_w} 0.433\right] (\frac{psi}{ft}) \cdot L(ft) \qquad (15)$$

The procedures for calculating oil, gas, and water flow rates and oil density to be used with the LPWE are described in Section 2.5.

Note under conditions of gas flow only (i.e., *qo = qw = 0*), equation (15) reduces to equation (1), the equation for gas wells. Also note that equation (15) for line pressure is derived using a vertical well. It is known that inclined wells exist in the field, which will experience a somewhat higher frictional drop due to longer flow length. Nonetheless, it expected that equation (15) would be able to account for minor increases in pressure drop due to increased frictional drop at inclined wells because frictional pressure drop component contributes a small amount to the total pressure drop (about 1% on average) and conservative assumptions were used in deriving equation (15) – notably bottom hole pressure = ½ of formation pressure.

[12] In this work, two models were used: (1) a "dynamic model" including above-the-bubble point calculations, and (2) a "simplified dynamic model" (e.g. without above-the-bubble point calculations and with a constant value for dissolved gas gravity.)_ See Section 4 for more details.

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In summary, equation (15) constitutes the LPWE developed in this work. This equation predicts the fluid pressure immediately upstream of the flow line. If this predicted pressure is higher than the available flow line pressure, the well can do an REC.

2.5 Determination of Oil Density, Oil Flow Rate, and Gas Flow Rate for Use in the LPWE[13]

2.5.1 Determination of Oil Density and Flow Rate

Oil density used in calculating the hydrostatic pressure drop for oil is defined as an arithmetic average of the oil density at bottomhole and the oil density at the wellhead. This accounts for the fact that the density of oil increases as the hydrocarbons move up the well and dissolved gases come out of the oil. The oil flow rate used in the LPWE corresponds to the flow rate at bottomhole conditions. In essence, starting with the bottomhole flow rate, the pressure drop across the well is calculated using this flowrate and the average oil density, and then the pressure at the wellhead is determined. This "marching" calculation procedure is also used in more complex multiphase flow models.

The oil density and volumetric flow rate at bottomhole conditions are calculated using the known values of oil API gravity and oil production rate (STBO/day) at a well site and the widely used correlations provided in Vasquez and Beggs (1980).[14] This calculation procedure is described below[15].

[13] Equations marked by asterisks (*) are not original work developed by ICF and the relevant citations are provided. ICF received an approval through EPA from the Society of Petroleum Engineers on March 14th, 2016 for reproduction and use of equations and correlations from publications in their journals.

[14] Vasquez, M. and Beggs, H.D., "Correlations for fluid physical property prediction," JPT, June 1980, 968. This paper provides correlations for oil properties including dissolved gas-oil ratio and oil formation volume factor based on approximately 6000 data points - measured over large ranges of pressure, temperature, oil gravity and gas gravity.
https://www.onepetro.org/journal-paper/SPE-6719-PA

[15] The calculation procedure uses correlations for flow conditions at or below bubble point. Runs of the Hagedorn and Brown model (see Table 1), with above-bubble-point correlations revealed that above-bubble-point conditions were met in less than 10% of all dynamic model runs (see Section 4) and above-bubble-point corrections amounted to oil density corrections on the order of 4% or less. Thus, the overall impact to predicted line pressure is considered to be relatively negligible and for simplicity above-bubble-point calculations are not included in the calculation procedure.

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Step 1: Determine the value of the bottom hole pressure, P_{BH}, based on available information at the well site, or by calculating it using the reservoir pressure, $P_R\ (psia)$, in the following equation:

$$P_{BH}\ (psia) = \frac{1}{2} P_R$$

Step 2: Determine the value of the bottom hole temperature, $T_{BH}\ (F)$, based on available information at the well site, or by calculating it using the true vertical depth of the well, *L(ft)*, in the following equation[16]:

$$T_{BH}\ (F) = 0.014 \times L\ + 79.081$$

Step 3: Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs}, using the following equation from Vasquez and Beggs (1980) [14] with: separator at standard conditions (pressure, $p = 14.7\ (psia)$, temperature, T $= 60\ (F)$); the API oil gravity at the well site, γ_o; and the oil specific gravity at the separator under standard conditions, $\gamma_{gp} = 0.75$:[17]

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912\ x\ 10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)^*$$

Step 4: Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation from Vasquez and Beggs (1980)[14] with: the bottom hole pressure, $P_{BH}\ (psia)$, determined in Step 1 above; the bottom hole temperature, $T_{BH}\ (F)$, determined in Step 2 above;

[16] Temperature gradient data from the United States Geological Service were regressed across the sedimentary basins in the US and modeled as a function of well depth. Data is derived from USGS Open-File Report 2010-1303 titled "Comprehensive Database of Wellbore Temperatures and Drilling Mud Weight Pressures by Depth for Judge Digby Field".
https://pubs.er.usgs.gov/publication/ofr20101303.

[17] The value of 0.75 is based on expert opinion considering the average natural gas concentration data referenced in the technical memo titled "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking," July, 2011, available in the NSPS OOOO rule making docket: https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084.

the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in Step 3 above; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table 2:

$$R_s(\frac{scf}{STBO}) = C1 \cdot \gamma_{gs} \cdot {P_{BH}}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH} + 460}\right)\right]^*$$

Table 2. Coefficients for the Vasquez and Beggs Correlation for R_s.

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

Step 5: Calculate the value of the oil formation volume factor, *Bo (bbl/STBO)*, using the following equation from Vasquez and Beggs (1980)[14] with: the bottom hole temperature, $T_{BH}\ (F)$,, determined in Step 2 above; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in Step 3 above; the dissolved GOR, Rs (scf/STBO), calculated in Step 4 above; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table 3:

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)^*$$

Table 3. Coefficients for the Vasquez and Beggs Correlation for B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}

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C3	-1.811×10^{-8}	1.337×10^{-9}

Step 6: Calculate the density of oil at the wellhead, ρ_{WH} $(\frac{lbm}{cu\ ft})$, using the following equation with the value of the oil API gravity, γ_o, at the well site:

$$\rho_{WH}\ (\frac{lbm}{cu\ ft}) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

Step 7: Calculate the density of oil at bottom hole conditions, ρ_{BH} $(\frac{lbm}{cu\ ft})$, using the following equation with: the dissolved GOR, Rs (scf/STBO), calculated in Step 4 above; the oil formation volume factor, Bo (bbl/STBO), calculated in Step 5 above; the oil density at the wellhead, ρ_{WH} $(\frac{lbm}{cu\ ft})$, calculated in Step 6 above; and the dissolved gas gravity, $\gamma_{gd} = 0.77$[18]:

$$\rho_{BH}\ (\frac{lbm}{cu\ ft}) = \frac{\rho_{WH} + 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

Step 8: Calculate the density of oil in the well, ρ_o $(\frac{lbm}{cu\ ft})$, using the following equation with the density of oil at the wellhead, ρ_{WH} $(\frac{lbm}{cu\ ft})$, calculated in Step 6 above; and the density of oil at bottom hole conditions, ρ_{BH} $(\frac{lbm}{cu\ ft})$, calculated in Step 7 above:

$$\rho_o\ (\frac{lbm}{cu\ ft}) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

[18] Figure B-10 (Katz diagram) from Brill, J.P. and Mukherjee, H., "Multiphase Flow in Wells", Monograph Volume 17, SPE, 1999 was used to calculate the values of this variable in the model runs described in Section 2.4. It was found that dissolved gas gravity, γ_{gd} , did not have a significant impact on predicted flow line pressure. Therefore a value of 0.77 is recommended to be used for $\gamma_{gd.}$ This value is the average of the values used in the dynamic model runs (see Section 4).

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Step 9: Calculate the oil flow rate, $q_o\ (cu\ ft/sec)$, using the following equation with: the oil formation volume factor, *Bo* (bbl/STBO), calculated in Step 4 above; and the estimated oil production rate at the well head, *Qo* (STBO/day):

$$q_o\left(\frac{cu\ ft}{sec}\right) = \text{Qo}\ \left(\frac{\text{STBO}}{\text{day}}\right) \times \text{Bo}\ \left(\frac{\text{bbl}}{\text{STBO}}\right) \times 5.614(\frac{cu\ ft}{\text{bbl}}) \times \frac{1}{24 \times 60 \times 60}(\frac{day}{sec})$$

2.5.2 Determination of Gas Flow Rate

As oil-gas-water mixture flows upwards in a well to a lower pressure location, gas volume changes and some of the dissolved gas evolves out of solution in oil. This results in gas volumetric flow (and therefore pressure gradient) changing with well depth.

The gas volumetric flow at bottomhole conditions is calculated in a sequential fashion, first evaluating terms to estimate gas compressibility factor, z. The Standing and Katz correlation and z-factor chart[19] was used to estimate critical pressure and temperature at bottomhole conditions. Then, adjustments were made to the critical pressure and temperature according to the Carr/Kobayashi[20] method to account for potential impurities in the natural gas. Finally, the Brill and Beggs correlation for compressibility[21] was utilized to estimate the z-factor. This calculation procedure is described below in detail:

Step 10: Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the aforementioned Standing and Katz correlation and Carr/Kobayashi adjustment with specific

[19] Standing, M.B. and Katz, D.L., "Density of Natural Gases," Transactions of the AIME, SPE, December, 1942, 146.
https://www.onepetro.org/journal-paper/SPE-942140-G.

[20] To derive the equations, first adjustment factors for N2, CO2, and H2S were obtained from Figure 8 in Carr, N. L., Kobayashi, R., and Burrows, D.B., "Viscosity of Hydrocarbon Gases Under Pressure," JPT, SPE, October, 1954, 6 . Then these factors were applied to Standing and Katz correlations for Pc and Tc.
https://www.onepetro.org/journal-paper/SPE-297-G.

[21] Guo, B., Ghalambor, A., "Natural Gas Engineering Handbook," Gulf Publishing Company, 2005, ISBN 0976511339, Chapter 2 equations 2.28 to 2.33.

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gravity of gas at standard conditions (p=14.7 psia and T = 60 F), SG = 0.75; and where the mole fractions in the gas of nitrogen, carbon dioxide and hydrogen sulfide are: $X_{N_2} = 0.168225$, $X_{CO_2} = 0.013163$, and $X_{H_2S} = 0.013680$[22]. The equations below for critical temperature and critical pressure represent the combined Standing correlation and Carr/Kobayashi adjustments into one form.

$$P_c(psia) = 678 - 50 \cdot (SG - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}^{*}$$

$$T_c(R) = 326 + 315.7 \cdot (SG - 0.5) - 240 \cdot X_{N_2} - 83.3 \cdot X_{CO_2} + 133.3 \cdot X_{H_2S}^{*}$$

Step 11: Calculate reduced pressure, P_r, and reduced temperature, T_r, using the following equations with: the bottom hole pressure, P_{BH} (psia), as determined in Step 1 above; the bottom hole temperature, T_{BH} (F), as determined in Step 2 above in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

$$T_r = \frac{(T_{BH} + 460)}{T_c}$$

Step 12: Calculate the gas compressibility factor, *Z*, using the following Brill and Beggs correlation with the reduced pressure, P_r, calculated in Step 10 above:

$$z = A + \frac{(1-A)}{e^B} + C \cdot p_r^{D*}$$

The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r, and reduced temperature, T_r, calculated in Step 10 above:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 \cdot T_r - 0.10$$

[22] The mole fractions are the averages for compositions in oil and gas wells and are based on information in Table 8 in the technical memo titled "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking,", July, 2011, available in the NSPS OOOO rule making docket https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0084.

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$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2 + \frac{0.32}{10^{9 \cdot (T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 \cdot T_r + 0.1824 \cdot T_r^2}$$

Step 13: Calculate the gas formation volume factor, $B_g \left(\frac{cuft}{scf}\right)$, using the real gas law below with the bottom hole pressure, $P_{BH}\ (psia)$, as determined in Step 1 above; and the bottom hole temperature, $T_{BH}\ (F)$, as determined in Step 2 above:

$$B_g \left(\frac{cuft}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}} *$$

Step 14: Calculate the gas flow rate, $q_g \left(\frac{cu\,ft}{sec}\right)$, using the following equation with: the value of gas formation volume factor, $B_g \left(\frac{cuft}{scf}\right)$, calculated in Step 12 above; the estimated gas production rate, Qg (scf/day); the estimated oil production rate, Qo (STBO/day); and the dissolved GOR, Rs (scf/STBO), as calculated in Step 4 above:

$$q_g \left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

2.5.3 Determination of Water Flow Rate

Step 15: Generally, water is relatively incompressible and gas solubility in water is negligible. Therefore, $q_w\ (\frac{cf}{sec})$, the flow rate of water in the well, is calculated using the following equation with the water production rate Qw (bbl/day) at the well site:

$$q_w \left(\frac{cf}{sec}\right) = \text{Qw} \left(\frac{\text{STB}}{\text{day}}\right) \times 5.614 (\frac{\text{cf}}{\text{bbl}}) \times \frac{1}{24 \times 60 \times 60} (\frac{day}{sec})$$

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4. Comparison of the Low Pressure Oil Well Equation Results with those from the Hagedorn and Brown Model

As discussed previously, the Hagedorn and Brown flow correlation method generally predicts pressure drop for vertical wells better than the other models. The Hagedorn and Brown model was used for validating the results of the LPWE, equation (15). For validation purposes, model runs were completed using the experimental matrix shown in Table 1 above.

Over 7,560 model runs were performed using the coded Hagedorn and Brown model and simultaneously corresponding calculations were made with the LPWE (equation (15). In this version of the Hagedorn and Brown model, called the dynamic model, certain calculations (i.e., bubble point pressure corrections and dissolved gas gravity) were completed using established correlations. While completing experimental matrix runs with the dynamic model, it was observed that correction for above-the-bubble point pressure and changes in dissolved gas gravity did not have a significant impact on model results (see footnotes 15 and 18). Consequently, a simplified dynamic model was created without above-the-bubble point calculations and with a fixed value for dissolved gas gravity (footnote 18). Subsequently, the same 7,560 model runs as above were completed with the simplified dynamic model. Results for line pressure from Hagedorn and Brown model runs are compared with corresponding results from the LPWE (equation (15) in Figure 1 for the dynamic model case and in Figure 2 for the simplified dynamic model case.

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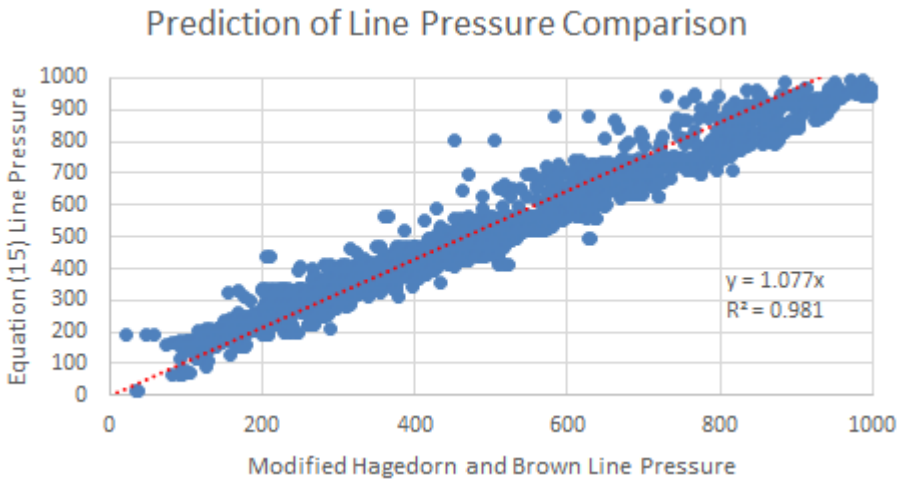


Figure 1: Comparison of Line Pressure Prediction for the Dynamic Model

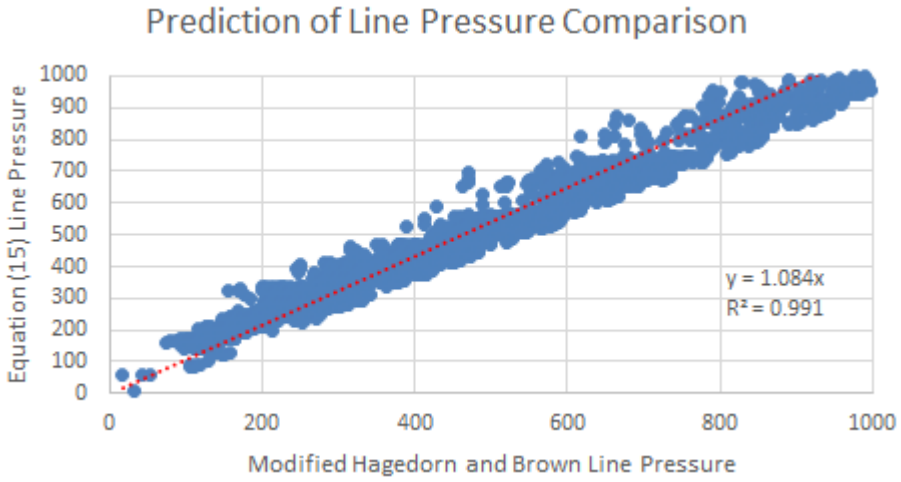


Figure 2: Comparison of Line Pressure Prediction for the Simplified Dynamic Model

Since the difference between Figure 1 and Figure 2 is negligible, the LPWE related calculation procedure described in Section 2.5 is appropriate. Finally, in addition to the comparison plots shown above, a multiple linear regression for line pressure predictions below 1000 psia was performed for data in Figure 2 and a standard error of 41 psia was observed[23]. These results indicate that the LPWE estimates pressure drops comparable to the Hagedorn and Brown model.

[23] The standard error in this context represents an over-prediction of line pressure by 41 psia on average for equation (15) when compared to the Hagedorn and Brown method.

5. Example Calculation

For the example calculation with the LPWE, input conditions (illustrative example) are defined as follows:

- Well depth, L = 7,900 feet
- Reservoir pressure, P_R = 2,700 psia
- Bottomhole temperature, T_{BH} = 180 °F
- Oil production rate, Qo = 465 STBOD
- Water production rate, Qw = 45 STBOD
- Gas production rate, Qg = 570,000 scf/day
- API gravity, γ_o = 25
- Available flow line pressure= 150 psia

Calculation of Oil Density and Flow Rate

Step 1. Calculate the bottomhole pressure using (Step 1, Section 2.5):

$$P_{BH}(psia) = \frac{1}{2}(2{,}700\ psia) = 1{,}350 psia$$

Step 2. Determine the bottomhole temperature (Step 2, Section 2.5):

From the information provided,

$$T_{BH}(F) = 180\ \text{F}$$

Step 3. Calculate gas gravity at from a separator pressure of 100 psig, γ_{gs} (Step 3, Section 2.5):

$$\gamma_{gs} = (0.75) \cdot \left(1.0 + 5.912\ x\ 10^{-5} \cdot 25 \cdot 60°F \cdot log\left(\frac{14.7\ psia}{114.7}\right)\right) = 0.691$$

Step 4. Calculate dissolved GOR, R_s (Step 4, Section 2.5):

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$$R_s\left(\frac{scf}{STBO}\right) = (0.0362)\cdot(0.691)\cdot(1{,}350\ psia)^{1.0937}\cdot exp\left[25.7240\cdot\left(\frac{25}{180°F+460}\right)\right]$$

$$= 181.14\left(\frac{scf}{STBO}\right)$$

Step 5. Calculate the volume formation factor for oil, B_o (Step 5, Section 2.5):

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + (4.677 * 10^{-4}\cdot 181.14\left(\frac{scf}{STBO}\right) + (180°F - 60)\left(\frac{25}{0.691}\right)$$

$$\cdot\left(1.751 * 10^{-5} - 1.811\cdot 10^{-8}\cdot 181.14\left(\frac{scf}{STBO}\right)\right) = 1.147\left(\frac{bbl}{STBO}\right)$$

Step 6. Calculate the density of oil at the wellhead (Step 6, Section 2.5):

$$\rho_{WH} = \frac{141.5}{25+131.5}\cdot 62.4 = 56.42\left(\frac{lb_m}{cuft}\right)$$

Step 7. Calculate the density of oil at bottomhole (Step 7, Section 2.5):

$$\rho_{BH}\left(\frac{lb_m}{cuft}\right) = \frac{56.42 + 0.0136\cdot 181.14\left(\frac{scf}{STBO}\right)\cdot 0.77}{1.147\left(\frac{bbl}{STBO}\right)} = 50.86\left(\frac{lb_m}{cuft}\right)$$

Step 8. Calculate the average oil density, ρ_o (Step 8, Section 2.5):

$$\rho_o\left(\frac{lb_m}{cuft}\right) = \frac{1}{2}\left[56.42\left(\frac{lb_m}{cuft}\right) + 50.86\ \left(\frac{lb_m}{cuft}\right)\right] = 53.64\left(\frac{lb_m}{cuft}\right)$$

Step 9: Calculate the oil flow rate at bottomhole conditions (Step 9, Section 2.5):

$$q_o\left(\frac{cuft}{sec}\right) = 465\ \frac{STBO}{Day}\cdot 1.147\left(\frac{bbl}{STBO}\right)\cdot\left(\frac{5.614}{24*60*60}\right) = 0.0346\left(\frac{cuft}{sec}\right)$$

Calculation of Gas Flow Rate

Step 10. Calculate critical pressure and temperature (Step 10, Section 2.5):

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$$P_c = 678 - 50 \cdot (0.75 - 0.5) - 206.7 \cdot 0.168225 + 440 \cdot 0.013163 + 606.7 \cdot 0.01368$$

$$= 644.819\ psia$$

$$T_c = 326 + 315.7 \cdot (0.75 - 0.5) - 240 \cdot 0.168225 - 83.3 \cdot 0.013163 + 133.3 \cdot 0.01368$$

$$= 365.278\ °R$$

Step 11. Calculate reduced pressure and temperature (Step 11, Section 2.5):

$$P_r = \frac{1{,}350\ psia}{644.819\ psia} = 2.094$$

$$T_r = \frac{640\ °R}{365.278\ °R} = 1.752$$

Step 12. Calculate gas compressibility factor, z (Step 12, Section 2.5):

$$A = 1.39 \cdot (1.753 - 0.92)^{0.5} - 0.36 \cdot 1.753 - 0.101 = 0.536$$

$$B = (0.62 - 0.23 \cdot 1.752) \cdot 2.094 + \left(\frac{0.066}{(1.752 - 0.86)} - 0.037\right) \cdot (2.094)^2 + \frac{0.32}{10^{9 \cdot (1.752-1)}}$$

$$\cdot (2.094)^6 = 0.616$$

$$C = (0.132 - 0.32 \cdot \log(1.752)) = 0.054$$

$$D = 10^{0.3106 - 0.49 \cdot (1.752) + 0.1824 \cdot (1.752)^2} = 1.028$$

$$z = 0.537 + \frac{(1 - 0.537)}{e^{0.245}} + 0.054 \cdot (0.968)^{1.028} = 0.902$$

Step 13. Calculate the gas formation volume factor, B_g (Step 13, Section 2.5):

$$B_g \left(\frac{cuft}{scuft}\right) = 0.0283 \cdot \left(\frac{0.902 * 640\ °R}{1{,}350\ psia}\right) = 0.0121 \left(\frac{cuft}{scuft}\right)$$

Step 14. Calculate the volumetric flow rate of the gas (Step 14, Section 2.5):

$$q_g \left(\frac{cuft}{sec}\right) = \left(570{,}000 \left(\frac{scf}{day}\right) - 181.14 \left(\frac{scf}{STBO}\right) \cdot 465\ stbod\right) \cdot 0.0121 \left(\frac{cuft}{scuft}\right) \cdot \left(\frac{1}{24 \cdot 60 \cdot 60}\right)$$

$$= 0.0680 \left(\frac{cuft}{sec}\right)$$

Step 15. Express water flow rate in cu ft/sec (Step 13, Section 2.5):

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$$q_w\left(\frac{cuft}{sec}\right) = 45\ \frac{STBO}{Day} \cdot \left(\frac{5.614}{24 * 60 * 60}\right) = 0.0029\left(\frac{cuft}{sec}\right)$$

Finally, the line pressure can be evaluated using equation (15) to determine predicted flow line pressure.

$$P_L\ (psia) = 0.495 \cdot 2{,}700(psia)$$

$$- \frac{0.068\left(\frac{cuft}{s}\right)}{\left(0.068\left(\frac{cuft}{s}\right) + 0.0.0346\left(\frac{cuft}{s}\right) + 0.0029\left(\frac{cuft}{s}\right)\right)}\left[0.05 \cdot 2{,}700(psia)\right.$$

$$\left. + 0.038\left(\frac{psia}{ft}\right) \cdot 7{,}900(ft) - 67.578(psia)\right]$$

$$- 1.00\left[\frac{0.0346\left(\frac{cuft}{s}\right)}{\left(0.068\left(\frac{cuft}{s}\right) + 0.0346\left(\frac{cuft}{s}\right) + 0.0029\left(\frac{cuft}{s}\right)\right)} \cdot \frac{53.641\left(\frac{lb_m}{cuft}\right)}{144\left(\frac{psia}{\left(\frac{lb_m}{ft^2}\right)}\right)}\right.$$

$$\left. + \frac{0.0029\left(\frac{cuft}{s}\right)}{\left(0.068\left(\frac{cuft}{s}\right) + 0.0346\left(\frac{cuft}{s}\right) + 0.0029\left(\frac{cuft}{s}\right)\right)} \cdot 0.433\left(\frac{psia}{ft}\right)\right]$$

$$\cdot 7{,}900(ft) = 39.7(psia)$$

Since $P_L = 39.7\ psia < available\ flow\ line\ pressure = 150\ psia$, the well may not be able to perform an REC. On the other hand, if the sales line pressure is below 39.7 psia, then the operator may be able to perform an REC within operational constraints.

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6. Summary

This memo describes the development of the low pressure well equation, LPWE, appropriate for use at well sites to determine whether or not a well can implement an REC. This equation uses only those inputs for which estimates are understood to be available before well completion activity starts to calculate the flowback fluid pressure immediately upstream of the flow line. If the well does not have adequate pressure to push the produced natural gas into the flow line then the well can be deemed a low pressure well and may not be able to perform REC. The equation was tested against an established and widely used multiphase flow model using a range of conditions representative of wells in the U.S. The results from the equation were generally consistent with those from the established Hagedorn and Brown model.

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Appendix

Additional analysis was performed to characterize oil and gas wells with respect to the low pressure well equation. The analysis informs assumptions about the proportion of hydraulically fractured well completions that would be considered low pressure using the low pressure well equation.

This document analyzes roughly 37,800 oil and gas wells across the United States and applies the low pressure well equation to each of the wells to determine a prediction of flow line pressure. Based on various filters described below, the wells were characterized in a set of tables. Finally, in addition to evaluating flow line pressure using the draft low pressure well equation, data from the Green House Gas Reporting Program (GHGRP) was utilized to determine average separator pressure and API gravity according to basin.

For all subsequent tables, wells were classified as low pressure wells if the predicted flow line pressure was less than the average separator pressure for the associated basin as reported in the GHGRP Subpart W for 2014. If the flow line pressure was greater than the average separator pressure, the well was classified as a high pressure well. Although in some cases there will be a dehydrator or other equipment downstream of the separator, which will result in a pressure drop, the separator pressure is the closest metric available to the flowline pressure, and was therefore used in this analysis.

Table 1 shows the distribution of oil and gas wells (identified using a GOR threshold of 100,000 scf/bbl) and whether the wells would be considered high pressure (HP) or low pressure (LP) using the LPWE. Table 2 performs the same analysis but excludes wells with GOR < 300 scf/bbl. Table 3 provides the oil and gas well splits with additional detail on basin type. Tables 1 through 3 are generated based on 2014 annual oil and gas production values[24].

[24] Values obtained from the DI Desktop™ commercial well database for well completions in 2014.

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We assume that hydraulically fractured oil well completions occur in shale oil basins. While variations from this assumption are very likely, we believe this is a reasonable assumption for this analysis. **Based on this assumption and according to this analysis, about 40 percent (3,717 of 9,227 completions) for shale oil wells with GOR>300 scf/bbl would be considered low pressure using the low pressure well equation.**

Table 1: Oil and Gas Well Splits with Gas Well Cutoff of 100,000 scf/bbl including all GORs

Well Type	Total Count	HP Well Count	LP Well Count
Oil Well	35,793	14,583	21,210
Gas Well	2,015	1,918	97

Table 2: Oil and Gas Well Splits with Gas Well Cutoff of 100,000 scf/bbl excluding GORs <300

Well Type	Total Count	HP Well Count	LP Well Count
Oil Well	22,093	13,701	8,392
Gas Well	2,015	1,918	97

Table 3: Oil and Gas Well Splits by Basin Type for GORs > 300 with Gas Well Cutoff of 100,000 scf/bbl[25]

Basin Type	Total Count	HP Well Count	LP Well Count
Conventional	12,505	8,770	3,735
Oil	*11,288*	*7,616*	*3,672*
Gas	*1,217*	*1,154*	*63*
Shale Oil	9,227	5,510	3,717
Tight Gas	1,953	972	981
Shale Gas	417	361	56
Coal Bed Methane	5	5	0

[25] The categories of shale oil, tight gas, and shale gas are based on the DI Database basin type designation. With the 100,000 scf/bbl cutoff, some of these wells could be classified as oil or gas wells but were not reclassified and the basin type designation was used to classify these wells.

REGULATORY ANALYSIS

for Proposed Revisions to
Colorado Air Quality Control Commission
Regulation Numbers 3, 6 and 7
(5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9)

February 11, 2014

Colorado Department of Public Health and Environment

Air Pollution Control Division
4300 Cherry Creek Drive South
Denver, CO 80246

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1 EXECUTIVE SUMMARY

The Colorado Air Pollution Control Division's ("Division's") proposed revisions to the Air Quality Control Commission's ("Commission's") Regulation Numbers 3, 6, and 7, collectively expand the air emission control requirements on oil and gas facilities in Colorado. They were developed after the Division's extensive, year-long stakeholder process leading up to the Commission's rulemaking hearing, including input from diverse industry, environmental and governmental stakeholders. The proposal has received the support of several industry and environmental leaders, including Anadarko Petroleum, Noble Energy, Encana Oil and Gas, and the Environmental Defense Fund. The proposal affects not only the oil and gas industry and supporting businesses in Colorado, but the Regulation Number 3 revisions broadly affect all businesses in Colorado. Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of oil and gas operations, given the anticipated emissions reductions that will be achieved and the reasonable associated cost of implementation. The Division estimates that the proposed strategies will result in substantial reductions of hydrocarbon emissions from the oil and gas industry. More specifically, the Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be $42.4 million per year. This translates to approximately $453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado Commission and the U.S. Environmental Protection Agency (EPA). In prehearing submittals to the Commission, the supporters of the proposal have concluded that the Division's costs estimates methodology and cost estimates are reasonable. Some opponents of the proposal have asserted that the costs may be much higher. The Commission will consider the Division's proposal and any alternate proposals at the rulemaking hearing commencing February 19, 2014.

2 INTRODUCTION

On December 13, 2013, interested parties, stakeholders, and state representatives filed eleven separate requests for both a Cost Benefit Analysis and a Regulatory Analysis ("Requests") with the Division, per C.R.S. §24-4-103(2.5), C.R.S. §24-4-103(4.5) and the Commission's Procedural Rules, 5 CCR 1001-1, §V.E.13. This document satisfies the requirements for a Regulatory Analysis, and is separate from the related Cost-Benefit Analysis. Similarly, this Regulatory Analysis is different from, but related to, the required Economic Impact Analysis, C.R.S. §25-7-110.5(4). The Requests were specific to proposed revisions to the Commission's Regulation Numbers 3, Parts A, B, and C ("Regulation 3"); Regulation 6, Part A ("Regulation 6"); and Regulation Number 7 ("Regulation 7").

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The Colorado Administrative Procedure Act ("APA")[1] serves as the legal authority for this rulemaking process, and sets forth requirements for both cost-benefit and regulatory analyses. Under the APA, any person may request an agency engaged in a rulemaking to prepare a regulatory analysis.[2] The regulatory analysis must include:

- A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule;
- To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons;
- The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues;
- A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction;
- A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule; and
- A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule.
- To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences.[3]

So long as the regulatory analysis is undertaken in good faith, it satisfies the APA.[4]

This Regulatory Analysis evaluates the Division's November 15, 2013 proposed revisions to Regulations 3, 6, and 7, as amended on January 30, 2014, using information gathered through the Division's Cost Benefit Analysis, and Economic Impact Analyses, and other documents associated with the administrative record for the February 19-23, 2014 Commission Hearing.

The Division's proposed revisions to Regulation 3, 6, and 7 are part of an overall effort to fully adopt federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO"), by incorporating them into Regulation Number 6, Part A, and making the corresponding revisions to the Regulation Number 3 catch-all provisions to address barriers that prevented full adoption of NSPS OOOO. The proposal also revises Regulation Number 7 to address differences and overlaps between NSPS OOOO and Regulation Number 7 oil and gas control requirements, and to further reduce hydrocarbon emissions and leaks from oil and gas facilities. These revisions include:

1. Expanding Colorado's adoption of NSPS OOOO, such that it is adopted in full (Regulation 6);
2. Removing "catch-all" provisions (Regulation 3);

[1] *See* C.R.S. § 24-4-101 *et. seq*.
[2] *Id. at* § 24-4-103(4.5)
[3] *Id.*
[4] *Id. at* § 24-4-103(2.5)(d) & § 24-4-103(4.5)(d).

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3. Removing crude oil storage tank permitting exemptions (Regulation 3);
4. Expanding condensate tank control requirements state-wide, including establishing storage tank emission monitoring ("STEM") requirements (Regulation 7);
5. Expanding dehydration unit ("dehy") control requirements state-wide (Regulation 7);
6. Establishing leak detection and repair ("LDAR") requirements for components at well production facilities and natural gas compressor stations state-wide (Regulation 7);
7. Establishing well maintenance and liquids unloading requirements state-wide (Regulation 7); and
8. Expanding pneumatic controller requirements state-wide (Regulation 7).

In addition to these more prominent revisions, these proposals also correct minor administrative errors, and make typographical, grammatical, and formatting changes in Regulation 3, 6, and 7. This Regulatory Analysis focuses on the more significant revisions and does not address typographical, grammatical, and formatting changes.

This analysis represents information gathered from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in this analysis.

3 ANALYSIS

3.1 Regulation Number 6

3.1.1 Proposed Revisions

The proposed revisions to Regulation 6 fully incorporate by reference the federal NSPS OOOO into Regulation Number 6, Part A, including the provisions not incorporated during the Commission's partial adoption. In late 2012, the Commission partially adopted the Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO"), such that Colorado currently administers NSPS OOOO, for all affected facilities under NSPS OOOO including centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, process unit equipment, and sweetening units, except for natural gas wells (well completion requirements) and equipment that emits less than current reporting and permitting thresholds. At that time, the Commission directed the Division to consider full adoption of NSPS OOOO, as well as other improvements to Colorado's oil and gas emission regulations.

It appears that all parties to the Commission rulemaking support the proposed revisions to Regulation 6.

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3.1.2 Class of Persons Affected

"A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule."

There is limited impact associated with this proposal, in that NSPS OOOO is already in effect on a federal level and the Commission has already partially adopted NSPS OOOO for Colorado. The classes of persons affected by the proposed full adoption of NSPS OOOO include oil and gas companies operating in Colorado, and businesses that support the oil and gas industry in Colorado. Also, citizens statewide are impacted by the proposal. In all cases, it is simpler and less confusing to no longer have to deal with federal and state agencies administering the same requirements.

Full adoption of NSPS OOOO does not have an additional cost impact on any affected classes of persons because this rule is currently in effect and federally enforceable. Full adoption of NSPS OOOO does not provide additional health or economic benefits to classes of persons affected by the proposal because NSPS OOOO is currently in effect and federally enforceable. However, affected classes of persons will benefit from the proposed full adoption of NSPS OOOO due to having Colorado implement and enforce NSPS OOOO for all sources subject to NSPS OOOO in Colorado.

Further, full adoption of NSPS OOOO benefits the United States Environmental Protection Agency ("EPA") by relieving the agency of the primary responsibility to implement and enforce NSPS OOOO in Colorado.

The Colorado Oil and Gas Conservation Commission ("COGCC") does have well completion requirements that are different but similar to NSPS OOOO requirements. However this proposal to fully adopt NSPS OOOO does not change the fact that there are two different requirements that may apply to natural gas wells. The Division continues to work with the COGCC to address this issue and coordinate implementation of these rules.

3.1.3 Quantitative and Qualitative Impacts

"To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons."

There are few if any additional quantitative impacts of the Regulation 6 proposal because these rules are already in effect on a federal level. The qualitative impact of the proposed rule upon affected classes of persons includes Colorado's implementation and enforcement of NSPS OOOO, using Division staff much more familiar with Colorado's oil and gas issues than EPA staff. Full adoption of NSPS OOOO does not provide any other additional costs or benefits beyond those affected by NSPS OOOO.

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3.1.4 Probable Agency Costs

"The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues."

The probable costs to the Division of implementing and enforcing the NSPS OOOO requirements for affected facilities below current Air Pollutant Emission Notice ("APEN") reporting and minor source permitting thresholds, as well as implementing and enforcing the NSPS OOOO well completion requirements, are unknown at this time. These sources are not currently subject to Colorado's reporting and permitting requirements.

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of nine full time inspectors and four term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from six inspectors to nine. In 2013, the legislature appropriated additional funds to hire four term limited inspectors to conduct IR camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the Commission chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection team in fiscal year 2013-14 is $1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

There is no anticipated effect on state revenues because the proposal does not assess any additional emissions reporting or permitting fees than those that already apply.

3.1.5 Comparison to Inaction

"A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction."

If the Commission does not fully adopt NSPS OOOO, EPA and the Division will continue to share the implementation and enforcement responsibilities for NSPS OOOO. However, regardless of partial or full adoption, NSPS OOOO remains effective and federally enforceable.

Importantly, the Division does not advocate full adoption of NSPS OOOO without removing the catch-all provisions in Regulation Number 3 due to the reporting and permitting impacts on both the regulated community and the Division.

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3.1.6 Less Costly Methods/Less Intrusive Methods

"A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule."

There are no less costly or intrusive methods for achieving full adoption of NSPS OOOO. Retaining partial adoption of NSPS OOOO will not resolve the issue of shared implementation responsibilities between EPA and the Division.

3.1.7 Alternative Methods

"A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule."

The Division did not consider any alternative methods for achieving full adoption of NSPS OOOO.

3.1.8 Quantification of Data

"To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences."

The short and long term consequences of the full adoption of NSPS OOOO are full implementation and enforcement by Colorado, instead of split implementation and enforcement between EPA and Colorado. The Division did not further quantify the short- or long-term consequences of the Regulation 6 proposal to fully adopt NSPS OOOO beyond what was already performed by EPA.

3.2 Regulation Number 3

3.2.1 Proposed Revisions

The Division is proposing revisions to Regulation 3's reporting and permitting requirements in order to improve the efficiency of Colorado's air quality reporting and permitting system.

The proposed revisions remove the requirement for sources subject to either a federal New Source Performance Standard ("NSPS") or federal National Emission Standards for Hazardous Air Pollutant ("NESHAP")/Maximum Available Control Technology ("MACT") adopted into Regulation Number 6, Part A or Number 8, Parts A, C, D, and E to file an APEN and obtain a minor source permit regardless of whether their emissions exceed the reporting or permitting thresholds ("catch-all provisions"). As a result, sources subject to a NSPS incorporated into Regulation Number 6, Part A or a NESHAP/MACT incorporated into Regulation Number 8,

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Parts A, C, D, or E are subject to APEN reporting and permitting **only** if their emissions exceed the applicable APEN and permitting thresholds.

In addition, the proposed revisions simplify the Appendix A non-criteria reportable pollutant de minimis determination to 250 pounds per year of any individual non-criteria reportable pollutant. The proposed revisions also remove the crude oil storage tank permitting exemptions.

Finally, the proposed revisions correct an inadvertent error to the minor source permitting exemption for crude oil and condensate truck loading equipment. This revision is administrative in nature, as the Division currently implements the provision as it was originally intended.

It appears that all parties to the Commission rulemaking support the proposed revisions to Regulation 3, and some parties have submitted alternative proposals requesting additional revisions (see Section 3.2.7 in this Regulatory Analysis).

3.2.2 Class of Persons Affected

"A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule."

The classes of persons affected by the proposed revisions to Regulation 3 are broad. Revisions to the catch-all provisions affect any stationary source subject to an NSPS adopted into Regulation Number 6 or NESHAP/MACT adopted into Regulation Number 8 that has emissions below the APEN reporting and minor source permitting thresholds. To demonstrate the breadth of impact, some examples of business and industry that are affected include dry cleaners, aggregate mining operations, grain elevators, natural gas compressor stations, surface coating operations, and power plants. Those activities subject to an NSPS or NESHAP/MACT, whose emissions fall below current reporting and permitting thresholds, will no longer have to report emissions and obtain minor source permits.

The proposed revisions to the non-criteria reportable pollutant de minimis threshold will affect stationary sources with emissions of non-criteria reportable pollutants greater than 250 pounds per year. This revision also has a broad impact, as most sources emit some degree of hazardous air pollutants or other non-criteria reportable pollutants.

Further, the revisions to the crude oil storage tank permit exemptions affect owners and operators of crude oil storage tanks with capacities of 40,000 gallons or less. The correction to the minor source permitting exemption for crude oil and condensate truck loading equipment is administrative in nature and affects oil and natural gas operations.

3.2.3 Quantitative and Qualitative Impacts

"To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons."

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Quantitative and qualitative consequences for each revision are discussed below. Short- and long-term consequences include the continued delay in adopting NSPS OOOO in full, as well as other federal NSPS and NESHAP/MACT that apply to small sources in Colorado. There are minimal if any costs to the regulated community due to these revisions, and in some cases, cost savings are anticipated. Further, the Division anticipates that there will be no significant environmental impact associated with the proposal.

3.2.3.1 Catch-all Provisions

There are no anticipated costs to either the regulated community or the government associated with these proposed revisions. Removal of the catchall provisions will actually reduce reporting, permitting, and associated cost burdens for the regulated community. By reducing reporting and permitting activities, the proposed revision will also reduce costs to the Division associated with these activities.

The Division conducted a permit tracking project from February, 2013 to September, 2013 to understand the impact of this proposal. All pre-construction permits issued were evaluated to determine if they would have required an APEN and permit under this proposal. The Division's permit tracking project indicated that 7% (167 of 2,355) permits processed required permits solely due to the catch-all provision, accounting for approximately 0.03% of the total uncontrolled actual criteria pollutant emissions and 0.003% of statewide uncontrolled actual criteria pollutant emissions. The total hourly permit processing fees for these permits was approximately $50,000.[5] This cost estimate does not include the time saved by the sources by no longer having to complete and submit an APEN or minor source permit application.

The environmental impacts of revising the catch-all provisions are minimal. Further, no emissions increases are anticipated from these sources that would no longer require a permit because these revisions will not exempt them from having to comply with the requirements of an applicable NSPS or NESHAP/MACT.

3.2.3.2 Non-criteria Reportable Pollutants

Some stationary sources affected by the proposed revisions to the non-criteria reportable pollutant thresholds may have new costs related to reporting emissions previously below reporting thresholds, including filing and annual fees. Revision of the threshold for non-criteria reportable pollutants could result in ether cost savings or additional costs to the regulated community depending on the source. Sources that are required to report hazardous air pollutants (a subset of non-criteria reportable pollutants) must pay an emission fee of $152.90 per ton. Currently Regulation Number 3 contains a complex reporting formula involving multiple and different thresholds, some of which are above and some of which are below the proposed 250 pound threshold. Accordingly, changing the threshold will reduce costs for some sources, while increasing costs for other sources. Based on an analysis of reported emissions, the proposed threshold change will reduce industry fees paid to the Division by $47,702 per year. Because the emissions from sources that are not currently reporting is unknown it is not possible to calculate

[5] Permit cost savings were calculated using an average of 4 hours spent per permit, as determined by the time spent on permits processed due to the catch-all provisions in the Division's permit tracking project, multiplied by the Division billing rate of $76.45 an hour.

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the additional costs to sources that will be required to report for the first time under the new proposed threshold. Based on the relative prevalence of different emissions, however, the Division believes that there will be a small net savings to the regulated community.

Additionally, beyond the actual emission fees, the current reporting system is very complex resulting in numerous hours being spent by both the regulated community and Division staff in determining whether reporting is required. Simplifying the reporting system will eliminate the costs associated with this analysis.

Some stationary sources affected by the proposed revisions would benefit because they would no longer be required to report their non-criteria reportable pollutant emissions, thus saving filing and possibly annual fees. The revised threshold of 250 pounds per year preserves at least 96% of the Division's current inventory of non-criteria reportable pollutants. Other sources may have new costs related to having to report emissions that were previously below reporting thresholds, including filing and annual fees. This impact is unknown at this time because these sources are not currently subject to Colorado's reporting and permitting requirements. While EPA does not require States to report hazardous air pollutant emissions, EPA utilizes this data to annually populate the National Emissions Inventory. Accordingly, Colorado will continue to provide a robust set of data while also serving an important regulatory streamlining purpose.

3.2.3.3 Crude Oil Storage Tanks

Owners and operators of crude oil storage tanks may have new costs related to obtaining permits for previously permit-exempt equipment. There are minimal direct costs projected for the affected businesses and industrial sector associated with the removal of the crude oil storage tank permitting exemption. Stationary sources with crude oil storage tanks whose uncontrolled actual emissions exceed the minor source or operating permit thresholds would be required to obtain a permit. In 2008, the Commission removed the reporting exemption for crude oil storage tanks to improve the inventory of uncontrolled actual emissions. While the Division believes there are many crude oil storage tanks in Colorado, the Division's APEN inventory only identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less in Colorado. Removal of the crude oil storage tank minor source permitting exemption would require these tanks to obtain minor source permits at a cost of approximately $19,500.

3.2.3.4 Minor Source Permitting Correction

No practical impact is anticipated as a result of this revision, as the Division continues to implement the provision as was originally intended.

3.2.4 Probable Agency Costs

"The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues."

The Division does not anticipate any negative effect on state revenues. Any potential Full Time Equivalent ("FTE") personnel savings will be redirected to addressing the current permitting backlog. Any loss in permitting fees, will be offset by the processing of backlog permits. In

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addition, the crude oil storage tank permitting exemption revisions will slightly increase the submission of permitting fees. Similarly, the Division anticipates the reduction in filing and annual fees due to the approximately 4% reduction in current non-criteria reportable pollutant reporting to be offset by the increased reporting and associated fees by stationary sources with non-criteria reportable pollutant emissions greater than 250 pounds per year.

3.2.4.1 Catch-all Provisions

The revisions to the catch-all provisions will reduce the administrative burden on both the Division and the regulated community. The Division estimated through the permit tracking project that the staffing of approximately 0.6 FTE would be saved due to the revisions. However, revising the catch-all provisions does not change the applicability or enforcement of the NSPS or NESHAP/MACT.

3.2.4.2 Non-criteria Reportable Pollutants

The revisions to the non-criteria reportable pollutant threshold establish a simplified, standard reporting threshold of 250 pounds per year for all non-criteria reportable pollutants. This eliminates the complicated matrix system and streamlines the process for sources, and for the Division, both in explaining the process to sources and reviewing reported emissions. The work associated with any increased reporting will be absorbed by existing Division staff or potentially offset by the approximately 4% reduction in current non-criteria reportable pollutant reporting.

3.2.4.3 Crude Oil Storage Tanks

The Division's APEN inventory currently identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less. The work associated with permitting and inspecting these, and potentially more, sources will be absorbed by existing Division staff.

3.2.4.4 Minor Source Permitting Correction

There are no additional agency costs incurred as a result of this revision, as the Division continues to implement the provision as was originally intended.

3.2.5 Comparison to Inaction

"A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction."

If the Commission does not adopt at least the proposed revisions to the catchall provisions, the Division would not recommend full adoption of NSPS OOOO. Further, absent adoption of the proposed revisions to the catchall provisions, the Division's permitting backlog will be negatively impacted. Finally, the public, regulated community, and other agencies will continue to experience the complexity and confusion of the APEN reporting thresholds and Appendix A de minimis levels applicability determinations. If the Commission does not adopt the proposed crude oil storage tank exemption revisions, a potentially significant source of emissions will continue to be exempt from permitting requirements. If the Commission does not make the minor source permitting correction, the provision will not align with the Commission's intent at the time of adoption nor the Division's current implementation of the provision. The purposes of the proposed revisions to Regulation 3 include allowing full adoption of NSPS OOOO,

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streamlining and clarifying reporting and permitting, and requiring permits for a potentially significant source of emissions.

3.2.5.1 Catch-all Provisions

The revisions to the catch-all provisions reduce reporting and permitting costs. If the Commission does not adopt the proposed revisions, the regulated community and the Division will retain those reporting and permitting costs. Further, if the Commission adopts NSPS OOOO, and other NSPS and NESHAP/MACT similarly affecting very small sources, in full without removing the catch-all provisions, the increase in APEN reporting and minor source permitting would overwhelm both the Division and the regulated community.

3.2.5.2 Non-criteria Reportable Pollutants

The revisions to the non-criteria reportable pollutant thresholds may reduce costs for some sources and increase costs for other sources. However, all sources will benefit from the increased clarity of the de minimis reporting determination. If the Commission does not adopt the proposed revisions, the public, regulated community, and the Division will continue to deal with a complex and confusing reporting determination.

3.2.5.3 Crude Oil Storage Tanks

The costs of the proposed revisions to the crude oil storage tank permit exemptions include the costs to the regulated community of obtaining permits and the costs to the Division of permitting and inspecting subject tanks. Removing the permitting exemptions also increases the consistency of Colorado's regulations with NSPS OOOO by requiring these sources to also be subject to Colorado's notification, recordkeeping, and control requirements. If the Commission does not adopt the proposed crude oil storage tank exemption revisions, there will not be costs associated with permitting but a potentially significant source of emissions will continue to be exempt from permitting requirements.

3.2.5.4 Minor Source Permitting Correction

No costs are anticipated with the proposed revisions, as the Division will continue to implement the provision as was originally intended.

3.2.6 Less Costly Methods/Less Intrusive Methods

"A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule."

The Division does not believe that there are less costly or less intrusive methods to fully adopt NSPS OOOO than the Division's proposal.

3.2.6.1 Catchall Provisions

The Division believes that the revisions to the catch-all provisions are necessary to adopt NSPS OOOO, and other NSPS and NESHAP/MACT similarly affecting very small sources, due to the anticipated extensive number of APENs and minor source permit applications that would be required. Consider how the current catch-all provisions would apply if the Commission adopts MACT JJJJJJ, which applies to a multitude of small boilers. Under the catch-all provisions,

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every boiler providing electricity, steam, or hot water in a hotel, restaurant, laundry, medical center, research center, institution of higher education, or manufacturing, processing, mining, or refining facility would be required to file an APEN and obtain a minor source permit, even if the source had emissions less than the reporting and permitting thresholds. Other examples of rules similarly affecting very small sources include NSPS JJJJ, which applies to numerous stationary spark ignition internal combustion engines; MACT M, which applies to all perchloroethylene dry cleaning facilities; MACT HHHHHH, which applies to paint stripping and spray applications of greater than three motor vehicles or mobile equipment; and MACT SSSSSS, which applies to all glass manufacturing facilities. Under the current catch-all provisions, all of these facilities would require APENs and minor source permits, even if emissions are below the reporting and permitting thresholds.

If NSPS OOOO is adopted in full without the corresponding adoption of the proposed revisions to the catch-all provisions, the regulated community will be required to file APENs and obtain minor source permits for every NSPS OOOO affected facility. In turn, the Division's permitting backlog will likely grow and industry's ability to obtain timely permits will be negatively impacted. In comparison, if NSPS OOOO is adopted in full along with the proposed revisions to the catch-all provisions, only NSPS OOOO affected facilities with emissions greater than the reporting and minor source permitting thresholds will be required to report emissions and obtain minor source permits. This is currently how the partial adoption of NSPS OOOO is implemented. Thus, the Division does not believe there are less costly or intrusive methods than the proposed catch-all provisions revisions to reduce the administrative impact of full adoption of NSPS OOOO.

Similarly, the Division does not believe there are less costly or intrusive methods than the proposed catch-all provisions revisions to improve the efficiency of Colorado's reporting and permitting system for NSPS or NESHAP/MACT subject sources with emissions below the reporting and permitting thresholds, especially since these revisions will save costs for both the Division and the regulated community.

3.2.6.2 Appendix A

The purpose of the revisions to the non-criteria reportable pollutant thresholds is to simplify a complex and confusing reporting determination.

The Division cannot quantify the costs of unknown non-criteria reportable pollutants but considers the true cost savings of the proposed revision to the non-criteria reportable pollutant threshold the savings in time and effort of the public and regulated community in determining applicability under the revised Appendix A. While some sources non-criteria reportable pollutant reporting will increase, the Division does not believe there is a less costly or intrusive method to streamline the non-criteria reportable pollutant reporting determination while still maintaining a robust non-criteria reportable pollutant inventory.

3.2.6.3 Crude Oil Tank Permit Exemption

Requiring permits for crude oil storage tanks, a potentially significant source of emissions, cannot be accomplished in any less costly or less intrusive method. Further, some sources will

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want enforceable permit limits on their crude oil storage tanks so as to be exempt from NSPS OOOO storage vessel requirements.

3.2.6.4 Minor Source Permitting Correction

There are no less costly or no less intrusive methods, as the Division will continue to implement the provision as was originally intended.

3.2.7 Alternative Methods

"A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule."

In addition to the Division's proposal, various parties to the rulemaking have submitted different alternative proposals for the Commission to consider. Some of these proposals request that the Commission adopt additional requirements, increasing APEN reporting and permitting thresholds, as well as change how emissions are reported to the Division.

The Division considered revising the APEN and minor source permitting thresholds to further simplify and clarify APEN reporting and minor source permitting. However, the Division decided not to pursue revising the APEN and minor source permitting thresholds at this time, in order to avoid diverting focus from the important emission reductions associated with the proposed revisions to Regulation Number 7, and provide additional time to work with EPA on the potential development of a sufficient noninterference demonstration for such revisions.

Further, the Division considered alternative thresholds for the proposed revisions to the non-criteria reportable threshold. The Division selected the 250 pound per year threshold due to concerns about higher thresholds and the retention of approximately 96% of the Division's current non-criteria reportable pollutant inventory under the proposed revision.

The Division did not consider any alternatives concerning the proposed revisions to the crude oil storage tank permitting exemptions or the minor source permitting correction.

3.2.8 Quantification of Data

"To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences."

The Division quantified the short-term consequences and used them to project long-term consequences of the Regulation 3 proposal.

3.2.8.1 Catch-all Provisions

The Division tracked all pre-construction permits, which includes permits processed for point sources at both major stationary sources and minor sources, between mid-February and September, 2013. The permit tracking project indicates that 7% (167 of 2,355) of those permits

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processed required permits because of the catch-all provision. In addition, the potentially eliminated emissions in comparison to statewide emissions are all much less than 1%, as illustrated in **Table 1** below.

Table 1: Emissions from Sources Potentially No Longer Requiring Permits due to the Catch-all Revisions (State-wide)

Pollutant	Uncontrolled actual emissions of potentially eliminated permits during tracking project (tpy, % of statewide emissions)	Uncontrolled actual emissions statewide[6] (tpy)
CO	45 (0.05%)	99,929
NOx	110 (0.07%)	165,192
Total PM[7]	32 (0.0004%)	7,385,720
SO2	0.2 (0.0002%)	115,715
VOC	24 (0.005%)	469,396
TOTAL	211.2 (0.003%)	8,235,952

Further, 4% (87 of 2,355) of the permits processed that required permits because of the catch-all provision are in the nonattainment area ("NAA"). The potentially eliminated emissions in comparison to NAA emissions are also much less than 1%, as illustrated in **Table 2** below.

Table 2: Emissions from Sources Potentially No Longer Requiring Permits due to the Catch-all Revisions (8-Hour Ozone NAA)

Pollutant	Uncontrolled actual emissions of potentially eliminated permits during tracking project in the NAA (tpy, % of NAA emissions)	NAA uncontrolled actual emissions[8] (tpy)
CO	19 (0.1%)	19,110
NOx	90 (0.24%)	37,831
Total PM[9]	15 (0.003%)	441,084
SO2	0.1 (0.0004%)	23,994
VOC	5 (0.004%)	140,463
TOTAL	129.1 (0.02%)	662,482

Importantly, these tables represent point source emissions, and do not include mobile source or area source emissions. Therefore, the percentage of emissions potentially eliminated from

[6] January-November, 2013, total emissions.
[7] Includes PM, PM10, and PM2.5.
[8] January-November, 2013, total emissions.
[9] Includes PM, PM10, and PM2.5.

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permitting due to the removal of the catch-all provisions is even less, if the total emissions inventory, including point, mobile and area source emissions, were used.

The revisions to the catch-all provisions reduce costs to affected classes of persons, due to fewer sources being required to file APENs and obtain minor source permits. The Division's permit tracking project shows that 7% (167 of 2,355) of the permits processed between mid-February and September, 2013, were permitted due to the catch-all provision. The total hourly permit processing fees for these permits was approximately $50,000[10]. This cost estimate does not include the time saved by the sources by no longer having to complete and submit an APEN or minor source permit application.

The environmental impacts of revising the catch-all provisions are minimal and no emissions increases are anticipated because these revisions will not exempt any source from complying with the requirements of an applicable NSPS or NESHAP/MACT. The Division's permit tracking project shows that the 7% of permits processed between mid-February 14, and September 30, 2013, accounted for approximately 0.03% of the total uncontrolled actual criteria pollutant emissions during the tracking project and 0.003% of statewide uncontrolled actual criteria pollutant emissions.[11]

3.2.8.2 Appendix A

There are potential increased costs to the affected classes of persons associated with the revisions to Appendix A, however the full extent is unknown. This revision may increase the reporting requirements for a currently unknown quantity of Bin B and Bin C non-criteria reportable pollutants because the revised threshold is lower than the current lowest de minimis reporting thresholds of 500 and 1,000 pounds per year, respectively. This revision may also decrease the reporting requirements for some Bin A pollutants because the revised threshold is higher than the current lowest de minimis reporting threshold of 50 pounds per year. Sources will save emission fees of $152.90 per ton of non-criteria reportable pollutant no longer required to report, not including the time saved by the sources due to not collecting the emissions data for and submitting APENs.

The environmental impacts of revising the catch-all provisions are minimal and no emissions increases are anticipated because these revisions will not exempt any source from complying with applicable requirements. In addition, the Division estimates that the proposed reporting thresholds of 250 pounds per year will retain at least 96% of the Division's current non-criteria reportable pollutant tracking for inventory purposes, which will continue to provide data to the EPA for the National Emissions Inventory, as well as to external custormers such as environmental groups and the public. In addition, because the proposed reporting threshold is less than the current thresholds for many of the current scenarios, the revision will result in additional emissions of Bin B and Bin C pollutants being reported.

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[10] Permit cost savings were calculated using an average of 4 hours spent per permit, as determined by the time spent on permits processed due to the catch-all provisions in the Division's permit tracking project, multiplied by the Division billing rate of $76.45 an hour.

[11] See the Division's January 29, 2014, CAA § 110(l) Noninterference Demonstration for a more detailed discussion of noninterference with the NAAQS.

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3.2.8.3 Crude Oil Tank Permit Exemption

There are anticipated costs to the affected classes of persons associated with the removal of the crude oil storage tank permitting exemptions. The Division's APEN inventory currently only identifies 64 crude oil storage tanks with a design capacity of 40,000 gallons or less in Colorado. Removal of the crude oil storage tank minor source permitting exemption would requires these tanks to obtain minor source permits at a cost of approximately $19,500.

The emissions from crude oil storage tanks can be significant and permitting exemptions are meant to be limited to emission points with negligible impacts on air quality. The environmental impacts of revising the crude oil storage tank permitting exemptions may be significant, however, due to data limitations that impact is known.

The short term consequences of the proposed catch-all revisions include allowing the Commission to fully adopt NSPS OOOO. The long term consequences of the proposed catch-all revisions include potentially allowing the Commission to adopt other NSPS and NESHAP/MACT similarly affecting very small sources.

The short term consequences of the proposed revisions to the non-criteria reportable pollutant threshold include simplifying the non-criteria reportable pollutant reporting determinations for both the Division and the regulated community and reducing the Division's current non-criteria reportable pollutant inventory by approximately 4%. The long term consequences of the proposed revisions to the non-criteria reportable pollutant threshold are unknown.

The short-term consequences of the proposed crude oil storage tank permit exemptions include requiring existing crude oil storage tanks with a capacity of 40,000 gallons or less to obtain permits. The long term consequences of the proposed crude oil storage tank permit exemptions include requiring new crude oil storage tanks to obtain permits.

3.2.8.4 Minor Source Permitting Correction

Short- and long-term consequences of the proposed correction include aligning the provision with the Commission's original intent. No data was quantified relating to this revision.

3.3 Regulation Number 7

3.3.1 Discussion of Proposed Revisions

The Regulation 7 rulemaking package proposes revisions that expand existing oil and gas control requirements and establish additional monitoring, recordkeeping and reporting requirements. These proposed revisions include the following:

1) Enhancing the existing control program for petroleum storage tanks by:
    a. Lowering the control requirement threshold for condensate storage tanks from 20 to 6 tons per year of uncontrolled actual volatile organic compound (VOC) emissions;

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    b. Requiring controls for crude oil and produced water storage tanks with uncontrolled actual VOC emissions that are equal or greater than 6 tons per year; and
    c. Expanding NAA requirements for tank controls during the first 90 days of production to the rest of the state;
2) Establishing requirements to ensure that emissions from controlled storage tanks are captured and routed to the control device;
3) Enhancing the existing control program for dehys by:
    a. Increasing the control requirements from 90% to 95%;
    b. Increasing designed destruction efficiency requirements from 95% to 98%;
    c. Establising more stringent requirements for individual dehys located in proximity to a building unit or designated outside activity area;
4) Establishing LDAR requirements for compressor stations and well production facilities, including requirements to reduce emissions from compressor seals and open ended lines consistent with current federal requirements;
5) Expanding the existing 8-hour ozone NAA requirements for auto-igniters on flare devices to the rest of the state;
6) Expanding the existing NAA requirements for low bleed pneumatic devices to the rest of the state and where feasible requiring no-bleed pneumatic devices; and
7) Requiring that the gas stream at newly constructed well production facilities either be connected to a pipeline or routed to a control device from the date of first production.

If adopted, these proposed revisions will result in substantial reduction of hydrocarbon emissions including volatile organic compounds (VOCs) and methane.

Several industry and environmental parties fully support the Division's proposed revisions to Regulation 7. Conversely, some parties request that the Commission adopt additional requirements that go beyond the Division's proposal, while other alternatives request that the Commission limit aspects of the Division's proposed revisions. See Section 3.3.7 of this Regulatory Analysis for details on the parties' alternative proposals.

3.3.2 Class of Persons Affected

"A description of the classes of persons who will be affected by the proposed rule, including classes that will bear the costs of the proposed rule and classes that will benefit from the proposed rule."

The proposal affects the oil and gas industry and supporting businesses in Colorado. Further, the proposal broadly benefits all persons in Colorado, especially those who live and work in the proximity of oil and gas operations. Companies that will bear the costs of this rule change include the oil and gas companies operating, drilling, recompleting or otherwise stimulating wells in the NAA, as well as well production facilities, compressor stations and dehys. Revisions to Regulation 7 may require installation of controls to reduce hydrocarbon emissions from storage tanks, dehys, and separators on newly constructed, hydraulically fractured or recompleted wells. Typically flares are used as control equipment, but vapor recovery units ("VRUs") and other

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Division-approved pollution prevention devices may be used. Use of best management practices or controls may also be required for well maintenance and liquids unloading activities. Regulation 7 revisions may also require installation of auto-igniters on combustion devices and installation of low- or no-bleed pneumatic controllers. In addition, compressor stations and well production facilities may be required to monitor components for emissions and repair leaks. Owners and operators of well production facilities or compressor stations that include compressor seals and open-ended lines may have to comply with additional work practice standards.

The proposed Regulation 7 will benefit those companies that manufacture and/or distribute flare control devices, VRUs, auto-igniters or low- and no-bleed pneumatic controllers. Companies that manufacture hydrocarbon monitoring equipment, including infra-red ("IR") cameras, photo-ionization detectors, flame ionization detectors and other Division-approved monitoring methods, as well as those companies that provide or support monitoring services may also benefit from these proposed revisions.

Given that VOCs are precursors to ozone, the citizens in the NAA will benefit from the proposed rule through reduced ozone precursor emissions. State-wide, persons living or working in proximity to storage tanks, dehys, wells, well production facilities or compressor stations will benefit from reduced air emissions. See Section 3.3.3 of this Regulatory Analysis for a more comprehensive review of public health impacts.

Thus, all persons in the State benefit from the proposed revisions.

3.3.3 Quantitative and Qualitative Impacts

"To the extent practicable, a description of the probable quantitative and qualitative impact of the proposed rule, economic or otherwise, upon affected classes of persons."

The proposed changes to Regulation Number 7 are projected to result in substantial reductions of hydrocarbon emissions (including both VOCs and methane/ethane) from the oil and gas industry. The Division estimates approximately 93,500 tons per year VOC, or 257 tons per day, and approximately 64,000 tons per year methane/ethane will be reduced.

Qualitative impacts of this Regulation 7 proposal are closely related to Colorado's air quality and economy. During the past ten years, Colorado has been a leader in developing and implementing requirements to reduce air emissions from the oil and gas sector. As a result of these efforts, Colorado now has in place a series of cost-effective requirements that significantly reduce air emissions from Colorado oil and gas facilities. Despite this success, however, the tremendous growth of oil and gas production in Colorado continues to threaten the air quality gains that we have achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. While this growth has provided important economic benefits for Colorado, increased air emissions can have a negative impact on Colorado's public health and environment.

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Specifically, VOC emissions contribute to the formation of ground level ozone. Ozone is photochemical oxidant and known respiratory irritant. Ground level ozone is a secondary pollutant produced through the reaction of VOCs, nitrogen oxides and sunlight. Elevated levels of ground level ozone have been linked to a variety of adverse health effects including decreased lung function, increased respiratory symptoms, serious indicators of respiratory morbidity including emergency visits and hospital admissions, as well as total non-accidental and cardio-respiratory mortality. According to EPA, ground-level ozone also damages vegetation and ecosystems. It leads to reduced agricultural crop and commercial forest yields, reduced growth and survivability of tree seedlings, and increased susceptibility to diseases, pests and other stresses such as harsh weather. In the United States alone, ground-level ozone is responsible for an estimated $500 million in reduced crop production each year. Ground-level ozone also damages the foliage of trees and other plants, affecting the landscape of cities, national parks and forests, and recreation areas.[12]

The U.S. EPA has set the current National Ambient Air Quality Standards ("NAAQS") for ground level ozone at 75 parts per billion (ppb) averaged over an 8-hour period. Based on a review of the then current health literature, the Clean Air Scientific Advisory Committee concluded in 2008 that the 75 ppb standard was not sufficiently protective of public health, and recommended that the standard be set at between 60 ppb and 70 ppb. EPA is in the process of considering whether to lower the ozone standard.

Currently, the Denver Metro/North Front Range area is out of attainment with federal health-based ground level ozone standards. This includes much of the Denver/Julesberg oil field. Other areas of the state have also experienced elevated ozone levels recently, with one monitor in Western Colorado showing concentrations above 75 ppb and a number of other monitors showing levels between 60 ppb and 75 ppb.

Addressing oil and gas emissions is a critical component of Colorado's efforts to lower ozone levels since this sector represents the largest source of VOC emissions in the state. Based on the most recent inventory (2011), 54% of the anthropogenic VOC emissions in the state come from the oil and gas sector, which is roughly triple the amount of emissions from the next largest source. Moreover, because of the ongoing growth in the oil and gas industry and the projected decline in VOC emissions from other sectors, the share of VOC emissions attributable to the oil and gas sector will likely increase over the foreseeable future. The proposed emission reduction strategies will further enhance existing public health and environment protections on both a local and regional scale.

In addition to VOC emissions, oil and gas operations are a large source of methane. Methane is a potent greenhouse gas, which contributes to global climate change. In addition to reducing VOCs that contribute to regional ozone pollution, the Division's proposed strategies will reduce methane, and thereby play a role in Colorado's overall efforts to reduce greenhouse gas emissions. Finally, the proposed strategies will reduce the exposure of people that live and work

[12] See EPA website, "Ozone – Good Up High Bad Nearby." http://www.epa.gov/oar/aqps/gooduphigh/bad.html. February 11, 2014.

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near oil and gas production sites to VOC emissions. Methane is also a valuable natural resource (natural gas), and reducing leaks will benefit Colorado's environment and economy.

The Division assesses the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7 in Section 3.3.8 of this Regulatory Analysis. Equipment costs, labor costs, maintenance costs, supervision costs, travel costs, and costs associated with recordkeeping and reporting are all evaluated. The Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately $59.2 million. Further, the proposed strategies are expected to result in the capture of additional product worth approximately $16.8 million, for a total net cost of $42.4 per year. In addition to these direct costs, implementation of the proposed strategies could result in the shut-in of certain marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of additional oil and gas that would be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.[13] An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.[14] This information will be considered by the Commission as part of the rulemaking hearing.

The Division recognizes that the oil and gas industry plays an important role in Colorado's economy in the evaluation of qualitative impacts of the Regulation 7 proposal. The industry is a significant employer of highly skilled and well-paid employees. The industry generates large revenues and pays significant taxes in the state. It produces valuable domestic resources that help keep prices low while adding to national stability and security. At the same time, emissions from the oil and gas industry represent a significant portion of the total VOC emissions both in the NAA and throughout the rest of the state. The Division's proposal is intended to achieve significant reductions in air emissions without imposing unreasonable costs that could stifle economic activity.

As discussed above, the Division's proposal is projected to result in a net annual cost to the industry of approximately $42.4 million. As with any increase in costs, the costs associated with the Division's proposal could have some adverse impact on economic activity associated with the oil and gas industry in Colorado. However, over the past decade Colorado's oil and gas industry has experienced unprecedented growth, even as Colorado has enacted regulatory measures to ensure that development continues in a protective and responsible manner. Moreover, given the relative size of the costs of the current proposal to the overall size of the industry, the total impact of these costs will likely be minimal. In 2012, for example, oil and gas producers in Colorado sold 48,450,717 barrels of oil and 1,661,073,176 MCF of natural gas.

Based on the current price of oil, $96 per barrel, and assuming a price for natural gas of

[13] See discussion in Section 3.3.8 of this Regulatory Analysis.
[14] See Attached Exhibit A.

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$3.5/MCF[15], annual revenue from the sale of oil and gas in Colorado based on 2012 production levels is approximately $10.5 billion. Accordingly, the net cost of the Division's proposal is approximately 0.4% of the annual revenues. Given this small percentage, the Division's proposal is unlikely to have any appreciable impact on the economic competitiveness of the industry as a whole. This conclusion is bolstered by the fact that several of the largest oil and gas companies in the state (Anadarko Petroleum Corp., Noble Energy, Inc., Encana Oil and Gas USA, and DCP Midstream) fully support the Division's proposed revisions. Collectively, the Division estimates that these companies will bear approximately 75% of the total annual cost of the proposed rules.

While it is unlikely that the costs associated with the proposed revisions will have any meaningfully adverse impacts on the competitiveness of the industry as a whole in Colorado, the costs could incrementally add to the current costs associated with operating marginally producing wells. This could potentially lead to some wells being shut in and the resultant economic consequences of these shut-ins including lost production revenue, lost royalties, lost severance taxes and potentially lost jobs. To mitigate against this possibility, the Division's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately $712.

Finally, it does not appear that the costs associated with the Division's proposal will have any meaningful negative impact on the general public or small businesses that purchase natural gas and other petroleum products. Oil and natural gas are sold on international and national markets, making it extremely unlikely that any increase in production costs in Colorado will be reflected in prices for Colorado consumers.

3.3.4 Probable Agency Costs

"The probable costs to the agency and to any other agency of the implementation and enforcement of the proposed rule and any anticipated effect on state revenues."

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of nine full time inspectors and four term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from six inspectors to nine. In 2013, the legislature appropriated additional funds to hire four term limited inspectors to conduct IR camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the Commission chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection

[15] The Division assumed a price per MCF of $3.50 throughout its analysis; however, natural gas prices are currently around $5 per MCF, suggesting that the Division has underestimated the value of gas saved by the proposal.

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team in fiscal year 2013-14 is $1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

The Division does not anticipate state revenues to be affected because the proposal does not assess any additional emissions reporting or permitting fees beyond those that already apply. However, state revenues could potentially be affected by implementation of the proposed strategies, in that they could potentially result in the shut-in of a few marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.

3.3.5 Comparison to Inaction

"A comparison of the probable costs and benefits of the proposed rule to the probable costs and benefits of inaction."

The Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be $42.4 million per year. This translates to approximately $453 per ton of VOC reduced. Costs and benefits of the proposed Regulation 7 revisions are detailed in Section 3.3.8.

Conversely, inaction would mean that the above emissions reductions are not realized, that the associated captured methane (natural gas), a valuable natural resource, is lost to the ambient air and that the estimated cost savings in captured product that can be sold at a profit is not realized. Further, emissions from this sector are projected to grow substantially, especially in shale gas/oil development.[16]

The forecast growth in shale gas/oil development will result in increased emissions of VOC and other hydrocarbons including greenhouse gases, unless additional controls are implemented. This could result in increases in ozone formation and the development of additional State Implementation Plan requirements to meet current and future NAAQS requirements. According to EPA, attaining the current ozone standard throughout the nation will result in between $6.9 billion and $18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieve a 70 ppb standard will result in between $13 billion and $37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between $22 billion and $61 billion per year. EPA does not report these health benefits by state, but since the population of the Denver Metropolitan Area/North Front Range NAA accounts for approximately 2.5% of the total national population living in areas that are in

[16] U. S. Energy Information Administration. "Annual Energy Outlook 2013". April 15-May 2, 2013.

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violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

The proposed rules will also produce substantial benefits associated with reducing greenhouse gases. As part of this rulemaking the Environmental Defense Fund has engaged an expert to analyze the benefits of the rulemaking based on the social cost of carbon. Based on this analysis, EDF projects that the total annual benefit from the projected methane reductions is between $104 million and $318 million in 2016 and between $132 million and $404 million in 2025.[17]

In addition to the benefits associated with reductions of VOCs and methane, the proposed rules will produce additional economic benefits in the form increased product capture and the creation of new jobs associated with the implementation of the new requirements.

3.3.6 Less Costly Methods/Less Intrusive Methods

"A determination of whether there are less costly methods or less intrusive methods for achieving the purpose of the proposed rule."

In 2004, 2006 and again in 2008, the Commission established oil and gas industry specific emissions control requirements in an effort to reduce VOC emissions in the 8-hour ozone NAA. The tremendous growth of oil and gas production in Colorado and the associated emissions continue to threaten the air quality gains that have been achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. Since then, the oil and gas industry has grown significantly (more than predicted), and changes in drilling technologies and other advancements have further supported growth in this industry. The oil and gas industry continues to be the largest VOC emitter in Colorado (illustrated in Figure 1, below).

Several industry alternative proposals identify less costly and/or less intrusive methods to reduce emissions (see Section 3.3.7 of this Regulatory Analysis). The Division made several clarifications based on these alternatives, but did not substantially revise the Division's Regulation 7 proposal. The Division believes the Regulation 7 proposal secures more emissions reductions than those alternatives, and those additional emission reductions are cost effective. Moreover, several parties have proposed more costly and/or more intrusive methods to reduce emissions. The Division believes that its proposal strikes a proper balance and achieves substantial emissions reductions in a cost effective manner.

[17] See Attached Exhibit B.

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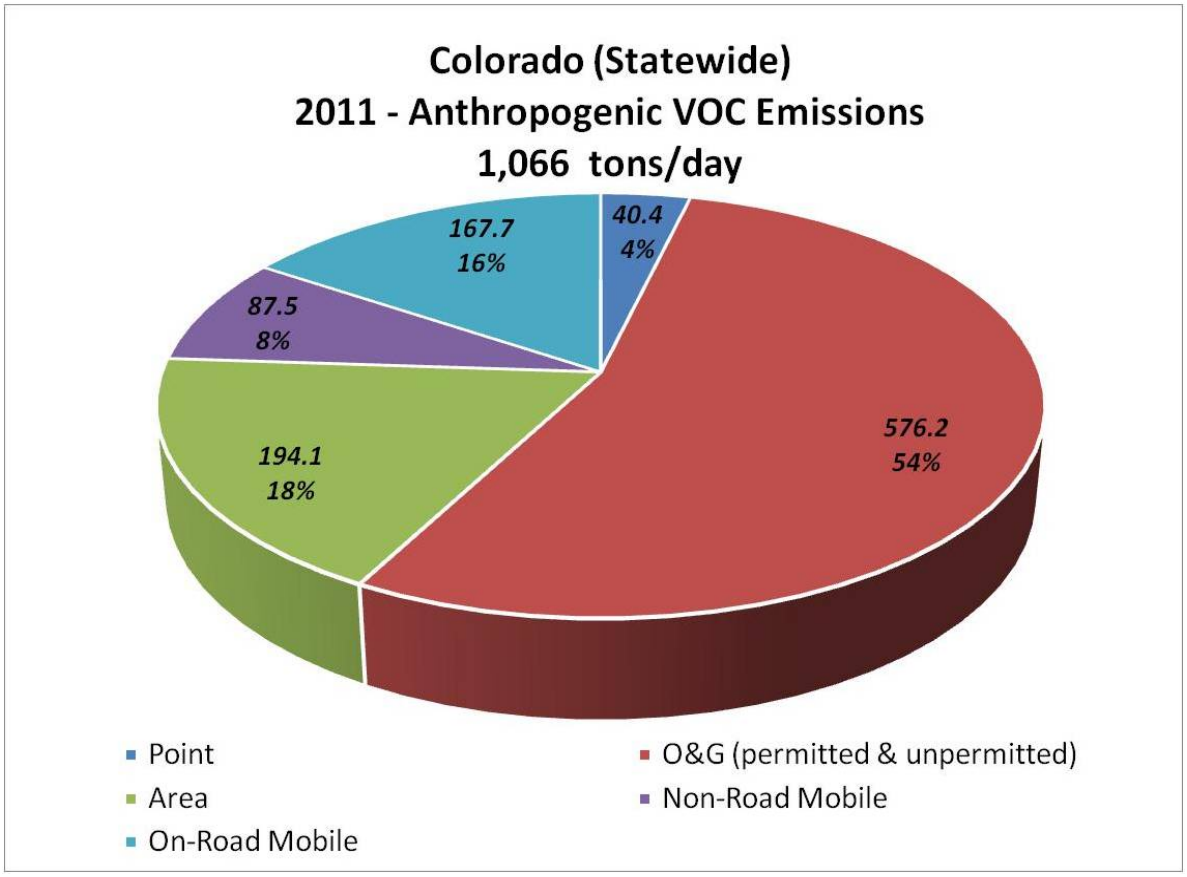


Figure 1 - Colorado Statewide Anthropogenic VOC Emissions (2011)

3.3.7 Alternative Methods

"A description of any alternative methods for achieving the purpose of the proposed rule that were seriously considered by the agency and the reasons why they were rejected in favor of the proposed rule."

In addition to the Division's proposal, various parties to the rulemaking have submitted 6 different alternative proposals for the Commission to consider. Some of these proposals request that the Commission adopt additional requirements that go beyond the Division's proposal, while other alternatives request that the Commission limit aspects of the Division's proposed revisions. In some cases, the parties submitting the proposals included analyses estimating the costs and benefits associated with their proposals. Copies of each of these proposals along with any economic impact analysis that the parties submitted identifying the projected costs and benefits of their particular proposals are attached to this Regulatory Analysis as exhibits. Upon evaluation of these proposals, and other parties' comments, the Division made several clarifications to but did not substantially revise the Division's Regulation 7 proposal. The Division believes the Regulation 7 proposal strikes an appropriate balance between the various alternatives.

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The section below identifies each of the submitted proposals, discusses how the proposals differ from the Division's proposal, and addresses the projected costs and benefits of each proposal.[18]

3.3.7.1 Joint Industry Work Group

A collection of oil and gas companies and industry trade groups have submitted an alternative proposal seeking to limit the requirements set forth in the Division's proposal.[19] Specifically, the Joint Industry Work Group request that the Commission limit the Division's proposal in the following respects: 1) restrict all proposed requirements to the Denver Metropolitan Area/North Front Range 8-hour ozone NAA; 2) reduce the required frequency proposed for leak inspection and repair; 3) eliminate the proposed requirements for dehydrators; 4) limit proposed requirements for compressor seals and open-ended lines to compressor stations; and 5) eliminate proposed requirements related to well maintenance and liquids unloading. In addition to these proposed limitations, the Joint Industry Work Group have proposed a number of additional changes, which could have some minimal additional impacts on the costs and benefits of the proposal.

Since the Joint Industry Group did not submit an economic analysis detailing the projected costs and benefits of their alternative proposal,[20] the Division has conducted an analysis of the Joint Industry Work Group alternative proposal utilizing the same methodologies and assumptions detailed in Section 3.3.8 of this Regulatory Analysis. Based on this analysis, the Division estimates that the Joint Industry Work Group alternative proposal would have a net cost[21] to the regulated community of approximately $32.2 million, and would reduce emissions of VOCs by 56,525 tons per year and methane/ethane by 33,058 tons per year. The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Finally, because the Joint Industry Work Group proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section 3.3.8 of this Regulatory Analysis would be reduced.

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[18] In instances where a party submitted an analysis of the costs and benefits associated with their proposal such analysis is attached. Where parties submitted proposal without an analysis of their own proposal the Division has endeavored to analyze the costs and benefits of these proposals using the same methodologies used to analyze the costs and benefits of the Division's proposal.

[19] A copy of this alternative proposal is attached to this Regulatory Analysis as Exhibit C.

[20] The group did submit an analysis of the Division's proposal showing substantially higher costs than reflected in the Division's analysis. A copy of this analysis is attached hereto as Exhibit A. It should be noted that while the Joint Industry Work Group predicts much higher costs from the Division's proposals, Anadarko Petroleum Corporation, Noble Energy, Inc. and Encana Oil and Gas USA have submitted information during the rulemaking supporting the reasonableness of the Division's cost and benefit calculations. Submissions from these companies can be found at the following link: ftp://ft.dphe.state.co.us/apc/aqcc/REBUTTAL%20STATEMENTS,%20EXHIBITS%20%26%20ALT%20PROPOSAL%20REVISIONS/

[21] Net cost reflects the cost of implementing the proposed strategy less the value of the additional product captured as a result of the proposed strategies.

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3.3.7.2 WPX Energy

WPX is the largest natural gas producer in the state. In the current rulemaking WPX has offered an alternative proposal that would decrease the total number of leak inspections by allowing well production facilities with low leak rates during two consecutive inspections to reduce inspection frequency from monthly to quarterly, or from quarterly to annually depending on the size of the facility.[22] While it is difficult to predict in advance how many facilities would be able to take advantage of this reduced inspection rate, for the purposes of this Regulatory Analysis the Division assumes that one half of the facilities would be able to utilize the reduced frequency. Based on this assumption, adoption of WPX's alternative proposal would reduce the total net annual cost of the proposed revisions from approximately $42.4 million to approximately $36.8 million. This change would also decrease the amount of emission reductions from the Division's proposal by 1,845 tons per year of VOC and 2,757 tons per year of methane/ethane.

The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. Given the relatively small difference in net costs between the two proposals, any positive impact should be fairly small. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Based on the number of inspection hours for each proposal, the number of new inspector jobs would decrease. Finally, because the WPX proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section 3.3.8 of this Regulatory Analysis would be reduced.

3.3.7.3 Conservation Groups

As part of the rulemaking a number of conservation groups have submitted an alternative proposal requiring additional leak detection inspections for well production facilities and compressor stations relative to the Division's proposal. In addition, the Conservation Groups' alternative proposal increases the number of pneumatic devices that would need to be retrofitted. A copy of the Conservation Groups' alternative proposal is attached as Exhibit D. Additionally, their analysis of the costs and benefits associated with their alternative proposal is attached as Exhibit E.

3.3.7.4 Local Community Organizations

A group of local community organizations have submitted an alternative proposal aimed at increasing the stringency of the Division's proposal for facilities that are located within 1,320 feet of a building unit or designated outdoor activity area. Specifically, for such facilities the Local Community Organizations' alternative proposal would decrease the threshold for controls from petroleum storage tanks from 6 tons per year (as proposed by the Division) to two tons per year. Additionally, facilities located within 1,320 feet of these designated areas would be subject to a more stringent leak inspection schedule. Copies of the Local Community Organizations'

[22] In addition to this change, WPX has proposed a limited number of additional changes and clarifications that do not impact the cost and benefit calculations conducted for the Division's proposal. A copy of WPX's alternative proposal is attached as Exhibit F.

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alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits G and H.

3.3.7.5 Local Government Coalition

The Local Government Coalition consists of a number of county and city governments including Adams County, Boulder County, La Plata County, Pitkin County and San Miguel County, Fort Collins, the City of Boulder, and the City and County of Denver. In their alternative proposal, the Local Government Coalition seeks to increase the number of leak detection inspections for compressor stations and well production facilities relative to the Division's proposal. The Local Government Coalition also seeks to require that well production facilities be tied in to a gas gathering line within 90 days after the date of first production, unless the Division approves an extension of this deadline. Copies of the Local Government Coalition's alternative proposal and documents assessing the costs and benefits of that proposal are attached hereto as Exhibits I through M.

3.3.7.6 Worldwide Liquid Solutions, LLC

Worldwide Liquid Solutions (WLS) is a manufacturer of emission reduction technology designed to control VOC emissions from petroleum storage tanks. According to WLS, their emission reduction technology cannot control methane and ethane and therefore cannot meet the control standards for tanks reflected in the Division proposal. To address this, WLS has submitted an alternative proposal that would only require reductions of VOCs from tanks and not methane/ethane. As an alternative to their alternative, WLS has proposed rejecting all of the proposed changes to Regulation No. 7 set forth in the Division's proposal. Copies of WLS' alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits N and O.

3.3.8 Quantification of Data

"To the extent practicable, a quantification of the data used in the analysis; the analysis must take into account both short-term and long-term consequences."

As set forth below, the Division has assessed the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7. The Division estimates revisions to Regulation 7 will reduce VOC emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be $42.4 million per year. This translates to approximately $453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado Commission and the EPA. The Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately $59.2 million. Further, the proposed strategies are expected to result in the capture of additional product worth approximately $16.8 million, for a total net cost of $42.4 million per year. In addition to these direct costs, implementation of the proposed strategies could potentially result in the shut-in of certain marginally producing wells, resulting in indirect

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costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities. To mitigate against this possibility, the Division's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately $712. An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.[23] This information will be considered by the Commission as part of the rulemaking hearing.

The detailed discussions below largely focus on short-term consequences of the proposal. Long term consequences potentially include having to establish greater and potentially more extreme control measures in the future to address the current mass of emissions and anticipated growth in emissions. The oil and gas industry is expected to continue to grow significantly, especially in shale gas/oil development.[24]

This continued growth in shale gas/oil development will result in increased emissions of VOC and other hydrocarbons including methane and ethane, unless additional controls are implemented. This could result in increases in ozone formation and additional State Implementation Plan requirements to meet current and future NAAQS requirements. According to EPA, attaining the current ozone standard throughout the nation will result in between $6.9 billion and $18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieving a 70 ppb standard will result in between $13 billion and $37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between $22 billion and $61 billion per year. EPA does not report these health benefits by state, but since the population of the Denver Metropolitan Area/North Front Range NAA accounts for approximately 2.5% of the total national population living in areas that are in violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

3.3.8.1 Control Requirements for Petroleum Storage Tanks

Commencing in 2004 the Commission has adopted a series of requirements aimed at reducing emissions from petroleum storage tanks at well production facilities, compressor stations and gas processing plants. Currently, condensate tanks with uncontrolled actual emissions of 20 tons per year or greater of VOC must be equipped with a control device that has a control efficiency of at least 95%. Additionally, with certain exceptions, operators in the NAA must achieve a 90% system-wide reduction of VOC emissions from condensate tanks during the period from May 1 through September 30, and 70% during the period from October 1 through April 30. These current requirements only apply to tanks that store condensate, which is defined in the Commission's Common Provisions regulation as "hydrocarbon liquids . . . with an API gravity

[23] See Attached Exhibit A.
[24] U. S. Energy Information Administration. "Annual Energy Outlook 2013". April 15-May 2, 2013.

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of 40 degrees or greater." While most of the petroleum liquid produced in Colorado qualifies as condensate, there are heavier hydrocarbon liquids, typically referred to as crude oil, with an API gravity below 40 degrees that are not subject to the current control requirements. Additionally, there are a number of high volume produced water tanks that have VOC emissions above 6 tons per year that are not currently regulated under the existing requirements.

While Colorado has achieved considerable success in controlling emissions from condensate tanks since 2004, petroleum storage tanks at oil and gas production and midstream facilities continue to be the most significant source of VOC emissions from this sector. To address this emission source the Division is proposing the following strategies: 1) reducing the control threshold from 20 tons per year VOC to 6 tons per year; 2) eliminating the distinction between condensate and other liquids and requiring controls strictly based on emission levels; and 3) extending the current requirement that all condensate tanks in the NAA be controlled during the first 90 days of production to storage tanks throughout the state. In order to meet each of these three strategies, the Division assumes that owners and operators will equip tanks with enclosed flares, as is the typical practice under the existing tank control requirements. The estimated costs associated with installing and maintaining an enclosed flare are set forth in subsection 3.3.8.1.1 of this Regulatory Analysis. Utilizing the calculated flare costs, the estimated costs and benefits for each of the three tank control strategies are discussed in subsections 3.3.8.1.2 – 3.3.8.1.4 of this Regulatory Analysis.

3.3.8.1.1 General Cost Estimates for Flares

The estimated cost for a flare control device is based on identified costs from a 2008 oil and gas cost study[25] adjusted for inflation. Based on this data, the estimated annualized cost of a flare control device with auto-igniter[26] is about $6,287.[27]

[25] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the Commission as part of the 2008 Ozone Action Plan process. For reference or background purposes, the Division has cited herein certain information that has been submitted to the Commission as part of the rulemaking; however, it is not necessarily included with this Regulatory Analysis as an exhibit.

[26] Currently only flares in the NAA are required to have auto-igniters. Under the current proposal, the auto-igniter requirement would be extended statewide. For the purposes of this cost analysis, it is assumed that auto-igniters will be required statewide. The cost and benefits associated with equipping existing flares outside the non-attainment with auto-igniters are discussed below in Section 3.3.8.1.7.

[27] Certain parties to the rulemaking have asserted that the actual cost per combustion device is higher based on EPA's cost analysis conducted in accordance with NSPS OOOO. Based on a review of EPA's analysis it appears that additional costs were included for surveillance systems that are not applicable to the proposed rule. Additionally, unlike the analysis in NSPS OOOO, the costs that the Division has identified are based on a Colorado specific cost analysis.

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*Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis**				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Flare	$18,169			
Freight/Engineering		$1,648		
Flare Installation		$6,980		
Auto Igniter	$1,648			
Pilot Fuel**			$768	
Maintenance			$2,197	
Subtotal Costs	$19,817	$8,628	$2,965	
Annualized Costs***	$2,747	$575	$2,965	$6,287

**Control cost evaluation based on 2008 Ozone Rulemaking cost survey and producer data. Control device costs were developed based on an oil and gas cost study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.*[28]
*** Pilot fuel costs $3.41/MMBtu (Henry Hub Spot Price - Aug. 2013)*
**** Annualized over 15 years at 5% ROR*

3.3.8.1.2 Lowering Statewide Condensate Tank Control Threshold (from 20 tpy to 6 tpy)

The Division is proposing to lower the uncontrolled VOC emission control threshold from 20 tpy down to 6 tpy on condensate storage tanks statewide. Based on an analysis of the Air Pollution Emissions Notice (APEN) database, the Division estimates that statewide there are 588 uncontrolled condensate tank batteries with VOC emissions over six tons per year. Of these 588 tanks, 396 are outside the NAA and the remaining 192 are within the current NAA.

Table 2: Condensate Tank Battery Analysis				
Tank Battery Type	Ozone NAA [count]	Outside NAA [count]	Cancelled Tanks [count]	Total Statewide Tanks [count]
Controlled Tanks	4,971	490		5,461
Uncontrolled Tanks	1,451	1,132	36	2,619
All Tanks	6,422	1,622	36	8,080
Uncontrolled Tanks (≥ 6 tpy)	192	396		588

Based on the reported uncontrolled actual VOC emissions for these 588 tanks, and assuming both that 75% of the VOC emissions are captured and sent to the flare,[29] and that the flare has a 95% destruction efficiency, the total VOC emission reduction associated with lowering the condensate tank threshold statewide is 5,162 tons per year.

[28] It has been suggested that the Division should have used the Producer Price Index to calculate an escalation from 2008 to 2013 costs. From 2008 to 2013, however, the Producer Price Index for the oil and gas field equipment sector grew at a slower rate than the CPI. Accordingly, the Division's analysis may actually overstate the increase in cost from 2008 to 2013.

[29] The costs and benefits associated with improving the capture percentage for controlled storage tanks are discussed below in Section 3.3.8.1.5.

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Table 3: Condensate Tank Battery Emissions Analysis for Lowering Statewide Threshold			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
NAA Uncontrolled Tanks (≥6 tpy)	2,355	677*	1,678
Outside NAA Uncontrolled Tanks (≥6 tpy)	4,890	1,406*	3,484
Totals:	7,245	2,083	5,162

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing 588 flare control devices is about $3.7 million dollars with an average cost effectiveness of about $716 per ton of VOC reduced. For the smallest individual tank battery subject to controls (6 tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 4: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices				
Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
588	$6,286.8	$3,696,638	5,162	$716

In addition to VOC reductions, this strategy will significantly reduce methane and ethane emissions from currently uncontrolled tanks. To calculate methane and ethane emission reductions, the Division determined the relative proportion of VOCs to methane and ethane based on reported average values from 30 natural gas liquid analyses submitted to the Division. Based on these analyses, methane/ethane emissions from condensate storage tanks are about 38% of the VOC emissions by weight. Accordingly, projected methane/ethane emission reductions from this proposed strategy are 1,963 tons per year or $1,884 per ton of methane/ethane reduced.

3.3.8.1.3 Requiring Controls for Produced Water and Crude Oil Tanks

As discussed above, the Division is proposing to eliminate the distinction between condensate tanks and other storage tanks. If the Commission adopts this proposal, crude oil tanks and produced water tanks with uncontrolled actual VOC emissions of six tons per year or greater will require controls. Because produced water and crude oil tanks are identified separately in the Division's APEN data base, the costs and benefits for these two types of storage tanks are broken out separately.

The Division is proposing that all statewide produced water tanks with uncontrolled VOC emissions over 6 tons/year be required to install emission controls. Some uncontrolled produced water tanks could be co-located at sites with condensate or crude oil tanks that have flare controls, but pressure and flow differences may require the installation of a separate flare control device for the water tank. Consequently, the control costs are based on the assumption that each water tank battery will install a new flare control device. Based on an analysis of the APEN

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database, the Division estimates that statewide there are 52 uncontrolled produced water tank batteries with VOC emissions over 6 tons/year.

Table 5: Produced Water Tank Battery Analysis	
Tank Battery Type	Total Statewide Water Tanks
Controlled Water Tanks:	338
Uncontrolled Water Tanks:	530
Total:	868
Uncontrolled Tanks (≥6 tpy)	52

Based on the reported uncontrolled actual emissions, the Division estimates that the total VOC emission reduction associated with controlling these produced water tanks statewide is 457 tons per year.

Table 6: Produced Water Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥6tpy)	641.4	184.4*	457

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing 52 flare control devices is about $327,000, with an average cost effectiveness of about $715 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 7: Produced Water Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
≥ 6tpy	52	$6,286.8	$326,914	457	$715

The Division is proposing that all statewide hydrocarbon liquid storage tanks with VOC emissions over six tons/year must install emission controls. Based on a recent analysis of 2013 APEN data, there are 67 reported crude oil tanks batteries statewide. Thirty seven of the tank batteries are already equipped with controls. Of the remaining thirty, eight are over the proposed six tons/year threshold. Given that approximately 5% of the total wells in the state report crude oil production to the Colorado Oil and Gas Conservation Commission (COGCC),[30] it appears

[30] Based on an analysis of 2010 COGCC data.

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likely that the Division's APEN database may be undercounting crude oil tanks, either because these tanks have not been reported or because they are being reported as condensate tanks.[31]

Table 8: Crude Oil Tank Battery Analysis	
Tank Battery Type	Total Statewide Crude Oil Tanks
Controlled Crude Oil Tanks	36
Uncontrolled Crude Oil Tanks	29
Total:	65
Uncontrolled Tanks (≥6 tpy)	8

The total VOC emission reduction associated with controlling these 8 crude oil tanks statewide is 118 tons per year.

Table 9: Crude Oil Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥6tpy)	165.2	47.5*	117.7

**Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.*

The annualized cost of installing eight flare control devices is about $50,294 dollars with an average cost effectiveness of about $427 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at $1,471 per ton of VOC reduced.

Table 10: Crude Oil Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
≥ 6tpy	8	$6,286.8	$50,294.4	117.7	$427

3.3.8.1.4 Requiring Controls During the First 90 Days of Production Statewide

Under current requirements owners and operators of new and modified storage tanks outside the NAA have 90 days after the date of first production to determine if emissions from the tank trigger the requirement to install a control. Because production is typically at its highest during this initial period, significant emissions can occur before controls are installed. To address this

[31] Prior to 2008 crude oil storage tanks were exempt from APEN reporting requirements, which may explain in part the small numbers of tanks identified in the system.

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issue in the NAA, the Commission mandated in the 2008 Ozone Action Plan that all condensate tanks be controlled during the first 90 days. The Division is now proposing to expand this requirement to storage tanks throughout the state.

To calculate the cost effectiveness of this strategy, the Division first determined the number of new and modified storage tanks outside the NAA based on reported APEN data for the period of 2010-2012. Based on this APEN data, there are on average 141 new and modified tanks each year, with yearly reported uncontrolled actual emissions of 7,370 tons VOC. Assuming that emissions during the first 90 days equal 1/4th of the annual reported emissions,[32] total uncontrolled actual VOC emissions from these tanks during the first 90 days is 1,842.5 tons. Assuming enhanced capture efficiency for these new tanks (see subsection 3.3.8.1.5 of this Regulatory Analysis) the flare control efficiency is 95%, and thus the calculated benefit from expanding the first 90 day control requirement to tanks outside the NAA will be 1,750.4 tons per year.

While the Division estimates that there are 141 new and modified storage tanks outside the NAA each year, the majority of these, 84, will require control devices regardless of this strategy since their uncontrolled actual emissions are over six tpy. For these 84 tanks, the cost of operating a flare during the first 90 days will be approximately 25% of the total annualized cost, or $1,571.70 per tank. For the remaining 57 tanks with emissions less than six tons/year, because controls for these tanks will only need to be in place for 90 days, the Division assumes that each flare can control 3 tanks per year, which means that 19 new flares are required to comply with this proposed strategy. For other applications, the annualized cost of a flare is estimated to be $6,287. Since flares required for this application will be relocated three times a year, the Division assumes an additional $3,000 in annual relocation costs, for a total annualized cost of about $9,287 per flare. Based on the emission reductions calculated above, the total cost effectiveness of this requirement is $176/ton of VOC reduction.

Table 11: Control Cost Estimates for Flare Control Devices Required During the First 90 Days of Production

Storage Tank Threshold [tpy]	Number of New Storage Tanks	Number of New Flares	Annualized Cost Each Flare	Total Flare Cost	Total VOC Reduction [tons/year]	VOC Control Cost [$/ton]
<6	57	19	$9,286.8	$176,449.2	44.7	$3,947
≥6	84	84	$1,571.7	$132,022.8	1,705.7	$77
	141			$308,472	1,750.4	$176

Using the methodology discussed in subsection 3.3.8.1.2 of this Regulatory Analysis, the projected methane/ethane emission reductions from this strategy is 665.5 tons per year or $464 per ton of methane/ethane reduced.

[32] Because reported emissions typically are based on a calculation assuming a standard rate of production decline after the first 90 days, actual emissions during the first 90 days could be much higher.

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3.3.8.1.5 Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order for storage tank control requirements to be effective, emissions from the tank must be routed to the control device. Historically the Division has assumed that 100% of a tank's emissions will be captured and routed to the control device, typically a flare, resulting in a 95% reduction of emissions. Field observations using IR cameras and other methodologies indicate that in actuality emissions from controlled storage tanks often escape through the thief hatches and pressure relief valves (PRV) and therefore are not being combusted in the flare. This occurs when the tank cannot adequately contain the flashing emissions that occur when pressurized liquids from the separator are dumped into the atmospheric tank. To address this issue, the Division is proposing new regulatory language clarifying that all emissions from controlled storage tanks must be routed to the control device and that these tanks must be operated without venting emissions from thief hatches, PRVs and other openings, except when venting is reasonably necessary for maintenance, gauging, or safety of personnel and equipment.

To assure compliance with these capture standards, the Division's proposal requires that owners and operators of controlled storage tanks implement a STEM plan. Pursuant to the STEM plan, owners and operators must evaluate and employ appropriate control technologies and/or operational practices designed to meet the proposed capture requirements, and certify that these technologies and/or operational practices are designed to minimize emissions from the tank. The Division's STEM proposal also requires implementation of a two-pronged monitoring strategy involving a weekly[33] auditory, visual, and olfactory (AVO) inspection for all controlled tanks, and a periodic instrument based monitoring for tanks using EPA Reference Method 21, an IR camera or other Division approved monitoring device or method. As proposed, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 12: Proposed Tiering for Instrument Based Tank Inspections

Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
≥ 6 tpy to ≤ 12 tpy	Annually
> 12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

In assessing the cost effectiveness of the proposed requirements, the Division first calculated the costs associated with implementing technological and/or operational changes at controlled tanks. For the purposes of this analysis the Division assumed that all tanks with uncontrolled actual emissions greater than or equal to 6 tons per year would need to be controlled consistent with the Division's proposal discussed in Section 3.3.1 of this Regulatory Analysis. Based on reported data, there are currently 5,310 storage tanks statewide with emissions greater than or equal to 6 tons per year. While the Division's proposal does not specify the type of technology or operational practices that operators will use, for the purposes of this analysis the Division

[33] There is an exception for the weekly inspection requirement where the operator loads out liquids from the storage tank on less than a weekly basis. In these circumstances the operator must conduct the inspection whenever liquids are loaded out, but no less often than every 30 days. Typically liquids are loaded out multiple times in a given week, meaning that for the majority of the tanks AVO inspections will be required weekly.

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assumed that buffer bottle technology would be installed on each of the subject tanks.[34] The buffer bottle technology utilizes a small tank that is installed after the separator which allows for a secondary flash of pressurized liquids prior to dumping into the storage tank. The second-stage flash reduces the pressure of the liquids going to the tank and thereby helps to ensure that the tank can adequately handle the flashing emissions that occur when the liquids are brought to atmospheric pressure. Based on industry provided information, the estimated annual cost of a buffer bottle is set forth in Table 13.[35]

Table 13: Annualized Cost Analysis for Buffer Bottle

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Buffer Bottle	$11,500			
Freight/Engr		$600		
Installation		$2,280		
Maintenance			$2,500	
Subtotal Costs	$11,500	$2,880	$2,500	
Annualized Costs*	$1,593.8	$192	$2,500	$4,285.8

** Annualized over 15 years at 5% ROR*

The Division also calculated the costs associated with conducting enhanced inspections. Based on the proposed tiering, operators will need to conduct 24,840 tank inspections per year.[36]

Assuming that each inspection takes two hours and utilizing a $103/hour [37] in-house inspection cost and a $134/hour contractor inspection cost (30% profit added to in-house rate), the total annual cost associated with conducting enhanced inspections under the proposed rule is $5,392,010, which equates to $1,015.4 per year for each tank that will be subject to STEM.

[34] Based on discussions with industry representatives during the stakeholder process there may be other less costly technologies and operational practices that could be used to ensure good emission capture from tanks such as replacing seals, more frequent maintenance, changing the size of piping going to the storage tank, and timing well dumps to avoid overloading the separator. There may also be other options for new facilities that allow for the capture and sale of additional gas such as the installation of high-low pressure separators or utilizing a liquids gathering system that eliminates atmospheric storage tanks at well sites.

[35] For this Regulatory Analysis, the Division increased the capital and maintenance costs for buffer bottles based on input from industry stakeholders.

[36] In practice, many operators are already conducting IR camera inspections at storage tanks, however, the Division does not have information regarding how many inspections are currently occurring.

[37] The hourly inspection cost is discussed below in Table 20.

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Table 14: Instrument Based Tank Inspections Based on Proposed Tiering					
Tank Uncontrolled Actual VOC Emissions	Inspection Type/Hourly Rate	Number of Tanks	Inspection Frequency	Number of Inspections	STEM Inspection Costs
>6 tpy to ≤ 12 tpy	In-House/$103	1,085	Annually	1,085	$223,510
>12 tpy to ≤ 50 tpy	In-House/$103	2,595	Quarterly	10,380	$2,138,280
> 50 tpy	In-House/$103	745	Monthly	8,940	$1,841,640
	Subtotal:	***4,425***		***20,405***	***$4,203,430***
>6 tpy to ≤ 12 tpy	Contractor/$134	323	Annually	323	$86,564
>12 tpy to ≤ 50 tpy	Contractor/$134	329	Quarterly	1,316	$352,688
> 50 tpy	Contractor/$134	233	Monthly	2,796	$749,328
	Subtotal:	***885***		***4,435***	***$1,188,580***
	Total:	**5,310**		**24,840**	**$5,392,010**

The Division also considered whether additional costs should be included for conducting periodic AVO inspections. Because these activities are already required for controlled storage tanks under existing regulation, the Division did not include these costs in determining the total cost of the proposed capture requirements. The Division also did not include costs associated with certifying that selected technologies and/or operational practices are designed to minimize emissions, since costs for certifying capture efficiency are already included in the annualized cost of required flares.[38] Accordingly, the total projected annual cost of the proposed capture requirements based on the use of a buffer bottle and enhanced monitoring requirements is $5,301.2 per tank.

To calculate the projected emissions reduction from the proposed capture requirements, the Division assumed a current capture rate of 75% for controlled tanks based on analytical work that the Division, EPA and others have performed. Based on this capture rate, the Division calculated the emissions reduction that would occur if the capture rate were increased to 100% using the following equation:

Emission reduction = [uncontrolled VOC*(1-(0.75*0.95))] – [uncontrolled VOC *(1-0.95)],

Using this equation as applied to the reported uncontrolled actual emissions from the 5,310 storage tanks statewide with emissions greater than or equal to six tons per day, the projected emission reduction from the proposed capture requirements is 53,386 tons per year. Included in the total are 33 existing crude oil tanks with flare controls (>6 tpy) and 8 crude oil tanks that would need flare controls (>6 tpy).

[38] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008, at pg. 8.

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Table 15: STEM Emission Control Analysis (Statewide)				
Number of Tanks ≥6 tpy	Uncontrolled VOC [tons/year]	Controlled VOC (@ 71.25% Control) [tons/year]	Controlled VOC (@ 95% Control) [tons/year]	VOC Reduction [tons/year]
5,269	221,569	63,701	11,078	52,623
41	3,213	924	161	763
5,310	224,782	64,625	11,239	53,386

Applying this reduction to the costs calculated above, the cost effectiveness of these proposed requirements is $527/ton of VOC.

Table 16: STEM Control Cost Estimates (Statewide)					
Type of Technology	Number of Tanks	Each Device Annualized Costs [$/year]	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
Buffer Bottle	5,310	$5,301.2	$28,149,372	53,386	$527.3

Using the average ratio of VOC to methane/ethane emissions from storage tanks, the projected methane/ethane reduction from this strategy is 20,287 tons per year, which equates to $1,388 per ton of methane/ethane reduced.

During the Division's stakeholder process leading up to the Commission's rulemaking hearing, certain parties have raised questions about the Division's assumption that currently controlled tanks have a 75% capture efficiency. In light of this the Division has also calculated cost effectiveness based on the assumption that current capture efficiency is 50% and 95%. For the 50% case, current controlled emissions would be 118,011 tpy VOC. Accordingly, the emission reduction benefit from increasing capture to 100% would be 106,772 tons per year (118,011-11,239) and the cost effectiveness would be $264/ton VOC[39]. For the 95% capture scenario, current controlled emissions would be 21,916 tons per year VOC and the emission reduction would be 10,677 tons per year (21,916-11,239). Under this scenario, the cost effectiveness would be $2,636/ton VOC[40].

While the buffer bottle technology offers a good alternative in a retrofit situation for reducing pressures to the tank and increasing emission capture, for new facilities, installation of a high-low pressure (HLP) separator to satisfy STEM may prove to be a better performing option. This equipment allows for two stages of separation of the gas and the liquids instead of the single stage separation accomplished in traditional separators. By adding a second stage of separation, the pressure of the liquids sent to the tank is significantly reduced, thereby helping to ensure

[39] This may overestimate the cost effectiveness given that if the current capture rate were only 50% additional costs could be required to increase the capture rate to 100%.
[40] This is a conservative calculation given that if the current capture rate were 95% it is likely that the control costs to increase the capture rate to 100% would be significantly less.

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complete capture of flashing emissions instead of venting a portion of the emission stream through the thief hatch or PRV. Additionally, rather than being routed to the flare, as in the case of the buffer bottle technology, gas from the second stage of separation can be sent to a vapor recovery unit (VRU), recompressed and sent to the sales line, resulting in increased product recovery. Based on information provided from industry, the Division has calculated that the annual cost of a HLP separator w/VRU is about $19,341.

Table 17: Annualized Cost Analysis for HLP Separator

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
HLP/VRU	$90,000			
Freight/Engr		$1,648		
HLP/VRU Installation		$11,154		
Maintenance			$9,396	
VRU Recovered NG *			$(3,382)	
Subtotal Costs	$90,000	$12,802	$6,014	
Annualized Costs**	$12,474	$853	$6,014	$19,341

** Recovered NG fuel costs $3.5/MCF (Henry Hub Spot Price - Aug. 2013) and average tank battery size of 63.2 tpy – based on 3-yr average of APEN data on storage tanks ≥6 tpy (uncontrolled VOC).*

*** Annualized over 15 years at 5% ROR*

Unlike the retrofit situation analyzed above where the emission controls are already in place, it is appropriate in new installations to aggregate the cost of the HLP separator w/VRU with the costs of the control unit (flare) to determine the overall cost of controlling emissions from the tank. Based on the $6,286.8 annual cost of a flare and annual instrument based monitoring costs of $1,015.4 per tank, the total annual control costs for a new tank will be $26,643 per year.

Based on an analysis of reported data for new tanks during the past three years, the average uncontrolled actual emissions of a new tank is 63.2 tpy. Assuming a 95% overall control efficiency, equipping a tank with an HLP separator and a flare will reduce the emissions from an average new tank by 60 tpy. This yields a cost effectiveness of $444 per ton VOC reduced. If instead, the highest cost scenario (using a six tpy tank) is assumed, the cost effectiveness is $4,674 per ton VOC. For methane ethane the cost per ton is $1,168 per ton reduced on average.

3.3.8.1.6 LDAR Requirements for Compressor Stations and Well Production Facilities

Commission Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement LDAR programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct periodic inspections using EPA Reference Method 21[41] and repair leaks within a prescribed time frame.

[41] While EPA Reference Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

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Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include LDAR requirements for these facilities.[42] To address these emissions, the Division is proposing regulatory changes that would establish LDAR requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with EPA Reference Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The proposed regulation establishes a tiered system to determine inspection frequency. For compressor stations the tiering is based on the uncontrolled actual leak emissions at the facility as follows:

Table 18: Proposed Tiering for Leak Inspections at Compressor Stations

Component Leak Uncontrolled Actual VOC Emissions	Inspection Frequency
≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

For well production facilities the proposed tiering is based on uncontrolled actual emissions from the largest emitting storage tank at the facility as set forth in Table 19. The tiering is based on tank emissions rather than uncontrolled actual leak emissions in order to create an EPA Reference Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of STEM emission capture requirements.[43]

[42] Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

[43] Because there may be a limited number of instances where well production facilities don't have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this Regulatory Analysis, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the same rate, the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

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Table 19: Proposed Tiering for Leak Inspections at Well Production Facilities	
Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
< 6 tpy	One Time (and Monthly AVO)
≥ 6 tpy to ≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed LDAR requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.[44] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in Table 20 below, the total annual cost for each inspector will be $193,629, which equates to an hourly inspection rate of $103.

Table 20: LDAR Inspector – Annualized Cost Analysis			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$122,000		
FLIR Camera Maintenance/Repair		$7,500	
Photo Ionization Detector	$5,000		
Vehicle (4x4 Truck)	$22,000		
Inspection Staff		$75,000	
Supervision (@ 20%)		$15,000	
Overhead (@10%)		$7,500	
Travel (@15%)		$11,250	
Recordkeeping (@10%)		$7,500	
Reporting (@10%)		$7,500	
Fringe (@30%)		$22,500	
Subtotal Costs	$149,000	$153,750	
Annualized Costs*	$39,879	$153,750	$193,629
**over 5 years at 6% ROR*		Annualized Hourly Rate	$103

Initially, the Division assumed that conducting inspections in-house would be the lowest cost option since it would not involve additional profit to be paid to a contractor. For smaller companies that cannot fully utilize an IR camera, however, conducting inspections in-house may not be the most cost effective option. To account for this in this Regulatory Analysis, the Division assumed a 30% profit margin for contractors, which it added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection ($134 per hour).

[44] This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

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Second, the Division calculated the average amount of time that it would take to conduct an EPA Reference Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.[45]

For compressor stations, the Division used reported component counts for compressor stations within each of the tiers identified in Table 18 above. Based on these counts, and the inspection times per component discussed above, the Division calculated that the total inspection time per compressor station facility tier are as follows:

Table 21: Calculated Inspection Time Compressor Station Leak Inspections

Component Leak Uncontrolled Actual VOC Emissions	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	21.2 hours	10.6 hours
>12 tpy to ≤ 50 tpy	56.2 hours	28.1 hours
> 50 tpy*		

* *there are currently no compressor stations in Colorado with calculated leaks at this level*

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the NAA and well production facilities outside the NAA. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 22.

Table 22: Calculated Inspection Times for Well Production Facility Leak Inspections

Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
NAA	12.2 hours	6.1 hours
Rest of the State	6.8 hours	3.4 hours

[45] Based on the Division's own IR camera inspections, and reports from various parties during the stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

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In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 20, for the purposes of this Regulatory Analysis the Division also assumed an additional three hours in travel time for each inspection outside the NAA. This assumption reflects the fact that certain well sites in basins outside the NAA may be remote, requiring additional travel.

Next, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For compressor stations the Division assumed that all inspections would be conducted by 3rd party contractors. For well production facilities, the Division assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use contractors.[46] Because the proposed rule also requires owners and operators of well production facilities that are not subject to monthly instrument monitoring to conduct monthly AVO inspections the Division considered whether additional costs should be included for these inspections. Based on information provided during the Division's stakeholder process leading up to the Commission's rulemaking hearing it appears that operators already routinely conduct such inspections and repair leaks identified during these AVO inspections. Additionally, while the proposed rule may impose recordkeeping and reporting requirements associated with these AVO inspections, given the relatively small number of leaks that are expected to be identified, and the fact that any recordkeeping can be readily included in existing inspection and maintenance records the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In its Initial EIA, the Division did not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective, assuming that the cost to repair and re-monitor would be offset by the cost savings from capturing additional product as a result of repairs. Based on information that the Conservation Groups submitted as part of their Pre-Hearing Statement to the Commission, it appears that the Division's assumption in the Initial EIA was reasonable. See Exhibit A to CG-PHS, Testimony of David McCabe at pg. 8. Nevertheless, for this Regulatory Analysis, the Division has included both repair costs and estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a $66.24 hourly rate to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the both type of component and the complexity of the repair.[47] To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking

[46] Based on this assumption, 3,545 inspections per year will be conducted using 3rd party contractors.
[47] See "Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards," Bradley Nelson and Heather Brown, April 17, 2012; "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011.

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component rate for facilities subject to annual inspections.[48] To account for the projected additional emission reductions from quarterly and monthly inspection schedules the Division used annual leaking component rates of 1.77% for facilities with quarterly inspection schedules and 2.36% for facilities with monthly inspection schedules. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to MCF of natural gas, with a price of $3.50/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible.

Based on this methodology, the calculated annual inspection costs for compressor stations are set forth in Table 23.

Table 23: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Annual Inspection Frequency	Time per IR Camera Inspection [hours]	Total Annual Inspection Time [hours]	Total Annual Inspection Cost
≤ 12 tpy	147	1	10.6	1,558.2	$208,799
>12 to ≤ 50 tpy	53	4	28.1	5,957.2	$798,265
≥ 50 tpy	0	12			
Total:	200			7,515.4	$1,007,064

Repair costs associated with these inspections are set forth in Table 24 and fuel savings associated with these repairs are set forth in Table 25.

Table 24: Compressor Station Leak Repair Costs

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Leak Repair Rate [$/hr]	Number of Leaks per Compressor Station	Total Leak Repair Time per CS [hours]	Total Annual Repair Cost
≤ 12 tpy	147	$66.24	30.1	23.0	$223,957.4
>12 to ≤ 50 tpy	53	$66.24	119.4	85.2	$299,113.3
≥ 50 tpy	0	$66.24	-	-	-
Total:	200				$523,071

[48] This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry's Proposed Revisions to Colorado's Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits (See footnote 41).

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Table 25: Compressor Station Recovered Natural Gas Value from Leak Repairs					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Total Recovered Natural Gas per CS [tons/year]	Value of Natural Gas [$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
≤ 12 tpy	147	10.2	$3.5	35.8	$187,875
>12 to ≤ 50 tpy	53	36.4	$3.5	35.8	$241,729
≥ 50 tpy	0		$3.5	35.8	-
Total:	200				$429,604

The total net costs for compressor station LDAR are set forth in Table 26.

Table 26: Compressor Station Net Leak Inspection and Repair Costs					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≤ 12 tpy	147	$208,799	$223,957.4	$187,875	$244,882
>12 to ≤ 50 tpy	53	$798,265	$299,113.3	$241,729	$855,650
≥ 50 tpy	0		-	-	-
Total:	200	$1,007,064	$523,071	$429,604	$1,100,531

For well production facilities the estimated annual inspection costs are set forth in Table 27.

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Table 27: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin*	Number of Facilities	Annual Inspection Frequency	Total Number of Inspections	Inspection Time Per Inspection [hours]	Total Annual Inspection Cost
In-House Inspections at $103/hour						
> 6 to ≤12	DJ/NAA	945	1	945	6.1	$593,744
> 12 to ≤ 50	DJ/NAA	2,447	4	9,788	6.1	$6,149,800
> 50	DJ/NAA	693	12	8,316	6.1	$5,224,943
	Subtotal:	4,085		19,049		$11,968,487
In-House Inspections at $103/hour						
> 6 to ≤12	ROS	173	1	173	6.4**	$114,042
> 12 to ≤ 50	ROS	176	4	704	6.4	$464,077
> 50	ROS	115	12	1,380	6.4	$909,696
	Subtotal:	464		2,257		$1,487,815
Contract Inspections at $134/hour						
> 6 to ≤12	DJ/NAA	150	1	150	6.1	$122,610
> 12 to ≤ 50	DJ/NAA	153	4	612	6.1	$500,249
> 50	DJ/NAA	118	12	1,416	6.1	$1,157,438
	Subtotal:	421		2,178		$1,780,297
Contractor Inspections at $134/hour						
> 6 to ≤12	ROS	140	1	140	6.4**	$120,064
> 12 to ≤ 50	ROS	148	4	592	6.4	$507,699
> 50	ROS	52	12	624	6.4	$535,142
	Subtotal:	340		1,356		$1,162,905
	Total:	**5,310**		**24,840**		**$16,399,504**

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Repair costs associated with these inspections are set forth in Table 28 and fuel savings associated with these repairs are set forth in Table 29.

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Table 28: Well Production Facility Leak Repair Costs					
Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities	Number of Leaks per Tank	Total Leak Repair Time per Tank [hours]	Total Annual Repair Cost
> 6 to ≤12	DJ/NAA	1,095	17.0	11.8	$855,887
> 12 to ≤ 50	DJ/NAA	2,600	25.5	17.7	$3,048,365
> 50	DJ/NAA	811	34.1	23.6	$1,267,807
	Subtotal:	4,506			$5,172,059
> 6 to ≤12	ROS	313	9.7	7.7	$159,645
> 12 to ≤ 50	ROS	324	14.5	11.6	$248,956
> 50	ROS	167	19.4	15.4	$170,356
	Subtotal:	804			$578,957
	Total:	**5,310**			**$5,751,016**

Table 29: Well Production Facility Recovered Natural Gas Value from Leak Repairs						
Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities	Total Recovered Natural Gas per tank [tons/year]	Value of Natural Gas [$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
> 6 to ≤12	DJ/NAA	1,095	4.6	$3.5	35.8	$631,136
> 12 to ≤ 50	DJ/NAA	2,600	7.0	$3.5	35.8	$2,280,460
> 50	DJ/NAA	811	9.3	$3.5	35.8	$945,050
	Subtotal:	4,506				$3,856,646
> 6 to ≤12	ROS	313	4.6	$3.5	35.8	$180,407
> 12 to ≤ 50	ROS	324	6.8	$3.5	35.8	$276,061
> 50	ROS	167	9.1	$3.5	35.8	$190,418
	Subtotal:	804				$646,886
	Total:	**5,310**				**$4,503,532**

The total net costs for well production facility station LDAR are set forth in Table 30.

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Table 30: Well Production Facility –Net Leak Inspection and Repair Costs						
Uncont. VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Total Annual Inspection Cost		Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
		In-House	Contractor			
> 6 to ≤12	DJ/NAA	$593,744	$122,610	$855,887	$631,136	$941,105
> 12 to ≤ 50	DJ/NAA	$6,149,800	$500,249	$3,048,365	$2,280,460	$7,417,954
> 50	DJ/NAA	$5,224,943	$1,157,438	$1,267,807	$945,050	$6,705,138
	Subtotal:	$11,968,487	$1,780,297	$5,172,059	$3,856,646	$15,064,197
> 6 to ≤12	ROS	$114,042	$120,064	$159,645	$180,407	$213,344
> 12 to ≤ 50	ROS	$464,077	$507,699	$248,956	$276,061	$944,671
> 50	ROS	$909,696	$535,142	$170,356	$190,418	$1,424,776
	Subtotal:	$1,487,815	$1,162,905	$578,957	$646,886	$2,582,791
	Total:	**$13,456,302**	**$2,943,202**	**$5,751,016**	**$4,503,532**	**$17,646,988**

Additionally, based on information in the Division's APEN reporting system, there are 2,799 well production facilities with uncontrolled actual storage tank emissions less than or equal to 6 tons per year that will be subject to a one-time instrument based inspection. The one-time cost for inspecting these facilities is estimated to be $1,639,239.[49]

Table 31: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities and Inspections	Inspection Time Per Inspection [hours]	Inspection Type/Hourly Rate	Total Annual Inspection Cost
≤ 6	DJ/NAA	1,598	6.1	In-House/$103	$1,004,023
≤ 6	ROS	500	3.4	In-House/$103	$175,100
	Subtotal:	2,098			$1,179,123
≤ 6	DJ/NAA	389	6.1	Contractor/$134	$317,969
≤ 6	ROS	312	3.4	Contractor/$134	$142,147
	Subtotal:	701			$460,116
	Total:	**2,799**			**$1,639,239**

[49] To calculate these costs the Division used the same methodology applicable to periodic inspection costs, except that it did not include additional travel time for facilities outside the NAA based on the assumption that companies could coordinate these one-time inspections with visits to the facilities for other purposes.

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The Division recognizes that there are likely additional facilities not included in the APEN database that will be subject to this one-time inspection requirement, thereby increasing the overall cost of the one-time inspection requirement. Roughly speaking the additional cost for one-time inspections will be proportional to the number of additional facilities, so that if there are twice the number of facilities, the overall cost will be approximately double. However, because the expected emission reduction benefit will increase roughly at the same rate as the cost of inspections the overall cost-effectiveness of the one-time inspection requirement should remain approximately the same regardless of the number of facilities.

Finally, the Division calculated the cost effectiveness of the proposed LDAR requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections.

Using this information the Division calculated that the total emission reductions from leaks at compressor stations will be 1,107 tpy VOC and 2,321 tons per year methane/ethane.

Table 32: Compressor Station Leak Inspection Emission Reductions

Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	LDAR Program Reduction %	Fugitive VOC Emissions for each CS tier [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each CS tier [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	147	40%	10.1	588.0	15.5	911.4
> 12 to ≤ 50	53	60%	16.4	519.4	44.3	1,409.8
> 50		80%				
	200			1,107.4		2,321.1

Based on these reductions, the cost effectiveness of conducting leak inspections at compressor stations is estimated to be $994/ton VOC and $474/ton methane/ethane.

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Table 33: Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21							
Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	Total Net Annual Inspection & Repair Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane -Ethane Control Cost [$/ton]
≤ 12	147	$244,882	40%	588.0	$416	911.4	$269
> 12 to ≤ 50	53	$855,650	60%	519.4	$1,647	1,409.8	$607
> 50			80%				
	200	$1,100,531		1,107.4	$994	2,321.2	$474

For well production facilities the total emission reductions is estimated to be 14,015 tpy VOC and 21,927 tpy methane/ethane.

Table 34: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
DJ/NAA						
> 6 to ≤ 12	1,095	40%	4.6	1,971.0	7.0	3,066.0
> 12 to ≤ 50	2,600	60%	4.6	7,280.0	7.0	10,920.0
> 50	811	80%	4.6	3,000.7	7.0	4,541.6
Subtotal:	**4,506**			**12,251.7**		**18,527.6**
Remainder of State						
> 6 to ≤ 12	313	40%	3.9	500.8	7.5	939.0
> 12 to ≤ 50	324	60%	3.9	745.2	7.5	1,458.0
> 50	167	80%	3.9	517.7	7.5	1,002.0
Subtotal:	**804**			**1,763.7**		**3,399.0**
Total:	**5,310**			**14,015.4**		**21,926.6**

Based on these reductions, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be $1,259/ton VOC and $805/ton methane/ethane.

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Table 35: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21							
Uncont. VOC at Tank Battery Tier [tpy]	Number of Tanks	Total Net Annual Leak Inspection & Repair Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane -Ethane Control Cost [$/ton]
DJ/NAA							
> 6 to ≤ 12	1,095	$941,105	40%	1,971.0	$477	3,066.0	$307
> 12 to ≤ 50	2,600	$7,417,954	60%	7,280.0	$1,019	10,920.0	$679
> 50	811	$6,705,138	80%	3,000.7	$2,235	4,541.6	$1,476
Subtotal:	4,506	$15,064,197		12,251.7	$1,230	18,527.6	$813
ROS							
> 6 to ≤ 12	313	$213,344	40%	500.8	$426	939.0	$227
> 12 to ≤ 50	324	$944,671	60%	745.2	$1,268	1,458.0	$648
> 50	167	$1,424,776	80%	517.7	$2,752	1,002.0	$1,422
Subtotal:	804	$2,582,791		**1,763.7**	$1,464	**3,399.0**	$760
Total:	5,310	$17,646,988		14,015.4	$1,259	21,926.6	$805

Additionally, for the 2,799 well production facilities with uncontrolled actual storage tank emissions equal to or less than 6 tons per year that will be subject to a one-time instrument based inspection, the calculated one-time benefit is 4,876 tons VOC and 8,000 tons methane/ethane, assuming a 40% reduction. Based on these reductions, for the one-time inspections of well production facilities with tanks that are less than six tons per year the cost effectiveness of the proposed rule is calculated to be $409/ton VOC and $249/ton methane/ethane.

In addition to the component LDAR requirements for compressor stations and well production facilities, the Division's proposal includes additional requirements designed to reduce leaks from open ended lines and valves, reciprocating compressors, and wet seal centrifugal compressors. These requirements mirror existing cost-effective requirements set forth in NSPS OOOO and other federal rules.

For open ended valves and lines at well production facilities and compressor stations, the proposal requires that each such valve or line be equipped with a cap, blind flange, plug or second valve commencing January 1, 2015. Alternatively, the Division's proposal allows operators to treat open-ended lines and valves as components and monitor them in accordance with the proposed LDAR requirements. As part of its LDAR cost effectiveness analysis detailed above, the Division included the costs of inspecting and repairing open ended lines and valves in its overall calculation. While the Division has not identified specific information regarding the costs and emission reduction benefits from equipping open ended lines with a cap, blind flange, plug or second valve it notes that the requirement has been included in a multitude of federal air quality rules, including NSPS VV, NSPS VVa, MACT H, MACT CC, MACT TT, MACT YY, MACT GGG, MACT III, and MACT MMM, dating back as far as 1983. Based on this

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widespread prevalence in federal rules the Division believes that the proposal represents a simple and cost-effective strategy to reduce emissions from open-ended lines and valves. However, to the extent that it is not cost effective in a specific case operators can employ the monitoring option allowed for under the proposed rule.

For centrifugal compressors, the Division's proposal requires that hydrocarbon emissions from wet seal fluid degassing systems be reduced by 95% beginning January 1, 2015. In its updated technical support document for NSPS OOOO, EPA analyzed the cost-effectiveness of this strategy and found that accounting revenues from the capture of additional product, implementation of this strategy would on a per unit basis reduce VOC emissions by 19.5 tpy, methane emissions by 216.2 tpy, and result in a net cost savings of $46,974.[50]

With respect to reciprocating compressors, the Division's proposal requires that commencing January 1, 2015, the rod packing for reciprocating compressors located at compressor stations be replaced every 26,000 hours of operation or every 36 months. As with the requirement for centrifugal compressors, EPA analyzed this proposed strategy as part of the adoption of NSPS OOOO and found that it was a cost-effective way to reduce VOC and methane emissions. Specifically, EPA found that per compressor the strategy reduces VOC emissions by 1.9 tons per year and methane emissions by 6.8 tons per year, at a net cost of $43 per ton of VOC reduced and $12 per ton of methane reduced.[51]

3.3.8.1.7 Auto Igniter Requirements on Existing Flare Control Devices Outside the NAA

Unlike the NAA, flares used to control emissions at condensate tank batteries and glycol dehydration units outside the NAA are not required to have auto-igniters. The Division is proposing that all flares used to control emissions at condensate tank batteries and glycol dehydration units statewide should have auto igniters. Based on an analysis of the APEN database, the Division estimates the statewide number of existing flare control devices without auto-igniters on condensate tank batteries, glycol dehydration, produced water tanks, and crude oil tanks is 796. The reported uncontrolled actual emissions from these units are 53,101.1 tons per year VOC.

The estimated annualized cost for an auto-igniter is $475 based on information that the industry provided to the Division in 2008, adjusted for inflation.[52]

[50] See APCD-PHS Ex. HHHH pp. 6-1—6-3
[51] See initial technical support document for NSPS OOOO (submitted as DGS-PHS Ex. NN) at pp. 6-12—6-17.
[52] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

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Table 36: Auto Igniter Control Device – Retrofit Cost Analysis				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Auto Igniter	$1,648			
Freight/Engineering		$200		
Flare Installation		$500		
Maintenance			$200	
Subtotal Costs	$1,648	$700	$200	
Annualized Costs*	$228.4	$46.7	$200	$475

** Annualized over 15 years at 5% ROR*

The Division estimates that a flare without an auto-igniter could experience about 3% pilot light downtime (262.8 hours) over a one year period. During the downtime period, any VOC emissions routed to the flare control device are uncontrolled. Based on the total uncontrolled actual emissions of 53,101.1tons per year VOC from units equipped with flares without auto-igniters, the emissions during this downtime period will be 1,593.1 tons of VOC. The Division assumes that as a result of the installation of an auto-igniter, the amount of downtime can be eliminated, for a total emission reduction of 1,251.7 tons/year. Given that the annualized cost of installing 796 auto-igniters is about $378,100 the estimated cost effectiveness of this strategy is about $302 per ton of VOC reduced.

Table 37: Auto Igniter Emission Reduction Estimates				
Source Type for Existing Flare Controls	Number of Auto Igniters	Uncontrolled VOC [tpy]	Uncontrolled VOC Using 3% Downtime [tpy]	Total VOC Reduction [tpy]
Condensate Tanks	490	31,170.6	935.1	666.3
Dehydrators	131	16,372.0	491.2	466.6
Produced Water Tanks	172	4,842.2	145.3	103.5
Crude Oil Tanks	3	716.3	21.5	15.3
	796	53,101.1	1,593.1	1251.7

** Dehydrator flares assumed to have 100% capture and 95% destruction – thus 95% control. Tank flares are assumed to have 75% capture and 95% destruction – thus 71.25% control.*

Table 38: Auto Igniter Control Cost Estimates (Outside NAA)				
Number	Each Auto-Igniter Annualized Costs	Total Annualized Costs	VOC Reduction* [tons/year]	Control Costs [$/ton]
796	$475	$378,100	1,251.7	$302

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3.3.8.2 Expanding Low Bleed Pneumatics Requirements Statewide

As part of the 2008 Ozone Action Plan the Commission adopted regulatory requirements mandating the use of low bleed pneumatic controllers in the NAA. The current proposal would expand this requirement statewide.

To estimate the costs and benefits of this proposed strategy, the Division estimated the number of high-bleed pneumatic devices based on Independent Petroleum Association of the Mountain States (IPAMS) survey data from 2006, which identified the average number of such devices per well. The Division then scaled this number up based on 2012 COGCC well count data. Based on this methodology, there are 9,877 high-bleed pneumatic devices outside the NAA. Assuming a 95% replacement rate, the proposed rule will result in the replacement of 9,384 high bleed devices with low bleed devices. Based on this count, and the average emission reductions per device replaced identified in the IPAMS survey, the projected benefit from the proposed expansion of the current NAA low bleed pneumatic rule will be approximately 14,921 tons per year VOC (40.9 tons per day). Based on this information and assuming an 80/20 ratio of methane/ethane to VOC by volume, the estimated methane/ethane reduction from this strategy is 17,100 tons per year.

The average retrofit cost of a high-bleed pneumatic device is based on costs from the 2008 cost study[53] adjusted for inflation. Utilizing this methodology, the annualized cost for each replaced device is $169. However, because the reduced bleed rate results in more natural gas being sold, operators will receive additional revenue as a result of the installation of a low bleed device. Based on the emission reduction data from the IPAMS survey and August 2013 spot prices for natural gas, the estimated average value of the recovered gas will be $1,268 for each device replaced. As a result, the net annual gain is $1,084 per replaced device. Based on this projected net gain, this strategy will pay for itself in approximately one year and two months.

Table 39: Replace High-Bleed Pneumatics with Low-Bleed Pneumatics – Annualized Cost Analysis*

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Low/No Bleed Device*	$1,033			
Labor		$387		
Value of NG Saved**			$(1,268)	
Maintenance			$16	
Subtotal Costs	$1,033	$387	$(1,253)	
Annualized Costs***	$143	$26	$(1,253)	$(1,084)

** Control device costs were developed based on an Oil and Gas Cost Study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.*
*** Recovered NG fuel costs $3.5/MCF (Henry Hub Spot Price - Aug. 2013)*
**** Annualized over 15 years at 5% ROR*

[53] See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

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Assuming 9,384 total devices replaced, adoption of this strategy will result in $10,169,441 in annual cost savings.

Table 40: Low Bleed Pneumatic Control Cost Estimates (Outside NAA)				
Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
9,384	$(1,084)	$(10,169,441)	14,921	NA

The proposed rule also requires the use of no-bleed pneumatic devices if it is technically and economically feasible and where on-site electrical grid power is being used. Use of no-bleed pneumatic devices will further reduce emissions relative to the use of low bleed devices. Since the Division does not have information indicating the number of no-bleed pneumatic devices that could be required, it is not possible to calculate the cost effectiveness of this particular provision. However, because the proposed requirement expressly provides that use of no-bleed pneumatics is only required where economically feasible the Division assumes that any use of no-bleed pneumatic devices pursuant to the proposed rule will be cost effective.

3.3.8.3 Require Newly Constructed Gas Wells be Connected to a Pipeline or Route Emissions to a Control Device

Currently in Colorado, natural gas produced at oil and gas sites is typically routed to a transmission pipeline. With the advent of new drilling technologies, additional areas of the state without established pipeline infrastructure may experience oil and gas exploration and production. This can lead to instances where produced gas is vented or flared instead of being put into a transmission line. To date the Division has identified 61 instances in Colorado where this is occurring. To address this, the proposed regulation provides that for newly constructed, hydraulically fractured, or recompleted wells, the gas stream must either be connected to a pipeline or routed to a control device achieving 95% control efficiency. Currently all of the sites that are not routed to a pipeline are flaring their gas. Additionally, because venting the gas at such sites would create a safety issue, the Division assumes that in the limited future instances where the gas stream is not routed to a pipeline, operators will route the emissions to a flare or other control device. Accordingly, adoption of this portion of the proposed regulation will likely not result in any additional costs.

3.3.8.4 Control Requirements for Glycol Dehydrators

The Division is proposing to revise the control requirements applicable to glycol natural gas dehydrators statewide. Currently any glycol natural gas dehydrator with uncontrolled actual VOC emissions of 2 tons per year or greater that is located at a facility where the sum of uncontrolled actual emissions from all of the dehydrators at the facility is greater than 15 tons per year, must be equipped with a control device that reduces emissions by at least 90%. Under the Division's proposal, all existing dehydrators with uncontrolled actual emissions of 6 tons per year or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. The proposal also provides that existing dehydrators with uncontrolled actual emissions of two tons per year or greater VOC must be controlled if they are located within

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1,320 feet of a building unit or designated outside activity area. Finally, the proposal requires that all new dehydrators with uncontrolled actual emissions of two tons per year or greater VOC be controlled. The Division assumes that newly subject glycol dehydrators will be controlled using flares that achieve a 95% destruction efficiency. The annual cost for these units is $6,286.80 per unit.

Based on industry reported APEN data, there are currently 433 uncontrolled dehydrators at sites with total dehydrator uncontrolled actual VOC emissions below 15 tpy. Of these, 217 have uncontrolled actual emissions greater than or equal to two tons per year. The total uncontrolled actual emissions for these 217 dehydrators are 1,827.5 tpy VOC. There are 148 dehydrators with uncontrolled actual VOC emissions greater than or equal to 6 tons per year. The total uncontrolled actual emissions for these 148 dehydrators are 1,549.7 tpy VOC. Currently, the Division does not have information regarding the location of these uncontrolled dehydrators relative to a building unit or designated outside activity area. Assuming, however, that all of the 2 to 6 ton dehydrators are located within 1,320 feet of a building unit or designated outside activity area and thus will require a control, the proposed requirement will reduce 1,736 tpy of VOC at a cost effectiveness of $786/ton VOC. For the smallest dehydrator subject to the proposed rule (2 ton/year) the cost effectiveness is estimated to be $3309 per ton of VOC reduced.

Table 41: Dehydrator Control Cost Estimates (2 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
217	$6,286.8	$1,364,236	1,736	$786

Conversely, if it is assumed that none of the 2 to 6 ton existing dehydrators will require controls the proposed requirement will reduce 1,472 tpy of VOC at a cost effectiveness of $632/ton VOC.

Table 42: Dehydrator Control Cost Estimates (6 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
148	$6,286.8	$930,446	1,472	$632

3.3.8.5 Control Requirements for Downhole Well Maintenance and Liquids Unloading Events

Historically, Colorado has not regulated air emissions from temporary activities such as well completions and well maintenance at well production sites. Recently, however, EPA, Colorado and other jurisdictions have identified these activities as potentially large sources of emissions from the oil and gas sector. In recognition of this, the Colorado Oil and Gas Conservation Commission and more recently EPA have adopted requirements for green completions to reduce hydrocarbon emissions during well completion activities. The Division is now proposing additional regulatory requirements designed to reduce emissions during well maintenance.

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Well maintenance is required when, over time, liquids build up inside the well and reduce gas and oil flow out of the well. To remove these liquids and improve flow, the liquids are blown out of the well under pressure. This process is typically referred to as liquids load-out or well blow-down. Historically emissions from well blow-downs are vented to the atmosphere. EPA has established emission factors for liquid unloading based on fluid equilibrium calculations to calculate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blow-down. Based on its calculations, EPA estimated that in the United States the combined methane emissions for liquid unloading and well completions in 2009, was 217 billion cubic feet, and that liquid unloading may account for 33% of the uncontrolled methane emissions from the natural gas industry.[54] For Colorado, the Division has calculated that emissions from well blow-downs in 2008 were approximately 9,306 tons of VOC per year.

To address these emissions, the Division is proposing a two pronged requirement aimed at reducing the number of required liquids unloading events and reducing the amount of emissions vented to the atmosphere during these events. Under the Division's proposal operators shall use best management practices to minimize the need for venting associated with downhole maintenance and liquids unloading. For example, EPA's Gas Star program advocates the use of a plunger lift system to reduce the need for liquids unloading. According to EPA, use of a plunger lift will on average pay for itself in less than one year through the capture of additional product. The Division's proposal also provides that emissions during well maintenance and liquids unloading shall be captured or controlled using best management practices to limit venting during well blow-downs to the maximum extent practicable. Based on information provided by Environmental Defense Fund, application of these requirements could result in annual VOC reductions of 2,881 tons and methane reductions of 19,207 tons per year. Given the wide variety of practices that this could entail, the Division currently does not have information about the precise cost-effectiveness of this provision. Given the fact that the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

4 CLOSING SUMMARY

On December 13, 2013, interested parties, stakeholders and state representatives filed requests for a Regulatory Analysis. This Regulatory Analysis is a careful and considerate response to those Requests and is a good faith effort on the part of the Division.

The Division has addressed, to the best of its ability, issues related to the entirety of proposed revisions to Regulation 3, 6, and 7. The Division believes that the proposal before the Commission reflects a balanced approach that includes proven and cost effective strategies to reduce emissions from the oil and gas sector, while enabling the sector to continue to grow in a responsible and protective manner. The Division looks forward to the Commission's consideration of its proposal and alternate proposals of other parties at the February 2014 hearing.

[54] See EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2009*, April, 2011.

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FINAL

ECONOMIC IMPACT ANALYSIS

For Industry's Proposed Revisions to
Colorado Air Quality Control Commission
Regulation Number 3, 6, and 7 (5 CCR 1001-9)

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Executive Summary

This document provides an economic analysis of the proposed revisions to Colorado Air Quality Control Commission (AQCC) Rules. This analysis is focused on specific parts of the regulations, including the costs for flares and auto-igniters, pneumatic controllers, storage tank emission management (STEM), and LDAR for well production facilities and compressor stations. Louis Berger has also estimated the value of the product saved as a result of the LDAR programs for well production facilities and compressor stations. Additionally, Louis Berger analyzed the impacts to marginally producing wells as they become less economically viable and are shut in or plugged as regulatory costs increase, resulting in loss of production, operator revenues, royalties, and severance taxes. Finally, Louis Berger provides estimates on the costs to the state to implement the proposed rules and regulations. This document also provides support for industry's proposed language.

Economic Impact Analysis

Important results of the analysis are summarized in table ES-1 and described in the bullets below.

- Louis Berger estimated pollution control costs using information obtained from industry sources. Total costs to add flares and auto-igniters to tanks between 6 and 20 TPY uncontrolled VOC emissions are estimated to be $5.8 million, $511,680, and $7,872 for condensate, produced water, and crude oil tanks, respectively. Annualized costs of buffer bottles are estimated to be $5,850, with a total annual cost of $31.1 million.
- LDAR programs result in decreased emission reduction benefits after the initial year of program implementation. That is, after initial monitoring, leaks are found and fixed, resulting in reduced leak frequencies and emissions. These decreased leak frequencies in subsequent years affect the cost effectiveness of the regulations. As emissions reductions decline in subsequent years, LDAR annualized costs decrease by a smaller proportion; therefore, costs per ton of VOC reduced in subsequent years are significantly higher in subsequent years compared to the initial year of implementation. Figure ES-1 shows how the emission reductions decline while LDAR costs per ton of VOC increase after the initial year. This figure also demonstrates the disparity in costs for the facilities with differing levels of uncontrolled emissions, with lower emitting tanks having a much higher cost per ton of VOC reduced than the higher emitting tanks.

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Table ES-1: Summary of Louis Berger Final EIA Results in Comparison to the Division's Updated EIA Estimates

Item	Louis Berger Estimate			Division Estimate		
	Total Annual Cost	Per Facility/ Tank Costs	Cost Per Ton of VOC Reduced	Total Annual Cost	Per Facility/ Tank Costs	Cost Per Ton of VOC Reduced
Lowering Threshold for Flares and Auto Igniters for Tanks						
Condensate Tanks	$5.8M	$9,840	$988	$3.7M	$6,287	$716
Produced Water Tanks	$511,680	$9,840	$1,121	$326,914	$6,287	$715
Crude Oil Tanks	$78,720	$9,840	$670	$50,294	$6,287	$427
Storage Tank Emission Management Plan (buffer bottle and inspections)						
Buffer Bottle	$31.1M	$5,850	-	$21.0M	$3,949	$391
Initial Year STEM Costs (with buffer bottle)						
6 to 12 TPY	$16.2M	$11,453	$4,800	$5.6M	$4,147	NA
12 to 50 TPY	$39.9M	$13,669	$1,945	$13.8M	$4,741	NA
Greater than 50	$21.0M	$21,433	$555	$6.2M	$6,325	NA
Total	**$77.1M**	**$14,509**	**$1,250**	**$25.6M**	**$4,875**	**$4,800***
Subsequent Year STEM Costs (with buffer bottle)						
6 to 12 TPY	$16.0M	$11,324	$20,172	$5.6M	$4,147	NA
12 to 50 TPY	$38.5M	$13,164	$7,960	$13.8M	$4,741	NA
Greater than 50	$19.5M	$19,903	$2,192	$6.2M	$6,325	NA
Total	**$73.9M**	**$13,915**	**$5,097**	**$25.6M**	**$4,875**	**$4,800***
LDAR for Well Production Facilities						
Initial Year LDAR Costs						
Less than 6 TPY	$19.8M	$6,995	$3,629	$1.3M	$470	NA
6 to 12 TPY	$9.8M	$6,962	$3,611	$663,993	$470	$256
12 to 50 TPY	$56.2M	$19,227	$9,818	$5.5M	$1,881	$682
Greater than 50	$50.9M	$51,999	$25,390	$5.5M	$5,643	$1,533
Total	**$136.7M**	**$16,778**	**$8,590**	**$13.0M**	**$1,598**	**$819**
Subsequent Year LDAR Costs						
Less than 6 TPY	$3.0M	$1,051	$5,454	$1.3M	$470	NA
6 to 12 TPY	$6.3M	$4,452	$9,815	$663,993	$470	$256
12 to 50 TPY	$27.3M	$9,336	$20,261	$5.5M	$1,881	$682
Greater than 50	$21.6M	$22,097	$45,855	$5.5M	$5,643	$1,533
Total	**$58.2M**	**$7,138**	**$19,354**	**$13.0M**	**$1,598**	**$819**
LDAR Costs for Compressor Stations						
Initial Year LDAR Costs						
Less than 12TPY	$3,873,936	$26,353	$3,465	$154,262	$1,049	$260
12 to 50 TPY	$11,532,775	$217,599	$17,344	$589,763	$11,128	$1,131
Greater than 50	-	-	-	-	-	-
Total	**$15,406,710**	**$77,033**	**$8,641**	**$744,025**	**$3,720**	**$667**
Subsequent Year LDAR Costs						
Less than 12TPY	$2,020,457	$13,745	$7,681	$154,262	$1,049	$260
12 to 50 TPY	$4,446,685	$83,900	$28,421	$589,763	$11,128	$1,131
Greater than 50	-	-	-	-	-	-
Total	$6,467,142	$32,336	$15,416	$744,025	$3,720	$667
Value of Product Savings – Initial Year						
Well Production Facilities	$12.4M	$1,532	-	NA	NA	NA
Compressor Station – Initial Year	$1.3M	$6,993	-	NA	NA	NA
Value of Product Savings – Subsequent Years						
Well Production Facilities	$2.3M	$289	-	NA	NA	NA
Compressor Stations	$329,453	$1,647	-	NA	NA	NA
Division Implementation Costs of Proposed Rules						
Hours	12,282			0		
FTE	6.1			0		

*Calculated based on the emission reductions associated with the STEM Control Analysis on page 12 of Division's Updated EIA.

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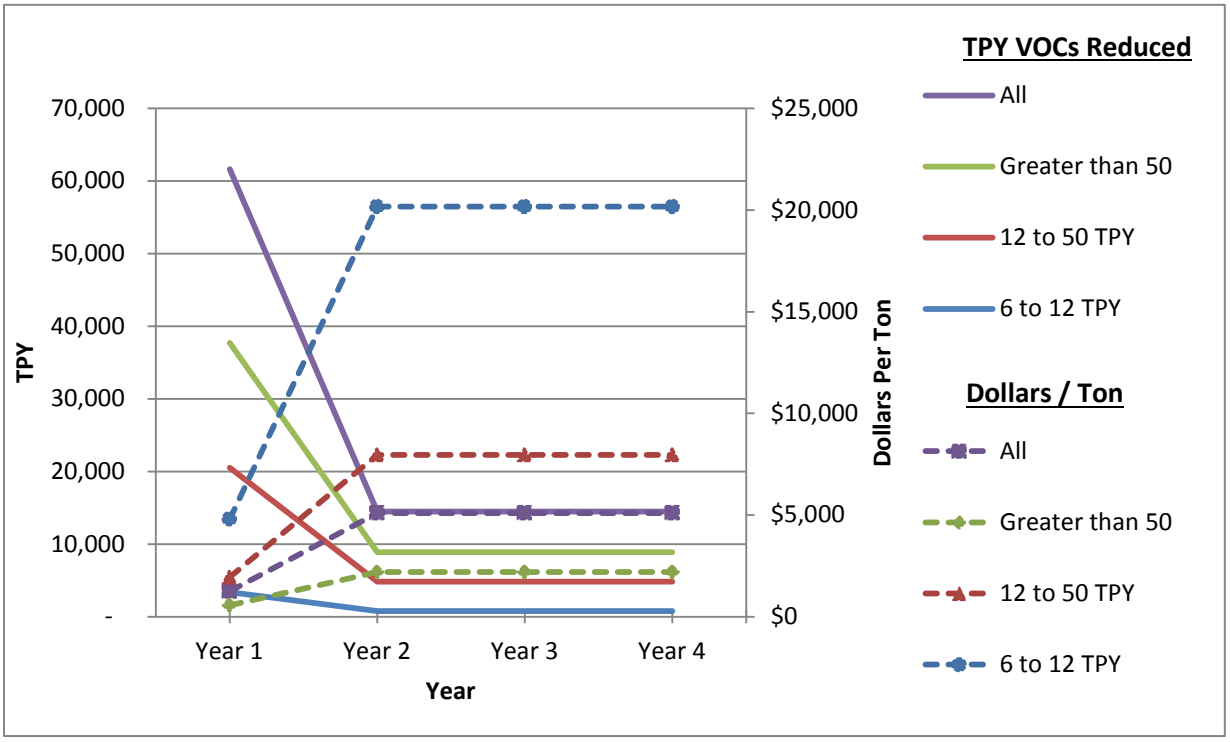


Figure ES-1: STEM Emission Reductions and Cost Per Ton of VOC Reduced

- STEM costs are estimated to be $77.1 million in the initial year and $73.9 million in subsequent years, while the cost per ton of VOC reduced is $1,250 in the initial year and $5,097 in subsequent years, on a recurring annual basis.
- Inspections and LDAR programs are more expensive to implement in the attainment area in comparison to the relatively dense operations in the non-attainment area due to the additional travel time, travel expenses, and fewer inspections possible on an annual basis in the attainment area. The STEM costs show that across all tank levels, the attainment area tanks have $1,000 higher costs per tank per year than in the non-attainment area to implement this program. Similar results occur for well production facilities, with LDAR costs per facility in the initial year higher in the attainment area than non-attainment area for each level of monitoring required.
- LDAR costs for well production facilities are considerable, with initial year costs of $136.7M ($16,778 per facility) and subsequent recurring annual costs of $58.2 million ($7,138 per facility). The cost per ton of VOC reduced is $8,590 in the initial year and $19,354 in the subsequent years on an annual recurring basis.
- LDAR costs for compressor stations are $15.4 million in the initial year ($77,033 per compressor station) and subsequent recurring annual costs of $6.5 million ($32,336 per compressor station). The cost per ton of VOC reduced is $8,641 in the initial year and $15,416 in the subsequent years on an annual recurring basis.
- The total cost to expand the regulatory mandate to modify or retrofit high-bleed pneumatic devices statewide was estimated to be $32 million. This includes the cost to replace an

estimated 9,800 high-bleed devices that are located at facilities outside the nonattainment area. When considering the amount of gas that can be recovered with the low-bleed devices, payback of the costs are expected to occur within 2.8 years. .

- Louis Berger estimated the product savings that can be expected from LDAR requirements for well production facilities and compressor stations. In the initial year, the value of the product captured represents approximately 8.7 percent of the LDAR costs. In subsequent years, the value of the natural gas captured represents 4 and 5 percent of the LDAR costs in subsequent years for well production facilities and compressor stations, respectively. The Economic Impact Analysis requires an assessment of the cost for the Division to implement the proposed rule changes. Oversight of an LDAR program, STEM plans, and annual report review of 5,312 tank batteries, 5,312 well production facilities, and 200 compressor stations with possibly hundreds of thousands of components would require additional Division manpower. Louis Berger reviewed the revised (November 21, 2013) Regulations 3, 6 and 7 to understand the implementation costs to the Division associated with the new rules. The net increase in the number of labor hours at the Division as result of the proposed regulations is anticipated to be approximately 12,282 labor hours annually. Notably, the Division would need 5,600 hours to review and approve initial STEM plans required under Regulation 7, the largest estimated time commitment for the Division. This represents approximately 6.1 FTEs of additional staff for the Division to review, oversee, inspect, manage, and approve various requirements associated with the proposed rules. Therefore, Louis Berger concludes that the Division would incur additional net costs to implement the proposed requirements beyond current expenditures.

In order to gain an understanding of the potential indirect costs to businesses, in particular small businesses if the proposed rules were implemented, Louis Berger evaluated the impacts on small, marginally producing wells within the state. Marginally producing wells with production less than 2 BOPD represent over half (55 percent) of the total producing wells in the state (46,495) as of 2013. Under current economic and regulatory conditions, the economic limit for marginally producing wells was estimated to be 0.43 BOPD, which is the point at which revenues would no longer cover operating expenses and the well would be shut in. Additional operating costs associated with the proposed rules were estimated per well production facility and tank and included in the analysis. Over time, the additional cost burden would result in as much as 128.6 million barrels of oil being left in place and not produced. The calculated present values for these losses include $1.9 billion in lost revenue to producers, $384 million in lost royalties and $96 million in lost severance taxes.

- Support of Industry's Proposed Language

The results of the final economic impact analysis presented here support the industry's key suggested revisions to the Division's proposed rule. Specifically, the proposed revisions will allow similar emission reductions to be achieved in a cost effective, achievable, and reasonable manner. Key points to the analysis include:

- Diminishing marginal benefits associated with LDAR programs implies decreasing cost effectiveness after initial rounds of inspections and repairs. Reducing the monitoring to reflect

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successful LDAR implementation reduces costs and improves the cost effectiveness of the proposed rule compared to the Division's proposal while maintaining program integrity through realized emission reductions. The "step-down" of monitoring frequency, which rewards companies with four inspections with no leaks, is an example of how the industry changes to the proposed rule would provide incentives for industry to maintain compliance and reduce costs for good behavior.

- Generally, compliance costs of STEM and LDAR for small tanks and well production facilities are more burdensome than for larger facilities on a cost per ton basis. As such, requiring a one-time LDAR inspection and monthly AVO for all facilities (including all well production facilities) with uncontrolled emissions between 2 and 6 TPY would improve the overall cost effectiveness of the proposed rule by limiting the very high costs per ton of VOC reduced incurred by very small facilities with very small VOC fugitive emissions.
- Compliance costs are higher for operations outside of the non-attainment area as the distance among facilities and tanks increases inspection travel time and expenses. Limiting the geographic scope to the non-attainment area will improve the cost effectiveness of the proposed rule.
- Allowing for the use of other established technology, such as the tunable diode laser absorption spectroscopy technology (TDLAS) as an option for inspection monitoring, would reduce costs to industry with faster inspections and reduced camera training requirements, among other factors.

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Economic Impact Analysis

This document provides an economic analysis of the proposed revisions to Colorado Air Quality Control Commission (AQCC) Regulation Number 3, 6 and 7. This analysis is focused on the specific parts of the regulation, including the costs for flares and auto-igniters, STEM, LDAR for well production facilities and compressor stations, and pneumatic controllers. Louis Berger has also estimated the value of the product saved as a result of the LDAR programs for well production facilities and compressor stations. Additionally, Louis Berger analyzed the impacts to marginally producing wells as they become less economically viable and are shut in or plugged as compliance costs increase resulting in a loss of production, operator revenues, royalties, and severance taxes. Finally, Louis Berger provided estimates on the costs to the state to implement the proposed rules and regulations.

Lowering Statewide Tank Control Threshold (from 20 tpy to 6 tpy)

Louis Berger evaluated the costs to industry associated with installing flares and auto-igniters on condensate tanks with uncontrolled emissions between 6 TPY and 20 TPY. The analysis used the state's estimate of 588 condensate tanks that that would be affected by the change in the regulatory threshold, along with updated costs estimated by the EPA and in the industry survey.

Louis Berger developed cost estimates for flares and auto-igniters using data and information obtained from an industry survey conducted in 2013 and data from the EPA. The capital, non-recurring and annual costs were obtained from the EPA.[1] Because the costs were reported in 2008 dollars they were escalated to 2013 dollars using the GDP price index obtained from the U.S. Office of Management and Budget.[2] These costs were annualized for an 11-year life of the equipment based on information obtained from the industry survey at a 5 percent interest rate. The annual cost for the flare is estimated to be $9,840 (Table 1).

Table 1: Estimated Cost for Flares and Auto-Igniters

Item	Estimated Cost (2013$)
Capital and Non-Recurring Cost	$35,070
Annual Costs	$5,823
Annualized Capital Costs	$4,018
Total Annual Costs	**$9,840**

The Division estimated the cost per ton of VOC emission reductions by lowering the statewide tank control threshold from 20 TPY to 6 TPY. According to the Division's analysis, there are 588 condensate tanks that would be affected by this rule change and that by adding flares to these particular tanks, VOC emissions would decline by 5,162 TPY. Louis Berger analyzed the cost of lowering the threshold from 20 tpy to 6 tpy using the flare cost estimate summarized above. The results are summarized in Table 2.

[1] EPA. 2011. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards.
[2] Office of Management and Budget. 2013. Fiscal Year 2014. Gross Domestic Product and Deflators Used in Historic Tables. Table 10.1. Available: http://www.whitehouse.gov/sites/default/files/omb/budget/fy2014/assets/hist.pdf

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When the costs are separated by uncontrolled emissions, the differences are significant. For tanks with lower uncontrolled emissions (6 to 10 TPY), the control costs are double what they are for the higher emitting tanks (between 10 and 20 TPY). Average cost per ton of VOC reduced is estimated to be $1,121.

Table 2: Estimated Cost Per Ton of VOCs Reduced for Condensate Water Tanks

Uncontrolled Emissions	Number of Tank Batteries Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * $9,840	(7) = (6)/(5)
6 to 10	235	7.35	1,729	1,232	$2,314,368	$1,879
10 to 20	353	13.98	4,932	3,514	$3,471,552	$988
Total Affected (State Estimate)	**588**	**12.32**	**7,244**	**5,161**	**$5,785,920**	**$1,121**

Using the same logic and data as described for condensate tanks, the controls for produced water tanks and crude oil tanks yields the following results. According to the Division's analysis, there are 52 produced water tanks and 8 crude oil tanks. Louis Berger believes that there are considerably more crude oil tanks than are reported in the APEN. However, without additional data, Louis Berger used the Division's estimate of 8. Cost per ton of VOC reduced for produced water and crude oil tanks are estimated to be $1,121 and $670, respectively.

Table 3: Estimated Cost Per Ton of VOCs for Produced Water Tanks

Uncontrolled Emissions	Number of Produced Water Tanks Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * $9,840	(7) = (6)/(5)
Total Affected (State Estimate)	**52**	**12.32**	**641**	**456**	**$511,680**	**$1,121**

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Table 4: Estimated Cost Per Ton of VOCs for Crude Oil Tanks

Uncontrolled Emissions	Number of Oil Tanks Affected	Average Uncontrolled Emissions per tank	Total Uncontrolled Emissions	Emission Reduction with Flare and Auto-Igniter	Total Cost of Flares Per Tank Category	Cost Per Ton of VOC Reduced Per Tank Category
(1)	(2)	(3)	(4) = (3) * (2)	(5) = (4) * 0.7125	(6) = (2) * $9,840	(7) = (6)/(5)
Total Affected (State Estimate)	**8**	**20.62**	**165**	**118**	**$78,720**	**$670**

Emission Capture Requirements for Controlled Petroleum Storage Tanks

This section of the analysis evaluates requirements under the Storage Tank Emissions Management (STEM) plan, including costs of adding a buffer bottle and implementing a LDAR program. With data collected from the industry survey conducted in 2013, Louis Berger estimated an annual cost for buffer bottles of $5,850, as described in Table 5.

Table 5: Estimated Cost for Buffer Bottles

Item	Estimated Cost (2013$)
Capital and Non-Recurring Cost	$25,000
Annual O&M Costs	$2,500
Annualized Capital Costs*	$3,350
Total Annual Costs	**$5,850**

*Capital costs and non-recurring costs were annualized over 9 years, the estimate life of the control technology.

The STEM program would require instrument based monitoring. The monitoring frequency would be based on the uncontrolled emissions of various tanks as reported in the APEN database. Louis Berger estimated the LDAR costs using data and information obtained through an operator survey and follow up interviews. Table 6 summarizes the cost assumptions for the analysis.

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Table 6: STEM Cost Assumptions for Tanks (2013$)

	LDAR			AVO		
Item	**Estimated Cost**	**Annualized***	**Unit Cost**	**Estimated Cost**	**Annualized***	**Unit Cost**
Capital and Non-Recurring Costs						
Camera	$122,000	$28,179	$46.96/inspection in NAA $70.45/inspection in the AA			
Vehicle	$30,000	$6,929	$11.54/inspection in the NAA $17.32/inspection in the NAA			
Program set up costs (i.e., Tagging, software, travel, etc.)	$1,000	$231	$231/Tank	$500	$115.49	$115.49/tank
Inspection, Operations and Maintenance costs						
Assume one camera can inspect 2 tanks a day in the AA, 400 tanks/year; 3 tanks per day in the NAA, 600 tanks/year; 10 weeks for repair and training. Assume weekly inspections for all tanks over 6 TPY.						
Inspection Labor, including travel time						
Hourly Rate:	$150		$150/hour	$100		$100/Hour
Inspection and Travel Time (NAA and crude)	3		4.75 hours	.5		0.5 Hours
Inspection and Travel Time (AA)	4		5.75 hours	.5		0.5 Hours
Camera/Inspection training	$7,500		Per 100 Tanks	$7,500		$7,500/100 tanks/year
Camera repair	$12,500		Camera			$12,500/camera/year
Travel and per diem costs (NAA Condensate and Crude Oil)	$30		Inspection			$30/inspection
Travel and per diem costs (AA Condensate)	$40					$40/inspection
Supervision	$100 (annual, quarterly) $200 (monthly)		Tank			$100/tank/year $200/tank/year
Compiling data, record-keeping and reporting	$1,530 (annual, quarterly) $3,060 (monthly)		Tank			$1,530/tank/year $3,060/tank/year

*Camera and set up costs annualized at 5% over 5 year-life of the equipment.

Louis Berger estimated the repair costs using information from a Canadian study and a Trihydro report that provide estimates of the number of components, potential number of leaks, and average leak

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frequency for production tanks.[3] Louis Berger assumed for this cost estimate that the typical production tank in Colorado has 38 components (Clearstone Engineering 2013) with an initial leak rate of 1.7 percent (Trihydro 2014), which equates to 0.65 components discovered leaking during each inspection. The Trihydro report indicates that subsequent leak frequencies associated with quarterly LDAR drop to 0.4 percent (0.15 leaking components per production tank), which was used to estimate the number of leaks repaired and re-monitored in subsequent years. Costs to repair components were obtained from Nelson and Brown (2012) and include only the labor needed to repair the leak, not materials and equipment costs.[4] Data and cost assumptions for the repair and re-monitoring costs are summarized in table 7. The re-monitoring cost was assumed to apply to the 25 percent of leaks, and the inspection and travel costs were obtained from the operator survey, with a cost estimate of $480 per inspection in the non-attainment area and $640 in the attainment area.

Table 7: Repair and Re-monitoring Cost Assumptions

Percent of Leaks	Type of repair	Repair Time (hours)	Hourly Rate	Re-monitor Cost (per leak)
75%	On-line	1	$75	-
25%	On the ground	4	$75	$480 (NAA) $640 (AA)

The total estimated cost of the proposed STEM program, which includes the costs for the inspections and the buffer bottles, are summarized in the following two tables. Total STEM costs include annualized capital costs, recurring inspection, operations, and maintenance costs, buffer bottle costs, repair costs, and re-monitoring costs. Total costs for all storage tanks are estimated to be $77.1 million, of which the non-attainment area tanks account for $64.1 million. When comparing the costs per condensate tank in the attainment area and non-attainment area over all the different types of tanks, costs per tank in the attainment area are approximately $1,000 higher than tanks in the non-attainment. The higher costs in the attainment area due to longer travel times and per diem costs, as ability to perform fewer inspections on an annual basis. For the greater than 50 TPY tanks, the STEM costs are $23,676 per tank in attainment area compared with the non-attainment area STEM costs of $20,966 per tank. The STEM costs are provided in Tables 8.1 and 8.2.

[3] Clearstone Engineering, Ltd. 2013. Technical Report: Draft Update of Fugitive Equipment Emissions Factors. Prepared for the Canadian Association of Petroleum Producers. August. See Tables 5 and 12.
Trihydro Corporation. 2014. Colorado Regulation/Litigation Support. Prepared for WPX Energy, Inc. January 6.
[4] Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April

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Table 8.1: Initial Year STEM Cost Analysis, Part 1

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Storage Tanks and Crude Oil Tanks	Number of inspections/ Year	Capital Costs for Inspections (annualized) (1)	Annual Costs for Inspections, O&M (2)	Number of Cameras Needed
Crude Oil Tanks						
6 to 12 TPY	annually	23	23	$9,314	$114,080	-
12 to 50 TPY	quarterly	5	20	$2,903	$32,000	-
Greater than 50	monthly	14	168	$14,681	$178,680	1
Total	-	**42**	**211**	**$26,898**	**$324,760**	**1**
Attainment Area Condensate Tanks						
6 to 12 TPY	annually	325	325	$141,125	$1,676,500	1
12 to 50 TPY	quarterly	323	1,292	$225,305	$2,323,920	4
Greater than 50	monthly	165	1,980	$230,950	$2,337,850	5
Total	-	**813**	**3,597**	**$597,381**	**$6,338,270**	**10**
Non-Attainment Area Condensate Tanks						
6 to 12 TPY	annually	1,065	1,065	$431,297	$5,307,400	2
12 to 50 TPY	quarterly	2,593	10,372	$1,505,272	$16,820,200	18
Greater than 50	monthly	799	9,588	$837,847	$9,684,130	16
Total	-	**4,457**	**21,025**	**$2,774,416**	**$31,811,730**	**36**
All Tanks						
6 to 12 TPY	annually	1,413	1,413	$581,736	$7,097,980	3
12 to 50 TPY	quarterly	2,921	11,684	$1,733,480	$19,176,120	22
Greater than 50	monthly	978	11,736	$1,083,478	$12,200,660	22
Total	-	**5,312**	**24,833**	**$3,398,695**	**$38,474,760**	**47**

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Table 8.2: Initial Year STEM Cost Analysis, Part 2

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Buffer Bottle Costs (3)	Annual Number of Leaks	Leak Repair Costs (4)	Re-monitoring Cost (5)	Total Initial Year STEM Costs for Tanks (1+2+3+4+5)	Per Tank Cost for Initial Year
Crude Oil Tanks							
6 to 12 TPY	annually	$134,545	15	$1,950	$1,783	$261,672	$11,377
12 to 50 TPY	quarterly	$29,248.83	13	$1,696	$1,550	$67,398	$13,480
Greater than 50	monthly	$81,897	109	$14,244	$13,023	$302,525	$21,609
Total	-	**$245,690**	**136**	**$17,890**	**$16,357**	**$631,595**	**$15,038**
Attainment Area Condensate Tanks							
6 to 12 TPY	annually	$1,901,174	210	$27,556	$33,592	$3,779,946	$11,631
12 to 50 TPY	quarterly	$1,889,474	835	$109,545	$133,541	$4,681,786	$14,495
Greater than 50	monthly	$965,211	1,279	$167,879	$204,653	$3,906,544	$23,676
Total	-	**$4,755,859**	**2,324**	**$304,981**	**$371,786**	**$12,368,276**	**$15,213**
Non-Attainment Area Condensate Tanks							
6 to 12 TPY	annually	$6,230,000	688	$90,299	$82,559	$12,141,554	$11,401
12 to 50 TPY	quarterly	$15,168,441	6,700	$879,416	$804,037	$35,177,366	$13,566
Greater than 50	monthly	$4,673,962	6,194	$812,943	$743,262	$16,752,144	$20,966
Total	-	**$26,072,403**	**13,582**	**$1,782,657**	**$1,629,858**	**$64,071,064**	**$14,375**
All Tanks							
6 to 12 TPY	annually	$8,265,719	$913	$119,805	$117,934	$16,183,172	$11,453
12 to 50 TPY	quarterly	$17,087,164	$7,548	$990,657	$939,128	$39,926,550	$13,669
Greater than 50	monthly	$5,721,070	$7,582	$995,066	$960,938	$20,961,213	$21,433
Total	-	**$31,073,952**	**$16,042**	**$2,105,528**	**$2,018,001**	**$77,070,935**	**$14,509**

As a result of initial implementation of a LDAR program, it has been shown that leak frequencies decrease from 1.7 percent to 0.4 percent (Trihydro 2014). Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency. The reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 9. It is assumed that subsequent LDAR and AVO capital (annualized), recurring annual, and annualized buffer bottle costs would remain as estimated in the initial year (table 8), while the number of repairs and re-monitoring needed would fall as the leak rate frequency also falls in subsequent years (table 9). The total STEM costs for subsequent years, shown in table 9, include the capital, inspection and O&M costs, and buffer bottle costs in table 8, with the adjusted leak repair and re-monitoring costs in table 9.

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Table 9: Subsequent Year STEM Cost Analysis

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Storage Tanks and Crude Oil Tanks	Annual Number of Leaks	Leak Repair Costs (4)	Re-monitoring Cost (5)	Total Subsequent Year STEM Costs for Tanks (Annual Cost) (1+2+3+4+5)	Per Tank Cost in Subsequent Years (Annual Cost)
Crude Oil Tanks							
6 to 12 TPY	annually	23	3	$459	$420	$258,817	$11,253
12 to 50 TPY	quarterly	5	3	$399	$365	$64,915	$12,983
Greater than 50	monthly	14	26	$3,352	$3,064	$281,673	$20,120
Total	-	**42**	**32**	**$4,209**	**$3,849**	**$605,406**	**$14,414**
Attainment Area Condensate Tanks							
6 to 12 TPY	annually	325	49	$6,484	$7,904	$3,733,186	$11,487
12 to 50 TPY	quarterly	323	196	$25,775	$31,421	$4,495,896	$13,919
Greater than 50	monthly	165	301	$39,501	$48,154	$3,621,666	$21,949
Total	-	**813**	**547**	**$71,760**	**$87,479**	**$11,850,749**	**$14,577**
Non-Attainment Area Condensate Tanks							
6 to 12 TPY	annually	1,065	162	$21,247	$19,426	$12,009,369	$11,276
12 to 50 TPY	quarterly	2,593	1,577	$206,921	$189,185	$33,890,019	$13,070
Greater than 50	monthly	799	1,457	$191,281	$174,885	$15,562,105	$19,477
Total	-	**4457**	**3,196**	**$419,449**	**$383,496**	**$61,461,493**	**$13,790**
All Tanks							
6 to 12 TPY	annually	1,413	214	28,190	27,750	$16,001,372	$11,324
12 to 50 TPY	quarterly	2,921	1,776	233,095	220,971	$38,450,830	$13,164
Greater than 50	monthly	978	1,784	234,134	226,103	$19,465,444	$19,903
Total	-	**5,312**	**3,775**	**495,418**	**474,824**	**$73,917,648**	**$13,915**

To better understand the costs per ton of VOCs reduced across the different levels of uncontrolled emissions, Louis Berger queried data from the APEN database provided by the Division to identify the uncontrolled emissions for the various tanks which is summarized in table 10.[5]

[5] The following Exhibits were analyzed on the state's rulemaking ftp site: APCD-PHS EX TT (produced water tanks), APCD-PHS-EX-LL (condensate tanks), APCD -PHS- EX - MM (crude oil tanks), APCD-PHS EX- (STEM emission control).

Table 10: Uncontrolled Emissions for Tanks

Tank Uncontrolled VOC Emissions	Monitoring frequency	Number of storage tanks and crude oil tanks	Uncontrolled VOC emissions per tank (TPY)	Total uncontrolled VOC emissions (TPY)
Crude Oil Tanks				
6 to 12 TPY	annually	23	8.70	200
12 to 50 TPY	quarterly	5	25.80	129
Greater than 50	monthly	14	268.63	3,760
Total	-	**42**	**97.38**	**4,090**
Attainment Area Condensate Tanks				
6 to 12 TPY	annually	325	8.62	2,802
12 to 50 TPY	quarterly	323	22.41	7,237
Greater than 50	monthly	165	156.01	25,742
Total	-	**813**	**44.01**	**35,781**
Non-Attainment Area Condensate Tanks				
6 to 12 TPY	annually	1,065	8.77	9,341
12 to 50 TPY	quarterly	2,593	26.15	67,797
Greater than 50	monthly	799	135.99	108,656
Total	-	**4,457**	**41.69**	**185,794**

The approach used by Louis Berger for the initial emission reductions (year 1) is very similar to that of the Division's: the uncontrolled emissions less the control for the flares (71.25%) or 0.2876 percent of the uncontrolled emissions, times 95 percent. *Note that the Division's efficiency rate for the flare and auto-igniter of 71.25 percent is not supported by empirical data or industry literature, nor is it consistent with EPA guidance regarding the estimated effectiveness of such control requirements for air quality planning purposes[6]. These sources would suggest that the control efficiency of flares is considerably higher than the estimates by the Division, and the effectiveness of such control requirements is also higher (83% under EPA's noted revised rule effectiveness guidance, not 75%). As such, the emission reductions attributed to STEM in this analysis (as well as in the Division's analysis) are likely overestimated. The cost per ton of VOC reduced associated with STEM are therefore likely to be higher than estimated in this analysis due to the higher efficiency factor of the flare, with fewer fugitive emissions to capture with STEM.*

The initial year results reveal an average of $1,250 per ton of VOC reduced. Emission reductions in subsequent years are much smaller than initial reductions, especially with leak definitions as low as 500 and 2,000 PPM. The Clearstone study has indicated that annual leak detection and monitoring emissions factors result in a net reduction of 75.3 percent compared to what would occur without instrument monitoring.[7] This is consistent with Trihydro's estimated drop in leak rate frequencies after quarterly LDAR from 1.7 percent to 0.4 percent (Trihydro 2014). Louis Berger assumed that the emissions

[6] Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations, Appendix B, Doc.No. EPA-454/R-05-001 (August 2005).
[7] See Clearstone Engineering study previously cited, page 19.

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reductions captured in subsequent years would be consistent with this decline in leak frequency. For example, if STEM was assumed to reduce emissions by 100 TPY in the initial year, the subsequent emissions reductions would be 23.5 percent (0.4/1.7) of the initial reduction.

It should be noted that the smaller tanks incur significantly larger costs per ton of VOC reduced. In the initial year, these costs per ton are $4,800 for tanks between 6 and 12 TPY uncontrolled emission, while tanks above 50 TPY, the initial year cost is $555 per ton reduced. Across all tanks, the subsequent year cost per ton of VOC reduced is approximately ***four times as high*** as the initial year cost, with the average cost in the subsequent years of $5,097 per ton of VOC reduced compared to the initial year cost per ton of VOC reduced of $1,250. This is due primarily to the effectiveness of the initial year LDAR in reducing fugitive emissions to a quarter of initial year rate. Despite the relatively higher travel and inspection costs in the attainment area, since the non-attainment area is where the overwhelming majority of tanks are located, there is not a considerable difference in the cost per ton of VOC reduced between these two geographic regions. However, as shown in Table 9, the tank STEM costs are more than $1,000 higher for attainment area tanks when compared to non-attainment tanks (for all tank uncontrolled emissions). Table 11 shows the initial year and subsequent total costs, emission reductions, and costs per ton of VOC reduced.

Figure 1 shows how the emission reductions decline after the initial year while LDAR costs per ton of VOC increase after the initial years. This figure also demonstrates the disparity in costs for facilities with different levels of uncontrolled emissions, with the lower emitting tanks having a much higher cost per ton of VOC reduced than higher emitting tanks. Over time, STEM for the tanks with the smallest uncontrolled emissions control the least amount of VOC emissions with the highest cost per ton of VOC ($20,172), while STEM for the tanks with the highest uncontrolled emissions capture the greatest amount of emissions and have the lowest cost per ton of VOC reduced ($2,192).

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Table 11: STEM Costs Per Ton of VOC Reduced

Tank Uncontrolled VOC Emissions	STEM Costs	Emission Reduction from STEM	STEM Cost Per Ton of VOC Reduced	Annual STEM Costs	Emission Reductions	Recurring Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Crude Oil Tanks						
6 to 12 TPY	$261,672	55	$4,786	$258,817	13	$20,120
12 to 50 TPY	$67,398	35	$1,913	$64,915	8	$7,831
Greater than 50	$302,525	1,027	$295	$281,673	242	$1,165
Total	**$631,595**	**1,117**	**$565**	**$605,406**	**263**	**$2,303**
Attainment Area Condensate Tanks						
6 to 12 TPY	$3,779,946	765	$4,939	$3,733,186	180	$20,732
12 to 50 TPY	$4,681,786	1,977	$2,369	$4,495,896	465	$9,667
Greater than 50	$3,906,544	7,031	$556	$3,621,666	1,654	$2,189
Total	**$12,368,276**	**9,773**	**$1,266**	**$11,850,749**	**2,299**	**$5,154**
Non-Attainment Area Condensate Tanks						
6 to 12 TPY	$12,141,554	2,551	$4,759	$12,009,369	600	$20,006
12 to 50 TPY	$35,177,366	18,517	$1,900	$33,890,019	4,357	$7,778
Greater than 50	$16,752,144	29,677	$564	$15,562,105	6,9823	$2,229
Total	**$64,071,064**	**50,745**	**$1,263**	**$61,461,493**	**11,940**	**$5,148**
Total Tanks						
6 to 12 TPY	$16,183,173	3,371	$4,800	$16,001,372	793	$20,172
12 to 50 TPY	$39,926,549	20,529	$1,945	$38,450,830	4,830	$7,960
Greater than 50	$20,961,213	37,735	$555	$19,465,444	8,879	$2,192
Total	**$77,070,935**	**61,635**	**$1,250**	**$73,917,648**	**14,502**	**$5,097**

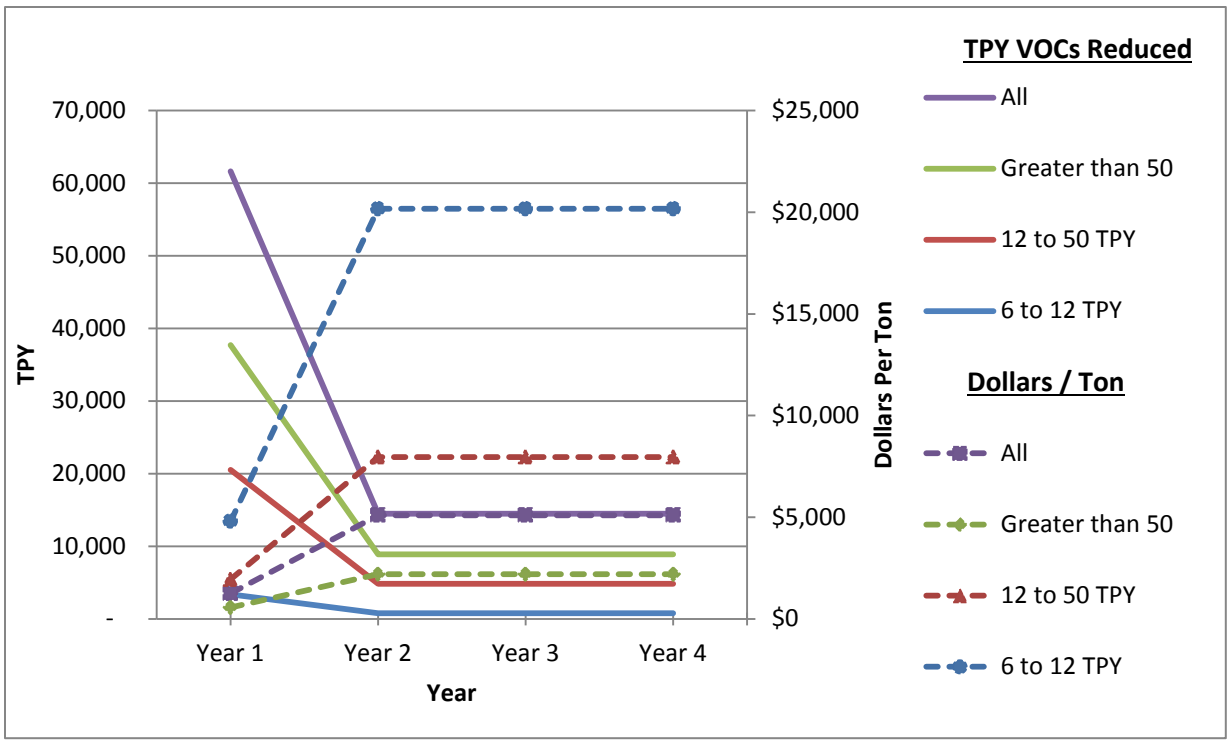


Figure 1: STEM Costs and Emission Reductions Over Time

Leak Detection and Repair Requirements for Well Production Facilities

The Division's proposed regulations include leak detection and repair requirements for well production facilities. The Division has based the LDAR monitoring frequency associated with these facilities on the uncontrolled VOC emissions with associated tanks. However, the Division's well production facility data (Exhibit RR) indicates that the tank VOC uncontrolled emissions do not correlate with fugitive emissions from well production facilities. The correlation coefficient is 0.19 indicating a weak positive correlation among the well production facilities and tank VOC uncontrolled emissions. For example, one tank had uncontrolled VOC emissions of 1,000 TPY, while the well production facilities accompanying the tank had a reported 2.4 TPY of VOC uncontrolled emissions. Regardless, the Division is requiring LDAR monitoring at various frequencies based on tank VOC uncontrolled emissions levels, and this section provides an estimate of the costs of these requirements to industry.

Louis Berger estimated LDAR inspection costs for well production facilities with a similar approach as described above for tanks. The Division has indicated that well production facilities would take on average 4.75 hours to inspect, which is consistent with Louis Berger's estimate of two facilities could be inspected per day in the non-attainment area. However, it is assumed that facilities in the attainment area would require an additional hour for travel time due to more remote operations and greater distance to access operations. Table 12 summarizes these assumptions for well production facilities.

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Table 12: Well Production Facility LDAR Cost Assumptions (2013$)

	LDAR			AVO		
Item	**Estimated Cost**	**Annualized***	**Unit Cost**	**Estimated Cost**	**Annualized***	**Unit Cost**
Capital and Non-Recurring Costs						
Camera	$122,000	$28,179	$70.45/inspection in the AA and NAA			
Vehicle	$30,000	$6,929	$17.32/inspection in the AA and NAA			
Program set up costs (i.e., Tagging, software, travel, etc.)	$1,000	$231	$231/WPF	$500	$115.49	$115.49/WPF
Inspection, Operations and Maintenance costs						
Assume one camera can inspect 2 well production facilities a day in the AA and NAA, 400 WPF/year; 10 weeks for repair and training. Assume monthly inspections for all tanks between 6 and 50 TPY.						
Inspection Labor, including travel time Hourly Rate: Inspection and Travel Time (NAA) Inspection and Travel Time (AA)	 $150 4.75 5.75		 $150/hour 4.75 hours 5.75 hours	 $100 .5 .5		 $100/Hour 0.5 Hours 0.5 Hours
Camera/Inspection training	$7,500		Per 100 WPF	$7,500		$7,500/100 WPF/year
Camera repair	$12,500		Camera			$12,500/ camera/ year
Travel and per diem costs (NAA Condensate and Crude Oil) Travel and per diem costs (AA Condensate)	$30 $40		Inspection			$30/inspection $40/inspection
Supervision	$100 (annual, quarterly) $200 (monthly)		WPF			$100/WPF/year $200/WPF/year
Compiling data, record-keeping and reporting	$1,530 (annual, quarterly) $3,060 (monthly)		WPF			$1,530/ WPF/year $3,060/ WPF/year

*Camera and set up costs annualized at 5% over 5 year-life of the equipment.

Similar to the storage tank analysis, data on costs to repair components for well production facilities were obtained from Nelson and Brown (2012).[8] The initial and subsequent year leak frequency rates were assumed to be 1.7 percent and 0.4 percent, respectively, consistent with the Trihydro report (2014) and Clearstone Engineering (2013) study. The number of components was consistent with the

[8] Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April. See attachments 3 and 4.

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analysis in the EPA technical memorandum, based on the well pad model plant 2, with an average number of components of 592.[9] As shown in the Division's analysis of its 40 well production facilities (Exhibit RR), the uncontrolled emissions of the tanks do not correlate with the components and uncontrolled emissions of the well production facilities. Additionally, information on 40 well production facilities does not provide a representative sample of well production facilities across the state, accounting for facilities in only five counties. As a result, without further information on the well production facilities, we used a constant number of components and uncontrolled emissions factors for all the well production facilities based on the EPA technical report (2011), consistent with information obtained from communications with industry representatives.

LDAR costs for well production facilities for the first year were estimated by Louis Berger using the approach described above to be $136.7 million, of which 81 percent of the cost is attributed to well production facilities in the non-attainment area. For each of the various tank uncontrolled emissions levels, the costs per well production facility are greater in the attainment area when compared to those in the non-attainment area. However, when averaged across all the facilities, since there are more higher cost tanks (in the 12-50 TPY and over 50 TPY) in the non-attainment area than in the attainment area, the per well production facility cost is actually higher in the non-attainment area. The LDAR costs are summarized in Tables 13.1 and 13.2.

[9] EPA. 2011. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards. See Table 8.3.

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Table 13.1: Well Production Facility LDAR Cost Analysis for the Initial Year, Part 1

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of WPF	Number of inspections/ Year	Capital Costs for Inspections (annualized) (1)	Annual Costs for Inspections (2)	Number of Cameras Needed
Attainment Area WPF						
Less than 6 TPY	One-time and monthly AVO	849	849	$368,662	$2,854,293	2
6 to 12 TPY	annually	328	328	$142,428	$1,105,560	1
12 to 50 TPY	quarterly	324	1,296	$226,003	$1,994,460	3
Greater than 50	monthly	169	2,028	$236,549	$2,456,385	5
Total	-	**1,670**	**4,501**	**$973,641**	**$8,410,698**	**11**
Non-Attainment WPF						
Less than 6 TPY	One-time and monthly AVO	1,986	1986	$862,381	$6,363,085	5
6 to 12 TPY	annually	1,085	1,085	$471,140	$3,479,663	3
12 to 50 TPY	quarterly	2,597	10,388	$1,811,512	$14,348,800	26
Greater than 50	monthly	809	9,708	$1,038,928	$8,900,035	25
Total	-	**6,477**	**23,167**	**$4,183,961**	**$33,091,583**	**59**
All WPF						
Less than 6 TPY	One-time and monthly AVO	2,835	2,835	$1,231,043	$9,217,378	7
6 to 12 TPY	annually	1,413	1,413	$613,568	$4,585,223	4
12 to 50 TPY	quarterly	2,921	11,684	$2,037,515	$16,343,260	29
Greater than 50	monthly	978	11,736	$1,275,477	$11,356,420	30
Total	-	**8,147**	**27,668**	**$5,157,602**	**$41,502,281**	**70**

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Table 13.2: Well Production Facility LDAR Cost Analysis, Part 2

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitoring Cost (4)	Total Initial Year LDAR Costs for WPF (1+2+3+4)	Per WPF Cost for Initial Year
Attainment Area WPF						
Less than 6 TPY	One-time and monthly AVO	8,544	$1,121,444	$1,927,816	$6,272,214	$7,388
6 to 12 TPY	annually	3,301	$433,255	$744,786	$2,426,029	$7,396
12 to 50 TPY	quarterly	13,043	$1,711,886	$2,942,814	$6,875,164	$21,220
Greater than 50	monthly	20,410	$2,678,785	$4,604,959	$9,957,162	$58,918
Total	-	**45,298**	**$5,945,371**	**10,220,376**	**$25,530,568**	**$15,288**
Non-Attainment Area WPF						
Under 6 TPY	One-time and monthly AVO	19,987	$2,623,307	$3,710,106	$13,558,880	$6,827
6 to 12 TPY	annually	10,919	$1,433,177	$2,026,921	$7,410,900	$6,830
12 to 50 TPY	quarterly	104,545	$13,721,509	$19,406,134	$49,287,955	$18,979
Greater than 50	monthly	97,701	$12,823,297	$18,135,806	$40,898,067	$50,554
Total	-	**233,153**	**$30,601,290**	**$43,278,968**	**$111,155,802**	**$17,162**
All WPF						
Under 6 TPY	One-time and monthly AVO	28,531	$3,744,751	$5,637,922	$19,831,094	$6,995
6 to 12 TPY	annually	14,220	$1,866,432	$2,771,707	$9,836,929	$6,962
12 to 50 TPY	quarterly	117,588	$15,433,395	$22,348,948	$56,163,119	$19,227
Greater than 50	monthly	118,111	$15,502,082	$22,740,765	$50,855,229	$51,999
Total	-	**278,451**	**$36,546,661**	**$53,499,344**	**$136,686,370**	**$16,778**

Similar to the storage tank STEM analysis, following the initial implementation of a LDAR program, leak frequencies decrease, and as a result, the number of leaking components also decrease along with repair and re-monitoring costs, when compared to the initial year. Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency (0.4%). As a result, reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 14. The total LDAR costs for subsequent years include the capital, and inspection and O&M costs in table 13 with the adjusted leak repair and re-monitoring costs in table 14. The exception is for well production facilities with tanks less than 6 TPY, which have been adjusted to include costs for a one-time LDAR inspection and monthly AVO.

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Table 14: Subsequent Year LDAR Cost Analysis for Well Production Facilities

Tank Uncontrolled VOC Emissions	Monitoring Requirement	Number of Well Production Facilities	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitoring Cost (4)	Total Subsequent Year LDAR Costs for WPF (Annual Cost) (1+2+3+4)	Per WPF Cost in Subsequent Years (Annual Cost)
Attainment Area Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	849	4,021	$263,869	$0	$892,542	$1,051
6 to 12 TPY	annually	328	777	$101,942	$175,244	$1,525,174	$4,650
12 to 50 TPY	quarterly	324	3,069	$402,797	$692,427	$3,315,687	$10,234
Greater than 50	monthly	169	4,802	$630,302	$1,083,520	$4,387,239	$25,960
Total	-	**1,670**	**12,669**	**$1,662,780**	**$2,858,398**	**$10,120,642**	**$6,060**
Non-Attainment Area Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	1,986	9,406	$617,249	$0	$2,087,856	$1,051
6 to 12 TPY	Annually	1,085	2,569	$337,218	$476,923	$4,764,943	$4,392
12 to 50 TPY	quarterly	2,597	24,599	$3,228,590	$4,566,149	$23,955,051	$9,224
Greater than 50	monthly	809	22,989	$3,017,246	$4,267,248	$17,223,458	$21,290
Total	-	**6,477**	**59,562**	**$6,583,055**	**$11,056,253**	**$48,031,308**	**$7,416**
All Well Production Facilities							
Less than 6 TPY	One-time with monthly AVO	2,835	13,427	$881,118	$0	$2,980,398	$1,051
6 to 12 TPY	Annually	1,413	3,346	$439,160	$652,167	$6,290,117	$4,452
12 to 50 TPY	quarterly	2,921	27,668	$3,631,387	$5,258,576	$27,270,738	$9,336
Greater than 50	monthly	978	27,791	$3,647,549	$5,350,768	$21,610,697	$22,097
Total	-	**8,147**	**72,231**	**$8,245,834**	**$13,914,651**	**$58,151,950**	**$7,138**

To better estimate the potential uncontrolled emissions from these facilities, uncontrolled emission factors from the well pad model number 2 were used from the EPA technical document.[10] As described above, the tank uncontrolled emissions factors do not correlate with uncontrolled emissions associated with the well production facilities.[11] Additionally, the Division has utilized a very small sample of the well production facilities in the state for its analysis. As a result, Louis Berger used the VOC uncontrolled emissions per well production facility of 2.56 TPY associated with well pad model number 2 (592 components), which we believe more accurately reflects the types of facilities operating in Colorado based on communication with industry representatives. Table 15 summarizes the uncontrolled emissions for well production facilities.

[10] See EPA (2011) previously cited, tables 8-2, 8-3, and 8-10.
[11] See Division's analysis of 40 well production facilities in Exhibit RR in the rulemaking documents.

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Table 15: Uncontrolled Emissions for Well Production Facilities

Uncontrolled VOC Emissions for Well Production Facilities	Monitoring Frequency	Number of Well Production Facilities	Uncontrolled VOC Emissions per Well Production Facility (TPY)	Total Uncontrolled VOC Emissions (TPY)
WPF in the Attainment Areas				
Less than 6 TPY	One time and AVO	849	2.560	2,173
6 to 12 TPY	annually	328	2.560	840
12 to 50 TPY	quarterly	324	2.560	829
Greater than 50	monthly	169	2.560	433
Total	-	**1,670**	-	**4,275**
WPF in the Non-Attainment Area				
Less than 6 TPY	One time and AVO	1,986	2.560	5,084
6 to 12 TPY	annually	1,085	2.560	2,778
12 to 50 TPY	quarterly	2,597	2.560	6,648
Greater than 50	monthly	809	2.560	2,071
Total	-	**6,477**	-	**16,581**
All WPFs				
Less than 6 TPY	One time and AVO	2,835	2.560	7,257
6 to 12 TPY	annually	1,413	2.560	3,618
12 to 50 TPY	quarterly	2,921	2.560	7,477
Greater than 50	monthly	978	2.560	2,504
Total	-	**8,147**	-	**20,856**

Louis Berger again uses an approach which utilizes a Canadian study, described above, and assumes an across the board reduction of 75.3 percent of uncontrolled emissions in the initial year with a one-time and annual LDAR program. The quarterly LDAR program is assumed to reduce emissions in the initial year by 76.5, consistent with the report by Trihydro (2013), and monthly LDAR is assumed to be even more effective, reducing emissions by 80 percent in the initial year. The average initial year cost per ton of VOC reduced across all well production facilities was estimated to be $8,590 per ton.

As with the STEM program, subsequent emission reductions in future years are expected to be much lower than in the initial year. The emission reductions in subsequent years are assumed to decline by the same proportion as the decline in leak frequency (0.4/1.7). The emission reductions were then divided by total annual costs in subsequent years to estimate the cost per ton of VOC reduced. In subsequent years, the average cost is $19,354 per ton of VOC reduced, approximately twice the initial year cost. Since uncontrolled emissions per well production facility are assumed constant across all of the tank uncontrolled emissions levels, the costs per tons of VOC reduced increase significantly with the higher tank VOC uncontrolled emissions levels (greater than 50 TPY) as more monitoring is required of these facilities. The cost per ton of VOC reduced for well production facilities is $45,855 in subsequent years for the greater than 50 TPY, while 12 to 20 TPY facilities incur a cost of $20,261 per ton of VOC reduced in subsequent years.

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When comparing across the geographies, the costs per ton reduced are approximately $1,000 more in the attainment area when compared to costs in the non-attainment area. Table 16 and Figure 2 shows the initial and subsequent year total costs, emission reductions, and cost per ton of VOC reduced.

Table 16: Well Production Facility LDAR Cost per Ton of VOC Reduced

Tank Uncontrolled VOC Emissions	LDAR Costs	Emission Reduction from LDAR	LDAR Cost Per Ton of VOC Reduced	Annual LDAR Costs	Emission Reductions with LDAR	Recurring LDAR Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Attainment Area WPF						
Less than 6 TPY	$6,272,214	1,637	$3,832	$892,542	164	$5,454
6 to 12 TPY	$2,426,029	632	$3,837	$1,525,174	149	$10,252
12 to 50 TPY	$6,875,164	635	$10,835	$3,315,687	149	$22,208
Greater than 50	$9,957,162	346	$28,769	$4,387,239	81	$53,872
Total	**$25,530,568**	**3,250**	**$7,857**	**$10,120,642**	**543**	**$18,633**
Non-Attainment Area WPF						
Less than 6 TPY	$13,558,880	3,828	$3,542	$2,087,856	383	$5,454
6 to 12 TPY	$7,410,900	2,092	$3,543	$4,764,943	492	$9,682
12 to 50 TPY	$49,287,955	5,086	$9,691	$23,955,051	1,197	$20,018
Greater than 50	$40,898,067	1,657	$24,684	$17,223,458	390	$44,181
Total	**$111,155,802**	**12,663**	**$8,778**	**$48,031,308**	**2,462**	**$19,513**
Total WPF						
Less than 6 TPY	$19,831,094	5,465	$3,629	$2,980,398	547	$5,454
6 to 12 TPY	$9,836,929	2,724	$3,611	$6,290,117	641	$9,815
12 to 50 TPY	$56,163,119	5,720	$9,818	$27,270,738	1,346	$20,261
Greater than 50	$50,855,229	2,003	$25,390	$21,610,697	471	$45,855
Total	**$136,686,370**	**15,913**	**$8,590**	**$58,151,950**	**3,005**	**$19,354**

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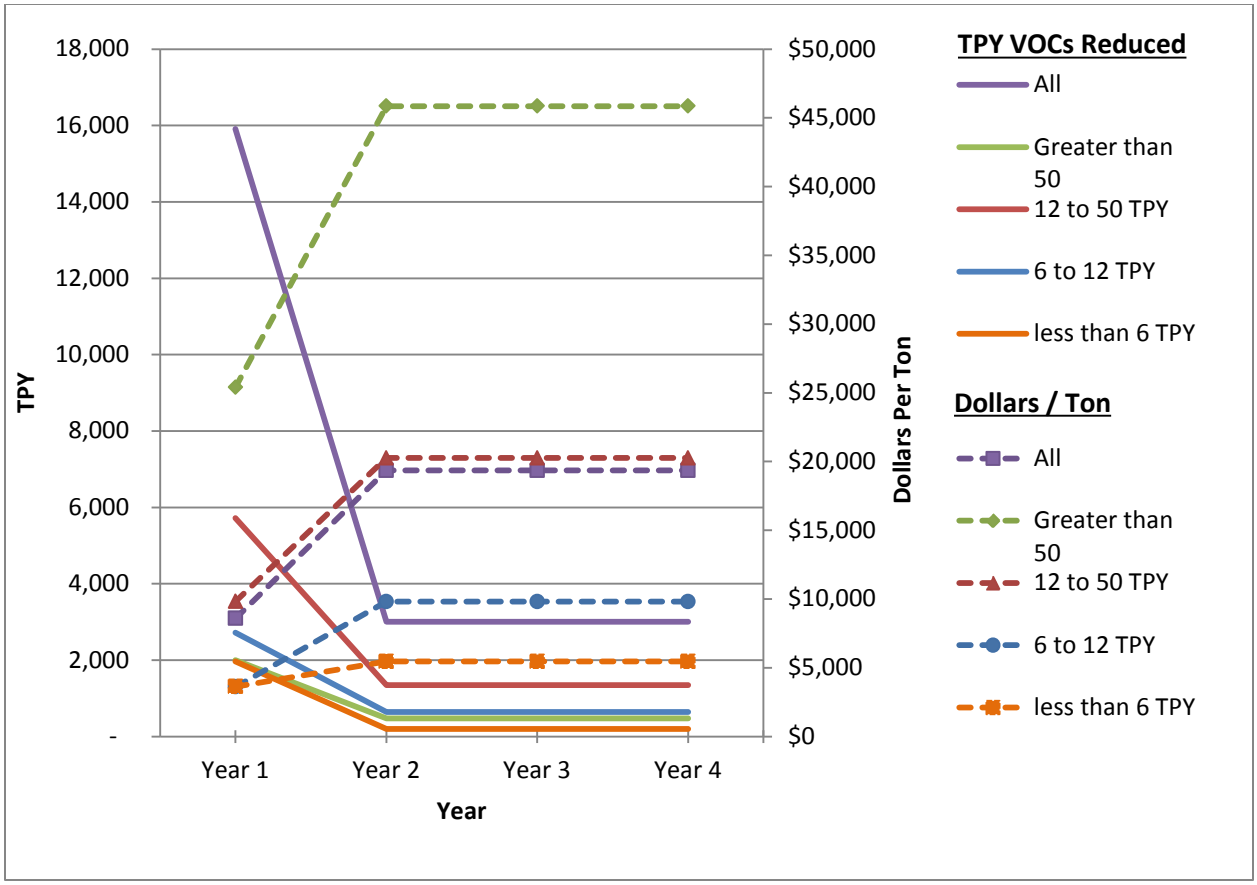


Figure 2: Well Production Facilities LDAR Costs and Emission Reductions Over Time

LDAR Costs for Compressor Stations

Louis Berger estimated LDAR costs for compressor stations with a similar approach as described above using the Division's estimates of the number of compressor stations affected by the proposed regulations. Louis Berger assumed two and four days per inspection for small and large compressor stations, respectively. Table 17 summarizes these assumptions.

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Table 17: Compressor Station LDAR Cost Assumptions (2013$)

Item	Estimated Cost	Annualized*	Unit Cost
Capital and Non-Recurring Costs			
Camera	$122,000	$28,179	$282 per inspection for small CS and $564 for large CS
Vehicle	$30,000	$6,929	$69 per inspection for small CS and $139 for large CS
Program set up costs (i.e., Tagging, software, travel, etc.)	$13,688 for small compressor stations, and $27,272 for large CS	$1,319 for small CS and $2,627 for large CS	$1,319/small CS and $2,627/large CS
Assume inspections would take 2 days to inspect for smaller facilities, 100 inspections with one camera per year; inspections would take 4 days for larger facilities, 50 inspections with one camera per year.			
Inspection, Operations and Maintenance costs			
Small CS with Annual LDAR	$6,468		$6,468/year/CS
Large CS with Quarterly LDAR	$32,683		$32,683/year/CS
Travel and per diem costs	$32		$32/Inspection
Supervision	$200		$200/CS
Camera Repair	$12,500		$12,500/year/camera
Camera Training	$7,500		$7,500 per 100 CS
Record-keeping and reporting of comments	$1,530 for small CS $3,060 for large CS		$1,540/small CS $3,060/large CS

*Camera and vehicle costs annualized at 5% over 5 year-life of the equipment. Program set up costs are annualized over 15 years at 5%.

Similar to the previous analysis, data on costs to repair components were obtained from Nelson and Brown (2012).[12] The initial year leak frequency rate was assumed to be 1.17 percent, consistent with the Trihydro study (2014). The number of components was assumed to be 2,544 for small compressor stations and 6,744 for large compressor stations. Cost assumptions for repairs and re-monitoring are similar to those described above.

Tables 18.1 and 18.2 summarize the LDAR costs for compressor stations. LDAR costs for 200 compressor stations were estimated to be $15.4 million. Small compressor stations are estimated to incur $26,353 per facility in the initial year, while larger compressor stations would incur $217,599 per facility in the initial year.

[12] Nelson, Bradley and Heather Brown. 2012. Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Use Emission and Cost Data from the Uniform Standards. Memorandum to Greg Nizich and Bruce Moore, EPA. April. See attachments 3 and 4.

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Table 18.1: Compressor Stations LDAR Cost Analysis for the Initial Year, Part 1

Compressor Station Uncontrolled VOC Emissions	Monitoring Frequency	Number of Compressor Stations	Number of Inspections/ Year	Capital Costs for Inspections (annualized) (1)	O&M Annual Costs for Inspections (2)	Number of Cameras Needed
Less than 12TPY	annual	147	147	$204,321	$1,245,835	2
12 to 50 TPY	quarterly	53	212	$288,112	$1,978,238	5
Greater than 50	monthly	-	-	-	-	-
Total	**-**	**200**	**359**	**$492,433**	**$3,224,073**	**7**

Table 18.2: Compressor Station LDAR Cost Analysis for the Initial Year, Part 2

Compressor Station Uncontrolled VOC Emissions	Monitoring Frequency	Number of Components	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitor Costs (4)	Total Annual LDAR Costs for Compressor Stations (1+2+3+4)	Per Compressor Station Cost, Initial Year
Less than 12	annual	2,544	6,357	$834,416	$1,589,364	$3,873,936	$26,353
12 to 50 TPY	quarterly	6,744	24,305	$3,190,081	$6,076,344	$11,532,775	$217,599
Greater than 50	monthly	-	-	$0	$0	$0	-
Total	**-**	**9,288**	**30,663**	**$4,024,497**	**$7,665,708**	**$15,406,710**	**$77,033**

Similar to the storage tank STEM analysis, following the initial implementation of a LDAR program, leak frequencies decrease, and as a result, the number of leaking components also decrease along with repair and re-monitoring costs, when compared to the initial year. Therefore, in subsequent years, the number of leaks was adjusted to reflect the reduced leak frequency (0.4%). As a result, reduced leak repair and re-monitoring costs with the adjusted number of leaks were estimated and shown in table 19. The total LDAR costs for subsequent years include the capital, and inspection and O&M costs in table 18 with the adjusted leak repair and re-monitoring costs in table 19.

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Table 19: Compressor Station LDAR Cost Analysis for Subsequent Years

Compressor Stations Uncontrolled VOC Emissions	Monitoring Frequency	Number of Components	Annual Number of Leaks	Leak Repair Costs (3)	Re-monitor Costs (4)	LDAR Costs for Compressor Stations in Subsequent Years (Annual Cost) (1+2+3+4)	Per Compressor Station Cost, Subsequent Years
Less than 12	annual	2,544	1,496	$196,333	$373,968	$2,020,457	$13,745
12 to 50 TPY	quarterly	6,744	5,719	$750,607	$1,429,728	$4,446,685	$83,900
Greater than 50	monthly	-	-	-	-	-	-
Total	**-**	**9,288**	**7,215**	**$946,940**	**$1,803,696**	**$6,467,142**	**$32,336**

The Division has identified an average uncontrolled emission rate for compressor stations of 10.1 TPY of VOCs for small compressor stations and 16.4 for large compressor stations, respectively. Louis Berger used these assumptions for uncontrolled emissions for the analysis as summarized in Table 20.

Table 20: Uncontrolled Emissions for Compressor Stations

Compressor Stations Uncontrolled VOC Emissions	Monitoring Frequency	Number of Compressor Stations	Uncontrolled VOC Emissions per Compressor Station (TPY)	Total Uncontrolled VOC Emissions (TPY)
Less than 12 TPY	annual	147	10.1	1,485
12 to 50 TPY	quarterly	53	16.4	869
Greater than 50	monthly	-	-	-
Total	**-**	**200**	**-**	**2,354**

Similar to the analyses on storage tanks and well production facilities, Louis Berger again uses the emission reductions associated with annual LDAR from the Clearstone Engineering, Ltd. study, described above, which estimates 75.3 percent emissions reductions associated with the annual LDAR program. Quarterly LDAR monitoring is assumed to be slightly more effective, reducing emissions by 76.5 percent, consistent with declining leak frequencies documented in the Trihydro report (2014).

As with tanks and well production facilities, Louis Berger accounts for subsequent year emission reductions with LDAR for compressor stations. The emission reductions in subsequent years are assumed to decrease by the proportion based on the reduction in leak frequency (0.4/1.7). The subsequent year costs were then divided by emission reductions in subsequent years to estimate the cost per ton of VOC reduced. Initial year cost per ton of VOC reduced is $8,641, while in subsequent years, the cost per ton of VOC reduced increases to $15,416. Table 21 shows the initial year and subsequent year total costs, emission reductions, and cost per ton of VOC reduced.

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Table 21: Compressor Station LDAR Cost per Ton of VOC Reduced in Initial and Subsequent Years

Compressor Stations VOC Uncontrolled Emissions	LDAR Costs	Emissions Reductions	Cost Per Ton of VOC Reduced	Annual LDAR Costs	Emission Reductions	Annual Cost Per Ton of VOC Reduced
	Initial Year			Subsequent Years		
Less than 12 TPY	$3,873,936	1,118	$3,465	$2,020,457	263	$7,681
12 to 50 TPY	$11,532,775	665	$17,344	$4,446,685	156	$28,421
Greater than 50	-	-	-	-	-	-
Total	**$15,406,710**	**1,783**	**$8,641**	**$6,467,142**	**420**	**$15,416**

Expanding Low Bleed Pneumatics Requirements Statewide

The Division is proposing to expand statewide the regulatory requirements mandating the use of low bleed pneumatic controls that were adopted for the nonattainment area in 2008. This section estimates the cost of the requirement to industry.

Under the proposed rules, high-bleed pneumatic controllers shall be replaced or retrofitted with low-bleed pneumatic devices by May 1, 2015. It is assumed that the Division would define a low-bleed pneumatic device as one that emits less than or equal to 6 standard cubic feet per hour (scfh), while high-bleed devices bleed at a rate greater than 6 scfh. The Division has estimated that 9,877 high-bleed pneumatic devices are being utilized outside the nonattainment area. Louis Berger utilizes this estimate of the number of devices that will need to be replaced to comply with the proposed rule.

The EPA through their Natural Gas Star Program, has evaluated the effectiveness of reducing methane emissions through the replacement of high-bleed pneumatic devices with low-bleed pneumatics. In the document titled, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", EPA provides estimates of costs, service life, benefits and decision process for determining the feasibility of replacing high-bleed pneumatics.[13] The costs of several models of pneumatic devices are summarized in Appendix B and range from $380 to $3,500 in 2006 dollars. In addition, EPA reported the average cost of a low-bleed pneumatic device of $2,553 in 2008 dollars. Based on this information, Louis Berger assumes the cost of low-bleed pneumatic devices averages $2,775 adjusted to 2013 dollars. In addition, the analysis assumes a service life of 5 years[14] and cost are annualized at a 5 percent interest rate.

Replacement of pneumatic devices would require an initial assessment of the devices used at various facilities. The EPA suggests that a system-wide or facility-specific pneumatic survey would need to record for each device "location, function, make and model, condition, age, estimated remaining useful

[13]U.S. EPA, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", October, 2006.
[14] U.S. EPA, "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry", October, 2006.

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life, and bleed rate characteristics (volume and whether intermittent or continuous)."[i] Louis Berger has estimated the cost of conducting a pneumatic survey in the cost of the regulatory mandate as summarized in Table 22. Total cost of the mandate is estimated to be $32 million.

Table 22: Estimated Cost of Low-Bleed Pneumatic Devices

Item	Estimated Cost	Annualized*
Capital and Non-Recurring Costs		
Low-Bleed Pneumatic Devices	$2,775	$641
Pneumatic Survey	$500	$115
Total Cost	**$3,275**	**$756**

*Annualized at 5% over a five year service life.

Replacing high-bleed pneumatics with low-bleed devices will likely result in gas savings and the value of these savings per device are estimated in Table 23. Payback period is estimated to be 2.8 years.

Table 23: Gas Savings Associated with Low-Bleed Pneumatic Devices

Estimated Annual Bleed Emission Reductions (Methane) (Tons)[ii]	Gas Volume (Mcf)	Gas Price ($/Mcf)	Value of Gas Recovered
(1)	(2) = (1)*40.49 Mcf/ton	(3)	(4) = (3) * (2)
6.65	269	$4.34	$1,168

Recovered Product Estimates Attributable to proposed STEM and LDAR Requirements

In their analysis of cost effectiveness of LDAR requirements, the Division "…assumes that the costs savings from additional product capture will be equal or greater than the cost of repair and re-inspection."[15] In order to test the validity of this assumption, Louis Berger estimated the product savings that can be expected from LDAR requirements for well production facilities and compressor stations.

Gas Savings Attributed to LDAR – Well Production Facilities

Product savings attributable to the LDAR program as it relates to well production facilities in the initial year are estimated as shown in Table 24. Column 1 shows that 15,913 tons of VOCs are estimated to be detected and captured by the LDAR program for all well production facilities in the initial year of the program (see Table 16). Louis Berger used a Gas/VOC ratio (22.4%) reported by the Division in their analysis of LDAR costs of well production facilities to estimate the amount of gas that would be captured by the controls. In this case, 71,040 tons of gas is expected to be captured by the LDAR program at well production facilities in the initial year. The gas mass was then converted to a volume metric using a

[15]Colorado Air Quality Control Commission 2014. Updated Economic Impact Analysis for Proposed Revisions to AQCC Regulations Number 7. Submitted with Pre-Hearing Statement on January 6, 2014. Page 17.

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natural gas density factor and results in 2,876,121Mcf of gas recovered. The value of the recovered gas was estimated at $12.4 million for the initial year using a recent natural gas price of$4.34 Mcf. The value of the product savings equates to 8.8 percent of the total LDAR costs ($136 million) for the initial year of implementation.

Table 24: Product Savings Attributable to the LDAR Program for Well Production Facilities for the Initial Year

Tons of VOCs Captured by LDAR Program at WPF	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for WPF (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
15,913	22.4%	71,040	2,876,121	$4.34	$12,482,363

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

For subsequent years, the LDAR program at well production facilities is expected to realize product savings though they are expect to decline from the initial year. An estimate of the amount and value of the product saved is estimated as shown in Table 25. Using the same approach as used for the initial year, the amount of natural gas expected to be recovered in subsequent years is estimated to be 543,125 Mcf and is valued at $2.3 million which is less than four percent of the total annual LDAR costs in subsequent years.

Table 25: Product Savings Attributable to the LDAR Program for Well Production Facilities for Subsequent Years

Tons of VOCs Captured by LDAR Program at WPF	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for WPF (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
3,005	22.4%	13,415	543,125	$4.34	$2,357,161

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

The Division's assertion that product captured and sold would offset costs of repair and re-monitoring is not supported by this analysis. Well production facility LDAR repair and re-monitoring costs in the initial year are estimated to be $90.0 million (see table 13), while the value of the recovered gas is estimated to be $12.4 million in the initial year, or 13.8 percent of the repair and re-monitoring cost. In subsequent years, the value of the gas recovered would offset 10.9 percent of the repair and re-monitoring costs.

Gas Savings Attributed to LDAR – Compression Stations

Gas savings attributable to the LDAR program as it relates to compressor stations in the initial year are estimated as shown in Table 26. The amount of gas that is expected to be detected and captured by a successful LDAR program at compressor stations during the initial year is 322,260 Mcf and is valued at $1.3 million. This value represents 8.6 percent of the total cost of the LDAR program during the initial year. It is worth noting that Louis Berger believes the estimated product savings for compressor stations may be conservatively high. This opinion is based on the likelihood that the gas/VOC ratio is not as high for compressor stations as it is for well production facilities.

Table 26: Product Savings Attributable to the LDAR Program for Compressor Stations for the Initial Year

Tons of VOCs Captured by LDAR Program for Compressor Stations	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for Compressor Stations (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
1,783	22.4%	7,960	322,260	$4.34	$1,398,608

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

For subsequent years, the LDAR program at compressor stations is also expected to generate gas savings though these savings are expected to decline from the initial year. An estimate of the amount and value of the project saved is shown in Table 27. The amount of natural gas expected to be recovered in subsequent years is estimated to be 1,875Mcf and is valued at $329,453 which represents 5 percent of total annual costs of the program in subsequent years.

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Table 27: Product Savings Attributable to the LDAR Program for Compressor Stations for Subsequent Years

Tons of VOCs Captured by LDAR Program for Compressor Stations	Average Gas/VOC Ratio[1]	Tons of Methane Captured by LDAR Program for Compressor Stations (Tons)	Natural Gas Volume Recovered (MCF)[2]	Natural Gas Price ($/Mcf)[3]	Value of Recovered Gas
(1)	(2)	(3) = (1) / (2)	(4) = (3)/0.0247 ton/mcf	(5)	(6) = (4) * (5)
420	22.4%	1,875	75,911	$4.34	$329,453

[1] Taken from the Division's calculation on LDAR costs for well production facilities. Spreadsheet titled "APCD-PHS EX-RR.xlsx"; sheet: statewide wells model FAC.

[2] Natural gas volumes calculated by assuming a gas density of 0.791 kg/m3 and converted to English units.

[3] Henry Hub Natural Gas Spot Price for December, 2013. Obtain from the Energy Information Agency at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

The Division's assertion that product captured and sold would offset costs of repair and re-monitoring is not supported by this analysis. Compressor station LDAR repair and re-monitoring costs in the initial year are estimated to be $11.7 million (see table 13), while the value of the recovered gas is estimated to be $1.4 million in the initial year, or 12.0 percent of the repair and re-monitoring cost. In subsequent years, the value of the gas recovered would also offset only 12.0 percent of the repair and re-monitoring costs.

Indirect Costs of Regulations on Small Operators and Marginally Producing Wells

In order to gain an understanding of the potential indirect costs to businesses, in particular small businesses, if the proposed rules were implemented, Louis Berger evaluated the impacts on small operators and marginally producing wells within the state. Evaluation of historical production and well count data maintained by the Colorado Oil and Gas Conservation Commission (COGCC) indicates that 25,463 conventionally completed wells produce approximately 1.57 million barrels of oil per month (BOPM) or on average two barrels of oil per day as of mid-year 2013. These marginally producing wells represent over half (55 percent) of the total producing wells in the state (46,495) as of 2013. Given the likelihood that smaller operations would be negatively impacted by the increased costs of the proposed rules and regulations as well as the large percentage of these wells that occur within the state, small and marginally producing operations are the focus of this analysis.

Louis Berger first evaluated the economic limit (in barrels per day) that marginally producing wells would realize under current economic and regulatory conditions. The economic limit is defined as the point that production levels are no longer economic given a number of factors (price of oil, lease costs, tax rates, etc.). Relevant assumptions for this analysis are as follows:

- Current Rate of Production – 2 BOPD
- Oil Price - $90 ($/BO)
- Severance Tax Rate – 5%

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- Net Return on Investment (NRI) (well income minus royalties) – 80%
- Lease Operating Expense ($/well/month) (includes ad valorem taxes) - $900
- Number of Tanks per lease – 2
- Number of Wells per lease – 4
- Production Decline Rate – 2.5%

The economic limit in barrels of oil per day (BOPD) was calculated for wells using the following equation.

$$\textit{Economic Limit (BOPD)} = \frac{\text{Lease Operating Expense (LOE)}}{\textit{(Oil Price) * (30.4 days) * (NRI * (1- severance tax))}}$$

Implementation of the new air quality rules would have an impact on lease operating expenses for each well. The increase costs would change the economic limit for each well as shown in Figure 3. Under current economic and regulatory conditions, the economic limit for marginally producing wells was estimated to be 0.43 BOPD. In other words, when production falls below 0.43 BOPD, the well is no longer economic and will be shut it or plugged. If lease operating costs increase, the economic limit increases, causing wells to be shut in earlier than planned. This leads to oil left in place as shown in Figure 3.

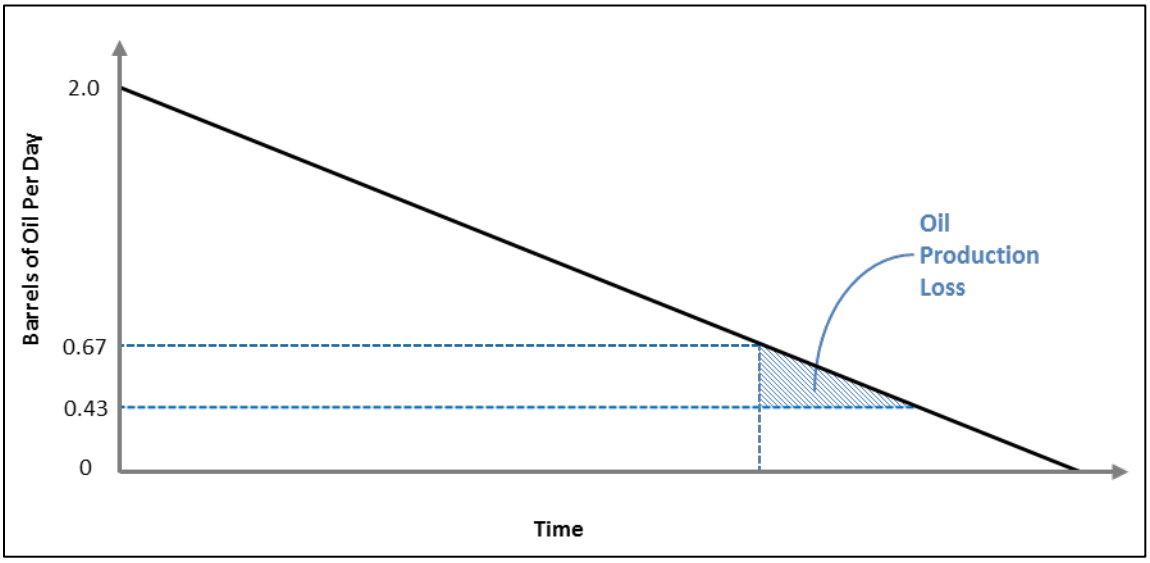


Figure 3: Oil Production Loss with an Increase in the Economic Limit

The amount of production that would result under different economic limits was calculated as follows.

$$\textbf{Remaining Oil} = \frac{(Q_i - Q_f) * 365}{\text{Limit } (1 - \text{Decline Rate})}$$

Where:

Q_i = *Current Production Rate = 2 BOPD*
Q_f = *Calculated Economic Limit*

Louis Berger estimated the economic limit for marginally producing wells if the air regulations relevant to oil and gas operations were implemented as proposed by the Division. The STEM costs for tanks and the LDAR costs for well production facilities were included as additional monthly unit costs in the lease operating expenses, increasing these costs for operators. The results are summarized in Table 19. Changes in lease operating costs due to the regulations were estimated for different sizes of facilities. Costs are expected to increase from $22 to $1,290 per month with an average of $729 for all facilities. The increase costs are expected to increase the economic limit from 0.44 to 1.05 BOPD, depending on the size of facilities.

The additional cost burden would result in as much as 128.6 million barrels of oil being left in place and not produced over time. Assuming a price per barrel of oil is $90, this would equate in $11.6 billion in lost revenue to producers, $2.3 billion in lost royalties and $579 million in lost severance taxes. Present values for these losses are $1.9 billion in lost revenue, $384 million in lost royalties and $96 million in lost severance taxes.[16]

[16] Present value analysis assumed a 10 percent discount rate over 60 years.

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Table 28: Evaluation of Impacts of Air Regulation Costs on Marginally Producing Wells

Item	Oil and Gas Leases					
	Base Case	WITH WPF & TANK less than 6	WITH WPF & TANK s>=6 to <=12	WITH WPF & TANK s>12 to <= 50	WITH WPF & TANK >50	WITH WPF & TANK TOTAL
LOE ($/well/month)	$900	$900	$900	$900	$900	$900
Additional LOE with new rules ($/well/month)	$0	$22	$565	$743	$1,290	$729
Total LOE ($/wee/month)	$900	$922	$1,465	$1,643	$2,190	$1,629
Economic Limit (BOPD)	0.43	0.44	0.70	0.79	1.05	0.78
Remaining Oil (BO)	22,594	22,442	18,679	17,442	13,652	17,543
Estimated Oil Shut In (BO)	-	152	3,914	5,151	8,942	5,051
Facility Allocation	-	0.35	0.17	0.35	0.12	1
Production Lost (BO)	-	1,353,302	16,944,548	45,908,655	27,321,315	128,611,449
Lost Royalties ($)	-	$24,359,432	$305,001,869	$826,355,781	$491,783,676	$2,315,006,074
Lost Severance Taxes ($)	-	$6,089,858	$76,250,467	$206,588,945	$122,945,919	$578,751,519

*Values in the table have not been discounted and reflect revenues and costs over the life of the well.

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Costs to Division to Implement Proposed Rules

The Economic Impact Analysis requires an assessment of the cost for the Division to implement the proposed rule changes. Oversight of an LDAR program, STEM plans, and annual report review of 5,312 tank batteries, 5,312 well production facilities, and 200 compressor stations with possibly hundreds of thousands of components would require additional Division manpower. Louis Berger reviewed the revised (November 21, 2013) Regulations 3, 6 and 7 to understand the implementation costs to the Division associated with the new rules. A summary of potential cost implications for the Division, as result of the rule changes, is provided in Table 29. The rationale for the estimated additional costs or cost savings is provided after the table.

Table 29: Summary of Potential Implementation Costs to the Division with Proposed Changes in Regulation 3, 6, and 7

Regulation Subpart	Description	Cost Impact	Estimated Savings/Cost
Regulation 3			
Minor Source Permits	Facilities with emissions less than the APEN no longer have to file for a minor source permit.	Cost Savings	An estimated 882 hours per year in labor would be saved from not having to review and approve minor source permits.
Standardization of de minimis Reporting Threshold	The de minimis reporting threshold would be set to a standard of 250 pounds per year. This increases the clarity of reporting requirements.	Cost Savings	An undetermined amount of savings would be realized by the Division.
Crude Oil Storage Tank Permitting	Additional permits would now be required for crude oil tanks as the tank permitting exemptions are removed.	Cost Increase	An estimated 128 hours per year in additional labor would be required to review and approve permits.
Regulation 6			
Adoption of NSPS OOOO	This regulation adopts NSPS OOOO. No additional impacts beyond the minimum required by federal law would occur.	No Impact	No Impact
Regulation 7			
Evaluation of Operation and Maintenance of Air Pollution Control Equipment	The Division would be required to make determinations on the acceptableness of operating and maintenance procedures used to control Air Pollution Control Equipment.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required to review and monitor o&m procedures.
Approval of STEM Plans	The Division would be required to review and approve STEM plans for compliance with regulatory requirements.	Cost Increase	An estimated 5,600 hours in additional labor would be required for review and approval of STEM plans.

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Ongoing Management of STEM Program	The Division would incur labor costs for review of records that would be retained by each operator or owner as part of their STEM plan compliance.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required.to manage the STEM program
Division Approval of Monitoring Devices or Methods	When the Division is required to approve monitoring devices or methods not mentioned in these regulations it is anticipated that additional labor costs to the Division would occur.	Cost Increase	An undetermined additional cost would be incurred by the Division.
Recordkeeping Requirements	The owner or operator of each facility is required to keep records of various tests and repairs. It anticipated that the Division would review a percentage of these records annually.	Cost Increase	An estimated 1,062 hours per year in additional labor would be required.
Reporting Requirements	Each owner or operator is required to submit an annual report summarizing the inspection and maintenance activities of all facilities during the previous year. It is anticipated that the Division would review a percentage of these annual reports.	Cost Increase	An estimated 2,125 hours per year in additional labor would be required to review annual reports.
Venting Recordkeeping Requirements	Each owner or operator is required to record venting statistics and make them available to the Division upon request. Additionally, the Division may be called upon to make a determination on the visibility of venting. It is anticipated that the Division would commit a certain amount of time annually to reviewing these venting records and making visibility determinations on venting events.	Cost Increase	An estimated 2,125 hours per year in additional labor would be required for review and monitoring.

The following section provides an explanation of the implementation cost analysis summarized in Table 29 for each proposed rule change.

Regulation 3

Minor Source Permits

Under Regulation 3, the Division is proposing that NSPS OOOO affected facilities with uncontrolled actual emissions that are less than the APEN and minor source permit thresholds no longer automatically have to file APENs and obtain minor source permits. As such, it expected that the Division would realize an implementation cost savings with this proposed rule change. As a result of this revision, up to 441 facilities would be exempt from submitting an APEN. If it is assumed that it requires two hours to process each APEN application, then this rule change could save the Division up to 882 hours of processing time. This would allow the Division to reallocate permitting resources to more complicated sources with greater impact to Colorado air quality, as well as develop and maintain other guidance and compliance assistance tools.

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Standardization of de minimis Reporting Threshold

The Division is proposing to revise method (Part A, Appendix A) for determining non-criteria reportable pollutant de minimis levels in order to standardize the de minimis reporting threshold and set a 250 pounds per year threshold for all non-criteria reportable pollutants, regardless of the pollutant, height of release point or distance to property boundary. This revision increases regulatory clarity and reduces the administrative reporting burdens on both sources and the Division by simplifying the process. This revision is therefore anticipated to reduce costs to the Division though it is uncertain what the cost savings would be for this rule change.

Crude Oil Storage Tank Permitting

The Division is proposing to remove the crude oil storage tank permitting exemptions in Part B, Section II.D.1.n. and Part C, Section II.E.3.ddd. It is estimated that up to 64 additional crude oil tanks would be required to obtain a permit under this revision. If it is assumed that it takes approximately two hours to review and issue each permit, it is anticipated that this would result in up to 128 hours of additional labor for the Division each year to implement this rule.

Regulation 6

This regulation adopts NSPS OOOO; therefore, this rule makes NSPS OOOO enforceable under Colorado law and is not anticipated to impose additional requirements beyond the minimum required by federal law. The revised changes to this regulation are not anticipated to impact regulation implementation costs to the Division.

Regulation 7

It is anticipated that several new provisions of the revised Regulation 7 would require owners or operators of facilities to prepare reports and documentation or perform tasks that would require review, approval and inspection by the Division. These additional tasks are expected to result in an increase in the implementation costs to the Division.

Evaluation of Operation and Maintenance of Air Pollution Control Equipment

The revised regulations would require that air pollution control equipment be maintained and operated in a manner consistent with good air pollution practices. A determination on whether or not acceptable operating and maintenance procedures are being used at a facility would be based on information provided to the Division by the owner or operator of the facility. This information could include, but would not be limited to: monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The requirement for the Division to make a determination on the acceptability of operating and maintenance procedures is expected to take 2 hours per facility per year. The Division has reported that there are 5,312 facilities that would be affected by this rule. If it is assumed that the Division would review approximately 10 percent of these records annually, then the rule change would require an additional 1,062 labor hours per year for implementation.

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Approval of STEM Plans

Owners or operators of storage tanks would be required to develop, certify and implement a Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation under the revised Regulation 7. It has been estimated that approximately 5,312 storage tanks under the revised regulations would have to meet the STEM requirements. Assuming that a STEM plan could be developed for sites with multiple tanks (2), at most, 2,800 STEM plans would be developed and require review by the Division. Assuming the Division would review and approve each plan and it would require 2 hours per review would result in an additional 5,600 hours to initially review and approve the individual STEM plans, resulting in additional implementation costs as a result of the revised regulation.

Ongoing Management of STEM Program

As each owner or operator of a storage tank subject to section XII.D or XVII.C under the revised regulation must maintain records of STEM, including the plan, any updates, and the certification; and as these records should be made available to the Division upon request, it is anticipated that the Division would incur additional implementation costs as a result of this requirement. Further document retention requirements under the revised regulation would include retention of the AIRS ID for the storage tank; the date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions; the date and duration of any period where the air pollution control equipment is not operating, or where a flare or other combustion device is being used; the date and result of any Method 22 test, as well as the timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions. While the Division is not required to review this information, the requirement for the retention of this information would allow it to be reviewed. It is anticipated that the Division would review approximately 10 percent of these records annually. As there would be at most 5,312 facilities under the revised regulations subject to these requirements and each would take an assumed 2 hours of review per set of records, this would require, at most, 1,062 hours per year, resulting in additional implementation costs as a result of the revised regulation.

Division Approval of Monitoring Devices or Methods

Under section XVII.F.6, the Division may be required to approve monitoring devices or methods not mentioned in these regulations, resulting in additional time and funding costs to the Division.

Recordkeeping Requirements

As a result of recordkeeping requirements under the proposed regulation, the owner or operator of each facility subject to inspection and maintenance requirements under Section XVII.F is required to maintain documentation of the pre-start-up pressure tests for new well production facilities; date and site information for each inspection; a list of leaking components and monitoring method used to determine the presence of the leak; the date of the first attempt to repair the leak and additional

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attempts; the date the leak was repaired; the delayed repair list; the date the leak was re-monitored to verify effectiveness of the repair and the results of re-monitoring effort; and a list of identification numbers for the components designated as unsafe or inaccessible to monitor, as well as an explanation for each component stating why the component was so designated and the plan for monitoring such components for a period of two years and make them available to the Division upon request. It is anticipated that the Division would review approximately 10 percent of these records annually. As there would be at most 5,312 facilities under the revised regulations subject to these requirements and it is assumed to take approximately 2 hours of review per set of records, this would require, at most, 1,062 hours per year in additional labor. This would result in increased implementation costs of Regulation 7.

Reporting Requirements

In addition to recordkeeping, the owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F would be required to submit a single annual report each year summarizing the inspection and maintenance activities at all of their subject facilities during the previous year. This report would contain at least the number of facilities inspected as well as the total number of inspections, leaks identified, categorized by component type and the number of leaks repaired. It would also require the identification of the number of leaks on the delayed repair list at the end of the calendar year. Additionally, each of these reports would be required to be accompanied by a self-certification form certifying the accuracy of the information in the report. It is anticipated that review of one annual report by the Division would require 4 hours. As there would be at most 5,312 annual reports, depending on the ownership of individual facilities in the state of Colorado, this new requirement is anticipated to add an additional amount of 2,125 hours, at most, of labor to the Division each year. This would result in increased implementation costs of Regulation 7.

Venting Recordkeeping Requirements

Records of the cause, date, time, and duration of venting events under Section XVII.H would be required to be kept and made available to the Division upon request under the revised regulation. Regarding visible emissions, the Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. When the venting event records are reviewed by the Division or if the Division makes a determination on the visibility of emissions this would result in additional implementation costs as a result of the revised regulation. It is anticipated that the average time required to determine the visibility of emissions or review the records of a facility would be four hours per facility. As there would be, at most, 5,312 facilities that may require review by an inspector annually and assuming 10 percent of these facilities require monitoring per year it is anticipated that up to 2,125 labor hours would be required. This would result in increased implementation costs of Regulation 7.

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Conclusions

The net increase in the number of labor hours at the Division as result of the proposed regulations is anticipated to be approximately 12,282 labor hours annually. Notably, the Division would need 5,600 hours to review and approve initial STEM plans required under Regulation 7, the largest estimated time commitment for the Division. This represents approximately 6.1 FTEs of additional staff for the Division to review, oversee, inspect, manage, and approve various requirements associated with the proposed rules. Therefore, Louis Berger concludes that the Division would incur significant additional net costs to implement the proposed requirements beyond current expenditures, contrary to the Division's assertions to date.

Support of Industry's Proposed Language

The results of the initial economic impact analysis presented here support the industry's key suggested revisions to the Division's proposed rule. Specifically, the proposed revisions will allow similar emission reductions to be achieved in a much more cost effective manner than the regulatory approach proposed by the Division. Key points to the analysis include:

- Diminishing marginal benefits associated with LDAR programs implies increasing costs per ton of VOC reduced after initial rounds of inspections and repairs. Reducing the monitoring to reflect successful LDAR implementation reduces costs and improves the cost effectiveness of the proposed rule compared to the Division's proposal while maintaining program integrity through realized emission reductions. The "step-down" of monitoring frequency, which rewards companies with four inspections with no leaks, is an example of how the industry changes to the proposed rule would provide incentives for industry to maintain compliance and reduce costs for good performance.
- Generally, compliance costs of STEM and LDAR for small tanks and well production facilities are more burdensome than for larger facilities on a cost per ton basis. As such, requiring a one-time LDAR inspection and monthly AVO for all facilities (including all well production facilities) with uncontrolled emissions between 2 and 6 TPY would improve the overall cost effectiveness of the proposed rule by limiting the very high costs per ton of VOC reduced incurred by very small facilities with very small VOC fugitive emissions.
- Compliance costs are higher for operations outside of the non-attainment area as the distance among facilities and tanks increases inspection travel time and expenses. Limiting the geographic scope to the non-attainment area will improve the cost effectiveness of the proposed rule.
- Allowing for the use of other established technology, such as the tunable diode laser absorption technology (TDLAS), as an option for inspection monitoring, would reduce costs to industry with faster inspections, reduced camera training requirements, among other factors.

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Expert Rebuttal Report and Rebuttal Written Testimony of Gernot Wagner, Ph.D. Characterizing the Economic Benefits of Anticipated Methane Reductions for the Proposed Amendment to Colorado's Proposed Oil and Gas Regulation with Respect to Climate Change

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January 30, 2014

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Expert Introduction: Dr. Gernot Wagner

My name is Gernot Wagner, Ph.D., and I am a senior economist at EDF, where I co-lead the office of economic policy and analysis to advocate for market-based solutions to a wide range of environmental problems. I teach energy economics as adjunct faculty at Columbia's School of International and Public Affairs, and I am the author of *But Will the Planet Notice?* (Hill & Wang/Farrar, Strauss & Giroux, 2011) and, joint author with Harvard University's Martin Weitzman, of the forthcoming *Climate Shock* (Princeton University Press). I am a research associate at the Harvard Kennedy School and a term member of the Council on Foreign Relations. Prior to EDF, I worked for the Boston Consulting Group and served on the editorial board of the *Financial Times*. I hold a Ph.D. and M.A. in Political Economy and Government as well as an A.B. in Environmental Science and Public Policy, and Economics (*magna cum laude* with highest honors in the field) from Harvard University, and an M.A. in Economics from Stanford University. A copy of my cv is attached as Exhibit A to this expert report and testimony.

The following is my written testimony on the topics covered in this report, based on my education, research, and expertise on the topic of the Social Cost of Carbon and related issues.

Summary of Written Testimony and Expert Opinion

Calculating the social costs of greenhouse gas pollutants has a long tradition in the academic literature. In 2010, the United States' Interagency Working Group ("IWG") calculated the Social Cost of Carbon ("SCC") in a transparent, well-reviewed inter-agency process involving a dozen federal agencies and entities. A routine update in 2013, reflecting the latest changes in the peer-reviewed literature resulted in a central estimate for the SCC of $37 per ton of carbon dioxide emitted in 2015. Converting the value into one reflecting the social cost of methane – and making conservative assumptions every step along the way – results in a central value of the social benefit of methane reductions for the proposed oil and gas rule in Colorado per year: over $104,000,000 when fully implemented in 2016 and increasing to $132,000,000 in 2025. The upper range of the central estimate reaches over $318,000,000 per year in 2016 and over $404,000,000 per year in 2025.

Social Cost of Carbon

The SCC is a monetary measure of the incremental damage to the climate resulting from carbon dioxide emissions. The SCC assigns a net present value to the marginal impact of one additional ton of carbon dioxide emissions released at a specific point in time. The SCC is based on a large and growing body of research regarding the quantitative economic damages that would result from unmitigated climate change. These economic estimates are typically based on the results of integrated assessment models, in which a scientific model of the predicted physical impacts of climate change is paired with a socio-economic model that evaluates the economic impact of these effects.

The most comprehensive effort to calculate the SCC is the work published by the IWG. The IWG is a group of numerous federal agencies/departments, including the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and the Department of the Treasury. The IWG developed the SCC through an open and transparent process, involving extensive meetings, public comment and peer review. The SCC developed by the IWG is widely used in regulatory rulemakings in the United States.[1]

[1] The SCC has been used in numerous notice-and-comment rulemakings by various agencies since it was published in 2010, and each of these occasions has provided opportunity for public comment on the SCC. *See, e.g.*, Energy Conservation Program: Energy Conservation Standards for Residential Clothes Washers, 77 Fed. Reg. 32,381 (May 31, 2012); Energy Conservation Program: Energy Conservation Standards for Residential Dishwashers, 77 Fed. Reg. 31,964 (May 30, 2012); Energy Conservation Program: Energy Conservation for Battery Chargers and External Power Supplies, 77 Fed. Reg. 18,478 (Mar. 27, 2012); Energy Conservation Program: Energy Conservation Standards for Standby Mode and Off Mode for Microwave Ovens, 77 Fed. Reg. 8526 (Feb. 14, 2012); Energy Conservation Program: Energy Conservation Standards for Distribution Transformers, 77 Fed. Reg. 7282 (Feb. 10, 2012); Energy Conservation Program for Certain Industrial Equipment: Energy Conservation Standards and Test Procedures for Commercial-Heating, Air-Conditioning, and Water-Heating Equipment, 77 Fed. Reg. 2356 (Jan. 17, 2012); 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards, 76 Fed. Reg. 74,854 (Dec. 1, 2011); Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738 (Aug. 23, 2011); Energy Conservation Program: Energy Conservation Standards for Residential Furnaces and Residential Central Air Conditioners and Heat Pumps, 76 Fed. Reg. 37,549 (June 27, 2011); Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers and Room Air Conditioners, 76 Fed. Reg. 22,324 (Apr. 21, 2011); Energy Conservation Program: Energy Conservation Standards for Fluorescent Lamp Ballasts, 76 Fed. Reg. 20,090 (Apr. 11, 2011); National Emission Standards for Hazardous Air Pollutants: Mercury Emissions from Mercury Cell Chlor-Alkali Plants, 76 Fed. Reg. 13,852 (Mar. 14, 2011); Greenhouse Gas Emissions Standards

The IWG's most recent value for the social cost of carbon is $37/ton (central value for a ton released in 2015, assuming a 3% discount rate).[2] The SCC is derived from running three state-of-the-art, peer-reviewed Integrated Assessment Models ("IAMs") that quantify the costs of climate change to the economy. They project future economic output with and without climate change using five reference scenarios and three constant discount rates of 2.5, 3, and 5 percent. The use of three models, three discount rates, and five scenarios produces a number of distributions for the SCC. The final $37 number is the average of the monetized effect found by all three models under the central model run, assuming a 3% discount rate. SCC values rise over time, reflecting the increased costs of unmitigated climate change over time. A ton emitted in 2020 is calculated to come with a social cost of $43; a ton emitted in 2025 will cost $47 (Table 1).

This central value is conservative because it does not reflect a declining discount rate, fully value impacts associated with catastrophic events, or include non-monetized benefits. The latter may be the most significant omission, since quantifying the full cost of climate damages is difficult. The IWG also presents a value for the 95th-percentile of the SCC distribution as a conservative proxy for including the value of extreme events (Table 1). This estimate can only be seen as a proxy and is likely a large underestimate of the actual damages in extreme situations.[3]

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and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, 75 Fed. Reg. 74,152 (Nov. 30, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, 75 Fed. Reg. 63,260 (Oct. 14, 2010); Energy Conservation Program: Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers, 75 Fed. Reg. 59,470 (Sept. 27, 2010); Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 75 Fed. Reg. 45,210 (Aug. 2, 2010).

[2] EDF-REB-GW-EX B. "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" (November 1, 2013)

[3] E.g.: Pindyck, Robert S. 2012. "Uncertain outcomes and climate change policy." Journal of Environmental Economics and Management 63, no. 3: 289-303. (EDF-REB-GW-EX C) Weitzman, Martin. "GHG Targets as Insurance Against Catastrophic Climate Damages." Journal of Public Economic Theory. 2012;14(2):221-244. (EDF-REB-GW-EX D) Pindyck, Robert S. 2013. "The Climate Policy Dilemma." Review of Environmental Economics and Policy vol. 7(2):219-237. (EDF-REB-GW-EX E) Wagner, Gernot and Richard J. Zeckhauser. "Expecting a Black Swan and Getting a Dragon: Confronting Deep Uncertainty in Climate Change." ASSA Conference presentation (January 3, 2014). (EDF-REB-GW-EX F)

Table 1—Social cost of carbon dioxide, 2010-2050 (in 2007 dollars per metric ton of CO_2)

	5.0%	3.0%	2.5%	3.0%
Year	Avg	Avg	Avg	95th
2010	11	32	51	89
2015	11	37	57	109
2020	12	43	64	128
2025	14	47	69	143
2030	16	52	75	159
2035	19	56	80	175
2040	21	61	86	191
2045	24	66	92	206
2050	26	71	97	220

Using the Social Cost of Carbon to Calculate Damage associated with Methane Emissions

Each greenhouse gas has its own potential to force changes to the climate, and those impacts can also differ over time. To evaluate the SCC of a non CO2 greenhouse gas, such as methane, it is necessary to convert those emissions to the same units as the SCC, using the Global Warming Potential ("GWP") of the gas at issue. GWP is a measure of the climate forcing potential of a gas (such as methane) relative to CO2.

The most recent Intergovernmental Panel on Climate Change ("IPCC") establishes the 100-year GWP for methane at a figure of at least 28, which means that methane is 28 times more potent

than CO2 over a 100-year period.[4] However, because methane causes greater climate damage over shorter time frames than over longer time frames, choosing a 100-year GWP will undervalue the short-term impacts of methane. Accordingly, the benefits of methane reductions should also be valued using the most-recent 20-year GWP for methane, which is at least 84.

These GWP values for methane (28 long term and 84 short term) are conservative because they do not include climate-carbon ("cc") feedbacks (which are feedbacks between climate change and the carbon cycle). The latest IPCC report concludes that, when cc is considered, methane has an even higher GWP on both 100- and 20-year timeframes of 34 and 86, respectively.[5] Other scientific analyses have likewise determined that methane is an even more potent climate forcer.[6]

Table 2 below shows the GWP of methane in the short and long term from the most recent IPCC report, both with and without climate-carbon feedback.

Table 2—Global Warming Potential (GWP) of methane relative to one metric ton of CO_2

	Global Warming Potential (GWP) relative to CO_2
100-year GWP without cc feedbacks	28
100-year GWP with cc feedbacks	34
20-year GWP without cc feedbacks	84
20-year GWP with cc feedbacks	86

[4] CLIMATE CHANGE 2013: THE PHYSICAL SCIENCE BASIS, CONTRIBUTION OF WORKING GROUP I TO THE FIFTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE at Table 8.A.1 (Joussaume, S., J. Penner & F. Tangang eds. 2013), *available at* http://www.climatechange2013.org/images/uploads/WGIAR5_WGI-12Doc2b_FinalDraft_All.pdf.
[5] *Id.* at Table 8.7.
[6] EDF-REB-GW-EX G. D.T. Shindell, G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, S.E. Bauer (2009) "Improved Attribution of Climate Forcing to Emissions," *Science* **326** 716-718.

This conversion yields a conservative estimate—undervaluing the benefits of methane reductions by up to 36%.[7]

Calculating the Benefits of Anticipated Methane Reductions from Proposed Changes to Air Pollution Control Regulations in Colorado

An expert retained by EDF, WZI Inc., estimates that the proposed rule will reduce methane emissions by around 112,000 short tons per year once fully implemented (EDF-PHS-WZI Expert Report, Table 7-1). Table 3, below, calculates the value of avoided methane emissions in 2007 dollars for 2015, 2020, and 2025 by using central values for the social cost of carbon (at the central 3% discount rate). This table results from the IWG values for SCC, the IPCC values for GWP of methane, and the WZI estimate of methane reductions. Benefits are calculated using both 100- and 20-year GWPs for methane, and GWPs with and without climate-carbon feedbacks. The calculations are performed by multiplying the SCC (shown in the top row) by the GWP of methane (shown in the column on the left) times the tons of methane reduced (112,000 short tons based on current oil and gas production activity in Colorado, equal to 102,000 metric tons).

In 2015, the central value for calculated benefits is $104,000,000, going as high as $318,000,000. In 2025, the central value for calculated benefits is $132,000,000, going as high as $404,000,000 (Table 3).

The values below almost certainly understate the actual SCC associated with these emissions. Among other things:

- The values are stated in 2007 dollars, so the values are understated in terms of current dollars.

[7] EDF-REB-GW-EX H. Marten, Alex L., and Stephen C. Newbold. "Estimating the social cost of non-CO2 GHG emissions: Methane and nitrous oxide." *Energy policy* 51 (2012): 957-972, at 964;Marten, A. L., and Newbold, S. C. (2011), "Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide," EPA NCEE Working Paper # 11-01, at 16, available at http://www.sciencedirect.com/science/article/pii/S0301421512008555.

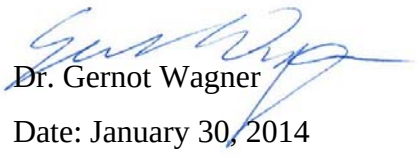
- The 2025 reductions only account for the existing rates of production. Production is projected to increase, so the actual reductions compared to the business as usual case would be greater than indicated below.
- This estimate does not include the monetary impact of extreme climate events. IWG prepared an SCC that includes these factors (shown as the "95th percentile" value in Table 1 above). The estimate for these factors would increase the values below by approximately a factor of three.
- The conversion of the SCC to the social cost of methane using GWP is likely conservative, resulting in a further underestimate.[8]

Table 3—Benefits of Methane reductions from Proposed Oil and Gas Rule (in 2007 dollars)

	2015	2020	2025
	3.0% Average (SCC: $37)	3.0% Average (SCC: $43)	3.0% Average (SCC: $47)
100-year GWP without cc feedbacks (GWP: 28)	$104 million	$120 million	$132 million
100-year GWP with cc feedbacks (GWP: 34)	$126 million	$146 million	$160 million
20-year GWP without cc feedbacks (GWP: 84)	$311 million	$361 million	$395 million
20-year GWP with cc feedbacks (GWP: 86)	$318 million	$370 million	$404 million

[8] See footnote 7 above.

I, Gernot Wagner, of proper age, state that the above-testimony has been prepared by me, or under my supervision and control, and that it is true and correct to the best of my knowledge, and belief, and would be the same if given orally under oath.



Dr. Gernot Wagner

Date: January 30, 2014

EXHIBIT A
TO THE JOINT INDUSTRY WORK GROUP REBUTTAL STATEMENT

REVISED COLLECTIVE PROPOSED REVISIONS

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 3

STATIONARY SOURCE PERMITTING AND AIR POLLUTANT EMISSION NOTICE REQUIREMENTS

5 CCR 1001-5

>>>>>>>>

PART A CONCERNING GENERAL PROVISIONS APPLICABLE TO REPORTING AND PERMITTING

>>>>>>>>

II. Air Pollutant Emission Notice (APEN) Requirements

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II.B.3. APEN Applicability

For the purposes of Air Pollutant Emission Notice applicability, a source will be considered to be an individual emission point, or group of points pursuant to Section II.B.4. of this Part A.

II.B.3.a. Criteria Pollutants

For criteria pollutants, Air Pollution Emission Notices are required for: ~~each individual emission point in a nonattainment area with uncontrolled action emissions of one ton per year or more of any criteria pollutant (pollutants are not summed) for which the area is nonattainment;~~ each individual emission point ~~in an attainment or attainment/maintenance area~~ with uncontrolled actual emissions of two tons per year or more of any individual criteria pollutant (pollutants are not summed)~~;~~ and each individual emission point with uncontrolled actual emissions of lead greater than one hundred pounds per year, regardless of where of where the source is located.

II.B.3.b. Non-criteria Reportable Pollutants

For non-criteria reportable pollutants, Air Pollutant Emission Notices are required for each individual emission point with uncontrolled actual emissions equal to or greater than 250 pounds per year or more of any individual non-criteria reportable pollutant (pollutants are not summed) ~~that exceed the de minimis levels as determined following the procedures set forth in Appendix A.~~

>>>>>>>>

II.D. Exemptions from Air Pollutant Emission Notice Requirements

II.D.1. ~~Notwithstanding the exemptions contained in Section II.D.1., Air Pollutant Emission Notices must be filed for all emission units specifically identified in the applicability section of any subpart of Part A of Regulation Number 6 (New Source Performance Standards) and/or Regulation Number 8 (Hazardous Air Pollutants), Parts A,C,D, and E. However, Air Pollutant Emission Notices need not be filed for wet screening operations subject to Subpart OOO of the New Source Performance Standards if the exemption in Section II.D.1.cccc. is applicable.~~

Stationary sources having emission units that are exempt from the requirement to file an Air Pollutant Emission Notice must nevertheless comply with all requirements that are otherwise applicable specifically to the exempted emission units, including, but not limited to: Title V, Prevention of Significant Deterioration, nonattainment New Source Review, opacity limitations, odor limitations, particulate matter limitations, and volatile organic compounds controls.

An applicant may not omit any information regarding APEN exempt emission units in any permit application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI., Part D of this Regulation Number 3), or nonattainment New Source Review (Section V., Part D of this Regulation Number 3).

The following sources are exempt from the requirement to file Air Pollutant Emission Notices because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality.

II.D.1.a. Individual emission points ~~in nonattainment areas having uncontrolled actual emissions of any criteria pollutant of less than one ton per year, and individual emission points in attainment or attainment/maintenance areas~~ having uncontrolled actual emissions of any criteria pollutant of less than two tons per year~~,~~ and each individual emission point with uncontrolled actual emissions of lead less than one hundred pounds per year~~, regardless of where the sources is located~~.

II.D.1.b. Individual emission points ~~of non-criteria reportable pollutants~~ having uncontrolled actual emissions of any individual non-criteria reportable pollutant less than ~~the de minimis levels as determined following the procedures set forth in Appendix A~~ 250 pounds per year.

>>>>>>>>

APPENDIX A
APPENDIX A
~~**Method For Determining**~~ **De Minimis Levels For Non-Criteria Reportable Pollutants**

An Air Pollutant Emission Notice must be filed for each emission point (individual or grouped) that has uncontrolled actual emissions equal to or greater than 250 pounds per year of any non-criteria reportable pollutant listed in Appendix B.

If a non-criteria pollutant is not listed in Appendix B, it does not have to be reported unless it is included in a chemical compound group.

~~**The following procedures must be followed in order to determine the appropriate de minimis (minimum) reporting level for each pollutant that is emitted from each emission point at a contiguous site. If you do not wish to use the three-scenario approach at your facility, you may elect to use Scenario 1 for all emission points.**~~

Definitions

~~Release Point - the lowest height above ground level from which the pollutants are emitted to the atmosphere.~~

~~Property Boundary - the distance from the base of the release point to the nearest property boundary.~~

Point - an individual emission point or a group of individual emission points reported on one Air Pollutant Emission Notice as provided for in Part A, Section II.B.4.

~~**Methodology**~~

~~To determine the de minimis level for a single pollutant being emitted from a point (single or grouped).~~

~~**STEP 1:**~~

~~Determine which of the three scenarios below applies to the emission point. If different scenarios can be applied to the same emission point, use the highest numbered scenario that applies. In the case of grouped emission points, use the lowest scenario number (for the entire group) that applies to any of the single emission points within the group.~~

~~Scenario 1: Release point less than 10 meters or property boundary less than 100 meters;~~

~~Scenario 2: Release point equal to or greater than 10 meters, but less than 50 meters, or property boundary equal to or greater than 100 meters, but less than 500 meters; or~~

~~Scenario 3: Release point equal to or greater than 50 meters, or property boundary equal to or greater than 500 meters.~~

~~**STEP 2:**~~

~~Use Appendix B to identify which of the three bins (Bin A, B, or C) the chemical is listed under.~~

~~If the pollutant is not listed, it does not have to be reported unless it is included in a chemical compound group.~~

~~**STEP 3:**~~

~~Use the table below to determine the de minimis level.~~

~~All values are in pounds per year.~~

	~~**Scenario 1**~~	~~**Scenario 2**~~	~~**Scenario 3**~~
~~Chemical Bin~~	~~De Minimis~~	~~De Minimis~~	~~De Minimis~~
~~Bin A~~	~~50~~	~~125~~	~~250~~

~~Bin B~~	~~500~~	~~1250~~	~~2500~~
~~Bin C~~	~~1000~~	~~2500~~	~~5000~~

~~**STEP 4:**~~

~~Repeat the above steps for each pollutant emitted from each emission point (single or grouped). One Air Pollutant Emission Notice must be filed for each emission point that emits one or more chemicals above the de minimis level.~~

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PART B CONCERNING CONSTRUCTION PERMITS

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II. General Requirements For Construction Permits

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II.A.5. Construction permits are required for hazardous air pollutants if:

II.A.5.a. The source is subject to Colorado Maximum Achievable Control Technology or Generally Available Control Technology~~; or~~

~~II.A.5.b. The source is subject to Federal National Emission Standards for Hazardous Air Pollutants; or~~

~~II.A.5.c. The source is subject to Federal Maximum Achievable Control Technology or Generally Available Control Technology standards; or~~

~~II.A.5.d. The source is subject to Regulation Number 8, Part E, where the more specific requirements of Regulation Number 8, Part E, take precedence over requirements in this regulation.~~

>>>>>>>>

II.D. Exemption from Construction Permit Requirements

~~None of the exemptions listed below in Sections II.D.1. through II.D.4. shall apply if a source is subject to Part A of Regulation Number 6 (New Source Performance Standards) and/or Regulation Number 8 (Hazardous Air Pollutants), Parts A,C, D, and E.~~ Permit exemptions taken under this section do not affect the applicability of ~~the~~ any State or Federal ~~r~~regulations that are otherwise applicable to the source.

An applicant may not omit any information regarding APEN or permit exempt emission units in any application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI. of Part D of this Regulation Number 3), or Nonattainment New Source Review (Section V. of Part D of this Regulation Number 3).

II.D.1. The following sources are exempt because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality:

>>>>>>>>

II.D.1.l. Crude oil truck loading equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year. ~~Crude oil or condensate loading truck equipment at crude oil production sites where the loading rate does not exceed 10,000 gallons per day averaged over any thirty-day period.~~

>>>>>>>>

II.D.1.n. Exemption Repealed ~~Crude oil storage tanks with a capacity of 40,000 gallons or less.~~

II.D.2. ~~Facilities located in a nonattainment area for any criteria pollutant for which the area is nonattainment; with t~~Total facility-wide uncontrolled actual emissions ~~(potential emissions at actual operating hours)~~ that are less than the following amounts:

II.D.2.a. ~~Two~~ Twenty five tons per year of volatile organic compounds.

II.D.2.b. ~~One ton per year PM10~~Twenty five tons per year of any other criteria pollutant, except for lead.

~~II.D.2.c. One ton per year PM2.5.~~

~~II.D.2.d. Five tons per year total suspended particulate.~~

~~II.D.2.e. Five tons per year carbon monoxide.~~

~~II.D.2.f. Five tons per year sulfur dioxide.~~

~~II.D.2.g. Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:~~

~~II.D.3. Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:~~

~~II.D.3.a. Five tons per year volatile organic compounds.~~

~~II.D.3.b. Five tons per year PM10.~~

~~II.D.3.c. Five tons per year PM2.5.~~

~~II.D.3.d. Ten tons per year total suspended particulate.~~

~~II.D.3.e. Ten tons per year carbon monoxide.~~

~~II.D.3.f. Ten tons per year sulfur dioxide.~~

~~II.D.3.g. Ten tons per year nitrogen oxides.~~

~~II.D.3.h. Two hundred pounds per year lead.~~

II.D.34. Facilities that emit any other criteria pollutant that is not listed in Sections II.D.2. and II.D.3., above (flourides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, and municipal waste combustor engines), with total facility uncontrolled actual emissions of such pollutants that are less than two twenty five tons per year.

II.D.55. When a facility that was previously exempt from permit requirements exceeds one of the permit de minimis levels stated in Sections II.D.2. through II.D.4., above, due to the addition of new emission points or an increase in uncontrolled actual emissions, the Division will issue either a facility-wide permit for all non-grandfathered emission units above that require Air Pollutant Emission Notices de minimis levels=, or individual emission permits for those emission units that are not otherwise permit exempt.

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PART C CONCERNING OPERATING PERMITS

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II.E. Insignificant Activities and Exemptions from Operating Permit Requirements

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The following sources are exempt from the requirement to obtain an operating permit pursuant to this Part C:

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II.E.3.ddd. Exemption Repealed *Crude oil storage tanks with a capacity of 40,000 gallons or less.

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PART D CONCERNING MAJOR STATIONARY SOURCE NEW SOURCE REVIEW AND PREVENTION OF SIGNIFICANT DETERIORATION

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XV. Actuals PALs

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XV.F. Contents of the PAL permit.

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XV.F.5. A requirement that, once the PAL expires, the major stationary source is subject to the requirements of Section XV.H.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 6

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

5 CCR 1001-8

PART A

Federal Register Regulations Adopted by Reference

>>>>>>>>

The Air Quality Control Commission adopts in full Subpart OOOO, ~~———~~Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution,~~.–~~ 40 CFR Part 60, Subpart OOOO (July 1, 2012), as amended by 78 Fed. Reg. 58416 (September 23, 2013) only ~~if~~ if the Environmental Protection Agency (EPA), approves the Air Quality Control Commission's Revisions to Regulation Number 3 adopted on [insert date]. If the EPA disapproves of the Air Quality Control Commission's Revisions to Regulation Number 3 adopted on [insert date], full adoption of Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, 40 CFR Part 60, Subpart OOOO (July 1, 2012), as amended by 78 Fed. Reg. 58416 (September 23, 2013) by the Air Quality Control Commission herein will be immediately and automatically withdrawn.~~,August 16, 2012, (77 FR 49490) where both uncontrolled actual emissions from the affected facility are equal to or greater than the Air Pollution Emission Notice (APEN) thresholds found at Regulation Number 3, Part A, Sections II.B.3.a. or II.B.3.b. and total facility uncontrolled actual emissions are equal to or greater than the permitting thresholds found at Regulation Number 3, Part B, Sections II.D.2., II.D.3., or II.D.4. for the following affected facilities: storage vessels at well sites beginning ninety days after the first day of production; storage vessels at any site other than well sites in the oil and natural gas production segment, the natural gas processing segment, and the natural gas transmission and storage segment; centrifugal compressors with wet seals; reciprocating compressors; pneumatic controllers; the group of all equipment (equipment leaks or leaking components) at on-shore natural gas processing plants; and sweetening units at on-shore natural gas processing plants~~.~~

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS ~~AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS~~

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

[The Joint Industry Work Group proposes that all Division Proposed Rules as well as any changes made in this Revised Collective Proposed Revisions document apply only in the ozone nonattainment area]

>>>>>>>>

II. General Provisions

>>>>>>>>

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

~~(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.~~

>>>>>>>>

XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. ~~"~~"Approved Instrument ~~Based~~ Monitoring Method" or "AIMM"~~," as used in this Section XVII."~~ means an infra-red camera with cooled InSb focal plane array with non-dispersive infra-red filter, tunable diode laser absorption spectroscopy ("TDLAS"), flame ionization detector, optical methane detector, infra-red controlled interference polarization spectrometer, cavity ring-down spectroscopy, mid-infra-red laser-based differential absorption light detection and ranging ("LIDAR"), pulsed infra-red laser, three-channel

non-dispersive gas correlation infra-red spectrometer, EPA Method 21, or other Division approved instrument ~~based~~ monitoring, device or method. If an owner~~/~~ or operator elects to use ~~a~~ Division approved ~~Continuous Emission Monitoring program~~continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations. ~~Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.~~

XVII.A.~~2.~~ ~~"Atmospheric", when used to modify the term "condensate storage tank", means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.~~3. ~~"~~"Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust ~~volatile organic compound~~ VOC emissions.

XVII.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

XVII.A.5. "Component" means each pump seal, ~~compressor seal~~, flange, pressure relief device, connector, ~~open ended line~~, and valve that contains or contacts a process stream with ~~hydrocarbons~~at least 10 percent VOCs by weight. For the purpose of Section IXVII., ~~P~~process stream~~s~~ does not include those streams consisting of glycol, amine, produced water, or methanol ~~are not components for purposes of this Section XVII~~.

XVII.A.~~5~~6. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.~~3~~6. "~~Condensate Storage Tank" means any production tank or series~~Date of First Production" means the date reported to the COGCC as the "~~first~~ date of first production ~~tanks that are manifolded together that store condensate~~."

XVII.A.~~7~~8. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.9 "Intermediate Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid, as defined in 40 CFR Part 60, Subpart OOOO.

~~XVII.A.89. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.~~

XVII.A.~~9~~10. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure ~~and recompress~~ prior to the inlet of a natural gas ~~prior to~~ processing plant.

XVII.A.~~10~~11. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. ~~For storage tanks at well production facilities, normal operation includes, but is not limited to, liquid dumps from the separator.~~

~~XVII.A.11~~XVII.A.12. "Open-Ended Valve or Line" means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

XVII.A.13. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the driveshaft.

XVII.A.14. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.~~12~~15. "Storage Tank" means any permanent fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

~~XVII.A.1316. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potentialimmediate danger as a consequence of such monitoring.~~

XVII.A.16. "Uncontrolled Release" means emissions from thief hatches (or other access points to the storage tank) and pressure relief devices at a storage tank that result from inadequate design, operation, or maintenance, except for those emissions that are necessary for the safety of personnel and equipment. Emissions during routine maintenance, tank gauging, and loadout operations shall not be considered Uncontrolled Releases.

XVII.A.~~14~~17. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor. This definition also applies to Visible Emissions as referred to in XII of this Regulation Number 7.

XVII.A.~~15~~18. "Well Production Facility" means all permanent equipment co-located at a single stationary source directly associated with one or more oil ~~wells~~ or gas production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline located at the inlet to the separator through the point of Custody Transfer. Oil and gas production wells located on the same surface disturbance as the single stationary source are included in the Well Production Facility. "Custody Transfer" means the transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from Storage Tanks or automatic transfer facilities to sales pipelines or any other forms of post-sales transportation or the point at which natural gas passes from Well Production Facilities to natural gas gathering lines through which gathered natural gas is conveyed to Compressor Stations.

XVII.B. (State Only) General Provisions

These Regulations shall not apply to any lands within the exterior boundaries of the Southern Ute Indian Reservation, as agreed in, and defined by, that Intergovernmental Agreement between the Southern Ute Indian Tribe and the State of Colorado Concerning Air Quality Control on the Southern Ute Indian

Reservation, codified at Colorado Revised Statutes Section 24-62-101 (2013); (see also C.R.S. § 25-7-1301 (2013)); and approved by the United States Environmental Protection Agency on March 2, 2012 at 77 Fed. Reg. 15267 (March 14, 2012).

XVII.B.1. General requirements for prevention of emissions and good air pollution control ~~equipment, prevention of leakage, and flares and combustion devices.~~practices for all ~~oil and gas exploration and production operations,~~ well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of ~~volatile organic compounds~~VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment ~~shall~~must be maintained and operated in a manner consistent with good air pollution control practices for minimizing VOC emissions. Determination of whether or not acceptable ~~operating~~operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of ~~operating~~operation and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment~~, flares, and combustion devices used~~ required to comply with Section XVII.

XVII.B.~~1~~2.a. All air pollution control equipment ~~required by this Section XVII~~ shall be operated and maintained pursuant to ~~manufacturer~~the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates ~~required by this Section XVII~~ and to handle reasonably foreseeable fluctuations in emissions of ~~volatile organic compounds~~VOCs ~~and other hydrocarbons~~ during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

~~XVII.B.1.b. All condensate collection, storage, processing and handling operations, regardless of size, shall be designed, operated and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.~~

XVII.B.~~1~~2.~~c~~b. If a ~~flare or other~~ combustion device is used to control emissions of ~~volatile organic compounds to comply with Section XVII~~VOCs ~~and other hydrocarbons~~ from storage tanks subject to Section XVII.C. and glycol natural gas dehydrators subject to Section XVII.D., it shall be enclosed except as described below in Section XVII.B.2.f., have no visible emissions during normal ~~operations~~operation, and be designed so ~~than~~that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other ~~convenient~~ means approved by the Division, determine whether it is operating properly. An owner or operator that installed a combustion device prior to [insert date of promulgation] with Division approval, either express or implied,

is not required to replace or retrofit the control device unless the combustion device is modified after [insert date of promulgation].

XVII.B.~~1~~2.~~d~~c. Any of the effective dates for installation of controls on ~~condensate~~storage tanks, glycol natural gas dehydrators, and/or internal combustion engines may be extended at the ~~air pollution control~~ Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of ~~hydrocarbons~~ VOCs from storage tanks subject to Section XVII.C. and glycol natural gas dehydrators subject to Section XVII.D. ~~shall~~must be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All such combustion devices installed on or after ~~May~~ January 1, 201~~5~~4, ~~will~~must be equipped with an operational auto-igniter upon installation of the combustion device~~.~~; and

XVII.B.2.d.(ii) All such combustion devices installed before ~~May~~ January 1, 201~~5~~4, ~~will~~must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. ~~As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.~~

XVII.B.2.f. An owner or operator may install a non-enclosed flare that otherwise meets the requirements of XVII.B.2.b. to control volatile organic compounds as follows:

XVII.B.2.f.(i) If the flare will control emissions at a Well Production Facility, Compressor Station, or natural gas processing plant and the required design capacity exceeds the reasonably available capacity for an enclosed combustor;

XVII.B.2.f.(ii) If the flare will serve as a backup to the primary means of control;

XVII.B.2.f. (iv) If the flare is located more than 1,320 feet from a Residential Area. For purposes of this Section XVII.B.2.f., Residential Area means an area where six (6) or more occupied residential homes are within a 1,320 foot radius of the Well Production Facility, Compressor Station, or natural gas processing plant at which the flare is located. The presence of a Residential Area shall be determined at the time the non-enclosed flare is installed. Owners and operators shall not be required to replace or retrofit the non-enclosed flare in the event that a Residential Area is later established within 1,320 feet of the Well Production Facility, Compressor Station, or natural gas processing plant.

(v) An owner or operator that installed a flare subject to one of the exceptions at XVII.B.2.f.(i). through (iv). or with prior division approval, either express

or implied, is not required to retrofit or replace the flare unless modified, pursuant to Regulation 3, and a cost-benefit analysis reasonably justifies retrofit or replacement.

XVII.B.2.g. In the event that a control device is inoperable or malfunctioning, the owner or operator may choose to shut-in operations to the source or site as an air pollution control alternative, in lieu of, emergency recordkeeping and reporting requirements. Only records of the shut-in and control device maintenance must be maintained.

XVII.B.3. Requirements for compressor seals and open-ended valves or lines at natural gas compressor stations only.

XVII.B.3.a. Beginning January 1, 2015, each open-ended valve or line at ~~well production facilities and~~ natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line.

XVII.B.3.b. Beginning January 1, 2015, uncontrolled actual ~~hydrocarbon~~ VOC emissions from wet seal fluid degassing systems on wet seal centrifugal compressors at natural gas compressor stations must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 C.F.R. Part 60, Subpart OOOO on that date or thereafter.

XVII.B.3.c. Beginning January 1, 2015, at natural gas compressor stations, the rod packing on any reciprocating compressor installed must be replaced every 26,000 hours of operation or every thirty six (36) months, unless the reciprocating compressor is subject to 40 C.F.R. Part 60, Subpart OOOO on that date or thereafter or if the vent gas from the rod packing is being captured, controlled or put to other beneficial use. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

X.V.II.B.4. Oil refineries are not subject to ~~this section of the rule~~Section XVII.

XVII.B.45. ~~Condensate tanks,~~Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to ~~this~~ Section XVII.

XVII.C. (State Only) Emission reduction from ~~condensate~~ storage tanks at ~~oil and gas exploration and production operations, natural gas compressor stations~~well production facilities, natural gas ~~drip~~compressor stations, and natural gas processing plants.

XVII.C.1. Control and monitoring requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all ~~atmospheric condensate~~ storage tanks storing condensate with uncontrolled actual emissions of ~~volatile organic compounds~~VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total ~~shall~~must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs ~~on such tanks~~.

XVII.C.~~2~~1.b. ~~For condensate~~Owners or operators of all storage tanks with ~~past,~~ uncontrolled actual emissions of ~~volatile organic compounds~~VOCs ~~of less~~equal to or greater than ~~20~~six (6) tons per year based on a rolling twelve-month total ~~that may become subject to Section XVII.C.1. by virtue of the addition of a newly drilled well or the recompletion or stimulation of an existing well, owners or operators of such tanks shall have until 90 days after the date of 1st production of the newly drilled, recompleted or stimulated well to install and~~must operate ~~any required~~ air pollution control equipment~~. If the owner or operator determines that emissions of volatile organic compounds will be below the 20 ton per year threshold, the owner or operator shall notify the Division of this determination in writing and include an explanation of the methodology used to make this determination.~~ that achieves an average ~~hydrocarbon~~ VOC control efficiency of 95%. If a combustion device is used, it ~~shall~~must have a design destruction efficiency of at least 98% for ~~hydrocarbons~~VOCs.

XVII.C.1.b.(i) Control requirements of Section XVII.C.1.b. must be achieved in accordance with the following schedule:

XVII.C.1.b.(i)(a) A storage tank constructed on or after ~~May~~ January 1, 201~~4~~5, must be in compliance ~~by~~within ninety (90) days from the date that the storage tank commences operation.

XVII.C.1.b.~~(ii)~~(i)(b) A storage tank ~~constructed~~ that began operating before ~~May~~ January 1, 201~~4~~5, must be in compliance by May 1, 201~~6~~5.

XVII.C.1.b.~~(iii)~~(i)(~~d~~c) A storage tank not otherwise subject to Sections XVII.C.1.b.(i)(a) or XVII.C.1.b.(i)(b)~~(ii), above~~, that increases uncontrolled actual emissions to six (6) tons per year VOC or more ~~per year~~ on a rolling twelve month basis after ~~May~~ January 1, 201~~4~~5, must be in compliance within sixty ~~days~~ (60) days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within ninety (90) days of the date of first production.

XVII.C.1.c.(i) Beginning ~~May~~ January 1, 201~~4~~5, owners or operators of storage tanks at well production facilities ~~shall~~must collect and control emissions by routing emissions to operating air pollution control equipment during the first ninety (90) calendar days after the date of first production. The air pollution control equipment ~~shall~~must achieve an average ~~hydrocarbon~~ VOC control efficiency of 95%. If a combustion device is used, it ~~shall~~must have a design destruction efficiency of at least 98% for ~~hydrocarbons~~VOCs. ~~Except that this~~This control requirement does not apply to storage tanks that are reasonably projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c.~~, above~~(i), may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are reasonably expected to be below the threshold in Section XVII.C.1.b~~., above~~.

~~XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or~~ XVII.C.1.

XVII.C.2.a. Beginning onJanuaryMay 1, 20154, or the applicable compliance date specified in Section XVII.C.1.b.(i), whichever comes later, owners andor operators of storage tanks shall route all hydrocarbon emissionssubject to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.1.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, conduct audio, visual, olfactory ("AVO") inspection and additional visual inspections of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed) as oftenat the same frequency as liquids are loaded out from the storage tank. However, AVO inspection isThese inspections are required no more frequently than every seven (7) days or less frequently than every thirty-one (310) days. AVO monitoring is not required for components and storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor. AVO inspection, as defined in Section XVII.C.1.e. The additional visualAVO inspections must include, at a minimum:

XVII.C.3.a.1.d.(i) Visual inspection of any storage tank thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.1.d.(ii) Visual inspection or monitoring of the storage tank air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.~~3.a.~~1.d.(iii) If a ~~flare or other~~ combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.~~3.a.~~1.d.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.~~3.~~1.d.(v) ~~Monitoring: The owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to this Section XVII.C. shall visually inspect or monitor the Air Pollution Control Equipment to ensure that it is operating at least as often as condensate is loaded out from the tank, unless a more frequent inspection or monitoring schedule is followed. In addition, if~~a.(v) If a ~~flare or~~ other combustion device is used, ~~the owner or operator shall visually inspect~~inspection of the device for the presence ~~of~~ or absence of smoke. If smoke is observed, either the equipment ~~will~~must be immediately shut-in to investigate ~~that~~the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 ~~shall~~must be conducted to determine whether visible emissions are present for a period of at least ~~as often as condensate is loaded out from the tank~~one (1) minute in fifteen (15) minutes.

XVII.C.1.e. If equipment associated with the storage tank is unsafe, difficult, or inaccessible to monitor, the owner or operator ~~is~~ shall not be required to monitor such equipment ~~until it becomes feasible to do so~~.

XVII.C.1.e.(i) ~~—~~Difficult to monitor equipment are those that ~~means it~~ cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

XVII.C.1.e.(ii) ~~-~~Unsafe to monitor means ~~it~~ equipment is unsafe to monitor because ~~cannot be monitored without exposing~~ monitoring personnel would be exposed to ~~an~~ imminent and potential ~~immediate~~ danger as a consequence of completing the monitoring.

XVII.C.1.e.(iii) ~~-~~Inaccessible to monitor equipment means equipment that is buried, insulated, or obstructed by equipment or piping that prevents access to the equipment by monitoring personnel.

XVII.C.2. Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Owners or operators of storage tanks must ~~route all hydrocarbon emissions to air pollution control equipment, and must~~ operate ~~without~~ to minimize ~~venting hydrocarbon emissions~~ uncontrolled releases to the maximum extent practicable from the thief hatches (or other access point to the tank) or pressure relief device ~~during normal operation, unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment. Compliance must be achieved~~ in accordance with the schedule in Section XVII.C.2.b.(ii).

XVII.C.2.b. Beginning on January 1, 2015, or the applicable compliance date in Section XVII.C.1.b.(i), whichever comes later, ~~O~~owners or operators of storage

tanks subject to control requirements of Sections XII.D.2., XVII.C.1.a. or XVII.C.1.b. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a. An owner or operator may develop a STEM plan applicable to multiple Storage Tanks across some or all of the owner or operators' assets and operations within Colorado. ~~-~~Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) The STEM plan must include selected control technologies, monitoring practices, operational practices, and/or other strategies; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with ~~approved instrument based monitoring methods~~AIMM following the applicable monitoring frequency in Table 1.

XVII.C.2.b.(ii) Owners or operators must achieve the requirements of Sections XVII.C.2.a. ~~and XVII.C.2.b.~~ and begin implementing the required ~~approved instrument based monitoring~~AIMM method in accordance with the following schedule:

XVII.C.2.b.(ii)(a) A storage tank constructed on or after ~~May~~ January 1, 201~~5~~4, must comply with the requirements of Sections XVII.C.2.a. ~~and XVII.C.2.b.~~ by the date that the storage tank commences operation. Approved instrument based monitoring method inspections must begin within ninety (90) days after the tank commences operation.

XVII.C.2.b.(ii)(b) A storage tank constructed before ~~May~~ January 1, 201~~5~~4, must comply with the requirements of Sections XVII.C.2.a. and XVII.C.2.b. by May 1, 201~~5~~6. Approved instrument based monitoring method inspections must begin within ninety (90) days of the Phase-In Schedule in Table 1, or within thirty (30) days for storage tanks with uncontrolled actual VOC emissions > 50 tons per year.

XVII.C.2.b.(ii)(c) A storage tank not otherwise subject to Sections XVII.C.2.b.(ii)(a) or XVII.C.2.b.(ii)(b) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after ~~May~~ January 1, 201~~5~~4, must be in compliance with Sections XVII.C.2.a. and XVII.C.2.b. and implement the required ~~approved instrument based monitoring~~AIMM method within sixty (60) days of discovery of the emissions increase.

XVII.C.2.b.(ii)(d) Following the first approved instrument based monitoring method inspection, owners or operators must continue conducting ~~approved instrument based monitoring~~AIMM method inspections in accordance with the Inspection Frequency in Table 1.

Table 1 – Storage Tank Inspections		
Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Based Monitoring Method Inspection Frequency	Phase-In Schedule
> 6 and ≤< 12	Annually	January 1, 2016
> 12 and ≤< 50	Quarterly	July 1, 2015
> 50	Monthly	January 1, 2015

XVII.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section XVII.C.1.e.

XVII.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Recordkeeping: The owner or operator of each condensate storage tank ~~shall~~subject to Sections XII.D. or XVII.C.1.b. must maintain ~~the following~~ records of STEM ~~as~~if applicable, including the plan, any updates, and the certification, ~~to be made~~and make them available to the Division upon request. In addition, for a period of ~~five~~two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.~~4~~3.a. ~~Monthly condensate production from the~~The AIRS ID for the storage tank.

XVII.C.~~4~~3.b. The date and duration of any period where uncontrolled releases are discovered at the storage tank thief hatch, pressure relief device, or other access point ~~are found to be venting hydrocarbon emissions~~.

XVII.C.~~4.~~3~~b~~c. ~~For any condensate storage tank required to be controlled pursuant to this Section XVII.C., the~~The date~~, time~~ and duration of any period where the air pollution control equipment is not operating. ~~The duration of a period of non-operation shall be from the time that the air pollution control equipment was last observed to be operating until the time the equipment recommences operation.~~

XVII.C.~~4~~3.c~~d~~. ~~For tanks where~~Where a ~~flare or other~~ combustion device is being used, the date and ~~time of any instances where visible emissions are observed from the device~~result of any EPA Method 22 test or investigation pursuant to Section XVII.C.4.1.d.(v).

XVII.C.3.e. The timing of and efforts made to eliminate ~~venting~~an uncontrolled release, restore operation of air pollution control equipment, and to mitigate visible emissions.

XVII.C.3.f. A list of equipment that ~~identification numbers for components that are~~is designated as unsafe, difficult, or inaccessible to monitor, as described in Section

XVII.C.1.e., an explanation stating why the equipment~~component~~ is so designated, and the plan for monitoring such equipment~~component(s)~~.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at ~~an oil and gas exploration and production operation~~a well production facility, natural gas compressor station, ~~drip station or~~ or natural gas gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of ~~a condenser or~~ air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

~~XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:~~

~~XVII.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and~~

~~XVII.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.~~

~~XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:~~

~~XVII.D.4.a. Actual uncontrolled emissions Owners or operators of volatile organic compounds from a single newa glycol natural gas dehydrator are constructed on or after May 1, 2015, with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year must be in compliance with Section XVII.D.3. by the date that the glycol natural gas dehydrator commences operation; or~~

~~XVII.D.4.b. Actual uncontrolled Uncontrolled actual emissions of volatile organic compoundsVOCs from a single existing glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.~~

~~XVII.D.4.c. For purposes of Section~~Sections XVII.D.3. and XVII.D.4.:

~~XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.~~

~~XVII.D.4.c.(ii) A designated outside activity area~~Designated Outside Activity Area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a ~~Designated Outside Activity~~designated outside activity area by the COGCC ~~Area~~; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator ~~on~~of any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table ~~1~~2 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table ~~1~~2 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE ~~1~~2

Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp	On or after January 1, 2008	2.0	4.0	1.0

and < 500 Hp	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for components at well production facilities~~,~~ ~~storage tanks,~~ and natural gas compressor stations, excluding storage tank thief hatches, pressure relief devices, and access points subject to STEM. Natural gas processing plants, including Components, Storage Tanks and Compressor Stations at natural gas processing plants, are not subject to this Section XVII.F.

XVII.F.1. Beginning ~~January 1, 2015~~the date the well production facility or natural gas compressor station becomes subject to this Section XVII.F., owners ~~and~~or operators of components at well production facilities ~~and~~or natural gas compressor stations ~~will~~must identify and repair leaks from such components ~~at these facilities~~ in accordance with the requirements of this ~~this~~ Section XVII.F. The ~~following~~ provisions of Section XVII.F. shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners ~~and~~or operators of components at well production facilities or natural gas compressor stations that monitor components as part of ~~this~~ Section XVII.F. may ~~opt to~~ estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

~~XVII.F.3. Owners andor operators of well production facilities or natural gas compressor stations shall utilizemust implement the Approved Instrument Based Monitoring Method approved instrument based monitoring method and AVO programinspections as outlined in Section XVII.F. AVO monitoringMonitoring is not required offor components and tanks that are unsafe to monitor, difficult, or inaccessible to monitor, pursuant toas defined in Section XVII.F.5.g6.~~

XVII.F.3. If upon the completion of four consecutive semi-annual AIMM inspection events, no leaks requiring repair are detected, AIMM inspection shall be conducted annually for that well production facility or natural gas compressor station. If upon the completion of four consecutive quarterly AIMM inspection events, no leaks requiring repair are detected, AIMM inspection shall be conducted semi-annually for that well production facility or natural gas compressor station. If two or more leaks requiring repair are

detected during subsequent AIMM inspection events, then the inspection frequency shall revert back to the original frequency for that well production facility or natural gas compressor station until the terms of this provision are again met.

XVII.F.3.a. An owner or operator may skip the next AIMM inspection event where the owner or operator demonstrates in the previous AIMM inspection event that less than or equal to 2 percent of components required repair for all well production facilities or natural gas compressor stations in a basin belonging to the same threshold class as set forth in Tables 2 and 3. An owner or operator may estimate a facility's component count using the Default Average Component Counts in 40 CFR Part 98, Subpart W, Tables W-1B and W-1C for equipment located at natural gas production facilities and oil production facilities, respectively.

XVII.F.4. ~~Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and~~ Leak detection for components at natural gas compressor stations.

XVII.F.4.a. Beginning January 1, 2016, within 180 days of startup of a new natural gas compressor station, ~~O~~owners or operators of natural gas compressor stations ~~shall~~must inspect components for leaks using an ~~Approved Instrument Based Monitoring Method approved instrument based monitoring~~AIMM ~~method~~, in accordance with ~~the following~~ Table ~~2~~3, except under the conditions described in XVII.F.6. ~~for components subject tothat are unsafe, difficult, or inaccessible to monitor, as defined in Section XVII.F.5.g~~6.

XVII.F.4.b. Owners or operators of existing natural gas compressor stations shall inspect components for leaks as set forth in Table 3, except under the conditions described in Section XVII.F.6.

XVII.F.4.c. ~~–~~For purposes of ~~this~~ Section XVII.F.4., fugitive VOC emissions ~~shall~~must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), ~~off~~or other Division approved method.

~~Table 2~~Table 3
~~–~~Compressor Station Component Inspections

Fugitive VOC Emissions (tpy)	AIMM Inspection Frequency (calendar basis)	Beginning of Phase-In Schedule for Existing Compressor Stations[1]
> 2 and < 6	One time, within five years of applicable phase-in or implementation date	July 1, 2016
>~~60~~ and < 20~~12~~	Annually	January 1, 2016
> ~~12~~ 20 and < 50	~~Quarterly~~Semi-annually	July 1, 2015
> 50	~~Monthly~~Quarterly	January 1, 2015

[1] As set forth in XVII.F.4.a., owners and operators of new Compressor Stations shall initiate compliance with this Table 2 within 180 days after the commenced construction date (i.e., the implementation date).

XVII.F.5. ~~Requirements~~ Leak detection for components at ~~for~~ well production facilities ~~and/or storage tanks~~

~~XVII.F.5.a. Beginning August 1, 2014, all new~~All well production facilities ~~shall~~constructed ~~on or after August 1, 2014, must have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shallinitial pressure test must be provided in the first annual report to the Division, as required by Section XVII.F.910.~~

XVII.F.5.a~~b~~. ~~Beginning January 1, 2015, within 90 days of startup of all new~~Owners or operators of well production facilities ~~and/or storage tanks, owners and/or operators shall~~ constructed on or after January 1, 201~~56~~, must ~~identify~~ inspect components for leaks using as set forth in Table 4 no later than 180 days after the date of first production, except under the conditions described in Section XVII.F.6.~~and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to approved instrument based monitoring method within ninety (90) days after the inspection frequencyfacility commences operation and in accordance with the Inspection Frequency schedule in Table 3~~. To the extent that pursuant to Table 4 an AIMM inspection and an AVO monitoring would occur simultaneously, then the AIMM inspection satisfies the requirement to conduct AVO for that inspection.

4. XVII.F.5.c. ~~Consistent with the provisions of XVII.F.5.f., owners and~~ Owners or operators of ~~existing~~ well production facilities ~~and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.~~

~~XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair~~ constructed before January 1, 201~~65~~, must ~~identify~~ inspect components for leaks as set forth in Table 4, except under the conditions described in Section XVII.F.6.~~from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. approved instrument based monitoring method within ninety (90) days of the Phase-In Schedule in Table 4, within thirty (30) days for > 50 tons per year, or by July 1, 2016, for > 0 and < 6 tons per year tanks. Thereafter, approved instrument based monitoring method and AVO inspections must be conducted in accordance with the Inspection frequency shall be determined according to Frequency in Table 3~~4. To the extent that pursuant to Table 4 an AIMM inspection and an AVO monitoring would occur simultaneously, then the AIMM inspection satisfies the requirement to conduct AVO for that inspection.

XVII.F.5.e~~d~~. For purposes of this Section XVII.F.5., ~~T~~the VOC thresholds shall be calculated using the estimated uncontrolled actual emissions from the largest single storage tank~~s~~ as set forth in Table 4. ~~determine the frequency at which inspections must be performed.~~ If no storage tanks storing oil or condensate are located at the well production facility ~~or multi-well site, owners or operators will~~must rely on VOC thresholds shall be calculated using the potential to emit of VOC for all of the emissions sources, including emissions from components located at the. ~~facility.~~

XVII.F.5.e. ~~All components at a~~ Inspection of components at a well production facility ~~or storage tank must be inspected~~ shall be conducted as set forth in Table 4:

~~Table 3~~Table 4
~~—~~Well Production Facility Component Inspections

VOC Threshold (per XVII.F.5.ed.) ~~VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks~~)	AIMM Inspection Frequency (calendar basis)	AVO Monitoring Frequency (calendar basis)	Beginning of Phase-In Schedule For Existing Well Production Facilities[2]
> 2 and < 6	One time, within five years of phase-in or implementation date ~~using Approved Instrument Based Monitoring Method~~approved ~~instrument based monitoring methods and thereafter using monthly AVO~~	Annual	July 1, 2016
> 6 and < ~~12~~20	Annually ~~with monthly AVO~~	Semi-annual	January 1, 2016
> ~~12~~ 20 and < 50	~~Quarterly with monthly AVO~~Semi-annually	Quarterly	July 1, 2015
> 50	~~Monthly~~Quarterly	Monthly	January 1, 2015
~~Multi~~Well production facilities ~~or multi-well sites~~ without storage tanks ~~after April 15, 2014,~~storing oil or condensate that have a ~~PTE~~potential to emit > 20 tpy VOC	~~Monthly~~Quarterly	Monthly	January 1, 2015

~~XVII.F.~~5.f. ~~Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:~~

~~XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.~~

~~XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.~~

~~XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.~~

~~XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.~~

~~XVII.F.5.g.~~XVII.F.6. If a component is unsafe, difficult~~, unsafe~~, or inaccessible to monitor, the owner or operator ~~shall~~is not ~~be~~ required to monitor the component or equipment~~until it becomes feasible to do so~~.

[2] As set forth in XVII.F.6.a., owners and operators of new Well Production Facilities installed after January 1, 2016 shall comply with this Table 3 within 180 days after the Date of First Production (i.e., the implementation date).

XVII.F.~~5.g.(i)~~6.a. Difficult to monitor components or equipment are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.~~5.g.(ii)~~6.b. Unsafe to monitor means a component or equipment that is unsafe because inspectings ~~are those that cannot be monitored without exposing monitoring~~ personnel would be exposed to ~~an~~ immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of AIMM (such as reflection due to precipitation).

XVII.F.~~5.g.(iii)~~6.c. Inaccessible to monitor components or equipment are those that are buried, insulated ~~in a manner that prevents access to the components by a monitor probe~~, or obstructed by equipment or piping that prevents AIMM inspection or AVO monitoring access to the components by ~~a monitor probe~~monitoring personnel.

XVII.F.~~6~~7 Leaks ~~detection~~ requiring repair: Leaks at components that are not otherwise designed to leak ~~shall~~must be identified utilizing the methods listed in ~~this~~ Section XVII.F.~~6.a. through XVII.F.6.d~~7. Only leaks detected pursuant to ~~this~~ Section ~~XVIII~~XVII.F.~~6. shall~~ 7, require repair under Section XVII.F.8.

XVII.F.~~6~~7.a. For EPA Method 21 or other quantitative AIMMs, monitoring at ~~existing~~ well production facilities and natural gas compressor stations constructed before ~~May~~ January 1, 201~~5~~4, a leak is any concentration of VOC above 10,000ppm ~~hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm~~.

~~XVII.F.67.b. For EPA Method 21 monitoring at facilities constructed on or after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.~~

XVII.F.~~6~~7.c. For ~~infra-red camera and~~ AVO monitoring or other non-quantitative AIMMs such as Infra-red camera, a leak is any detectable VOC emissions except as described in XVII.F.7.d ~~emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation~~.

~~XVII.F.67.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.~~

XVII.F.7.d For leaks identified using AVO, or other non-quantitative AIMM, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.8. or conducting follow-up monitoring using EPA Method 21 within fifteen (15) working days of the day the leak was detected. If the follow-up EPA Method 21 monitoring shows that the leak concentration is less than or equal to 10,000 ppm volatile organic compound for well production facilities or natural gas compressor stations, then the emissions shall not be considered a leak for purposes of this Section and shall not require repair.

XVII.F.7.e. If a leak is identified using AIMM or AVO and the leak is immediately repaired (within the same working day), any such leak does not constitute a leak under this Section XVII.F.7. and is not subject to the Repair and Re-monitoring or Recordkeeping and Reporting requirements at Sections XVII.F.8. through XVII.F.10.

XVII.F.~~7~~8. Repair and remonitoring

XVII.F.~~7~~8.a. First attempt to repair a leak that requires repair pursuant to XVII.F.7. ~~shall~~must be made no later than ~~five~~ fifteen (15) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they ~~shall~~must be ordered promptly and the repair ~~shall~~must be made within ~~fifteen~~ thirty (~~15~~30) working days of receipt of the parts. If shutdown is required, the leak ~~shall~~must be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs ~~shall~~must be completed within ~~fifteen~~ thirty (30~~15~~) working days after the owner or operator has reason to believe the cause of delay ceases to exist.

XVII.F.~~7~~8.b. Within ~~fifteen~~ thirty (30~~15~~) working days of completion of a repair, the ~~leaks shall~~leak that is repaired according to Section XVII.F.7. must be remonitored to verify the repair was effective utilizing AIMM.

XVII.F.~~7~~8.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F.7. shall not be a violation of the Air Quality Control Commission's Rules or subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.~~7~~8.

~~XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method approved instrument based monitoring method, owners and or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.78. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detecteddetection. If the follow-up EPA Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be consideredis a leak for purposes of thisas defined in Section XVII.F.7., the leak must be repaired and remonitored in accordance with Section XVII.F.8.~~

XVII.F.~~8~~9. Recordkeeping: The owner or operator of each well production facility or natural gas compressor station subject to the ~~inspection~~leak detection and ~~maintenance~~repair requirements in ~~this~~ Section XVII.F. ~~shall~~must maintain the following records for a period of two (2) years and make them available to the Division upon request.

~~XVII.F.89.a. Documentation of the pre-start-up pressure tests for new well production facilities;~~

XVII.F.~~8~~9.~~a~~b. The date and site information for each inspection;

XVII.F.~~8~~9.~~c~~b. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.~~8~~9.~~d~~c. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.~~8~~9.~~d~~e. The date the leak was ~~repair~~repaired;

XVII.F.~~8~~9.~~d~~f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.~~8~~9.~~f~~g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.~~8~~9.~~g~~h. A list of ~~identification numbers for~~ components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.~~5.g~~6., and an explanation ~~for each component~~ stating why the component is so designated~~, and the plan for monitoring such component(s)~~.

XVII.F.~~9~~10. Reporting: The owner or operator of each well production facility and natural gas compressor station subject to the ~~inspection~~leak detection and ~~maintenance~~repair requirements in this Section XVII.F. ~~shall~~must submit a single annual report on or before ~~April 30th~~May 31st of each year ~~summarizing~~ that includes the following information regarding inspection and maintenance ~~inspection~~~~leak detection and~~ ~~maintenance~~repair activities at all of their subject facilities during the previous calendar year~~. This report shallmust contain, at a minimum, the following information~~:

XVII.F.~~9~~10.a. The number of facilities inspected;

XVII.F.~~9~~10.b. The total number of inspections;

XVII.F.~~9~~10.c. The total number of leaks identified that require repair, broken out by component type;

XVII.F.~~9~~10.d. The total number of leaks repaired;

XVII.F.~~9~~10.e. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.~~9~~10.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by an authorized representative ~~responsible official~~ of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

~~XVII.G.1. Well Operation and Maintenance:~~ On or after August 1, 2014, ~~during normal operation~~ gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled from the date of first production by air pollution control equipment that achieves an average ~~hydrocarbon~~ VOC control efficiency of 95~~% from the date of first production.~~%. If a combustion device is used, it ~~shall~~must have a design destruction efficiency ~~of~~for at least 98% of ~~hydrocarbons~~VOCs.

~~XVII.H. (State Only) Venting during downhole well maintenance and unloading events~~

~~XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.~~

~~XVII.H.1.a. Operators shallOwners or operators must use best management practices to minimize the need for well venting associated with downhole well~~

maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure willmust first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting willmust be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shallmust be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shallmust ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. willmust be kept and made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations in the 8-Hour Ozone Control Area or Any Ozone Nonattainment or Attainment/Maintenance Area

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operationswell production facilities, and natural gas compressor stations, and/or natural gas drip stations) in the 8-Hour Ozone Control Area or any Ozone Nonattainment or Attainment/Maintenance Area.

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operationswell production facilities, and natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. "No-bleedBleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.~~6~~7. "Pneumatic Controller" shall mean a~~n~~ continuous bleed instrument that is actuated using ~~natural~~pressurized gas ~~pressure~~ and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.~~3~~1.c.

XVIII.C.~~2~~1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.~~3~~1.c.

XVIII.C.~~3~~1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.~~3~~1.~~a~~c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.~~3~~1.~~b~~c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.~~XVIII.D. Monitoring~~

XVIII.C.2. Statewide:

XVIII.C.2.a. All continuous bleed pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.~~c~~a.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.~~c~~a.(ii) Where the operator is using on-site electrical grid power and where use of ~~Utilize~~ no-bleed pneumatic controllers ~~where on-site electrical grid power is being used and~~ is technically and economically feasible, operators shall employ no-bleed pneumatic controllers. Nothing in this provision shall require an operator to bring electrical grid power to the location in order to meet this requirement or replace or retrofit low-bleed pneumatic controllers upon availability of electrical grid power to the location.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) ~~All~~For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in ~~Section~~Sections XVIII.C.~~3~~1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.~~2~~1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2~~.~~., and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, ~~perform~~undergo necessary enhanced maintenance as defined in Section XVIII.B.2 , and ~~maintain the device~~be maintained according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in ~~Section~~Sections XVIII.C.~~3~~1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to ~~Section~~Sections XVIII.C.~~3~~1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the ~~division~~Division upon request.

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DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

>>>>>>>>

II. General Provisions

>>>>>>>>

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

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XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. "Approved Instrument Based Monitoring Method," as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved

Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

XVII.A.4. "Component" means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.5. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.6. "Date of First Production" means the date reported to the COGCC as the "first date of production."

XVII.A.7. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.8. "Multi-Well Site" means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.9. "Natural Gas Compressor Station" means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing, as well as well as compressors located downstream of processing plants.

XVII.A.10. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

XVII.A.11. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.12. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.13. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.14. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy or water vapor.

XVII.A.15. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2015~~6~~, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds equal to or greater than six (6) tons per year based on a rolling twelve-month total must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six tons VOC or more per year on a rolling twelve month basis after May 1, 2014, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design

destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply where the Division has approved a demonstration that the~~to~~ storage tanks ~~that are projected to~~ will have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the threshold in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies designed to meet the requirements of XVII.C.2.a. ~~minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation~~. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies ~~designed to meet the requirements set forth in Section XVII.C.2.a., above,~~ and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to meet the requirements of XVII.C.2.a.~~minimize emissions from storage tanks and~~

~~associated equipment components at the facility or facilities, including thief hatches and pressure relief devices~~.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence of absence of smoke. If smoke is observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping and Reporting: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, and submit them to the Division by the applicable compliance date specified in section XVII.C.1.b.~~to be made available to the Division upon request~~. In addition, for a period of five~~two~~ years, the owner or operator

must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce

uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

XVII.D.4.c. For purposes of Section XVII.D.4.:

XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1

Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal

combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. ~~For purposes of this Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method~~.

Table 2	
~~Fugitive VOC Emissions (tpy)~~ VOC Emissions – PTE (tpy)	Inspection Frequency
>0 and ≤ 12	Annually with monthly AVO
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. ~~Consistent with the provisions of XVII.F.5.f.~~Beginning January 1, 2015, owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the ~~implementation~~ schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3	
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	Inspection Frequency
> 0 and ≤ 12~~6~~	Annually with monthly AVO~~One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO~~
~~> 6 and ≤ 12~~	~~Annually with monthly AVO~~
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Monthly

~~XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:~~

~~XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.~~

~~XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.~~

~~XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.~~

~~XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.~~

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVIII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. First attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable or, the equipment requires shutdown to complete repair~~, or other good cause exists~~. If parts are unavailable, they shall be ordered promptly and the repair shall be made within five (5)~~fifteen (15)~~ working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. ~~If delay is attributable to other good cause,~~

~~repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.~~

XVII.F.7.b. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of five (5) ~~two (2)~~ years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repair;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an

explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all of their subject facilities during the previous calendar year. This report shall contain at a minimum the following information:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1. Well Operation and Maintenance: On or after August 1, 2014, during normal operation gas coming off a separator produced from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the

well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the best management practices employed under this Section XVII.H., and the cause, date, time, and duration of venting events ~~under this Section XVII.H.,~~ will be kept and submitted annually ~~made available~~ to the Division ~~upon request~~.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. "No-bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.7. "Pneumatic Controller" shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All ~~high-bleed~~ pneumatic controllers in service prior to May 1, 2014 with VOC emissions greater than a low-bleed pneumatic controller~~,~~ shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All ~~high-bleed~~ controllers with VOC emissions greater than a low-bleed pneumatic controller that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) A~~For~~l~~l high-bleed~~ pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for ~~high-bleed~~ all pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For ~~high-bleed~~ pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for ~~high-bleed~~ all pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each ~~high-bleed~~ pneumatic controller with VOC emissions greater than a low-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique ~~high-bleed~~ pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each ~~high-bleed~~ pneumatic controller with VOC emissions greater than a low-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to ~~high-bleed~~ pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of ~~high-bleed~~ pneumatic controllers with VOC emissions greater than a low-bleed pneumatic controller and their associated controller numbers per facility, the total number of ~~high-bleed~~ such pneumatic controllers per company and the associated justification that those ~~high-bleed~~ pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, ~~high-bleed~~ pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of five (5) ~~three~~ years and readily made available to the Division upon request.

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FINAL
ECONOMIC IMPACT ANALYSIS
PER § 25-7-110.5(4), C.R.S.

For Conservation Groups' Alternate Proposal modifying proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

This economic analysis addresses the impact of the Conservation Groups' alternate proposal on the Division-proposed revisions to Regulation 7. The alternate proposal includes the following changes covered in this analysis:[1]

1. Leak detection requirements for compressors should be expanded in two ways:

   a. The definition of "Natural Gas Compressor Station" in Rule XVII.A.10 should be expanded so that it is not limited to those compressors upstream of processing facilities.

   b. The inspection frequencies for compressor stations in Rule XVII.F should be calculated based on <u>total</u> VOC emissions (potential to emit), similar to the approach for well production facilities, rather than based only on <u>fugitive</u> VOC emissions.

2. For well production facilities and tanks with uncontrolled actual emissions of less than 6 tpy, the leak detection schedule in Rule XVII.F should require an instrument-based inspection on an annual basis – not just a single time.

3. Under Rule XVIII.C, the requirement to retrofit existing high-bleed pneumatic controllers should be clarified to ensure that it requires retrofitting <u>all</u> pneumatics emitting VOCs at a rate higher than a low-bleed pneumatic. This would include retrofitting <u>intermittent-bleed</u> pneumatics.

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[1] The alternate proposal includes several other proposed changes, such as shortening excessively long phase-in periods and requiring that records be kept for a longer time period. These proposed requirements are not separately analyzed in the discussion below because they are not expected to involve any material costs to companies. This is consistent with the approach taken by the Division in its initial economic analysis, which does not alter its analysis of a requirement's cost-effectiveness based on when the requirement takes effect, or how long records must be retained, for example.

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The discussion below uses the relevant sections from the Division's initial economic analysis, with modifications reflecting the limited changes proposed by the Conservation Groups.

II. COST/BENEFIT ANALYSIS:

A. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

AQCC Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement leak detection and repair programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct periodic inspections using EPA Reference Method 21[2] and repair leaks within a prescribed time frame.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include leak detection and repair requirements for these facilities.[3] To address these emissions, the Division is proposing regulatory changes that would establish leak detection and repair requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with Method 21 or utilizing an IR camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The Division's Proposal would establish a tiered system to determine inspection frequency. For well production facilities, the tiering is based on the uncontrolled actual emissions from the largest storage tank at the facility.[4] This approach creates a Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of the STEM emission capture requirements. The Conservation Groups would use the same approach, but require that facilities with emissions under 6 tpy conduct annual instrument-based inspections (instead of just a one-time inspection as proposed by the Division). For compressor stations, the Division proposes tiers based on the station's fugitive emissions. The Conservation Groups tiering is based instead on the facility's potential to emit (PTE) VOCs.

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[2] While Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

[3] Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

[4] Because there may be instances where facilities do not have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's potential to emit (PTE) VOC.

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For compressor stations and well production facilities, the frequencies proposed by the Conservation Groups are described as follows in Tables 1-2:

Table 1: Conservation Groups' Proposed Tiering for Leak Inspections at Compressor Stations	
PTE VOCs	Inspection Frequency
≤ 12 tpy	Annually, with monthly AVO
>12 tpy to ≤ 50 tpy	Quarterly, with monthly AVO
> 50 tpy	Monthly

Table 2: Conservtion Groups' Proposed Tiering for Leak Inspections at Well Production Facilities	
Tank Uncontrolled Actual VOC Emissions or PTE	Inspection Frequency
≤ 12 tpy	Annually (and monthly AVO)
>12 tpy to ≤ 50 tpy	Quarterly (and monthly AVO)
> 50 tpy	Monthly

1. Well production facilities

To evaluate the cost-effectiveness of the alternate proposal with regard to well production facilities, the Conservation Groups followed the approach used by the Division in its initial economic analysis. The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.[5] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in the Division's EIA Table 20 (reproduced below), the total annual cost for each inspector will be $186,129, which equates to an hourly inspection rate of $99.

Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis (Division EIA Table 20)			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	$122,000		
Photo Ionization Detector	$5,000		
Vehicle (4x4 Truck)	$22,000		
Inspection Staff		$75,000	
Supervision (@ 20%)		$15,000	
Overhead (@10%)		$7,500	
Travel (@15%)		$11,250	

[5] This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

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Recordkeeping (@10%)		$7,500	
Reporting (@10%)		$7,500	
Fringe (@30%)		$22,500	
Subtotal Costs	$149,000	$146,250	
Annualized Costs*	$39,879	$146,250	$186,129
**over 5 years at 6% ROR*		Annualized Hourly Rate	$99

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of its analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection. Discussions with multiple private contractors that perform these inspections at well production and oil and gas processing facilities indicates that, on average, the value of 30 seconds per component for camera-based inspections errs on the side of over-estimation of time. One contractor with extensive experience with camera-based inpsections stated that inspections can be conducted for 300 to 400 components per hour, when components are generally accessible.

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on this overall average component count each Method 21 inspection will take 9.5 hours and each IR camera based inspection will take 4.75 hours.

Next, the Division calculated the projected inspection costs for well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. The calculated inspection costs for well production facilities do not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective. Conversely, the calculated costs also do not account for the cost savings from capturing additional product as a result of repairs. For the purposes of its initial cost analysis the Division assumes that the cost savings from additional product capture will be equal to or greater than the cost of repair and re-inspection. The Division's estimated annual inspection costs for well production facilities are set forth in its EIA Table 23.[6]

[6] The Division's proposal also requires monthly AVO inspections at facilities. Based on information provided during the stakeholder process, the Division reports that AVO inspections are part of current standard operational practice. Accordingly, the regulatory provisions should not result in additional costs.

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Taking the same approach, the Conservation Groups' estimated annual inspection costs for well production facilities are set forth in Table 3.

Table 3: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled Tank Battery VOCs/PTE Tier [tpy]	Number of Facilities	Annual Inspection Frequency	Inspection Time Per Inspection [hours]	Total Inspection Time [hours]	Total Annual Inspection Cost
≤12	4,200	1	4.75	19,950	$1,975,050
> 12 to ≤ 50	2,916	4	4.75	55,404.0	$5,484,996
> 50	964	12	4.75	54,498.0	$5,439,852
Total:	8,080			129,852	$12,899,898

Finally, the Division calculated the cost effectiveness of the proposed leak detection and repair requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections. The Division estimated total emissions reductions at well production facilities from its proposal would be 14,153 tpy VOC and 22,461 tpy methane/ethane. This resulted in a Division estimate that its proposal would cost $818/ton VOC controlled, and $516/ton methane/ethane controlled, at well production facilities. These were calculated in Tables 26-27 of the Division's EIA.

The Conservation Groups have used a similar approach. The total emissions reductions and cost-effectiveness at well production facilities from the alternate proposal are set forth in Tables 4-5. Under the alternate proposal, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be $668/ton VOC and $421/ton methane/ethane. Thus, the Conservation Groups' alternate proposal for well production facilities is more cost-effective than the Division proposal.

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Table 4: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled Tank Battery VOCs/PTE Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	4,200	40%	4.6	7,728	7.3	12,264
> 12 to ≤ 50	2,916	60%	4.6	8,048.2	7.3	12,772.1
> 50	964	80%	4.6	3,547.5	7.3	5,629.8
Total:	8,080			19,323.7		30,665.9

Table 5: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21							
Uncont. Tank Battery VOCs/PTE Tier [tpy]	Number of Tanks	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction [tpy]	Methane -Ethane Control Cost [$/ton]
≤ 12	4,200	$1,975,050	40%	7,728	$256	12,264	$161
> 12 to ≤ 50	2,919	$5,484,996	60%	8,048.2	$682	12,772.1	$429
> 50	964	$5,439,852	80%	3,547.5	$1533	5,629.8	$966
Total:	8,080	$12,899,898		19,323	$668	30,665.9	$421

Finally, it should be noted that the Division's methodology for calculating the cost-effectiveness of LDAR at well production facilities is conservative in several respects. An analysis by the Clean Air Task Force of data from actual inspections found that costs are lower than those estimated by the Division. Testimony of David McCabe at 7-8.

2. Compressor stations

The Division's analysis of cost-effectiveness for compressor stations was similar to its analysis for well production facilities. It concluded that VOCs would be controlled at a cost of $667/ton, and methane/ethane controlled for $321/ton. These estimates are summarized in Table 25 of the Division's initial EIA.

Division Proposal - Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21 (Division EIA Table 25)							
Comp. Station Fugitive VOC Tier	Number of Comp Stations	Total Annual Inspection Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [$/ton]	Total Methane-Ethane Reduction	Methane-Ethane Control Cost [$/ton]

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[tpy]						[tpy]	
≤ 12	147	$154,262	40%	593.9	$260	911.4	$169
> 12 to ≤ 50	53	$589,763	60%	521.5	$1,131	1,408.7	$419
> 50			80%				
	200	$744,025		1,115.4	$667	2,320.1	$321

For compressor stations, the Conservation Groups do not have data that allows for a comparable calculation of the cost-effectiveness of their alternate proposal. Testimony of Maureen Barrett at 3-4. As a result, the Conservation Groups cannot provide numeric estimates of: (a) how many additional facilities would be affected if the LDAR provisions cover compressor stations downstream of processing plants; (b) how many compressor stations would fall into each inspection tier based on total VOCs (instead of fugitive VOCs); and (c) the potential to emit of each compressor station.

With regard to the estimated 200 compressor stations upstream of processing plants, the Conservation Groups expect that their alternate proposal will be cost-effective. For these compressors, the alternate proposal is expected to require more frequent inpections because total facility VOC emissions are typically much greater than the fugitive emissions counted by the Division Proposal. Barrett testimony at 2-3. While the increased inspections will result in greater costs, that expense will be offset by greater reductions of VOCs and methane/ethane at compressors than would result from the Division Proposal. An analysis by Clean Air Task Force estimates that quarterly instrument-based inspections of compressor stations controls VOC emissions at a cost of $800/metric ton, and the cost for monthly insepctions is under $3,500/metric ton. See McCabe testimony at 8. The control costs for methane are only about $10/metric ton with quarterly inspections, and just over $50/metric ton for monthly inspections. Id. at 4.

With regard to compressor stations downstream of processing plants, the cost of controlling methane/ethane reductions is likely to be even lower than for their upstream counterparts. The CATF figures indicate that methane control costs at transmission compressor stations are somewhat lower than those for gathering stations. McCabe testimony at 8-9.[7]

The cost per ton of VOC reductions for transmission compressor stations, however, likely would be greater than for compressors upstream of processing plants. Limited data is available, but the Title V permits for two such compressor stations, Kerr McGee's Fort Lupton station and DCP Midstream's Enterprise station, include limits for VOC fugitive emissions that allow for a conservative estimate of cost-effectiveness. The Kerr-McGee permit has a limit of 30.8 tpy fugitive VOCs, Supp. Testimony of Maureen Barrett at 2, and the DCP permit has a limit of 18.22 tpy fugitive VOCs. The Conservation Groups' alternate proposal would subject these two facilities to monthly instrument-based inspections. Assuming that such inspections reduce

[7] If the value of gas conserved by LDAR programs is not considered in the analysis of abatement costs for transmission compressor stations (because the facility owners may not own the gas), the methane abatement cost for those facilities is slightly higher than for gathering compressor stations, but still very reasonable (under $3/ metric ton CO_2e). McCabe testimony at 9 n. 5.

NMED Exhibit 71

NMED Exhibit 71

BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WPX ENERGY ROCKY MOUNTAIN, LLC'S AND WPX ENERGY PRODUCTION, LLC'S PROPOSED REGULATION TEXT – WPX REB EX A

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS REGARDING PROPOSED REVISIONS TO:
REGULATION NUMBER 3, PARTS A, B, AND C;
REGULATION NUMBER 6, PART A;
REGULATION NUMBER 7

WPX ENERGY ROCKY MOUNTAIN, LLC and WPX ENERGY PRODUCTION, LLC (collectively "WPX") respectfully submit to the Colorado Air Quality Control Commission ("Commission") WPX's final proposed regulation text to accompany WPX's alternate proposal[1] pursuant to Procedural Rule § V.C.3.c.

Based on the revised language of the Proposed Regulation Text circulated by the Division on January 24, 2014, please see the attached revised alternate proposal by WPX indicated by the redlined attachment. *See* attached WPX ALT EX D REVISED. For clarity, WPX has only included here the sections for which it proposes changes, and has indicated such changes in the attached redline.

[1] Note that WPX does not believe that the minor changes it proposed on January 6, 2014, rise to the level of an alternate proposal. However, out of an abundance of caution, WPX filed its proposed revisions to the Division rules as an alternate proposal with the documents described in 5 CCR 1001-1 ("Procedural Rules") Section V.C.3.a through k.

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

XVII.C.1.e.(ii) (new section) Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of Approved Instrument Based Monitoring Methods (such as reflection due to precipitation).

XVII.F.5.c. Owners or operators of well production facilities constructed before January 1, 2015, must identify leaks from components using an approved instrument based monitoring method within ninety (90) days of the Phase-In Schedule in Table 4, within thirty (30) days for > 50 tons per year, or by July 1, 2016, for > 0 and < 6 tons per year tanks. Thereafter, approved instrument based monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequency in Table ~~4.~~4 or when a reduced LDAR demonstration is made, the frequency may be determined by Alternative Table 4A pursuant to Section XVII.F.5.d.

XVII.F.5.~~e~~d. The largest estimated uncontrolled actual emissions from a single storage ~~tanks determine~~tank batterys determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility or multi-well site, owners or operators must rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the well production facility~~.~~ in accordance with Table 4 of Alternative Table 4A.

Table 4 – Well Production Facility Component Inspections

Threshold (per XVII.F.5.d.) VOC Emissions (tpy)	Inspection Frequency	Phase-In Schedule
> 0 and < 6	One time using approved Instrument based monitoring method and thereafter using monthly AVO	July 1, 2016
> 6 and < 12	Annually with monthly AVO	January 1, 2016
> 12 and < 50	Quarterly with monthly AVO	July 1, 2015
> 50	Monthly	January 1, 2015
Well production facilities or multi-well sites without storage tanks storing oil or condensate that have a potential to emit > 20 tpy VOC	Monthly	January 1, 2015

An alternative inspection frequency schedule pursuant to Alternative Table 4A may be implemented once a reduced LDAR demonstration is made. A reduced LDAR demonstration requires that an owner or operator identify fewer than either (1) the specified number of leaking components listed in "Demonstration of Reduced LDAR – Monitoring History" in Alternative Table 4A or (2) two percent of the total components for that facility during a single monitoring event, for at least two consecutive monitoring events.

Once the reduced LDAR demonstration is made pursuant to this Section, the alternative inspection frequency pursuant to Alternative Table 4A may remain in place until, during any monitoring event under the alternative inspection frequency, more leaks are indentified than allowed under Alternative Table 4A's "Demonstration of Reduced LDAR – Monitoring History." Using the alternative inspection frequency identified in Alternative Table 4A, during any monitoring event, if more leaks are identified than listed in the "Demonstration of Reduced LDAR – Monitoring History," then the original monitoring frequency identified in Table 4 shall become applicable until or if the operator can make another reduced LDAR demonstration for that facility.

Alternative Table 4A		
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	Demonstration of Reduced LDAR - Monitoring History	Alternative Inspection Frequency
> 0 and < 6		One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO
> 6 and < 12		Annually with monthly AVO
> 12 and < 50	5 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.	Annually with monthly AVO
> 50	10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.	Quarterly with monthly AVO
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	10 or less component leaks (or 2% of total components) identified in each of two consecutive monitoring events.	Quarterly with monthly AVO

XVII.F.~~5.g.(ii)~~6.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring, which includes weather conditions preventing access to the site, or that endanger monitoring personnel or equipment, or prevent use of Approved Instrument Based Monitoring Methods (such as reflection due to precipitation).

XVII.F.~~6.~~7.a. For EPA Method 21 monitoring at facilities constructed before May 1, 2014, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm~~.~~ after January 1, 2016.

XVII.F.~~6.~~7.b. For EPA Method 21 monitoring at facilities constructed on or after ~~May~~January 1, ~~2014,~~2016, a leak is any concentration of hydrocarbon above 500 ppm.

EXHIBIT 9.C

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

>>>>>>>>

II. General Provisions

>>>>>>>>

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

>>>>>>>>

XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. "Approved Instrument Based Monitoring Method," as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.3. ”Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

XVII.A.4. “Building Unit” shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.A.5~~4~~. “Component” means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.6~~5~~. “Connector” means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.7~~6~~. “Date of First Production” means the date reported to the COGCC as the “first date of production.”

XVII.A.8. “Designated Outside Activity Area” shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.A.9~~7~~. “Glycol Natural Gas Dehydrator” means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.10. “Major Gas Leak” shall mean any leak greater than 10,000 ppm hydrocarbon concentration above background as determined through an approved instrument based monitoring method.

XVII.A.11~~8~~. “Multi-Well Site” means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.12~~9~~. “Natural Gas Compressor Station” means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing.

XVII.A.13~~0~~. “Normal Operation” means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

XVII.A.14~~1~~. “Stabilized” when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to

those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.15~~2~~. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.16~~3~~. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.17~~4~~. "Visible Emissions" means observations of smoke and/or hydrocarbon vapors for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy ~~or water vapor~~.

XVII.A.18~~5~~. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with ~~good air pollution control~~best management practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent. ~~to the extent practicable,~~ and consistent with technological limitations and ~~good~~ best engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations.

Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds, based on a rolling twelve-month total, equal to or greater than six (6) tons per year, ~~based on a rolling twelve-month total~~ or two (2) tons per year if the storage tanks is located within 1,320 feet of a building unit or designated outside activity area, must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of no less than 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six (6) tons VOC or more per year on a rolling twelve month basis after May 1, 2014, or two tons VOC or more per year if located within 1,320 feet of a building unit or designated outside activity area, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production, or 0.5 tons of VOC emissions during the first 90 days after the date of first production if located 1,320 feet from a building unit or designated outdoor activity area.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the thresholds in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and

implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence ~~of~~ or absence of smoke or vapors. If smoke or vapors are ~~is~~ observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible

emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, to be made available to the Division upon request. In addition, for a period of two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two (2) tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

~~XVII.D.4.c. For purposes of Section XVII.D.4.:~~

~~XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.~~

~~XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.~~

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed in or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1

Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and best~~good~~ engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile

organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this

Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), of other Division approved method.

Table 2	
Fugitive VOC Emissions (tpy)	Inspection Frequency
>0 and ≤ 12	Annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. Consistent with the provisions of XVII.F.5.f., owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3		
Threshold (per XVII.F.5.e.) VOC	Threshold within 1,320 feet of a building	Inspection Frequency

Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	unit or designated outside activity area (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with tanks or PTE for sites without tanks)	
> 0 and ≤ 6		One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO
> 6 and ≤ 12	> 0 and < 6	Annually with monthly AVO
> 12 and ≤ 50	> 6 and < 12	Quarterly with monthly AVO
> 50	> 12	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 12 tpy VOC	Monthly

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than 50 tpy or multi-well sites.

XVII.F.5.f.(ii) Beginning July 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 tpy but less than or equal to 50 tpy.

XVII.F.5.f.(iii) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions greater than 6 tpy but less than or equal to 20 tpy.

XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a

monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVIII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. Except as provided in Section XVII.F.7.b. below, the f~~F~~irst attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they shall be ordered promptly and the repair shall be made within fifteen (15) working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.

XVII.F.7.b. Repairs to major gas leaks that are discovered within 1,320 feet of a building unit or designated outside activity area shall be made no later than 24 hours after discovery. If a repair is not possible with 24 hours, the well shall be shut down until a repair can be made. If shutting down the well will not stop the leak, demonstrable efforts should be made to minimize the leak within the first 24 hours.

XVII.F.7.c~~b~~. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.d~~c~~. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.e~~d~~. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing

facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all of their subject facilities during the previous calendar year. Reports will be made publicly available on the APCD Website and searchable by API well number, APEN permit number, operator, date, and geographic area. In addition to this information, ~~This~~ the report shall also contain ~~at a minimum~~ the following information:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. Each major gas leak discovered and how quickly it was repaired;

XVII.F.9.f~~e~~. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.g~~f~~. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on

information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1. Well Operation and Maintenance: On or after August 1, 2014, during normal operation gas coming off a separator produced from any newly constructed, hydraulically fractured, or recompleted oil and gas well must either be routed to a gas gathering line or controlled by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. will be kept and made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. “Affected Operations” shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. “Enhanced Maintenance” is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. “High-Bleed Pneumatic Controller” shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. “Low-Bleed Pneumatic controller” shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. “Natural Gas Processing Plant” shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. “No-bleed Pneumatic Controller” shall mean any pneumatic controller that is not using hydrocarbon gas as the valve’s actuating gas.

XVIII.B.7. “Pneumatic Controller” shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) All high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

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XIX. Statements of Basis, Specific Statutory Authority and Purpose

The Local Community Organizations adopt the Statement of Basis and Purpose proposed by the APCD.

EXHIBIT I.

LOCAL COMMUNITY ORGANIZATIONS' FINAL ECONOMIC IMPACT ANALYSIS PER § 25-7-110.5(4), C.R.S.

For proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

This final economic impact analysis will cover only the changes the Local Community Organizations have made to the Air Quality Control Division's (APCD) proposal. The Local Community Organizations appreciate the assistance from the APCD in the creation of this final economic impact analysis.

II. OVERVIEW OF PROPOSED REGULATORY CHANGES

The Local Community Organizations are proposing revisions to the APCD's proposed AQCC Regulation Number 7. This Regulation Number 7 rulemaking package adopts nearly all of the changes proposed by the Colorado Air Pollution Control Division but amends specific sections to accomplish the following:

1) Reduce nearby residents' exposure to air toxics by requiring operators of facilities within 1,320 feet of a building unit or outdoor activity area to

    a. control VOCs down to 2 TPY,
    b. conduct more frequent inspections, and
    c. repair "major leaks" within 24 hours.

2) Increase transparency by requiring annual inspection reports to be posted online and accessible by the public.

III. COST/BENEFIT ANALYSIS:

A. Control Requirements for Petroleum Storage Tanks

The Local Community Organizations have proposed changes to require that tanks within 1,320 feet (1/4 mile) of a building unit or designated outdoor activity area must utilize air pollution control equipment if the tanks have uncontrolled actual emissions of equal or greater than two (2) tons per year.

The proposed APCD regulations would require operators with tanks that have uncontrolled emissions of at least **six (6) tons** per year to use emission control devices capable of achieving 95% control efficiency of volatile organic compounds (VOCs). Currently, the Colorado Oil and Gas Conservation Commission (COGCC) requires all tanks with uncontrolled emissions of VOCs

of five (5) tons per year or greater that are located within 1,320 feet of a Building Unit, or a Designated Outside Activity Area to use an emission control device capable of achieving 95% control efficiency of VOCs. (COGCC Rule 805.b.(2)). Therefore, this change only will affect those tanks that emit from 2-5 tons of VOCs per year.

1. General Cost Estimates for Flares

Using the data obtained from the APCD Initial Economic Impact Analysis, we assume that the estimated annualized cost of a flare control device with auto-igniter is about $6,287.

2. Annualized Cost for Buffer Bottles

As reported in the Division's initial economic impact analysis, the annualized costs for buffer bottles is $3,024 per unit.

3. Lowering Statewide Condensate Tank Control Threshold (from 6(5) tpy to 2 tpy)

The Local Community Organization is proposing to lower the uncontrolled VOC emission control threshold from the state-proposed 6 tpy to 2 tpy on all tanks within 1,320 feet of a Building Unit, or a Designated Outside Activity Area.

As stated above, the COGCC currently requires tanks to control VOCs to five (5) tons per year within 1,320 feet of a home so the regulation only affects those tanks that emit two (2) to five (5) tpy.

Using numbers obtained from the APCD, there are 1,506 tanks that are emitting between 2-5 tpy VOCs.

Of this number, at least 2/3 of the tanks would not be located within 1,320 feet of a home or designated outdoor recreation area. The COGCC supplied data during the setback hearing that indicated that approximately 26% of new and expanded well sites were located within 1,000 feet of a building unit. (COGCC analysis is attached). Expanding the area from 1,000 to 1,320 feet we have allowed for the percentage of wells affected to climb to 1/3 or 33%. Therefore, 2/3 of the potential tanks affected will not be affected by this regulation and are listed in Table 1 as "cancelled tanks".

Using the assumption of 33% of tanks being within 1,230 feet of a building unit we get 497 tanks.

Table 1: Tank Battery Analysis

	2-3 TPY	3-4 TPY	4-5 TPY	5-6 TPY	Total Tanks 2-5 TPY	Total Tanks 2-6 TPY
Tanks	610	485	411	374	1,506	1,880
Cancelled Tanks	409	325	275	251	1,009	1,260
TOTAL AFFECTED TANKS (2-5 tpy)	201	160	136	123	497	620

The annual cost of installing 497 flare control devices is about $3,125,000 with an average cost effectiveness of about $1,884.5 per ton of VOCs reduced. See Table 2. VOC reduction in the 497 tanks that are within 1,320 feet of a building unit or designated outside activity area AND emit =>2 tpy of VOCS but less than 5 tpy of VOCs was calculated by summing the VOC emissions of ALL tanks that emit =>2 tpy but less than 5 tpy and then multiplying this sum by 0.33, assuming only 33% of all such tanks lie within 1,320 feet of a building unit or designated outside activity area. The emission data came from the APCD.

Table 2: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices (inc. buffer bottle)

Affected Tanks [count]	Each Flare + buffer bottle Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [$/ton]
497	$9,310.8	$4,627,467.6	1,658	$2,791

B. Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order to prevent leaks and ensure that oil and gas facilities closest to homes and schools are being properly maintained, the Local Community Organizations are proposing that tanks within 1,320 feet of a building unit or designated outdoor recreation area be subject to more frequent instrument based monitoring using Method 21, an IR camera or other Division approved monitoring device or method. As proposed by the APCD, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 3: Proposed Tiering for Instrument Based Tank Inspections - ¼ mile of building units

Tank Uncontrolled Actual VOC Emissions	Number of Tanks Affected	Inspection Frequency	Additional Number of Inspections	Additional Inspection Costs
≥ 2 tpy to ≤ 6 tpy	497	Annually	497	$98,406
>6 tpy to ≤ 12 tpy	459	Quarterly	1,376	$272,448
>12 tpy to 50 tpy	962	Monthly	7,698	$1,524,204

In assessing the cost-effectiveness of the proposed requirements, the Local Community Organizations first calculated the number of tanks that would be affected (1/3 in each category of tanks) and then the additional inspections necessary. That is, going from annual inspection to quarterly inspections would require an additional three inspections, quarterly to monthly would require an additional eight inspections per tank. These figures were then multiplied by the state's estimate of $198 per inspection to come up with the figures in Table 3.

C. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

The Local Community Organizations have requested that major leaks of over 10,000 ppm within 1,320 feet of building units should be repaired within 24 hours. We do not believe there will be

any additional costs associated with this practice since the leaks would already have to be repaired within five days and most operators will make immediate repairs if major leaks are discovered for safety purposes and to conserve the oil and gas.

D. Require the APCD to Place Annual Inspection Reports on their Website

The Local Community Organizations have requested that the APCD assist in finalizing this economic impact analysis. They hope to receive that information as to the cost of this provision in the coming weeks. In the meantime, we would expect that the COGCC would be willing to post the annual inspection reports on its website. The cost to post on the COGCC website would be much less given the website is already set-up to allow the public to search by API well number.

IV. CONCLUSION

The Local Community Organizations estimate that their requested revisions to increase tank controls within 1,320 feet of building units will cost $4,627,467– reducing 1,658 tpy of VOCs at a cost of $2,791 tons/year. The total cost for the increased inspection schedules within 1,320 feet of homes is $1,895,058.

The cost to the APCD for design and maintenance of a website that will contain annual inspection reports is still to be determined.

LGC EXHIBIT A. ALTERNATIVE PROPOSED REGULATION

AMENDED REVISIONS BY THE LGC TO:

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS

(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

Field Code Changed

5 CCR 1001-9

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II. General Provisions

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II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Sections XVII. and XVIII.

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XVII. (State Only, except Section XVII.E.3.a. which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines

XVII.A. (State Only) Definitions

XVII.A.1 "Air Pollution Control Equipment," as used in this Section XVII, means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section XVII.B.2.e.

XVII.A.2. ”Approved Instrument Based Monitoring Method,” as used in this Section XVII. means an infra-red camera, Method 21, or other Division approved instrument based monitoring device or method. If an owner/operator elects to use a Division approved Continuous Emission Monitoring program, the Division may approve a streamlined inspection and reporting program for such operations. Any instrument based monitoring method approved by the Division under this definition must be at least as effective as Method 21 or an infra-red camera.

XVII.A.3. ”Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

XVII.A.4. “Component” means each pump seal, compressor seal, flange, pressure relief device, connector, open ended line, and valve that contains or contacts a process stream with hydrocarbons. Process streams consisting of glycol, amine, produced water, or methanol are not components for purposes of this Section XVII.

XVII.A.5. “Connector” means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Jointed fittings welded completely around the circumference of the interface are not considered connectors.

XVII.A.6. “Date of First Production” means the date reported to the COGCC as the “first date of production.”

XVII.A.7. “Glycol Natural Gas Dehydrator” means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

XVII.A.8. “Multi-Well Site” means a common well pad from which multiple wells may be drilled to various bottomhole locations.

XVII.A.9. “Natural Gas Compressor Station” means a facility which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure and recompress natural gas prior to processing.

XVII.A.10. “Normal Operation” means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

XVII.A.11. “Stabilized” when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited

to those commonly referred to within the industry as working, breathing, and standing losses.

XVII.A.12. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage vessel is as defined in 40 CFR Part 60, Subpart OOOO. Storage tanks may be located at a well production facility or other location.

XVII.A.13. "Unsafe to Monitor" means a component is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of such monitoring.

XVII.A.14. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation. Visible emissions do not include radiant energy or water vapor.

XVII.A.15. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or gas wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

XVII.B. (State Only) General Provisions

XVII.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.B.1.a. All intermediate hydrocarbon liquids collection, storage, processing, and handling operations, regardless of size, shall be designed, operated, and maintained so as to minimize leakage of volatile organic compounds to the atmosphere to the extent reasonably practicable.

XVII.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment shall be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

XVII.B.2. General requirements for air pollution control equipment, flares, and combustion devices used to comply with Section XVII.

XVII.B.2.a. All air pollution control equipment shall be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds and hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

XVII.B.2.b. If a flare or other combustion device is used to control emissions of hydrocarbons, it shall be enclosed, have no visible emissions during normal operations, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other means approved by the Division, determine whether it is operating properly.

XVII.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

XVII.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons shall be equipped with and operate an auto-igniter as follows:

XVII.B.2.d.(i) All combustion devices installed on or after May 1, 2014, will be equipped with an operational auto-igniter upon installation of the combustion device.

XVII.B.2.d.(ii) All combustion devices installed before May 1, 2014, will be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

XVII.B.2.e. Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section XVII, if the Division approves the equipment, device or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section XVII.

XVII.B.3. Oil refineries are not subject to Section XVII.

XVII.B.4. Glycol natural gas dehydrators and internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 are not subject to this Section XVII.

XVII.C. (State Only) Emission reduction from storage tanks at oil and gas exploration and production operations, well production facilities, natural gas compressor stations, and natural gas processing plants.

XVII.C.1. Control requirements for storage tanks

XVII.C.1.a. Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of volatile organic compounds equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must operate air pollution control equipment that has an average control efficiency of at least 95% for VOCs.

XVII.C.1.b. Owners or operators of all storage tanks with uncontrolled actual emissions of volatile organic compounds equal to or greater than six (6) tons per year based on a rolling twelve-month total must operate air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.C.1.b.(i) A storage tank constructed on or after May 1, 2014, must be in compliance by the date that the storage tank commences operation.

XVII.C.1.b.(ii) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

XVII.C.1.b.(iii) A storage tank not otherwise subject to Sections XVII.C.1.b.(i) or XVII.C.1.b.(ii), above, that increases uncontrolled actual emissions to six tons VOC or more per year on a rolling twelve month basis after May 1, 2014, must be in compliance within sixty days of discovery of the emissions increase.

XVII.C.1.c. Control requirements within 90 days of the date of first production.

XVII.C.1.c.(i) Beginning May 1, 2014, owners or operators of storage tanks at well production facilities shall collect and control emissions by routing emissions to operating air pollution control equipment during the first 90 calendar days after the date of first production. The air pollution

control equipment shall achieve an average hydrocarbon control efficiency of 95%. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons. Except that this requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first 90 days after the date of first production.

XVII.C.1.c.(ii) The air pollution control equipment and any associated monitoring equipment required pursuant to Section XVII.C.1.c., above, may be removed at any time after the first 90 calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank are below the threshold in Section XVII.C.1.b., above.

XVII.C.2. Capture requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1.

XVII.C.2.a. Beginning on the applicable compliance date specified in Section XVII.C.1.b., owners and operators of storage tanks shall route all hydrocarbon emissions to air pollution control equipment, and shall operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation unless venting is reasonably required for maintenance, gauging, or safety of personnel and equipment.

XVII.C.2.b. Beginning on the applicable compliance date specified in section XVII.C.1.b., owners and operators of storage tanks shall develop, certify, and implement a document Storage Tank Emission Management System (STEM) plan to identify appropriate strategies to minimize emissions from venting at thief hatches (or other access points to a storage tank) and pressure relief devices during normal operation. As part of STEM, owners and operators shall evaluate and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section XVII.C.2.a., above, and will update the STEM plan as necessary to achieve or maintain compliance. Owners and operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed below.

XVII.C.2.b.(i) STEM must include a monitoring strategy that incorporates the minimum monitoring frequency set forth in Section XVII.F.5.e., procedures for evaluating ongoing storage tank emission capture performance, and, if applicable, the selected strategies.

XVII.C.2.b.(ii) STEM must include a certification by the owner or operator that the selected STEM strategy or strategies are designed to minimize emissions from storage tanks and associated equipment components at

the facility or facilities, including thief hatches and pressure relief devices.

XVII.C.3. Monitoring: The monitoring strategy of each STEM plan must include monitoring in accordance with Approved Instrument Based Monitoring Methods, as specified in Section XVII.F.5.

XVII.C.3.a. In addition to any applicable Approved Instrument Based Monitoring Methods, audio, visual, olfactory ("AVO") inspection of the storage tank and any associated equipment (i.e. separator, air pollution control equipment, or other pressure reducing equipment), must be completed as often as liquids are loaded out from the storage tank. However, AVO inspection is required no more frequently than every seven (7) days or less frequently than every thirty (30) days. AVO monitoring is not required for components and tanks that are unsafe to monitor. AVO inspection must include, at a minimum:

XVII.C.3.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are enclosed and properly sealed;

XVII.C.3.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment;

XVII.C.3.a.(iii) If a flare or other combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light, to ensure they are functioning properly;

XVII.C.3.a.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open; and

XVII.C.3.a.(v) If a flare or other combustion device is used, inspection of the device for the presence of absence of smoke. If smoke is observed, either the equipment will be immediately shut-in to investigate that potential cause for smoke and perform repairs, as necessary, or Method 22 shall be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

XVII.C.4. Recordkeeping: The owner or operator of each storage tank subject to XII.D. or XVII.C. must maintain records of STEM as applicable, including the plan, any updates, and the certification, to be made available to the Division upon request. In addition, for a period of two years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including:

XVII.C.4.a. The AIRS ID for the storage tank.

XVII.C.4.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions.

XVII.C.4.c. The date and duration of any period where the air pollution control equipment is not operating.

XVII.C.4.d. Where a flare or other combustion device is being used, the date and result of any Method 22 test.

XVII.C.4.e. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions.

XVII.D. (State Only) Emission reductions from glycol natural gas dehydrators

XVII.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

XVII.D.2. The control requirement in Section XVII.D.1. shall apply where:

XVII.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

XVII.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

XVII.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, and drip station or gas-processing plant subject to control requirements pursuant to Section XVII.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons.

XVII.D.4. The control requirement in Section XVII.D.3. shall apply where:

XVII.D.4.a. Actual uncontrolled emissions of volatile organic compounds from a single new glycol natural gas dehydrator are equal to or greater than two tons per year; or

XVII.D.4.b. Actual uncontrolled emissions of volatile organic compounds from a single existing glycol natural gas dehydrator are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

XVII.D.4.c. For purposes of Section XVII.D.4.:

XVII.D.4.c.(i) Building Unit shall mean a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

XVII.D.4.c.(ii) A designated outside activity area shall mean an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

XVII.E. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

XVII.E.1. (State Only) The requirements of this Section XVII.E. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.2. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.2.a. Except as provided in Section XVII.E.2.b. below, the owner or operator on any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in the table below shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the

extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section XVII.E.2.b. Table 1 below.

XVII.E.2.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 below as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

XVII.E.3. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

XVII.E.3.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

XVII.E.3.a.(i) Except as provided in Sections XVII.3.1.(i)(b) and (c) and XVII.E.3.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

XVII.E.3.a.(i)(a) All control equipment required by this Section XVII.E.3.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent

practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

XVII.E.3.a.(i)(b) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63, a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 are not subject to this Section XVII.E.3.a.

XVII.E.3.a.(i)(c) The requirements of this Section XVII.E.3.a. shall not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

XVII.E.3.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1,2009.

XVII.E.3.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

XVII.E.3.b.(i) Except as provided in Section XVII.E.3.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

XVII.E.3.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index)

is exempt complying with Section XVII.E.3.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

XVII.F. (State Only) Leak detection and repair program for well production facilities, storage tanks, and compressor stations

XVII.F.1. Beginning January 1, 2015, owners and operators of well production facilities and compressor stations will identify and repair leaks from components at these facilities in accordance with the requirements of this Section XVII.F. The following shall apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

XVII.F.2. Owners and operators of well production facilities or natural gas compressor stations that monitor components as part of this Section XVII.F. may opt to estimate emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

XVII.F.3. Owners and operators of well production facilities or natural gas compressor stations shall utilize the Approved Instrument Based Monitoring Method and AVO program as outlined in Section XVII.F. AVO monitoring is not required of components and tanks that are unsafe to monitor or inaccessible to monitor, pursuant to XVII.F.5.g.

XVII.F.4. Inspection schedules for natural gas compressor stations: Beginning January 1, 2015, owners and operators of natural gas compressor stations shall inspect components for leaks using an Approved Instrument Based Monitoring Method, in accordance with the following Table 2, except for components subject to XVII.F.5.g. For purposes of this Section XVII.F.4., fugitive emissions shall be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), of other Division approved method.

Table 2	
Fugitive VOC Emissions (tpy)	Inspection Frequency
>0 and ≤ 12	Semi-~~A~~annually

> 12 and ≤ 50	Quarterly
> 50	Monthly

XVII.F.5. Requirements for well production facilities and/or storage tanks

XVII.F.5.a. Beginning August 1, 2014, all new well production facilities shall have a documented pressure test performed on all equipment and piping prior to start up. Documentation of this 90 day testing and monitoring shall be provided in the first annual report to the Division, as required by Section XVII.F.9.

XVII.F.5.b. Beginning January 1, 2015, within 90 days of startup of all new well production facilities and/or storage tanks, owners and/or operators shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method. Such action shall qualify as an inspection pursuant to the inspection frequency schedule in Table 3.

XVII.F.5.c. Consistent with the provisions of XVII.F.5.f., owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks using an Approved Instrument Based Monitoring Method, in accordance with the implementation schedule in XVII.F.5.e. Inspection frequency shall be determined according to Table 3.

XVII.F.5.d. Consistent with the provisions of XVII.F.5.f., owners and operators of new well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method beginning on January 1, 2015. Inspection frequency shall be determined according to Table 3.

XVII.F.5.e. The estimated uncontrolled actual emissions from storage tanks determine the frequency at which inspections must be performed. If no storage tanks are located at the well production facility or multi-well site, operators will rely on the potential to emit of VOC for all of the emissions sources, including emissions from components located at the facility. All components at a well production facility or storage tank must be inspected:

Table 3	
Threshold (per XVII.F.5.e.) VOC Emissions (tpy, uncontrolled actual for sites with	Inspection Frequency

tanks or PTE for sites without tanks)	
> 0 and ≤ 6	~~One time using Approved Instrument Based Monitoring Method and thereafter using monthly AVO~~Every two years with monthly AVO
> 6 and ≤ 12	Semi-a~~A~~nnually with monthly AVO
> 12 and ≤ 50	Quarterly with monthly AVO
> 50	Monthly
Multi-well sites without storage tanks after April 15, 2014, that have a PTE > 20 tpy VOC	Monthly

XVII.F.5.f. Phase-in of Approved Instrument Based Monitoring Methods: Owners and operators of existing well production facilities and/or storage tanks shall identify and repair leaks from components using an Approved Instrument Based Monitoring Method, in accordance with the following schedule:

XVII.F.5.f.(i) Beginning January 1, 2015, facilities with uncontrolled actual VOC emissions greater than ~~50~~ 6 tpy or multi-well sites.

~~XVII.F.5.f.(ii) Beginning July January May 1, 2015, facilities with uncontrolled actual VOC emissions greater than 20 6 tpy but less than or equal to 50 tpy.~~

XVII.F.5.f.(ii~~i~~) Beginning January 1, 2016, facilities with uncontrolled actual VOC emissions ~~greater~~ less than or equat to~~than~~ 6 tpy ~~but less than or equal to 20 tpy~~.

~~XVII.F.5.g.(iv) By July 1, 2016, facilities with uncontrolled actual VOC emissions less than or equal to 6 tpy.~~

XVII.F.5.g. If a component is difficult, unsafe, or inaccessible to monitor, the owner or operator shall not be required to monitor the component until it becomes feasible to do so.

XVII.F.5.g.(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or are unable to be reached via a

wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

XVII.F.5.g.(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

XVII.F.5.g.(iii) Inaccessible to monitor components are those that are buried, insulated in a manner that prevents access to the components by a monitor probe, or obstructed by equipment or piping that prevents access to the components by a monitor probe.

XVII.F.6 Leak detection requiring repair: Leaks shall be identified utilizing the methods listed in this Section XVII.F.6.a. through XVII.F.6.d. Only leaks detected pursuant to this Section XVIII.F.6. shall require repair under Section XVII.F.

XVII.F.6.a. For Method 21 monitoring at existing facilities, a leak is any concentration of hydrocarbon above 2,000 parts per million (ppm), except for existing well production facilities where leak is defined as any concentration of hydrocarbon above 500 ppm.

XVII.F.6.b. For Method 21 monitoring at facilities constructed after May 1, 2014, a leak is any concentration of hydrocarbon above 500 ppm.

XVII.F.6.c. For infra-red camera and AVO monitoring, a leak is any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

XVII.F.6.d. For other Division approved monitoring devices or methods, leak identification requiring repair will be established as set forth in the Division's approval.

XVII.F.7. Repair and remonitoring

XVII.F.7.a. First attempt to repair a leak shall be made no later than five (5) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists. If parts are unavailable, they shall be ordered promptly and the repair shall be made within fifteen (15) working days of receipt of the parts. If shutdown is required, the leak shall be repaired during the next scheduled shutdown. If delay is attributable to other good cause, repairs shall be completed within fifteen (15) working days after the cause of delay ceases to exist.

XVII.F.7.b. Within fifteen (15) working days of completion of a repair, the leaks shall be remonitored to verify the repair was effective.

XVII.F.7.c. Leaks discovered pursuant to the leak detection methods of Section XVII.F. shall not be subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section XVII.F.7.

XVII.F.7.d. For leaks identified using an Approved Instrument Based Monitoring Method, owners and operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section XVII.F.7. or conducting follow-up monitoring using Method 21 within five (5) working days of the leak detected. If the follow-up Method 21 monitoring shows that the leak concentration is less than or equal to 2,000 ppm hydrocarbon for existing facilities (other than existing well production facilities), or 500 ppm for new facilities or existing well production facilities, then the emission shall not be considered a leak for purposes of this Section.

XVII.F.8. Recordkeeping: The owner or operator of each facility subject to the inspection and maintenance requirements in this Section XVII.F. shall maintain the following for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the pre-start-up pressure tests for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repair;

XVII.F.8.f. The delayed repair list including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of identification numbers for components that are designated as unsafe or inaccessible to monitor, as described in Section XVII.F.5.g., an explanation for each component stating why the component is so designated, and the plan for monitoring such component(s).

XVII.F.9. Reporting: The owner or operator of each facility subject to the inspection and maintenance requirements in Section XVII.F. shall submit a single annual report on or before April 30th of each year summarizing inspection and maintenance activities at all

of their subject facilities during the previous calendar year. This report shall contain at a minimum the following information:

XVII.F.9.a. The number of facilities inspected;

XVII.F.9.b. The total number of inspections;

XVII.F.9.c. The total number of leaks identified, broken out by component type;

XVII.F.9.d. The total number of leaks repaired;

XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and

XVII.F.9.f. Each report shall be accompanied by a self-certification form. The form shall contain a certification by a responsible official of the truth, accuracy, and completeness of such form, report, or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

XVII.G. (State Only) Control of emissions from well production facilities

XVII.G.1Control Standards

XVII.G.1.A Well Operation and Maintenance: On or after ~~August~~ January 1, 201~~5~~4, ~~during normal operation~~ gas coming off a separator produced from any newly ~~–~~constructed, hydraulically fractured, or recompleted oil and gas well must either ~~,~~ be routed to a gas gathering line or controlled by air pollution control equipment ~~,~~ ~~t~~that achieves an average hydrocarbon control efficiency of 95% from the date of first production. If a combustion device is used, it shall have a design destruction efficiency of at least 98% of hydrocarbons.

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XVII.G.1.B Unless otherwise approved by the Division, on or before 90 days from the date of first production from the well or [January 1, 2015], whichever is later, the well must be connected to a gas gathering line. In determining whether to approve an extension of the 90 day period, the Division will consider the economic feasibility of connecting the well to a gas gathering line, the amount of gas being routed to air pollution equipment, the economic feasibility of alternative uses of the gas, the owner/operators' future plans for connecting the well to a gas line, and any other relevant information from the owner or operator. The division will also consider input received from the Colorado Oil & Gas Conservation Commission and will assess economic feasibility subject to a feasibility criterior of $2,500 per ton.

XVII.G.2 Monitoring: The owner or operator of any well production facility that is using air pollution control equipment to comply with section XVII.G.1.A. shall visually inspect or monitor the air pollution control equipment to ensure that it is operating. In addition, if a flare or other combustion device is used, the owner or operator shall visually inspect the device for visible emissions. These inspections shall occur as often as liquids are loaded out from the well production facility. However, these inspections are required no more frequently than every seven days or less frequently than every 90 days.

XVII.G.3 Recordkeeping: The owner or operator of an oil or gas well shall maintain the following records for a period of five years and make them available to the Division upon request.

XVII.G.3.A The date of each visual inspection required under Section XVII.G.2

XVII.G.3.B The date, time and duration of any period where the air pollution control equipment is not operating. The duration of a period of non-operation is from the time that the air pollution control equipment was last observed to be operating until the time the equipment recommences operation.

XVII.G.3.C Where a flare or other combustion device is being used, the date and time of any instances where visible emissions are observed from the device.

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XVII.H. (State Only) Venting during downhole well maintenance and unloading events

XVII.H.1. Well Maintenance: Beginning May 1, 2014, hydrocarbon emissions from flowing wells must be captured or controlled during downhole well maintenance or servicing activities, unless venting is necessary for safety.

XVII.H.1.a. Operators shall use best management practices to minimize the need for well venting associated with downhole well maintenance and liquids unloading. During liquids unloading events, any means of creating differential pressure will first be used to attempt to unload the liquids from the well without venting. If these methods are not successful in unloading the liquids from the well, the well may be vented to the atmosphere to create the necessary differential pressure to bring the liquids to the surface.

XVII.H.1.b. Venting will be minimized to the extent possible, using best management practices during the well maintenance and liquids unloading events in XVII.H.1.a. The owner and/or operator shall be present on-site during any planned well maintenance and liquids unloading event in XVII.H.1.a. and

shall ensure that any venting to the atmosphere is limited to the maximum extent practicable.

XVII.H.1.c. Records of the cause, date, time, and duration of venting events under this Section XVII.H. will be kept and made available to the Division upon request.

XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

XVIII.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B. Definitions

XVIII.B.1. "Affected Operations" shall mean pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations, natural gas compressor stations, and/or natural gas drip stations).

XVIII.B.2. "Enhanced Maintenance" is specific to high-bleed devices and shall include but is not limited to cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

XVIII.B.3. "High-Bleed Pneumatic Controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

XVIII.B.4. "Low-Bleed Pneumatic controller" shall mean a pneumatic controller that is designed to have a constant bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

XVIII.B.5. "Natural Gas Processing Plant" shall mean any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

XVIII.B.6. "No-bleed Pneumatic Controller" shall mean any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

XVIII.B.7. "Pneumatic Controller" shall mean an instrument that is actuated using natural gas pressure and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

XVIII.C. Emission Reduction Requirements

The owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

XVIII.C.1. In the 8-Hour Ozone Control Area:

XVIII.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, shall emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section XVIII.C.1.c.

XVIII.C.1.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2. Statewide:

XVIII.C.2.a. All pneumatic controllers placed in service on or after May 1, 2014, shall:

XVIII.C.2.c.(i) Emit VOCs in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.; or

XVIII.C.2.c.(ii) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and is technically and economically feasible.

XVIII.C.2.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, shall be replaced or retrofitted by May 1, 2015, such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section XVIII.C.2.c.

XVIII.C.2.c. All high-bleed controllers that must remain in service due to safety and/or process purposes must have Division approval and comply with Sections XVIII.D. and XVIII.E.

XVIII.C.2.c.(i) All high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.C.2.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator shall submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes prior to installation. The Division shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days upon receipt.

XVIII.D. Monitoring

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.D.1. In the 8-Hour Ozone Control Area

XVIII.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.1.b. Effective May 1, 2009, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.D.2. Statewide:

XVIII.D.2.a. Effective May 1, 2015, each high-bleed pneumatic controller shall be physically tagged by the owner/operator identifying it with a unique high-bleed

pneumatic controller number that is assigned and maintained by the owner/operator.

XVIII.D.2.b. Effective May 1, 2015, each high-bleed pneumatic controller shall be inspected on a monthly basis, perform necessary enhanced maintenance as defined in Section XVIII.B.2 , and maintain the device according to manufacturer specifications to ensure that the controller's VOC emissions are minimized.

XVIII.E. Recordkeeping

This section applies only to high-bleed pneumatic controllers identified in Sections XVIII.C.1.c. and XVIII.C.2.c.

XVIII.E.1. The owner or operator of affected operations shall maintain a log of the total number of high-bleed pneumatic controllers and their associated controller numbers per facility, the total number of high-bleed pneumatic controllers per company and the associated justification that the high-bleed pneumatic controllers must be used pursuant to Sections XVIII.C.1.c. and XVIII.C.2.c. The log shall be updated on a monthly basis.

XVIII.E.2. The owner or operator shall maintain a log of enhanced maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, high-bleed pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

XVIII.E.3. Records of enhanced maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

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XIX. Statements of Basis, Specific Statutory Authority and Purpose

XIX.N. February 21, 2014 (Sections II., XVII., and XVIII.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

The oil and gas industry is a source of volatile organic compounds ("VOCs"), an ozone precursor. Additionally, oil and gas operations are a source of other hydrocarbon emissions, such as methane, through the leaking and venting of natural gas.

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result.

The Commission supports the EPA's development of NSPS OOOO, and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. The Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"). It is also likely that EPA will lower the ozone NAAQS in the near future. In addition, Colorado has seen significant growth of oil and gas development in recent years, and that growth is expected to continue in the foreseeable future. The oil and gas industry is a significant source of VOC emissions (an ozone precursor). This is particularly true of oil and gas storage tanks. Oil and gas operations also emit methane, a negligibly reactive ozone precursor and a potent greenhouse gas. Division air monitors and other sampling indicate elevated levels of oil and gas related compounds in oil and gas development areas. Improved technologies and business practices can reduce emissions of hydrocarbons such as VOCs and methane in a cost effective manner. Many Colorado operators are already utilizing such technologies and practices to some degree including, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras). These technologies and practices have the added benefit of reducing several types of hydrocarbon emissions at the same time.

Colorado has vast experience with the regulation of oil and gas sources. In 2004, 2006, and 2008, the Commission established oil and gas industry emissions controls in Regulation Number 7, Sections XII., XVII., and XVIII. In March 2004, the Commission required condensate tank, controlled under the system-wide approach in what was known as the 8-Hour Ozone Control Area, to meet a 95% control efficiency requirement. This provision was approved into the State Implementation Plan ("SIP"). In December 2006, the Commission determined that on a state-wide, state-only basis, all (new and existing) condensate storage tanks must install air pollution control equipment and meet 95% destruction of VOC, if the total VOC emissions from the tank were equal to or greater than twenty (20) tons per year ("tpy"). Due to "flash," operators have had difficulty consistently meeting this 95% control requirement.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. These regulations apply on a state-wide, state-only basis, and are not a part of Colorado's SIP. This approach gives the Commission, the Division, and stakeholders the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The Commission adopts revisions throughout Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and compressor stations. The revisions expand existing oil and gas control requirements and establish additional monitoring, recordkeeping, and reporting requirements. For example, regarding oil and gas storage tanks, the revisions increase control requirements and improve capture efficiency requirements. The Commission also seeks to minimize fugitive emissions from leaking components at compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells, and wells undergoing maintenance. The Commission also expands control requirements for pneumatic devices and glycol dehydrators. The Commission believes that this combination of revisions is appropriate to fully adopt NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;
- Amend definitions in Section XVII.A. and XVIII.B.;
- Strengthen good air pollution control practices, require use of auto-igniters, and remove the off-ramp for condensate tanks if subject to NSPS, MACT, or BACT in Section XVII.B.;
- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;

- Limit venting and establish a storage tank emissions monitoring system ("STEM"), and associated recordkeeping and reporting requirements in Section XVII.C.;
- Expand glycol dehydrator control requirements in Section XVII.D.;
- Establish a leak detection and repair program for compressor stations and well production facilities in Section XVII.F.;
- Establish control measures for oil and gas wells in Section XVII.G.;
- Limit venting during well maintenance in Section XVII.H.; and
- Expand pneumatic device requirements in Section XVII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The Commission intends that all the revisions to Regulation Number 7, are state-only requirements.

The following explanations provide further insight into the Commission's intention for certain revisions.

Joint Applicability of NSPS OOOO and Regulation Number 7 Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates an overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil storage vessels. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with 6 tpy of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado's SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado. Thus, the Commission intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT requirement to avoid having to comply with overlapping requirements in Section XVII.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. In those limited cases where storage tanks are subject to

both NSPS OOOO and current Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring.

However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy (the equivalent of six (6) tpy VOC on a controlled actual basis). While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary.

It is the Commission's intent that compliance with Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC emissions and emissions of other hydrocarbons such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how the Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions going forward. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of one (1) minute during a fifteen (15) minute time period. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth below.

"Normal operation" is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of "malfunction" as set forth in the Common Provision regulations.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both the COGCC and Commission requirements.

"Storage tank," means a single tank, as well as a tank battery if the tanks are manifolded together. In recent years, it has become more common for multiple tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of "storage tank," the Commission revises the definition of storage tank to specify that a tank battery must be manifolded by liquid line, and not just be gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small tanks in a battery. The Commission's definition differs from EPA's definition of "storage vessel" and the description of an affected storage vessel facility in NSPS OOOO. EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. However, this approach differs from how Colorado has required emissions reporting and permitting for storage tanks, and the Commission intends to maintain that distinction. The Commission, therefore, deletes the previously used definition of "atmospheric condensate storage tank" and creates a new definition of "storage tank" which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

"Well production facilities" are subject to leak detection and maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, located at the same stationary source (a defined term specific to permitting).

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas sources, including those below the control threshold or even below Regulation Number 3 APEN and permitting thresholds, be required to adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;
- Inspecting and repairing seals on their hatches, access points, or other openings of storage tanks;
- Initiating timely action to address leaks or unpermitted emissions; and
- Maintaining equipment and facility in good operating condition.

Controls for Storage Tanks Over 6 tpy (Section XVII.C.)

EPA established a six (6) tpy VOC threshold for applying storage vessel controls. This threshold differs from Regulation Number 7, Section XVII. in that it applies to individual tanks on a controlled actual emissions basis. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for reporting, permitting, and

control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control devices can be removed if the following conditions are met: (1) storage tank (including manifolded tanks) emissions are below the uncontrolled actual six (6) tpy threshold, on a rolling twelve month basis and (2) controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the six (6) tpy threshold, control equipment must be installed within sixty (60) days of discovery of the increase.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead by significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used, it must have a design destruction efficiency of at least 98%. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more than properly operated.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. Venting includes emissions from equipment such as a storage tank at the thief hatch, pressure relief valve, or other access point. Access points are not limited to points of entry of liquids or gas into the storage tank, but include any route from which emissions can escape. However, there are limited circumstances which should not be considered venting, such as where storage tanks emit in emergency situations, during maintenance, gauging, or where necessary to ensure the safety of personnel and equipment. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. Inadequate design of a storage tank emissions capture system is not a legitimate reason for venting. The Commission intends that the burden remain on the owner/operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2.

The Commission further intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to operators, provided that the operators demonstrate that the elements of the malfunction affirmative defense have been met. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices, and not as emission

devices. Nothing in this revision is intended to increase risk or compromise safety of personnel and equipment. The Commission recognizes that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if an operator has identified a leak and is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners and operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tank Emission Management System (STEM) Plan, Monitoring, and Recordkeeping (Section XVII.C.)

All owners and operators of any storage tank not containing only stabilized liquid must develop, certify, and implement a STEM plan designed, in part, to ensure compliance with the "without venting" requirement of Section XVII.C., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies and monitoring, maintenance, and operational practices, to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility in the development of individualized STEM plans. STEM plans may be developed on an individual basis for each storage tank or may be developed for a swath of similarly designed or sized tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review.

Owners and operators of storage tanks containing only stabilized liquids are not required to develop and implement a STEM plan. However, these tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include the following elements:

- A monitoring strategy with a minimum of the applicable inspection frequency and methodology;
- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training by documented to permit the operator to demonstrate the quality and achievements of its STEM plan;

- The calibration methodology and schedule for emission detection equipment used in the monitoring;
- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to preventing venting;
- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;
- A procedures to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and
- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

Monitoring for storage tanks must be conducted utilizing an Approved Instrument Based Monitoring Method, on a frequency schedule that is tied to an emissions from the tank. In addition to any applicable Approve Instrument Based Monitoring Method, the Commission intends that all owners or operators of a storage tank (whether or not it contains stabilized liquids) conduct applicable audio, visual, olfactory ("AVO") monitoring. AVO inspection is not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO inspection, and indicates the frequency with which AVO inspection is required.

Documentation of the STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of STEM monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Glycol dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. Currently, any glycol natural gas dehydrator with uncontrolled actual VOC emissions of two tons per year or greater that is located at a facility where the sum of uncontrolled actual VOC emissions from all of the dehydrators at the facility is greater than fifteen tpy must be equipped with a control device that reduces emissions by at least 90%. This revision requires that all existing dehydrators with uncontrolled actual emissions of six (6) tpy or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. This revision also provides that existing dehydrator with uncontrolled actual emissions of two (2) tpy or greater VOC must be controlled if they are located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations. Finally, this revision requires that all new dehydrators with uncontrolled actual emissions of two (2) tpy or greater VOC must be controlled. The

Commission intends that the air pollution control equipment achieves an average hydrocarbon control efficiency of at least 95%, and if a combustion device is uses, it must have a design destruction efficiency of at least 98%. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. STEM targets venting from storage tanks, while the detection and repair program more broadly target leaks from components at compressor stations and well production facilities, even if they do not include storage tanks. The use of an Approved Instrument Based Monitoring Method as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may need or want additional time to comply and may have lower emissions. Owner and operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor.

The Commission has defined a leak in a manner that is dependent on the monitoring methodology used in detection. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Reference Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identifies the emission rate. IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, but they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in choosing instrument based detection methodology.

If Method 21 is utilized, the Commission has set the threshold at which component leaks must be repaired at 2,000 parts per million ("ppm") hydrocarbons for existing compressor stations and 500 ppm for new (constructed after May 1, 2014) compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is used, a leak is any detectable emission not associated with normal equipment operation. These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources. Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO establishes leak detection at natural gas processing component type. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an

IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country. The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in existing permits. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

Well Maintenance and Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading is estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008 rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. While the use of low-bleed pneumatics will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources. However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying

a facility, the Commission is requiring the use of no-bleed pneumatics at facilities that are connected to the electric grid and using electricity to power equipment, but only where technically and economically feasible.

ADDITIONAL CONSIDERATIONS

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Section XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to be incorporated into Colorado's SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

I. The revisions to Regulation Number 7 address hydrocarbon emissions from oil and gas facilities, including well production facilities and compressor stations. The majority of sources subject to the revised rules will not also be subject to NSPS OOOO or other federal law for such emissions. One goal of the revisions is to address individual sources below NSPS OOOO thresholds, yet that collectively contribute significantly to ozone formation in Colorado. Additionally, it is the Commission's determination that the venting of emissions from storage tanks at oil and gas facilities, caused primarily by over pressurization, is not adequately addressed under NSPS OOOO and therefore warrants Colorado-specific regulations. Moreover, leaks or fugitive emissions of hydrocarbons, such as VOCs and methane, particularly from well production facilities and compressor stations, are not adequately addressed under NSPS OOOO. Thus, Colorado specific regulations are appropriate. Finally, some very large sources (e.g. storage vessels emitting 120 tpy uncontrolled VOC) will be subject to both the revised rules and NSPS OOOO, including the reporting and monitoring requirements.

   In addition to NSPS OOOO, several other federal NSPS, as well as National Emission Standards for Hazardous Air Pollutants ("NESHAP") that apply Maximum Achievable Control Technologies ("MACT") may apply to the tanks, dehydrators, leaking components, and pneumatic devices at oil and gas facilities subject to these revisions. These include, but are not limited to, NSPS Kb and NSPS KKK (which incorporate NSPS VV or VVa) and NESHAP HH and HHH. However, the Regulation Number 7 revisions apply on a broader basis to more tanks, dehydrators, leaking components, and pneumatic devices, and address more hydrocarbon emissions. Some examples include: tank and dehydrator control measures that apply at lower thresholds; leak detection and repair requirements applicable to components beyond gas processing plants; and pneumatic device provisions that require the use of lower emitting devices.

II. NSPS OOOO is primarily technology-based in that it largely prescribes the use of specific technologies in order to comply. EPA has provided some flexibility by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The

Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled PTE of their storage vessels, which may be used to avoid NSPS OOOO applicability.

III. There are no federal requirements related to the revisions to Regulation Number 7 that specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. NSPS OOOO addresses VOC emissions and certain co-benefits of reducing such emissions, but does not address hydrocarbon emissions in the more comprehensive manner addressed by these revisions. Following these revisions, Regulation Number 7 will surpass federal requirements in several ways, including, without limitation: (a) Regulation Number 7 will apply to a broader class of tanks than NSPS OOOO; (b) Regulation Number 7 will require a leak detection and repair program for more categories and components that NSPS OOOO; and (c) Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado, combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.

IV. Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for more costly retrofits at a later date. The Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS. Other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. Colorado may also be required to comply with a future ozone NAAQS that is lower than the current standard. The revised rules are intended to reduce ozone levels now by utilizing controls and techniques already being used or readily available. Utilizing these controls and techniques may prevent the need for more costly retrofitting in the future by addressing ozone precursor emissions now and not waiting until after ozone levels have increased.

V. Adoption at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid being subject to

NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.

VI. The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the sector to assure air quality is maintained while also allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while widely utilizing many of the technologies and practices set forth in these revisions.

VII. The revisions to Regulation Number 7 establish reasonably equity for oil and gas facilities subject to these rules by providing the same standards for similarly situated sources. The revisions to Regulation Number 7 were proposed after a lengthy stakeholder process. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector.

VIII. The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions.

IX. The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to achieve the Commission's goals while maintaining flexibility for the operators.

X. Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the auto-igniters and pneumatic devices. In addition, many oil and gas operators are already using the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the rules provide for Division approved extensions to compliance.

XI. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The

reductions of other hydrocarbon emissions such as methane add to the already cost-effective and appropriate emission reduction requirements.

XII. Alternative rules requiring differing or additional controls for oil and gas facilities could also provide reductions in hydrocarbon emissions. The Commission could adopt some or all of these proposed revisions. However, the revisions to Regulation Number 7 were proposed after a lengthy stakeholder process and provide a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado's economy and the nation's energy independence. A no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursors pollutants, necessary for attaining or maintaining the ozone NAAQS in Colorado.

XIII. The Commission has taken into consideration any evidence submitted regarding the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address the differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, the Commission hereby makes the determination that:

I. These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

II. Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of hydrocarbon emissions.

III. Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

IV. The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

V. The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

LEAK DETECTION AND REPAIR (LDAR) INSPECTION PROGRAM - ESTIMATED TRAVEL, EQUIPMENT AND LABOR COSTS

1.0 INTRODUCTION

There is economic burden for oil and gas (O&G) companies in the State of Colorado to implement leak detection and repair (LDAR) programs for their Colorado O&G facilities. Recently, a proposed amendment to Regulation 7 of the Colorado Department of Public Health and Environment (CDPHE), Air Pollution and Control Division (APCD) air regulations would lower the volatile organic compound (VOC) emissions threshold for which LDAR would be required. For this task, Boulder County requested that Terracon analyze the estimated travel time, labor and equipment costs for three typical mid-size Colorado O&G companies with multiple well production facilities (with the potential to emit 6 to 12 tons of uncontrolled VOC emissions per year per facility) and assuming that the company would self-perform its LDAR inspection program with leased monitoring equipment.

Terracon's task was to prepare geographical information system (GIS) simulations to estimate O&G company travel times, labor and equipment costs to self-perform LDAR inspections for their well production facilities in Colorado. Three "mid-sized" O&G companies (2013 statewide gas production volumes of 1.2 to 42 million MCF of gas) in Colorado were evaluated. Production values were obtained from the Colorado Oil and Gas Conservation Commission (COGCC) online database.

2.0 MODELING APPROACH

The initial modeling approach was to evaluate one worst-case scenario where an O&G company would conduct LDAR inspections for its well production facilities in both "urban" and "rural" settings. For purposes of this model, an "urban" setting includes the Denver-Julesburg (DJ) Basin north of Denver, and a "rural" setting includes the Piceance or Paradox Basins on the western slope. Additionally, the modeling approach was intended to evaluate two O&G companies in "rural" settings. However, based on our review of the COGCC database, we were unable to identify companies with well production facilities in the 6 to 12 tons per year uncontrolled VOC emissions range in only "rural" areas. Therefore, the remaining two modeling approaches included two companies with 6 to 12 ton emission well production facilities in "urban" Colorado.

For these simulations, Terracon used ESRI's Network Analyst to compute a least-cost (least-time) path using ESRI's Detailed Streets Layer (2007) and well production facility locational information provided by CDPHE.

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3.0 MODELING ASSUMPTIONS AND ATTRIBUTES

The following assumptions were made in preparing the following LDAR inspection travel time and cost estimates:

1. An LDAR inspection/monitoring loop consists of a round trip circuit to each well production facility containing equipment with uncontrolled VOC emissions ranging from 6 to 12 tons per year.
2. Each O&G operator self-performs the LDAR inspections using rented monitoring equipment, either a total vapor analyzer (TVA) or an infrared (IR) camera.
3. An average of three hours of monitoring time are required at each facility regardless of the instrument used. This time estimate is based on discussions with several LDAR vendors in Colorado.
4. One technician and one LDAR monitoring instrument is used
5. The ESRI 2007 street network is conservative for estimating distances between sites.
6. Although actual well production facility location information was provided by CDPHE, minor modifications to the latitude and/or longitude values were inputted into the GIS to preserve the anonymity of the O&G companies used for the GIS evaluation.

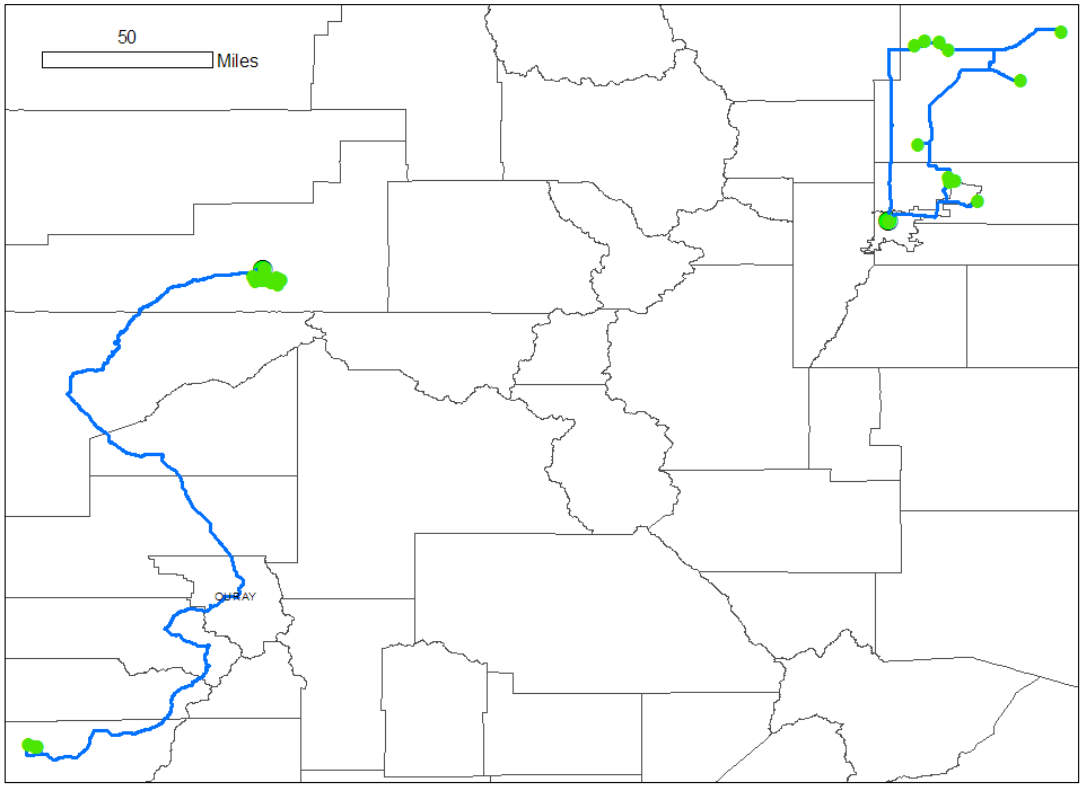
The following attributes were used to prepare ESRI's Detailed North America Street Map into a network dataset with least-cost routing capability.

Name	Usage	Units	Data Type
Length	Cost	Miles	Double
Oneway	Restriction	Unknown	Boolean
RoadClass	Descriptor	Unknown	Integer
Minutes	Cost	Minutes	Double
Hierarchy	Hierarchy	Unknown	Integer

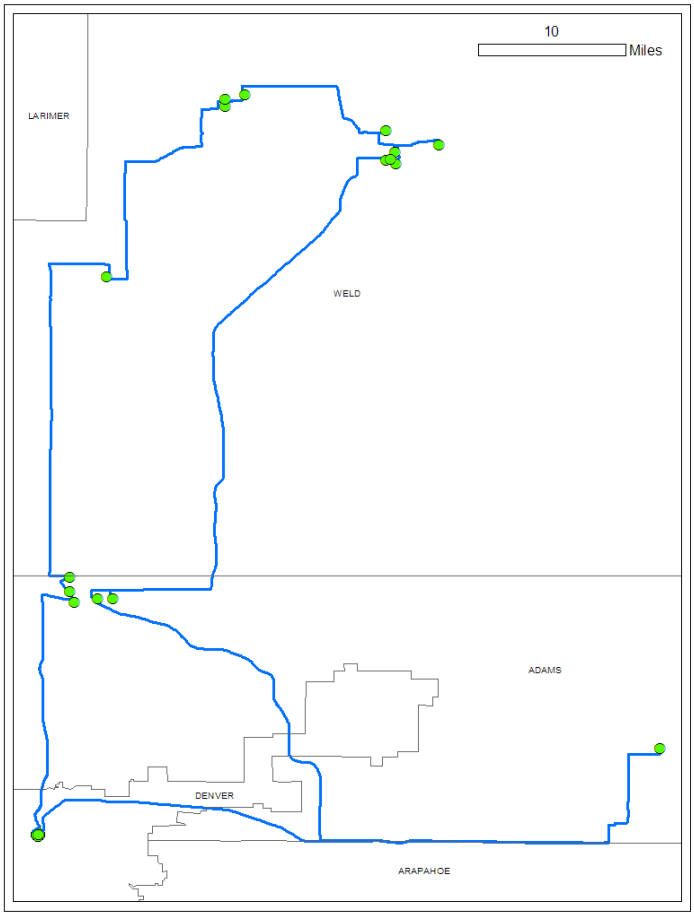
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Figure 1 – Optimized Travel Routes for Companies A, B and C

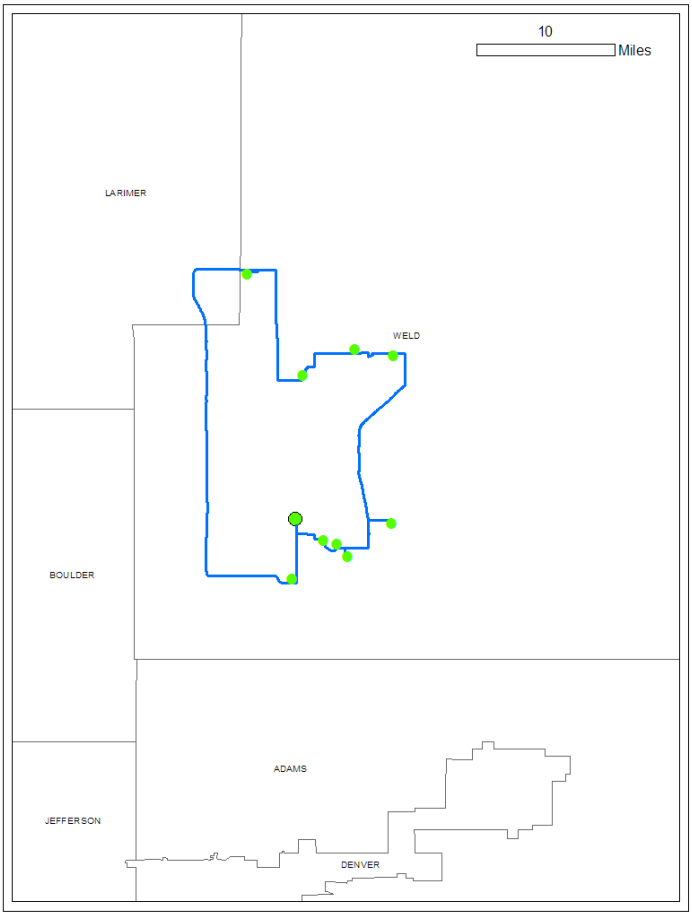
Company A



Company B



Company C



Map Legend

1. Green points represent well production facilities with tanks or equipment with 6 - 12 tons per year in uncontrolled VOC emissions.
2. The Blue route lines between points represent the calculated shortest distance along the road network between every facility, starting and finishing at a point of origin.
3. Company A has two loops. One loop in the DJ Basin. The second loop in the Piceance and Paradox Basins with a starting point at an office in proximity to the Basin.
4. Companies B and C each have one loop with their starting points originating near Denver.

4.0 CALCULATION OF ESTIMATED LDAR INSPECTION PROGRAM LABOR AND EQUIPMENT COSTS

The total time to complete one LDAR monitoring loop includes the travel time between well production sites and the LDAR monitoring time at each site. The total labor cost, in dollars, is the total time to complete one LDAR monitoring loop times the monitoring technician's hourly rate. The total equipment cost is the total time to complete one LDAR monitoring loop times the daily rental rate for the monitoring equipment. Table 1 (see Attachment A) provides a summary of estimated labor and equipment costs for Companies A, B and C to complete one LDAR inspection and annual LDAR inspection costs assuming biannual inspections.

4.1 Method 21 – TVA 1000B Instrument

As indicated in Table 1 (Attachment A), one-time estimated LDAR inspection costs with a TVA 1000B instrument ranged from $2,094 for Company C ("rural" setting) to $8,891 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using a TVA 1000B instrument, assuming two inspections per year, ranged from $4,188 for Company C ("rural" setting) to $17,782 for Company A ("rural" and "urban" setting).

4.2 Method 21 – IR Camera

As indicated in Table 1 (Attachment A), one-time estimated LDAR inspection costs with an IR camera ranged from $4,494 for Company C ("rural" setting) to $18,491 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using an IR camera, assuming two inspections per year, ranged from $8,988 for Company C ("rural" setting) to $36,982 for Company A ("rural" and "urban" setting). Inspection times with an IR camera were assumed to be the same as a TVA 1000B (3 hours per site). Actual inspection times may be less using an IR camera, but are not quantified in this analysis.

4.3 Cost Exceptions

The estimated costs do not include the following:

1. LDAR program development costs
2. Method 21 certification or employee LDAR training
3. Purchase of leak detection Instruments
4. Preparation of LDAR reports for submittal to CDPHE
5. Repair or replacement of faulty equipment
6. Internal auditing
7. Per diem (meals and lodging) expenses
8. Supervisor and administrative support
9. Equipment calibration or accessories

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5.0 CONCLUSIONS

Terracon used GIS simulations to estimate travel time and costs for three O&G companies to self-perform LDAR inspections for multiple well production facilities in Colorado. The analysis only included facilities with uncontrolled VOC emissions between 6 to 12 tons per year. Three companies were evaluated; one "rural and urban" company (Company A) with facilities in the DJ, Piceance and Paradox Basins and two "urban" companies (Companies B and C) with facilities only in the DJ Basin area.

One-time estimated LDAR inspection costs with a TVA 1000B instrument ranged from $2,094 for Company C ("rural" setting) to $8,891 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using a TVA 1000B instrument, assuming two inspections per year, ranged from $4,188 for Company C ("rural" setting) to $17,782 for Company A ("rural" and "urban" setting).

One-time estimated LDAR inspection costs with an IR camera ranged from $4,494 for Company C ("rural" setting) to $18,491 for Company A ("rural" and "urban" setting). Annual LDAR inspection costs using an IR camera, assuming two inspections per year, ranged from $8,988 for Company C ("rural" setting) to $36,982 for Company A ("rural" and "urban" setting).

6.0 QUALIFICATIONS AND LIMITATIONS

GIS simulations were developed to provide Boulder County with estimates of reasonable costs that may potentially be incurred by three mid-sized O&G companies to conduct LDAR inspections at Colorado well production facilities with tanks having uncontrolled VOC emissions ranging from 6 to 12 tons per year. This is an order-of-magnitude evaluation that provides the basis for more detailed cost evaluations. Our estimates are based on metropolitan and field office origination points, use of a least-time travel route, and average labor and equipment rates provided by LDAR inspection vendors. An actual LDAR inspection cost proposal could be obtained from a vendor provided that the number and locations of facilities and number of components at each facility are specified.

Terracon has endeavored to use a reasonable cost estimate approach to derive the conceptual LDAR inspection cost estimates given the stated assumptions. Potential inspection costs that were not evaluated or estimated are stated in our assumptions section of this report. In preparing this analysis, our scope was strictly limited to an evaluation of costs associated with travel, equipment and labor for LDAR inspections, and we are not providing opinions as to the cost burden for full implementation of the proposed amendments to Regulation 7 of the APCD CDPHE air regulations.

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ATTACHMENT A

TABLE 1

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Table 1: Estimated Labor and Equipment Costs for Three Colorado O&G Companies to Perform LDAR Inspections

O&G Company	Facilities[1]	Urban or Rural[2]	Total Distance[3] (Miles)	Total Time (Hours)[4,5]	Cost per Inspection Event			Cost per Year (Assuming Biannual Inspections)		
					Travel and Inspection Cost[6]	Travel and Inspection Cost using TVA 1000B[7]	Travel and Inspection Cost using Infrared Camera[8]	Travel and Inspection Cost[6]	Travel and Inspection Cost using TVA 1000B[7]	Travel and Inspection Cost using Infrared Camera[8]
A (2 loops combined)	34	Urban and Rural	787	121	$6,491	$8,891	$18,491	$12,982	$17,782	$36,982
B	16	Urban	217	53	$2,771	$3,821	$8,021	$5,542	$7,642	$16,042
C	9	Urban	78	29	$1,494	$2,094	$4,494	$2,988	$4,188	$8,988

NOTES:

(See Figure 1 for route maps)

[1] Facilities with uncontrolled VOC emissions between 6 to 12 tons per year

[2] Location of facilities

[3] Obtained from GIS Model

[4] Total travel time from the GIS Model

[5] Includes 3 hours per facility to complete LDAR inspection

[6] Technician rate of $ 50 per hour and $0.56 per mile travelled

[7] "TVA 1000B" analyzer cost is $ 150.00 per day. Assume 8 hour days. Shipping costs are not included.

[8] Infrared camera cost is $ 750.00 per day. Assume 8 hour days. Shipping costs are not included.

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OIL & GAS PRODUCTION FACILITIES
POTENTIAL SOURCES OF FUGITIVE VOC EMISSIONS

Prepared for

Boulder County
Colorado

NMED Exhibit 71

WHERE CAN FUGITIVE VOC EMISSIONS OCCUR?

Fugitive VOC emissions can occur on various types of equipment and devices involved in the production, storage, and conveyance of oil and gas.



Well Heads





Valve seals and joints

Compressor Engines



Seals, flanges and joints

NMED Exhibit 71

Process Equipment



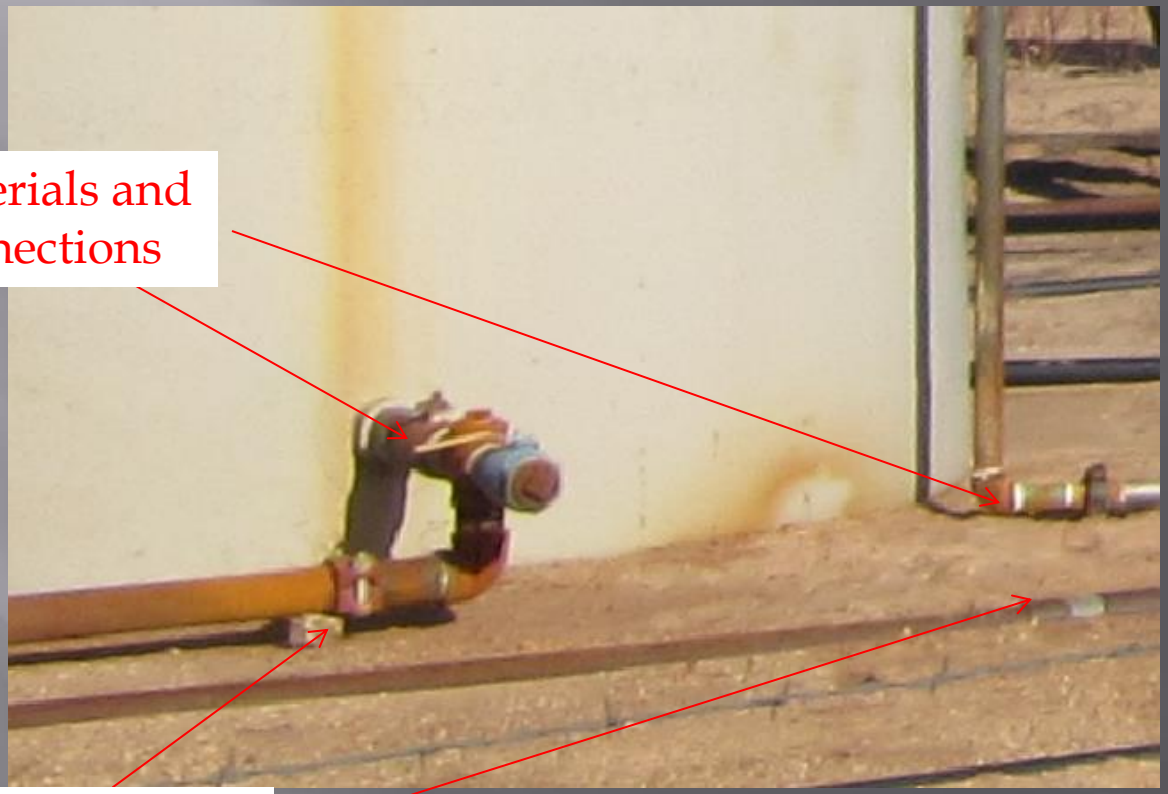
Flanges and fittings

NMED Exhibit 71

Tank Battery Site

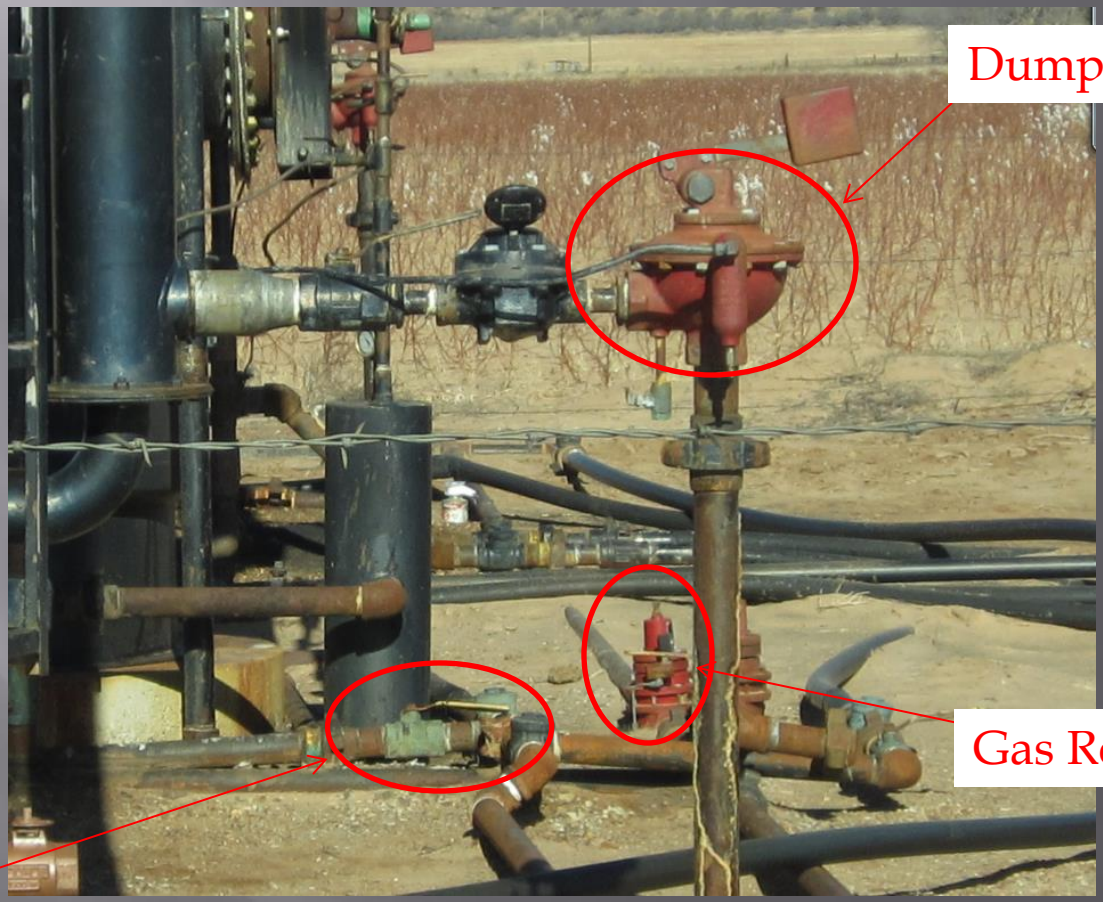


Tank Battery Site



NMED Exhibit 71

Tank Battery Site



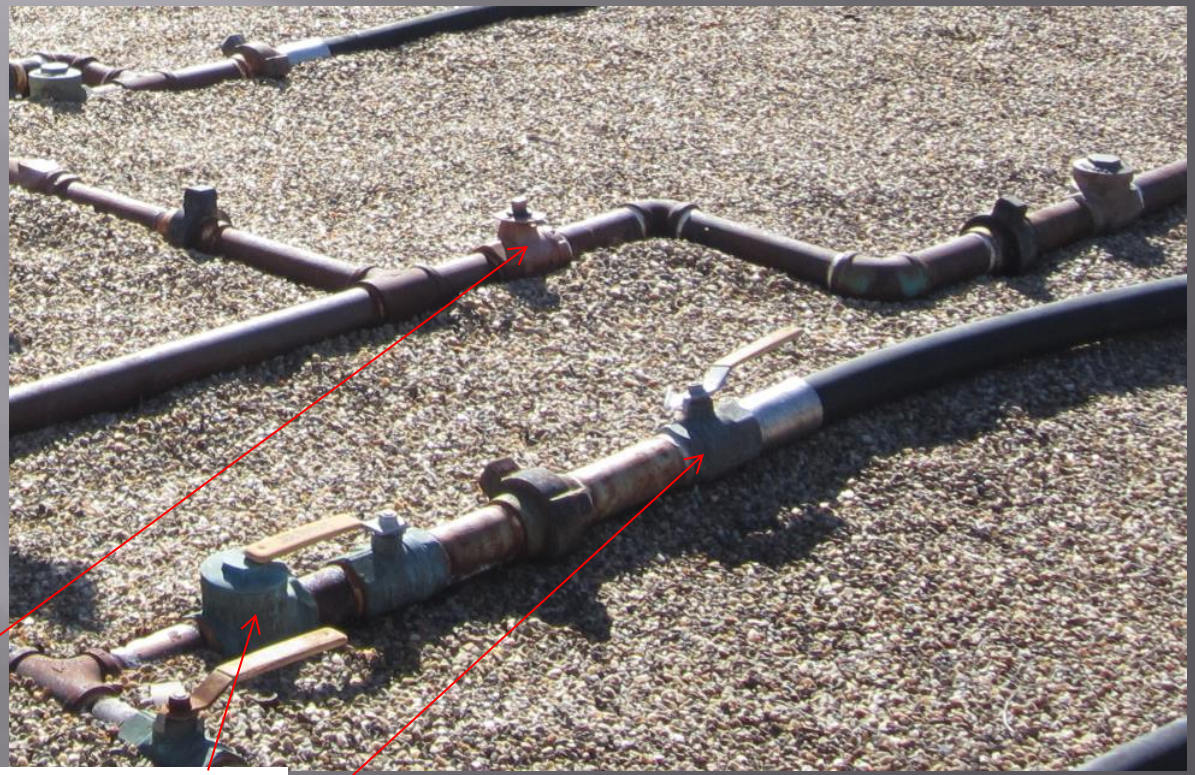
NMED Exhibit 71

Tank Battery Site



NMED Exhibit 71

Tank Battery Site



Valves with
threaded connections

NMED Exhibit 71

Tank Battery Site



Flanged connections

NMED Exhibit 71

Tank Battery Site – Heater Treater



Fittings with
threaded connections

NMED Exhibit 71

Tank Battery Site



Pneumatic Controller

NMED Exhibit 71

Tank Battery Site



Elbow fitting with inadequate support

NMED Exhibit 71

Tank Battery Site

(Unions, Couplings, Elbows and Valves)



NMED Exhibit 71

What causes some leaks to occur?

- Threaded Connections:
  - Improper selection and/or application of thread tape can lead to material degradation or inability to create a seal. Thread tapes rated for greater than operating pressure and temperature should be chosen;
  - Inadequate support to pipes can lead to vibrations during pressure variations in the system, resulting in leaks; and
  - Connections near or under the ground in the presence of water may expand unevenly resulting in leaks.

Why do leaks occur? (cont..)

- Valves, Pressure Relief Valves (PRVs), Compressors, Pumps and Meters
  - Debris in the flow system can prevent the valve from completely closing allowing gas or oil to escape from the system downstream from the valve;
  - A damaged valve seat or seal;
  - Not performing scheduled re-greasing and/or equipment inspections per manufacturer recommendations; and
  - Lack or implementation of a regular operations and maintenance (O&M) program.

Why do leaks occur? (cont..)

- Inadequate O&M program may fail to identify:
  - Damage from impact;
  - Excessive corrosion;
  - Cracked seals;
  - Metal fatigue and stress cracks from hydrogen sulfide attack; and
  - Over-pressurization of storage vessel from inoperable PRV.

Potential Benefits of Implementing an LDAR Program*

- Reducing Product Losses,
- Decreasing exposure to surrounding community, and
- Potentially reducing emission fees

* Per EPA "Leak Detection and Repair-A Best Practices Guide"

NMED Exhibit 71

LDAR SERVICE PROVIDERS

- http://www.dexterfs.com
- http://www.enrud.com
- http://www.erm.com
- http://www.flir.com
- http://www.guardiancompliance.com
- http://www.heathus.com
- http://www.ldarsolutions.com
- http://www.ldartools.com
- http://www.inficon.com
- http://www.thermoscientific.com
- http://www.americanleakdetection.com
- http://customstackanalysis.com
- http://www.afcintl.com
- http://www.pesldar.com
- http://www.ldarsolutions.com
- http://www.iprems.com
- http://www.emsi-air.com/
- http://www.iprems.com/
- http://www.trihydro.com/

NMED Exhibit 71

LDAR SERVICE VENDORS OVERVIEW

Prepared for

Boulder County
Colorado

NMED Exhibit 71

VENDOR CONTACT & INFORMATION COLLECTION

- Several subcontractors contacted that provide LDAR monitoring services to the oil and gas industry in Colorado.
- The objective was to approximate costs charged for LDAR monitoring.
- Of the companies contacted, four companies provided responses.

TYPICAL LDAR SERVICES VENDOR COST BREAKDOWN

VENDORS[1]	LDAR TECHNICIAN HOURLY COST[2]	LDAR SUPERVISOR HOURLY COST	EQUIPMENT CHARGES PER DAY [3]	MILEAGE CHARGE PER MILE	NOTES
Vendor 1	$ 35.00	$ 45.00	Included for Method 21	Did not provide	---
Vendor 2	$ 60.00	NA	$ 200.00 (Equipment and vehicle charge)	Did not provide	---
Vendor 3	$ 42.00	$ 46.00	Included for Method 21	$ 0.56	IR Camera - $ 750.00 per day additional charge
Vendor 4[4]	$ 48.00	$ 65.00	Included for Method 21	$ 1.00	IR Camera - $ 750.00 per day additional charge

1 Actual vendor names not provided as site specific information was not provided and to protect vendor competitive interests. Vendors have also indicated that pricing may vary based on site specific factors.

2 Technician hourly cost does not include food/per diem expenses, overtime, hotel expenses or other travel expenses.

3 Method 21 does not specify an instrument detector type, but the detector used must satisfy the performance criteria specified in the method. The detector can use catalytic oxidation, flame ionization, infrared absorption, or photoionization. Vendors 1, 2 and 4 indicated that for LDAR inspection as per Method 21, there will be no additional equipment charges. However, if IR cameras are employed, there will be additional charges. Vendors may charge additional for tag sets, wires and cables.

4 Vendor 4 indicated that if only IR camera is used for leak detection then the LDAR technician hourly cost will be $ 67.50 and Supervisor hourly cost will be $ 90.00.

Notes from Vendor discussions

- IR cameras approved for Method 21 may not be readily available because of cost.
- Due to differences in training required for IR cameras, technician charges are usually higher.
- IR cameras approved for Method 21 are typically used to detect high concentrations or larger leaks and other Method 21 equipment is typically used for lower concentrations. Some vendors indicated that they could use a combination of Method 21 equipment and IR cameras based on the size of the site and number of potential fugitive emission sources.
- Most commonly used equipment for Method 21 is Thermo Toxic Vapor (TVA) Analyzer, TVA-1000B. As per research, rental cost for the equipment averages around $ 150 per day, not including accessories or other miscellaneous parts/calibration kits.
- Most commonly used Infrared Camera was FLIR GasFindIR MW camera. As per research, rental cost for the camera averages around $750 per day.

List of Vendors contacted

- http://www.dexterfs.com
- http://www.enrud.com
- http://www.erm.com
- http://www.flir.com
- http://www.guardiancompliance.com
- http://www.heathus.com
- http://www.ldarsolutions.com
- http://www.ldartools.com
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- http://www.americanleakdetection.com
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- http://www.pesldar.com
- http://www.ldarsolutions.com
- http://www.iprems.com
- http://www.emsi-air.com/
- http://www.iprems.com/
- http://www.trihydro.com/

Not all vendors responded to requests.

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The next worksheet is the final EIA for the 6-12 TPY well production facility (WPF) changes that the LGC alternate proposal addresses.

The main difference between the LGC alternate proposal and the Division's is that WPFs in the 6-12 TPY category get inspected twice per year in the LGC alternate proposal versus once per year in the Division's.

The initial EIA cost estimates for compressor stations in the 0-12 TPY category and the WPFs in the 0-6 TPY category, also proposed by the LGC to be inspected more frequently than the Division's proposal, remain as stated within the LGC - PHS.

The costs on the following worksheet are based off of data the LGC commissioned Terracon to develop for WPFs in the 6-12 TPY uncontrolled VOC range. The assumptions and results are included as rebuttal exhibits LGC - REB EXH A1, A2, and A3. These costs supersede the values for the 6-12 TPY facilities in the initial EIA, contained within the LGC - PHS.

Economic Impact Analysis for Biannual Inspections of Well Production Facilities as Recommended by the LGC

Number of Facilities	1412	6-12 TPY threshold
Inspections per facility per year	2	
VOC per facility - uncontrolled (6-12 TPY range)	9	TPY
Cumulative VOC - uncontrolled	12708	TPY
Current VOC capture rate	71.25%	(CDPHE EIA - Table 15)
Current VOC emissions - controlled	3654	TPY
Intended VOC capture rate	95%	(CDPHE EIA - Table 15)
Intended VOC emissions (with STEM and LDAR)	635	TPY (@ 95% effectiveness)
Potential VOC emissions avoided (w/ STEM & LDAR)	3018	TPY (going from 71.25% to 95% effectiveness)
Potential WPF VOC emissions avoided (w/ LDAR)	2598	TPY (CDPHE EIA Table 26, 6-12 TPY)
Total LDAR inspection costs @ 2x/year	$1,503,547	using TVA1000B rental costs (see below)
Total LDAR inspection costs @ 2x/year	**$2,350,747**	using FLIR camera rental costs (see below)
Total LDAR inspection costs @ 2x/year	**$1,327,986**	CDPHE EIA (Table 27, 6-12 TPY); multiplied $663K by 2 to compare with proposed LGC semi-annual inspections vs annual
Total LDAR inspection costs @ 2x/year	**$6,042,560**	DGS Client Group PHS EX C (Table 12 Part I, 6-12 TPY); multiplied $3M by 2 to compare with proposed LGC semi-annual inspections vs annual
Annual LDAR inspection costs per facility @ 2x/year	$1,065	(w/ TVA 1000B)
Annual LDAR inspection costs per facility @ 2x/year	$1,665	(w/ FLIR Camera)
Annual LDAR inspection costs per facility @ 2x/year	**$1,365**	Average of TVA and FLIR
Annual LDAR inspection costs per facility @ 1x/year	$926	(CDPHE EIA w/ FLIR - Table 14)
Cost per ton of VOC reductions (w/ LDAR)	$579	(using TVA 1000B costs)
Cost per ton of VOC reductions @2x per year (w/ LDAR)	**$905**	(using FLIR camera costs)
Cost per ton of VOC reductions (LDAR)	**$512**	CDPHE EIA (Table 27, 6-12 TPY); multiplied $256 by 2 to compare with proposed LGC semi-annual inspections vs annual
Cost per ton of VOC reductions (LDAR)	**$3,702**	DGS EIA (Table 14, 6-12 TPY); multiplied $1851 (Year 1) by 2 to compare with proposed LGC semi-annual inspections vs annual

Supporting data used to estimate LDAR inspection costs:

LDAR Inspection time	3	hours (per LGC REB EXH A1)
Avg daily round trip distance	90	miles (@ 2 inspections per day)
Per mile costs	0.56	per mile rate (2014 GSA)
Avg speed	50	mph
Travel time per inspection	0.9	hours
Technician hourly rate	$50	
Additional staff costs multiplier	1.55	(CDPHE EIA - Table 20)
Overhead multiplier	1.10	(CDPHE EIA - Table 20)
Fringe multiplier	1.30	(CDPHE EIA - Table 20)
Labor costs per inspection w/travel time	$432	
Mileage costs per inspection	$25	
Total Labor and mileage costs per Inspection	$457	
Total Annual Labor and Mileage Costs	**$1,291,747**	(@ 2 inspections per year per facility)
Total number of inspections	2824	LGC @ 2x per year
Inspections per day	2	LGC estimate
Number of days	1412	to complete
TVA equipment costs (rental)	$150	per day (Terracon)
FLIR equipment costs (rental)	$750	per day (Terracon)
	$211,800	**Annual TVA Costs (LGC)**
	$1,059,000	**Annual FLIR Costs (LGC)**
	$1,503,547	**Total Annual Inspection Costs with TVA (LGC)**
	$2,350,747	**Total Annual Inspection Costs FLIR Costs (LGC)**

2824 inspections

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BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WORLDWIDE LIQUID SOLUTIONS, LLC ALTERNATIVE PROPOSALS

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS:
REGULATION NUMBER 3, PARTS A, B AND C
REGULATION NUMBER 6, PART A and
REGULATION NUMBER 7

Worldwide Liquid Solutions, LLC, by and through its attorney, Dan E. Wilson, Attorney at Law, LLC, files its Alternative Proposals in the above referenced matter.

1. In its initial Request for Party Status, Worldwide Liquid Solutions ("WLS") suggested the alternative of deleting ethane and methane from proposed Rule. 7 (5CCR 10001-9), to wit:

   a. In II. B. Exemptions, strike all proposed language for addition to the rule (specifically striking the addition of methane and ethane in Sections XVII and XVIII).

   b. Consistent with this change, change all references throughout the draft proposed rule noted as "hydrocarbons" to "volatile organic compounds". A more accurate description would be to identify them as precursors to ozone producing compounds within the definition of the rules.

   c. In XVII.C.4.c. Recordkeeping, please be informed that a properly functioning passive volatile organic compound absorption filter ("PVOCAF") will continue to capture VOCs in an upset condition until such filter is filled or replaced under a service schedule. This rule needs to be modified to reflect a release of "volatile organic compounds" released to the atmosphere, or to note repair of the "burp valve", or when the passive absorption filter is replaced.

2. Upon further review, WLS would suggest the complete incorporation of 40 CFR Part 60, subpart OOOO as revised through 9/23/2013.

   a. Such incorporation would likely be made into Rule 6, Part A. Rule 3, Parts A, B and C could be promulgated. If done, Rule 7 would be stricken in its entirety.

b. Such action would bring the Air Quality Control Commission ("AQCC") current from its partial incorporation of 40 CFR Part 60, subpart OOOO on October 12, 2012.

3. A good faith argument can be made to limit the application of proposed Rule 7 to the Denver Metropolitan/North Front Range nonattainment areas. Such an effort would require a major effort to compile the necessary data supporting analyses to support Rule 7 even in these non-attainment areas. The analyses will not likely support the addition of the de minimis, negligibly reactive compounds of ethane and methane for pollution purposes but may prove more cost effective in these locations.

Respectfully submitted this 6th day of January, 2014.

Dan E. Wilson
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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was sent via email to the following persons whose names and addresses are listed below on January 6, 2014.

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BEFORE THE COLORADO AIR QUALITY CONTROL COMMISSION
COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

WORLDWIDE LIQUID SOLUTIONS, LLC – ECONOMIC IMPACT ANALYSIS STATEMENT

IN THE MATTER OF OIL & GAS RULEMAKING EFFORTS:
REGULATION NUMBER 3, PARTS A, B AND C
REGULATION NUMBER 6, PART A and
REGULATION NUMBER 7

Worldwide Liquid Solutions, LLC, by and through its attorney, Dan E. Wilson, Attorney at Law, LLC, files its Economic Impact Analysis in the above referenced matter.

A. SUMMARY

Worldwide Liquid Solutions ("WLS") participated as a stakeholder in the above referenced rulemaking process. However, despite repeated promises by the Colorado Department of Public Health and Environment ("CDPHE" or "Division") to hold technical working group sessions to evaluate emerging technical solutions, no such meetings were ever held by CDPHE, nor alternative solutions evaluated in connection with the proposed rules.

WLS manufactures a passive volatile organic compound ("VOC") absorption filter ("PVOCAF"). The filter is passive and requires no outside source for electrical power to operate. Wind turbines or solar collection devices are adequate power sources for small storage tank filters to maintain negative pressure. The filters are housed in a non-absorptive, recyclable 'short stack' which holds a filter of absorptive carbon material that captures VOC compounds as they pass up the stack.

The PVOCAF is entirely constructed of material that can be recycled into a fresh filter. A WLS vendor will recover the captured VOCs and regenerate the carbon filtering material for reuse. Development of a full scale carbon recovery program is possible with a significant percentage of participants within the oil and gas industry.

The PVOCAF offers a low cost, low energy, carbon capturing, recyclable alternative to flaring and combustion devices without creating additional, secondary pollution. However, PVOCAF will not capture ethane and methane, not currently regulated by Quad O. The inclusion of ethane and methane in the draft Colorado Rule 7 will render this advanced technology unusable in Colorado.

When compared to published data from EPA, the PVOCAF demonstrates a cost savings advantage over flares and combustion devices for VOC emissions from storage tanks in many scenarios. The cost effectiveness of the PVOCAF is extended in remote areas where there is no electrical service or where generators would be required to power a flare or combustion device.

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The PVOCAF offers an additional advantage over flares and combustion devices because it consumes no fuel (ethane and methane) to operate, reducing the cost of fuel and avoiding the secondary pollution of NOx, CO, methane and primarily CO2 created by these devices. Currently, EPA has set the Best System of Emission Reduction ("BSER") at 4 tpy VOC under Quad O determining that below this limit, flares and combustion devices are no longer cost effective, will create additional pollution and environmental impacts and consume too much energy to be effective. WLS is working with Wyoming, Texas, Utah, and U. S. EPA for use of the PVOCAF as an alternative to flaring. The PVOCAF may revolutionize the BSER for the oil and gas industry because it can cost effectively capture VOCs well below the current BSER limits.

B. ECONOMIC IMPACT ANALYSIS

WLS estimates that it can provide passive volatile organic compound absorption filters ("PVOCAF") for storage tanks at the initial start-up investment of $1,000 per filter and $1,100 per ton of VOC removal. This cost will include the initial potential to emit analysis, including VOC testing and gas chromatography. Actual VOC monitoring of the PVOCAF should be set at monthly to quarterly schedules depending on the initial potential to emit ("PET") determination or changes in tank usage. These estimates include maintenance, monitoring and filter replacement costs.

VOC (tpy)	PVOCAF	EPA	CDPHE
1	$2100 per ton		
2	$1600 per ton	$10,000 per ton	
3	$1433 per ton	$6900 per ton	
4	$1350 per ton	$5100 per ton	
5	$1300 per ton		
6	$1267 per ton		
7	$1243 per ton		
8	$1225 per ton		
9	$1211 per ton		
10	$1200 per ton		
11	$1191 per ton		
12	$1183 per ton		

The chart above is based upon the cost estimates provided by WLS and what has been most currently published by EPA in connection with the Quad O revisions, 78 FR 58416, at page 58429 (9/23/13). The CDPHE cost projections have not yet been submitted as part of the rulemaking process. However, it should be noted that EPA has expressed concern over CDPHE's costs being used in the current rulemaking process. See, 78 FR at page 58429.

Please keep in mind that there is no secondary pollution or fuel cost to operate the PVOCAF, so there is no corresponding BSER limit. In other words, the PVOCAF can cost

effectively capture VOCs below the 4 tpy BSER limit established by EPA for flares and combustion devices.

WLS submits that the PVOCAF is a cost effective alternative to flares and combustion devices that should be utilized to capture VOCs in Colorado. The device has the potential to reduce VOC emissions below the current EPA BSER limit of 4 tpy VOC and could cost effectively be used in areas where VOC capture needs to occur below these limits, such as to protect residents in close proximity to VOC emissions or help achieve VOC compliance in non-attainment areas.

Respectfully submitted this 30th day of January, 2014.

Dan E. Wilson
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CERTIFICATE OF SERVICE

This is to certify that I have duly served the within **Worldwide Liquid Solutions, LLC-Rebuttal Statement** upon all parties herein by e-mail or by depositing copies of same in the United States mail, first-class postage prepaid, at Denver, Colorado, this 30th day of January, 2014, addressed as follows:

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Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems

May 2016

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page

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Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
AR4	UNFCCC Fourth Assessment Report
Bcf	Billion Cubic Feet
CapEx	Capital Expenditures
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
EDF	Environmental Defense Fund
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GWP	Global Warming Potential
HAP	Hazardous Air Pollutant
hp	Horsepower
IR	Infrared
LDAR	Leak Detection and Repair
LDCs	Local Distribution Companies
LNG	Liquefied Natural Gas
MAC	Marginal Abatement Cost
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
$MMTCH_4$	Million Metric Tonnes Methane
$MMTCO_2e$	Million Metric Tonnes CO_2 equivalent
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per Day
scfh	Standard Cubic Feet per Hour
VRU	Vapor Recovery Unit

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1. Executive Summary

Our Nation's Energy Future Coalition (ONE Future) [1] commissioned ICF to conduct this analysis of the marginal abatement cost (MAC) of various methane emission abatement technologies and work practices for the natural gas industry. The goal of this MAC analysis is threefold: (1) to identify the emission sources that provide the greatest opportunity for methane emission reduction from the natural gas system, (2) to develop a comprehensive listing of known emission abatement technologies for each of the identified emission sources, and (3) to calculate the cost of deploying each emission abatement technology and to develop a MAC curve for these emission reductions. The findings of this report will be utilized by ONE Future to develop segment-specific methane emission reduction goals that, when combined, will achieve a collective 1% (or less) emission target in the most cost-effective manner. This report will also assist each ONE Future member to customize its abatement strategy to fit its particular emission profile.

This analysis is based on a MAC curve model developed by ICF for the Environmental Defense Fund (EDF) in 2014. The current study incorporates more recent information on emissions and equipment costs and modified assumptions provided by the One Future participants. Appendix A summarizes and compares the key assumptions and results for the two studies. The study utilized the following approach:

- The baseline for methane emissions from the natural gas sector was established as the U.S. EPA Inventory of Greenhouse Gas Emissions for 2012 to match the baseline year employed in the U.S. methane emissions reduction goals.[2]
- A review of existing literature and additional analysis was conducted to identify the largest emission reduction opportunities; a cost-benefit estimate for each of the mitigation technologies was calculated.
- Interviews with One Future members, industry, technology innovators, and equipment vendors were conducted with a specific focus on identifying additional mitigation options and characterizing the cost and performance of the options.
- Information from the analysis was used to develop MAC curves for the methane reduction opportunities.

The analysis estimates reductions for each segment of the natural gas industry. The MAC analysis identified reductions totaling 88.3 Bcf/year of methane at a total annualized cost of $296 million or $3.35/Mcf of methane reduced for all segments except the distribution segment. The reductions for the distribution segment were calculated separately, and total 8.9 Bcf. An additional 12.3 Bcf of reductions were projected for the application of reduced emission completions for gas wells with hydraulic

[1] ONE Future is a coalition of companies that aims to achieve an average rate of methane emissions across the entire natural gas value chain that is one percent or less of total natural gas production.

[2] This analysis was completed prior to the updates to the methodologies incorporated into the U.S. Greenhouse Gas Inventory (GHGI) on April, 15, 2016.

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fracturing. This was not required in 2012 but is now legally required, and was therefore included as a reduction from the baseline but not as part of the MAC analysis. This brings the total industry-wide methane reduction to 109.5 Bcf from the 2012 baseline emissions.

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2. Approach and Methodology

2.1. Overview of Methodology

This section provides an overview of the methodology applied for this study. The major steps were:

- **Establish the 2012 Baseline for analysis** – the analysis started with the U.S. EPA inventory of methane emissions in the EPA Inventory of U.S. GHG Emissions (GHGI) published in April 2014 with data for 2012[3]. The most recent edition of the Inventory, released in April 2016, includes significant revisions, which are not included in this analysis. ICF expects future inventories will be updated to incorporate additional emissions and activity data collected from activities include:
  - Greenhouse Gas Reporting Program (GHGRP) inventory data collected in 2016 from companies in the gathering and boosting segment;
  - Information Collection Request (ICR)[4] for additional regulations, which will require operators to provide key activity and emissions data; and
  - Private and Government-sponsored scientific studies, including several multi-million dollar research projects focused on methane emissions from oil and gas operations sponsored by Department of Energy[5]

  Potential future updates to the GHGI may require a future update of this analysis to include those changes.

- **Identification of major sources and key mitigation options** – the next step was to identify the largest emitting sources in the inventory and the mitigation options that would be most effective and cost-effective for these sources.
- **Characterization of emission reduction technologies** – a key part of the study was to review and update information on the cost and performance of the selected mitigation technologies. Information was gathered from ONE Future Members, equipment manufacturers, other oil and gas companies, and other knowledgeable parties.
- **Development of the marginal abatement cost curves** – the technology information was applied to the emissions inventory to calculate the potential emission reduction and cost. The results were displayed in a series of marginal abatement cost curves.

The analysis calculates the annualized cost of emission reductions based on the capital and operating costs of the emission reduction technologies and the value of recovered gas in the production segment. This annualized cost is divided by the emission reductions to calculate the primary figure of merit -

[3] U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990-2012", http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html
[4] https://www3.epa.gov/airquality/oilandgas/methane.html
[5] http://www.netl.doe.gov/research/oil-and-gas/project-summaries/natural-gas-resources

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$/unit of emissions reduced. This is expressed as $/Mcf methane reduced, $/tonne methane reduced, or $/tonne CO_2 equivalent reduced. This figure of merit is consistent with the format used in other pollution control programs (SO_2, NO_x, VOC, etc.), which typically focus on $/ton of pollutant reduced.

In the 2014 report for EDF, ICF concluded that the weighted average methane reduction cost was $0.66/Mcf of methane reduced. The annual costs were also presented as normalized by gross natural gas production, dividing the annual cost by total U.S. natural gas production. Since methane emissions are only a few percent of total production, this value is very small – less than $0.01/Mcf of gas produced in the U.S., depending on the specific assumptions. However this second metric is different from the approach typically used by industry and regulators to characterize the cost-effectiveness of emission reduction technologies and should not be compared to a $/unit of methane reduced. In addition, the ONE Future sponsor companies reported that the metric that focuses on methane reduced is more useful to companies operating in different segments in assessing technologies and opportunities at new and existing facilities within each segment. Therefore, this report employs only the more commonly used weighted annual cost per methane reduced.

2.2. Identification of Targeted Emission Sources

Table 2-1 summarizes the largest emitting source categories for the oil and gas sectors by major source category in the EPA inventory for 2012. Due to the lack of specific data on the emission sources for offshore oil and gas production, the study focused on onshore production and offshore emissions are excluded from this list. The top 24 source categories account for nearly 90% of the total 2012 onshore methane emissions of 353 Bcf and were the primary focus of this analysis. The remaining 100+ categories each account for 1% or less of the total emissions. Although there are demonstrated methane reduction technologies that can provide cost-effective reductions for many of these smaller sources, these source categories were not included in this analysis due to their relative minor contribution to the overall emissions and reduction opportunity. In addition, the 2014 inventory for 2012 has a limited representation[6] of the gathering segment and therefore the analysis likely does not represent the full potential reductions that could be achieved from this segment.

The distribution of emission sources is shown in Table 2-1 and Figure 2-1. Fugitive emissions are the largest emission source category overall across the oil and natural gas systems. Vented emissions from pneumatic controllers and pumps, and venting from wet seal centrifugal compressors are some of the significant methane emissions venting sources from the natural gas industry. Completion emissions from hydraulic fracturing were a significant source at this time however have since been regulated.

[6] See Table 1, Inventory of U.S. GHG Emissions and Sinks: Revision Under Consideration for Gathering and Boosting Emissions, February 2016

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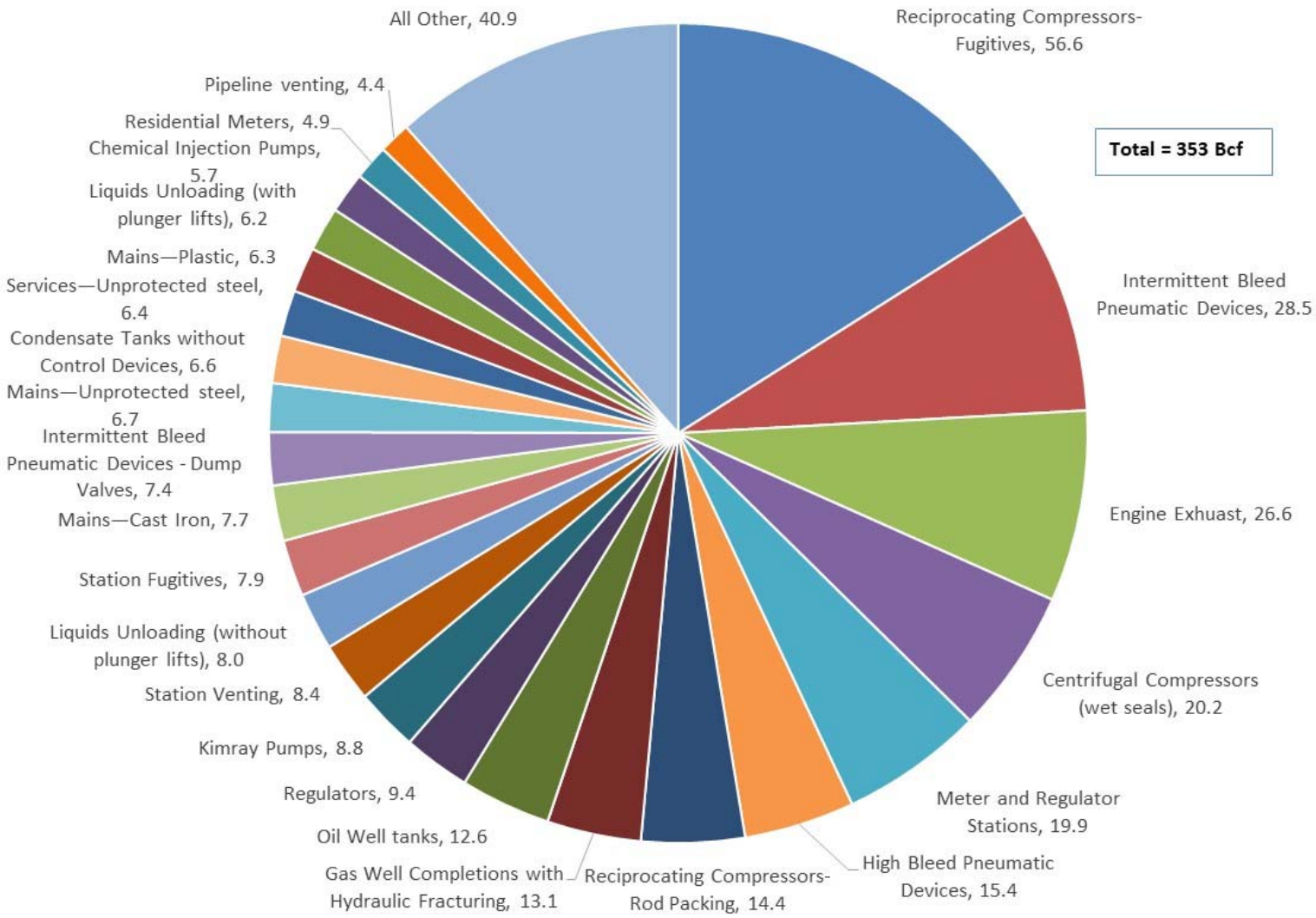
Table 2-1 - Highest (Top-24) Emitting Onshore Methane Source Categories

Source	2012 Emissions (Bcf)	Cumulative Bcf	2012 Emissions (MM tonnes)	Percent of Total	Cumulative %	Type*
Reciprocating Compressors-Fugitives	56.6	56.6	1.1	16%	16%	F
Intermittent Bleed Pneumatic Devices	28.5	85.1	0.5	8%	24%	V
Engine Exhaust	26.6	111.7	0.5	8%	32%	V
Centrifugal Compressors (wet seals)	20.2	131.9	0.4	6%	37%	V
Meter and Regulator Stations	19.9	151.9	0.4	6%	43%	F
High Bleed Pneumatic Devices	15.4	167.3	0.3	4%	47%	V
Reciprocating Compressors-Rod Packing	14.4	181.7	0.3	4%	51%	V
Gas Well Completions with Hydraulic Fracturing	13.1	194.8	0.3	4%	55%	V
Oil Well tanks	12.6	207.4	0.2	4%	59%	V
Regulators	9.4	216.7	0.2	3%	61%	V
Kimray Pumps	8.8	225.5	0.2	2%	64%	V
Station Venting	8.4	233.9	0.2	2%	66%	V
Liquids Unloading (without plunger lifts)	8.0	241.9	0.2	2%	69%	V
Station Fugitives	7.9	249.8	0.2	2%	71%	F
Mains—Cast Iron	7.7	257.5	0.1	2%	73%	F
Intermittent Bleed Pneumatic Devices - Dump Valves	7.4	264.9	0.1	2%	75%	V
Mains—Unprotected steel	6.7	271.6	0.1	2%	77%	F
Condensate Tanks without Control Devices	6.6	278.2	0.1	2%	79%	V
Services—Unprotected steel	6.4	284.6	0.1	2%	81%	F
Mains—Plastic	6.3	290.9	0.1	2%	82%	F
Liquids Unloading (with plunger lifts)	6.2	297.1	0.1	2%	84%	V
Chemical Injection Pumps	5.7	302.8	0.1	2%	86%	V
Residential Meters	4.9	307.7	0.1	1%	87%	V
Pipeline venting	4.4	312.1	0.1	1%	88%	V

- F=Fugitive V=Vented

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Figure 2-1 - 2012 Onshore Emissions (Bcf) from EPA Inventory



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2.3. Selected Mitigation Technologies

The following sections describe the mitigation measures included in this analysis to address the high-emitting source categories identified in Table 2-1. The smaller sources individually were judged to have an insignificant effect on the overall emissions analysis even if cost-effective mitigation technologies were available. Much of the cost and performance data for the technologies is based on information from the EPA Natural Gas STAR program[7] but was updated and augmented with information provided by industry and equipment vendor sources consulted during the EDF study. Further updates and information were provided by ONE Future members for this study.

This analysis attempts to define reasonable estimates of average cost and performance based on the available data and experiences of operators, including ONE Future members. The costs and performance of an actual individual project may not be directly comparable to the averages employed in this analysis because implementation costs and technology effectiveness are highly site-specific. Some technologies, like the efficiency of plunger-lifts for liquids unloading to reduce emissions, depend on the operating conditions of the well. Further, certain low-production or lower utilized compressor stations may have lower emissions. Costs for specific actual facilities could be higher or lower than the averages used in this analysis.

Several of the sources identified in Table 2-1 do not have commercially available mitigation technologies (e.g., engine exhaust) or are not currently cost-effective (e.g. cast iron main replacement). ICF analyzed various mitigation options for each of the 24 sources based on cost, reduction potential and market-penetration and considered 16 sources and mitigation measures for further modeling and evaluation.

Table 2-2 summarizes the mitigation measures applied in the analysis for each of the 16 major emission sources.

Table 2-2 - Summary of Mitigation Measures Modeled

Source	Mitigation Measure
Condensate Tanks w/o Control Devices	Install vapor recovery units
Wellhead Oil Tanks w/o Control Devices	Install vapor recovery units
Liquids Unloading - Wells w/o Plunger Lifts	Install plunger lift systems in gas wells
High Bleed Pneumatic Devices	Early replacement of high-bleed devices with low-bleed devices
Intermittent Bleed Pneumatic Devices	Replace with instrument air systems – intermittent
Chemical Injection Pumps	Replace pneumatic chemical injection pumps with Solar electric pumps
Kimray Pumps	Replace Kimray pumps with electric pumps

[7] http://www.epa.gov/gasstar/

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Source	Mitigation Measure
Pipeline Venting	Pipeline pump-down before maintenance
Centrifugal Compressors (wet seals)	Wet seal gas capture or dry seals
Transmission Station Venting	Redesign blowdown systems and alter ESD practice
Gas Well Completions - with Fracturing	Install flares – portable
Reciprocating Compressor Rod Packing	Replacement of compressor rod packing systems
Reciprocating Compressor Fugitives[8]	Leak detection and repair (LDAR)[9]
Compressor Station Fugitives[10]	Leak detection and repair (LDAR)
Well Fugitives	Leak detection and repair (LDAR)
Gathering Station Fugitives	Leak detection and repair (LDAR)

[8] Includes blowdown and unit isolation valves, connectors, other valves, meters, open-ended lines, and PRVs that are associated with the compressors.

[9] LDAR here is used generically to mean a wide range of leak detection, inspection, and repair activities.

[10] Includes valves, connectors, meters, open-ended lines, and pressure reducing valves (PRVs) that are located throughout the station and not associated with the compressors.

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Table 2-3 summarizes the key characteristics (i.e. capital costs, operating costs and reduction efficiency) of the 16 measures modeled. (The assumptions and analytical approach for LDAR are addressed further below.) The costs are for U.S. Gulf Coast and are adjusted by regional cost factors in the MAC curve analysis in Section 3. The sources and derivation of these values are listed in Appendix B. Table 2-4 shows the baseline cost effectiveness ($/Mcf, tonnes, or CO_2e of methane removed) for each measure modeled with and without credit for any recovered gas. The credit applies where emission reduction measures result in gas being recovered by the company. In the production segment, gas that is recovered can be sold and therefore has an economic value. In that case, the value of recovered gas is subtracted from the annual operating costs.

In the transmission and distribution segments, rate regulation typically requires pipeline and distribution companies to pass any cost reductions, including reduced losses, along to customers, thus the companies typically cannot capture the financial benefit of recovered gas. The contractual provisions for gathering, processing, and storage are variable but the ONE Future members reported that these companies typically do not take ownership of the gas but rather are paid a fee for their service. Reduced losses could result in increased throughput and increased recovery of the fee (which is much less than the value of the gas itself) but only if the metering point is downstream of the potential gas recovery.

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Table 2-3 - Summary of Mitigation Measure Characteristics (Gulf-Coast Cost Basis)

Mitigation strategy	Capital Cost	Operating Cost	Percent Reduction
Early replacement of high-bleed devices with low-bleed devices	$3,000	$0	78%
Replacement of Reciprocating Compressor Rod Packing Systems	$6,600	$0	31%
Install Flares-Portable	$30,000	$6,000	98%
Install Plunger Lift Systems in Gas Wells	$20,000	$2,400	95%
Install Vapor Recovery Units	$50,636	$9,166	95%
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$5,000	$75	100%
Replace Kimray Pumps with Electric Pumps	$10,000	$2,000	100%
Pipeline Pump-Down Before Maintenance	$0	$30,155	80%
Redesign Blowdown Systems and Alter ESD Practices	$15,000	$0	95%
Wet Seal Degassing Recovery System for Centrifugal Compressors	$70,000	$0	95%
Replace with Instrument Air Systems - Intermittent	$60,000	$17,770	100%

The members also reported that the metering for most of these facilities is at the entry point of the facility, thus preventing the operator from capturing the value of recovered gas. Based on this information, the value of recovered gas was included only for the production sector in this study. This is a change from the 2014 EDF study. The gas price was assumed to be $3/Mcf[11], reduced by 25% to account for royalties and fees, for a net value of $2.25/Mcf[12].

[11] EIA Short Term Energy Outlook, March 9, 2016, Henry Hub spot prices are forecast to average $3.11/MMBtu in 2017.
[12] A fuel price sensitivity analysis is included in Appendix A.

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Table 2-4 – Calculated Emission Reduction Cost per Mitigation Technology or Practice (Gulf Coast Cost Basis)

Name	$/Mcf* w/ Credit	$/Mcf w/o Credit	$/tonne CH4 w/Credit	$/tonne CH4 w/o Credit	$/tonne CO_2e ** w/Credit	$/tonne CO_2e w/o Credit
Early replacement of high-bleed devices with low-bleed devices	$4.91	$7.61	$257.01	$398.49	$10.28	$15.94
Replacement of Reciprocating Compressor Rod Packing Systems	$3.36	$6.06	$175.90	$317.39	$7.04	$12.70
Install Flares-Portable	$0.20	$0.20	$10.37	$10.37	$0.41	$0.41
Install Plunger Lift Systems in Gas Wells	$2.33	$5.03	$121.81	$263.30	$4.87	$10.53
Install Vapor Recovery Units	-$0.82	$1.89	-$42.72	$98.76	-$1.71	$3.95
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$2.16	$4.86	$112.90	$254.38	$4.52	$10.18
Replace Kimray Pumps with Electric Pumps	-$1.79	$0.91	-$93.98	$47.50	-$3.76	$1.90
Pipeline Pump-Down Before Maintenance	$1.14	$3.84	$59.70	$201.19	$2.39	$8.05
Redesign Blowdown Systems and Alter ESD Practices	-$4.10	$0.98	-$214.62	$51.27	-$8.58	$2.05
Wet Seal Degassing Recovery System for Centrifugal Compressors	-$2.38	$0.32	-$124.57	$16.91	-$4.98	$0.68
Replace with Instrument Air Systems - Intermittent	-$1.46	$1.24	-$76.49	$65.00	-$3.06	$2.60

* Gas recovery credit is applied only for the Production Segment

** GWP=25

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The annual cost was calculated as the annual amortized capital cost over the equipment life plus annual operating costs. This was divided by annual methane reductions to calculate the cost-effectiveness without credit for recovered gas. Where gas can be recovered and monetized by the operating company, the value of that gas was subtracted from the annual cost to calculate the cost-effectiveness with credit for recovered gas. The costs shown here are the baseline costs, which are adjusted for regional cost variation in the later MAC analysis. As noted earlier, these are average costs that may not reflect site-specific conditions at individual facilities.

Fugitive emissions are the unplanned loss of methane from pipes, valves, flanges, and other types of equipment. Fugitive emissions from reciprocating compressors, compressor stations (transmission, storage, and gathering), wells, and LDC metering and regulator equipment are the largest combined emission category, accounting for over 30% of the highlighted sources. The potential size and nature of these fugitive emissions can vary widely by industry segment and even by site.

Leak Detection and Repair (LDAR) is the generic term for the process of locating and repairing these fugitive leaks. There are a variety of techniques and types of equipment that can be used to locate and quantify these fugitive emissions. The analysis of LDAR cost and effectiveness for this study is a little different from the treatment of other measures because it is largely a function of labor required for inspections and repairs.

Extensive work has been done by EPA and others to document and describe these techniques, both in the Gas STAR reference materials and in several regulatory analyses, including for the EPA's NSPS Subpart OOOO[13] and the Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9)[14]. This study used both the Colorado regulatory analysis and the EPA Technical Support Document (TSD) [15] for NSPS Subpart OOOO as the basis for the analytical framework. Additional cost information was provided by ONE Future members.

The key factors in the analysis are how much time it takes an inspector to survey each facility, how many inspections are required each year, how much reduction can be achieved, and how much time is required for repairs. ICF adapted the structure (but not all of the specific inputs) of the Colorado analysis, which calculates the capital and labor cost to field a full-time inspector, including allowances for travel and record-keeping (Table 2-5). Specific cost factors were updated based on input from the ONE Future member companies. The combined hourly cost was the basis for the cost estimates. The capital cost includes a variety of leak detection and measurement equipment, a truck and the cost of a record-keeping system. These are estimated average costs and are highly variable depending on site-

[13] http://www.epa.gov/airquality/oilandgas/

[14] http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820

[15] U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards". http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf

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specific conditions and scale. In addition, the Gathering and Boosting segment is included in the Production segment in these analysis due to the design of the EPA inventory.

Table 2-5 - LDAR Hourly Cost Calculation

Labor			Capital and Initial Costs	
Inspection Staff	$86,155		FLIR Thermal Camera	$122,200
Supervision (@ 20%)	$17,231		Remote Methane Leak Detector (RMLD)	$20,000
Overhead (@10%)	$8,616		Photo Ionization Detector	$5,000
Travel (@0%)	$0		Flame Ionization Detector	$12,000
Recordkeeping (@5%)	$4,308		Hi-Flow Sampler	$21,450
Reporting (@0%)	$0		Miscellaneous	$3,000
Fringe (@50%)	$43,078		Truck	$22,000
Subtotal Costs	$159,387		Monitoring system	$14,500
			Total	$220,150
Hours/yr.	1880		Training Dollars	$6,782
Hourly Rate	$84.78		Amortized Capital+Training	$59,864
			Annual Labor	$207,203
Training Hours	80		Annual Total	$267,067
Training Dollars	$6,782			
			Total Hourly Rate	$142.06

Many analyses have used facility component counts and historical data on the time required to inspect each component to estimate facility survey times. However, the use of the infrared camera technology allows much shorter survey times[16] and the EPA and Colorado time estimates have been criticized as too long. The estimates here are based on ICF and ONE Future company experience. ICF added additional time for training relative to the Colorado analysis.

ICF then adopted the baseline emission values for wells, gathering and transmission stations, and processing stations from the EPA NSPS analysis[15]. The 2014 EDF analysis had very limited data for LDC

[16] Robinson, D, et. al., "Refinery Evaluation of Optical Imaging to Locate Fugitive Emissions". Journal of the Air & Waste Management Association. Volume 57 June 2007.

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programs and resulted in very high reduction costs. Since a different approach was taken for the LDC segment in this analysis (see below) LDCs were not included here.

Table 2-6 summarizes the assumptions for the overall LDAR calculation. This analysis assumes annual emission surveys for all facilities. The reduction is assumed to be a 40% reduction, consistent with the experience of ONE Future members. In addition to the surveys, the estimate includes one initial visit to each site to inventory the equipment (equivalent hours to two inspection visits for each site with cost averaged over five years) and additional visits for repairs. Gas processing plants are already subject to some LDAR requirements for conventional pollutants, which result in co-benefit methane reductions. The miscellaneous fugitive emissions for gas processing were below the size threshold for this analysis but the costs developed here for gas processing are applied to compressors in that segment.

Table 2-6 – Cost Calculation – Annual LDAR

	Well Pads	Processing	Transmission
Methane Mcf/yr[15]	3,057	5,986	3,605
% Reduction	40%	40%	40%
Reduction Mcf	1,223	2,394	1,442
Hours each Inspection (includes survey, travel, recordkeeping, review and training)	5.5	40	32
Frequency (per year)	1	1	1
Annual Inspection Cost	$781	$5,682	$4,546
Initial Set-Up	$156	$1,136	$909
Repair Labor Cost	$781	$5,682	$4,546
Total Cost/yr	$1,719	$12,501	$10,001
Recovered Gas Value*	$3,303	NA	NA
Net Cost	-$1,584	$12,501	$10,001
Cost Effectiveness ($/Mcf CH_4 reduced)	-$1.30	$5.22	$6.94

*Gas at $3/Mcf minus royalty = $2.25/Mcf

Some repairs can be made at the time of the survey, such as tightening valve packing or flanges, but others will require additional repair time. This analysis assumes repair time equivalent to one survey visit for each facility for repairs each year. The capital cost of larger repairs is not included on the assumption that these repairs would need to be made anyway and the LDAR program is simply alerting the operator to the need. This lower repair estimate takes into account that:

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- These are average values across facilities – not every facility will require repairs.
- These are average values over time – not every facility will need repairs every year while being monitored on a continuing basis.
- Some or all of cost of major repairs is assumed to be part of regular facility maintenance.

Replacement costs for large diameter, high pressure components are significantly greater than these average annual repair costs. The replacement frequency for large diameter, high pressure components at any individual facility cannot be accurately predicted or estimated.

The value of reduced gas losses is credited to the program for production only. These final reduction cost values were used for the analysis.

2.4. Treatment of LDC Reductions

The 2014 EDF study found that methane emission reductions from LDCs were extremely expensive, mostly due to the low baseline emissions and the high capital cost of some options, such as cast iron pipe replacement. Cast iron mains have been identified is a significant emission source, however they are primarily located in congested urban areas where replacement or repair is very expensive, reported as $1 million to $3 million per mile. This makes for a very expensive control option based purely on emission reduction. Moreover, these expenditures must be approved by state utility commissions, whose purview typically does not extend to environmental remediation of this type. That said, approximately 3% of cast iron mains are being replaced each year for safety reasons, so the emissions are gradually declining.

For this study, a separate analysis of emission reductions was developed for the LDC segment to account for reductions that will be undertaken even though they may not be cost-effective as emission control measures alone. The analysis assumed three types of activities:

- Cast iron main replacement at 3% per year
- Unprotected steel pipe replacement at 3% per year
- Miscellaneous other emission reduction measures such as: service line replacement, blowdown gas recovery, hot tapping, M&R Station upgrades, and dig-in mitigations, assumed to be 6% of the remaining emissions (excluding cast iron and unprotected steel mains) between 2012 and 2025.

Using the baseline emissions and the emission factors from the EPA 2012 inventory, these emission reductions were calculated as:

- Cast iron main replacement – 2.9 Bcf
- Unprotected steel pipe replacement – 2.5 Bcf
- Miscellaneous other emission reduction measures – 3.5 Bcf

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2.5. Completion Emissions from Hydraulic Fracturing

Gas well completion emissions from hydraulic fracturing were estimated at 13.1 Bcf in the 2012 inventory. These emissions were regulated during the second half of 2012 and are assumed to be controlled going forward. Therefore they are not included in the MAC analysis but are counted as a reduction of 12.3 Bcf in the overall reductions from the base year.

2.6. Source Categories Not Addressed

Several source categories with relatively large emissions were not addressed in the analysis. The sources and the reasons for their treatment are summarized below.

- **Off-shore oil and gas production** – As noted earlier, the EPA inventory provides very limited data on offshore emissions, which were not adequate to apply the methodology used for other sources. This is an area in which further analysis would probably yield additional opportunities for reduction.
- **Engine exhaust** – The exhaust from gas-burning engines and turbines contains a small amount of unburned methane from incomplete combustion of the fuel. While it is a small percentage, it is significant in aggregate. Oxidation catalyst devices are used to reduce unburned emissions of other hydrocarbons in the exhaust but they are not effective at reducing emissions of methane due to its lower reactivity. However, new catalysts are being developed, in part for natural gas vehicles, which may be applicable to these sources. This is a topic for further research and technology deployment.
- **Other sources** – There are additional cost-effective measures for methane reduction that have been identified by the EPA Gas STAR program and others. They are not included here because this report focuses only on the largest emitting sources. However, their omission should not be taken to indicate that the measures listed here are the only cost-effective methane reduction measures.
- **Gathering and Boosting** – The gathering and boosting segment is not called out as a separate segment in the 2014 edition of the EPA inventory for 2012 and therefore was not addressed as a separate source of potential reductions in this study. The 2016 edition has developed new emission factors and significantly increased the activity counts in the gathering segment, however these higher emissions and potential reductions were not included in this analysis, which was completed prior to that release. Since the GHGRP now mandates reporting of emissions data from such facilities, and with the data to be gathered by EPA pursuant to the ICR process, we expect further updates in future GHGI releases. Further, several key government-sponsored studies of emissions from gathering and boosting facilities will be published by the end of 2016. All of this data will support future updates to the methane emissions profile from this segment and available abatement potential.

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3. Analytical Results

3.1. Development of Emission Control Cost Curves

Section 2 identified 16 discrete control technologies and the associated costs, reduction potential, and cost-effectiveness in terms of annualized cost per ton or Mcf of methane reduced based on Gulf Coast region capital costs. In this Section 3, we model the cumulative reductions and marginal abatement costs from a 2012 U.S. methane emissions baseline for the oil and natural gas sector, employing the technology-level data generated in Section 2. Employing data from the EPA 2012 Greenhouse Gas Inventory and source/control technology data presented in Section 2, adjusted for regional cost differences, ICF computed the methane abatement potential from the natural gas sector from a 2012 baseline.

The model developed for this task includes the individual source categories for each segment of the oil and gas industry. Mitigation technologies are matched to each source or individual measure in various segments of the oil and gas value chain. The model calculates the reduction achieved for each source within each segment and calculates the cost of control based on the capital and operating costs, the equipment life, and where appropriate, the value of recovered gas. Key global input assumptions include: whether a particular segment is able to monetize the value of recovered gas, the value of gas, and the discount rate/cost of capital. As discussed above, the value of recovered gas was included only for the production segment and the gas price was assumed to be $3/Mcf minus 25% for royalties and fees, for a net value of $2.25/Mcf. A 10% discount rate was used for the analysis. These calculations include two factors that were not included in the baseline costs presented in Section 2:

- A construction cost index is used to account for regional cost differences, which averages 15% higher than the baseline Gulf Coast costs.
- The methane content is adjusted depending on whether the application is upstream or downstream in the value chain. This adjustment affects the value of recovered gas where the gas value can be monetized.

These two factors result in some of the costs in the MAC curve results presented in this chapter being higher than the baseline costs presented in Section 2. These and other key assumptions are listed in Appendix A.

Table 3-1 lists the emission reduction measures by industry segment with their reduction and cost, depicted in several formats. The total reduction is 88.3 Bcf/year of methane from the U.S. oil and gas segment at a total annualized cost of $296 million or $3.35/Mcf of methane reduced from the 2012 baseline. The reductions for the LDC segment calculated separately total 8.9 Bcf and the reductions from reduced emission well completions result in a total reduction of 109.5 Bcf of methane reduction.

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Table 3-1 – Annualized Methane Reduction and Cost – U.S.

Segment - Mitigation Option	Bcf CH_4 Reduced	Gg CH_4 Reduced	MMTonnes CO2e	$/Mcf CH_4 Reduced	$/Mcf Natural Gas Reduced	$/Tonne CO2e
Gas Processing - LDAR Processing	7.4	141.8	3.6	$5.98	$4.98	$12.43
Gas Processing - Replace Kimray Pumps with Electric Pumps	0.1	2.5	0.1	$1.04	$0.87	$2.16
Gas Processing - Replacement of Reciprocating Compressor Rod Packing Systems	0.3	6.0	0.2	$6.94	$5.78	$14.42
Gas Processing - Wet Seal Degassing Recovery System for Centrifugal Compressors	7.5	144.7	3.6	$0.37	$0.31	$0.77
Gas Production - Early replacement of high-bleed devices with low-bleed devices	5.3	101.9	2.6	$6.02	$5.23	$12.50
Gas Production - Install Plunger Lift Systems in Gas Wells	2.3	43.9	1.1	$3.06	$2.66	$6.35
Gas Production - Install Vapor Recovery Units	1.6	30.1	0.8	($0.54)	($0.47)	($1.12)
Gas Production - LDAR Wells	3.3	64.2	1.6	($1.09)	($0.95)	($2.26)
Gas Production - Replace Kimray Pumps with Electric Pumps	4.3	81.8	2.1	($1.66)	($1.45)	($3.45)
Gas Production - Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	2.7	51.4	1.3	$2.86	$2.49	$5.95
Gas Production - Replacement of Reciprocating Compressor Rod Packing Systems	0.6	11.2	0.3	$4.24	$3.69	$8.81
Gas Storage - Early replacement of high-bleed devices with low-bleed devices	0.1	1.8	0.0	$8.72	$8.14	$18.11
Gas Storage - LDAR Transmission	2.9	56.2	1.4	$7.95	$7.42	$16.51
Gas Storage - LDAR Wells	0.2	4.4	0.1	$1.61	$1.50	$3.35
Gas Storage - Redesign Blowdown Systems and Alter ESD Practices	1.2	23.4	0.6	$1.12	$1.05	$2.33
Gas Storage - Replace with Instrument Air Systems - Intermittent	0.1	2.2	0.1	$1.42	$1.33	$2.95
Gas Storage - Replacement of Reciprocating Compressor Rod Packing Systems	0.4	6.9	0.2	$6.94	$6.49	$14.42

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Segment - Mitigation Option	Bcf CH_4 Reduced	Gg CH_4 Reduced	MMTonnes CO2e	$/Mcf CH_4 Reduced	$/Mcf Natural Gas Reduced	$/Tonne CO2e
Gas Storage - Wet Seal Degassing Recovery System for Centrifugal Compressors	0.8	14.5	0.4	$0.37	$0.35	$0.77
Gas Transmission - Early replacement of high-bleed devices with low-bleed devices	0.5	9.5	0.2	$8.72	$8.14	$18.11
Gas Transmission - LDAR Transmission	14.0	268.5	6.7	$7.95	$7.42	$16.51
Gas Transmission - Pipeline Pump-Down Before Maintenance	2.8	53.9	1.4	$4.40	$4.11	$9.14
Gas Transmission - Redesign Blowdown Systems and Alter ESD Practices	6.4	122.5	3.1	$1.12	$1.05	$2.33
Gas Transmission - Replace with Instrument Air Systems - Intermittent	0.6	11.2	0.3	$1.42	$1.33	$2.95
Gas Transmission - Replacement of Reciprocating Compressor Rod Packing Systems	1.8	35.4	0.9	$6.94	$6.49	$14.42
Gas Transmission - Wet Seal Degassing Recovery System for Centrifugal Compressors	7.4	141.6	3.6	$0.37	$0.35	$0.77
Oil Production - Early replacement of high-bleed devices with low-bleed devices	4.6	88.5	2.2	$6.02	$5.01	$12.50
Oil Production - Install Vapor Recovery Units	6.0	114.7	2.9	($0.54)	($0.45)	($1.12)
Oil Production - LDAR Wells	0.0	0.3	0.0	($1.09)	($0.91)	($2.26)
Oil Production - Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	1.9	36.1	0.9	$2.86	$0.00	$5.95
Oil Production - Replace with Instrument Air Systems - Intermittent	1.1	20.6	0.5	($1.28)	$0.00	($2.66)
Total	**88.3**	**1,699.8**	**0.9**			
Gas Production - Reduced Emission Completions	12.3	236.4	5.9	N/A	N/A	N/A
Gas Distribution - Cast Iron Main Replacement	2.9	55.6	1.4	N/A	N/A	N/A
Gas Distribution - Bare Steel Replacement	2.5	47.9	1.2	N/A	N/A	N/A
Gas Distribution - Miscellaneous	3.5	67.1	1.7	N/A	N/A	N/A
Grand Total	**109.5**	**2,106.8**	**11.1**			

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The results can also be presented as a Marginal Abatement Cost Curve (MAC curve), shown in Figure 3-1. This representation shows the emission reductions sorted from lowest to highest cost-of-reduction and shows the amount of emission reduction available at each cost level. The vertical axis shows the cost per unit in $/Mcf of methane reduced. A negative cost-of-reduction indicates that the measure has a positive financial return, i.e. saves money for the operator. The horizontal width of the bars shows the amount of reduction. The area within the bars is the total cost per year. The area below the horizontal axis represents savings and the area above the axis represents cost. The net sum of the two is the total net cost per year.

Figure 3-1 – Example MAC Curve

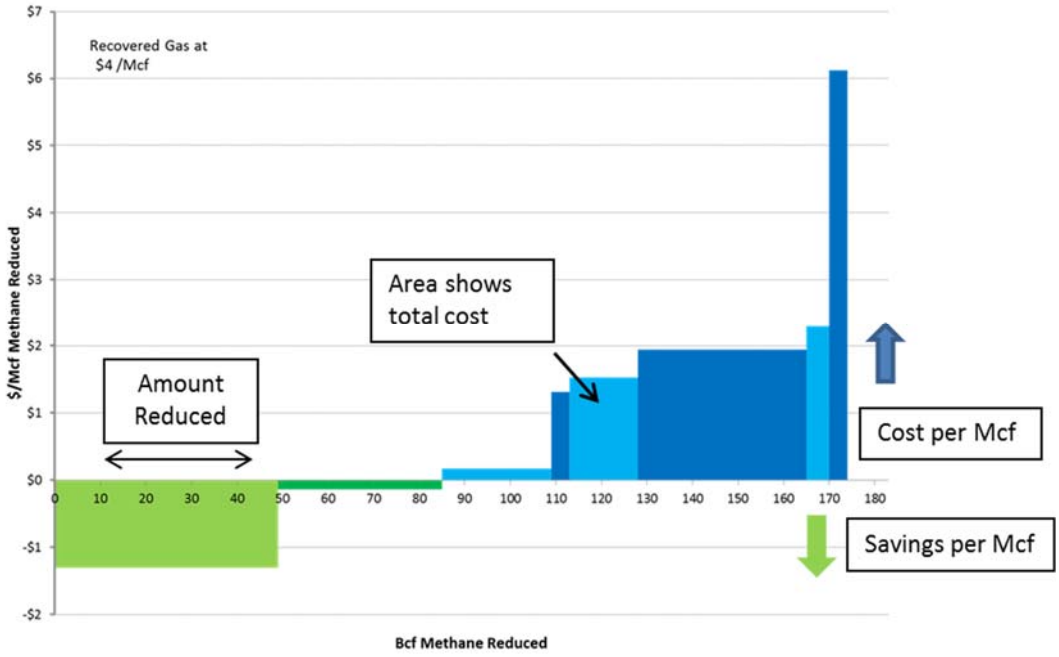


Figure 3-2 shows the reduction for each measure across all industry segments in the MAC curve format. Figure 3-3 shows the reduction in methane emissions by industry segment. The transmission and production sectors have the greatest reductions. The costs for each sector depend on the particular mitigation options available in each and their aggregate cost.

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Figure 3-2 – National Aggregate MAC Curve by Measure

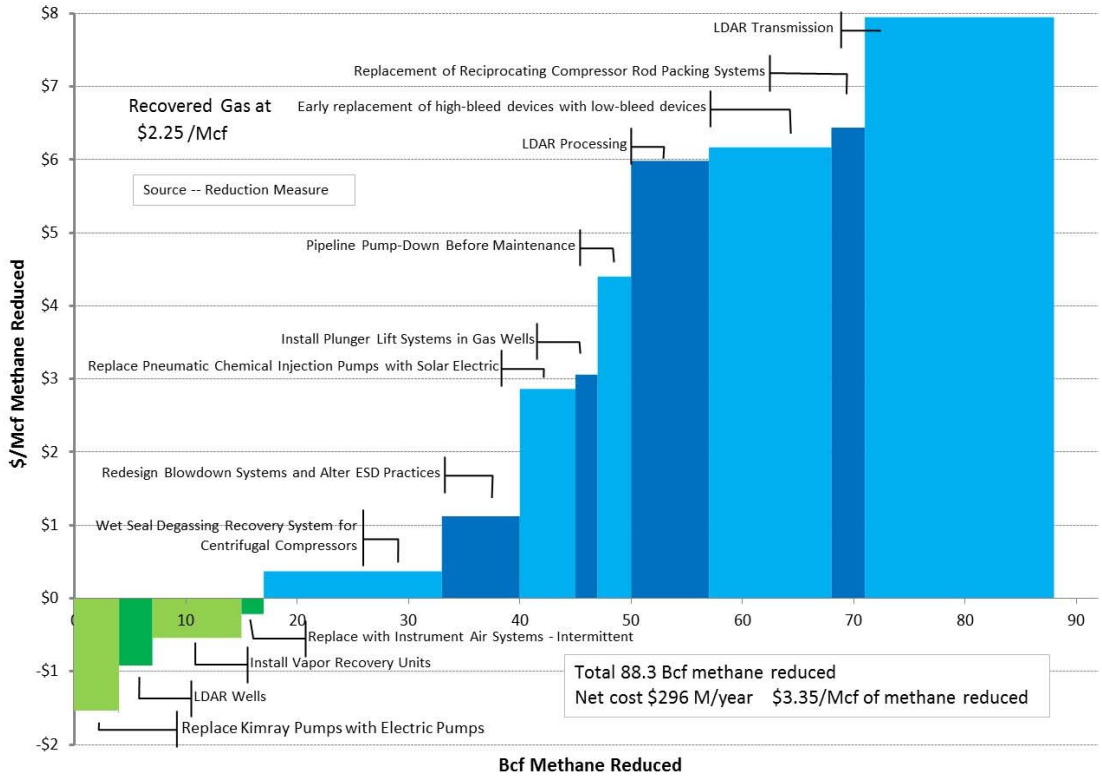
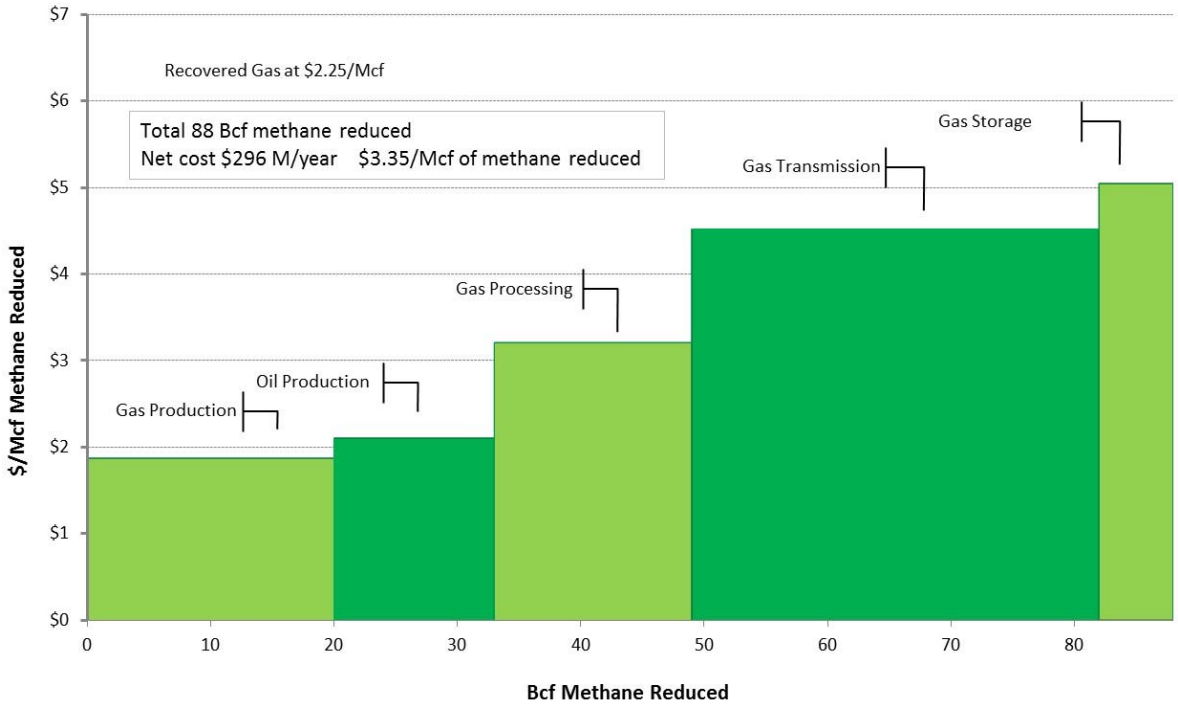


Figure 3-3 – National Aggregate MAC Curve by Industry Segment



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Appendix A.
Summary and Comparison of Assumptions and Results

This section summarizes and compares the key assumptions and results for this study and the 2014 EDF study. The assumptions for each study were largely specified by the clients for each. Table A-1 summarizes some of the key assumptions and results. The primary difference in total reduction volume is the lower reduction from less frequent LDAR and the smaller baseline in the current study due to a different base year and exclusion of the distribution segment.

Table A-1 - Summary of Baseline Assumptions and MAC Curve Results

	ONE Future 2016	EDF 2014
Inventory Baseline	EPA Inventory 2012 – 353 Bcf methane	EPA Inventory 2011 modified and projected to 2018 – 404 Bcf methane
Natural Gas Price	$2.25/Mcf ($3/Mcf – 25% royalty and fee payments)	$4/Mcf
LDAR Frequency and reduction	Annual – 40%	Quarterly – 60%
Gas Value Credit for Reductions	Production segment only	All except transmission and distribution
Net Annualized Cost	$296 million	$108 million
Annual reduction	88.3 Bcf methane	163 Bcf methane
Average cost of reduction	$3.35/Mcf methane reduced	$0.66/Mcf methane reduced

The primary drivers of the difference in the average cost of reduction between the two studies are the different gas price and the assumptions on which sectors can monetize the value of recovered gas. Table A-2 provides a sensitivity analysis of the gas price effect on the annualized cost of reduction per Mcf.

Table A-2 – Cost per Mcf of Methane Reduced – Gas Price Sensitivity

Gas Price	ONE Future 2016	EDF 2014
$2.25/Mcf	$3.35	
$3.00/Mcf	$3.01	$1.48
$4.00/Mcf	$2.55	$0.66
$5.00/Mcf		-$0.15

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Table A-3 - Mitigation Technology Characteristics – ONE Future 2016

Mitigation strategy	Capital Cost	Operating Cost	Percent Reduction	$/Mcf* w/ Credit	$/Mcf w/o Credit
Early replacement of high-bleed devices with low-bleed devices	$3,000	$0	78%	$4.91	$7.61
Replacement of Reciprocating Compressor Rod Packing Systems	$6,600	$0	31%	$3.36	$6.06
Install Flares-Portable	$30,000	$6,000	98%	$0.20	$0.20
Install Plunger Lift Systems in Gas Wells	$20,000	$2,400	95%	$2.33	$5.03
Install Vapor Recovery Units	$50,636	$9,166	95%	-$0.82	$1.89
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$5,000	$75	100%	$2.16	$4.86
Replace Kimray Pumps with Electric Pumps	$10,000	$2,000	100%	-$1.79	$0.91
Pipeline Pump-Down Before Maintenance	$0	$30,155	80%	$1.14	$3.84
Redesign Blowdown Systems and Alter ESD Practices	$15,000	$0	95%	-$4.10	$0.98
Wet Seal Degassing Recovery System for Centrifugal Compressors	$70,000	$0	95%	-$2.38	$0.32
Replace with Instrument Air Systems - Intermittent	$60,000	$17,770	100%	-$1.46	$1.24

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Table A-4 – Mitigation Technology Characteristics – EDF 2014

Name	Capital Cost	Operating Cost	Percent Reduction	$/Mcf w/ Credit	$/Mcf w/o Credit
Early replacement of high-bleed devices with low-bleed devices	$3,000	$0	97%	-$3.08	$1.99
Early replacement of intermittent-bleed devices with low-bleed devices	$3,000	$0	91%	$0.58	$5.65
Replacement of Reciprocating Compressor Rod Packing Systems	$6,000	$0	35%	$1.82	$6.89
Install Flares-Completion	$50,000	$6,000	98%	N/A	$1.86
Install Flares-Venting	$50,000	$6,000	98%	N/A	$0.26
Liquid Unloading – Install Plunger Lift Systems in Gas Wells	$20,000	$2,400	95%	-$0.05	$5.03
Install Vapor Recovery Units on Tanks	$100,000	$7,500	95%	-$0.51	$4.57
Transmission Station Venting –Redesign Blowdown Systems /ESD Practices	$15,000	$0	95%	-$4.10	$0.98
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$5,000	$75	100%	-$0.22	$4.86
Replace Kimray Pumps with Electric Pumps	$10,000	$2,000	100%	-$4.17	$0.91
Pipeline Venting – Pump-Down Before Maintenance	$0	$12,000	80%	-$4.67	$0.41
Wet Seal Degassing Recovery System for Centrifugal Compressors	$50,000	$0	95%	-$4.87	$0.21
LDAR Wells	$169,923	$146,250	60%	$2.52	$7.60
LDAR Gathering	$169,923	$146,250	60%	$0.91	$5.98
LDAR Large LDC Facilities	$169,923	$146,250	60%	$10.03	$14.45
LDAR Processing	$169,923	$146,250	60%	-$0.98	$4.10
LDAR Transmission	$169,923	$146,250	60%	-$2.28	$2.15

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Table A-5 – Annualized Cost and Reduction Comparison

	EDF 2014			ONE Future 2016		
Source/Measure	Annualized Cost ($ million/yr)	Bcf Methane Reduced/yr	$/ MCF Methane Reduced	Annualized Cost ($ million/yr)	Bcf Methane Reduced/yr	$/ MCF Methane Reduced
Replace Kimray Pumps with Electric Pumps	-$23.4	5.8	-$4.05	-$7.0	4.4	-$1.58
Wet Seal Degassing Recovery System for Centrifugal Compressors	-$58.7	19.1	-$3.07	$5.8	15.7	$0.37
Compressor Stations (Storage)--LDAR	-$4.5	1.5	-$3.03	Included in Transmission		
Early replacement of high-bleed devices with low-bleed devices	-$67.4	25.4	-$2.65	$64.9	10.5	$6.17
Reciprocating Compressor Fugitives--LDAR	-$10.5	32.3	-$0.33	Included in Transmission		
Condensate Tanks w/o Control Devices--VRU	$0.1	0.4	$0.21	-$4.1	7.6	-$0.54
Stranded Gas Venting from Oil Wells--Flares	$2.4	8.2	$0.30	NA		
Oil Tanks--VRU	$1.8	5.5	$0.33	Included with Condensate Tanks		
Pipeline Pump-Down Before Maintenance	$2.3	4.2	$0.53	$12.4	2.8	$4.40
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps	$2.7	4.8	$0.57	$13.1	4.6	$2.86
Install Plunger Lift Systems in Gas Wells	$1.2	1.6	$0.74	$7.0	2.3	$3.06
Redesign Blowdown Systems and Alter ESD Practices	$7.5	5.9	$1.27	$8.5	7.6	$1.12
Gathering and Boosting Stations--LDAR	$5.0	3.3	$1.51	Included in Production		
Intermittent Bleed Pneumatic Devices--Low Bleed	$20.9	12.1	$1.72	NA		
Replace with Instrument Air Systems - Intermittent	NA			-$0.4	1.8	-$0.22
Oil Well Completions - with Fracturing--Flares	$14.5	6.8	$2.13	NA		
Compressor Stations (Transmission)--LDAR	$7.7	2.8	$2.79	$134.3	16.9	$7.95
Well Fugitives--LDAR	$43.9	12.5	$3.51	-$3.3	3.6	-$0.92

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Replacement of Reciprocating Compressor Rod Packing Systems	$22.3	3.6	$6.11	$20.0	3.1	$6.44
LDC Meters and Regulators--LDAR	$140.6	7.1	$19.75	NA		
Grand Total	**$108.3**	**162.9**	**$0.66**	**$295.9**	**88.3**	**$3.35**

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Appendix B.
Data Sources

The follow notes explain the sources and derivation of the capital cost (Capex), operating cost (Opex), and emission reduction potential of the emission reduction options assessed in this study. The primary sources are a variety of EPA sources – particularly data from the Gas STAR program, the Greenhouse Gas Reporting, and support documents from NSPS OOOO, as well as industry comments received during the 2014 EDF study, and comments from the ONE Future sponsors of this study. Each emission reduction option is discussed below:

- **Early replacement of high-bleed devices with low-bleed devices** – Capex $3,000, Opex $0, Reduction 78%. The Capex and Opex were based on Gas STAR data updated by industry review in both studies. There is no incremental Opex for pneumatic devices. The reduction estimate was based on the performance of high bleed and low bleed pneumatic devices found in two field measurement studies completed by the University of Texas [17, 18] and sponsored by industry participants and EDF.
- **Replacement of Reciprocating Compressor Rod Packing Systems –** Capex $6,600, Opex $0, Reduction 31%. The Capex was based on Gas STAR data updated by industry in both studies. There is no incremental Opex for this measure. The reduction estimate was based on an analysis by ICF that calculates the reductions due to more frequent replacement of rod packing seals relative to less frequent replacement.
- **Install Flares-Portable** – Capex $30,000, Opex $6,000, Reduction 98%. The Capex and Opex were based on industry input during both the EDF and ONE Future studies. The reduction is an EPA Gas STAR/inventory assumption of 98% flare combustion efficiency. Additional information was derived from GHGRP Subpart W.
- **Install Plunger Lift Systems in Gas Wells** – Capex - $20,000, Opex $2,400, Reduction 95%. These values were based on industry input during both studies. They do not include the value of increased production, which is typically the primary driver for liquids unloading. The cost and effectiveness of plunger lifts are highly variable depending on the well characteristics. Plunger lifts can be an effective mitigation measure for certain wells at certain times over their operating life but may not

[17] Allen, David T. et al. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States." *Proceedings of the National Academy of Sciences of the United States of America* 110.44 (2013): 17768–17773.

[18] Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers. David T. Allen et al. Environmental Science & Technology 2015 49 (1), 633-640. DOI: 10.1021/es5040156. Available online at: http://pubs.acs.org/doi/abs/10.1021/es5040156

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be effective or feasible for other wells or even for the same well at a different point in its operating life. Applicability information was derived from GHGRP subpart W.

- **Install Vapor Recovery Units –** Capex $50,636, Opex $9,166, Reduction 95%. These values were based on EPA Gas STAR data, independent ICF analysis, and updates from vendors and industry commenters in both studies.
- **Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps -** Capex $5,000, Opex $75, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Replace Kimray Pumps with Electric Pumps** – Capex $10,000, Opex $2,000, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Pipeline Pump-Down Before Maintenance** – Capex $0, Opex $30,155, Reduction 80%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies. The required equipment is typically leased so there is no Capex.
- **Redesign Blowdown Systems and Alter ESD Practices** - Capex $15,000, Opex $0, Reduction 95%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Wet Seal Degassing Recovery System for Centrifugal Compressors** – Capex $70,000, Opex $0, reduction 95%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **Replace with Instrument Air Systems – Intermittent** – Capex $60,000, Opex $17,770, Reduction 100%. These values were based on EPA Gas STAR data with updates from vendors and industry commenters in both studies.
- **LDAR Costs** – The structure of the LDAR cost analysis is different from the other measures, as discussed in the body of the report. The cost analysis structure is based on the regulatory analysis for the Colorado methane rule but most of the values have been updated. The ONE Future sponsors provided extensive input on the labor and instrumentation costs. The baseline labor costs were increased and the number of measurement devices was increased from the Colorado assumptions. The time allocated for inspections was also increased relative to the 2014 EDF report based on input from the sponsors. The baseline emissions were from the EPA Technical Support Document for NSPS OOOO.

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Options for Removing Accumulated Fluid and Improving Flow in Gas Wells



Executive Summary

When first completed, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and liquid hydrocarbon) to the surface along with the produced gas. As gas production continues, the reservoir pressure declines, and as pressure declines, the velocity of the fluid in the well tubing decreases. Eventually, the gas velocity up the production tubing is no longer sufficient to lift liquid droplets to the surface. Liquids accumulate in the tubing, creating additional pressure drop, slowing gas velocity, and raising pressure in the reservoir surrounding the well perforations and inside the casing. As the bottom well pressure approaches reservoir shut-in pressure, gas flow stops and all liquids accumulate at the bottom of the tubing. A common approach to temporarily restore flow is to vent the well to the atmosphere (well "blowdown"), which produces substantial methane emissions. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990—2008* estimates 9.6 billion cubic feet (Bcf) of annual methane emissions from venting of low pressure gas wells.

At different stages in the life of a gas well, various alternatives to repeated well venting can be deployed to move accumulated liquids to the surface. These options include:

- ★ Foaming agents or surfactants
- ★ Velocity tubing
- ★ Plunger lift, operated manually or with 'smart' well automation
- ★ Downhole pumps, which include reciprocating (beam) pumps and rotating (progressive cavity) pumps.

Natural Gas STAR Partners report significant methane emission reductions and economic benefits from implementing one or more lift options to remove accumulated liquids in gas wells. Not only are vented methane emissions reduced or eliminated, but these lift techniques can provide the additional benefit of increased gas production.

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings and Incremental Production[1] (Mcf/well/year)	Value of Natural Gas Savings and Additional Production (Mcf/well/year)			Implementation Cost[1] (2010 $/Well)	Project Payback (years)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Use Foaming Agents	500 – 9,360	$1,500 - $28,080	$2,500 - $46,800	$3,500 - $65,520	$500 - $9,880	0 to 7	0 to 4	0 to 3
Install Velocity Tubing	9,285 – 27,610	$27,855 - $82,830	$46,425 - $138,050	$64,995 - $193,270	$7,000 - $64,000	0 to 3	0 to 2	0 to 1
"Smart" Well Automated Controls for Plunger Lift[2]	800 – 1,463[2]	$2,400 - $4,389	$4,000 - $7,315	$5,600 - $10,241	$5,700 - $18,000	1 to 8	1 to 5	1 to 4
Install Rod Pumps and Pumping Units[2]	973 – 2,040[2]	$2,919 - $6,120	$4,865 - $10,200	$6,811 - $14,280	$41,000 - $62,000	6 to 22	4 to 13	3 to 10

[1]Based on results reported by Natural Gas STAR Partners
[2]Does not include incremental gas production. Includes only potential gas savings from avoided well venting.

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By avoiding or reducing well blowdowns, Partners report annual methane emissions savings that range from 500 thousand cubic feet (Mcf) per well to more than 27,000 Mcf/well. The benefit of increased gas production will vary considerably among individual wells and reservoirs, but can be substantial. For example, Partners report that increased gas production following plunger lift installation yielded as much as 18,250 Mcf per well.

Technology Background

Most gas wells will have liquid loading occur at some point during the productive life of the well. When this occurs, a common course of action to improve gas flow includes:

- ★ Shutting–in the well to allow bottom hole pressure to increase,
- ★ Swabbing the well to remove accumulated fluids,
- ★ Venting the well to the atmosphere (well blowdown),
- ★ Installing an artificial lift system.

'No-Emissions' Solutions for Liquid Loading in Gas Wells:

- ★ Foaming Agents/ Surfactants
  - – Low cost/ low volume lift method
  - – Applied early in production decline, when the bottom hole pressure still generates sufficient velocity to lift liquid droplets
- ★ Velocity Tubing
  - – Low maintenance, effective for low volumes lifted
  - – Somewhat expensive to acquire and install
  - – Often deployed in combination with foaming agents
- ★ Plunger Lift
  - – Long lasting
  - – Less expense to install and operate than a pumping unit
  - – Often, plunger lift cannot produce a well to its economic limit (abandonment).
  - – Challenging to operate effectively; requires more time and expertise to manage.
- ★ Rod Pumping Units
  - – Can be deployed in applications to remove greater liquid volumes than plunger lift.

Swabbing and "blowing down" a well to temporarily restore production can vent significant methane emissions, from 80 to 1600 Mcf/year per well. The process must be repeated as fluids reaccumulate, resulting in additional methane emissions. Operators may wait until well blowdown becomes increasingly ineffective before implementing some type of artificial lift. At this point, the cumulative methane emissions from a well could be substantial.

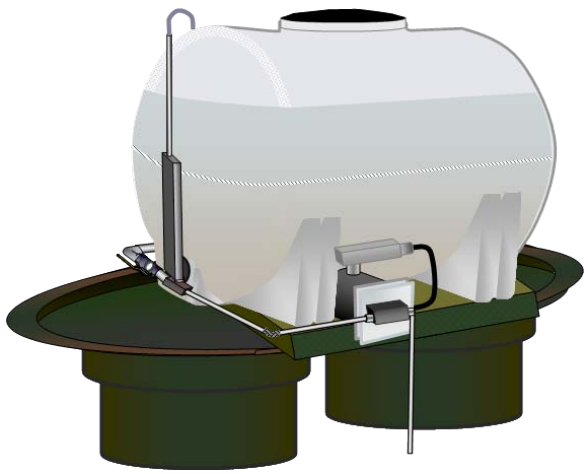
Natural Gas STAR Partners have found that applying artificial lift options early in the life of a well offers significant emissions savings and economic benefits. Each method for lifting liquid in a well has advantages and disadvantages for prolonging the economic life of a well. Total gas savings and methane emission reductions that result from reducing or eliminating well venting will vary for each well depending on flow line operating pressure, reservoir pressure, liquid volume, specific gravity and the number of blowdowns eliminated.

Fluid Removal Options for Gas Wells

Foaming Agents

The use of foam produced by surfactants can be effective for gas wells that accumulate liquid at low rates (Exhibit 1). Foam reduces the density and surface tension of the fluid column, which reduces the critical gas velocity needed to lift fluids to surface and aids liquid removal from the well. Compared to other artificial lift methods, foaming agents are one of the least costly applications for unloading gas wells. Foaming agents work best if the fluid in the well is at least 50 percent water. Surfactants are not

Exhibit 1: Liquid Foaming Agent



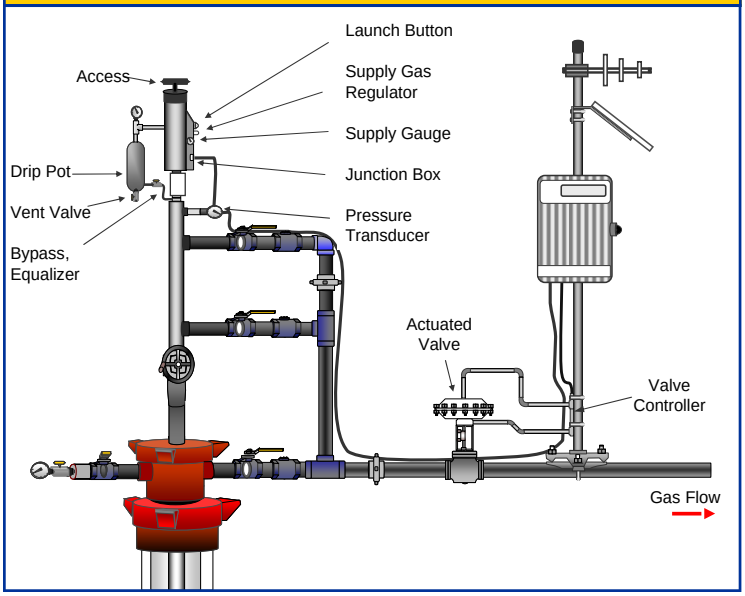
Source: S. Bumgardner, Advanced Resources International, inc.

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effective for natural gas liquids or liquid hydrocarbons.

Surfactants are delivered to the well as soap sticks or as a liquid injected directly into the casing-tubing annulus or down a capillary tubing string. For shallow wells, the surfactant delivery can be as simple as the operator periodically pouring surfactant down the annulus of the well through an open valve. For deep wells, a surfactant injection system requires the installation of surface equipment, as well as regular monitoring. The surface equipment includes a surfactant or 'soap' reservoir, an injection pump, a motor valve with a timer (depending on the installation design), and a power source for the pump (Exhibit 2). No equipment is required in the well, although foaming agents and velocity tubing may be more effective when used in combination.

Exhibit 2: Soap Stick Launcher with Automatic Controller



Source: S. Bumgardner, Advanced Resources International, inc.

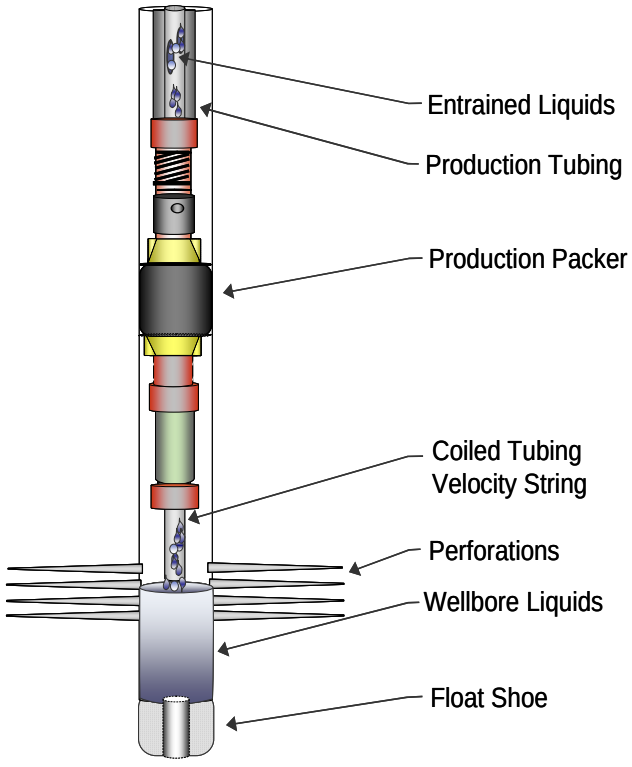
Electric pumps can be powered by AC power where available or by solar power to charge batteries. Other pump choices include mechanical pumps that are actuated by the movement of another piece of equipment or pneumatic pumps actuated by gas pressure. Different pump types have different advantages with respect to reliability, precision, remote operation, simplicity, maintenance frequency, efficiency, and equipment compatibility.

Velocity Tubing

The velocity at which gas flows through pipe determines the capacity to lift liquids. When the gas flow velocity in a well is not sufficient to move reservoir fluids, the liquids will build up in the well tubing and eventually block gas flow from the reservoir. One option to overcome liquid loading is to install smaller diameter production tubing or 'velocity tubing'. The cross-sectional area of the conduit through which gas is produced determines the velocity of flow and can be critical for controlling liquid loading. A velocity string reduces the cross-sectional area of flow and increases the flow velocity, achieving liquid removal while limiting blowdowns to the atmosphere.

Exhibit 3 shows that the conduit for gas flow up a wellbore can be either production tubing, the casing-tubing annulus or simultaneous flow through both the tubing and the annulus. In any case, a 2004 study estimated that gas velocity must be at least 5 to 10 ft/sec (300 to 600 ft/min) to effectively remove hydrocarbon liquids from a well, and at least 10 to 20 ft/ sec (600 to 1200 ft/min) to move produced water. As a rule of thumb, gas flow velocity of 1,000 feet per minute is needed to remove liquid. These figures assume used pipe in good condition with low relative roughness of the pipe wall.

Exhibit 3: Velocity Tubing



Source: S. Bumgardner, Advanced Resources International, inc.

The installation of a velocity string is relatively simple and requires calculation of the proper tubing diameter to achieve the required velocity at the inlet and outlet pressures of the tubing. Velocity tubing to facilitate liquid removal can be successfully deployed in low volume gas wells upon initial completion or near the end of their productive lives. Candidate wells include marginal gas wells producing less than 60 Mfcd. Installation of velocity tubing requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well.

Coiled tubing may also be used, allowing for easier installation and the application of a greater range of tubing diameters as small as 0.25 inches. Coiled tubing can be applied in wells with lower velocity gas production due to better relative roughness characteristics of the tubing and the absence of pipe joint connections. Studies indicate that seamed coiled tubing provides better lift characteristics due to the elimination of turbulence in the flow stream because the seam acts as a "straightening vane".

Plunger Lift with 'Smart' Well Automation

Plunger lifts are commonly used to lift fluids from gas wells. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger and a column of fluid above the plunger up the well tubing to the surface. Exhibit 4 shows a conventional plunger lift installation on a gas well.

Exhibit 4: Plunger Lift



Source: Chesapeake Energy

The operation of a plunger lift system relies on pressure buildup in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must significantly exceed the sales line pressure in order to lift the plunger and load of accumulated fluid to the surface against the sales line backpressure. A companion Lessons Learned paper, *Installing Plunger Lift Systems in Gas Wells,* discusses the installation, gas savings and economics of plunger lift systems. The focus of the present Lessons Learned paper are the incremental gas savings obtained from installing 'smart' automation systems to better manage the operation of plunger lift installations on a field-wide or basin-wide scale.

Most plunger systems operate on a fixed time cycle or on a preset differential pressure. Regardless of activation system (manual, fixed time cycle, or preset pressure differential), a valve mechanism and controller at the surface cause gas volume and pressure to build up in the wellbore initiating the plunger release cycle. At this point, the surface valve closes and the plunger drops to the bottom of the well. Once adequate pressure is reached, the surface valve opens and the plunger rises to the surface with the liquid load. Insufficient reservoir energy, or too much fluid buildup can overload a plunger lift. When that occurs, venting the well to the atmosphere (well blowdown) instantaneously reduces the backpressure on the plunger and usually allows the plunger to return to the surface.

Automated control systems optimize plunger lift and well unloading operations to prevent overloading (plunger cannot overcome backpressure and rise to the surface) and underloading (plunger rises to quickly, possibly damaging equipment) therefore reducing or eliminating well venting. "Smart" automated control systems combine customized control software with standard well control hardware such as remote terminal units (RTUs) and programmable logic controllers (PLCs) to cycle the plunger system and lift fluids out of the tubing. The artificial intelligence component of a smart automation system monitors the tubing and sales line pressures and allows the PLC to "learn" a well's performance characteristics (such as flow rate and plunger velocity) and to build an inflow performance relationship (IPR) curve for the well. The frequency and duration of the plunger cycle is then modified to optimize well performance.

Data analysis combined with wellhead control technology is the key to an effective gas well "smart" automation system. A smart automation system stores historical well production data allowing the program to learn from experience by monitoring and analyzing wellhead instrument data. The control system relays wellhead

instrument data to a central computer, tracks venting times, and reports well problems and high-venting wells, all of which allow custom management of field production.

The components of a smart well automation system that must be installed on each gas well include:

- ★ remote terminal unit with PLC,
- ★ tubing and casing transmitters,
- ★ gas measurement equipment,
- ★ control valve, and
- ★ plunger detector.

Automated controllers at the wellhead monitor well parameters and adjust plunger cycling. These typically operate on low-voltage, solar batteries. Exhibit 5 illustrates typical wellhead equipment and telemetry for plunger lift automated control systems. A host system capable of retrieving and presenting data is also required for continuous data logging and remote data transition. Operators configure all controls and send them to the RTU from the host system. Engineering time is needed to customize the control software and optimize the system. Field operating practices and protocols must be flexible to quickly address well performance deficiencies and operating problems.

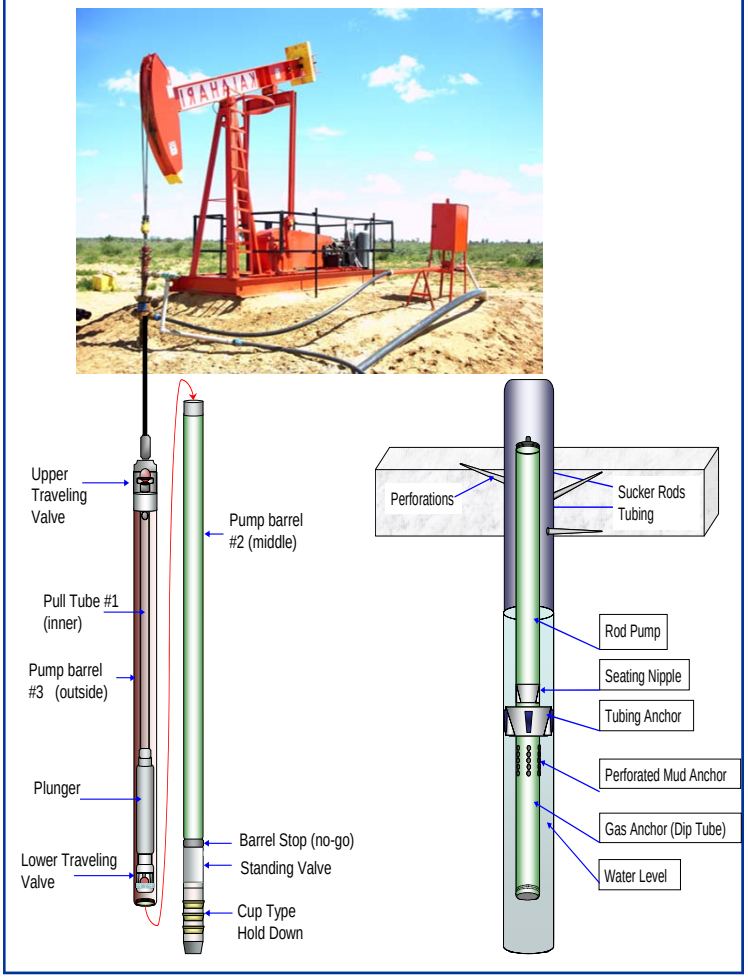
Partners have found that optimized plunger lift cycling to remove liquids can decrease the amount of gas vented by up to 90+ percent. Methane emission savings from reduced well venting is a significant benefit that can add up to huge volumes when applied on a field or basin scale.

Exhibit 5: Typical Wellhead Equipment and Telemetry for Automated Control Systems for Plunger Lift



Source: BP

Exhibit 6: Diagram of a Sucker Rod Pump and Pump Jack



Source: S. Bumgardner, Advanced Resources International, inc.

Rod Pumps and Pumping Units

A downhole positive displacement, reciprocating rod pump with surface pump unit can be deployed in the later stages of a well's life to remove liquids from the wellbore and maximize production until the well is depleted (Exhibit 6). Pumping units can be installed when there is insufficient reservoir pressure to operate a plunger lift. The units can be manually controlled by the field pumper, or very low volume wells may be operated with a timer.

Pumping units not only eliminate the need to vent the well to unload fluids but also extend the productive life of a well. Methane emissions can be further reduced by operating pumping units with electric motors, rather than natural gas-fueled engines. The annual fuel requirement for a typical pumping unit is approximately 1,500 Mcf per unit, of which 0.5 percent is emitted as unburned methane (8 Mcf per unit per year).

A well workover rig is required to install the downhole rod pump, rods, and tubing in the well. Field personnel must be trained for rod pump operations and proper maintenance of the surface equipment. Excessive wear of the rods and tubing can be a major expense for rod pump applications where solids are produced or down hole corrosion is a problem.

A common problem with reciprocating pumps in gas wells is gas locking of the rod pump valves, which prevents the pump from delivering fluid to the surface at the design rate. The presence of free gas in the subsurface sucker rod pump decreases the volumetric pump efficiency and can prevent the pump from lifting fluid. This is not a problem found in progressive cavity pumps as there are no valves to gas lock.

Economic and Environmental Benefits

Implementation of fluid removal options and artificial lift provide economic and environmentally beneficial alternatives to well blowdown. The major benefit of the various fluid removal options is extending the productive life of a well. The full scope of environmental and economic benefits depend on the type of artificial lift system and the remaining productive capacity of the well. Several benefits described below, are realized with the progressive application of fluid removal options in gas wells.

- ★ **Improved gas production rates and extended well life.** Fluid removal and artificial lift systems conserve reservoir energy and boost gas production. Regular fluid removal generally extends the economic life of declining wells resulting in more continuous gas production, improved gas production rates, and incremental ultimate recovery.

- ★ **Reclaims vented gas to sales.** Avoiding well blowdown reclaims the value of gas that would otherwise be vented to the atmosphere.

- ★ **Reduced pollution.** Eliminating well blowdown and gas venting eliminates a significant source of methane and other air pollutant emissions.

- ★ **Lower well maintenance costs and fewer remedial treatments.** Overall well maintenance costs can be reduced by eliminating the cost of a workover rig for swabbing wells. Other savings occur when well blowdowns are significantly reduced or eliminated.

Four Steps for Evaluating Artificial Lift Options:

1. **Determine the technical feasibility of various artificial lift options.**
2. **Determine the cost of various options.**
3. **Estimate the natural gas savings and production increase.**
4. **Evaluate and compare the economics of artificial lift options.**

Decision Process

The decision to implement any type of liquid removal option during the life-cycle of a gas well should be made when the value of the estimated incremental gas production exceeds the cost of the fluid removal option. When one fluid removal approach becomes ineffective and uneconomic, another can be deployed. If venting a well is the current fluid removal approach, the application of foaming agents, velocity tubing or plunger lift should be evaluated before well blowdowns become too frequent, less effective and costly. Natural Gas STAR Partners can use the following decision process as a guide to evaluate the application, safety, and cost effectiveness of fluid removal and artificial lift installations.

Step 1: Determine the technical feasibility of a fluid removal option or artificial lift installation.

Various data and criteria should be evaluated to select a fluid removal approach that is both technically feasible and cost effective. These data include IPR (inflow

NMED Exhibit 73 - 0006

performance relationship) curves; reservoir pressure; gas and fluid production flow rates; fluid levels in the well; the desired flowing bottom hole pressure and casing pressure; production tubing size, the downhole condition of the well; other mechanical limitations of the well and production site; and the capabilities and training of field personnel.

Appendix A (Exhibit A1 and A2) shows the Turner relationship and Lee relationship between critical flow rate (critical gas velocity), and flowing pressure for various sizes of production tubing. If the relationship between flow rate and pressure falls below a line specifying a size of production tubing, a well will not flow liquids to the surface for the indicated tubing size. If flow rate vs pressure falls on or above the line for a specified tubing size, a well meets or exceeds the critical flow rate for the specified tubing size and the well is able to unload fluid to the surface. Exhibits A1 and A2 can be used as starting points to estimate whether a fluid removal or artificial lift option is likely to be effective. Following are some technical considerations that enter into the decision process for each fluid removal option:

- ★ **Foaming Agents.** Partners typically use foaming agents early in the life of gas wells when the wells begin to load with formation water and the liquid production rate is comparatively low. Foaming works best if the liquid in the wellbore is mainly water, and condensate content is less than 50 percent. Foaming agents may also be used in combination with other well treatments that reduce salt and scale build up, or may be applied in combination with velocity tubing.

- ★ **Velocity Tubing**. Velocity tubing strings are appropriate for natural gas wells with relatively small liquid production and higher reservoir pressure. Low surface pipeline pressure relative to the reservoir pressure is also necessary to create the pressure drop that will achieve an adequate flow rate. The depth of the well affects the overall cost of the installation, but is usually offset by the higher pressure and gas volume in deeper wells. Velocity tubing can also be a good option for deviated wells and crooked well bores. Rod pumped wells with deviation and or dog legs that become uneconomic due to high failure rates and servicing costs may also be candidates for velocity strings.

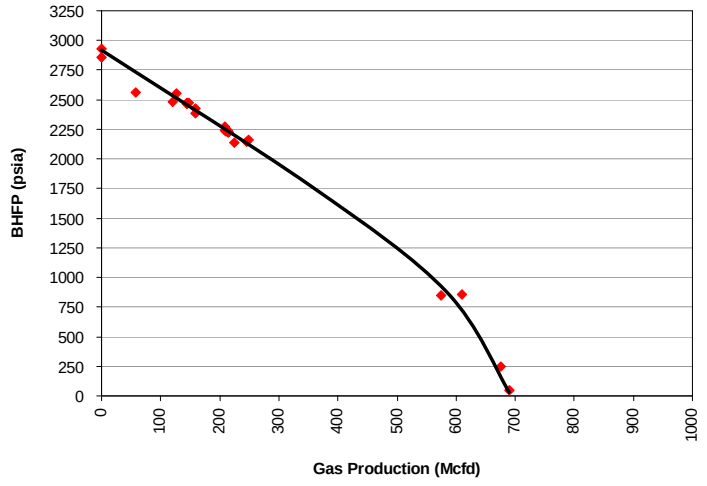
Determining the feasibility of installing a velocity tubing string is relatively straightforward. An inflow performance relationship (IPR curve) is calculated to establish the flow regime in the well tubing, as shown in Exhibit 7. The diagram shown in Exhibit 7 illustrates the relationship between gas production and the bottom hole flowing pressure (BHFP). Gas flow is evaluated and the velocity relationships for various sizes of tubing are developed to determine the appropriate diameter for use in each well. As a rule of thumb, a gas flow velocity of approximately 1,000 feet per minute is the minimum necessary to remove fresh water. Condensate requires less velocity due to its lower density while more dense brine requires a higher velocity.

Once the velocity string is installed, no other artificial lift equipment is required until the reservoir pressure declines to the point that

Indicators of Liquid Loading in Gas Wells:

1. Construct an IPR curve and evaluate the production efficiency of the well.
2. Monitor production curves for each well on a regular basis. Liquid loading is indicated if the curve for a normally declining well becomes erratic and the production rate drops.
3. Compute the critical gas velocity (flow rate) at which liquid can no longer be lifted in the tubing (see Appendix)
4. Critical velocity vs. flowing tubing pressure can be constructed for various tubing diameters.

Exhibit 7: Example of Inflow Performance Relationship Curve for Evaluating Fluid Removal Options



Source: S. Bumgardner, Advanced Resources International, inc.

velocities of 1,000 feet per minute are no longer possible in the tubing. The introduction of a foaming agent to the bottom of a tubing string will extend the effective life of a velocity string below the 1,000 feet per minute velocity required to lift water by reducing the density of the column that is lifted. This only applies to water lifted from the well tubing since condensate is not affected by a surfactant.

★ **"Smart" Well Automation of Plunger Lift.** Candidate wells for plunger lift generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system. Like pumping units, plunger lifts are used to extend the productive life of a well. Installation is less expensive than rod pumps, but plunger lifts may be difficult to operate.

Conventional plunger lift operations rely upon manual, on-site adjustments to tune a plunger cycle time. When a plunger lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. A "smart" well automation system enhances plunger performance by monitoring parameters such as tubing and casing pressure, well flow rate and plunger cycle frequency (travel time). Data for each well are relayed to a host computer where operators review the data and address any performance deficiencies or operating problems. This helps to optimize plunger lift performance, improve gas production, and reduce well venting.

Optimum plunger lift performance generally occurs when the plunger cycle is frequent and set to lift the smallest liquid loads. Small liquid loads require lower operating bottom hole pressure, which allows for better inflow performance. As with velocity tubing, a desirable velocity for a plunger to ascend in tubing is in the range of 500 to 1,000 ft per minute.

★ **Pumping Units.** Rod pump installations for gas wells can be costly to install and operate, but can extend well life, increase ultimate recovery, increase profits and reduce methane emissions. A rod pumping application for gas wells must be carefully designed to ensure trouble-free installation of the pumping units, minimize installation costs, and maximize operating cost savings by reducing mechanical wear and the need for well servicing.

Technical considerations for a rod pump application include the amount of pump capacity required, the pump setting depth in the well, and the type and gravity of the fluid in the hole (brine, fresh water, hydrocarbon, hydrogen sulfide, carbon dioxide, etc.). These factors influence the components of a rod pump installation, including rod pump materials, rod string size and grade, pumping unit design, size of the prime mover (motor), pump speed and stroke length. Resources available for evaluating and designing rod pump applications for gas wells include American Petroleum Institute and various Society of Petroleum Engineers publications; commercial pumping unit vendors; and computer design models. In general, rod pump installations for gas wells have lower fluid volumes than for oil wells. Operating costs can be minimized by correctly sizing the artificial lift and pumping as slow as possible while maintaining a pumped-off condition. The use of pump-off controllers are also effective by matching the pump displacement to the volume of fluid entering the well bore.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

Step 2. Determine the cost of fluid removal options.

Costs associated with the various fluid removal options include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the systems.

★ **Foaming Agents.** Partners report upfront capital and start-up costs to install soap launchers ranging from $500 to $3,880 per well. Monthly cost for the foaming agent is $500 per well, or approximately $6,000 per year. As such, typical costs can vary between $500 and $9,880.

★ **Velocity Tubing.** One Partner reports total capital and installation costs of at least $25,000 per well, which includes the workover rig time, downhole tools, tubing connections and supervision. Another Partner has deployed velocity tubing in more than 100 wells and reports total installation costs ranging from $8,100 per well to $30,000 per well. Based on Partner experiences, typical costs will vary between $7,000 and $64,000 per well.

NMED Exhibit 73 - 0008

- **"Smart" Well Automation of Plunger Lift.** Two Partners report implementing "smart" automation systems to control plunger lift operations. One operation is fairly small, consisting of 21 wells. The second is a basin-wide deployment on more than 2,150 wells. Reported upfront costs for the smaller installation is $6,300 per well. Total cost over 5 years reported for the larger automation project is $12,200,000 or approximately $5,700 per well. Typical costs will vary between $5,700 and $18,000 depending on the complexity of the "smart" automation system. These costs would be incremental over the cost of installing a plunger lift system.

- **Pumping Units.** Capital and installation costs include the use of a workover rig and crew, for approximately one day, sucker rods, rod guides and pump costs, and the cost of the pumping unit and motor. Other start-up costs can include miscellaneous clean out operations to prepare the well to receive a down hole pump and sucker rods.

  Partners report that location preparation, well clean out, artificial lift equipment, and a pumping unit can be installed for approximately $41,000 to $62,000 per well. The reported average cost of the pumping unit alone appears to range from approximately $17,000 to $27,000. Most companies have surplus units in stock that can be deployed at the expense of transportation and repair, or may purchase used units.

Step 3. Estimate the savings from various fluid removal options.

The total savings associated with any of the fluid removal and artificial lift options include:

- Revenue from incremental increased gas production;
- Revenue from avoided emissions;
- Additional avoided costs such as well treatment and workover costs, and reduced fuel and electricity;
- Salvage value.

Revenue from Increased Production

The most significant benefit of deploying foaming agents, velocity tubing or a pumping unit is to extend the productive life of the well by decreasing the abandonment pressure of the reservoir and increasing the cumulative gas production. The benefit of automating a plunger lift system is to optimize the plunger cycle. Most of the increase in gas production is realized by the initial decision to install plunger lifts. Installing a 'smart' automated control system provides some incremental increase in gas production over a plunger lift system operated manually or by a timer, but the most significant benefit is the emissions avoided from repeated well blowdowns and the reduction in personnel time required at the well.

The fluid removal options are evaluated based on the incremental gas production predicted by well blowdowns. For wells that are not on production decline, the incremental gas production from installing velocity tubing or artificial lift can be estimated by assuming the average peak production after a well blowdown event represents the incremental peak production that will be achieved after the fluid removal option is implemented in the well.

The more common evaluation is for a well already experiencing production decline. In such a case, estimating incremental gas production from implementing a fluid removal/ artificial lift method is more complex and requires generating a new "expected" production and decline curve that would result from reducing the back pressure at the well perforations. This requires well-specific reservoir engineering analyses, a basic example of which is provided in Appendix B.

Once the incremental gas production from implementing a fluid removal approach is estimated, operators can

Exhibit 8: Gas Production Increase from Application of Foaming Agents — One Partner's Experience

- One Gas STAR Partner reports injecting foaming agent into 15 wells using soap sticks.
- Incremental gas production of individual wells increased an average of 513 Mcf per well per year.
- Annual incremental gas production for the entire project was 7,700 Mcf.
- Total cost for the project was $8,871 in 2010 dollars.
- At nominal gas prices ranging from $3.00/ Mcf to $5.00/ Mcf, the value incremental gas production ranges from approximately $23,100 to $38,500/ year and project payback occurs in 3 to 5 months.

NMED Exhibit 73 - 0009

calculate the value of the incremental gas and estimate the economics of the application. Exhibit 8 is an example of the potential revenue from increased gas production using foaming agents. Note that Exhibit 8 does not include other benefits such as avoided blowdown emissions and operations cost savings.

Revenue from Avoided Emissions

Emissions from venting gas to the atmosphere vary in both frequency and flow rates, and are entirely well and reservoir specific. The volume of natural gas emissions avoided by reducing or eliminating well blow-downs will vary due to individual characteristics such as sales line pressure, well shut-in pressure, fluid accumulation rate, and well dimensions (such as depth and casing and tubing diameters). Another key variable is an operator's normal practice for venting wells. Some operators put wells on automatic vent timers. Some wells are vented manually with personnel standing by monitoring the blow-down. In some cases, wells are open to vent and unattended for hours or days, depending upon the time it typically takes the well to clear liquids. The economic benefits of avoided emissions will vary considerably, and some projects will have significantly shorter payback periods than others.

Partner-reported annual emissions attributable to well blowdowns vary from 1 Mcf per well to several thousand Mcf per well, so methane emissions savings attributable to avoided emissions will also vary according to the characteristics and available data for the particular wells being vented. Exhibit 9 illustrates the range of avoided emissions reported by various Partners after applying specific fluid removal and artificial lift strategies in their operations.

Revenue from avoided emissions can be calculated by multiplying the sales price of the gas by the volume of vented gas. If well emissions have not been measured, they can be estimated. The volume of emissions from well venting can be estimated by constructing an IPR curve to predict the open flow potential of the well based on reservoir pressure, depth, tubular sizes, and fluid constituents. Other operator methods are discussed in Appendix C. The volume of gas released during well blow-down is dependent on the duration of the event, wellhead temperature and pressure, size of the vent line, the properties of the gas, and the quantity of water produced.

Four approaches to estimating well blow-down emissions are provided in Appendix C. None of the estimations discussed in Appendix C provide the "exact" result in an absolute sense, but they are accurate enough for effective management of producing gas wells. One emission estimation approach calculates well blow-down volume as a function of venting time, normal production rate, well volume and gas properties. Another approach uses

Exhibit 9: Comparison of Partner-Reported Costs and Emissions Savings for Fluid Removal / Artificial Lift Options

Fluid Removal Approach	Installation Costs ($/well)	Incremental Gas Production (Mcf/well/year)	Avoided Methane Emissions from Swabbing/ Blowdown[2] (Mcf/Well/Year)	Other Potential Cost Savings ($/well)
Use Foaming Agents	$500 - $9,880 *(installation of soap launcher);* $500/month *(surfactant)*	365 – 1,095	178 – 7,394	$2,000 *(eliminate well swabbing)*
Install Velocity Tubing	$7,000 - $64,000	9,125 – 18,250	146 – 7,394	$2,000 - $13,200 *(eliminate well swabbing & blowdown)*
"Smart" Well Automated Controls for Plunger Lift[1]	Partner reported average cost = $5,700 - $18,000	Not reported by Partners (*5,000 Mcf estimated for average U.S. gas well by assuming a 10-20% increase in production)*	Partner reported = 630 – 900 (500 Mcf estimated *for average U.S. well by assuming 1 % of annual production)*	$7,500 *(reduces labor cost to monitor plunger lift installations in the field)*
Install Rod Pumps and Pumping Units	$41,000 - $62,000	Not reported	769 – 1,612	$22,994 *(salvage value at end of well life)*

[1]Incremental cost, gas production and methane emissions savings for installation of automated plunger lift control system.
[2]Assumes methane content of natural gas at wellhead is 79 percent, unless reported otherwise.

NMED Exhibit 73 - 0010

pressure transient analysis to extrapolate gas flow rate from wellhead pressure. A final approach installs an orifice meter on a vent line and measures specific vent volume over time. The resulting vent rates expressed in Mcf/minute are averaged by producing formation and extrapolated from the initial subset of wells measured to the larger well population.

Avoided Costs and Other Benefits

Avoided costs and additional benefits depend on the type of fluid removal/ artificial lift system currently applied in the well and the new system to be deployed. These can include avoided chemical treatments, fewer well workovers, lower fuel costs and lower daily operations and maintenance costs. Partners report using foaming agents to replace well swabbing for a savings of approximately $2,000 annually per well. EPA's Natural Gas STAR Partners report that "smart" well automated control systems for plunger lifts have reduced the labor cost for field monitoring by approximately $7,500 per well. Velocity tubing eliminates well swabbing, well blowdowns and chemical treatments, the cost of which are reported to range from a few thousand to more than $13,000 per treatment.

Step 4. Evaluate the economics of fluid removal options.

Basic cash flow analysis can be used to compare the costs and benefits of the various fluid removal options. Exhibit 9 is a summary of the installation costs, gas savings and reduced methane losses associated with each fluid removal approach that have been reported by Natural Gas STAR Partners. Cash flow analyses based on Partner-reported experience and data are provided in Exhibit 10 for installing velocity tubing strings and in Exhibit 11 for "smart" well automated control systems for plunger lift.

Partner Experience

This section highlights specific experiences reported by Gas STAR Partners with the selected fluid removal options for gas wells.

Install Velocity Tubing Strings.

One Partner reported installation of velocity tubing in two Gulf Coast wells during 2008. Total installation cost in 2008 was $25,000 per well, which included a workover rig to remove and replace tubing, downhole tools, connections and supervision. Due to low inflation between years 2008 and 2010, the installation cost in 2010 dollars is only slightly higher than 2008.

The velocity tubing installation in these wells improved gas production by 25 Mcfd to 50 Mcfd, which equates to annual incremental gas production of approximately 9,125 Mcf to 18,250 Mcf per well. In addition, gas savings from eliminating well swabbing is 160 Mcf per year per well. Methane content of gas at the well head is 91 percent, so the estimated reduction in methane losses are 146 Mcf per well. Velocity tubing also eliminated annual swabbing costs of approximately $2000 per well per year. Exhibit 10

Exhibit 10: Economic Analysis of Velocity Tubing Installation Replacing Periodic Swabbing

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production[1]		$36,500	$36,500	$36,500	$36,500	$36,500
Value of Gas from Avoided Emissions[2]		$640	$640	$640	$640	$640
Velocity Tubing Installation Cost	($25,000)					
Avoided Swabbing Cost		$2,000	$2,000	$2,000	$2,000	$2,000
Net Annual Cash Flow	**($25,000)**	**$39,140**	**$39,140**	**$39,140**	**$39,140**	**$39,140**

Internal Rate of Return = 155%
NPV (Net Present Value)[3] = $112,156
Payback Period = 8 months

[1] Gas valued at $4.00/ Mcf for 9,125 Mcf/well (25 Mcfd) due to increased gas production
[2] Gas valued at $4.00/Mcf for 160 Mcf /well of avoided gas emissions due to elimination of well swabbing
[3] Net present value based on 10 percent discount rate over 5 years

NMED Exhibit 73 - 0011

provides a cash flow analysis of this Partner's velocity tubing installation replacing well swabbing.

Install "Smart" Automated Control Systems on Plunger Lifts

Two Partners have applied "smart" well automated control systems at plunger lift installations. One Partner—BP—initiated an automation project in 2000, and in 2001 began installing automated plunger lift control systems across their San Juan Basin operations. BP justified the project based on gas and methane emissions savings resulting from a 50 percent reduction in well venting between 2000 and 2004. By 2007, BP implemented automated control systems for more than 2,150 wells equipped with plunger lift which resulted in average methane emissions savings of 900 Mcf per well. Total cost for the "smart" automation systems was $12.2 million. Total gas venting was reduced from approximately 4 billion cubic feet of gas per year (Bcf) to approximately 0.8 Bcf.

Another Natural Gas STAR Partner found that a substantially smaller application of "smart" automated controls for plunger lift can be similarly effective. An automated control system was implemented for 21 wells equipped with plunger lifts. Total gas savings are 16,800 Mcf per year, or 800 Mcf per well. Assuming a methane content of 79 percent, estimated annual methane emissions savings are 632 Mcf per well.

The wide range in upfront capital and installation costs for components of plunger lift automated control systems are indicated in Exhibit 9. The host computer and communication system can be quite costly ($50,000 to $750,000) depending upon the size of the project, but as more plunger lift-equipped wells are added, the unit cost for the automated control system is significantly reduced. The two Natural Gas STAR Partners report approximate unit costs for plunger lift automated control systems of $6,800 and $5,950 per well, respectively. Exhibit 11 provides a basic cash flow analysis of "smart" well automated control systems for plunger lift based on

Exhibit 11: Economic Analysis of "Smart" Well Automated Control Systems for Plunger Lift for Hypothetical Onshore Gas Field[1]

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production[2]		$220,000	$220,000	$220,000	$220,000	$220,000
Value of Gas from Avoided Emissions[3]		$40,000	$40,000	$40,000	$40,000	$40,000
Install RTUs at Wells, $ ($11,000/well x 20 wells)	($220,000)					
Install Host Computer/ Communication ($50K - - $750K)	($200,000)					
Avoided Labor Cost for Field Monitoring ($7500/well x 20 wells)		$150,000	$150,000	$150,000	$150,000	$150,000
Net Cash Inflow	**($420,000)**	**$410,000**	**$410,000**	**$410,000**	**$410,000**	**$410,000**

Internal Rate of Return = 94%
NPV (Net Present Value)[4] = $1,031,111
Payback Period = 12.3months

[1] Assumes production from average US gas well is 50,000 Mcf/Year
[2] Gas valued at $4.00/Mcf for 5,000 Mcf /well of increased gas production due to optimized plunger lift operation; equivalent to 10% of production for average US onshore gas well. Assumes 20 wells in project.
[3] Gas valued at $4.00/Mcf for 500 Mcf of gas savings due to reduced well blowdown/venting; equivalent to 1% of production for average US onshore gas well. Assumes 20 wells in project.
[4] Net present value based on 10 percent discount rate over 5 years

NMED Exhibit 73 - 0012

generic assumptions about potential increased gas production and methane emissions savings for the average onshore natural gas well in the United States.

Install Pumping Units on Wells Lifting Low Water Volumes

ConocoPhillips installed pumping units on 45 low-pressure gas wells in 2003 to remove low water volumes from the wells and prevent them from loading up. This installation eliminated routine venting of the wells for up to one hour per day. The primary benefit of installing pumping units on these wells is the incremental gas production gained by extending the productive life of the wells. The Partner reported gas savings of 973 Mcf per well from the elimination of well blowdowns as a secondary, but not insignificant, benefit. The pump jacks at this installation are powered by electric motors rather than natural gas engines, which contributes to fewer methane emissions and lower maintenance costs.

ConocoPhillips reported total gas savings of 43,780 Mcf for the project or approximately 973 Mcf per well per year. At a nominal gas price of $4.00 to $5.00/Mcf, this corresponds to savings of approximately $3,892 to $4,865 per unit, or $175,140 to $218,900 per year for the entire project consisting of 45 wells. Assuming a methane content of 79 percent, this project has reduced methane losses by 34,586 Mcf per year.

Total capital and installation costs for the downhole pumps and surface pumping units were estimated to be $62,000 per well in 2003 or the equivalent of $73,332 in 2010 dollars. The total cost in 2003 included $45,000 for site preparation, downhole equipment, and installation plus an average cost of $17,000 per pumping unit. The project was expanded in subsequent years. ConocoPhillips reported a total of 100 pumping units installed from 2005 through 2007. During this time, the average reported upfront installation cost declined to approximately $38,000 per unit in 2010 dollars. Assuming a nominal gas price of $4, the vented gas savings alone pays back the typical pumping unit installation for this project in less than 10 years.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Lessons Learned

- ★ For natural gas wells, a progression of fluid removal options are available to unload accumulated fluid, boost gas production, extend well life and reduce or eliminate the need for well venting.
- ★ Options for removing accumulated wellbore fluids from gas wells range from relatively low cost application of surfactants, appropriate for wells with low fluid production and significant remaining reservoir energy, to installing pumping units and downhole rod pumps on wells with depleted reservoir pressure and significant water production.
- ★ The best approach will depend on the where a well is performing along the continuum of its productive life.
- ★ Well blowdown and swabbing can release large volumes of natural gas to the atmosphere, producing significant methane emissions and gas losses.
- ★ Fluid removal approaches presented in this paper can reduce the amount of remedial work needed during the lifetime of a well, eliminate well blowdowns, and increase the ultimate recovery of the well while minimizing methane emissions to the atmosphere.
- ★ If a well is in production decline, the fluid removal alternatives discussed here will increase gas production in most cases or at least arrest the decline.
- ★ This increased gas production should be captured in analyses of cash flow and future economic benefit when evaluating fluid removal options for gas wells. In most cases, increased gas production is the primary benefit from implementing any or all of the fluid removal options.

NMED Exhibit 73 - 0013

★ Methane emissions and gas savings from the elimination of well venting is generally a secondary, but significant, benefit, which may cover all or most of the upfront installation costs for a fluid removal technology.

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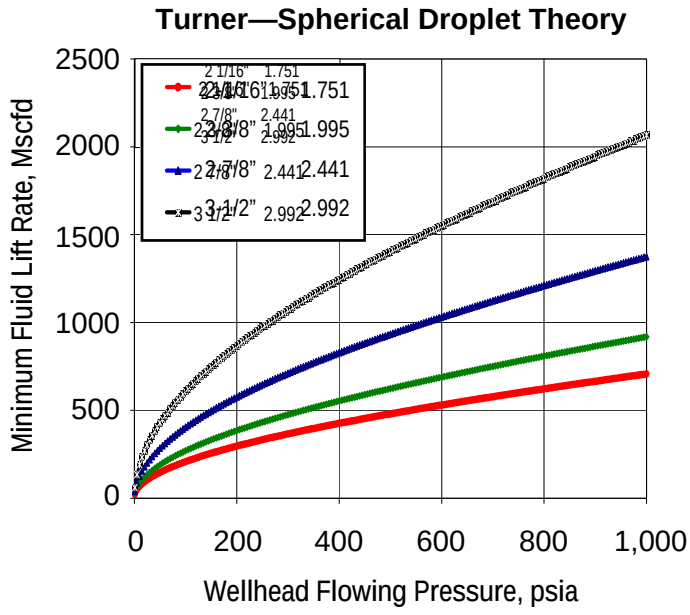
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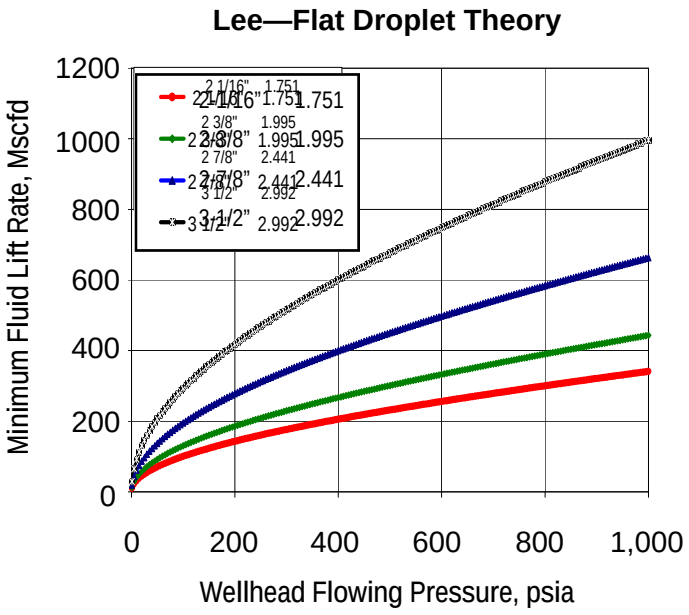
APPENDIX A: Estimating the Critical Flow Rate to Remove Liquids from Production Tubing

Exhibit A1: Turner Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

Exhibit A2: Lee Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

APPENDIX B: Estimating Incremental Production for Declining Wells

From Dake's Fundamentals of Reservoir Engineering (1978) the following analytical model can be used to estimate increased gas flow into a well in response to reducing back pressure on the perforations by removing accumulated liquids. The semi-steady state inflow equation is:

$$m(p_{avg})-m(p_{wf})=[(1422 \times Q \times T)/(k \times h)] \times [\ln(r_e/r_w)-3/4+S)] \times (8.15)$$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

Incremental production achieved by implementing various artificial lift options can be estimated by solving this equation for `Q' calculated for retarded flow with fluids in the hole (current conditions and current decline curve), and comparing to `Q' calculated for the condition of no fluids in the hole (artificial lift active and improved decline curve). This discussion is intended as a guide for estimating the potential impact of fluid removal alternatives, and is not a substitute for thorough reservoir engineering analyses of specific wells.

APPENDIX C: Alternate Techniques for Estimating Avoided Emissions When Replacing Blowdowns

Simple Vent Volume Calculation

A conservative estimate of well venting volumes can be made using the following equation:

Annual Vent Volume, Mscf/yr = (0.37×10^{-6})*(Casing Diameter^2)*(Well Depth)*(Shut-in Pressure)*# of Annual Vents)

Where, casing diameter is in inches, well depth is in feet and shut-in pressure is in psia. If the shut-in pressure is not known, a suitable surrogate is the casing pressure at the surface.

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure.

If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to sales line pressure.

Partners can estimate the minimum time needed to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If a Partner's practice is to open and vent the wells for a longer time than calculated by these methods, the Annual Vent Volume calculated by this equation can be scaled up according to the ratio of the actual vent time versus the minimum vent time calculated using the Weymouth equation.

Natural Gas STAR Partner, BP, has reported three approaches to estimating well venting and completion emissions, which include: 1) a more detailed version of the vent volume calculation method above, 2) pressure transient analysis, and 3) installing an orifice meter on the vent line.

Detailed Vent Volume Calculation

The detailed vent volume calculation is a function of venting time, normal production rate, and "well blowdown value" that represents the volume of gas in a well under an assumption of line pressure.

Vent Volume(Mcf) =
((Vent Time – 30 min)*(1/1440)* Production Rate) + (Well Blowdown Volume)

Well Blowdown Volume (Mcf) =
(well depth*3.1416*(casing diameter/2)^2) * ((tubing press + atmospheric press)/14.7) * (520/(Temp+460))/ Z/ 1000

Variables:

- production rate, Mcf per day
- well depth, ft
- atmospheric pressure, psia
- shut-in tubing pressure, psig
- temperature of gas in pipeline, ^{o}F
- diameter of production casing, ft
- compressibility, Z

A limitation of the vent volume calculation method is that it does not account for either the volume or weight of a column of fluid in the wellbore at the time of venting.

Pressure Transient Analysis

This method is based on observations of wellhead pressure versus flow rate for a specific set of wells which are used to develop a linear expression of gas flow rate versus wellhead pressure. This relationship is then applied to pressure transient data during blowdown to extrapolate Mcf versus time for the venting period. All data are evaluated using pressure data analysis software to extrapolate total vented volumes based on the blowdown time, pipe diameter and the decline in well head pressure during the process. An advantage of this approach is that it accounts for choke flow and is tailored to specific wells. Limitations of the approach are that it fails to account for very large influx into the reservoir and the observations data set may not be representative of the formation. To make the data set more representative, it is recommended that the data include at least one point within the following 5 ranges:

- ★ $P \leq 25$ psia
- ★ 25 psia $< P \leq 60$ psia

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- ★ 60 psia < P ≤ 110 psia
- ★ 110 psia < P ≤ 200 psia
- ★ 200 psia < P

Orifice Metering of Blow Down

For this approach, an orifice meter is installed on a vent line and flow rates are measured directly during blowdown. An advantage of this approach is the precision of the data that are obtained, potentially offering meaningful comparisons of vent volumes between well types, well completions or producing formations.

A limitation of the approach is that results obtained from a 'study population' or small subset of producing wells will likely be extrapolated to a larger field or producing area, and the original study wells may not be representative of field operations as a whole.

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1200 Pennsylvania Ave., NW
Washington, DC 20460

2011

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

Installing Plunger Lift Systems In Gas Wells



Executive Summary

In mature gas wells, the accumulation of fluids in the well can impede and sometimes halt gas production. Gas flow is maintained by removing accumulated fluids through the use of a beam pump or remedial treatments, such as swabbing, soaping, or venting the well to atmospheric pressure (referred to as "blowing down" the well). Fluid removal operations, particularly well blowdowns, may result in substantial methane emissions to the atmosphere.

Installing a plunger lift system is a cost-effective alternative for removing liquids. Plunger lift systems have the additional benefit of increasing production, as well as significantly reducing methane emissions associated with blowdown operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Natural Gas STAR Partners report significant economic benefits and methane emission reductions from installing plunger lift systems in gas wells. Companies have reported annual gas savings averaging 600 thousand cubic feet (Mcf) per well by avoiding blowdowns. In addition, increased gas production following plunger lift installation has yielded total gas benefits of up to 18,250 Mcf per well, worth an estimated $127,750. Benefits from both increased gas production and emissions savings are well- and reservoir-specific and will vary considerably.

Technology Background

Liquid loading of the wellbore is often a serious problem in aging production wells. Operators commonly use beam lift pumps or remedial techniques, such as venting or "blowing down" the well to atmospheric pressure, to remove liquid buildup and restore well productivity. These techniques, however, result in gas losses. In the case of blowing down a well, the process must be repeated over time as fluids reaccumulate, resulting in additional methane emissions.

Plunger lift systems are a cost-effective alternative to both beam lifts and well blowdowns and can significantly reduce gas losses, eliminate or reduce the frequency of future well treatments, and improve well productivity. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface. The plunger serves as a piston between the liquid and the gas, which minimizes liquid fallback, and as a scale and paraffin scraper. Exhibit 1 depicts a typical plunger lift system.

The operation of a plunger lift system relies on the natural buildup of pressure in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must be sufficiently higher than the sales-line pressure to lift the plunger and liquid load to the surface. A valve mechanism, controlled by a microprocessor, regulates gas input to the casing and automates the process. The controller is normally powered by a solar recharged battery and can be a simple timer-cycle or have solid state

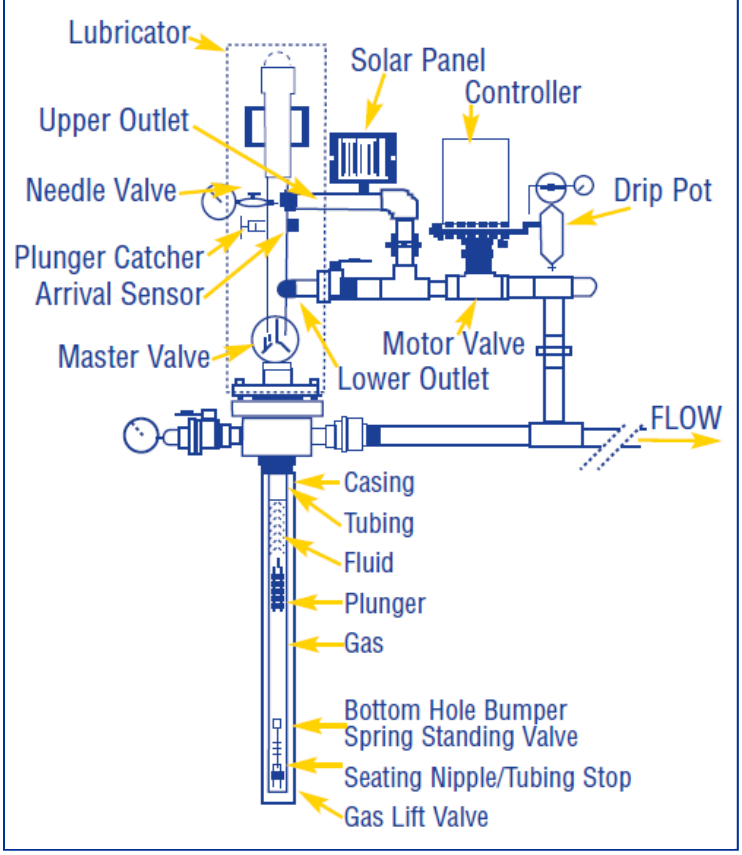
Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Potential Gas Savings from Increased Gas Production and Avoided Emissions (Mcf)	Value of Natural Gas Production and Savings ($)			Implementation Cost ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Install a Plunger Lift System	4,700 - 18,250[a] per year per well	$14,100 - $54,750 per year	$23,500 - $91,250 per year	$32,900 - $127,750 per year	$2,591 - $10,363 per year per well	1 - 9	1 - 6	1 - 4

General Assumptions:
[a] Based on results reported by Natural Gas STAR Partners.

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Exhibit 1: Plunger Lifts



memory and programmable functions based on process sensors.

Operation of a typical plunger lift system involves the following steps:

1. The plunger rests on the bottom hole bumper spring located at the base of the well. As gas is produced to the sales line, liquids accumulate in the well-bore, creating a gradual increase in backpressure that slows gas production.

2. To reverse the decline in gas production, the well is shut-in at the surface by an automatic controller. This causes well pressure to increase as a large volume of high pressure gas accumulates in the annulus between the casing and tubing. Once a sufficient volume of gas and pressure is obtained, the plunger and liquid load are pushed to the surface.

3. As the plunger is lifted to the surface, gas and accumulated liquids above the plunger flow through the upper and lower outlets.

4. The plunger arrives and is captured in the lubricator, situated across the upper lubricator outlet.

5. The gas that has lifted the plunger flows through the lower outlet to the sales line.

6. Once gas flow is stabilized, the automatic controller releases the plunger, dropping it back down the tubing.

7. The cycle repeats.

New information technology systems have streamlined plunger lift monitoring and control. For example, technologies such as smart automation, online data management and satellite communications allow operators to control plunger lift systems remotely, without regular field visits. Operators visit only the wells that need attention, which increases efficiency and reduces cost. For more information regarding this technology and other artificial lift systems, see the Lessons Learned document titled "Options for Removing Accumulated Fluid and Improving Flow in Gas Wells".

Economic and Environmental Benefits

The installation of a plunger lift system serves as a cost-effective alternative to beam lifts and well blowdown and yields significant economic and environmental benefits. The extent and nature of these benefits depend on the liquid removal system that the plunger lift is replacing.

- ★ **Lower capital cost versus installing beam lift equipment.** The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain beam lift equipment.

- ★ **Lower well maintenance and fewer remedial treatments.** Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blowdowns are reduced or no longer needed with plunger lift systems.

- ★ **Continuous production improves gas production rates and increases efficiency.** Plunger lift systems can conserve the well's lifting energy and increase gas production. Regular fluid

removal allows the well to produce gas continuously and prevent fluid loading that periodically halts gas production or "kills" the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

★ **Reduced paraffin and scale buildup.** In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with "wobble-washers" to improve their "scraping" performance.

★ **Lower methane emissions.** Eliminating repetitive remedial treatments and well workovers also reduces methane emissions. Natural Gas STAR Partners have reported annual gas savings averaging 600 Mcf per well by avoiding blowdown and an average of 30 Mcf per year by eliminating workovers.

★ **Other economic benefits.** In calculating the economic benefits of plunger lifts, the savings from avoided emissions are only one of many factors to consider in the analysis. Additional savings may result from the salvage value of surplus production equipment and the associated reduction in electricity and work over costs. Moreover, wells that move water continuously out of the well bore have the potential to produce more condensate and oil.

Decision Process

Operators should evaluate plunger lifts as an alternative to well blowdown and beam lift equipment. The decision to install a plunger lift system must be made on a case-by-case basis. Partners can use the following decision process as a guide to evaluate the applicability and cost-effectiveness of plunger lift systems for their gas production wells.

Step 1: Determine the technical feasibility of a plunger lift installation.

Plunger lifts are applicable in gas wells that experience liquid loading and have sufficient gas volume and excess shut-in pressure to lift the liquids from the reservoir to the surface. Exhibit 2 lists four common well characteristics that are good indicators of plunger lift applicability. Vendors often will supply written materials designed to help operators ascertain whether a particular well would benefit from the installation of a plunger lift system. As an example, a well that is 3,000 feet deep, producing to a sales line at 100 psig, has a shut-in pressure of 150 psig and must be vented to the atmosphere daily to expel and average of three barrels per day of water accumulation. This well has sufficient excess shut-in pressure and would have to produce 3,600 scf per day (400 scf/bbl/1000 feet of depth times 3000 feet of depth, times 3 barrels of water per day) to justify use of a plunger lift.

Four Steps for Evaluating Plunger Lift Systems:
1. Determine the technical feasibility of a plunger lift installation;
2. Determine the cost of a plunger lift system;
3. Estimate the savings of a plunger lift; and
4. Evaluate the plunger lift's economics.

Exhibit 2: Common Requirements for Plunger Lift Applications

★ Well blowdowns and other fluid removal techniques are necessary to maintain production.

★ Wells must produce at least 400 scf of gas per barrel of fluid per 1,000 feet of depth.

★ Wells with shut-in wellhead pressure that is 1.5 times the sales line pressure.

★ Wells with scale or paraffin buildup.

Step 2: Determine the cost of a plunger lift system.

Costs associated with plunger lifts include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the system. These costs include:

★ **Capital, installation, and start-up costs.** The basic plunger lift installation costs approximately $1,900 to $7,800. In contrast, installation of surface pumping equipment, such as a beam lift, costs between $26,000 and $52,000. Plunger lift installation costs include installing the piping, valves, controller and power supply on the wellhead and setting the down-hole plunger bumper assembly assuming the well tubing is open and clear. The largest variable in the installation cost is running a wire-line to gauge the tubing (check for internal blockages) and test run a plunger from top to bottom (broaching) to assure that the plunger will move freely up and down the tubing string. Other start-up costs can include a well depth survey, swabbing to

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Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

remove well bore fluids, acidizing to remove mineral scale and clean out perforations, fishing-out debris in the well, and other miscellaneous well clean out operations. These additional start-up costs can range from $700 to more than $2,600.

Operators considering a plunger lift installation should note that the system requires continuous tubing string with a constant internal diameter in good condition. The replacement of the tubing string, if required, can add several thousands of dollars more to the cost of installation, depending upon the depth of the well.

★ **Operating costs.** Plunger lift maintenance requires routine inspection of the lubricator and plunger. Typically, these items need to be replaced every 6 to 12 months, at an approximate cost of $700 to $1,300 per year. Other system components are inspected annually.

Step 3: Estimate the savings of a plunger lift.

The savings associated with a plunger lift include:

★ Revenue from increased production;

★ Revenue from avoided emissions;

★ Additional avoided costs—well treatment costs, reduced electricity costs, workover costs; and

★ Salvage value.

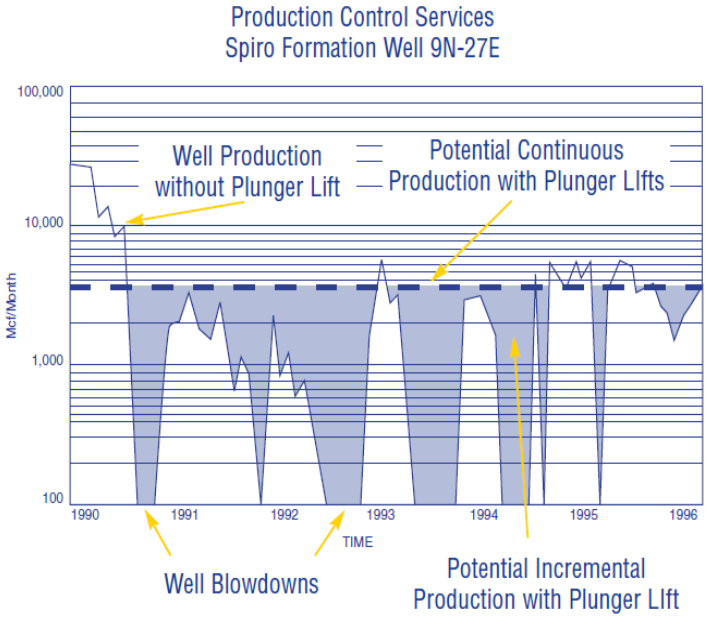
Revenue from Increased Production

The most significant benefit of plunger lift installations is the resulting increase in gas production. During the decision process, the increase in production cannot be measured directly and must be estimated. The methodology for estimating this expected incremental production varies depending on the state of the well. The methodology for continuous or non-declining wells is relatively straightforward. In contrast, the methodology for estimating the incremental production for wells in decline is more complex.

★ **Estimating incremental gas production for non-declining wells.** The incremental gas production from a plunger lift installation may be estimated by assuming that the average peak production rate achieved after blowdown is near the potential peak production rate for the well with fluid removed. A well log, like that illustrated in Exhibit 3, can be used to estimate the potential production increase.

In this exhibit, the solid line shows well production rate gradually, then steeply declining as liquids accumulate in the tubing. Production is restored by venting the well to the atmosphere, but then declines again with reaccumulation of liquids. Note that the production rate scale, in thousands of cubic feet per month, is a log scale. The dashed line shows the

Exhibit 3: Incremental Production for Non-Declining Wells



average peak production rate after liquids unloading. This is assumed to be equal to the potential peak production rate that could be achieved with a plunger lift system, typically at least 80 percent of the peak production rate after blowdown. The shaded area between the potential production (dashed-line) and the actual well production (solid-line) represents the estimate of incremental increase in gas production that can be achieved with a plunger lift system.

★ **Estimating incremental production for declining wells or for situations in which the maximum production level after blowdown is not known.** Wells that are in decline or operated without periodic blowdowns require more detailed methods for estimating incremental production under plunger lift systems. Plunger lift installations on declining wells, for example, will require generating an improved declining curve resulting from decreased pressure at perforations. Operators should seek the assistance of a reservoir engineer to aid in these determinations (see Appendix).

Once incremental production from a plunger lift installation is estimated, operators can calculate the value of incremental gas and estimate the economics of the plunger lift installation. Exhibit 4 presents an example of potential financial returns at different levels of increase in gas production. It is important to recognize that local costs and conditions may vary. Note also that the example in Exhibit 4 does not take into account other financial benefits of a plunger lift installation project, such as avoided emissions and decreased electricity and chemical treatment costs, which are described later in this Lessons Learned. Consideration of these additional benefits may improve the already excellent financial returns of a plunger lift installation.

Exhibit 4: Example of Estimated Financial Returns for Various Levels of Incremental Gas Production from a Plunger Installation

Incremental Gas Production (Mcfd)	Payout Time (months)	Internal Rate of Return (%)
3	14	71
5	8	141
10	4	309
15	3	475
20	2	640
25	2	804
30	2	969

Assumptions:
Value of gas = $7.00/Mcf.
Plunger system cost of $7,772 including start-up cost.
Lease operating expense of $790/year.
Production decline of 6%/year.

Source: Production Control Services, Inc.

Revenue from Avoided Emissions

The amount of natural gas emissions reduced following plunger lift installation will vary greatly from well to well, based on the individual well and reservoir characteristics such as sales line pressure, well shut-in pressure, liquids accumulation rate, and well dimensions (depth, casing diameter, tubing diameter). The most important variable, however, is the normal operating practice of venting wells. Some operators put wells on automatic vent timers, while others manually vent the wells with the operator standing by monitoring the vent, and still others open the well vent and leave, returning in hours or up to days, depending on how long it typically takes the well to clear liquids. Thus, the economic benefits from avoided emissions will also vary considerably. Such wide variability means that some projects will have much shorter payback periods than others. While most plunger lift installations will be justified by increased gas production rates alone, methane emissions reductions can provide an additional revenue stream.

★ **Avoided emissions when replacing blowdowns.** In wells where plunger lift systems are installed, emissions from blowing down the well can be reduced. Blowdown emissions vary widely in both their frequency and flow rates and are entirely well and reservoir specific. Emissions attributable to blowdown activities have been reported from 1 Mcf per year to thousands of Mcf per year per well. Therefore, the savings attributable to avoided emissions will vary greatly based on the data for the particular well being rehauled.

Revenue from avoided emissions can be calculated by multiplying the market value of the gas by the volume of avoided emissions. If the emissions per well per blowdown have not been measured, they must be estimated. In the example below, the amount of gas that is vented from a low pressure gas well at each blowdown is estimated as 0.5625 times the sustained flow gas rate. This emission factor assumes that the integrated average flow over the blowdown period is 56.25 percent of full well flow. Using this assumption, Exhibit 5 demonstrates that

NMED Exhibit 74 - 0005

for an unloaded well producing 100 Mcf per day, the gas vented to the atmosphere can be estimated at 2 Mcf per hour of blowdown.

Exhibit 5: Example—Estimate Avoided Emissions from Blowdowns

Avoided Emissions per Hour of Blowdown[a]	= (0.56251 x Sustained Daily Flow Rate) / 24 hrs/day
Avoided Emissions[b]	= (0.5625 x 100 Mcfd) / 24 = 2 Mcf per hour of blowdown
Annual Value of Avoided Emissions[c]	= 2 Mcf x 12 x $7.00/Mcf = $168 per year

[a] Recommended methane emission factor reported in the joint GRI/EPA study, Methane Emissions From the Natural Gas Industry, Volume 7: Blow and Purge Activities (June 1995). The study estimated that at the beginning of a blowdown event, gas flow is restricted by fluids in the well to 25 percent of full flow. By the end of the blowdown event, gas flow is returned to 100 percent. The integrated average flow over the blowdown period is 56.25 percent of full well flow.
[b] Assuming a sustained daily production rate of 100 Mcfd.
[c] Assuming 1 blowdown per month lasting 1 hour.

This method is simple to use, but anecdotal evidence suggests that it produces estimates of methane emissions avoided that are unrealistically low. For an alternate method for estimating avoided emissions from blowdowns, see the Appendix.

Given the high degree of variability in emissions based on well and reservoir specific characteristics, measurement is the preferred method for determining avoided emissions. Field measurements can provide the data necessary to accurately determine the savings attributable to avoided emissions.

★ **Avoided emissions when replacing beam lifts.** In cases where plunger lifts replace beam lifts rather than blowdowns, emissions will be avoided due to reduced workovers for mechanical repairs, to remove debris and cleanout perforations, to remove mineral scale and paraffin deposits from the sucker rods. The average emissions associated with workovers have been reported as approximately 2 Mcf per workover; the frequency of workovers has been reported to range from 1 to 15 per year. Due to well-specific characteristics such as flow during workover, duration of workover, and frequency of workover, avoided emissions can vary greatly.

Avoided Costs and Additional Benefits

Avoided costs depend on the type of liquid removal systems currently in place, but can include avoided well treatment, reduced electricity costs, and reduced workover costs. Avoided well treatment costs are applicable when plunger lifts replace beam lifts or other remedial techniques such as blowdown, swabbing, or soaping. Reduced electricity costs, reduced workovers, and recovered salvage value are only applicable if plunger lifts replace beam lifts.

★ **Avoided well treatment costs.** Well treatment costs include chemical treatments, microbial cleanups, and removal of rods and scraping the borehole. Information from shallow 1,500-foot wells show well remediation costs including rod removal and tubing rehabilitation at more than $14,500 per well. Chemical treatment costs (inhibitors, solvents, dispersants, hot fluids, crystal modifiers, and surfactants) are reported in the literature at a minimum of $13,200 per well per year. Microbial costs to reduce paraffin have been shown to be $6,600 per well per year (note that microbial treatments do not address the fluids influx problem). Each of these treatment costs increases as the severity of the scale or paraffin increases, and as the depth of the well increases.

★ **Reduced electricity costs compared to beam lifts.** Reduced electric operating costs further increase the economic return of plunger lifts. No electrical costs are associated with plunger lifts, because most controllers are solar-powered with battery backup. Exhibit 6 presents a range of avoided electricity costs reported by operators who have installed plunger lifts. Assuming 365 days of operation, avoided electricity costs range from $1,000 to $7,300 per year.

★ **Reduced workover costs compared to beam lifts.** Workover costs associated with beam lifts have been reported as $1,300 per day. While typical

Exhibit 6: Electricity Costs[a] Avoided by Using a Plunger Lift in Place of a Beam Lift

Motor Size (BHP)	Operation Cost ($/day)
10	3
20	7
30	10
40	13
50	17
60	20

[a] Electricity cost assumes 50 percent of full load, running 50 percent of the time, with cost of 7.5 cents/kWh.

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workovers may take one day, wells more than 8,000 feet deep will require more than one day of workover time. Depending on the well, from 1 to 15 workovers can be required per year. These costs are avoided by using a plunger lift.

★ **Recovered salvage value when replacing a beam lift.** If the plunger being installed is replacing a beam lift, extra income and a better economic return are realized from the salvage value of the old production hardware. Exhibit 7 shows the salvage value that may be obtained by selling the surplus pumping units. In some cases, salvage sales alone may pay for the installation of plunger lifts.

Exhibit 7: Salvage Value[a] of Legacy Equipment When Converting from Beam Lift to Plunger Lift Operations

Capital Savings from Salvaging Equipment	
Size of Pumping Unit (inch-lbs torque)	**Equipment Salvage Value ($)**
114,000	12,300
160,000	16,800
228,000	21,300
320,000	27,200
456,000	34,300
640,000	41,500

[a] Salvage costs include low estimate sale value of pumping unit, electric motor, and rod string.

Step 4: Evaluate the plunger lift's economics.

A basic cash flow analysis can be used to compare the costs and benefits of a plunger lift with other liquid removal options. Exhibit 8 shows a summary of the costs associated with each option.

★ **Economics of Replacing a Beam Lift with a Plunger Lift.** In Exhibit 9 the data from Exhibit 8 is used to model a hypothetical 100 Mcfd well and to evaluate the economics of plunger lift installation. The increase in production is 20 Mcf per day, yielding an annual increase in production of 7,300 Mcf. Assuming one workover per year prior to installation, the switch to a plunger lift also provides 2 Mcf of avoided emissions per year. The project profits greatly from the salvage value of the surplus beam lift equipment, yielding an immediate payback. Even if the salvage value is not recovered, the project may yield payback after only a few months depending on the well's productivity.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

★ **Economics of Avoiding Blowdown with a Plunger Lift.** Exhibit 10 uses data from Exhibit 8 to evaluate the economics of a hypothetical 100 Mcfd well at which a plunger lift is installed to replace blowdown as the method for removing liquid from the well. Assuming the increased production is 20 Mcf per day, the annual increase in production is 7,300 Mcf. In addition, there will be savings from avoided emissions during blowdown. Assuming 12 one-hour blowdowns per year, the avoided emissions are 24 Mcf per year.

Exhibit 8: Cost Comparison of Plunger Lift vs. Other Options

Cost Category	Plunger Lift	Traditional Beam Lift	Remedial Treatment[a]
Capital and Startup Costs	$1,943 - $7,772	$25,907 - $51,813	$0
Implementation Costs:			
Maintenance[b]	$1,300/yr	$1,300 - $19,500/yr	$0
Well Treatment[c]	$0	$13,200+	$13,200+
Electrical[d]	$0	$1,000 - $7,300/yr	$0
Salvage	$0	($12,000 - $41,500)	$0

[a] Includes soaping, swabbing, and blowing down.
[b] For traditional beam lift, maintenance costs include workovers and assume 1 to 15 workovers per year at $1,300 per workover.
[c] Costs may vary depending on the nature of the liquid.
[d] Electricity costs for plunger lift: assume the lift is solar and well powered.

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Exhibit 9: Economic Analysis of Plunger Lift Replacing a Beam Lift

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions[a]		$51,114	$51,114	$51,114	$51,114	$51,114
Plunger Lift Equipment and Setup Cost	($7,772)					
Plunger Lift Maintenance		($1,300)	($1,300)	($1,300)	($1,300)	($1,300)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Salvage Value Beam Lift Equipment	$21,300					
Avoided Beam Lift Maintenance (1 workover/yr)		$1,300	$1,300	$1,300	$1,300	$1,300
Avoided Beam Lift Electricity Costs (10HP motor)		$1,000	$1,000	$1,000	$1,000	$1,000
Avoided Chemical Treatments		$13,200	$13,200	$13,200	$13,200	$13,200
Net Cash Inflow	$13,528	$65,314	$65,314	$65,314	$65,314	$65,314

NPV (Net Present Value)[b] = $261,119

Payback Period = Immediate

[a] Gas valued at $7.00 per Mcf for 7,300 Mcf due to increased production and 2 Mcf from avoided emissions per event (based on 1 workover per year).
[b] Net present value based on 10 percent discount rate over 5 years.

Exhibit 10: Economic Analysis of Plunger Lift Replacing Blowdown

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production and Avoided Emissions[a]		$51,268	$51,268	$51,268	$51,268	$51,268
Plunger Lift Equipment and Setup Cost	$(7,772)					
Plunger Lift Maintenance		($1,300)	($1,300)	($1,300)	($1,300)	($1,300)
Electric Cost per Year	$0	$0	$0	$0	$0	$0
Avoided Chemical Treatments		$13,200	$13,200	$13,200	$13,200	$13,200
Net Cash Inflow	($7,772)	$63,168	$63,168	$63,168	$63,168	$63,168

NPV (Net Present Value)[b] = $231,684

Payback Period = 2 months

[a] Gas valued at $7.00 per Mcf for 7,300 Mcf due to increased production and 24 Mcf from avoided emissions per event (based on 12 blowdowns per year and 2 Mcf per blowdown).
[b] Net present value based on 10 percent discount rate over 5 years.

When assessing options for installing plunger lift systems on gas wells, natural gas price may influence the decision making process. Exhibit 11 shows an economic analysis of installing a plunger lift system rather than blowing down a well to the atmosphere to lift accumulated fluid at different natural gas prices.

Exhibit 11: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$21,972	$36,620	$51,268	$58,592	$73,240
Payback Period (months)	3	2	2	2	2
Internal Rate of Return (IRR)	436%	624%	813%	907%	1095%
Net Present Value (*i*=10%)	$120,630	$176,157	$231,684	$259,448	$314,976

Case Studies

BP (formerly Amoco) Midland Farm Field

Amoco Corporation, a Natural Gas STAR charter Partner (now merged with BP), documented its success in replacing beam lift, rod pump well production equipment with plunger lifts at its Midland Farm field. Prior to installing plunger lift systems, Amoco used beam lift installations with fiberglass rod strings. The lift equipment was primarily 640 inch-lb pumping units powered by 60 HP motors. Operations personnel noted that wells at the field were having problems with paraffin plating the well bore and sucker rods, which blocked fluid flow and interfered with fiberglass sucker rod movement. Plunger lifts were seen as a possible solution to inhibit the accumulation of paraffin downhole.

Amoco began its plunger lift replacement program with a single-well pilot project. Based on the success of this initial effort, Amoco then expanded the replacement process to the entire field. As a result of the success in the Midland Farm field, Amoco installed 190 plunger lift units at its Denver City and Sundown, Texas locations, replacing other beam lift applications.

Costs and Benefits

Amoco estimated that plunger lift system installation costs -including plunger equipment and tubing conversion costs- averaged $13,000 per well (initial pilot costs were higher than average during the learning phase, and the cost of tubing conversion is included).

Amoco then calculated savings resulting from avoided costs in three areas—electricity, workover, and chemical treatment. Overall, Amoco estimated that the avoided costs of electricity, workover, and paraffin control averaged $24,000 per well per year.

- **Electricity.** Cost savings were estimated based on 50 percent run times. Using the costs from Exhibit 6, the estimated electrical cost savings were estimated to be $20 per day.
- **Workover.** On average, Amoco had one workover per year per well to fix rod parts. With the old beam lift systems, the cost of this operation was $4,000, averaging about $11 per day.
- **Chemical treatment.** The biggest savings were realized from avoided chemical treatment. Amoco was able to save the approximately $13,000 per well per year for paraffin control because the plunger operation removed paraffin accumulation in the tubing.

Increased Gas Production and Revenue

For the initial plunger lift installation, Amoco realized an increase in gas production of more than 400 Mcf per day. Upon expansion of the plunger lift installation to the entire field, the company realized notable success in many wells—although some showed little or no production increase during the 30 day evaluation period. Total production increase (including both incremental production and non-emitted gas) across all wells where plunger lifts were installed was 1,348 Mcf per day. The average annual gas savings, which assumes a 6 percent production decline, was 11,274 Mcf per well or approximately $78,918 per well at 2006 prices. Exhibit 12 and Exhibit 13 summarize the initial results and first year economics of Amoco's Midland Farm plunger lift installation. In addition to the gas savings and cost savings from the plunger lift installations, Amoco realized a one-time gain from the sale of surplus pumping units

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Exhibit 12: Change in Production Rates due to Plunger Lift Installation in Midland Farm Field, Texas

[a]Well #	Production Before Plunger Lift			Production 30 Days After Installation		
	Gas (Mcfd)	Oil (Bpd)	Water (Bpd)	Gas (Mcfd)	Oil (Bpd)	Water (Bpd)
1	233	6	1	676	5	1
2	280	15	1	345	15	1
3	240	13	2	531	33	11
4	180	12	2	180	16	3
5	250	5	2	500	5	2
6	95	8	2	75	12	0
7	125	13	1	125	14	0
8	55	6	1	55	13	2
9	120	45	6	175	40	0
10	160	16	3	334	17	3
11	180	7	12	80	6	6
12	215	15	4	388	21	2
13	122	8	8	124	12	7
14	88	5	10	23	9	1
Avg.	167	12	4	258	16	3

[a] All wells approximately 11,400 feet deep.

Source: World Oil, November, 1995.

Exhibit 13: BP Economics of Plunger Lifts Replacing Beam Lifts

Average Annual Gas Savings[a] (Mcf/year)	Value of Gas Saved per Year[b]	Plunger Lift Installation Cost per Well	Avoided Rod Workover Cost per Well per Year	Avoided Chemical Treatment per Well per Year	Avoided Electrical Costs per Well per Day	Average Savings per Well[c]	Additional Salvage Value of Beam Lift per Well
11,274	$78,918	$13,000	$4,000	$13,000	$20	$90,200	$41,500

[a] Average initial gas production = 1,348 Mcfd. Assumes 6 percent annual production decline.
[b] Gas valued at $7.00 per Mcf.
[c] Value saved is averaged over 14 wells.

and motors, resulting in additional revenue of $41,500 per installation.

Analysis

A summary of the costs and benefits associated with Amoco's plunger lift installation program is provided below in Exhibit 13. For the first year of operation, the company realized an average annual savings of approximately $90,200 per well at 2006 prices. In addition the company realized approximately $41,500 per well from salvage of the beam lift equipment at 2006 costs.

ExxonMobil Big Piney Field

At Big Piney Field in Wyoming, Natural Gas STAR charter Partner Mobil Oil Corporation (now merged with Exxon) has installed plunger lift systems at 19 wells. The first two plunger lifts were installed in 1995, and the remaining wells were equipped in 1997. As a result of these installations, Mobil reduced overall blowdown gas emissions by 12,164 Mcf per year. In addition to the methane emission reduction, the plunger lift system reduced the venting of ethane (6 percent by volume), C3 hydrocarbons + VOCs (5 percent), and inerts (2 percent). Exhibit 14 shows the emission reductions for each well after plunger lift installation.

Installation Tips

The following suggestions can help ensure trouble-free installation of a plunger lift system:

- ★ **Do not use a completion packer, because it limits the amount of gas production per plunger trip.** Without a completion packer, the entire annular void space is available to create a large compressed gas supply. The greater the volume of gas, the larger the volume of water that can be lifted.

- ★ **Check for tubing obstructions with a gauge ring before installation.** Tubing obstructions hinder plunger movement and may require replacement of production tubing.

- ★ **Capture the plunger after the first trip.** Inspection of the plunger for the presence of any damage, sand, or scale will help prevent any subsequent plunger lift operational difficulties, permitting immediate operational repair while the crew and installation equipment are mobilized.

Lessons Learned

Plunger lift systems offer several advantages over other remedial treatments for removing reservoir fluids from wells: increased gas sales, increased well life, decreased well maintenance, and decreased methane emissions. The following should be considered when installing a plunger lift system:

- ★ Plunger lift installations can offer quick paybacks and high return on investments whether replacing a beam lift or blowdowns.

- ★ Plunger lift installations can greatly reduce the amount of remedial work needed throughout the

Exhibit 14: Plunger Lift Program at Big Piney, Wyoming

Well #	Pre-Plunger Emission Volume (Mcf/yr/well)	Post-Plunger Emission Volume (Mcf/yr/well)	Annualized Reduction (Mcf/yr/well)
1	1,456	0	1,456
2	581	0	581
3	1,959	318	1,641
4	924	0	924
5	105	24	81
6	263	95	168
7	713	80	633
8	753	0	753
9	333	0	333
10	765	217	548
11	1,442	129	1,313
12	1,175	991	184
13	694	215	479
14	1,416	1,259	157
15	1,132	708	424
16	1,940	561	1,379
17	731	461	270
18	246	0	246
19	594	0	594
Totals	**17,222**	**5,058**	**12,164**

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lifetime of the well and the amount of methane vented to the atmosphere.

- ★ An economic analysis of plunger lift installation should include the incremental boost in productivity as well as the associated extension in well life.
- ★ Even when the well pressure declines below that necessary to lift the plunger and liquids against sales line back pressure, a plunger is more efficient in removing liquids with the well vented to the atmosphere than simply blowing the well without a plunger lift.
- ★ Include methane emission reductions from installing plunger lift systems in annual reports submitted as part of the Natural Gas STAR Program.

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NMED Exhibit 74 - 0012

Appendix

Estimating incremental production for declining wells.

From Dake's *Fundamentals of Reservoir Engineering* (1982) we can use the following equation to calculate the increase in downhole flow for reduced pressure that may be seen when using a plunger lift. A semi-steady state inflow equation can be expressed as:

$m(p_{avg}) - m(p_{wf}) = [(1422 \times Q \times T)/(k \times h)] \times [\ln(r_e/r_w) - 3/4 + S)] \times (8.15)$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

After the reservoir parameters are gathered, this equation can be solved for Q for the retarded flow with fluids in the hole (current conditions and current decline curve), and Q for no fluids in the hole (plunger lift active and improved decline curve). This is a guideline, and operators are reminded to use a reservoir engineer to aid in this determination.

Alternate technique for calculating avoided emissions when replacing blowdowns.

A conservative estimate of well venting volumes can be made using the following equation:

Annual Vent Volume, Mscf/yr = $(0.37 \times 10^{-6}) \times$ (Casing Diameter)^2 × Well Depth × Shut-in Pressure × Annual Vents

Where casing diameter is in inches, well depth is in feet and shut-in pressure is in psig. Exhibit A1 shows an example calculation.

Exhibit A1: Example—Estimate Avoided Emissions from Blowdowns

Casing Diameter	8 inches
Well Depth	10,000 feet
Shut-in Pressure	214.7 psig
Annual Vents	52 (weekly venting)

Annual Vent Volume = $(0.37 \times 10^{-6}) \times 8^2 \times 10{,}000 \times 214.7 \times 52$ = 2,644 Mscf/yr

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure. If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation in Exhibit 2, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to zero psig. Partners can estimate the minimum time to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If the Partner's practice and experience is to vent the wells a longer time than calculated by these methods, the conservative Annual Vent Volume can be increased by a simple ratio of the actual vent times and the minimum vent time calculated using the Weymouth equation.

NMED Exhibit 74 - 0013

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

October 2006

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

NMED Exhibit 74 - 0014

MEMORANDUM

DATE: December 21, 2006

SUBJECT: Impacts of Applying Management Practices to a Single Oil and Natural Gas Production Area Source Facility

FROM: Heather P. Brown, P.E.

TO: Greg Nizich, EPA/OAQPS/SPPD/CCG

I. INTRODUCTION AND BACKGROUND

On July 8, 2005, (70 FR 39443), the United States Environmental Protection Agency (EPA) issued a supplemental proposal to the February 6, 1998 (63 FR 6288), proposed standards for oil and natural gas production area sources. In response to comments received on the two proposals, EPA is requiring certain triethylene glycol (TEG) dehydration units located at area source oil and natural gas production facilities to reduce emissions by implementing the management practice of optimizing the glycol circulation rate.

Most dehydration systems use TEG as an absorbent to remove water from natural gas. As the TEG absorbs water, it also absorbs methane and any other hazardous air pollutants (HAP) or volatile organic compounds (VOC) entrained in the methane. As the TEG is regenerated in the reboiler, any absorbed compounds (i.e., methane, HAP, and VOC) are vented to the atmosphere. The amount of methane absorbed and vented is directly proportional to the TEG circulation rate. According to the Natural Gas STAR Partners, many wells operate below their original design capacity but continue to circulate the TEG at rates two to three times higher than needed for a particular water removal rate.[a] Therefore, by reducing the glycol circulation rate, HAP emissions can be reduced.

In addition to reducing HAP emissions, reducing the glycol circulation rate also reduces the TEG circulation rate has the added benefit of reducing the amount of natural gas absorbed by the TEG and subsequently emitted through the reboiler vent thereby resulting in a natural gas savings. Furthermore, optimizing the TEG circulation rate can be achieved without sacrificing the performance of the TEG dehydration unit, does not require the presence of an on-site operator to maintain, can be optimized for minimal capital cost (e.g., a new pump may be required), and could result in an annual cost savings due to the reduction of the natural gas losses. The purpose of this memorandum is to estimate air emission and cost impacts associated with reducing the glycol circulation rate to an optimized level for a single TEG dehydration unit.

[a] Lessons Learned: From Natural Gas STAR Partners. "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators." http://www.epa.gov/gasstar/pdf/lessons/ll_flashtanks3.pdf

II. AIR EMISSIONS IMPACTS

In order to estimate the air emissions impact from reducing the TEG circulation rate to an optimum level, GRI-GLYCalc Version 4.0 (GLYCalc) was used to estimate baseline emissions and emissions from the optimized TEG circulation rate.

Table 1 presents baseline emissions estimated using the following inputs for GLYCalc:

- The glycol recirculation ratio was set at the industry average of 5.9 gallons of glycol per pound of water removed (gal TEG/lb H_2O).[b] This corresponds to a circulation rate of approximately 37 gallons of TEG per hour (gal TEG/hr).
- Because emissions are proportional to the natural gas throughput, the emission reduction is not impacted by the throughput level (i.e., TEG dehydration units with a natural gas throughputs of 3 MMSCF/D and 5 MMSCF/D have the same emission reduction of 45 percent). Therefore, the natural gas throughput was set at the applicability cutoff of 3 million standard cubic feet per day (MMSCF/D).
- According to Natural Gas STAR Partners, smaller and older units are not equipped with a flash tank. Therefore, no flash tank was used.[c]
- According to Natural Gas STAR Partners, remote gas fields do not have electrical power and instead use energy-exchange (or gas injection) pumps. Therefore, the pump type was set as a gas injection pump.[d]
- Other program inputs were chosen to be consistent with values used in previous impacts calculations.[e]

Attachment 1 contains the summary of input values and emissions data generated by the GLYCalc program for baseline emissions.

To calculate emissions at the optimal glycol circulation rate, a glycol recirculation ratio of 3 gal TEG/lb H_2O was used. This ratio is considered the rule-of-thumb for the industry[f] and corresponds to a TEG circulation rate of approximately 19 gal TEG/hr. The remaining inputs were the same as those used to estimate baseline emissions. Emissions at the optimal glycol circulation rate are also presented in Table 1 (a summary of input values and emissions data is presented in Attachment 2).

As shown in Table 1, optimizing the glycol circulation rate reduces HAP emission by approximately 45 percent. Likewise, VOC emissions were reduced by 48 percent and benzene emissions were reduced by 47 percent.

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[b] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage. Background Information Document for Proposed Standards. Page 3-4. EPA-453/R-94-079a.

[c] See footnote a.

[d] See footnote a.

[e] Memorandum from Brown, H.P., EC/R Incorporated to Nizich, G., United States Environmental Protection Agency. Revised Impacts for Area Sources in the Oil and Natural Gas Production Source Category. June 25, 2006.

[f] See footnote a.

NMED Exhibit 76 - 0002

Table 1. Emissions Impacts of Reducing TEG Circulation Rate for a Single TEG Dehydration Unit[1]

Pollutant	Emissions at Baseline Circulation Rate (tpy)[2]	Emissions at Optimized Circulation Rate (tpy)[3]	Emission Reduction (%)
HAP	6.1482	3.376	45
VOC	15.281	7.9982	48
Benzene	1.8076	0.9498	47

[1] Emissions for the baseline circulation rate and optimized circulation rate were generated using GLYCalc. Input summaries and emissions results are presented in Attachments 1 and 2, respectively.

[2] Baseline circulation rate = 37 gal/hr (corresponding to a baseline recirculation ratio of 5.9 gal TEG/lb H_2O).

[3] Optimized circulation rate = 19 gal/hr (corresponding to an optimal recirculation ratio of 3 gal TEG/lb H_2O).

NMED Exhibit 76 - 0003

III. COST IMPACTS

While some facilities may be able to adjust the circulation rate without replacing equipment, it was assumed that at a minimum, the glycol pump would have to be replaced. Therefore, cost impacts were generated to represent the costs related to pump replacement.

Equipment costs were developed based on information from Kimray, Inc., a pump vendor (See Attachment 3).[g] Table 2 presents the capital costs for installing a new pump to achieve the optimized TEG circulation rate. The total capital investment for installing a new pump was estimated to be $1,540. The annual costs were estimated to be $914 per year for a single unit and are presented in Table 3. For sources that do not have to purchase a new pump to meet the optimal circulation rate, the only costs associated with the implementing the optimal TEG circulation rate are related to operational costs. The annual cost of implementing the optimal circulation rate without replacing the pump was approximately $600 per year and is presented in Table 4.

[g] Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006. Available on the Internet at http://www.kimray.com/pricebook.html

NMED Exhibit 76 - 0004

Table 2. Capital Costs for Installation of a New Glycol Pump for an Existing TEG Dehydration Unit

Cost Item	Description	Size	Factor	July '06 Cost
DIRECT COSTS				
Purchased equipment cost				
Glycol Pump (EC)	Gas assisted pump	average	NOTE 1	$ 922
Instrumentation	(assume no instrumentation is necessary)			
Sales Taxes		7% of EC		$ 65
Freight		5% of EC	NOTE 2	$ 46
Purchased equipment cost, PEC				$ 1,033
Direct Installation Costs[a]				
Piping		2% of PEC	NOTE 2	$ 21
Direct Installation Cost				$ 21
Total Direct Cost, DC				$ 1,054
INDIRECT COSTS				
Engineering		10% of PEC	NOTE 2	$ 103
Construction and field expenses		5% of PEC	NOTE 2	$ 52
Startup		2% of PEC	NOTE 2	$ 21
Contingencies		3% of PEC	NOTE 2	$ 310
Total Indirect Cost, IC				$ 485
Total Capital Investment = DC + IC				$ 1,539

a - The only direct installation cost is for piping changes necessary to fit the new pump. No site preparation and building necessary

NOTE 1: New Pump Purchase Price = $ 922 (Pressure Volume Pump, capacity range 12-40 gal/hr, working pressure range 400-1500 psig)
Average of four pumps of this size, Model 4015V
(Reference: Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006 http://www.kimray.com/pricebook.html)

NOTE 2: OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

NMED Exhibit 76 - 0005

Table 3. Annual Costs for Installation of a New Glycol Pump on an Existing TEG Dehydration Unit

Cost Item	Suggested Factor	Cost	Factor	July '06 Cost
DIRECT ANNUAL COSTS, DC				
Operating Labor				
Operator	26 hr/yr	$25/hr	NOTE 1	$ 650.00
Supervisor	15% of operator		NOTE 2	$ 97.50
Maintenance				
Labor	8 hr/y	$25/hr	NOTE 3	$ 200.00
Materials	Average repair kit price	$ 63.06 (Ref 3)		$ 63.06
Natural Gas Consumption	3.9 scf/gal	7.51 $/mcf	NOTE 4	$ 4,787.63
Total DC				$ 5,798.19
INDIRECT ANNUAL COSTS, IC				
Overhead	60% of operating and labor costs		NOTE 2	$ 606.34
Administrative charges	2% of TCI		NOTE 2	$ 30.78
Property taxes	1% of TCI		NOTE 2	$ 15.39
Insurance	1% of TCI		NOTE 2	$ 15.39
Capital Recovery Factor	0.1627 of TCI		NOTE 2	$ 250.47
	10% interest, 10 yr equp life			
Total IC				$ 918.37
Gas Savings Credit for reducing the circulation rate			NOTE 5	$ (5,802.47)
Total Annual Cost				$ 914.10

NOTE 1: The resources needed 1/2 hr of labor at $25/hr, assumed to be on a weekly basis. (Reference: Lessons Learned: From Natural Gas STAR Partners. "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators." .http://www.epa.gov/gasstar/pdf/lessons/ll_flashtanks3.pdf)

NOTE 2: OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

NOTE 3: Assumed one day of maintenance per year because very little maintenance is needed. (Reference: Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006 http://www.kimray.com/pricebook.html)

NOTE 4: Wellhead price of natural gas published by the Energy Information Administration for 2005. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

NOTE 5: Value of gas saved = [Original TEG Circulation Rate - Optimal TEG Circulation Rate] * [TEG Absorption Rate + Energy-Exchange Pump gas] * Hours/yr * Gas Price/1000

Original TEG Circulation Rate = 36.66 gal/hr (@ industry average of 5.9 gal/lb H2O, see Attachment 1)

Optimal TEG Circulation Rate = 18.66 gal/hr (@ opbimized rate of 3 gal/lb H2O, see Attachment 2)

Value of gas saved = $ 5,802

NMED Exhibit 76 - 0006

Table 4. Annual Costs Associated with Operating TEG Dehydration Unit at Optimal Circulation Rate

Cost Item	Suggested Factor	Cost	Factor	July '06 Cost
DIRECT ANNUAL COSTS, DC				
Operating Labor				
Operator	26 hr/yr	$25/hr	NOTE 1	$ 650.00
Supervisor	15% of operator		NOTE 2	$ 97.50
Maintenance				
Labor	8 hr/y	$25/hr	NOTE 3	$ 200.00
Materials	Average repair kit price	$ 63.06 (Ref 3)		$ 63.06
Natural Gas Consumption	3.9 scf/gal	7.51 $/mcf	NOTE 4	$ 4,787.63
Total DC				$ 5,798.19
INDIRECT ANNUAL COSTS, IC				
Overhead	60% of operating and labor costs		NOTE 2	$ 606.34
Total IC				$ 606.34
Gas Savings Credit for reducing the circulation rate			NOTE 5	$ (5,802.47)
Total Annual Cost				$ 602.06

NOTE 1: The resources needed 1/2 hr of labor at $25/hr, assumed to be on a weekly basis. (Reference: Lessons Learned: From Natural Gas STAR Partners. "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators." .http://www.epa.gov/gasstar/pdf/lessons/ll_flashtanks3.pdf)

NOTE 2: OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

NOTE 3: Assumed one day of maintenance per year because very little maintenance is needed. (Reference: Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006 http://www.kimray.com/pricebook.html)

NOTE 4: Wellhead price of natural gas published by the Energy Information Administration for 2005. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

NOTE 5: Value of gas saved = [Original TEG Circulation Rate - Optimal TEG Circulation Rate] * [TEG Absorption Rate + Energy-Exchange Pump gas] * Hours/yr * Gas Price/1000

Original TEG Circulation Rate = 36.66 gal/hr (@ industry average of 5.9 gal/lb H2O, see Attachment 1)

Optimal TEG Circulation Rate = 18.66 gal/hr (@ opbimized rate of 3 gal/lb H2O, see Attachment 2)

Value of gas saved = $ 5,802

NMED Exhibit 76 - 0007

Attachment 1

GRI-GLYCalc, Version 4.0 Input Summary and Aggregate Emissions Summary for Baseline Glycol Circulation Rate (5 gal TEG/lb H_2O)

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: BMP Baseline
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 5_9 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 5.9
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 3.0 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Gas Injection
Gas Injection Pump Volume Ratio: 0.080 acfm gas/gpm glycol

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: BMP Baseline
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 5_9 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 5.9
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	6.5143	156.344	28.5328
Ethane	0.9196	22.070	4.0278
Propane	0.4047	9.713	1.7726
n-Butane	0.6887	16.528	3.0164
n-Pentane	0.8590	20.616	3.7624
n-Hexane	0.0633	1.520	0.2774
Other Hexanes	0.1029	2.468	0.4505
Heptanes	0.0299	0.717	0.1309
2,2,4-Trimethylpentane	0.0344	0.825	0.1505
Benzene	0.4127	9.905	1.8076
Toluene	0.3763	9.031	1.6481
Ethylbenzene	0.0616	1.477	0.2696
Xylenes	0.4555	10.931	1.9949
Total Emissions	10.9227	262.146	47.8416
Total Hydrocarbon Emissions	10.9227	262.146	47.8416
Total VOC Emissions	3.4888	83.732	15.2810
Total HAP Emissions	1.4037	33.689	6.1482
Total BTEX Emissions	1.3060	31.344	5.7203

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature:	90.0 deg. F
Pressure:	700.0 psig
Dry Gas Flow Rate:	3.0000 MMSCF/day
Glycol Losses with Dry Gas:	0.0180 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.33%	56.67%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.33%	99.67%
n-Hexane	0.39%	99.61%
Other Hexanes	0.72%	99.28%
Heptanes	0.43%	99.57%
2,2,4-Trimethylpentane	1.11%	98.89%
Benzene	4.96%	95.04%
Toluene	7.86%	92.14%
Ethylbenzene	10.37%	89.63%
Xylenes	12.88%	87.12%

STREAM REPORTS:

WET GAS STREAM

Temperature:	90.00 deg. F
Pressure:	714.70 psia
Flow Rate:	1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e+000
Carbon Dioxide	9.99e-001	1.45e+002
Methane	8.99e+001	4.76e+003
Ethane	5.29e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.30e+002
n-Pentane	9.99e-001	2.38e+002
n-Hexane	4.19e-002	1.19e+001
Other Hexanes	8.39e-002	2.39e+001
Heptanes	9.99e-003	3.30e+000
2,2,4-Trimethylpentane	2.00e-002	7.53e+000
Benzene	1.04e-002	2.68e+000
Toluene	5.59e-003	1.70e+000
Ethylbenzene	5.99e-004	2.10e-001
Xylenes	3.40e-003	1.19e+000
Total Components	100.00	6.14e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	3.62e-001
Carbon Dioxide	9.98e-001	1.45e+002
Methane	9.00e+001	4.76e+003
Ethane	5.30e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.29e+002
n-Pentane	9.98e-001	2.37e+002
n-Hexane	4.18e-002	1.19e+001
Other Hexanes	8.38e-002	2.38e+001
Heptanes	9.92e-003	3.28e+000
2,2,4-Trimethylpentane	1.99e-002	7.50e+000
Benzene	8.81e-003	2.27e+000
Toluene	4.37e-003	1.33e+000
Ethylbenzene	4.25e-004	1.49e-001
Xylenes	2.10e-003	7.35e-001
Total Components	100.00	6.13e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 6.11e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	3.39e+002
Water	1.50e+000	5.16e+000
Carbon Dioxide	9.88e-012	3.40e-011
Methane	7.59e-018	2.61e-017
Ethane	3.93e-008	1.35e-007

Propane	2.09e-009	7.20e-009
n-Butane	2.97e-009	1.02e-008
n-Pentane	8.36e-004	2.88e-003
n-Hexane	7.15e-005	2.46e-004
Other Hexanes	2.17e-004	7.48e-004
Heptanes	3.78e-005	1.30e-004
2,2,4-Trimethylpentane	1.12e-004	3.85e-004
Benzene	6.26e-003	2.16e-002
Toluene	9.33e-003	3.21e-002
Ethylbenzene	2.07e-003	7.12e-003
Xylenes	1.96e-002	6.73e-002
Total Components	100.00	3.44e+002

RICH GLYCOL AND PUMP GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 6.50e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.35e+001	3.39e+002
Water	3.29e+000	1.19e+001
Carbon Dioxide	1.42e-001	5.15e-001
Methane	1.80e+000	6.51e+000
Ethane	2.54e-001	9.20e-001
Propane	1.12e-001	4.05e-001
n-Butane	1.90e-001	6.89e-001
n-Pentane	2.38e-001	8.62e-001
n-Hexane	1.76e-002	6.36e-002
Other Hexanes	2.86e-002	1.04e-001
Heptanes	8.29e-003	3.00e-002
2,2,4-Trimethylpentane	9.59e-003	3.47e-002
Benzene	1.20e-001	4.34e-001
Toluene	1.13e-001	4.08e-001
Ethylbenzene	1.90e-002	6.87e-002
Xylenes	1.44e-001	5.23e-001
Total Components	100.00	3.62e+002

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.31e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	4.29e+001	6.75e+000
Carbon Dioxide	1.34e+000	5.15e-001
Methane	4.65e+001	6.51e+000
Ethane	3.50e+000	9.20e-001
Propane	1.05e+000	4.05e-001
n-Butane	1.36e+000	6.89e-001
n-Pentane	1.36e+000	8.59e-001

n-Hexane	8.42e-002	6.33e-002
Other Hexanes	1.37e-001	1.03e-001
Heptanes	3.42e-002	2.99e-002
2,2,4-Trimethylpentane	3.45e-002	3.44e-002
Benzene	6.05e-001	4.13e-001
Toluene	4.68e-001	3.76e-001
Ethylbenzene	6.64e-002	6.16e-002
Xylenes	4.91e-001	4.55e-001
Total Components	100.00	1.82e+001

ANNUAL AIR-COOLED CONDENSER PERFORMANCE:

ANNUAL AIR-COOLED CONDENSER PERFORMANCE

Nearest Site for Air Temperature Data: Amarillo, TX

Ambient Air Dry Bulb Temperature (deg. F)	Frequency (%)	Condenser Outlet Temperature (deg. F)
<=50	39.18	<=70
51-55	7.45	71-75
56-60	8.35	76-80
61-65	9.54	81-85
66-70	10.13	86-90
71-75	8.17	91-95
76-80	6.28	96-100
81-85	4.74	101-105
86-90	3.53	106-110
91-95	1.97	111-115
96-100	0.59	116-120
>100	0.09	>120

Condenser outlet temperature approach to ambient: 20.00 deg. F

Annual air-cooled condenser emissions and control efficiency:

	Uncontrolled emissions tons/year	Controlled emissions tons/year	% Control
Benzene	1.808	1.808	0.00
BTEX	5.720	5.720	0.00
Total HAP	6.148	6.148	0.00
VOC	15.281	15.281	0.00

Attachment 2

GRI-GLYCalc, Version 4.0 Input Summary and Aggregate Emissions Summary for Optimized Glycol Circulation Rate (3 gal TEG/lb H_2O)

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: BMP Case
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 3 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 3
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 3.0 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 3.0 gal/lb H2O

PUMP:

Glycol Pump Type: Gas Injection
Gas Injection Pump Volume Ratio: 0.080 acfm gas/gpm glycol

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: BMP Case
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 3 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 3
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	3.3565	80.555	14.7013
Ethane	0.4679	11.230	2.0495
Propane	0.2070	4.967	0.9065
n-Butane	0.3493	8.382	1.5298
n-Pentane	0.4329	10.390	1.8962
n-Hexane	0.0316	0.758	0.1384
Other Hexanes	0.0514	1.235	0.2253
Heptanes	0.0147	0.353	0.0644
2,2,4-Trimethylpentane	0.0170	0.408	0.0745
Benzene	0.2168	5.204	0.9498
Toluene	0.2026	4.862	0.8873
Ethylbenzene	0.0342	0.821	0.1499
Xylenes	0.2685	6.444	1.1761
Total Emissions	5.6504	135.611	24.7489
Total Hydrocarbon Emissions	5.6504	135.611	24.7489
Total VOC Emissions	1.8261	43.826	7.9982
Total HAP Emissions	0.7708	18.499	3.3760
Total BTEX Emissions	0.7222	17.332	3.1631

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 4.24 lbs. H2O/MMSCF

Temperature:	90.0 deg. F
Pressure:	700.0 psig
Dry Gas Flow Rate:	3.0000 MMSCF/day
Glycol Losses with Dry Gas:	0.0180 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	3.00 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	7.45%	92.55%
Carbon Dioxide	99.88%	0.12%
Methane	99.99%	0.01%
Ethane	99.97%	0.03%
Propane	99.95%	0.05%
n-Butane	99.91%	0.09%
n-Pentane	99.88%	0.12%
n-Hexane	99.80%	0.20%
Other Hexanes	99.85%	0.15%
Heptanes	99.62%	0.38%
2,2,4-Trimethylpentane	99.84%	0.16%
Benzene	91.96%	8.04%
Toluene	88.15%	11.85%
Ethylbenzene	83.76%	16.24%
Xylenes	77.48%	22.52%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	28.52%	71.48%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.33%	99.67%
n-Hexane	0.38%	99.62%
Other Hexanes	0.71%	99.29%
Heptanes	0.43%	99.57%
2,2,4-Trimethylpentane	1.09%	98.91%
Benzene	4.96%	95.04%
Toluene	7.87%	92.13%
Ethylbenzene	10.38%	89.62%
Xylenes	12.90%	87.10%

STREAM REPORTS:

WET GAS STREAM

Temperature:	90.00 deg. F
Pressure:	714.70 psia
Flow Rate:	1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e+000
Carbon Dioxide	9.99e-001	1.45e+002
Methane	8.99e+001	4.76e+003
Ethane	5.29e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.30e+002
n-Pentane	9.99e-001	2.38e+002
n-Hexane	4.19e-002	1.19e+001
Other Hexanes	8.39e-002	2.39e+001
Heptanes	9.99e-003	3.30e+000
2,2,4-Trimethylpentane	2.00e-002	7.53e+000
Benzene	1.04e-002	2.68e+000
Toluene	5.59e-003	1.70e+000
Ethylbenzene	5.99e-004	2.10e-001
Xylenes	3.40e-003	1.19e+000
Total Components	100.00	6.14e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	8.92e-003	5.30e-001
Carbon Dioxide	9.99e-001	1.45e+002
Methane	9.00e+001	4.76e+003
Ethane	5.30e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.30e+002
n-Pentane	9.99e-001	2.37e+002
n-Hexane	4.19e-002	1.19e+001
Other Hexanes	8.39e-002	2.38e+001
Heptanes	9.96e-003	3.29e+000
2,2,4-Trimethylpentane	2.00e-002	7.52e+000
Benzene	9.56e-003	2.46e+000
Toluene	4.94e-003	1.50e+000
Ethylbenzene	5.03e-004	1.76e-001
Xylenes	2.63e-003	9.22e-001
Total Components	100.00	6.14e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 3.11e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	1.72e+002
Water	1.50e+000	2.63e+000
Carbon Dioxide	9.78e-012	1.71e-011
Methane	7.36e-018	1.29e-017
Ethane	3.77e-008	6.60e-008

Propane	2.07e-009	3.62e-009
n-Butane	2.92e-009	5.10e-009
n-Pentane	8.17e-004	1.43e-003
n-Hexane	6.93e-005	1.21e-004
Other Hexanes	2.11e-004	3.69e-004
Heptanes	3.63e-005	6.35e-005
2,2,4-Trimethylpentane	1.07e-004	1.87e-004
Benzene	6.47e-003	1.13e-002
Toluene	9.89e-003	1.73e-002
Ethylbenzene	2.26e-003	3.96e-003
Xylenes	2.27e-002	3.98e-002
Total Components	100.00	1.75e+002

RICH GLYCOL AND PUMP GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.37e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.19e+001	1.72e+002
Water	4.91e+000	9.20e+000
Carbon Dioxide	1.40e-001	2.62e-001
Methane	1.79e+000	3.36e+000
Ethane	2.50e-001	4.68e-001
Propane	1.10e-001	2.07e-001
n-Butane	1.86e-001	3.49e-001
n-Pentane	2.32e-001	4.34e-001
n-Hexane	1.69e-002	3.17e-002
Other Hexanes	2.77e-002	5.18e-002
Heptanes	7.88e-003	1.48e-002
2,2,4-Trimethylpentane	9.18e-003	1.72e-002
Benzene	1.22e-001	2.28e-001
Toluene	1.17e-001	2.20e-001
Ethylbenzene	2.04e-002	3.82e-002
Xylenes	1.65e-001	3.08e-001
Total Components	100.00	1.87e+002

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.36e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	5.87e+001	6.58e+000
Carbon Dioxide	9.56e-001	2.62e-001
Methane	3.37e+001	3.36e+000
Ethane	2.50e+000	4.68e-001
Propane	7.55e-001	2.07e-001
n-Butane	9.66e-001	3.49e-001
n-Pentane	9.65e-001	4.33e-001

n-Hexane	5.90e-002	3.16e-002
Other Hexanes	9.60e-002	5.14e-002
Heptanes	2.36e-002	1.47e-002
2,2,4-Trimethylpentane	2.39e-002	1.70e-002
Benzene	4.46e-001	2.17e-001
Toluene	3.54e-001	2.03e-001
Ethylbenzene	5.18e-002	3.42e-002
Xylenes	4.07e-001	2.69e-001
Total Components	100.00	1.25e+001

ANNUAL AIR-COOLED CONDENSER PERFORMANCE:

ANNUAL AIR-COOLED CONDENSER PERFORMANCE

Nearest Site for Air Temperature Data: Amarillo, TX

Ambient Air Dry Bulb Temperature (deg. F)	Frequency (%)	Condenser Outlet Temperature (deg. F)
<=50	39.18	<=70
51-55	7.45	71-75
56-60	8.35	76-80
61-65	9.54	81-85
66-70	10.13	86-90
71-75	8.17	91-95
76-80	6.28	96-100
81-85	4.74	101-105
86-90	3.53	106-110
91-95	1.97	111-115
96-100	0.59	116-120
>100	0.09	>120

Condenser outlet temperature approach to ambient: 20.00 deg. F

Annual air-cooled condenser emissions and control efficiency:

	Uncontrolled emissions tons/year	Controlled emissions tons/year	% Control
Benzene	0.950	0.950	0.00
BTEX	3.163	3.163	0.00
Total HAP	3.376	3.376	0.00
VOC	7.998	7.998	0.00

MEMORANDUM

DATE: June 25, 2005

SUBJECT: Revised Impacts for Area Sources in the Oil and Natural Gas Production Source Category

FROM: Heather P. Brown, P.E.

TO: Greg Nizich, EPA/OAQPS/ESD/WCPG

On February 6, 1998 (63 FR 6288), the United States Environmental Protection Agency (EPA) proposed standards for major and area sources in the Oil and Natural Gas Production Source Category. When the major source rule was finalized on June 17, 1999 (64 FR 32610) under 40 CFR part 63, subpart HH, the regulation of oil and natural production area source facilities was deferred. EPA is now proposing amendments to subpart HH to add regulatory language for area sources. The proposed amendments require area sources to reduce HAP emissions from each triethylene glycol (TEG) dehydration unit with a natural gas throughput greater than or equal to 3 million standard cubic feet per day (MMscf/d) or with benzene emissions greater than or equal to 1 ton per year (tpy) by 95 percent or to a level such that benzene emissions are less than 1 tpy.

The purpose of this memorandum is to present the revised impacts for area source TEG units in the oil and natural gas production source category. The impacts presented include primary air impacts, secondary environmental impacts (air pollution, water and solid waste impacts), energy impacts, and cost impacts. In addition, the incremental cost effectiveness evaluation is documented in this memorandum.

PRIMARY ENVIRONMENTAL IMPACTS

This section presents the revised nationwide primary air pollution impacts (i.e., the reduction of HAP emissions) associated with the proposed area source standards. EPA estimated that there are potentially 38,067 area source TEG dehydration units in the United States. Throughput categories were established and the number of TEG dehydration units were distributed across these categories. The basis for the distribution of facilities is presented in another memorandum.[1] Table 1 presents the throughput categories and the number of units within each category.

[1]Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., United States Environmental Protection Agency. Methodology for Estimating the Number of Area Sources in the Oil and Natural Gas Production Source Category. June 15, 2005.

NMED Exhibit 78 - 0001

Table 1. Throughput Category Distribution of Area Source TEG Dehydration Units

Throughput category (MMscf/d)	Average Throughput (MMscf/d)	Number of TEG Dehydration Units	Number of TEG Dehydration Units Without Flash Tank	Number of TEG Dehydration Units With Flash Tank
≤ 0.1	0.1	7,050	6,345	705
>0.1 and ≤ 0.2	0.2	5,837	5,253	584
>0.2 and ≤ 0.3	0.3	4,833	4,350	483
>0.3 and ≤ 0.4	0.4	4,002	3,602	400
>0.4 and ≤ 0.5	0.5	3,313	2,982	331
>0.5 and ≤ 0.6	0.6	2,743	2,469	274
>0.6 and ≤ 0.7	0.7	2,272	2,045	227
>0.7 and ≤ 0.8	0.8	1,881	1,693	188
>0.8 and ≤ 0.9	0.9	1,557	1,401	156
>0.9 and ≤ 1	1	1,289	1,160	129
>1 and ≤ 2	2	1,068	961	107
>2 and ≤ 3	3	884	796	88
>3 and ≤ 4	4	732	659	73
>4 and ≤ 5	5	606	545	61
	Total	38,067	34,261	3,806

For the purposes of estimating baseline emissions, EPA estimated that 10 percent of the existing TEG dehydration units would be equipped with a flash tank.[2] The number of units within each throughput category with and without flash tanks are also presented in Table 1 as well as the average throughput for each category.

Baseline emissions were estimated using GRI-GLYCalc (Version 4.0)©. Attachment A contains the input summary files for each run. The following inputs were used for each GRI-GLYCalc© run:

- Temperature = 90^{O}F;
- Pressure = 700 psig;
- Dry gas water content = 7 lb/MMscf/d; and
- Glycol Circulation rate = 5.9 gal glycol/lb water removed

Table 2 presents baseline HAP, VOC, and benzene emissions for a single TEG dehydration unit within each throughput category.

Nationwide baseline emissions were estimated based on the number of TEG units per throughput category (Table 1) and baseline single unit emissions (Table 2). Nationwide baseline emissions are presented in Table 3.

Controlled emissions were estimated for area source TEG dehydration units that would be subject to area source standards. Each area source TEG dehydration unit with a throughput greater than or equal to 3 MMscf/d or benzene emissions greater than or equal to 1 tpy must choose between two control scenarios. Under Control Scenario 1, TEG dehydration units would reduce emissions by 95 percent. Area sources also have the option of reducing emissions to a level such that benzene emissions are less than 1 tpy, defined as Control Scenario 2. Controlled emissions are presented for Control Scenario 1 in Table 3 (95-percent emission reduction) and for Control Scenario 2 in Table 4 (1 tpy benzene). Table 5 presents the total emission reductions for each control scenario.

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage. Background Information Document for Proposed Standards. EPA-453/R-94-079a.

NMED Exhibit 78 - 0003

Table 2. Baseline Emissions For Area Source TEG Dehydration Units

	No Flash Tank			Flash Tank		
Throughput category (MMscf/d)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
≤ 0.1	0.20	0.38	0.06	0.20	0.38	0.06
>0.1 and ≤ 0.2	0.40	0.77	0.12	0.40	0.77	0.12
>0.2 and ≤ 0.3	0.60	1.15	0.18	0.60	1.15	0.18
>0.3 and ≤ 0.4	0.80	1.54	0.24	0.80	1.54	0.24
>0.4 and ≤ 0.5	1.00	1.92	0.30	1.00	1.92	0.30
>0.5 and ≤ 0.6	1.20	2.31	0.36	1.20	2.31	0.36
>0.6 and ≤ 0.7	1.40	2.69	0.42	1.40	2.69	0.42
>0.7 and ≤ 0.8	1.60	3.08	0.48	1.53	3.08	0.48
>0.8 and ≤ 0.9	1.80	3.46	0.54	1.80	3.46	0.54
>0.9 and ≤ 1	2.01	3.85	0.60	2.01	3.85	0.60
>1 and ≤ 2	4.01	7.69	1.20	4.01	7.69	1.20
>2 and ≤ 3	6.02	11.54	1.79	6.02	11.54	1.79
>3 and ≤ 4	8.02	15.38	2.39	8.02	15.38	2.39
>4 and ≤ 5	10.02	19.23	2.99	10.03	19.23	2.99
Total	39.00	75.00	12.00	39.00	75.00	12.00

NMED Exhibit 78 - 0004

Table 3. Nationwide Baseline Emissions and Controlled Emissions for Area Sources Applying 95 Percent Control (Control Scenario 1)

Throughput category (MMscf/d)	Nationwide						Emissions after 95-Percent Emission Reduction					
	No Flash Tank			Flash Tank			No Flash Tank			Flash Tank		
	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
≤ 0.1	1,272	2,440	379	141	271	42	1,272	2,440	379	141	271	42
>0.1 and ≤ 0.2	2,107	4,041	628	234	449	70	2,107	4,041	628	234	449	70
>0.2 and ≤ 0.3	2,617	5,019	782	291	557	87	2,617	5,019	782	291	557	87
>0.3 and ≤ 0.4	2,889	5,541	861	321	615	96	2,889	5,541	861	321	615	96
>0.4 and ≤0.5	2,990	5,735	891	332	636	99	2,990	5,735	891	332	636	99
>0.5 and ≤0.6	2,971	5,698	886	330	632	98	2,971	5,698	886	330	632	98
>0.6 and ≤0.7	2,869	5,504	856	319	611	95	2,869	5,504	856	319	611	95
>0.7 and ≤0.8	2,715	5,208	810	302	578	90	2,715	5,208	810	302	578	90
>0.8 and ≤0.9	2,529	4,850	754	282	540	84	2,529	4,850	754	282	540	84
>0.9 and ≤1	2,327	4,463	694	259	496	77	2,327	4,463	694	259	496	77
>1 and ≤2	3,852	7,389	1,149	429	823	128	3,852	7,389	1,149	429	823	128
>2 and ≤3	4,788	9,183	1,428	529	1,015	158	239	459	71	26	51	8
>3 and ≤4	5,284	10,136	1,576	585	1,123	175	264	507	79	29	56	9
>4 and ≤5	5,461	10,480	1,629	612	1,173	182	273	524	81	31	59	9
Total	44,669	85,686	13,322	4,,964	9,521	1480	29,913	57,376	8,921	3,324	6,376	991

NMED Exhibit 78 - 0005

Table 4. Nationwide Baseline Emissions and Controlled Emissions for Area Sources Reducing Benzene Emissions to 1 tpy (Control Scenario 2)

Throughput category (MMscf/d)	Nationwide						Emissions Reduced to Achieve ≤1 tpy Benzene					
	No Flash Tank			Flash Tank			No Flash Tank			Flash Tank		
	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
≤ 0.1	1,272	2,440	379	141	271	42	1,272	2,440	379	141	271	42
>0.1and≤0.2	2,107	4,041	628	234	449	70	2,107	4,041	628	234	449	70
>0.2and≤0.3	2,617	5,019	782	291	557	87	2,617	5,019	782	291	557	87
>0.3and≤0.4	2,889	5,541	861	321	615	96	2,889	5,541	861	321	615	96
>0.4and≤0.5	2,990	5,735	891	332	636	99	2,990	5,735	891	332	636	99
>0.5and≤0.6	2,971	5,698	886	330	632	98	2,971	5,698	886	330	632	98
>0.6and≤0.7	2,869	5,504	856	319	611	95	2,869	5,504	856	319	611	95
>0.7and≤0.8	2,715	5,208	810	302	578	90	2,715	5,208	810	302	578	90
>0.8and≤0.9	2,529	4,850	754	282	540	84	2,529	4,850	754	282	540	84
>0.9and≤1	2,327	4,463	694	259	496	77	2,327	4,463	694	259	496	77
>1and≤2	3,852	7,389	1,149	429	823	128	3,852	7,389	1,149	429	823	128
>2and≤3	4,788	9,183	1,428	529	1,015	158	2,669	5,120	796	295	566	88
>3and≤4	5,284	10,136	1,576	585	1,123	175	2,210	4,239	659	245	470	73
>4and≤5	5,461	10,480	1,629	612	1,173	182	1,827	3,506	545	205	392	61
Total	44,669	85,686	13,322	4,964	9,521	1,480	35,842	68,751	10,690	3,982	7,638	1,187

NMED Exhibit 78 - 0006

Table 5. Emission Reductions

Pollutant	Control Scenario 1	Control Scenario 2
HAP	16,396	9,809
VOC	31,455	18,817
Benzene	4,890	2,925

[1] 95-percent Control Emission Reduction.
[2] Reduce benzene emissions to 1 tpy.

NMED Exhibit 78 - 0007

SECONDARY ENVIRONMENTAL IMPACTS

Although the intent of the area source standards is to reduce HAP emissions, the application of control technologies can lead to other secondary environmental impacts. These secondary impacts can have a positive environmental impact, such as the reduction of VOC emissions, or a negative impact. Negative impacts may result from air pollutants emitted as a result of combustion sources (e.g., flares) or generation of a solid or liquid waste stream. The secondary impacts on air pollution and water and solid waste are discussed in this section.

Air Pollution

The primary method of HAP control from area source TEG dehydration units is the installation of a condenser and, if not present, a gas condensate glycol separator (GCG separator or flash tank). The secondary air pollution impacts associated with the application of this type of control are the decreased VOC emissions resulting from capture and control of HAP emissions.

Other secondary environmental impacts are those associated with the operation of certain air emission control devices, (i.e., flares). If a facility does not have the ability to handle the collected vapor for use as a fuel or recycle the collected vapor back into the process. In such cases, the collected vapors may be directed to an on-site flare. EPA estimated that 10 percent of the facilities would direct all collected vapors to an on-site flare.[3] The adverse secondary air impacts resulting from the use of a flare would be minimal in comparison to the primary HAP reduction benefits from implementing the proposed control options for area sources. Table 6 presents the secondary air impacts due to the use of flares for area sources.

Water and Solid Waste Impacts

The water impacts associated the installation of a condenser system for the TEG dehydration unit reboiler vent would be minimal. The condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection.[4]

There is no solid waste generated from the control of HAP emissions using a condenser. Therefore, we do not anticipate any adverse solid waste impacts from the implementation of the area source standards.

[3]Reference 2, page 5-2.

[4]Reference 2, page 5-6.

NMED Exhibit 78 - 0008

Table 6. Secondary Air Pollutant Impacts Due to the Use of a Flare for Area Sources in the Oil and Natural Gas Production Source Category

Pollutant	Estimated Emissions per Flare (lb/yr)[a]	Estimated Number of Units Installing a Flare	Nationwide Emissions (tpy)
SO_X	2	222	<1
NO_X	106	222	12
CO	22	222	2

[a]Reference 2, page 5-7.

NMED Exhibit 78 - 0009

ENERGY IMPACTS

Energy impacts are those energy requirements associated with the operation of emission control devices. There would be no national energy demand increase from the operation of any of the control options analyzed under the proposed oil and natural gas production standards for area sources. The proposed area source standards encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate, that can be used on-site as fuel or reprocessed, within the production process, for sale. Thus, the proposed standards have a positive impact associated with the recovery of non-renewable energy resources.

COST IMPACTS

The cost impacts due to the application of control devices to meet the proposed area source standards include the cost of the control equipment that must be purchased, along with the cost of the installation of that control equipment. There are also costs for the operation and maintenance of the equipment. Finally, there are costs associated with the required monitoring, inspection, recordkeeping, and reporting (MIRR). This section presents the estimated costs associated with compliance with the area source standards. These cost estimates apply to both control scenarios.

Cost estimates for condensers were developed for the 1998 proposal and are documented in the Background Information Document (BID).[5] The original cost estimates were based on 1993 cost data. Therefore, these estimates were revised to reflect 2004 prices. The following tables present these revised cost estimates. Equipment costs were updated to represent 2004 prices using the Chemical Engineering[6] cost index. In addition, labor rates were updated to 2004 prices using information from the Bureau of Labor Statistics.[7,8] Table 7 presents the updated capital costs for installing a condenser on a TEG dehydration unit that does not have existing flash tanks and must install a flash tank to comply with the area source standards. Table 8 presents a summary of the updated capital costs for installing a condenser on a TEG dehydration units that are equipped with a flash tank. Table 9 presents the updated annual cost for condensers and Table 10 presents the costs associated with MIRR. Finally, Table 11 presents the nationwide costs for the oil and natural gas production industry.

[5]Reference 2, Chapter 6.

[6]Chemical Engineering. http://www.che.com. August 2004. Economic Indicators.

[7]Bureau of Labor Statistics. http://www.bls.gov/ncs/ect/home.htm. Employer Costs for Employee Compensation - March 2004. Table 11.

[8]Bureau of Labor Statistics. http://www.bls.gov/ces/ The Employment Situation. Table B-3Employer Costs for Employee Compensation - March 2004. Table 11.

Table 7. Updated Condenser Capital Costs for TEG Dehydration Units without Existing Flash Tanks

Equipment	Description	Size	Factor	Jul-93 Cost	Apr-04 Cost
Condenser	Condenser, piping to control device	All	Reference 9	$6,800	$8,598
Condensate storage vessel	Fixed-roof tank	50 gal	2.72 (Vtank) + 1,960 Reference 10	$2,210	$2,794
Flash tank	Low pressure separator	125 psig	Reference 11	$1,750	$2,213
Purchased equipment cost (PEC)				$10,760	$13,606
Enhanced monitoring equipment (EM)			0.10(PEC)	$1,076	$1,361
Total capital investment for a new unit (TCIN)			PEC + EM	**$11,840**	**$14,970**
Total capital investment for an existing unit (TCIE) [a]			1.15(TCIN)	**$13,620**	**$17,220**

a - Total capital investment for an existing unit accounts for a retrofit factor of 1.15.

Notes

All dollar amounts are in July 1993 dollars and scaled to 2004 costs using the following cost indeces

July 1993 cost index = 394.4

Apr 2004 Cost Index = 498.7

Direct and indirect costs are included in the condenser cost.

The estimated cost for a flash tank has been added to the capital cost.

[9]Rule 71.5, Glycol Dehydrators (Draft Staff Report). Executive Summary. Ventura County Air Pollution Control District, California. August 8, 1994.

[10]OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

[11]BTEX Emissions from Gas/Glycol Dehydrators: Air Quality Case Histories. Alan S. Owens. Proceedings of the 1994 GRI Glycol Dehydrator/Gas Processing Air Toxics Conference. Gas Research Institute. Chicago, IL. June 1994.

NMED Exhibit 78 - 0011

Table 8. Updated Condenser Capital Costs for TEG Dehydration Units with Existing Flash Tanks

Equipment	Description	Size	Factor	Jul-93 Cost	Apr-04 Cost
Condenser	Condenser, piping to control device	All	Reference 9	$6,800	$8,598.28
Condensate storage vessel	Fixed-roof tank	50 gal	2.72 (Vtank) + 1,960 Reference 10	$2,210	$2,794.44
Purchased equipment cost (PEC)				$9,010	$11,393
Enhanced monitoring equipment (EM)			0.10(PEC)	$901	$1,139
Total capital investment for a new unit (TCIN)			PEC + EM	**$9,910**	**$12,530**
Total capital investment for an existing unit (TCIE) [a]			1.15(TCIN)	**$11,400**	**$14,410**

a - Total capital investment for an existing unit accounts for a retrofit factor of 1.15.

Notes

All dollar amounts are in July 1993 dollars and scaled to 2004 costs using the following cost indeces

July 1993 cost index = 394.4

Apr 2004 Cost Index = 498.7

Direct and indirect costs are included in the condenser cost.

These model plants already have flash tanks.

NMED Exhibit 78 - 0012

Table 9. Condenser Annual Costs for TEG Dehydration Units

		TEG-A		TEG-A'	
Direct Annual Costs (DAC)					
Operating labor	130 hours/yr x $24.24/hr (Reference 13)	$3,151		$3,151	
Supervising labor	0.15 x Operating labor	473		473	
Operating materials	None required	0		0	
Maintenance					
Labor	130 hours/yr x $26.63/hr	3,462	26.627273	3,462	26.627273
Material	0.50 x Maintenance labor	1,731		1,731	
Utilities	None required	0	$8,816	0	$8,816
Indirect Annual Costs (IAC)					
Overhead	0.60 x Total labor plus Maintenance materials	$4,251		$4,251	
Administrative	0.02 x TCIE	344		288	
Property tax	0.01 x TCIE	172		144	
Insurance	0.01 x TCIE	172	$4,940	144	$4,828
Capital recovery (a)	0.1098 x TCIE	1,891		1,582	
Recovery credits (b)					
Condensate	Barrels/yr x $/barrel(c)	($141)		($141)	
Total Net Annual Cost (DAC + IAC)		$15,500		$15,100	

a - Capital recovery is based on equipment life of 15 years and an interest rate of 7%.

b - Numbers in parentheses reflect a savings.

c- $/barrel is the average US crude price (Reference 12) 38.54

All dollar amounts are in July 1993 dollars and scaled to 2004 costs using the following cost indeces
July 1993 cost index = 394.4
Apr 2004 Cost Index = 498.7

TEG-A' has a flash tank. TEG-A does not and a flash tank has been added to the capital cost.
It is assumed that all new sources will have flash tanks.

[12]Oil and Gas Journal Online. September 3, 2004. http://ogj.pennnet.com/industrystats/industrystats.cfm?Section=Stats

[13]Bureau of Labor Statistics (http://www.bls.gov/news.release/pdf/empsit.pdf) Table B-3, June 2004

NMED Exhibit 78 - 0013

Table 10. Annual MIRR Costs per Glycol Dehydration Unit

Activity	Technical hours per activity (A)	Number of activities per year (B)	Activity cost parameters Technical hours per year (C)	Management hours per activity (D)	Clerical hours per activity (E)	Total annual costs in $ per year (F)
Read rule and instructions	1.5	2	3	0.15	0.3	$ 137.88
Plan activities	3	1	3	0.15	0.3	$ 137.88
Training	1	1	1	0.05	0.1	$ 45.96
Testing/Development	20	1	20	1	2	$ 919.22
Monitoring/Inspection	0.1	52	5.2	0.26	0.52	$ 239.00
Process/Review	1.5	1	1.5	0.08	0.15	$ 69.25
Complete reports	5	1	5	0.25	0.5	$ 229.80
Record/Report	0.5	6	3	0.15	0.3	$ 137.88
Store/Maintain data	0.5	12	6	0.3	0.6	$ 275.76
Totals[a]			47.7	2.39	4.77	$ 2,192.64

Activity cost parameters

C = A x B
D = 0.05 x C
E = 0.10 x C
F = ($tech x C) + ($mgmt x D) + ($clerical x E)

a - Total hours are rounded to nearest hour and total dollars rounded to nearest $100.

Technical Labor Hourly Rate = 39.75
Management Labor Hourly Rate = 62.39
Clerical Labor Hourly Rate = 30.92
(Reference 14. All labor rates are multiplied by 1.5 to account for overhead)

[14]Bureau of Labor Statistics (http://www.bls.gov/news.release/pdf/ecec.pdf) Table 11. March 2004

NMED Exhibit 78 - 0014

Table 11. Nationwide Cost Impacts for Area Sources

	National Revised Costs	
	TEG-A	**TEG-A'**
Estimated Number of Impacted Units	2,000	222
Capital Costs	17,220	14,410
Annualized Capital Costs	1,891	1,582
O&M	8,816	8,816
Other Annual Costs (Admin., taxes, ins.)	4,940	4,828
Product Recovery	(141)	(141)
MIRR (c)	2,193	2,193
Cost Impact Summary for one Model Unit		
Total Capital Investment	17,220	14,410
Total Annual Cost	17,699	17,278
Nationwide Impacts		
Total Capital Investment	34,440,000	3,199,020
Total Annual Cost	35,397,951	3,835,724
	39,233,675	

a- Costs for the proposed rule are in July 1993 dollars

b- Revised costs are in April 2004 dollars

c- Labor cost for MIRR was updated based on March 2004 data f

REGULATORY ACTION LEVELS

In the preamble to the proposed area source standard (63 FR 6288), four regulatory alternatives were evaluated. Each regulatory alternative was characterized in terms of an action level, above which HAP emissions must be controlled. Action levels were expressed as the actual annual average flow rate of natural gas to the TEG dehydration unit (MMscf/d). For the proposed amendments, four similar action levels were evaluated for Control Scenarios 1 and 2 (95-percent control and 1-tpy benzene emissions, respectively). Table 12 presents the regulatory action levels for Control Scenario 1 (reduce emissions by 95 percent). Table 13 presents the regulatory action levels for Control Scenario 2 (control emissions so that benzene emissions are less than 1 tpy).

Tables 12 and 13 also present the cost effectiveness of each regulatory action level as well as the incremental cost effectiveness. As shown in Table 12, the incremental cost effectiveness between the 3-MMscf/d action level and the 2-MMscf/d is approximately $4,600 per ton for sources that would apply 95 percent control (Control Scenario 1). However, when considering the incremental cost effectiveness between the same to action levels for Control Scenario 2 (reducing benzene emissions to less than 1 tpy), the value is approximately $27,000 per ton. Since it is more likely that sources will opt for Control Scenario 2, which is less stringent than Control Scenario 1, the 3-MMScf/d regulatory action level is appropriate.

NMED Exhibit 78 - 0016

Table 12. Regulatory Action Levels for Area Source Glycol Dehydration Units - Control Scenario 1[1]

Size-Based Action Level (MMSCF/D)	Number of Units Impacted	HAP Reduction (1,000 tpy)	Total Capital Costs ($million)	Annual Costs ($million)	MIRR Costs ($million)	Total Annual Costs ($million)	Cost Effectiveness ($/ton HAP)	Incremental Cost Effectiveness ($/ton HAP)
4	1,338	11.35	22.7	20.7	2.9	23.6	2,082	--
3	2,222	16.40	37.6	34.4	4.9	39.2	2,392	3,089
2	3,289	20.46	55.7	50.9	7.2	58.1	2,838	4,634
0.3	25,180	43.59	426.5	389.3	55.2	444.5	10,198	16,713

[1] Control Scenario 1 - Reduce emissions by 95 percent.

Table 13. Regulatory Action Levels for Area Source Glycol Dehydration Units - Control Scenario 2[1]

Size-Based Action Level (MMSCF/D)	Number of Units Impacted	HAP Reduction (1,000 tpy)	Total Capital Costs ($million)	Annual Costs ($million)	MIRR Costs ($million)	Total Annual Costs ($million)	Cost Effectiveness ($/ton HAP)	Incremental Cost Effectiveness ($/ton HAP)
4	1,338	7.46	22.7	20.7	2.9	23.6	3,168	--
3	2,222	9.81	37.6	34.4	4.9	39.2	3,999	6,633
2	3,289	10.51	55.7	50.9	7.2	58.1	5,525	26,896
0.3	3,289	10.51	55.7	50.9	7.2	58.1	5,525	--

[1] Control Scenario 2 - Units with benzene emissions greater than or equal to 1 tpy of benzene will reduce emissions such that benzene emissions are less than 1 tpy.

ATTACHMENT A

GRI-GLYCalc (Version 4.0)© Input Summary Files

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0259	0.622	0.1135
Ethane	0.0095	0.229	0.0418
Propane	0.0059	0.142	0.0258
n-Butane	0.0137	0.329	0.0601
n-Pentane	0.0191	0.458	0.0836
n-Hexane	0.0016	0.039	0.0071
Other Hexanes	0.0025	0.059	0.0108
Heptanes	0.0009	0.021	0.0038
2,2,4-Trimethylpentane	0.0008	0.020	0.0037
Benzene	0.0136	0.328	0.0598
Toluene	0.0125	0.299	0.0546
Ethylbenzene	0.0020	0.049	0.0090
Xylenes	0.0151	0.363	0.0663
Total Emissions	0.1233	2.958	0.5399
Total Hydrocarbon Emissions	0.1233	2.958	0.5399
Total VOC Emissions	0.0878	2.107	0.3846
Total HAP Emissions	0.0458	1.099	0.2005
Total BTEX Emissions	0.0433	1.039	0.1897

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.1000 MMSCF/day
Glycol Losses with Dry Gas: 0.0006 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	2.37e-001
Carbon Dioxide	9.99e-001	4.83e+000
Methane	8.99e+001	1.59e+002
Ethane	5.29e+000	1.75e+001
Propane	1.30e+000	6.30e+000
n-Butane	1.20e+000	7.66e+000
n-Pentane	9.99e-001	7.93e+000
n-Hexane	4.19e-002	3.98e-001
Other Hexanes	8.39e-002	7.95e-001
Heptanes	9.99e-003	1.10e-001
2,2,4-Trimethylpentane	2.00e-002	2.51e-001
Benzene	1.04e-002	8.92e-002
Toluene	5.59e-003	5.67e-002
Ethylbenzene	5.99e-004	7.00e-003
Xylenes	3.40e-003	3.97e-002
Total Components	100.00	2.05e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	1.21e-002
Carbon Dioxide	9.98e-001	4.82e+000
Methane	9.00e+001	1.59e+002
Ethane	5.30e+000	1.75e+001
Propane	1.30e+000	6.29e+000
n-Butane	1.20e+000	7.65e+000
n-Pentane	9.98e-001	7.91e+000
n-Hexane	4.18e-002	3.96e-001
Other Hexanes	8.38e-002	7.93e-001
Heptanes	9.92e-003	1.09e-001
2,2,4-Trimethylpentane	1.99e-002	2.50e-001
Benzene	8.81e-003	7.56e-002
Toluene	4.37e-003	4.42e-002
Ethylbenzene	4.25e-004	4.95e-003
Xylenes	2.10e-003	2.45e-002
Total Components	100.00	2.04e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 2.04e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	1.13e+001
Water	1.50e+000	1.72e-001
Carbon Dioxide	9.88e-012	1.13e-012
Methane	7.59e-018	8.70e-019
Ethane	3.93e-008	4.51e-009
Propane	2.09e-009	2.40e-010
n-Butane	2.97e-009	3.40e-010
n-Pentane	8.36e-004	9.59e-005
n-Hexane	7.15e-005	8.20e-006
Other Hexanes	2.17e-004	2.49e-005
Heptanes	3.78e-005	4.34e-006
2,2,4-Trimethylpentane	1.12e-004	1.28e-005
Benzene	6.26e-003	7.18e-004
Toluene	9.33e-003	1.07e-003
Ethylbenzene	2.07e-003	2.37e-004
Xylenes	1.96e-002	2.24e-003
Total Components	100.00	1.15e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.11e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	1.13e+001
Water	3.36e+000	3.97e-001
Carbon Dioxide	9.58e-002	1.13e-002
Methane	2.19e-001	2.59e-002
Ethane	8.07e-002	9.55e-003
Propane	4.99e-002	5.90e-003
n-Butane	1.16e-001	1.37e-002
n-Pentane	1.62e-001	1.92e-002
n-Hexane	1.39e-002	1.64e-003
Other Hexanes	2.11e-002	2.49e-003
Heptanes	7.34e-003	8.68e-004
2,2,4-Trimethylpentane	7.23e-003	8.56e-004
Benzene	1.21e-001	1.44e-002
Toluene	1.15e-001	1.35e-002
Ethylbenzene	1.93e-002	2.28e-003
Xylenes	1.47e-001	1.74e-002
Total Components	100.00	1.18e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 6.01e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	2.25e-001
Carbon Dioxide	1.63e+000	1.13e-002
Methane	1.02e+001	2.59e-002
Ethane	2.00e+000	9.55e-003
Propane	8.44e-001	5.90e-003
n-Butane	1.49e+000	1.37e-002
n-Pentane	1.67e+000	1.91e-002
n-Hexane	1.20e-001	1.63e-003
Other Hexanes	1.81e-001	2.47e-003
Heptanes	5.44e-002	8.64e-004
2,2,4-Trimethylpentane	4.66e-002	8.43e-004
Benzene	1.10e+000	1.36e-002
Toluene	8.55e-001	1.25e-002
Ethylbenzene	1.22e-001	2.04e-003
Xylenes	9.00e-001	1.51e-002
Total Components	100.00	3.59e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.1 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0011	0.027	0.0049
Ethane	0.0012	0.029	0.0053
Propane	0.0013	0.032	0.0059
n-Butane	0.0048	0.114	0.0209
n-Pentane	0.0079	0.190	0.0346
n-Hexane	0.0009	0.021	0.0039
Other Hexanes	0.0012	0.029	0.0052
Heptanes	0.0006	0.014	0.0026
2,2,4-Trimethylpentane	0.0005	0.011	0.0020
Benzene	0.0132	0.317	0.0578
Toluene	0.0122	0.292	0.0534
Ethylbenzene	0.0020	0.048	0.0088
Xylenes	0.0150	0.359	0.0656
Total Emissions	0.0618	1.484	0.2709

Total Hydrocarbon Emissions	0.0618	1.484	0.2709
Total VOC Emissions	0.0595	1.429	0.2607
Total HAP Emissions	0.0437	1.049	0.1914
Total BTEX Emissions	0.0424	1.017	0.1855

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0248	0.595	0.1086
Ethane	0.0083	0.200	0.0365
Propane	0.0045	0.109	0.0199
n-Butane	0.0089	0.215	0.0392
n-Pentane	0.0112	0.268	0.0489
n-Hexane	0.0007	0.018	0.0033
Other Hexanes	0.0013	0.031	0.0056
Heptanes	0.0003	0.006	0.0012

2,2,4-Trimethylpentane	0.0004	0.009	0.0017
Benzene	0.0005	0.011	0.0020
Toluene	0.0003	0.007	0.0013
Ethylbenzene	<0.0001	0.001	0.0001
Xylenes	0.0002	0.004	0.0007
Total Emissions	0.0614	1.474	0.2690

Total Hydrocarbon Emissions	0.0614	1.474	0.2690
Total VOC Emissions	0.0283	0.679	0.1239
Total HAP Emissions	0.0021	0.050	0.0091
Total BTEX Emissions	0.0009	0.023	0.0041

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages:	1.25
Calculated Dry Gas Dew Point:	2.90 lbs. H2O/MMSCF
Temperature:	90.0 deg. F
Pressure:	700.0 psig
Dry Gas Flow Rate:	0.1000 MMSCF/day
Glycol Losses with Dry Gas:	0.0006 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	2.37e-001
Carbon Dioxide	9.99e-001	4.83e+000
Methane	8.99e+001	1.59e+002
Ethane	5.29e+000	1.75e+001
Propane	1.30e+000	6.30e+000
n-Butane	1.20e+000	7.66e+000
n-Pentane	9.99e-001	7.93e+000
n-Hexane	4.19e-002	3.98e-001
Other Hexanes	8.39e-002	7.95e-001
Heptanes	9.99e-003	1.10e-001
2,2,4-Trimethylpentane	2.00e-002	2.51e-001
Benzene	1.04e-002	8.92e-002
Toluene	5.59e-003	5.67e-002
Ethylbenzene	5.99e-004	7.00e-003
Xylenes	3.40e-003	3.97e-002
Total Components	100.00	2.05e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	1.21e-002
Carbon Dioxide	9.98e-001	4.82e+000
Methane	9.00e+001	1.59e+002
Ethane	5.30e+000	1.75e+001
Propane	1.30e+000	6.29e+000
n-Butane	1.20e+000	7.65e+000
n-Pentane	9.98e-001	7.91e+000
n-Hexane	4.18e-002	3.96e-001
Other Hexanes	8.38e-002	7.93e-001
Heptanes	9.92e-003	1.09e-001
2,2,4-Trimethylpentane	1.99e-002	2.50e-001
Benzene	8.81e-003	7.56e-002
Toluene	4.37e-003	4.42e-002
Ethylbenzene	4.25e-004	4.95e-003
Xylenes	2.10e-003	2.45e-002
Total Components	100.00	2.04e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 2.04e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	1.13e+001
Water	1.50e+000	1.72e-001
Carbon Dioxide	9.88e-012	1.13e-012
Methane	7.59e-018	8.70e-019
Ethane	3.93e-008	4.51e-009
Propane	2.09e-009	2.40e-010
n-Butane	2.97e-009	3.40e-010
n-Pentane	8.36e-004	9.59e-005
n-Hexane	7.15e-005	8.20e-006
Other Hexanes	2.17e-004	2.49e-005
Heptanes	3.78e-005	4.34e-006
2,2,4-Trimethylpentane	1.12e-004	1.28e-005
Benzene	6.26e-003	7.18e-004
Toluene	9.33e-003	1.07e-003
Ethylbenzene	2.07e-003	2.37e-004
Xylenes	1.96e-002	2.24e-003
Total Components	100.00	1.15e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.11e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	1.13e+001
Water	3.36e+000	3.97e-001
Carbon Dioxide	9.58e-002	1.13e-002
Methane	2.19e-001	2.59e-002
Ethane	8.07e-002	9.55e-003
Propane	4.99e-002	5.90e-003
n-Butane	1.16e-001	1.37e-002
n-Pentane	1.62e-001	1.92e-002
n-Hexane	1.39e-002	1.64e-003
Other Hexanes	2.11e-002	2.49e-003
Heptanes	7.34e-003	8.68e-004
2,2,4-Trimethylpentane	7.23e-003	8.56e-004
Benzene	1.21e-001	1.44e-002
Toluene	1.15e-001	1.35e-002
Ethylbenzene	1.93e-002	2.28e-003
Xylenes	1.47e-001	1.74e-002
Total Components	100.00	1.18e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 9.40e-001 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	4.21e-004
Carbon Dioxide	7.28e+000	7.94e-003
Methane	6.23e+001	2.48e-002
Ethane	1.12e+001	8.34e-003
Propane	4.16e+000	4.55e-003
n-Butane	6.21e+000	8.95e-003
n-Pentane	6.25e+000	1.12e-002
n-Hexane	3.48e-001	7.44e-004
Other Hexanes	6.00e-001	1.28e-003
Heptanes	1.06e-001	2.63e-004
2,2,4-Trimethylpentane	1.36e-001	3.84e-004
Benzene	2.38e-001	4.61e-004
Toluene	1.28e-001	2.93e-004
Ethylbenzene	1.13e-002	2.98e-005
Xylenes	5.98e-002	1.57e-004
Total Components	100.00	6.98e-002

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 2.10e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	1.13e+001
Water	3.37e+000	3.96e-001
Carbon Dioxide	2.89e-002	3.40e-003
Methane	9.52e-003	1.12e-003
Ethane	1.03e-002	1.21e-003
Propane	1.15e-002	1.35e-003
n-Butane	4.06e-002	4.77e-003
n-Pentane	6.81e-002	8.00e-003
n-Hexane	7.63e-003	8.97e-004
Other Hexanes	1.03e-002	1.21e-003
Heptanes	5.14e-003	6.05e-004
2,2,4-Trimethylpentane	4.01e-003	4.72e-004
Benzene	1.18e-001	1.39e-002
Toluene	1.13e-001	1.33e-002
Ethylbenzene	1.91e-002	2.25e-003
Xylenes	1.46e-001	1.72e-002
Total Components	100.00	1.18e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 5.07e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	2.24e-001
Carbon Dioxide	5.78e-001	3.40e-003

Methane	5.23e-001	1.12e-003
Ethane	3.01e-001	1.21e-003
Propane	2.29e-001	1.35e-003
n-Butane	6.14e-001	4.77e-003
n-Pentane	8.20e-001	7.91e-003
n-Hexane	7.72e-002	8.88e-004
Other Hexanes	1.03e-001	1.19e-003
Heptanes	4.48e-002	6.00e-004
2,2,4-Trimethylpentane	3.01e-002	4.59e-004
Benzene	1.26e+000	1.32e-002
Toluene	9.89e-001	1.22e-002
Ethylbenzene	1.42e-001	2.01e-003
Xylenes	1.06e+000	1.50e-002
Total Components	100.00	2.90e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.1 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0518	1.243	0.2269
Ethane	0.0191	0.458	0.0836
Propane	0.0118	0.283	0.0517
n-Butane	0.0274	0.659	0.1202
n-Pentane	0.0382	0.916	0.1671
n-Hexane	0.0033	0.078	0.0143
Other Hexanes	0.0049	0.119	0.0216
Heptanes	0.0017	0.041	0.0076
2,2,4-Trimethylpentane	0.0017	0.040	0.0074
Benzene	0.0273	0.655	0.1196
Toluene	0.0249	0.599	0.1093
Ethylbenzene	0.0041	0.098	0.0179
Xylenes	0.0303	0.726	0.1326
Total Emissions	0.2465	5.916	1.0797
Total Hydrocarbon Emissions	0.2465	5.916	1.0797
Total VOC Emissions	0.1756	4.215	0.7692
Total HAP Emissions	0.0916	2.197	0.4010
Total BTEX Emissions	0.0866	2.078	0.3793

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.2000 MMSCF/day
Glycol Losses with Dry Gas: 0.0012 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.35e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	4.74e-001
Carbon Dioxide	9.99e-001	9.67e+000
Methane	8.99e+001	3.17e+002
Ethane	5.29e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.99e-001	1.59e+001
n-Hexane	4.19e-002	7.95e-001
Other Hexanes	8.39e-002	1.59e+000
Heptanes	9.99e-003	2.20e-001
2,2,4-Trimethylpentane	2.00e-002	5.02e-001
Benzene	1.04e-002	1.78e-001
Toluene	5.59e-003	1.13e-001
Ethylbenzene	5.99e-004	1.40e-002
Xylenes	3.40e-003	7.93e-002
Total Components	100.00	4.10e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.33e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	2.41e-002
Carbon Dioxide	9.98e-001	9.65e+000
Methane	9.00e+001	3.17e+002
Ethane	5.30e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.98e-001	1.58e+001
n-Hexane	4.18e-002	7.92e-001
Other Hexanes	8.38e-002	1.59e+000
Heptanes	9.92e-003	2.18e-001
2,2,4-Trimethylpentane	1.99e-002	5.00e-001
Benzene	8.81e-003	1.51e-001
Toluene	4.37e-003	8.84e-002
Ethylbenzene	4.25e-004	9.91e-003
Xylenes	2.10e-003	4.90e-002
Total Components	100.00	4.09e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 4.07e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	2.26e+001
Water	1.50e+000	3.44e-001
Carbon Dioxide	9.88e-012	2.27e-012
Methane	7.59e-018	1.74e-018
Ethane	3.93e-008	9.01e-009
Propane	2.09e-009	4.80e-010
n-Butane	2.97e-009	6.80e-010
n-Pentane	8.36e-004	1.92e-004
n-Hexane	7.15e-005	1.64e-005
Other Hexanes	2.17e-004	4.99e-005
Heptanes	3.78e-005	8.68e-006
2,2,4-Trimethylpentane	1.12e-004	2.57e-005
Benzene	6.26e-003	1.44e-003
Toluene	9.33e-003	2.14e-003
Ethylbenzene	2.07e-003	4.75e-004
Xylenes	1.96e-002	4.49e-003
Total Components	100.00	2.29e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.22e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	2.26e+001
Water	3.36e+000	7.94e-001
Carbon Dioxide	9.58e-002	2.27e-002
Methane	2.19e-001	5.18e-002
Ethane	8.07e-002	1.91e-002
Propane	4.99e-002	1.18e-002
n-Butane	1.16e-001	2.74e-002
n-Pentane	1.62e-001	3.83e-002
n-Hexane	1.39e-002	3.28e-003
Other Hexanes	2.11e-002	4.99e-003
Heptanes	7.34e-003	1.74e-003
2,2,4-Trimethylpentane	7.23e-003	1.71e-003
Benzene	1.21e-001	2.87e-002
Toluene	1.15e-001	2.71e-002
Ethylbenzene	1.93e-002	4.56e-003
Xylenes	1.47e-001	3.48e-002
Total Components	100.00	2.37e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.20e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	4.49e-001
Carbon Dioxide	1.63e+000	2.27e-002
Methane	1.02e+001	5.18e-002
Ethane	2.00e+000	1.91e-002
Propane	8.44e-001	1.18e-002
n-Butane	1.49e+000	2.74e-002
n-Pentane	1.67e+000	3.82e-002
n-Hexane	1.20e-001	3.26e-003
Other Hexanes	1.81e-001	4.94e-003
Heptanes	5.44e-002	1.73e-003
2,2,4-Trimethylpentane	4.66e-002	1.69e-003
Benzene	1.10e+000	2.73e-002
Toluene	8.55e-001	2.49e-002
Ethylbenzene	1.22e-001	4.09e-003
Xylenes	9.00e-001	3.03e-002
Total Components	100.00	7.19e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.2 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0022	0.054	0.0098
Ethane	0.0024	0.058	0.0106
Propane	0.0027	0.065	0.0118
n-Butane	0.0095	0.229	0.0418
n-Pentane	0.0158	0.380	0.0693
n-Hexane	0.0018	0.043	0.0078
Other Hexanes	0.0024	0.057	0.0104
Heptanes	0.0012	0.029	0.0053
2,2,4-Trimethylpentane	0.0009	0.022	0.0040
Benzene	0.0264	0.633	0.1155
Toluene	0.0244	0.585	0.1067
Ethylbenzene	0.0040	0.097	0.0176
Xylenes	0.0300	0.719	0.1312
Total Emissions	0.1237	2.969	0.5418

Total Hydrocarbon Emissions	0.1237	2.969	0.5418
Total VOC Emissions	0.1190	2.857	0.5214
Total HAP Emissions	0.0874	2.098	0.3829
Total BTEX Emissions	0.0847	2.033	0.3711

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0496	1.190	0.2171
Ethane	0.0167	0.400	0.0730
Propane	0.0091	0.218	0.0398
n-Butane	0.0179	0.430	0.0784
n-Pentane	0.0223	0.536	0.0979
n-Hexane	0.0015	0.036	0.0065
Other Hexanes	0.0026	0.062	0.0112
Heptanes	0.0005	0.013	0.0023

2,2,4-Trimethylpentane	0.0008	0.018	0.0034
Benzene	0.0009	0.022	0.0040
Toluene	0.0006	0.014	0.0026
Ethylbenzene	0.0001	0.001	0.0003
Xylenes	0.0003	0.008	0.0014
Total Emissions	0.1228	2.948	0.5379
Total Hydrocarbon Emissions	0.1228	2.948	0.5379
Total VOC Emissions	0.0566	1.358	0.2478
Total HAP Emissions	0.0041	0.099	0.0181
Total BTEX Emissions	0.0019	0.045	0.0083

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.2000 MMSCF/day
Glycol Losses with Dry Gas: 0.0012 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 8.35e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	4.74e-001
Carbon Dioxide	9.99e-001	9.67e+000
Methane	8.99e+001	3.17e+002
Ethane	5.29e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.99e-001	1.59e+001
n-Hexane	4.19e-002	7.95e-001
Other Hexanes	8.39e-002	1.59e+000
Heptanes	9.99e-003	2.20e-001
2,2,4-Trimethylpentane	2.00e-002	5.02e-001
Benzene	1.04e-002	1.78e-001
Toluene	5.59e-003	1.13e-001
Ethylbenzene	5.99e-004	1.40e-002
Xylenes	3.40e-003	7.93e-002
Total Components	100.00	4.10e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.33e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	2.41e-002
Carbon Dioxide	9.98e-001	9.65e+000
Methane	9.00e+001	3.17e+002
Ethane	5.30e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.98e-001	1.58e+001
n-Hexane	4.18e-002	7.92e-001
Other Hexanes	8.38e-002	1.59e+000
Heptanes	9.92e-003	2.18e-001
2,2,4-Trimethylpentane	1.99e-002	5.00e-001
Benzene	8.81e-003	1.51e-001
Toluene	4.37e-003	8.84e-002
Ethylbenzene	4.25e-004	9.91e-003
Xylenes	2.10e-003	4.90e-002
Total Components	100.00	4.09e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 4.07e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	2.26e+001
Water	1.50e+000	3.44e-001
Carbon Dioxide	9.88e-012	2.27e-012
Methane	7.59e-018	1.74e-018
Ethane	3.93e-008	9.01e-009
Propane	2.09e-009	4.80e-010
n-Butane	2.97e-009	6.80e-010
n-Pentane	8.36e-004	1.92e-004
n-Hexane	7.15e-005	1.64e-005
Other Hexanes	2.17e-004	4.99e-005
Heptanes	3.78e-005	8.68e-006
2,2,4-Trimethylpentane	1.12e-004	2.57e-005
Benzene	6.26e-003	1.44e-003
Toluene	9.33e-003	2.14e-003
Ethylbenzene	2.07e-003	4.75e-004
Xylenes	1.96e-002	4.49e-003
Total Components	100.00	2.29e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.22e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	2.26e+001
Water	3.36e+000	7.94e-001
Carbon Dioxide	9.58e-002	2.27e-002
Methane	2.19e-001	5.18e-002
Ethane	8.07e-002	1.91e-002
Propane	4.99e-002	1.18e-002
n-Butane	1.16e-001	2.74e-002
n-Pentane	1.62e-001	3.83e-002
n-Hexane	1.39e-002	3.28e-003
Other Hexanes	2.11e-002	4.99e-003
Heptanes	7.34e-003	1.74e-003
2,2,4-Trimethylpentane	7.23e-003	1.71e-003
Benzene	1.21e-001	2.87e-002
Toluene	1.15e-001	2.71e-002
Ethylbenzene	1.93e-002	4.56e-003
Xylenes	1.47e-001	3.48e-002
Total Components	100.00	2.37e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 1.88e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	8.41e-004
Carbon Dioxide	7.28e+000	1.59e-002
Methane	6.23e+001	4.96e-002
Ethane	1.12e+001	1.67e-002
Propane	4.16e+000	9.10e-003
n-Butane	6.21e+000	1.79e-002
n-Pentane	6.25e+000	2.23e-002
n-Hexane	3.48e-001	1.49e-003
Other Hexanes	6.00e-001	2.56e-003
Heptanes	1.06e-001	5.27e-004
2,2,4-Trimethylpentane	1.36e-001	7.68e-004
Benzene	2.38e-001	9.23e-004
Toluene	1.28e-001	5.87e-004
Ethylbenzene	1.13e-002	5.95e-005
Xylenes	5.98e-002	3.15e-004
Total Components	100.00	1.40e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 4.19e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	2.26e+001
Water	3.37e+000	7.93e-001
Carbon Dioxide	2.89e-002	6.80e-003
Methane	9.52e-003	2.24e-003
Ethane	1.03e-002	2.41e-003
Propane	1.15e-002	2.70e-003
n-Butane	4.06e-002	9.54e-003
n-Pentane	6.81e-002	1.60e-002
n-Hexane	7.63e-003	1.79e-003
Other Hexanes	1.03e-002	2.43e-003
Heptanes	5.14e-003	1.21e-003
2,2,4-Trimethylpentane	4.01e-003	9.43e-004
Benzene	1.18e-001	2.78e-002
Toluene	1.13e-001	2.65e-002
Ethylbenzene	1.91e-002	4.50e-003
Xylenes	1.46e-001	3.44e-002
Total Components	100.00	2.35e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.01e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	4.49e-001
Carbon Dioxide	5.78e-001	6.80e-003

Methane	5.23e-001	2.24e-003
Ethane	3.01e-001	2.41e-003
Propane	2.29e-001	2.70e-003
n-Butane	6.14e-001	9.54e-003
n-Pentane	8.20e-001	1.58e-002
n-Hexane	7.72e-002	1.78e-003
Other Hexanes	1.03e-001	2.38e-003
Heptanes	4.48e-002	1.20e-003
2,2,4-Trimethylpentane	3.01e-002	9.18e-004
Benzene	1.26e+000	2.64e-002
Toluene	9.89e-001	2.44e-002
Ethylbenzene	1.42e-001	4.03e-003
Xylenes	1.06e+000	3.00e-002
Total Components	100.00	5.79e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.2 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0777	1.865	0.3404
Ethane	0.0286	0.687	0.1254
Propane	0.0177	0.425	0.0775
n-Butane	0.0412	0.988	0.1803
n-Pentane	0.0572	1.374	0.2507
n-Hexane	0.0049	0.117	0.0214
Other Hexanes	0.0074	0.178	0.0325
Heptanes	0.0026	0.062	0.0113
2,2,4-Trimethylpentane	0.0025	0.061	0.0111
Benzene	0.0409	0.983	0.1794
Toluene	0.0374	0.898	0.1639
Ethylbenzene	0.0061	0.147	0.0269
Xylenes	0.0454	1.090	0.1989
Total Emissions	0.3698	8.874	1.6196
Total Hydrocarbon Emissions	0.3698	8.874	1.6196
Total VOC Emissions	0.2634	6.322	1.1537
Total HAP Emissions	0.1373	3.296	0.6015
Total BTEX Emissions	0.1299	3.118	0.5690

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.3000 MMSCF/day
Glycol Losses with Dry Gas: 0.0018 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e-001
Carbon Dioxide	9.99e-001	1.45e+001
Methane	8.99e+001	4.76e+002
Ethane	5.29e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.30e+001
n-Pentane	9.99e-001	2.38e+001
n-Hexane	4.19e-002	1.19e+000
Other Hexanes	8.39e-002	2.39e+000
Heptanes	9.99e-003	3.30e-001
2,2,4-Trimethylpentane	2.00e-002	7.53e-001
Benzene	1.04e-002	2.68e-001
Toluene	5.59e-003	1.70e-001
Ethylbenzene	5.99e-004	2.10e-002
Xylenes	3.40e-003	1.19e-001
Total Components	100.00	6.14e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	3.62e-002
Carbon Dioxide	9.98e-001	1.45e+001
Methane	9.00e+001	4.76e+002
Ethane	5.30e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.29e+001
n-Pentane	9.98e-001	2.37e+001
n-Hexane	4.18e-002	1.19e+000
Other Hexanes	8.38e-002	2.38e+000
Heptanes	9.92e-003	3.28e-001
2,2,4-Trimethylpentane	1.99e-002	7.50e-001
Benzene	8.81e-003	2.27e-001
Toluene	4.37e-003	1.33e-001
Ethylbenzene	4.25e-004	1.49e-002
Xylenes	2.10e-003	7.35e-002
Total Components	100.00	6.13e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 6.11e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	3.39e+001
Water	1.50e+000	5.16e-001
Carbon Dioxide	9.88e-012	3.40e-012
Methane	7.59e-018	2.61e-018
Ethane	3.93e-008	1.35e-008
Propane	2.09e-009	7.20e-010
n-Butane	2.97e-009	1.02e-009
n-Pentane	8.36e-004	2.88e-004
n-Hexane	7.15e-005	2.46e-005
Other Hexanes	2.17e-004	7.48e-005
Heptanes	3.78e-005	1.30e-005
2,2,4-Trimethylpentane	1.12e-004	3.85e-005
Benzene	6.26e-003	2.16e-003
Toluene	9.33e-003	3.21e-003
Ethylbenzene	2.07e-003	7.12e-004
Xylenes	1.96e-002	6.73e-003
Total Components	100.00	3.44e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 6.33e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	3.39e+001
Water	3.36e+000	1.19e+000
Carbon Dioxide	9.58e-002	3.40e-002
Methane	2.19e-001	7.77e-002
Ethane	8.07e-002	2.86e-002
Propane	4.99e-002	1.77e-002
n-Butane	1.16e-001	4.12e-002
n-Pentane	1.62e-001	5.75e-002
n-Hexane	1.39e-002	4.92e-003
Other Hexanes	2.11e-002	7.48e-003
Heptanes	7.34e-003	2.60e-003
2,2,4-Trimethylpentane	7.23e-003	2.57e-003
Benzene	1.21e-001	4.31e-002
Toluene	1.15e-001	4.06e-002
Ethylbenzene	1.93e-002	6.84e-003
Xylenes	1.47e-001	5.21e-002
Total Components	100.00	3.55e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.80e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	6.74e-001
Carbon Dioxide	1.63e+000	3.40e-002
Methane	1.02e+001	7.77e-002
Ethane	2.00e+000	2.86e-002
Propane	8.44e-001	1.77e-002
n-Butane	1.49e+000	4.12e-002
n-Pentane	1.67e+000	5.72e-002
n-Hexane	1.20e-001	4.90e-003
Other Hexanes	1.81e-001	7.41e-003
Heptanes	5.44e-002	2.59e-003
2,2,4-Trimethylpentane	4.66e-002	2.53e-003
Benzene	1.10e+000	4.09e-002
Toluene	8.55e-001	3.74e-002
Ethylbenzene	1.22e-001	6.13e-003
Xylenes	9.00e-001	4.54e-002
Total Components	100.00	1.08e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.3 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0034	0.081	0.0147
Ethane	0.0036	0.087	0.0159
Propane	0.0040	0.097	0.0177
n-Butane	0.0143	0.343	0.0627
n-Pentane	0.0237	0.569	0.1039
n-Hexane	0.0027	0.064	0.0117
Other Hexanes	0.0036	0.086	0.0156
Heptanes	0.0018	0.043	0.0079
2,2,4-Trimethylpentane	0.0014	0.033	0.0060
Benzene	0.0396	0.950	0.1733
Toluene	0.0365	0.877	0.1601
Ethylbenzene	0.0060	0.145	0.0265
Xylenes	0.0449	1.078	0.1968
Total Emissions	0.1855	4.453	0.8127

Total Hydrocarbon Emissions	0.1855	4.453	0.8127
Total VOC Emissions	0.1786	4.286	0.7821
Total HAP Emissions	0.1311	3.147	0.5743
Total BTEX Emissions	0.1271	3.050	0.5566

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0744	1.785	0.3257
Ethane	0.0250	0.600	0.1096
Propane	0.0136	0.327	0.0598
n-Butane	0.0268	0.644	0.1176
n-Pentane	0.0335	0.804	0.1468
n-Hexane	0.0022	0.054	0.0098
Other Hexanes	0.0038	0.092	0.0168
Heptanes	0.0008	0.019	0.0035

2,2,4-Trimethylpentane	0.0012	0.028	0.0050
Benzene	0.0014	0.033	0.0061
Toluene	0.0009	0.021	0.0039
Ethylbenzene	0.0001	0.002	0.0004
Xylenes	0.0005	0.011	0.0021
Total Emissions	0.1842	4.421	0.8069
Total Hydrocarbon Emissions	0.1842	4.421	0.8069
Total VOC Emissions	0.0848	2.036	0.3716
Total HAP Emissions	0.0062	0.149	0.0272
Total BTEX Emissions	0.0028	0.068	0.0124

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.3000 MMSCF/day
Glycol Losses with Dry Gas: 0.0018 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e-001
Carbon Dioxide	9.99e-001	1.45e+001
Methane	8.99e+001	4.76e+002
Ethane	5.29e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.30e+001
n-Pentane	9.99e-001	2.38e+001
n-Hexane	4.19e-002	1.19e+000
Other Hexanes	8.39e-002	2.39e+000
Heptanes	9.99e-003	3.30e-001
2,2,4-Trimethylpentane	2.00e-002	7.53e-001
Benzene	1.04e-002	2.68e-001
Toluene	5.59e-003	1.70e-001
Ethylbenzene	5.99e-004	2.10e-002
Xylenes	3.40e-003	1.19e-001
Total Components	100.00	6.14e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	3.62e-002
Carbon Dioxide	9.98e-001	1.45e+001
Methane	9.00e+001	4.76e+002
Ethane	5.30e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.29e+001
n-Pentane	9.98e-001	2.37e+001
n-Hexane	4.18e-002	1.19e+000
Other Hexanes	8.38e-002	2.38e+000
Heptanes	9.92e-003	3.28e-001
2,2,4-Trimethylpentane	1.99e-002	7.50e-001
Benzene	8.81e-003	2.27e-001
Toluene	4.37e-003	1.33e-001
Ethylbenzene	4.25e-004	1.49e-002
Xylenes	2.10e-003	7.35e-002
Total Components	100.00	6.13e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 6.11e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	3.39e+001
Water	1.50e+000	5.16e-001
Carbon Dioxide	9.88e-012	3.40e-012
Methane	7.59e-018	2.61e-018
Ethane	3.93e-008	1.35e-008
Propane	2.09e-009	7.20e-010
n-Butane	2.97e-009	1.02e-009
n-Pentane	8.36e-004	2.88e-004
n-Hexane	7.15e-005	2.46e-005
Other Hexanes	2.17e-004	7.48e-005
Heptanes	3.78e-005	1.30e-005
2,2,4-Trimethylpentane	1.12e-004	3.85e-005
Benzene	6.26e-003	2.16e-003
Toluene	9.33e-003	3.21e-003
Ethylbenzene	2.07e-003	7.12e-004
Xylenes	1.96e-002	6.73e-003
Total Components	100.00	3.44e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 6.33e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	3.39e+001
Water	3.36e+000	1.19e+000
Carbon Dioxide	9.58e-002	3.40e-002
Methane	2.19e-001	7.77e-002
Ethane	8.07e-002	2.86e-002
Propane	4.99e-002	1.77e-002
n-Butane	1.16e-001	4.12e-002
n-Pentane	1.62e-001	5.75e-002
n-Hexane	1.39e-002	4.92e-003
Other Hexanes	2.11e-002	7.48e-003
Heptanes	7.34e-003	2.60e-003
2,2,4-Trimethylpentane	7.23e-003	2.57e-003
Benzene	1.21e-001	4.31e-002
Toluene	1.15e-001	4.06e-002
Ethylbenzene	1.93e-002	6.84e-003
Xylenes	1.47e-001	5.21e-002
Total Components	100.00	3.55e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 2.82e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	1.26e-003
Carbon Dioxide	7.28e+000	2.38e-002
Methane	6.23e+001	7.44e-002
Ethane	1.12e+001	2.50e-002
Propane	4.16e+000	1.36e-002
n-Butane	6.21e+000	2.68e-002
n-Pentane	6.25e+000	3.35e-002
n-Hexane	3.48e-001	2.23e-003
Other Hexanes	6.00e-001	3.85e-003
Heptanes	1.06e-001	7.90e-004
2,2,4-Trimethylpentane	1.36e-001	1.15e-003
Benzene	2.38e-001	1.38e-003
Toluene	1.28e-001	8.80e-004
Ethylbenzene	1.13e-002	8.93e-005
Xylenes	5.98e-002	4.72e-004
Total Components	100.00	2.09e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 6.29e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	3.39e+001
Water	3.37e+000	1.19e+000
Carbon Dioxide	2.89e-002	1.02e-002
Methane	9.52e-003	3.36e-003
Ethane	1.03e-002	3.62e-003
Propane	1.15e-002	4.05e-003
n-Butane	4.06e-002	1.43e-002
n-Pentane	6.81e-002	2.40e-002
n-Hexane	7.63e-003	2.69e-003
Other Hexanes	1.03e-002	3.64e-003
Heptanes	5.14e-003	1.81e-003
2,2,4-Trimethylpentane	4.01e-003	1.42e-003
Benzene	1.18e-001	4.17e-002
Toluene	1.13e-001	3.98e-002
Ethylbenzene	1.91e-002	6.75e-003
Xylenes	1.46e-001	5.17e-002
Total Components	100.00	3.53e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.52e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	6.73e-001
Carbon Dioxide	5.78e-001	1.02e-002

Methane	5.23e-001	3.36e-003
Ethane	3.01e-001	3.62e-003
Propane	2.29e-001	4.05e-003
n-Butane	6.14e-001	1.43e-002
n-Pentane	8.20e-001	2.37e-002
n-Hexane	7.72e-002	2.67e-003
Other Hexanes	1.03e-001	3.56e-003
Heptanes	4.48e-002	1.80e-003
2,2,4-Trimethylpentane	3.01e-002	1.38e-003
Benzene	1.26e+000	3.96e-002
Toluene	9.89e-001	3.65e-002
Ethylbenzene	1.42e-001	6.04e-003
Xylenes	1.06e+000	4.49e-002
Total Components	100.00	8.69e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.3 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1036	2.487	0.4539
Ethane	0.0382	0.916	0.1672
Propane	0.0236	0.566	0.1033
n-Butane	0.0549	1.317	0.2404
n-Pentane	0.0763	1.831	0.3342
n-Hexane	0.0065	0.157	0.0286
Other Hexanes	0.0099	0.237	0.0433
Heptanes	0.0035	0.083	0.0151
2,2,4-Trimethylpentane	0.0034	0.081	0.0148
Benzene	0.0546	1.310	0.2391
Toluene	0.0499	1.198	0.2185
Ethylbenzene	0.0082	0.196	0.0358
Xylenes	0.0605	1.453	0.2652
Total Emissions	0.4930	11.832	2.1594
Total Hydrocarbon Emissions	0.4930	11.832	2.1594
Total VOC Emissions	0.3512	8.429	1.5383
Total HAP Emissions	0.1831	4.394	0.8020
Total BTEX Emissions	0.1732	4.157	0.7586

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.4000 MMSCF/day
Glycol Losses with Dry Gas: 0.0024 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	9.47e-001
Carbon Dioxide	9.99e-001	1.93e+001
Methane	8.99e+001	6.34e+002
Ethane	5.29e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.99e-001	3.17e+001
n-Hexane	4.19e-002	1.59e+000
Other Hexanes	8.39e-002	3.18e+000
Heptanes	9.99e-003	4.40e-001
2,2,4-Trimethylpentane	2.00e-002	1.00e+000
Benzene	1.04e-002	3.57e-001
Toluene	5.59e-003	2.27e-001
Ethylbenzene	5.99e-004	2.80e-002
Xylenes	3.40e-003	1.59e-001
Total Components	100.00	8.19e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	4.83e-002
Carbon Dioxide	9.98e-001	1.93e+001
Methane	9.00e+001	6.34e+002
Ethane	5.30e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.98e-001	3.16e+001
n-Hexane	4.18e-002	1.58e+000
Other Hexanes	8.38e-002	3.17e+000
Heptanes	9.92e-003	4.37e-001
2,2,4-Trimethylpentane	1.99e-002	1.00e+000
Benzene	8.81e-003	3.02e-001
Toluene	4.37e-003	1.77e-001
Ethylbenzene	4.25e-004	1.98e-002
Xylenes	2.10e-003	9.81e-002
Total Components	100.00	8.18e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 8.15e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	4.52e+001
Water	1.50e+000	6.88e-001
Carbon Dioxide	9.88e-012	4.53e-012
Methane	7.59e-018	3.48e-018
Ethane	3.93e-008	1.80e-008
Propane	2.09e-009	9.60e-010
n-Butane	2.97e-009	1.36e-009
n-Pentane	8.36e-004	3.83e-004
n-Hexane	7.15e-005	3.28e-005
Other Hexanes	2.17e-004	9.98e-005
Heptanes	3.78e-005	1.74e-005
2,2,4-Trimethylpentane	1.12e-004	5.13e-005
Benzene	6.26e-003	2.87e-003
Toluene	9.33e-003	4.28e-003
Ethylbenzene	2.07e-003	9.50e-004
Xylenes	1.96e-002	8.98e-003
Total Components	100.00	4.59e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.44e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	4.52e+001
Water	3.36e+000	1.59e+000
Carbon Dioxide	9.58e-002	4.53e-002
Methane	2.19e-001	1.04e-001
Ethane	8.07e-002	3.82e-002
Propane	4.99e-002	2.36e-002
n-Butane	1.16e-001	5.49e-002
n-Pentane	1.62e-001	7.67e-002
n-Hexane	1.39e-002	6.56e-003
Other Hexanes	2.11e-002	9.98e-003
Heptanes	7.34e-003	3.47e-003
2,2,4-Trimethylpentane	7.23e-003	3.42e-003
Benzene	1.21e-001	5.75e-002
Toluene	1.15e-001	5.42e-002
Ethylbenzene	1.93e-002	9.12e-003
Xylenes	1.47e-001	6.95e-002
Total Components	100.00	4.73e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.40e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	8.99e-001
Carbon Dioxide	1.63e+000	4.53e-002
Methane	1.02e+001	1.04e-001
Ethane	2.00e+000	3.82e-002
Propane	8.44e-001	2.36e-002
n-Butane	1.49e+000	5.49e-002
n-Pentane	1.67e+000	7.63e-002
n-Hexane	1.20e-001	6.53e-003
Other Hexanes	1.81e-001	9.88e-003
Heptanes	5.44e-002	3.45e-003
2,2,4-Trimethylpentane	4.66e-002	3.37e-003
Benzene	1.10e+000	5.46e-002
Toluene	8.55e-001	4.99e-002
Ethylbenzene	1.22e-001	8.17e-003
Xylenes	9.00e-001	6.05e-002
Total Components	100.00	1.44e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.4 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0045	0.108	0.0196
Ethane	0.0048	0.116	0.0212
Propane	0.0054	0.130	0.0237
n-Butane	0.0191	0.458	0.0836
n-Pentane	0.0316	0.759	0.1385
n-Hexane	0.0036	0.085	0.0156
Other Hexanes	0.0048	0.114	0.0208
Heptanes	0.0024	0.058	0.0105
2,2,4-Trimethylpentane	0.0018	0.044	0.0080
Benzene	0.0528	1.266	0.2311
Toluene	0.0487	1.169	0.2134
Ethylbenzene	0.0081	0.193	0.0353
Xylenes	0.0599	1.438	0.2624
Total Emissions	0.2474	5.938	1.0836
Total Hydrocarbon Emissions	0.2474	5.938	1.0836
Total VOC Emissions	0.2381	5.714	1.0428
Total HAP Emissions	0.1748	4.196	0.7657
Total BTEX Emissions	0.1694	4.067	0.7421

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0991	2.379	0.4342
Ethane	0.0334	0.801	0.1461
Propane	0.0182	0.437	0.0797
n-Butane	0.0358	0.859	0.1568
n-Pentane	0.0447	1.072	0.1957
n-Hexane	0.0030	0.071	0.0130
Other Hexanes	0.0051	0.123	0.0225
Heptanes	0.0011	0.025	0.0046

2,2,4-Trimethylpentane	0.0015	0.037	0.0067
Benzene	0.0018	0.044	0.0081
Toluene	0.0012	0.028	0.0051
Ethylbenzene	0.0001	0.003	0.0005
Xylenes	0.0006	0.015	0.0028
Total Emissions	0.2456	5.895	1.0758
Total Hydrocarbon Emissions	0.2456	5.895	1.0758
Total VOC Emissions	0.1131	2.715	0.4955
Total HAP Emissions	0.0083	0.199	0.0363
Total BTEX Emissions	0.0038	0.090	0.0165

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.4000 MMSCF/day
Glycol Losses with Dry Gas: 0.0024 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	9.47e-001
Carbon Dioxide	9.99e-001	1.93e+001
Methane	8.99e+001	6.34e+002
Ethane	5.29e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.99e-001	3.17e+001
n-Hexane	4.19e-002	1.59e+000
Other Hexanes	8.39e-002	3.18e+000
Heptanes	9.99e-003	4.40e-001
2,2,4-Trimethylpentane	2.00e-002	1.00e+000
Benzene	1.04e-002	3.57e-001
Toluene	5.59e-003	2.27e-001
Ethylbenzene	5.99e-004	2.80e-002
Xylenes	3.40e-003	1.59e-001
Total Components	100.00	8.19e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	4.83e-002
Carbon Dioxide	9.98e-001	1.93e+001
Methane	9.00e+001	6.34e+002
Ethane	5.30e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.98e-001	3.16e+001
n-Hexane	4.18e-002	1.58e+000
Other Hexanes	8.38e-002	3.17e+000
Heptanes	9.92e-003	4.37e-001
2,2,4-Trimethylpentane	1.99e-002	1.00e+000
Benzene	8.81e-003	3.02e-001
Toluene	4.37e-003	1.77e-001
Ethylbenzene	4.25e-004	1.98e-002
Xylenes	2.10e-003	9.81e-002
Total Components	100.00	8.18e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 8.15e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	4.52e+001
Water	1.50e+000	6.88e-001
Carbon Dioxide	9.88e-012	4.53e-012
Methane	7.59e-018	3.48e-018
Ethane	3.93e-008	1.80e-008
Propane	2.09e-009	9.60e-010
n-Butane	2.97e-009	1.36e-009
n-Pentane	8.36e-004	3.83e-004
n-Hexane	7.15e-005	3.28e-005
Other Hexanes	2.17e-004	9.98e-005
Heptanes	3.78e-005	1.74e-005
2,2,4-Trimethylpentane	1.12e-004	5.13e-005
Benzene	6.26e-003	2.87e-003
Toluene	9.33e-003	4.28e-003
Ethylbenzene	2.07e-003	9.50e-004
Xylenes	1.96e-002	8.98e-003
Total Components	100.00	4.59e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.44e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	4.52e+001
Water	3.36e+000	1.59e+000
Carbon Dioxide	9.58e-002	4.53e-002
Methane	2.19e-001	1.04e-001
Ethane	8.07e-002	3.82e-002
Propane	4.99e-002	2.36e-002
n-Butane	1.16e-001	5.49e-002
n-Pentane	1.62e-001	7.67e-002
n-Hexane	1.39e-002	6.56e-003
Other Hexanes	2.11e-002	9.98e-003
Heptanes	7.34e-003	3.47e-003
2,2,4-Trimethylpentane	7.23e-003	3.42e-003
Benzene	1.21e-001	5.75e-002
Toluene	1.15e-001	5.42e-002
Ethylbenzene	1.93e-002	9.12e-003
Xylenes	1.47e-001	6.95e-002
Total Components	100.00	4.73e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 3.76e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	1.68e-003
Carbon Dioxide	7.28e+000	3.17e-002
Methane	6.23e+001	9.91e-002
Ethane	1.12e+001	3.34e-002
Propane	4.16e+000	1.82e-002
n-Butane	6.21e+000	3.58e-002
n-Pentane	6.25e+000	4.47e-002
n-Hexane	3.48e-001	2.97e-003
Other Hexanes	6.00e-001	5.13e-003
Heptanes	1.06e-001	1.05e-003
2,2,4-Trimethylpentane	1.36e-001	1.54e-003
Benzene	2.38e-001	1.85e-003
Toluene	1.28e-001	1.17e-003
Ethylbenzene	1.13e-002	1.19e-004
Xylenes	5.98e-002	6.30e-004
Total Components	100.00	2.79e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 8.38e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	4.52e+001
Water	3.37e+000	1.59e+000
Carbon Dioxide	2.89e-002	1.36e-002
Methane	9.52e-003	4.48e-003
Ethane	1.03e-002	4.83e-003
Propane	1.15e-002	5.40e-003
n-Butane	4.06e-002	1.91e-002
n-Pentane	6.81e-002	3.20e-002
n-Hexane	7.63e-003	3.59e-003
Other Hexanes	1.03e-002	4.85e-003
Heptanes	5.14e-003	2.42e-003
2,2,4-Trimethylpentane	4.01e-003	1.89e-003
Benzene	1.18e-001	5.56e-002
Toluene	1.13e-001	5.30e-002
Ethylbenzene	1.91e-002	9.00e-003
Xylenes	1.46e-001	6.89e-002
Total Components	100.00	4.70e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.03e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	8.97e-001
Carbon Dioxide	5.78e-001	1.36e-002

Methane	5.23e-001	4.48e-003
Ethane	3.01e-001	4.83e-003
Propane	2.29e-001	5.40e-003
n-Butane	6.14e-001	1.91e-002
n-Pentane	8.20e-001	3.16e-002
n-Hexane	7.72e-002	3.55e-003
Other Hexanes	1.03e-001	4.75e-003
Heptanes	4.48e-002	2.40e-003
2,2,4-Trimethylpentane	3.01e-002	1.84e-003
Benzene	1.26e+000	5.28e-002
Toluene	9.89e-001	4.87e-002
Ethylbenzene	1.42e-001	8.06e-003
Xylenes	1.06e+000	5.99e-002
Total Components	100.00	1.16e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.4 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1295	3.109	0.5673
Ethane	0.0477	1.146	0.2091
Propane	0.0295	0.708	0.1292
n-Butane	0.0686	1.646	0.3004
n-Pentane	0.0954	2.289	0.4178
n-Hexane	0.0082	0.196	0.0357
Other Hexanes	0.0123	0.296	0.0541
Heptanes	0.0043	0.104	0.0189
2,2,4-Trimethylpentane	0.0042	0.101	0.0185
Benzene	0.0682	1.638	0.2989
Toluene	0.0624	1.497	0.2732
Ethylbenzene	0.0102	0.245	0.0448
Xylenes	0.0757	1.816	0.3314
Total Emissions	0.6163	14.791	2.6993

Total Hydrocarbon Emissions	0.6163	14.791	2.6993
Total VOC Emissions	0.4390	10.536	1.9229
Total HAP Emissions	0.2289	5.493	1.0025
Total BTEX Emissions	0.2165	5.196	0.9483

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.5000 MMSCF/day
Glycol Losses with Dry Gas: 0.0030 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.09e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.18e+000
Carbon Dioxide	9.99e-001	2.42e+001
Methane	8.99e+001	7.93e+002
Ethane	5.29e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.83e+001
n-Pentane	9.99e-001	3.96e+001
n-Hexane	4.19e-002	1.99e+000
Other Hexanes	8.39e-002	3.98e+000
Heptanes	9.99e-003	5.50e-001
2,2,4-Trimethylpentane	2.00e-002	1.25e+000
Benzene	1.04e-002	4.46e-001
Toluene	5.59e-003	2.83e-001
Ethylbenzene	5.99e-004	3.50e-002
Xylenes	3.40e-003	1.98e-001
Total Components	100.00	1.02e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.08e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	6.03e-002
Carbon Dioxide	9.98e-001	2.41e+001
Methane	9.00e+001	7.93e+002
Ethane	5.30e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.82e+001
n-Pentane	9.98e-001	3.95e+001
n-Hexane	4.18e-002	1.98e+000
Other Hexanes	8.38e-002	3.96e+000
Heptanes	9.92e-003	5.46e-001
2,2,4-Trimethylpentane	1.99e-002	1.25e+000
Benzene	8.81e-003	3.78e-001
Toluene	4.37e-003	2.21e-001
Ethylbenzene	4.25e-004	2.48e-002
Xylenes	2.10e-003	1.23e-001
Total Components	100.00	1.02e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.02e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	5.65e+001
Water	1.50e+000	8.60e-001
Carbon Dioxide	9.88e-012	5.67e-012
Methane	7.59e-018	4.35e-018
Ethane	3.93e-008	2.25e-008
Propane	2.09e-009	1.20e-009
n-Butane	2.97e-009	1.70e-009
n-Pentane	8.36e-004	4.79e-004
n-Hexane	7.15e-005	4.10e-005
Other Hexanes	2.17e-004	1.25e-004
Heptanes	3.78e-005	2.17e-005
2,2,4-Trimethylpentane	1.12e-004	6.42e-005
Benzene	6.26e-003	3.59e-003
Toluene	9.33e-003	5.35e-003
Ethylbenzene	2.07e-003	1.19e-003
Xylenes	1.96e-002	1.12e-002
Total Components	100.00	5.74e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.06e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	5.65e+001
Water	3.36e+000	1.98e+000
Carbon Dioxide	9.58e-002	5.67e-002
Methane	2.19e-001	1.30e-001
Ethane	8.07e-002	4.77e-002
Propane	4.99e-002	2.95e-002
n-Butane	1.16e-001	6.86e-002
n-Pentane	1.62e-001	9.59e-002
n-Hexane	1.39e-002	8.20e-003
Other Hexanes	2.11e-002	1.25e-002
Heptanes	7.34e-003	4.34e-003
2,2,4-Trimethylpentane	7.23e-003	4.28e-003
Benzene	1.21e-001	7.18e-002
Toluene	1.15e-001	6.77e-002
Ethylbenzene	1.93e-002	1.14e-002
Xylenes	1.47e-001	8.69e-002
Total Components	100.00	5.91e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.00e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.12e+000
Carbon Dioxide	1.63e+000	5.67e-002
Methane	1.02e+001	1.30e-001
Ethane	2.00e+000	4.77e-002
Propane	8.44e-001	2.95e-002
n-Butane	1.49e+000	6.86e-002
n-Pentane	1.67e+000	9.54e-002
n-Hexane	1.20e-001	8.16e-003
Other Hexanes	1.81e-001	1.23e-002
Heptanes	5.44e-002	4.32e-003
2,2,4-Trimethylpentane	4.66e-002	4.21e-003
Benzene	1.10e+000	6.82e-002
Toluene	8.55e-001	6.24e-002
Ethylbenzene	1.22e-001	1.02e-002
Xylenes	9.00e-001	7.57e-002
Total Components	100.00	1.80e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.5 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0056	0.134	0.0245
Ethane	0.0060	0.145	0.0264
Propane	0.0067	0.162	0.0296
n-Butane	0.0239	0.572	0.1045
n-Pentane	0.0395	0.949	0.1732
n-Hexane	0.0044	0.107	0.0195
Other Hexanes	0.0059	0.143	0.0260
Heptanes	0.0030	0.072	0.0131
2,2,4-Trimethylpentane	0.0023	0.055	0.0100
Benzene	0.0659	1.583	0.2888
Toluene	0.0609	1.462	0.2668
Ethylbenzene	0.0101	0.242	0.0441
Xylenes	0.0749	1.797	0.3280
Total Emissions	0.3092	7.422	1.3545
Total Hydrocarbon Emissions	0.3092	7.422	1.3545
Total VOC Emissions	0.2976	7.143	1.3035
Total HAP Emissions	0.2185	5.245	0.9572
Total BTEX Emissions	0.2118	5.083	0.9277

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1239	2.974	0.5428
Ethane	0.0417	1.001	0.1826
Propane	0.0227	0.546	0.0996
n-Butane	0.0447	1.074	0.1960
n-Pentane	0.0559	1.340	0.2446
n-Hexane	0.0037	0.089	0.0163
Other Hexanes	0.0064	0.154	0.0281
Heptanes	0.0013	0.032	0.0058

2,2,4-Trimethylpentane	0.0019	0.046	0.0084
Benzene	0.0023	0.055	0.0101
Toluene	0.0015	0.035	0.0064
Ethylbenzene	0.0001	0.004	0.0007
Xylenes	0.0008	0.019	0.0034
Total Emissions	0.3070	7.369	1.3448
Total Hydrocarbon Emissions	0.3070	7.369	1.3448
Total VOC Emissions	0.1414	3.394	0.6194
Total HAP Emissions	0.0103	0.248	0.0453
Total BTEX Emissions	0.0047	0.113	0.0206

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.5000 MMSCF/day
Glycol Losses with Dry Gas: 0.0030 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 2.09e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.18e+000
Carbon Dioxide	9.99e-001	2.42e+001
Methane	8.99e+001	7.93e+002
Ethane	5.29e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.83e+001
n-Pentane	9.99e-001	3.96e+001
n-Hexane	4.19e-002	1.99e+000
Other Hexanes	8.39e-002	3.98e+000
Heptanes	9.99e-003	5.50e-001
2,2,4-Trimethylpentane	2.00e-002	1.25e+000
Benzene	1.04e-002	4.46e-001
Toluene	5.59e-003	2.83e-001
Ethylbenzene	5.99e-004	3.50e-002
Xylenes	3.40e-003	1.98e-001
Total Components	100.00	1.02e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.08e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	6.03e-002
Carbon Dioxide	9.98e-001	2.41e+001
Methane	9.00e+001	7.93e+002
Ethane	5.30e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.82e+001
n-Pentane	9.98e-001	3.95e+001
n-Hexane	4.18e-002	1.98e+000
Other Hexanes	8.38e-002	3.96e+000
Heptanes	9.92e-003	5.46e-001
2,2,4-Trimethylpentane	1.99e-002	1.25e+000
Benzene	8.81e-003	3.78e-001
Toluene	4.37e-003	2.21e-001
Ethylbenzene	4.25e-004	2.48e-002
Xylenes	2.10e-003	1.23e-001
Total Components	100.00	1.02e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.02e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	5.65e+001
Water	1.50e+000	8.60e-001
Carbon Dioxide	9.88e-012	5.67e-012
Methane	7.59e-018	4.35e-018
Ethane	3.93e-008	2.25e-008
Propane	2.09e-009	1.20e-009
n-Butane	2.97e-009	1.70e-009
n-Pentane	8.36e-004	4.79e-004
n-Hexane	7.15e-005	4.10e-005
Other Hexanes	2.17e-004	1.25e-004
Heptanes	3.78e-005	2.17e-005
2,2,4-Trimethylpentane	1.12e-004	6.42e-005
Benzene	6.26e-003	3.59e-003
Toluene	9.33e-003	5.35e-003
Ethylbenzene	2.07e-003	1.19e-003
Xylenes	1.96e-002	1.12e-002
Total Components	100.00	5.74e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.06e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	5.65e+001
Water	3.36e+000	1.98e+000
Carbon Dioxide	9.58e-002	5.67e-002
Methane	2.19e-001	1.30e-001
Ethane	8.07e-002	4.77e-002
Propane	4.99e-002	2.95e-002
n-Butane	1.16e-001	6.86e-002
n-Pentane	1.62e-001	9.59e-002
n-Hexane	1.39e-002	8.20e-003
Other Hexanes	2.11e-002	1.25e-002
Heptanes	7.34e-003	4.34e-003
2,2,4-Trimethylpentane	7.23e-003	4.28e-003
Benzene	1.21e-001	7.18e-002
Toluene	1.15e-001	6.77e-002
Ethylbenzene	1.93e-002	1.14e-002
Xylenes	1.47e-001	8.69e-002
Total Components	100.00	5.91e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 4.70e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	2.10e-003
Carbon Dioxide	7.28e+000	3.97e-002
Methane	6.23e+001	1.24e-001
Ethane	1.12e+001	4.17e-002
Propane	4.16e+000	2.27e-002
n-Butane	6.21e+000	4.47e-002
n-Pentane	6.25e+000	5.59e-002
n-Hexane	3.48e-001	3.72e-003
Other Hexanes	6.00e-001	6.41e-003
Heptanes	1.06e-001	1.32e-003
2,2,4-Trimethylpentane	1.36e-001	1.92e-003
Benzene	2.38e-001	2.31e-003
Toluene	1.28e-001	1.47e-003
Ethylbenzene	1.13e-002	1.49e-004
Xylenes	5.98e-002	7.87e-004
Total Components	100.00	3.49e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.05e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	5.65e+001
Water	3.37e+000	1.98e+000
Carbon Dioxide	2.89e-002	1.70e-002
Methane	9.52e-003	5.60e-003
Ethane	1.03e-002	6.04e-003
Propane	1.15e-002	6.75e-003
n-Butane	4.06e-002	2.39e-002
n-Pentane	6.81e-002	4.00e-002
n-Hexane	7.63e-003	4.48e-003
Other Hexanes	1.03e-002	6.06e-003
Heptanes	5.14e-003	3.02e-003
2,2,4-Trimethylpentane	4.01e-003	2.36e-003
Benzene	1.18e-001	6.95e-002
Toluene	1.13e-001	6.63e-002
Ethylbenzene	1.91e-002	1.13e-002
Xylenes	1.46e-001	8.61e-002
Total Components	100.00	5.88e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.53e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.12e+000
Carbon Dioxide	5.78e-001	1.70e-002

Methane	5.23e-001	5.60e-003
Ethane	3.01e-001	6.04e-003
Propane	2.29e-001	6.75e-003
n-Butane	6.14e-001	2.39e-002
n-Pentane	8.20e-001	3.95e-002
n-Hexane	7.72e-002	4.44e-003
Other Hexanes	1.03e-001	5.94e-003
Heptanes	4.48e-002	3.00e-003
2,2,4-Trimethylpentane	3.01e-002	2.29e-003
Benzene	1.26e+000	6.59e-002
Toluene	9.89e-001	6.09e-002
Ethylbenzene	1.42e-001	1.01e-002
Xylenes	1.06e+000	7.49e-002
Total Components	100.00	1.45e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.5 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1554	3.730	0.6808
Ethane	0.0573	1.375	0.2509
Propane	0.0354	0.849	0.1550
n-Butane	0.0823	1.976	0.3605
n-Pentane	0.1145	2.747	0.5014
n-Hexane	0.0098	0.235	0.0429
Other Hexanes	0.0148	0.356	0.0649
Heptanes	0.0052	0.124	0.0227
2,2,4-Trimethylpentane	0.0051	0.121	0.0221
Benzene	0.0819	1.965	0.3587
Toluene	0.0748	1.796	0.3278
Ethylbenzene	0.0123	0.294	0.0537
Xylenes	0.0908	2.179	0.3977
Total Emissions	0.7395	17.749	3.2391
Total Hydrocarbon Emissions	0.7395	17.749	3.2391
Total VOC Emissions	0.5268	12.644	2.3075
Total HAP Emissions	0.2747	6.592	1.2030
Total BTEX Emissions	0.2598	6.235	1.1380

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.6000 MMSCF/day
Glycol Losses with Dry Gas: 0.0036 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.42e+000
Carbon Dioxide	9.99e-001	2.90e+001
Methane	8.99e+001	9.52e+002
Ethane	5.29e+000	1.05e+002
Propane	1.30e+000	3.78e+001
n-Butane	1.20e+000	4.60e+001
n-Pentane	9.99e-001	4.76e+001
n-Hexane	4.19e-002	2.39e+000
Other Hexanes	8.39e-002	4.77e+000
Heptanes	9.99e-003	6.60e-001
2,2,4-Trimethylpentane	2.00e-002	1.51e+000
Benzene	1.04e-002	5.35e-001
Toluene	5.59e-003	3.40e-001
Ethylbenzene	5.99e-004	4.20e-002
Xylenes	3.40e-003	2.38e-001
Total Components	100.00	1.23e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	7.24e-002
Carbon Dioxide	9.98e-001	2.89e+001
Methane	9.00e+001	9.52e+002
Ethane	5.30e+000	1.05e+002
Propane	1.30e+000	3.77e+001
n-Butane	1.20e+000	4.59e+001
n-Pentane	9.98e-001	4.74e+001
n-Hexane	4.18e-002	2.38e+000
Other Hexanes	8.38e-002	4.76e+000
Heptanes	9.92e-003	6.55e-001
2,2,4-Trimethylpentane	1.99e-002	1.50e+000
Benzene	8.81e-003	4.53e-001
Toluene	4.37e-003	2.65e-001
Ethylbenzene	4.25e-004	2.97e-002
Xylenes	2.10e-003	1.47e-001
Total Components	100.00	1.23e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.22e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	6.78e+001
Water	1.50e+000	1.03e+000
Carbon Dioxide	9.88e-012	6.80e-012
Methane	7.59e-018	5.22e-018
Ethane	3.93e-008	2.70e-008
Propane	2.09e-009	1.44e-009
n-Butane	2.97e-009	2.04e-009
n-Pentane	8.36e-004	5.75e-004
n-Hexane	7.15e-005	4.92e-005
Other Hexanes	2.17e-004	1.50e-004
Heptanes	3.78e-005	2.60e-005
2,2,4-Trimethylpentane	1.12e-004	7.70e-005
Benzene	6.26e-003	4.31e-003
Toluene	9.33e-003	6.42e-003
Ethylbenzene	2.07e-003	1.42e-003
Xylenes	1.96e-002	1.35e-002
Total Components	100.00	6.88e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.27e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	6.77e+001
Water	3.36e+000	2.38e+000
Carbon Dioxide	9.58e-002	6.80e-002
Methane	2.19e-001	1.55e-001
Ethane	8.07e-002	5.73e-002
Propane	4.99e-002	3.54e-002
n-Butane	1.16e-001	8.23e-002
n-Pentane	1.62e-001	1.15e-001
n-Hexane	1.39e-002	9.84e-003
Other Hexanes	2.11e-002	1.50e-002
Heptanes	7.34e-003	5.21e-003
2,2,4-Trimethylpentane	7.23e-003	5.13e-003
Benzene	1.21e-001	8.62e-002
Toluene	1.15e-001	8.13e-002
Ethylbenzene	1.93e-002	1.37e-002
Xylenes	1.47e-001	1.04e-001
Total Components	100.00	7.10e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.61e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.35e+000
Carbon Dioxide	1.63e+000	6.80e-002
Methane	1.02e+001	1.55e-001
Ethane	2.00e+000	5.73e-002
Propane	8.44e-001	3.54e-002
n-Butane	1.49e+000	8.23e-002
n-Pentane	1.67e+000	1.14e-001
n-Hexane	1.20e-001	9.79e-003
Other Hexanes	1.81e-001	1.48e-002
Heptanes	5.44e-002	5.18e-003
2,2,4-Trimethylpentane	4.66e-002	5.06e-003
Benzene	1.10e+000	8.19e-002
Toluene	8.55e-001	7.48e-002
Ethylbenzene	1.22e-001	1.23e-002
Xylenes	9.00e-001	9.08e-002
Total Components	100.00	2.16e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.6 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0067	0.161	0.0294
Ethane	0.0072	0.174	0.0317
Propane	0.0081	0.194	0.0355
n-Butane	0.0286	0.687	0.1254
n-Pentane	0.0474	1.139	0.2078
n-Hexane	0.0053	0.128	0.0233
Other Hexanes	0.0071	0.171	0.0312
Heptanes	0.0036	0.086	0.0158
2,2,4-Trimethylpentane	0.0028	0.066	0.0121
Benzene	0.0791	1.899	0.3466
Toluene	0.0731	1.754	0.3201
Ethylbenzene	0.0121	0.290	0.0529
Xylenes	0.0899	2.157	0.3936
Total Emissions	0.3711	8.906	1.6254

Total Hydrocarbon Emissions	0.3711	8.906	1.6254
Total VOC Emissions	0.3571	8.571	1.5642
Total HAP Emissions	0.2622	6.294	1.1486
Total BTEX Emissions	0.2542	6.100	1.1132

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1487	3.569	0.6514
Ethane	0.0500	1.201	0.2191
Propane	0.0273	0.655	0.1195
n-Butane	0.0537	1.289	0.2352
n-Pentane	0.0670	1.609	0.2936
n-Hexane	0.0045	0.107	0.0195
Other Hexanes	0.0077	0.185	0.0337
Heptanes	0.0016	0.038	0.0069

2,2,4-Trimethylpentane	0.0023	0.055	0.0101
Benzene	0.0028	0.066	0.0121
Toluene	0.0018	0.042	0.0077
Ethylbenzene	0.0002	0.004	0.0008
Xylenes	0.0009	0.023	0.0041
Total Emissions	0.3684	8.843	1.6138
Total Hydrocarbon Emissions	0.3684	8.843	1.6138
Total VOC Emissions	0.1697	4.073	0.7433
Total HAP Emissions	0.0124	0.298	0.0544
Total BTEX Emissions	0.0057	0.136	0.0248

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.6000 MMSCF/day
Glycol Losses with Dry Gas: 0.0036 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.42e+000
Carbon Dioxide	9.99e-001	2.90e+001
Methane	8.99e+001	9.52e+002
Ethane	5.29e+000	1.05e+002
Propane	1.30e+000	3.78e+001
n-Butane	1.20e+000	4.60e+001
n-Pentane	9.99e-001	4.76e+001
n-Hexane	4.19e-002	2.39e+000
Other Hexanes	8.39e-002	4.77e+000
Heptanes	9.99e-003	6.60e-001
2,2,4-Trimethylpentane	2.00e-002	1.51e+000
Benzene	1.04e-002	5.35e-001
Toluene	5.59e-003	3.40e-001
Ethylbenzene	5.99e-004	4.20e-002
Xylenes	3.40e-003	2.38e-001
Total Components	100.00	1.23e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	7.24e-002
Carbon Dioxide	9.98e-001	2.89e+001
Methane	9.00e+001	9.52e+002
Ethane	5.30e+000	1.05e+002
Propane	1.30e+000	3.77e+001
n-Butane	1.20e+000	4.59e+001
n-Pentane	9.98e-001	4.74e+001
n-Hexane	4.18e-002	2.38e+000
Other Hexanes	8.38e-002	4.76e+000
Heptanes	9.92e-003	6.55e-001
2,2,4-Trimethylpentane	1.99e-002	1.50e+000
Benzene	8.81e-003	4.53e-001
Toluene	4.37e-003	2.65e-001
Ethylbenzene	4.25e-004	2.97e-002
Xylenes	2.10e-003	1.47e-001
Total Components	100.00	1.23e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.22e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	6.78e+001
Water	1.50e+000	1.03e+000
Carbon Dioxide	9.88e-012	6.80e-012
Methane	7.59e-018	5.22e-018
Ethane	3.93e-008	2.70e-008
Propane	2.09e-009	1.44e-009
n-Butane	2.97e-009	2.04e-009
n-Pentane	8.36e-004	5.75e-004
n-Hexane	7.15e-005	4.92e-005
Other Hexanes	2.17e-004	1.50e-004
Heptanes	3.78e-005	2.60e-005
2,2,4-Trimethylpentane	1.12e-004	7.70e-005
Benzene	6.26e-003	4.31e-003
Toluene	9.33e-003	6.42e-003
Ethylbenzene	2.07e-003	1.42e-003
Xylenes	1.96e-002	1.35e-002
Total Components	100.00	6.88e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.27e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	6.77e+001
Water	3.36e+000	2.38e+000
Carbon Dioxide	9.58e-002	6.80e-002
Methane	2.19e-001	1.55e-001
Ethane	8.07e-002	5.73e-002
Propane	4.99e-002	3.54e-002
n-Butane	1.16e-001	8.23e-002
n-Pentane	1.62e-001	1.15e-001
n-Hexane	1.39e-002	9.84e-003
Other Hexanes	2.11e-002	1.50e-002
Heptanes	7.34e-003	5.21e-003
2,2,4-Trimethylpentane	7.23e-003	5.13e-003
Benzene	1.21e-001	8.62e-002
Toluene	1.15e-001	8.13e-002
Ethylbenzene	1.93e-002	1.37e-002
Xylenes	1.47e-001	1.04e-001
Total Components	100.00	7.10e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 5.64e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	2.52e-003
Carbon Dioxide	7.28e+000	4.76e-002
Methane	6.23e+001	1.49e-001
Ethane	1.12e+001	5.00e-002
Propane	4.16e+000	2.73e-002
n-Butane	6.21e+000	5.37e-002
n-Pentane	6.25e+000	6.70e-002
n-Hexane	3.48e-001	4.46e-003
Other Hexanes	6.00e-001	7.69e-003
Heptanes	1.06e-001	1.58e-003
2,2,4-Trimethylpentane	1.36e-001	2.30e-003
Benzene	2.38e-001	2.77e-003
Toluene	1.28e-001	1.76e-003
Ethylbenzene	1.13e-002	1.79e-004
Xylenes	5.98e-002	9.45e-004
Total Components	100.00	4.19e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.26e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	6.77e+001
Water	3.37e+000	2.38e+000
Carbon Dioxide	2.89e-002	2.04e-002
Methane	9.52e-003	6.72e-003
Ethane	1.03e-002	7.24e-003
Propane	1.15e-002	8.10e-003
n-Butane	4.06e-002	2.86e-002
n-Pentane	6.81e-002	4.80e-002
n-Hexane	7.63e-003	5.38e-003
Other Hexanes	1.03e-002	7.28e-003
Heptanes	5.14e-003	3.63e-003
2,2,4-Trimethylpentane	4.01e-003	2.83e-003
Benzene	1.18e-001	8.34e-002
Toluene	1.13e-001	7.95e-002
Ethylbenzene	1.91e-002	1.35e-002
Xylenes	1.46e-001	1.03e-001
Total Components	100.00	7.05e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.04e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.35e+000
Carbon Dioxide	5.78e-001	2.04e-002

Methane	5.23e-001	6.72e-003
Ethane	3.01e-001	7.24e-003
Propane	2.29e-001	8.10e-003
n-Butane	6.14e-001	2.86e-002
n-Pentane	8.20e-001	4.74e-002
n-Hexane	7.72e-002	5.33e-003
Other Hexanes	1.03e-001	7.13e-003
Heptanes	4.48e-002	3.60e-003
2,2,4-Trimethylpentane	3.01e-002	2.75e-003
Benzene	1.26e+000	7.91e-002
Toluene	9.89e-001	7.31e-002
Ethylbenzene	1.42e-001	1.21e-002
Xylenes	1.06e+000	8.99e-002
Total Components	100.00	1.74e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.6 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1813	4.352	0.7943
Ethane	0.0668	1.604	0.2927
Propane	0.0413	0.991	0.1808
n-Butane	0.0960	2.305	0.4206
n-Pentane	0.1335	3.205	0.5849
n-Hexane	0.0114	0.274	0.0500
Other Hexanes	0.0173	0.415	0.0757
Heptanes	0.0060	0.145	0.0265
2,2,4-Trimethylpentane	0.0059	0.142	0.0258
Benzene	0.0955	2.293	0.4185
Toluene	0.0873	2.096	0.3825
Ethylbenzene	0.0143	0.343	0.0627
Xylenes	0.1059	2.543	0.4640
Total Emissions	0.8628	20.707	3.7790
Total Hydrocarbon Emissions	0.8628	20.707	3.7790
Total VOC Emissions	0.6146	14.751	2.6921
Total HAP Emissions	0.3204	7.690	1.4035
Total BTEX Emissions	0.3031	7.275	1.3276

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.7000 MMSCF/day
Glycol Losses with Dry Gas: 0.0042 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.66e+000
Carbon Dioxide	9.99e-001	3.38e+001
Methane	8.99e+001	1.11e+003
Ethane	5.29e+000	1.23e+002
Propane	1.30e+000	4.41e+001
n-Butane	1.20e+000	5.36e+001
n-Pentane	9.99e-001	5.55e+001
n-Hexane	4.19e-002	2.78e+000
Other Hexanes	8.39e-002	5.57e+000
Heptanes	9.99e-003	7.71e-001
2,2,4-Trimethylpentane	2.00e-002	1.76e+000
Benzene	1.04e-002	6.25e-001
Toluene	5.59e-003	3.97e-001
Ethylbenzene	5.99e-004	4.90e-002
Xylenes	3.40e-003	2.78e-001
Total Components	100.00	1.43e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	8.44e-002
Carbon Dioxide	9.98e-001	3.38e+001
Methane	9.00e+001	1.11e+003
Ethane	5.30e+000	1.22e+002
Propane	1.30e+000	4.40e+001
n-Butane	1.20e+000	5.35e+001
n-Pentane	9.98e-001	5.53e+001
n-Hexane	4.18e-002	2.77e+000
Other Hexanes	8.38e-002	5.55e+000
Heptanes	9.92e-003	7.64e-001
2,2,4-Trimethylpentane	1.99e-002	1.75e+000
Benzene	8.81e-003	5.29e-001
Toluene	4.37e-003	3.09e-001
Ethylbenzene	4.25e-004	3.47e-002
Xylenes	2.10e-003	1.72e-001
Total Components	100.00	1.43e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.43e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	7.91e+001
Water	1.50e+000	1.20e+000
Carbon Dioxide	9.88e-012	7.93e-012
Methane	7.59e-018	6.09e-018
Ethane	3.93e-008	3.15e-008
Propane	2.09e-009	1.68e-009
n-Butane	2.97e-009	2.38e-009
n-Pentane	8.36e-004	6.71e-004
n-Hexane	7.15e-005	5.74e-005
Other Hexanes	2.17e-004	1.75e-004
Heptanes	3.78e-005	3.04e-005
2,2,4-Trimethylpentane	1.12e-004	8.98e-005
Benzene	6.26e-003	5.03e-003
Toluene	9.33e-003	7.49e-003
Ethylbenzene	2.07e-003	1.66e-003
Xylenes	1.96e-002	1.57e-002
Total Components	100.00	8.03e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.48e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	7.90e+001
Water	3.36e+000	2.78e+000
Carbon Dioxide	9.58e-002	7.94e-002
Methane	2.19e-001	1.81e-001
Ethane	8.07e-002	6.68e-002
Propane	4.99e-002	4.13e-002
n-Butane	1.16e-001	9.60e-002
n-Pentane	1.62e-001	1.34e-001
n-Hexane	1.39e-002	1.15e-002
Other Hexanes	2.11e-002	1.75e-002
Heptanes	7.34e-003	6.08e-003
2,2,4-Trimethylpentane	7.23e-003	5.99e-003
Benzene	1.21e-001	1.01e-001
Toluene	1.15e-001	9.48e-002
Ethylbenzene	1.93e-002	1.60e-002
Xylenes	1.47e-001	1.22e-001
Total Components	100.00	8.28e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 4.21e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.57e+000
Carbon Dioxide	1.63e+000	7.94e-002
Methane	1.02e+001	1.81e-001
Ethane	2.00e+000	6.68e-002
Propane	8.44e-001	4.13e-002
n-Butane	1.49e+000	9.60e-002
n-Pentane	1.67e+000	1.34e-001
n-Hexane	1.20e-001	1.14e-002
Other Hexanes	1.81e-001	1.73e-002
Heptanes	5.44e-002	6.05e-003
2,2,4-Trimethylpentane	4.66e-002	5.90e-003
Benzene	1.10e+000	9.55e-002
Toluene	8.55e-001	8.73e-002
Ethylbenzene	1.22e-001	1.43e-002
Xylenes	9.00e-001	1.06e-001
Total Components	100.00	2.52e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.7 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0078	0.188	0.0343
Ethane	0.0085	0.203	0.0370
Propane	0.0094	0.227	0.0414
n-Butane	0.0334	0.801	0.1463
n-Pentane	0.0553	1.328	0.2424
n-Hexane	0.0062	0.149	0.0272
Other Hexanes	0.0083	0.200	0.0364
Heptanes	0.0042	0.101	0.0184
2,2,4-Trimethylpentane	0.0032	0.077	0.0141
Benzene	0.0923	2.216	0.4043
Toluene	0.0853	2.046	0.3735
Ethylbenzene	0.0141	0.338	0.0617
Xylenes	0.1048	2.516	0.4592
Total Emissions	0.4329	10.391	1.8963

Total Hydrocarbon Emissions	0.4329	10.391	1.8963
Total VOC Emissions	0.4167	10.000	1.8249
Total HAP Emissions	0.3059	7.343	1.3400
Total BTEX Emissions	0.2965	7.116	1.2987

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1735	4.164	0.7599
Ethane	0.0584	1.401	0.2557
Propane	0.0318	0.764	0.1394
n-Butane	0.0626	1.503	0.2744
n-Pentane	0.0782	1.877	0.3425
n-Hexane	0.0052	0.125	0.0228
Other Hexanes	0.0090	0.215	0.0393
Heptanes	0.0018	0.044	0.0081

2,2,4-Trimethylpentane	0.0027	0.065	0.0118
Benzene	0.0032	0.077	0.0141
Toluene	0.0021	0.049	0.0090
Ethylbenzene	0.0002	0.005	0.0009
Xylenes	0.0011	0.026	0.0048
Total Emissions	0.4298	10.316	1.8827
Total Hydrocarbon Emissions	0.4298	10.316	1.8827
Total VOC Emissions	0.1980	4.751	0.8671
Total HAP Emissions	0.0145	0.348	0.0634
Total BTEX Emissions	0.0066	0.158	0.0289

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.7000 MMSCF/day
Glycol Losses with Dry Gas: 0.0042 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.66e+000
Carbon Dioxide	9.99e-001	3.38e+001
Methane	8.99e+001	1.11e+003
Ethane	5.29e+000	1.23e+002
Propane	1.30e+000	4.41e+001
n-Butane	1.20e+000	5.36e+001
n-Pentane	9.99e-001	5.55e+001
n-Hexane	4.19e-002	2.78e+000
Other Hexanes	8.39e-002	5.57e+000
Heptanes	9.99e-003	7.71e-001
2,2,4-Trimethylpentane	2.00e-002	1.76e+000
Benzene	1.04e-002	6.25e-001
Toluene	5.59e-003	3.97e-001
Ethylbenzene	5.99e-004	4.90e-002
Xylenes	3.40e-003	2.78e-001
Total Components	100.00	1.43e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	8.44e-002
Carbon Dioxide	9.98e-001	3.38e+001
Methane	9.00e+001	1.11e+003
Ethane	5.30e+000	1.22e+002
Propane	1.30e+000	4.40e+001
n-Butane	1.20e+000	5.35e+001
n-Pentane	9.98e-001	5.53e+001
n-Hexane	4.18e-002	2.77e+000
Other Hexanes	8.38e-002	5.55e+000
Heptanes	9.92e-003	7.64e-001
2,2,4-Trimethylpentane	1.99e-002	1.75e+000
Benzene	8.81e-003	5.29e-001
Toluene	4.37e-003	3.09e-001
Ethylbenzene	4.25e-004	3.47e-002
Xylenes	2.10e-003	1.72e-001
Total Components	100.00	1.43e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.43e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	7.91e+001
Water	1.50e+000	1.20e+000
Carbon Dioxide	9.88e-012	7.93e-012
Methane	7.59e-018	6.09e-018
Ethane	3.93e-008	3.15e-008
Propane	2.09e-009	1.68e-009
n-Butane	2.97e-009	2.38e-009
n-Pentane	8.36e-004	6.71e-004
n-Hexane	7.15e-005	5.74e-005
Other Hexanes	2.17e-004	1.75e-004
Heptanes	3.78e-005	3.04e-005
2,2,4-Trimethylpentane	1.12e-004	8.98e-005
Benzene	6.26e-003	5.03e-003
Toluene	9.33e-003	7.49e-003
Ethylbenzene	2.07e-003	1.66e-003
Xylenes	1.96e-002	1.57e-002
Total Components	100.00	8.03e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.48e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	7.90e+001
Water	3.36e+000	2.78e+000
Carbon Dioxide	9.58e-002	7.94e-002
Methane	2.19e-001	1.81e-001
Ethane	8.07e-002	6.68e-002
Propane	4.99e-002	4.13e-002
n-Butane	1.16e-001	9.60e-002
n-Pentane	1.62e-001	1.34e-001
n-Hexane	1.39e-002	1.15e-002
Other Hexanes	2.11e-002	1.75e-002
Heptanes	7.34e-003	6.08e-003
2,2,4-Trimethylpentane	7.23e-003	5.99e-003
Benzene	1.21e-001	1.01e-001
Toluene	1.15e-001	9.48e-002
Ethylbenzene	1.93e-002	1.60e-002
Xylenes	1.47e-001	1.22e-001
Total Components	100.00	8.28e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 6.58e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	2.94e-003
Carbon Dioxide	7.28e+000	5.55e-002
Methane	6.23e+001	1.74e-001
Ethane	1.12e+001	5.84e-002
Propane	4.16e+000	3.18e-002
n-Butane	6.21e+000	6.26e-002
n-Pentane	6.25e+000	7.82e-002
n-Hexane	3.48e-001	5.21e-003
Other Hexanes	6.00e-001	8.97e-003
Heptanes	1.06e-001	1.84e-003
2,2,4-Trimethylpentane	1.36e-001	2.69e-003
Benzene	2.38e-001	3.23e-003
Toluene	1.28e-001	2.05e-003
Ethylbenzene	1.13e-002	2.08e-004
Xylenes	5.98e-002	1.10e-003
Total Components	100.00	4.88e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.47e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	7.90e+001
Water	3.37e+000	2.77e+000
Carbon Dioxide	2.89e-002	2.38e-002
Methane	9.52e-003	7.84e-003
Ethane	1.03e-002	8.45e-003
Propane	1.15e-002	9.45e-003
n-Butane	4.06e-002	3.34e-002
n-Pentane	6.81e-002	5.60e-002
n-Hexane	7.63e-003	6.28e-003
Other Hexanes	1.03e-002	8.49e-003
Heptanes	5.14e-003	4.23e-003
2,2,4-Trimethylpentane	4.01e-003	3.30e-003
Benzene	1.18e-001	9.73e-002
Toluene	1.13e-001	9.28e-002
Ethylbenzene	1.91e-002	1.58e-002
Xylenes	1.46e-001	1.21e-001
Total Components	100.00	8.23e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.55e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.57e+000
Carbon Dioxide	5.78e-001	2.38e-002

Methane	5.23e-001	7.84e-003
Ethane	3.01e-001	8.45e-003
Propane	2.29e-001	9.45e-003
n-Butane	6.14e-001	3.34e-002
n-Pentane	8.20e-001	5.53e-002
n-Hexane	7.72e-002	6.22e-003
Other Hexanes	1.03e-001	8.31e-003
Heptanes	4.48e-002	4.20e-003
2,2,4-Trimethylpentane	3.01e-002	3.21e-003
Benzene	1.26e+000	9.23e-002
Toluene	9.89e-001	8.53e-002
Ethylbenzene	1.42e-001	1.41e-002
Xylenes	1.06e+000	1.05e-001
Total Components	100.00	2.03e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.7 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.2072	4.974	0.9077
Ethane	0.0764	1.833	0.3345
Propane	0.0472	1.132	0.2067
n-Butane	0.1098	2.634	0.4807
n-Pentane	0.1526	3.663	0.6685
n-Hexane	0.0131	0.313	0.0572
Other Hexanes	0.0198	0.474	0.0865
Heptanes	0.0069	0.166	0.0303
2,2,4-Trimethylpentane	0.0067	0.162	0.0295
Benzene	0.1092	2.621	0.4783
Toluene	0.0998	2.395	0.4371
Ethylbenzene	0.0163	0.392	0.0716
Xylenes	0.1211	2.906	0.5303
Total Emissions	0.9860	23.665	4.3188
Total Hydrocarbon Emissions	0.9860	23.665	4.3188
Total VOC Emissions	0.7024	16.858	3.0766
Total HAP Emissions	0.3662	8.789	1.6040
Total BTEX Emissions	0.3464	8.314	1.5173

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.8000 MMSCF/day
Glycol Losses with Dry Gas: 0.0048 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.34e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.89e+000
Carbon Dioxide	9.99e-001	3.87e+001
Methane	8.99e+001	1.27e+003
Ethane	5.29e+000	1.40e+002
Propane	1.30e+000	5.04e+001
n-Butane	1.20e+000	6.13e+001
n-Pentane	9.99e-001	6.34e+001
n-Hexane	4.19e-002	3.18e+000
Other Hexanes	8.39e-002	6.36e+000
Heptanes	9.99e-003	8.81e-001
2,2,4-Trimethylpentane	2.00e-002	2.01e+000
Benzene	1.04e-002	7.14e-001
Toluene	5.59e-003	4.53e-001
Ethylbenzene	5.99e-004	5.60e-002
Xylenes	3.40e-003	3.17e-001
Total Components	100.00	1.64e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.33e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	9.65e-002
Carbon Dioxide	9.98e-001	3.86e+001
Methane	9.00e+001	1.27e+003
Ethane	5.30e+000	1.40e+002
Propane	1.30e+000	5.03e+001
n-Butane	1.20e+000	6.12e+001
n-Pentane	9.98e-001	6.32e+001
n-Hexane	4.18e-002	3.17e+000
Other Hexanes	8.38e-002	6.34e+000
Heptanes	9.92e-003	8.74e-001
2,2,4-Trimethylpentane	1.99e-002	2.00e+000
Benzene	8.81e-003	6.05e-001
Toluene	4.37e-003	3.54e-001
Ethylbenzene	4.25e-004	3.96e-002
Xylenes	2.10e-003	1.96e-001
Total Components	100.00	1.64e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.63e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	9.04e+001
Water	1.50e+000	1.38e+000
Carbon Dioxide	9.88e-012	9.07e-012
Methane	7.59e-018	6.96e-018
Ethane	3.93e-008	3.60e-008
Propane	2.09e-009	1.92e-009
n-Butane	2.97e-009	2.72e-009
n-Pentane	8.36e-004	7.67e-004
n-Hexane	7.15e-005	6.56e-005
Other Hexanes	2.17e-004	2.00e-004
Heptanes	3.78e-005	3.47e-005
2,2,4-Trimethylpentane	1.12e-004	1.03e-004
Benzene	6.26e-003	5.75e-003
Toluene	9.33e-003	8.56e-003
Ethylbenzene	2.07e-003	1.90e-003
Xylenes	1.96e-002	1.80e-002
Total Components	100.00	9.18e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.69e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	9.03e+001
Water	3.36e+000	3.17e+000
Carbon Dioxide	9.58e-002	9.07e-002
Methane	2.19e-001	2.07e-001
Ethane	8.07e-002	7.64e-002
Propane	4.99e-002	4.72e-002
n-Butane	1.16e-001	1.10e-001
n-Pentane	1.62e-001	1.53e-001
n-Hexane	1.39e-002	1.31e-002
Other Hexanes	2.11e-002	2.00e-002
Heptanes	7.34e-003	6.94e-003
2,2,4-Trimethylpentane	7.23e-003	6.84e-003
Benzene	1.21e-001	1.15e-001
Toluene	1.15e-001	1.08e-001
Ethylbenzene	1.93e-002	1.82e-002
Xylenes	1.47e-001	1.39e-001
Total Components	100.00	9.46e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 4.81e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.80e+000
Carbon Dioxide	1.63e+000	9.07e-002
Methane	1.02e+001	2.07e-001
Ethane	2.00e+000	7.64e-002
Propane	8.44e-001	4.72e-002
n-Butane	1.49e+000	1.10e-001
n-Pentane	1.67e+000	1.53e-001
n-Hexane	1.20e-001	1.31e-002
Other Hexanes	1.81e-001	1.98e-002
Heptanes	5.44e-002	6.91e-003
2,2,4-Trimethylpentane	4.66e-002	6.74e-003
Benzene	1.10e+000	1.09e-001
Toluene	8.55e-001	9.98e-002
Ethylbenzene	1.22e-001	1.63e-002
Xylenes	9.00e-001	1.21e-001
Total Components	100.00	2.87e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.8 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0090	0.215	0.0392
Ethane	0.0097	0.232	0.0423
Propane	0.0108	0.259	0.0473
n-Butane	0.0382	0.916	0.1672
n-Pentane	0.0633	1.518	0.2771
n-Hexane	0.0071	0.171	0.0311
Other Hexanes	0.0095	0.228	0.0416
Heptanes	0.0048	0.115	0.0210
2,2,4-Trimethylpentane	0.0037	0.088	0.0161
Benzene	0.1055	2.532	0.4621
Toluene	0.0974	2.339	0.4268
Ethylbenzene	0.0161	0.387	0.0706
Xylenes	0.1198	2.876	0.5248
Total Emissions	0.4948	11.875	2.1672
Total Hydrocarbon Emissions	0.4948	11.875	2.1672
Total VOC Emissions	0.4762	11.428	2.0856
Total HAP Emissions	0.3497	8.392	1.5315
Total BTEX Emissions	0.3389	8.133	1.4843

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1983	4.759	0.8685
Ethane	0.0667	1.601	0.2922
Propane	0.0364	0.873	0.1594
n-Butane	0.0716	1.718	0.3136
n-Pentane	0.0894	2.145	0.3914
n-Hexane	0.0059	0.143	0.0261
Other Hexanes	0.0103	0.246	0.0449
Heptanes	0.0021	0.051	0.0092

2,2,4-Trimethylpentane	0.0031	0.074	0.0135
Benzene	0.0037	0.089	0.0162
Toluene	0.0023	0.056	0.0103
Ethylbenzene	0.0002	0.006	0.0010
Xylenes	0.0013	0.030	0.0055
Total Emissions	0.4913	11.790	2.1517
Total Hydrocarbon Emissions	0.4913	11.790	2.1517
Total VOC Emissions	0.2263	5.430	0.9910
Total HAP Emissions	0.0166	0.397	0.0725
Total BTEX Emissions	0.0075	0.181	0.0330

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.8000 MMSCF/day
Glycol Losses with Dry Gas: 0.0048 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 3.34e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.89e+000
Carbon Dioxide	9.99e-001	3.87e+001
Methane	8.99e+001	1.27e+003
Ethane	5.29e+000	1.40e+002
Propane	1.30e+000	5.04e+001
n-Butane	1.20e+000	6.13e+001
n-Pentane	9.99e-001	6.34e+001
n-Hexane	4.19e-002	3.18e+000
Other Hexanes	8.39e-002	6.36e+000
Heptanes	9.99e-003	8.81e-001
2,2,4-Trimethylpentane	2.00e-002	2.01e+000
Benzene	1.04e-002	7.14e-001
Toluene	5.59e-003	4.53e-001
Ethylbenzene	5.99e-004	5.60e-002
Xylenes	3.40e-003	3.17e-001
Total Components	100.00	1.64e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.33e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	9.65e-002
Carbon Dioxide	9.98e-001	3.86e+001
Methane	9.00e+001	1.27e+003
Ethane	5.30e+000	1.40e+002
Propane	1.30e+000	5.03e+001
n-Butane	1.20e+000	6.12e+001
n-Pentane	9.98e-001	6.32e+001
n-Hexane	4.18e-002	3.17e+000
Other Hexanes	8.38e-002	6.34e+000
Heptanes	9.92e-003	8.74e-001
2,2,4-Trimethylpentane	1.99e-002	2.00e+000
Benzene	8.81e-003	6.05e-001
Toluene	4.37e-003	3.54e-001
Ethylbenzene	4.25e-004	3.96e-002
Xylenes	2.10e-003	1.96e-001
Total Components	100.00	1.64e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.63e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	9.04e+001
Water	1.50e+000	1.38e+000
Carbon Dioxide	9.88e-012	9.07e-012
Methane	7.59e-018	6.96e-018
Ethane	3.93e-008	3.60e-008
Propane	2.09e-009	1.92e-009
n-Butane	2.97e-009	2.72e-009
n-Pentane	8.36e-004	7.67e-004
n-Hexane	7.15e-005	6.56e-005
Other Hexanes	2.17e-004	2.00e-004
Heptanes	3.78e-005	3.47e-005
2,2,4-Trimethylpentane	1.12e-004	1.03e-004
Benzene	6.26e-003	5.75e-003
Toluene	9.33e-003	8.56e-003
Ethylbenzene	2.07e-003	1.90e-003
Xylenes	1.96e-002	1.80e-002
Total Components	100.00	9.18e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.69e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	9.03e+001
Water	3.36e+000	3.17e+000
Carbon Dioxide	9.58e-002	9.07e-002
Methane	2.19e-001	2.07e-001
Ethane	8.07e-002	7.64e-002
Propane	4.99e-002	4.72e-002
n-Butane	1.16e-001	1.10e-001
n-Pentane	1.62e-001	1.53e-001
n-Hexane	1.39e-002	1.31e-002
Other Hexanes	2.11e-002	2.00e-002
Heptanes	7.34e-003	6.94e-003
2,2,4-Trimethylpentane	7.23e-003	6.84e-003
Benzene	1.21e-001	1.15e-001
Toluene	1.15e-001	1.08e-001
Ethylbenzene	1.93e-002	1.82e-002
Xylenes	1.47e-001	1.39e-001
Total Components	100.00	9.46e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 7.52e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	3.37e-003
Carbon Dioxide	7.28e+000	6.35e-002
Methane	6.23e+001	1.98e-001
Ethane	1.12e+001	6.67e-002
Propane	4.16e+000	3.64e-002
n-Butane	6.21e+000	7.16e-002
n-Pentane	6.25e+000	8.94e-002
n-Hexane	3.48e-001	5.95e-003
Other Hexanes	6.00e-001	1.03e-002
Heptanes	1.06e-001	2.11e-003
2,2,4-Trimethylpentane	1.36e-001	3.07e-003
Benzene	2.38e-001	3.69e-003
Toluene	1.28e-001	2.35e-003
Ethylbenzene	1.13e-002	2.38e-004
Xylenes	5.98e-002	1.26e-003
Total Components	100.00	5.58e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.68e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	9.03e+001
Water	3.37e+000	3.17e+000
Carbon Dioxide	2.89e-002	2.72e-002
Methane	9.52e-003	8.96e-003
Ethane	1.03e-002	9.66e-003
Propane	1.15e-002	1.08e-002
n-Butane	4.06e-002	3.82e-002
n-Pentane	6.81e-002	6.40e-002
n-Hexane	7.63e-003	7.17e-003
Other Hexanes	1.03e-002	9.70e-003
Heptanes	5.14e-003	4.84e-003
2,2,4-Trimethylpentane	4.01e-003	3.77e-003
Benzene	1.18e-001	1.11e-001
Toluene	1.13e-001	1.06e-001
Ethylbenzene	1.91e-002	1.80e-002
Xylenes	1.46e-001	1.38e-001
Total Components	100.00	9.41e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 4.06e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.79e+000
Carbon Dioxide	5.78e-001	2.72e-002

Methane	5.23e-001	8.96e-003
Ethane	3.01e-001	9.66e-003
Propane	2.29e-001	1.08e-002
n-Butane	6.14e-001	3.82e-002
n-Pentane	8.20e-001	6.33e-002
n-Hexane	7.72e-002	7.11e-003
Other Hexanes	1.03e-001	9.50e-003
Heptanes	4.48e-002	4.80e-003
2,2,4-Trimethylpentane	3.01e-002	3.67e-003
Benzene	1.26e+000	1.06e-001
Toluene	9.89e-001	9.74e-002
Ethylbenzene	1.42e-001	1.61e-002
Xylenes	1.06e+000	1.20e-001
Total Components	100.00	2.32e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.8 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .9 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.9mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .9 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.2331	5.596	1.0212
Ethane	0.0859	2.062	0.3763
Propane	0.0531	1.274	0.2325
n-Butane	0.1235	2.963	0.5408
n-Pentane	0.1717	4.121	0.7520
n-Hexane	0.0147	0.352	0.0643
Other Hexanes	0.0222	0.533	0.0974
Heptanes	0.0078	0.187	0.0340
2,2,4-Trimethylpentane	0.0076	0.182	0.0332
Benzene	0.1228	2.948	0.5381
Toluene	0.1123	2.694	0.4917
Ethylbenzene	0.0184	0.441	0.0806
Xylenes	0.1362	3.269	0.5966
Total Emissions	1.1093	26.623	4.8587
Total Hydrocarbon Emissions	1.1093	26.623	4.8587
Total VOC Emissions	0.7902	18.966	3.4612
Total HAP Emissions	0.4120	9.888	1.8045
Total BTEX Emissions	0.3897	9.353	1.7069

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.9000 MMSCF/day
Glycol Losses with Dry Gas: 0.0054 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

MEMORANDUM

DATE: December 21, 2006

SUBJECT: Impacts of the Final Standards for Oil and Natural Gas Production Area Sources

FROM: Heather P. Brown, P.E.

TO: Greg Nizich, EPA/OAQPS/SPPD/CCG

I. INTRODUCTION AND BACKGROUND

On July 8, 2005, (70 FR 39441), the United States Environmental Protection Agency (EPA) issued a supplemental proposal to the February 6, 1998 (63 FR 6288), proposed standards for oil and natural gas production area sources. Impacts were developed for the July 2005 supplemental proposed action based on regulating area sources on a nationwide basis.[1] For the final rule, EPA has created three subcategories of sources: (1) triethylene glycol (TEG) dehydration units with either an annual average natural gas flow rate less than 3 million standard cubic feet per day (MMSCF/D) or benzene emissions less than 1 ton per year (tpy); (2) TEG dehydration units with an annual average natural gas flow rate equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1 tpy and located within areas of higher population densities with 10,000 people or more; and (3) TEG dehydration units with an annual average natural gas flow rate equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1 tpy and located outside areas of higher population densities with 10,000 people or more.

The purpose of this memorandum is to present the regulatory alternatives considered, as well as the impacts for the final standards for oil and natural gas production. The impacts presented include primary air impacts, secondary environmental impacts (air pollution, water, and solid waste impacts), energy impacts, and cost impacts.

II. REGULATORY ALTERNATIVES

The oil and natural gas production source category is unique compared to many source categories since the location of the facilities is dictated by the location of the natural resources, rather than a need to serve a particular population center. For this reason, many sources are located in remote or rural areas. Further, these sources do not require on-site operators and are usually not manned by large staff, if manned at all. Finally, the operation of these sources is not

[1] Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., US Environmental Protection Agency. Revised Impacts for Area Sources in the Oil and Natural Gas Production Source Category. June 25, 2005. Docket No. EPA-HQ-OAR-2004-0238-0002, 0003.

dependant on being close to populated areas. Based on these factors, EPA explored two regulatory alternatives for applying add-on controls to TEG dehydration units in the two subcategories of sources with an annual average natural gas flow rate equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1 tpy. The first alternative was to apply add-on control requirements to TEG dehydration units nationwide. The second alternative was to apply add-on control requirements to units located in areas of high population densities.

A. Regulatory Alternative 1: Apply Add-on Control Requirements Nationwide

Under this regulatory alternative, each subject TEG dehydration unit at an area source is required to: (1) reduce hazardous air pollutant (HAP) emissions by 95 percent or more; (2) reduce HAP emissions to an outlet concentration of 20 parts per million by volume (ppmv); or (3) reduce benzene emissions to a level less than 1.0 tpy. For the purposes of this memorandum, an emission reduction of 77.5 percent was assumed.

In the July 2005 supplemental proposal, EPA estimated that there are potentially 38,067 area source TEG dehydration units in the United States. Of the 38,067 potential TEG dehydration units, EPA estimates that 2,222 have actual annual average natural gas throughputs greater than 3 MMSCF/D and benzene emission greater than 1.0 tpy. Baseline HAP emissions of 49,635 tpy (14,803 tpy benzene) were estimated using GRI-GLYCalc© (version 4.0).[2] Reducing emissions by 77.5 percent resulted in an emission reduction of 13,377 tpy HAP (3,989 tpy benzene).

Using an approach consistent with that used in the July 2005 proposal (70 FR 39446), EPA evaluated the affected TEG dehydration units relative to the populations contained in the top 13 natural gas producing States (Alabama, Alaska, California, Colorado, Kansas, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, Utah, and Wyoming). EPA estimated that these 2,222 TEG dehydration units were located in States with a combined population of 92 million people.[3] The annual cost for this option was estimated to be $39 million.[4]

B. Regulatory Alternative 2: Apply Add-on Control Requirements to Units Located in Areas of High Population Densities

Under this regulatory alternative, TEG units located in areas of higher population densities with 10,000 people or more would be required to apply add-on controls (see Regulatory Alternative 1). EPA defines areas of higher population densities with 10,000 people or more as including the area occupied by each urban cluster[5] (UC) with 10,000 or more (referred to as UC

[2] See footnote 1.
[3] Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., US Environmental Protection Agency. Evaluation of Number of Sources Potentially Affected within Census Designated Geographies for 13 States Responsible for the Highest Oil and Natural Gas Production. June 29, 2006. Docket No. . EPA-HQ-OAR-2004-0238-0013.
[4] See footnote 1.
[5] An Urban Cluster refers to o Census 2000 Urban Cluster, which is defined in the *Urban Area Criteria for Census 2000,* 67 FR 11667 (March 15, 2002). Essentially, an UC consists of densely settled territory with at least 2,500 people but fewer than 50,000 people.

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≥ 10,000) and each urbanized area[6] (UA) plus the area located two miles or less from each UA boundary,[7] referred to by the phrase "UA plus offset." Based on this definition, EPA estimates that 50 TEG dehydration units would be required to apply add-on controls.[8] Baseline emissions from a single TEG dehydration unit are presented in another memorandum.[9] Table 1 presents baseline emissions from the 50 TEG dehydration units located within UC ≥ 10,000 and UA plus offset boundaries as well as emissions after reducing benzene emissions by 77.5 percent tpy by applying add-on controls. Emission reductions were estimated to be 301 tpy HAP (90 tpy of benzene).

EPA estimated that these 50 units are located in urban areas with a combined population of 76 million people.[10] Annual costs for a single unit without a flash tank were estimated to be $17,700 per year and for those with a flash tank annual costs were estimated to be $17,280 per year.[11] Assuming that 45 units do not have a flash tank and 5 units have a flash tank,[12] the annual costs for the 50 TEG dehydration units located within UC ≥ 10,000 and UA plus offset boundaries were estimated to be approximately $880 thousand per year.

C. Results of Regulatory Alternative Evaluation

Table 2 presents a cost comparison of Regulatory Alternatives 1 and 2. As shown in Table 2, extending the add-on control requirement to sources outside UC ≥ 10,000 and UA plus offset boundaries would result in an additional annual cost exceeding $38 million per year in an area with a combined population of 16 million people. This analysis shows that the overall cost of controlling units outside UC ≥ 10,000 and UA plus offset boundaries was much higher for a lower total population. Therefore, impacts were developed for Regulatory Alternative 2: apply the add-on control requirement to those TEG dehydration units located within UC ≥ 10,000 and UA plus offset boundaries.

III. PRIMARY AIR IMPACTS

This purpose of this section is to present the primary air pollution impacts (i.e., the reduction of HAP emissions) associated with the area source standards for existing and new sources.

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[6] An Urbanized Area refers to Census 2000 Urbanized Area, which is defined in the *Urban Area Criteria for Census 2000*, 67 FR 11663, 11667 (March 15, 2002). Essentially, an UA consists of densely settled territory with a population of at least 50,000 people.

[7] Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., US Environmental Protection Agency. Estimation of Land Area and Population Associated with Urbanized Area/Urban Cluster plus Offset Boundaries. December 21, 2006.

[8] See footnote 7.

[9] See footnote 1.

[10] See footnote 7.

[11] See footnote 1.

[12] See footnote 1.

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Table 1. Nationwide Baseline Emissions Using UC ≥ 10,000 and UA Plus Offset Definition

Throughput (MMSCF/D)[1]	Number of TEG Dehydration Units	Number Without Flash Tank	Number With Flash Tank[2]	Nationwide						Emissions after control					
				No Flash Tank			Flash Tank			No Flash Tank			Flash Tank		
				Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
3	20	18	2	108	206	32	12	23	4	24	46	7	3	5	1
4	16	14	2	116	223	35	16	31	5	26	50	8	4	7	1
5	14	13	1	127	243	38	10	19	3	28	55	8	2	4	1
	50	45	5	350	672	104	38	73	11	79	151	24	9	16	3

[1] Throughput used as an input to GLYCalc. See footnote 1.

[2] Approximately 10 percent of units are assumed to have a flash tank. See footnote 1.

Table 2. Comparison of Regulatory Alternatives 1 and 2

Factor	Regulatory Alternative 1	Regulatory Alternative 2
Number of Sources	2,222	50
HAP Emission Reductions (tpy)	13,377	301
Affected Population in 13 States (million)	92	76
Annual Cost ($million)	39	0.880

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Existing Sources

As previously stated, EPA has estimated that there are potentially 38,067 existing area source TEG dehydration units in the U.S. Of these, EPA has identified 35,845 TEG dehydration units that fall within the subcategory of sources with either an annual average natural gas flow rate less than 3 MMSCF/D or benzene emissions less than 1.0 tpy. Baseline emissions for these units were estimated to be 32,375 tpy. [13] For this subcategory, EPA has determined that GACT is no control.

There are 2,222 TEG dehydration units with annual average natural gas flow rates equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1.0 tpy and are subject to emission reduction requirements. There are two subcategories within this group of sources. One subcategory consists of the 50 TEG dehydration units identified as being located within UC $\geq$ 10,000 and UA plus offset boundaries. EPA determined that these sources are subject to the add-on controls requirements of Regulatory Alternative 2.

The remaining 2,172 TEG dehydration units fall within the subcategory of sources located outside of UC $\geq$ 10,000 and UA plus offset boundaries. These units would be required to implement management practices by reducing their glycol circulation rate to an optimum rate. Impacts of implementing management practices for a single unit were developed in a separate memorandum.[14] It was determined that reducing the glycol circulation rate to an optimum level would result in a HAP emission reduction of 45 percent (47 percent for benzene). To estimate national impacts, the same relative distribution used to estimate impacts at proposal[15] was used to determine how many TEG units fall within each throughput category (3, 4, and 5 MMSCF/D). Tables 3 and 4 present the HAP and benzene air emission impacts, respectively, associated with applying Regulatory Alternative 2 plus implementing management practices. The overall emission reduction was estimated to be 7,909 tpy HAP (2,455 tpy benzene).

New Sources

EPA has estimated that there will be 423 new TEG dehydration units (141 each year) that will come into service during the first three years after promulgation (from 2007 to 2009).[16] Assuming the same location distribution of existing sources, it was estimated that 3 new TEG dehydration units (2.2 percent of 141) would be located within UC $\geq$ 10,000 and UA plus offset boundaries, and would be subject to add-on control requirements. Additionally, it was estimated that 138 new TEG dehydration units would be required to implement management practices.

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[13] Memorandum from Brown. H., EC/R Incorporated, to Nizich, G., United States Environmental Protection Agency. Methodology for Estimating the Number of Area Sources in the Oil and Natural Gas Production Source Category. June 15, 2005. Docket No. EPA-HQ-OAR-2004-0238-0005.

[14] Memorandum from Brown, H., EC/R Incorporated to Nizich, G., United States Environmental Protection Agency. Impacts of Applying Management Practices to a Single Oil and Natural Gas Production Area Source Facility. December 21, 2006.

[15] See footnote 1.

[16] Memorandum from Brown. H., EC/R Incorporated, to Nizich, G., United States Environmental Protection Agency. Estimation of the Number of New Area Source Triethylene Glycol Dehydration Units in the Oil and Natural Gas Production Source Category. December 21, 2006.

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Table 3. HAP Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to Existing Sources

Throughput Category (MMscf/d)	Number of Units	Total HAP Emissions (tpy)	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Management Practices (tpy)**	Total HAP Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	35,845	32,375	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	884	5,317	20	93	864	2,343	2,437
>3 and ≤4	732	5,871	16	99	716	2,589	2,689
>4 and ≤5	606	6,072	14	109	592	2,675	2,784
Total	2,222	17,260	50	301	2,172	7,607	7,909

* Emission reduction of 77.5%

** Emission reductions of 45% (see footnote 13).

NMED Exhibit 79 - 0007

Table 4. Benzene Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to Existing Sources

Throughput Category (MMscf/d)	Number of Units	Total Benzene Emissions (tpy)	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Management Practices (tpy)**	Total Benzene Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	35,845	9,655	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	884	1,585	20	28	864	728	756
>3 and ≤4	732	1,750	16	30	716	805	834
>4 and ≤5	606	1,811	14	32	592	832	864
Total	2,222	5,147	50	90	2,172	2,365	2,455

* Emission reduction of 77.5%

** Emission reductions of 47% (see footnote 13).

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Tables 5 and 6 present the HAP and benzene air emission impacts, respectively, for new sources. The overall emission reduction associated with the regulation of new sources was estimated to be 501 tpy HAP (155 tpy benzene).

IV. SECONDARY ENVIRONMENTAL IMPACTS

Although the intent of the area source standards is to reduce HAP emissions, the application of control technologies can lead to other secondary environmental impacts. These secondary impacts can have a positive environmental impact, such as the reduction of volatile organic compounds (VOC) emissions, or a negative impact. Negative impacts may result from air pollutants emitted as a result of combustion sources (e.g., flares) or generation of a solid or liquid waste stream. The secondary impacts on air pollution and water and solid waste are discussed in this section.

A. Air Pollution Impacts

The primary method of HAP control from area source TEG dehydration units located within UC $\geq$ 10,000 and UA plus offset boundaries is the installation of a condenser and, if not present, a gas condensate glycol separator (GCG separator or flash tank). The secondary air pollution impacts associated with the application of this type of control are the decreased VOC emissions resulting from capture and control of HAP emissions. For TEG dehydration units located outside of UC $\geq$ 10,000 and UA plus offset boundaries, reducing the glycol circulation rate to the optimum level also decreases VOC emissions. Table 7 presents the total VOC emissions reduction (approximately 16,004 tpy) for existing area sources. Table 8 presents the VOC emissions reduction (approximately 1,013 tpy) for new sources.

Other secondary air pollution impacts are those associated with the operation of certain air emission control devices (i.e., flares). For facilities located within UC $\geq$ 10,000 and UA plus offset areas EPA assumed that 90 percent of the facilities would install condensers. Of these, EPA estimated that 45 percent of impacted facilities would be able to recycle the non-condensable vapors into a low pressure header system for combination with other hydrocarbon streams handled at the facilities and 45 percent of impacted facilities would use the non-condensable portion of the emission stream as a supplemental fuel for the glycol reboiler.[17] Therefore, for 90 percent of the impacted facilities there is no net change in energy use associated with the application of this control technology for facilities that incorporate this design and no net change in combustion-related emissions. In some cases, a facility does not have the ability to handle the collected vapor for use as a fuel or recycle the collected vapor back into the process. In such cases, the collected vapors may be directed to an on-site flare. EPA estimated that 10 percent of the facilities required to install add-on controls would direct all collected non-condensable vapors to an on-site flare.[18] The adverse secondary air impacts resulting from the use of a flare would be minimal in comparison to the primary HAP reduction

[17] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage. Background Information Document for Proposed Standards. EPA-453/R-94-079a. page 5-2.

[18] See footnote 17.

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Table 5. HAP Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to New Sources

Throughput Category (MMscf/d)	Number of Units	Total HAP Emissions (tpy)	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Management Practices (tpy)**	Total HAP Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	2,269	2,050	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	56	337	1	5	55	149	154
>3 and ≤4	46	372	1	6	45	164	170
>4 and ≤5	38	385	1	8	37	169	177
Total	141	1,093	3	19	138	482	501

* Emission reduction of 77.5%

** Emission reductions of 45% (see footnote 13).

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Table 6. Benzene Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to New Sources

Throughput Category (MMscf/d)	Number of Units	Total Benzene Emissions (tpy)	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Management Practices (tpy)**	Total Benzene Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	2,269	611	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	56	100	1	1	55	46	48
>3 and ≤4	46	111	1	2	45	51	53
>4 and ≤5	38	115	1	2	37	52	55
Total	141	326	3	6	138	150	155

* Emission reduction of 77.5%

** Emission reductions of 47% (see footnote 13).

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Table 7. Secondary VOC Air Pollution Impacts Associated with Applying Add-on Controls and Management Practices to Existing Sources

Throughput Category (MMscf/d)	Number of Units	Total VOC Emissions (tpy)	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Management Practices (tpy)**	Total VOC Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	35,845	62,098	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	884	10,199	20	179	864	4,751	4,930
>3 and ≤4	732	11,261	16	191	716	5,249	5,440
>4 and ≤5	606	11,653	14	209	592	5,425	5,634
Total	2,222	33,112	50	578	2,172	15,426	16,004

* Emission reduction of 77.5%

** Emission reductions of 48% (see footnote 13).

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Table 8. Secondary VOC Air Pollution Impacts Associated with Applying Add-on Controls and Management Practices to New Sources

Throughput Category (MMscf/d)	Number of Units	Total VOC Emissions (tpy)	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Management Practices (tpy)**	Total VOC Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	2,269	3,931	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	56	646	1	9	55	302	311
>3 and ≤4	46	713	1	12	45	332	344
>4 and ≤5	38	738	1	15	37	342	357
Total	141	2,096	3	36	138	977	1,013

* Emission reduction of 77.5%

** Emission reductions of 48% (see footnote 13).

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benefits from implementing the proposed control options for area sources. The secondary air impacts due to the use of flares are presented in Table 9 for existing area sources and Table 10 for new sources.

B. Water and Solid Waste Impacts

The water impacts associated the installation of a condenser system for the TEG dehydration unit reboiler vent would be minimal. The condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection.[19]

There is no solid waste generated from the control of HAP emissions using a condenser. Therefore, we do not anticipate any adverse solid waste impacts from the implementation of the area source standards.

V. ENERGY IMPACTS

Energy impacts are those energy requirements associated with the operation of emission control devices. There would be no national energy demand increase from the operation of any of the control options analyzed under the oil and natural gas production standards for area sources. The area source standards (1) encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate, which can be used on-site as fuel or reprocessed within the production process and sold and (2) require management practices that result in a natural gas savings. Thus, the standards have a positive impact associated with the recovery of non-renewable energy resources.

VI. COST IMPACTS

The cost impacts due to the final area source standards include the cost of equipment that must be purchased, along with the cost of the installation of the equipment. There are also costs for the operation and maintenance of the equipment. Finally, there are costs associated with the required monitoring, inspection, recordkeeping, and reporting (MIRR). This section presents the estimated costs associated with compliance with the area source standards.

Existing Sources

The total capital investment and total annual costs associated with the installation of add-on controls for a single unit were estimated during the development of the July 2005 proposal and are summarized in Table 11.[20] Table 11 also presents the nationwide impacts for total capital investment ($847 thousand) and total annual cost ($883 thousand) for the 50 existing sources located within UC $\geq$ 10,000 and UA plus offset boundaries.

[19] See footnote 18, page 5-6.
[20] See footnote 14.

NMED Exhibit 79 - 0014

Table 9. Secondary Air Pollution Impacts Due to the Use of a Flare for Existing Area Sources in the Oil and Natural Gas Production Source Category

Pollutant	Estimated Emissions per Flare (lb/yr)*	Estimated Number of Units Installing a Flare	Nationwide Emissions (tpy)
SO_x	2.20	5	0.01
NO_x	106	5	0.26
CO	22	5	0.06

* See footnote 17, page 5-7.

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Table 10. Secondary Air Pollution Impacts Due to the Use of a Flare for New Area Sources in the Oil and Natural Gas Production Source Category

Pollutant	Estimated Emissions per Flare (lb/yr)*	Estimated Number of Units Installing a Flare	Nationwide Emissions (tpy)
SO_x	22.05	1	0.01
NO_x	22	1	0.01
CO	5	1	0.00

* See footnote 17, page 5-7.

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Table 11. Cost Impacts Associated with Add-on Controls for Existing Area Sources

	UC ≥ 10,000 and UA Plus Offset Revised Costs(a,b)	
Cost Parameter	**TEG-A (without flash tank)**	**TEG-A' (with flash tank)**
Capital Costs	17,220	14,410
Annualized Capital Costs	1,891	1,582
O&M	8,816	8,816
Other Annual Costs (Admin., taxes, ins.)	4,940	4,828
Product Recovery	(141)	(141)
MIRR (c)	2,193	2,193
Cost Impact Summary for one Unit		
Total Capital Investment	17,220	14,410
Total Annual Cost	17,699	17,278
Nationwide Impacts		
Estimated Number of Impacted Units (d)	45	5
Total Capital Investment	774,902	72,050
Total Annual Cost	796,456	86,390
Nationwide Total Capital Investment =		846,952
Nationwide Total Annual Cost =		882,846

a- Costs for the proposed rule are in July 1993 dollars

b- Revised costs are in April 2004 dollars

c- Labor cost for MIRR was updated based on March 2004 data from the BLS

d- Ten percent of TEG dehydration units are equipped with flash tanks

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Table 12. Cost Impacts Associated with Implementing Management Practices for Existing Sources

Cost Parameter	Single Unit	Number of Impacted Units	Nationwide Cost Impacts
Total Capital Investment			
TEG dehydration units required to install a new pump	$ 1,539	1,086	$ 1,671,409
TEG dehydration units not required to install a new pump	$ -	1,086	$ -
Total	na	**2,172**	**$ 1,671,409**
Total Annual Costs			
TEG dehydration units required to install a new pump	$ 6,717	1,086	$ 7,294,187
TEG dehydration units not required to install a new pump	$ 6,405	1,086	$ 6,955,316
Total	na	**2,172**	**$ 14,249,503**
Total Gas Savings (all TEG dehydration units)	$ (5,802)	2,172	$ (12,602,957)
Total	na	**2,172**	**$ 1,646,546**

Table 13. Cost Impacts for Existing Sources and New Sources

Cost Parameter	Existing Sources	New Sources
Total Capital Investment		
Add-On Controls	$846,952	$37,590
Management Practices	$1,671,409	$106,195
Total	$2,518,361	$143,785
Total Annual Cost		
Add-On Controls	$882,846	$50,989
Management Practices	$14,249,503	$905,355
Gas Savings (Due to management practices)	($12,602,957)	($800,740)
Total	$2,529,392	$155,604

The total capital investment and total annual costs, as well as the gas savings, associated with the implementation of management practices for a single unit are presented in another memorandum.[21] Table 12 presents a summary of these impacts for the 2,172 existing sources estimated to be located outside of UC $\geq$ 10,000 and UA plus offset boundaries. It was assumed that 50 percent of these existing sources (1,086) would be required to install a new pump.

Table 13 presents the combined impacts for existing sources associated with the application of add-on controls and the implementation of management practices.

New Sources

To estimate the impacts of the area source standards on new sources, it was assumed that no new sources would be constructed without flash tanks. Therefore, total capital investment and total annual cost associated with applying add-on controls to new sources was calculated only for those already with flash tanks for the 3 new sources assumed to be located within UC $\geq$ 10,000 and UA plus offset boundaries. A summary of the cost impact calculations associated with the installation of add-on controls is presented in Table 14. A retrofit factor of 15 percent was assumed for existing sources.[22] Therefore, the new source capital investment values are 1.15 times lower than those presented in Table 11. The annual costs were calculated using the same methodology as used to estimate existing source annual costs.[23]

To estimate the cost impacts of applying management practices to new sources, the total capital investment and total annual cost associated with the reduction of the glycol circulation rate are the same as for existing sources.[24] Table 15 presents a summary of these impacts. The national impacts presented in Table 15 were estimated for the 138 new sources determined to be located outside of UC $\geq$ 10,000 and UA plus offset boundaries. Of these, 69 (50 percent of 138) were assumed to require the installation of a new pump and the remaining 69 were assumed to be able to design the TEG dehydration unit to achieve the optimum glycol circulation rate.

Table 13 also presents the combined impacts for new sources associated with the application of add-on controls and the implementation of management practices.

[21] See footnote 14.
[22] See footnote 1. Table 8.
[23] See footnote 1. Table 9.
[24] See footnote 14.

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Table 14. Cost Impacts Associated with Add-on Controls for New Area Sources

	New Sources UC > 10,000 and UA Plus Offset Revised Costs(a,b)	
Cost Parameter	**TEG-A (without flash tank)**	**TEG-A' (with flash tank)**
Capital Costs	0	12,530
Annualized Capital Costs	0	1,376
O&M	0	8,816
Other Annual Costs (Admin., taxes, ins.)	0	4,752
Product Recovery	0	(141)
MIRR (c)	0	2,193
Cost Impact Summary for one Unit		
Total Capital Investment	0	12,530
Total Annual Cost	0	16,996
Nationwide Impacts		
Estimated Number of Impacted Units	0	3
Total Capital Investment	0	37,590
Total Annual Cost	0	50,989
Nationwide Total Capital Investment =		37,590
Nationwide Total Annual Cost =		50,989

a- Costs for the proposed rule are in July 1993 dollars

b- Revised costs are in April 2004 dollars

c- Labor cost for MIRR was updated based on March 2004 data from the BLS

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Table 15. Cost Impacts Associated with Implementing Management Practices for New Sources

Cost Parameter	Single Unit	Number of Impacted Units	Nationwide Cost Impacts
Total Capital Investment			
TEG dehydration units required to install a new pump	$ 1,539	69	$ 106,195
TEG dehydration units not required to install a new pump	$ -	69	$ -
Total	na	**138**	**$ 106,195**
Total Annual Costs (not including gas savings)			
TEG dehydration units required to install a new pump	$ 6,717	69	$ 463,443
TEG dehydration units not required to install a new pump	$ 6,405	69	$ 441,912
Total	na	**138**	**$ 905,355**
Total Gas Savings (all TEG dehydration units)	$ (5,802)	138	$ (800,740)
Total Annual Cost (including gas savings)	na	**138**	**$ 104,615**

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Part V

Environmental Protection Agency

40 CFR Part 63
National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9676–8]

RIN 2060–AR13

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: In this action the EPA is taking final action on its reconsideration of certain issues in the emission standards for the control of hazardous air pollutants from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants, which were issued under section 112 of the Clean Air Act. As part of this action, the EPA is making technical corrections to the final rule to clarify definitions, references, applicability and compliance issues raised by petitioners and other stakeholders affected by this rule. On March 21, 2011, the EPA promulgated national emission standards for this source category. On that same day, the EPA also published a notice announcing its intent to reconsider certain provisions of the final rule. Following these actions, the Administrator received several petitions for reconsideration. After consideration of the petitions received, on December 23, 2011, the EPA proposed revisions to certain provisions of the March 21, 2011, final rule, and requested public comment on several provisions of the final rule. The EPA is now taking final action on the proposed reconsideration.

DATES: The May 18, 2011 (76 FR28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted January 31, 2013. The amendments in this rule to 40 CFR part 63, subpart DDDDD are effective as of April 1, 2013.

ADDRESSES: The EPA established a single docket under Docket ID No. EPA–HQ–OAR–2002–0058 for this action. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5426; Fax number (919) 541–5450; Email address: *eddinger.jim@epa.gov*.

SUPPLEMENTARY INFORMATION:

Executive Summary

Purpose of This Regulatory Action

The EPA is taking final action on its proposed reconsideration of certain provisions of its March 21, 2011, final rule that established standards for new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants. Section 112(d) of the CAA requires the EPA to regulate HAP from major stationary sources based on the performance of MACT. Section 112(h) of the CAA allows the EPA to establish work practice standards in lieu of numerical emission limits only in cases where the agency determines that it is not feasible to prescribe or enforce an emission standard, including circumstances in which the agency determines that the application of measurement methodology is not practicable due to technological and economic limitations. The EPA is revising certain MACT standards established in March 2011 for boilers and process heaters, including standards for CO—as a surrogate for organic HAP; HCl—as a surrogate for acid gas HAP; Hg; TSM or filterable PM—as a surrogate for non-Hg metallic HAP; and dioxin/furan.

This final rule amends certain provisions of the final rule issued by the EPA on March 21, 2011. The EPA delayed the effective date of the 2011 rule in a May 18, 2011, notice, but that delay notice was vacated by the U.S. District Court for the District of Columbia on January 9, 2012, and the March 2011 final rule was, therefore, in effect until publication of this action.

Summary of Major Reconsideration Provisions

In general, this final rule requires facilities classified as major sources of HAP with affected boilers or process heaters to reduce emissions of harmful toxic air emissions from these combustion sources. This will improve air quality and protect public health in communities where these facilities are located.

Recognizing the diversity of this source category and the multiple sectors of the economy this final rule effects, the EPA is revising certain subcategories for boilers and process heaters in this action that were established in the March 2011 final rule, based on the design of the combustion equipment. These revisions result in 19 subcategories for the boilers and process heaters source category. Numerical emission limits are established for most of the subcategories for five pollutants, CO, HCl, Hg, and PM or TSM. The review of existing data and consideration of new data have resulted in changes to some of the emission limits contained in the March 2011 final rule. Overall, for both new and existing affected units, about 30 percent of the emission limits are more stringent, half are less stringent, and 20 percent unchanged as compared to the March 2011 final rule. Also, based on its review and analysis of new data submissions, the EPA is establishing an alternative emission standard for CO, based on CEMS data for several subcategories with CO CEMS data available. This alternative standard is based on a 30-day rolling average for subcategories for which sufficient CEMS data were available for more than a 30-day period, or a 10-day rolling average for subcategories for which CEMS data were available for less than a 30-day period, and provides additional compliance flexibility to sources. All of the subcategories are subject to periodic tune-up work practices for dioxin/furan emissions.

The compliance dates for the rule are January 31, 2016, for existing sources and, January 31, 2013, or upon startup, whichever is later, for new sources. New sources are defined as sources that began operation on or after June 4, 2010.

Costs and Benefits

The final rule affects 1,700 existing major source facilities with an estimated 14,136 boilers and process heaters and the EPA projects an additional 1,844 new boilers and process heaters to be subject to this final rule over the next 3

years. This final rule affects multiple sectors of the economy including small entities. Table 1 summarizes the costs and benefits associated with this final rule. A more detailed discussion of the costs and benefits of this final rule is provided in section VI of this preamble.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$25,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,000 to $59,000.
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of Hg and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.

[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the ''social cost of carbon,'' which is discussed further in the RIA.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ACC American Chemistry Council
ACCCI American Coke and Coal Chemicals Institute
AF&PA American Forest and Paper Association
AHFA American Home Furnishings Alliance
AISI American Iron and Steel Institute
AMP American Municipal Power Inc.
AIE Alliance for Industrial Efficiency
APCD air pollution control devices
API American Petroleum Institute
AIF Auto Industry Forum
BFG Blast furnace gas
BLDS Bag leak detection system
BCSE The Business Council for Sustainable Energy
CIBO Council of Industrial Boiler Owners
CO Carbon monoxide
CO_2 Carbon dioxide
CEMS Continuous emissions monitoring system
CEG Citizens Energy Group
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous parameter monitoring system
CMI CraftMaster Manufacturing Inc.
ERT Electronic Reporting Tool
ESP Electrostatic precipitator
EPA Environmental Protection Agency
FBC Fluidized bed combustion
FR Federal Register
FSI Florida Sugar Industry
GPSP Great Plains Synfuels Plant
HAP Hazardous air pollutants
HBES Health-based emissions standard
HF Hydrogen fluoride
Hg Mercury
HCl Hydrogen chloride
kWh Kilowatt hours
ISO International Standards Organization
lb Pounds
LFG Landfill gas
MACT Maximum achievable control technology
MATS Mercury Air Toxics Standards
MSU Michigan State University
MMBtu Million British thermal units
NESHAP National Emission Standards for Hazardous Air Pollutants
NPRA National Petrochemical and Refiners Association
NTTAA National Technology Transfer and Advancement Act
NAICS North American Industry Classification System
NO_X Nitrogen oxide
NSR New Source Review
OMB Office of Management and Budget
PM Particulate matter
PSU Penn State University
PS Performance Specification
ppm Parts per million
QA Quality assurance
QC Quality control
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RPU Rochester Public Utilities
RTC Response to comment
SCR Selective catalytic reduction
SNCR Selective non-catalytic reduction
SO_2 Sulfur dioxide
TBtu/yr Trillion British thermal units per year
THC Total hydrocarbon
TSM Total selected metals
TTN Technology Transfer Network
tpy Tons per year
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USCHPA US Clean Heat Power Association
US Sugar United States Sugar Corporation
UPL Upper prediction limit
UARG Utility Air Regulatory Group
VCS Voluntary Consensus Standards
VOC Volatile organic compounds
WM Waste Management Inc.
WEPCO Wisconsin Electric Power Company
WWW Worldwide Web

Organization of this Document. The information presented in this preamble is organized as follows:

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I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by this action include:

TABLE 2—POTENTIAL REGULATED CATEGORIES AND ENTITIES AFFECTED

Category	NAICS code[1]	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this reconsideration action. To determine whether your facility may be affected by this reconsideration action, you should examine the applicability criteria in 40 CFR 63.7485 of subpart DDDDD (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters). If you have any questions regarding the applicability of this final rule to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this action will also be available on the WWW through the TTN. Following signature, a copy of the action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under the CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 1, 2013. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

II. Background Information

A. Chronological History of Related Actions

On March 21, 2011, the EPA issued final standards for new and existing industrial, commercial, and institutional boilers and process heaters, pursuant to its authority under section 112 of the CAA. On the same day as the final rule was issued, the EPA stated in a separate notice that it planned to initiate a reconsideration of several provisions of the final rule. This reconsideration notice identified several provisions of the March 2011 final rule where additional public comment was appropriate. This notice also identified several issues of central relevance to the rulemaking where reconsideration was appropriate under CAA section 307(d).

On May 18, 2011, the EPA issued a notice to postpone the effective date of the March 21, 2011 final rule. Following promulgation of the final rule, the EPA received petitions for reconsideration from the following organizations

(''Petitioners''): AIE, USCHPA, Alyeska Pipeline, ACC, AHFA, AISI, ACCCI, AMP, API, NPRA, AIF, Citizens Energy Group (CEG), CIBO, CMI, District Energy St. Paul, FSI, GPSP, Hovensa L.L.C., Tesoro Hawaii Corp., Industry Coalition (AF&PA *et al.*), JELD–WEN Inc., MSU, PSU, Purdue University, Renovar Energy Corp., RPU, Sierra Club, Southeastern Lumber Manufacturers Association, State of Washington Department of Ecology, BCSE, UARG, US Sugar, WM and WEPCO. Copies of these petitions are provided in the docket (see Docket ID No. EPA–HQ–OAR–2002–0058). Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider numerous provisions in the rule. On December 23, 2011, the EPA granted the petitions for reconsideration on certain issues, and proposed certain revisions to the final rule in response to the reconsideration petitions and to address the issues that the EPA previously identified as warranting reconsideration. That proposal solicited comment on several specific aspects of the rule, including:

- Revising the proposed subcategories.
- Solicitation of new data or corrections to existing data to revise emission standards calculations.
- Establishing an alternative TSM limit.
- Appropriateness of an alternative TSM limit for the liquid subcategories.
- Establishing work practice standards for dioxin/furan emissions.
- Revising the efficiency assumptions for the alternative output-based emission standards.
- Accommodating emissions averaging provisions in the alternative output-based emission standards.
- Establishing a mercury fuel specification through which gas-fired boilers that use a fuel other than natural gas or refinery gas may be considered Gas 1 units.
- Establishing a work practice standard for limited use units.
- Providing an affirmative defense for malfunction events.
- Revisions to the monitoring requirements for oxygen in the March 2011 final rule.
- Establishing a full-load stack test requirement for carbon monoxide coupled with continuous oxygen (oxygen trim) monitoring.
- Revising PM monitoring requirements from CEMS to CPMS and exempting biomass units from PM CPMS requirements.
- Revising mercury monitoring requirements to allow for an alternative mercury CEMS.
- Considering use of SO_2 CEMS to demonstrate compliance with HCl limits.
- Minimum data availability provisions.
- Averaging times for monitored parameters and pollutants.
- Revised methods for computing minimum detection levels.
- Providing an alternative CO emission limit based on CO CEMS data.
- Soliciting additional data to set MACT floor emission limits for non-continental liquid units.
- Selecting a 99 percent confidence interval for setting the CO emission limit.
- Tune-up frequencies, timing of initial tune-ups and adjusted tune-up requirements for shutdown units.
- Scope and duration of the energy assessment and deadline for completing the assessment.
- Revising work practices during startup and shutdown.
- Revisions to certain exemptions, including units serving as control devices, waste heat process heaters, units firing comparable fuels and residential units.
- Revisions to reduced testing frequency for emission limits that are established at minimum detection levels.
- Removing fuel analysis requirements for gas 1 fuels at co-fired units.
- Revisions to automating techniques for coal sampling.
- Revisions to emissions averaging across subcategories when units opt to switch to natural gas.
- Consideration of a new subcategory for units installed and used in place of flares.

In this action, the EPA is finalizing multiple changes to the March 2011 final rule after considering public comments on the items under reconsideration.

III. Summary of This Final Rule

As stated above, the December 23, 2011 proposed rule addressed specific issues and provisions the EPA identified for reconsideration. This summary of the final rule reflects the changes to 40 CFR part 63, subpart DDDDD (March 21, 2011 final rule) in regards to those provisions identified for reconsideration and on other discrete matters identified in response to comments or data received during the comment period. Information on other provisions and issues not proposed for reconsideration is contained in the notice and record for the 2011 final rule. [See 76 FR 15608]

This section summarizes the requirements of this action. Section IV below provides a summary of the significant changes to the March 21, 2011 final rule.

A. What is an affected source?

This final rule revises the list of exemptions in § 63.7491 to include residential boilers that may be located at an industrial, commercial or institutional major source. The exemption for boilers or process heaters used specifically for research and development has been revised to include boilers used for certain testing purposes.

B. What are the subcategories of boilers and process heaters?

In this final rule, we are finalizing separate subcategories for heavy liquid-fired, light liquid-fired and liquid-fired units in non-continental locations for PM and CO, pollutants that are dependent on combustor design. In addition, a new subcategory for coal-fired fluidized bed boilers with integrated fluidized bed heat exchangers has been included in the final rule for CO which is dependent on boiler design. Finally, we are finalizing the subcategory for PM at coal/fossil solid units across all coal combustor designs.

C. What emission limits and work practice standards are being finalized?

You must meet the emission limits presented in Table 3 of this preamble for each subcategory of units listed in the table. This final rule includes 19 subcategories, which are based on unit design. New and existing units in three of the subcategories are subject to work practices standards in lieu of emission limits for all pollutants. Numeric emission limits are finalized for new and existing sources in each of the other 16 subcategories.

The changes associated with the emission limits are due to new data, corrections to old data, and inventory changes. In summary, for existing subcategories, for the HCl emission limits, 10 are more stringent, 3 are less stringent and 1 remained the same from the March 21, 2011 final rule; for the mercury emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule; for the PM emission limits, 2 are more stringent, 7 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 4 are more stringent and 10 are less stringent from the March 21, 2011 final rule. For new subcategories, for the HCl emission limits, 13 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the mercury emission limits, 11 are more

stringent, 2 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the PM emission limits, 9 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule.

TABLE 3—EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[lb/MMBtu heat input basis unless noted; alternative output based limits are not shown in the summary table below]

Subcategory	Filterable PM (or total selected metals) (lb per MMBtu of heat input) [a]	HCl (lb per MMBtu of heat input) [a]	Mercury (lb per MMBtu of heat input) [a]	CO (ppm @3% oxygen) [a]	Alternate CO CEMS limit, (ppm @3% oxygen) [b]
Existing—Coal Stoker	0.040 (5.3E–05)	0.022	5.7E–06	160	340
Existing—Coal Fluidized Bed	0.040 (5.3E–05)	0.022	5.7E–06	130	230
Existing—Coal Fluidized Bed with FB heat exchanger	0.040 (5.3E–05)	0.022	5.7E–06	140	150
Existing—Coal-Burning Pulverized Coal	0.040 (5.3E–05)	0.022	5.7E–06	130	320
Existing—Biomass Wet Stoker/Sloped Grate/Other	0.037 (2.4E–04)	0.022	5.7E–06	1,500	720
Existing—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.32 (4.0E–03)	0.022	5.7E–06	460	ND
Existing—Biomass Fluidized Bed	0.11 (1.2E–03)	0.022	5.7E–06	470	310
Existing—Biomass Suspension Burner	0.051 (6.5E–03)	0.022	5.7E–06	2,400	[c] 2,000
Existing—Biomass Dutch Ovens/Pile Burners	0.28 (2.0E–03)	0.022	5.7E–06	770	[c] 520
Existing—Biomass Fuel Cells	0.020 (5.8E–03)	0.022	5.7E–06	1,100	ND
Existing—Biomass Hybrid Suspension Grate	0.44(4.5E–04)	0.022	5.7E–06	2,800	900
Existing—Heavy Liquid	0.062 (2.0E–04)	0.0011	2.0E–06	130	ND
Existing—Light Liquid	0.0079 (6.2E–05)	0.0011	2.0E–06	130	ND
Existing—non-Continental Liquid	0.27 (8.6E–04)	0.0011	2.0E–06	130	ND
Existing—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND
New—Coal Stoker	0.0011 (2.3E–05)	0.022	8.0E–07	130	340
New—Coal Fluidized Bed	0.0011 (2.3E–05)	0.022	8.0E–07	130	230
New—Coal Fluidized Bed with FB Heat Exchanger	0.0011 (2.3E–05)	0.022	8.0E–07	140	150
New—Coal-Burning Pulverized Coal	0.0011 (2.3E–05)	0.022	8.0E–07	130	320
New—Biomass Wet Stoker/Sloped Grate/Other	0.030 (2.6E–05)	0.022	8.0E–07	620	390
New—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.030 (4.0E–03)	0.022	8.0E–07	460	ND
New—Biomass Fluidized Bed	0.0098 (8.3E–05)	0.022	8.0E–07	230	310
New—Biomass Suspension Burner	0.030 (6.5E–03)	0.022	8.0E–07	2,400	[c] 2,000
New—Biomass Dutch Ovens/Pile Burners	0.0032 (3.9E–05)	0.022	8.0E–07	330	[c] 520
New—Biomass Fuel Cells	0.020 (2.9E–05)	0.022	8.0E–07	910	ND
New—Biomass Hybrid Suspension Grate	0.026 (4.4E–04)	0.022	8.0E–07	1,100	900
New—Heavy Liquid	0.013 (7.5E–05)	4.4E–04	4.8E–07	130	ND
New—Light Liquid	0.0011 (2.9E–05)	4.4E–04	4.8E–07	130	ND
New—Non-Continental Liquid	0.023 (8.6E–04)	4.4E–04	4.8E–07	130	ND
New—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND

NA-Not applicable; ND-No data available
[a] 3-run average, unless otherwise noted.
[b] 30-day rolling average, unless otherwise noted.
[c] 10-day rolling average.

We also are finalizing a work practice standard for dioxin/furan emissions from all subcategories.

D. What are the requirements during periods of startup and shutdown?

We are finalizing revised work practice standards for periods of startup and shutdown to better reflect the maximum achievable control technology during those periods. In addition, we are finalizing definitions of startup and shutdown. We are defining startup as the period between the state of first-firing of fuel in the unit after a shutdown to the period where the unit first supplies steam. We are defining shutdown as the period that begins when no more steam is supplied or at the point of no fuel being fired in the unit. For periods of startup and shutdown, we are finalizing the following work practice standard: You must operate all continuous monitoring systems during startup and shutdown. For startup, you must use one or a combination of the listed clean fuels. Once you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must engage all of the applicable control devices except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems as expeditiously as possible. During shutdown while firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must comply with all applicable emissions and operating limits at all times the unit is in operation except for periods that meet the definitions of startup and shutdown in this subpart, during which times you must comply with these work practices. You must keep records during periods of startup or shutdown. You must keep records concerning the date, duration, and fuel usage during startup and shutdown.

E. What are the testing and initial compliance requirements?

We are requiring that the owner or operator of a new or existing boiler or process heater conduct performance tests to demonstrate compliance with all applicable emission limits. This final rule adds the requirement to conduct initial and annual stack tests to determine compliance with the TSM emission limits using EPA Method 29 for those subcategories with alternate TSM limits.

F. What are the continuous compliance requirements?

This final rule removes the requirement for units combusting biomass with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain and operate a CEMS measuring PM emissions. This final rule requires units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain, and operate PM CPMS. Moreover, owners or operators of units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater are allowed to install, certify, maintain and operate PM CEMS as an alternative to the use of PM CPMS, consistent with regulations for similarly-sized commercial and industrial solid waste incinerators units and EGUs subject to the MATS. Just as units using PM CPMS will not be required to conduct parameter monitoring for PM, units using PM CEMS will not be required to conduct parameter monitoring for PM.

This final rule also includes an alternative method of demonstrating continuous compliance with the HCl emission limit. This method allows using SO_2 emissions as an alternate operating limit. This method of demonstrating continuous compliance will be allowed only on a unit that utilizes a SO_2 CEMS and an acid-gas control technology including wet scrubber, dry scrubbers and duct sorbent injection. Boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS would be required to maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

G. What are the compliance dates?

For existing sources, the EPA is establishing a compliance date of January 31, 2016. New sources must comply by January 31, 2013, or upon startup, whichever is later. New sources are defined as sources which commenced construction or reconstruction on or after June 4, 2010 pursuant to section 112(a)(4).

Commenters have argued that the 3-year compliance deadline the EPA is establishing for existing sources to meet the standards does not provide them with sufficient time to meet the standards in view of the large number of sources that will be competing for the needed resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers.

As an initial matter, we note that many sources subject to the emission standards in the final rule should be able to meet the standards within three years, even those that need to install pollution control technologies to do so. In addition, many sources subject to the rule are gas fired units or small boilers (less than 10 MMBtu/hr) and will not need to install controls in order to demonstrate compliance, as these sources are subject to work practice standards. For these sources, the 3-year compliance deadline is highly unlikely to be problematic either in general, or with respect to the claims commenters have made about the possibility that the demand for resources related to control technology will exceed the supply.

At the same time, the CAA allows title V permitting authorities to grant sources, on a case-by-case basis, extensions to the compliance time of up to one year if such time is needed for the installation of controls. *See* CAA section 112(i)(4)(i)(A). Permitting authorities are already familiar with, and in many cases have experience with, applying the 1-year extension authority under section 112(i)(4)(A) since the provision applies to all NESHAP. We believe that should the range of circumstances that commenters have cited as impeding sources' ability to install controls within three years materialize, then it is reasonable for permitting authorities to take those circumstances into consideration when evaluating a source's request for a 1-year extension, and where such applications prove to be well-founded, it is also reasonable for permitting authorities to make the 1-year extension available to applicants.

In making a determination as to whether an extension is appropriate, we believe it is also reasonable for permitting authorities to consider the large number of pollution control retrofit projects being undertaken for purposes of complying either with the standards in this rule or with those of other rules such as MATS for the power sector that may be competing for similar resources.

Further, commenters have pointed out that in some cases operators of existing sources that are subject to these standards and that generate energy may opt to meet the standards by terminating operations at these sources and building new sources to replace the energy generation at the shut-down sources. While the ultimate discretion to provide a 1-year extension lies with the permitting authority, the EPA believes that it is reasonable for permitting authorities to allow the fourth year extension for the installation of replacement sources of energy generation at the site of a facility applying for an extension for that purpose. Specifically, the EPA believes where an applicant demonstrates that it is building replacement sources of energy generation for purposes of meeting the requirements of these standards such a replacement project could be deemed to constitute the ''installation of controls'' under section 112(i)(3)(B).

In a case where pollution controls are being installed or onsite replacement energy generation is being constructed to allow for retirement of older, under-controlled energy generation units, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies are likely to undertake a number of steps relatively soon after the effective date of the rule, including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement energy generation units. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement energy generation is being constructed. As a result, a permitting authority will be in a position to make a determination as to whether a source's compliance schedule will exceed 3 years and to quickly make a determination as to when an extension is appropriate.

In sum, the EPA believes that although most, if not all, units will be able to fully comply with the standards within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. Of course in situations where EPA is the permitting authority, we would also consider the above circumstances when acting on a permit application.

IV. Summary of Significant Changes Since Proposal

The EPA has made numerous changes in this final rule from the proposal after consideration of the public comments received. Most are changes to clarify applicability and implementation issues raised by the commenters. The public comments received on the proposed changes and the responses to them can be viewed in the memorandum ''Response to Comments for Industrial, Commercial, and Institutional Boilers

and Process Heaters National Emission Standards for Hazardous Air Pollutants'' located in the docket.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability of this final rule. We have clarified that the exemption for boilers and process heaters used for research and development includes boilers used for testing the propulsion systems on military vessels. This is consistent with the intent of the exemption in that these test boilers do not provide steam for heating, to a process, or other non-propulsion related uses but are used exclusively to test the propulsion systems of nuclear-powered aircraft carriers that are undergoing repair, overhaul, or installation.

B. Subcategories

As described in the preamble to the proposed reconsideration rule, within the basic unit types of boilers and process heaters there are different designs and combustion systems that, while having a minor effect on fuel-dependent HAP emissions, have a much larger effect on pollutants whose emissions depend on the combustion conditions in a boiler or process heater. In the case of boilers and process heaters, the combustion-related pollutants are the organic HAP. In the proposed rule, we identified the following 17 subcategories for organic HAP: (1) Pulverized coal units; (2) stokers designed to burn coal; (3) fluidized bed units designed to burn coal; (4) stokers designed to burn wet biomass; (5) stokers designed to burn kiln-dried biomass; (6) fluidized bed units designed to burn biomass; (7) suspension burners designed to burn biomass; (8) dutch ovens/pile burners designed to burn biomass; (9) fuel cells designed to burn biomass; (10) hybrid suspension grate units designed to burn biomass; (11) units designed to burn heavy liquid fuel; (12) units designed to burn light liquid fuel; (13) non-continental liquid units; (14) units designed to burn natural gas/refinery gas; (15) units designed to burn other gases; (16) metal process furnaces; and (17) limited-use units.

In this final rule, we are also adding a separate subcategory for fluidized bed units with a fluidized bed heat exchanger designed to burn coal and adjusted the definition of the limited use subcategory.

Fluidized bed boilers are designed to combust fuel with relatively low heating value and high ash compared to other combustor designs. Two fuel properties of coal are heating values and ash content. As the heating value of the coal decreases, ash content increases. Fluidized bed boilers are designed to have large tube surface areas to transfer heat from the fuel through the process of conduction and convection, but in some cases the amount of tube surface area in the furnace for heat transfer is insufficient. In order to overcome insufficient heat exchange, certain fluidized bed boilers adopt a fluidized bed heat exchanger design to achieve heat transfer. The fluidized bed heat exchanger is located at the exit of the cyclone section of the unit. This design allows the boiler to combust coal with a lower heating value than a coal-fired fluidized bed boiler without a fluidized bed heat exchanger. Therefore, because this boiler design does have different combustion-related HAP emission characteristics, a new subcategory of coal fluidized bed with integrated heat exchanger was added to the final rule.

The EPA is also revising the definition of the limited use subcategory. Many affected units operate on standby mode or low loads for periods longer than the proposed definition for limited use units, which limited operation to 876 hours per year. By converting to a capacity-factor approach, we are allowing more flexibility on unit operations without increasing emissions or harm to human health and the environment. For example, units operating at 10 percent load for 8,760 hours per year would emit the same amount of emissions as units operating at full load for 876 hours per year. Further, it is technically infeasible to schedule stack testing for these limited use units since these units serve as back up energy sources and their operating schedules can be intermittent and unpredictable. The limited use subcategory was adjusted to be based on units with a federally enforceable operating limit of less than or equal to 10 percent of an average annual capacity factor.

C. Performance Test Requirements

Table 5 of this final rule has been revised to add performance test procedures for conducting performance stack tests for demonstrating compliance with the alternate TSM emission limits. In the reconsideration proposal, we proposed emissions limits for TSM (i.e., arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium) as an alternative to the proposed PM emission limits for many of the subcategories. In the preamble to the proposed rule, we added procedures in Table 6 of the rule for conducting fuel analysis for total selected metals but we inadvertently failed to add performance test requirements for stack sampling of TSM emissions in Table 5 of the rule.

D. Emission Limits

One significant change since proposal is related to the PM emission limits for the coal subcategories. Several petitioners disagreed with EPA's position to set different PM limits for subcategories of boilers and process heaters based on the fuel used, and instead offered information to support the position that PM should be considered a combustion-based pollutant. The differences in PM particle size, fouling characteristics and feasibility of certain control technologies on certain unit designs suggested that PM is more appropriately classified as a combustion-based pollutant, but only for the coal subcategories. After assessing the points raised by the petitioners, the EPA agreed that PM emissions are influenced by unit design, and fuel type, and proposed to create combustion-based pollutant subcategories for coal and solid fuels and create fuel-based subcategories for liquid and biomass fuel units. The EPA is finalizing a single PM limit for all coal/solid fossil fuel subcategories, and is also finalizing emissions limits based on PM as a combustion-based pollutant for the biomass and liquid fuel subcategories.

Another change from proposal is that the alternative TSM emission limits are now applicable to the three liquid fuel subcategories. Several commenters provided data and comments supporting these alternative emission standards for non-mercury metallic HAP. After assessing the revised data and the points made by the commenters, the EPA agrees that the limited data available for liquid fuel units are not unique to this subcategory. Based on the EPA agreeing with the commenters, the EPA re-calculated the TSM emission limits for the liquid fuel subcategories and included them in the final rule.

The CO emission limit for several subcategories, both new and existing, have been revised to reflect a CO level that is consistent with MACT for organic HAP reduction. Several commenters recommended that the EPA evaluate a minimum CO standard (i.e., 100 ppm corrected to 7 percent oxygen) to serve as a lower bound surrogate for organic HAP. Commenters also provided data and information to support such a standard, and noted that the EPA has taken a similar approach in other emission standards under section 112.

The EPA evaluated whether there is a minimum CO level for boilers and

process heaters below which there is no further benefit in organic HAP reduction/destruction. Specifically, we evaluated the relationship between CO and formaldehyde using the available data obtained during the rulemaking. Formaldehyde was selected as the basis of the organic HAP comparison because it is the most prevalent organic HAP in the emission database and a large number of paired tests existed for boilers and process heaters for CO and formaldehyde. The paired data show decreasing formaldehyde emissions with decreasing CO emissions down to CO levels around 300 ppm, supporting the selection of CO as a surrogate for organic HAP emissions. A slight increase in formaldehyde emissions is observed at CO levels below around 200 ppm, suggesting a breakdown in the CO-formaldehyde relationship at low CO levels. At levels lower than 150 ppm, the mean levels of formaldehyde appear to increase, as does the overall maximum value of and variability in formaldehyde emissions. However, we are aware of no reason why CO concentrations would continue to decrease and formaldehyde concentrations would increase as combustion conditions improve. It is possible that imprecise formaldehyde measurements at low concentrations (i.e., 1–2 ppm) may account for this slight increase in formaldehyde emissions observed at CO levels below 100 ppm corrected to 7 percent oxygen. Based on this, we do not believe that such measurements are sufficiently reliable to use as a basis for establishing an emissions limit.

Therefore, based on the above analysis, we are promulgating a minimum MACT floor level for CO of 130 ppm corrected to 3 percent oxygen (which is equivalent to 100 ppm corrected to 7 percent oxygen). We note this is the same approach used to establish the CO emission limit of 100 ppm corrected to 7 percent oxygen for the Burning of Hazardous Waste in Boilers and Industrial Furnaces rule. Additional discussion of the rationale for this approach can be found in the memorandum ''Revised MACT Floor Analysis (August 2012) for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.''

Subcategories where the initial MACT floor 99 percent UPL calculations for CO were less than 100 ppm corrected to 7 percent oxygen (or equivalently 130 ppm corrected to 3 percent oxygen) are as follows:

- New and Existing Subcategories: Coal-FB, Coal-PC, Heavy Liquid, Light Liquid, Non-Continental Liquid, Process Gas
- New Subcategories: Coal-Stoker

We believe a CO level of 130 ppm corrected to 3 percent oxygen is an appropriate minimum MACT floor level. Although some measurements show CO levels below 130 ppm corrected to 3 percent oxygen, it is not appropriate to establish a lower floor level because CO is a conservative surrogate for organic HAP. In other words, organic HAP emissions are extremely low when sources operate under the good combustion conditions required to achieve CO levels in the range of zero to 100 ppm. As such, lowering the CO floor below 100 ppm will not provide reductions in organic HAP emissions. There are myriad factors that affect combustion efficiency and, as a function of combustion efficiency, CO emissions. As combustion conditions improve and hydrocarbon levels decrease, the larger and easier to combust compounds are oxidized to form smaller compounds that are, in turn, oxidized to form CO and water. As combustion continues, CO is then oxidized to form carbon dioxide and water. Because CO is a difficult to destroy refractory compound (*i.e.,* oxidation of CO to carbon dioxide is the slowest and last step in the oxidation of hydrocarbons), it is a conservative surrogate for destruction of hydrocarbons, including organic HAP.

The conservative nature of CO as an indicator of good combustion practices is supported by our data. At CO levels less than 100 ppm corrected to 7 percent oxygen, our data indicate that there is no apparent relationship between CO and organic HAP (i.e., formaldehyde). For example, a source with a CO level of 20 ppm may have the same measured formaldehyde as a source achieving a CO emission level of 100 ppm corrected to 7 percent oxygen. Sources are required to establish operating requirements based on operating levels that were demonstrated during the test. Sources must comply with these operating requirements on a continuous basis. Compliance with these requirements adequately assures sources will be controlling organic HAP emissions to MACT levels.

As detailed in the docketed memorandum ''Beyond the Floor Technology Analysis for Major Source Boilers and Process Heaters (Revised August 2012),'' we reviewed the emission limits that are becoming less stringent since the March 2011 final rule in order to assess whether a beyond the floor option was technically achievable and cost effective. As a result of this review, the PM emission limits for several new biomass subcategories have been changed to reflect a beyond the floor limit of 0.03 lb/MMBtu, based on the limit for new biomass boilers in 40 CFR part 60 subparts Db and Dc. Due to the low mercury emission limits for new solid fuel boilers, these new biomass units are expected to install a fabric filter level of control in order to meet the new source mercury limits for the solid fuel subcategory. This mercury control has the co-benefit of reducing PM emissions down to levels of 0.03 lb/MMBtu so there is no incremental cost to achieve these additional reductions in PM for the biomass units that have a design heat input capacity between 10 and 30 MMBtu/hr. For units with a design heat input capacity of 30 MMBtu/hr or greater, these units are already subject to a PM limit of 0.03 lb/MMBtu and adjusting these new source limits to this level of control makes the limits consistent between both rules, without adding additional costs. We did not identify any beyond the floor options for existing source PM limits or new and existing limits for other pollutants as technically feasible or cost effective.

The other changes associated with the other emission limits are due to new data, corrections to old data, and inventory changes. In summary, compared to the December 23, 2011 proposed limits for existing units, the final HCl emission limits remained the same; for the final mercury emission limits, 3 are more stringent, 10 are less stringent and 1 is unchanged; for the final PM emission limits, 3 are more stringent, 5 are less stringent and 6 are unchanged; and for the final CO emission limits, 3 are more stringent and 11 are less stringent. For new units, compared to the proposed emission limits, 3 of the final HCl emission limits are more stringent and 11 remained the same; for the final mercury emission limits, 10 are more stringent and 4 are unchanged; for the final PM emission limits, 5 are more stringent, 2 are less stringent and 7 are unchanged; and for the final CO emission limits, 2 are more stringent, 11 are less stringent and 1 is unchanged.

E. Work Practice Requirement

In this final rule several changes have been made to the work practice requirement to conduct a tune-up. First, the requirement to inspect the burner has been revised to allow units that sell electricity to schedule the burner inspection, as well as the air-to-fuel system inspection, at the time of the first outage but not to exceed 36 months from the previous inspection. This

change is being made to this final rule because commenters stated that large boilers that serve electricity for sale may not require annual outages and would, therefore, need to be taken off-line for the sole purpose of an annual tune-up. This frequency is consistent with the requirements of the NESHAP for electric utility boilers (40 CFR part 63, subpart UUUUU).

Also, for units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or into process equipment. Commenters indicated that some process heaters are installed inside tanks and entry into the tank to access the heater may not occur within a 5 year period.

The requirement to optimize total emissions of CO has been revised to require that this optimization not only be consistent with the manufacturer's specifications but also with any NO_X emission requirement to which the unit is subject. Some commenters indicated that many boilers need different tune-up criteria due to their requirement to also comply with low NO_X emission limits. We are also aware that several states have boiler tune-up requirements to minimize NO_X emissions first and then optimize CO emissions.

We have added boilers or process heaters that have a continuous oxygen trim system to the types of boilers or process heaters that must conduct a tune-up every 5 years. These units do not need to be tuned as frequently because the trim system is designed to continuously measure and maintain an optimum air to fuel ratio which is the purpose of a tune-up.

F. Averaging Times Definitions

We revised the definitions of ''30-day rolling average'' and ''daily block average'' to exclude periods of startup and shutdown or downtime from the arithmetic mean. Commenters requested that the EPA specify how a 30-day rolling average is calculated and whether it includes the previous 720 hours of valid operating data and that the valid data exclude hours during startup and shutdown as well as unit down time. We agree with the commenters that the definitions need clarification and that these periods should not be included in calculating the 30-day rolling average. Therefore, we have revised the definitions accordingly.

We have also included in the final rule a definition of ''10-day rolling average'' that is consistent with the revised definition of ''30-day rolling average.''

G. Energy Assessment

In this final rule, we have revised the definition of energy assessment per the requirements of Table 3 of this final rule by providing duration for performing the energy assessment for large fuel use facilities. In numbered paragraph (3) in the definition of ''Energy assessment'' in § 63.7575, which is for facilities with units having a combined heat input capacity greater than 1 TBtu/yr, we added time duration/size ratio and included a cap to the maximum number of on-site technical hours that should be used in the energy assessment. This addition of a duration for large fuel use facilities is being made to be consistent with durations specified for small [paragraph (1) in the definition of ''Energy assessment''] and medium [paragraph (2) in the definition of ''Energy assessment''] fuel use facilities. The energy assessment for facilities with affected boilers and process heaters having a combined heat input capacity greater than 1.0 TBtu/yr will be up to 24 on-site technical labor hours for the first TBtu/yr plus 8 technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 technical hours, but may be longer at the discretion of the owner or operator.

The revised definition of energy assessment also clarifies our intentions that the scope of assessment is based on energy use by discrete segments of a facility and not by a total aggregation of all individual energy using elements of a facility. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. We have added the following paragraph (4), to the energy assessment definition to help resolve current problems in identifying the scope of the various energy use systems in a large industrial complex and allow for more streamlined assessments:

''(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2) and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).''

We have also revised paragraph 4 of Table 3 of the final rule to allow a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, which includes the affected units, to satisfy the energy assessment requirement. We consider these energy management programs to be equivalent to the one-time energy assessment because facilities having these programs operate under a set of practices and procedures designed to manage energy use on an ongoing basis. These programs contain energy performance measurements and tracking plans with periodic reviews.

The definition of ''Energy use system'' has also been revised in this final rule to clarify that energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

H. Startup and Shutdown Definitions

A number of commenters indicated that the proposed load specifications (i.e., 25 percent load) within the definitions of ''startup'' and ''shutdown'' were inconsistent with either safe or normal (proper) operation of the various types of boilers and process heaters encountered within the source category. As the basis for defining periods of startup and shutdown, a number of commenters suggested alternative load specifications based on the specific considerations of their boilers; other commenters suggested the achievement of various steady-state conditions.

We have reviewed these comments and believe adjustments are appropriate in the definition of ''startup'' and ''shutdown.'' These adjustments are tailored for industrial boilers and are consistent with the definitions of ''startup'' and ''shutdown'' contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that industrial boilers function to provide steam or, in the case of cogeneration units, electricity; therefore, industrial boilers should be considered to be operating normally at all times steam of the proper pressure, temperature, and flow rate is being supplied to a common header system or energy user(s) for use as either process steam or for the cogeneration of electricity. The definitions of ''startup'' and ''shutdown'' have been revised in the final rule as follows:

''*Startup* means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler or process heater after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose.''

''*Shutdown* means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is both no steam or heat being supplied and no fuel being fired in the boiler or process heater.''

The EPA is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR) when firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases in the boiler or process heater during startup or shutdown. It is the responsibility of the operators of affected boilers and process heaters to start their limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems appropriately to comply with relevant standards applicable during normal operation. Startup ends and normal operating standards apply when heat or steam is supplied for any purpose.

The EPA carefully considered fuels and potential operational constraints of APCD when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning clean fuels (e.g., natural gas, distillate oil) for longer portions of startup or shutdown periods at a boiler and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCD. The EPA is aware that SNCR and SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_X reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature, and that fabric filters need to be operated at temperatures above the acid dew point. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of affected boilers and process heaters to start their SNCR, SCR, fabric filter and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

I. Fuel Sampling Frequency

The sampling frequency for gaseous fuel-fired units that elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory has been revised in this final rule. If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification, no further sampling is required. If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification, only semi-annual sampling need to be conducted. If the initial mercury constituents are greater than 75 percent of the mercury specification, monthly sampling is required.

J. Affirmative Defense

In the proposal, we used terms such as ''exceedance'' or ''excess emissions'' in § 63.7501, which created unnecessary confusion as to when the affirmative defense could be used. In the final amended rule, we have eliminated those terms and used the word ''violation'' to make clear that the affirmative defense to civil penalties is available only where an event that causes a violation of the emissions standard meets the definition of malfunction under § 63.2.

We have also eliminated the 2-day notification requirement that was included in 40 CFR 63.7501(b) at proposal because we expect to receive sufficient notification of malfunction events that result in violations in other required compliance reports, such as the malfunction report required under 40 CFR 63.7550(c). In addition, we have revised the 45-day affirmative defense reporting requirement that was included in 40 CFR 63.7501(b) at proposal to require sources to include the report in the first compliance, deviation or excess emission report due after the initial occurrence of the violation, unless the compliance, deviation or excess emission report is due less than 45 days after the violation. In that case, the affirmative defense report may be included in the second compliance, deviation or excess emission report due after the initial occurrence of the violation. Because the affirmative defense report is now included in a subsequent compliance, deviation or excess emission report, there is no longer a need for the proposed 30-day extension for submitting a stand-alone affirmative defense report. Consequently, we are not including this provision in the final amended rule. We have also re-evaluated the language concerning the use of off-shift and overtime labor to the extent practicable and believe that the language is not necessary. Thus, we have deleted that phrase from section 63.7501(a)(2).

V. Other Actions We Are Taking

Section 307(d)(7)(B) of the CAA states that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b)).''

As to the first procedural criterion for reconsideration, a petitioner must show why the issue could not have been presented during the comment period, either because it was impracticable to raise the issue during that time or because the grounds for the issue arose after the period for public comment (but within 60 days of publication of the final action). The EPA is denying the petitions for reconsideration on a number of issues because this criterion has not been met. In many cases, the petitions reiterate comments made on the proposed June 2011 rule during the public comment period for that rule. On those issues, the EPA responded to those comments in the final rule and made appropriate revisions to the proposed rule after consideration of public comments received. It is well-established that an agency may refine its proposed approach without providing an additional opportunity for public comment. See *Community Nutrition Institute* v. *Block,* 749 F.2d at 58 and *International Fabricare Institute* v. *EPA,* 972 F.2d 384, 399 (D.C. Cir. 1992) (notice and comment is not intended to result in ''interminable back-and-forth[,]'' nor is agency required to provide additional opportunity to comment on its response to comments) and *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d 506, 547 (D.C. Cir. 1983) (''notice requirement

should not force an agency endlessly to repropose a rule because of minor changes'')

In the EPA's view, an objection is of central relevance to the outcome of the rule only if it provides substantial support for the argument that the promulgated regulation should be revised. See *Union Oil* v. *EPA,* 821 F.2d 768, 683 (D.C. Cir. 1987) (court declined to remand rule because petitioners failed to show substantial likelihood that final rule would have been changed based on information in petition). See also the EPA's *Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202 of the Clean Air Act,* 75 FR at 49556, 49561 (August 13, 2010). See also, 75 FR at 49556, 49560–49563 (August 13, 2010) and 76 FR at 4780, 4786–4788 (January 26, 2011) for additional discussion of the standard for reconsideration under CAA section 307(d)(7)(B).

We are denying reconsideration on the following 57 issues contained in the petitions for reconsideration because they failed to meet the standard described above for reconsideration under CAA section 307(d)(7)(B). Specifically, on these issues, the petitioner has failed to show the following: that it was impracticable to raise their objections during the comment period or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. Therefore, the EPA is denying the petitions for reconsideration on the issues for the reasons described below.

Issue: Delist gas units.

The petitioners (API, NPRA) requested that the EPA remove gas-fired units from the section 112(c) list of source categories for which the EPA is required to establish emissions standards under section 112(d). The EPA is denying the petition for reconsideration for the following reasons. First, the issue is outside the scope of this rulemaking, which establishes emissions standards for new and existing units within the major source boilers and process heaters source category. The EPA did not solicit comment in the proposed rule regarding the scope of the subcategory. Further, petitioners provide no information to support delisting gas units under section 112(c)(9), which requires the EPA to make certain findings before delisting any sources. In addition, the petition does not address the D.C. Circuit's decision in *NRDC* v. *EPA,* 489 F.3d 1364 (2007), regarding the EPA's ability to delist subcategories of a source category pursuant to section 112(c)(9). For these reasons, the petitions do not provide support for the argument that the regulation should be changed. For this reason, the petition does not demonstrate that the issue is of central relevance to the outcome of the final rule and the EPA is denying the request for reconsideration.

Issue: Exempt natural gas hot water heaters with tanks greater than 120 gallons.

The petitioner (AIF) requested that the EPA exempt natural gas hot water heaters with tanks greater than 120 gallons. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed work practice standards for such units in its June 2010 proposal, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt natural gas and distillate oil-fired circulating hot water systems with a design capacity of 10 MMBtu/hr or less.

The petitioner (CIBO) requested that the EPA exempt natural gas and distillate oil-fired circulation hot water systems that are not greater than 10 MMBtu/hr. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed emissions standards for such units, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. In addition, the petition does not provide any information to demonstrate that these units should be delisted pursuant to section 112(c)(9). Therefore, the EPA is denying the request for reconsideration.

Issue: Confirm in definitions that open flame heaters (e.g., asphalt tank heaters) are not process heaters.

The petitioners (API, NPRA) requested that the EPA clarify in the definition of ''process heater'' that open flame heaters do not meet the definition. While the EPA disagrees with the petitioners whether clarification is needed in regards to open flame heaters, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed definition. The definition that the EPA proposed clearly states that process heaters are enclosed devices in which the combustion gases do not come into contact with process materials, and as such, does not include open flame heaters. Therefore, the EPA is denying reconsideration.

Issue: For blast furnace fuel-fired boiler exemption, compute the 90 percent BFG by volume threshold to exclude periods of BFG curtailment.

The petitioners (AISI, ACCCI) requested that the EPA revise the exemption for BFG fuel-fired boilers to exclude periods of BFG curtailment. While the EPA disagrees with the petitioners regarding revising the exemption, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed exemption for BFG fuel-fired boilers. The EPA proposed the exemption for these boilers, and petitioners therefore had the opportunity to comment on whether the exemption should apply to periods of BFG curtailment. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt boilers whose flue gases are used in direct-fired process heaters subject to other NESHAP.

The petitioner (CMI) requested that the EPA exempt from the rule boilers whose flue gases are used in direct-fired process heaters that are subject to other NESHAP. The final rule does not apply to such units if they are subject to another NESHAP. The EPA does not see a need for further clarification. Since the final rule does in fact exempt these units, the EPA is denying the request for reconsideration.

Issue: Work practice standards do not meet EPA obligations under 112(c)(6).

The petitioner (Sierra Club) requested that the EPA establish numeric emissions limits for Gas 1 units rather than work practice standards. Specifically, the petitioner alleges that the work practice standards do not meet the EPA's obligations under section 112(c)(6) of the CAA, and that it was not the case that data were below the detection level for all HAP emitted from these units. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's arguments regarding the legal authority to establish work practice standards for Gas 1 units and the basis for such standards, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for Gas 1 units and explained in the proposal its rationale for such standards, including the fact that a significant portion of the

emissions data were below the detection level. 75 *FR* at 32024–25. Therefore, the petitioner had the opportunity to comment on this issue, and did in fact submit comments regarding the EPA's legal authority to establish work practice standards for Gas 1 units. Therefore, the EPA is denying reconsideration on this issue.

Issue: Work practices for small units are not justified by 112(h) since small units were not given their own subcategory.

The petitioner (Sierra Club) requested that the EPA require small units, those having a heat input capacity of less than 10 MMBtu/hr, to meet numeric emissions limits rather than work practice standards. The EPA is denying the request for reconsideration on this issue because the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for these units and explained in the proposal its rationale for such standards. 75 *FR* at 32024–25. The EPA did in fact receive comments regarding the proposed standards, to which it responded in the final rule. 76 *FR* at 15640. Moreover, the EPA notes that nothing in section 112(h) limits the EPA's discretion to establish work practice standards to the establishment of such standards for an entire category or subcategory. Therefore, the EPA is denying the request for reconsideration.

Issue: PM is not an adequate surrogate for non-mercury metallic HAP.

The petitioner (Sierra Club) requested that the EPA remove the PM standard as a surrogate for non-mercury metallic HAP and instead adopt a numeric limit for non-mercury metallic HAP because PM is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of PM as a surrogate for non-mercury metallic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed PM standards as a surrogate for non-mercury metallic HAP and explained in the proposal the agency's basis for concluding that PM was an appropriate surrogate. 75 *FR* at 32018. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish direct limits on organics or select a surrogate besides CO.

The petitioner (Sierra Club) requested that the EPA remove the CO standard as a surrogate for organic HAP and instead adopt a numeric limit for these HAP, because CO is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of CO as a surrogate for organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed CO standards as a surrogate for organic HAP and explained in the proposal the agency's basis for concluding that CO was an appropriate surrogate. 75 *FR* at 32018. The EPA received comments on this issue, including comments stating that CO is not an appropriate surrogate for organic HAP. Therefore, the EPA is denying the request for reconsideration.

Issue: Adopt an alternative THC emission standard.

The petitioner (CIBO) requested that the EPA adopt a THC emissions standard as an alternative to the CO standard. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding whether a THC alternative standard is appropriate as a surrogate for non-dioxin organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA raised in the proposal the possibility of THC as a surrogate for non-dioxin organic HAP, and explained why the use of CO as a surrogate was preferable. 75 *FR* at 32018. In addition, the EPA did not receive any comments or data during the public comment period on the proposed rule that would have enabled the agency to establish a THC alternative standard, including THC emissions data, nor did the petitioner provide any such data. Therefore, the petition does not provide substantial support for its argument that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration on this issue.

Issue: Regulation of Total dioxin/furans exceeds statutory authority as only 2 compounds are in 112(b)(1).

The petitioners (AISI, ACCCI, AF&PA) alleged that the EPA lacks statutory authority to regulate total dioxin/furans under CAA section 112, and that the EPA's response in the final rule explaining why it is issuing a total dioxin/furan standard was not a logical outgrowth of the proposed rule. The EPA is denying the request for reconsideration on this issue. First, the EPA disagrees that the final rule is not a logical outgrowth of the proposal. The EPA proposed emissions standards for total dioxin/furans and adopted a final emissions standard for the same pollutant. Therefore, the commenter had the opportunity to provide its views during the public comment period regarding the EPA's proposed emissions standard, including its views regarding the EPA's authority to regulate the pollutant at issue. The fact that the EPA responded to those comments does not mean that the petitioner lacked the opportunity to comment—in fact, the petitioner did provide such comments. 76 *FR* at 15640. For this reason, the EPA is denying the petition for reconsideration.

Issue: HCl is an inadequate surrogate for all acid gases.

The petitioner (Sierra Club) requested that the EPA remove the HCl standard as a surrogate for acid gases and instead adopt a numeric limit for these HAP, because HCl is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of HCl as a surrogate for acid gases, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed HCl standards as a surrogate for acid gases and explained in the proposal the agency's basis for concluding that HCl was an appropriate surrogate. 75 *FR* at 32018. While the EPA had emission data for HCl from hundreds of affected units upon which to establish standards, the EPA did not have sufficient data on the other acid gases to do so (hydrogen fluoride, hydrogen cyanide and chlorine). The petitioner did not refer to any such data and, therefore, the issue is not of central relevance to the outcome of the final rule. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO as a surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA adopt a work practice standard for organic HAP rather than a numeric emissions limit based on CO as a surrogate for organic HAP. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees that a work practice standard is appropriate for such HAP for the subcategories for which the EPA adopted a numeric CO limit in the final rule, the petitioners have not demonstrated that they lacked the opportunity to comment on this issue. The EPA proposed numeric CO limits rather than a work practice, and the petitioners had the opportunity to provide their views during the public comment period on the proposed rule regarding why it believed a work practice standard should instead be

finalized. Therefore, the EPA is denying the petition for reconsideration.

Issue: Allow health based compliance alternatives for HCl, other acid gases and manganese.

The petitioners (AMP, AF&PA, AHFA, AISI, ACCCI, RPU, CIBO) requested that the EPA adopt a HBES for HCl and other acid gases as well as for manganese, pursuant to section 112(d)(4). The petitioners also requested that the EPA grant reconsideration on this issue to better address the comments and data submitted during the public comment period for the proposed rule. The EPA is denying the request for reconsideration of this issue. The EPA did not propose a HBES for any pollutants, but did solicit public comment on such standards, explaining its concerns regarding health-based standards, including the lack of available data on which to base such standards. 75 *FR* at 32030. The EPA received comments addressing those concerns and responded to them in the final rule. 76 *FR* at 15642. Therefore, the petitioners have not demonstrated that it lacked the opportunity to comment on this issue. Further, the EPA received no data during the public comment period for the proposed rule on which it could base a HBES for HCl, other acid gases or manganese. Therefore, the petitions do not provide substantial support to demonstrate that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration.

Issue: Provide additional compliance alternatives according to Executive Order 13563 (additional subcategories and HBES).

The petitioner (AHFA) requested that the EPA provide additional compliance alternatives in the final rule pursuant to Executive Order 13563 (Improving Regulation and Regulatory Review), including HBES. The EPA is denying the request for reconsideration on this issue because it is not of central relevance. First, nothing in Executive Order 13563 affects the EPA's discretion to establish HBES under the CAA. Additionally, the petition does not provide any information to address our concerns regarding HBES or data to establish such standards.

Issue: Remove energy assessment requirements.

The petitioners (AHFA, AISI, ACCCI, API, NPRA, AIF, CIBO, AF&PA, U.S. Sugar) requested that the EPA remove from the final rule the requirement that existing sources conduct an energy assessment. The EPA is denying the request for reconsideration on this issue. The EPA proposed an energy assessment requirement as a beyond-the-floor standard, and petitioners commented on that proposal. The EPA addressed those comments in the final rule, and petitioners have not demonstrated that they lacked the opportunity to comment on whether the EPA should require an energy assessment, including the EPA's legal authority to do so. 76 *FR* at 15631. Therefore, the EPA is denying the petition for reconsideration. The EPA continues to believe that an energy assessment is not only authorized by the CAA but required as a cost-effective beyond-the-floor standard in accordance with section 112(d)(2).

Issue: Require energy assessment to be conducted every 5 years.

The petitioner (Washington Dept. of Ecology) requested that the EPA require more frequent energy assessments. The EPA proposed a one-time assessment (75 *FR* at p. 32036) and the petitioner has not demonstrated it lacked the opportunity to comment on the frequency of the assessment requirement. Therefore, the EPA is denying the petition.

Issue: Modify cost analysis to include potential fuel savings from implementing assessment findings.

The petitioners (AIE, USCHPA) requested that the EPA modify its cost impacts analysis to include potential fuel savings from implementing energy assessment findings. The EPA is denying the petition. The impacts analysis, including specific mention of how cost savings for energy assessments were handled quantitatively, was explained in the proposal (see 75 FR 32026), and the petitioner therefore had the opportunity to comment on this issue. For this reason, the EPA is denying the petition for reconsideration on this issue.

Issue: Reconsider definition of ''cost effective.''

The petitioners (AIE, USCHPA) requested that the EPA reconsider the definition of ''cost-effective'' in the final rule. The EPA is denying the request for reconsideration on this issue. The EPA proposed to define cost-effective energy conservation measures as any measure with return of investment period of two years or less. 75 *FR* at 32036. The petitioners have not demonstrated it lacked the opportunity to comment on the proposed definition. Therefore, the EPA is denying the petition for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA establish work practice standards for controlling organic HAP instead of using CO as a surrogate for organic HAP and establishing CO emission limits. The EPA is denying the request for reconsideration on this issue. Use of CO as a surrogate for organic HAP was subject to notice and comment. (75 FR 32018, 75 FR 32041). Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section ''Choice of Regulated Pollutants: THC vs. CO vs. Other Organic HAP''.

Issue: Provide alternative format for units of measure for CO emission limits to allow sources to use their existing monitoring equipment.

The petitioners (UARG, CIBO) requested that the EPA provide an alternative format (ppm at X percent CO_2) for units of measure for CO emissions in addition to ppm at 3 percent oxygen. The EPA is denying the petition because the petitioners do not demonstrate that it was impracticable to comment on this issue. The format for units of measure for the limits was provided in the proposed rule, and petitioners could have commented on whether the proposed units were appropriate.

Issue: New source emission limits are unachievable and the EPA should collect additional fuel variability data from top performing units to adjust the limits.

The petitioner (AF&PA) requested that the EPA adjust the emissions limits for new sources by collecting additional data from the best performing units that they believed would result in increased variability. The petitioners have not demonstrated that they lacked the opportunity to comment. We proposed standards based on the data we had, including data collected during the ICR process in which petitioners participated, and that data were available for public review. Therefore, petitioners could have commented on this issue. Second, the CAA requires that we base the standards on the sources for which we have emissions information. Petitioners are always free to provide more information to us and the EPA specifically requested new data at each stage of the rulemaking to support the development of emission limits for each subcategory. (75 FR 32041, 76 FR 28663, 76 FR 80612). The EPA has incorporated revised data corrections or new data submittals in its analysis for the final rule. The EPA is denying the request for reconsideration.

Issue: Adjust the methodology for computing MACT floors to address statistical errors and variability concerns.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA adjust the

methodology for computing MACT floors to address statistical errors and variability concerns, including: (1) Dataset reflects the ''best of the best'' units; (2) misapplication of statistical formulae to address distribution, confidence limits, and variability; and (3) failure to address variability in emissions from one unit over time. The methods used to compute the MACT floors were subject to notice and comment. Where new data or data corrections have been submitted that might alter data distributions, identifying best performers or application of fuel variability factors, these changes have been made in the final rule, but the general methodology remains the same. See *Solite Corp.* v. *EPA,* 952 F.2d 473, 485 (D.C. Cir. 1991) (public had sufficient notice of final rule threshold calculations where methodology did not change significantly from proposed rule). The EPA explained the MACT floor methodology in the proposed rule, and addressed comments received on the proposed methodology in the final rule (75 FR 32019–26, 32027–29, 76 15621–30, 76 FR 80614). Therefore, the EPA is denying the request for reconsideration.

Issue: Modify the basis for ranking the top performing units.

The petitioner (WEPCO) requested that the EPA modify the basis for ranking the top performing units, especially for new units, according to the average performance of the unit. The EPA is denying the petition. The methods used to rank units to establish the MACT floors were subject to notice and comment. The EPA explained its methodology in the proposed rule and addressed comments received on the ranking of data for computing the MACT floor in the final rule (75 FR 32019–26, 32027–29, 76 FR 15627).

Issue: Do not use a pollutant-by-pollutant approach to establish MACT floors.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA not use a pollutant-by-pollutant approach to establish MACT floors. The petitioners stated that this method is not a reasonable interpretation of Section 112(d)(3) of the CAA and that MACT floors should reflect levels achieved in practice, not aspirational controls. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed MACT floors based on the pollutant-by-pollutant methodology, and therefore petitioners could, and in fact did, provide comments opposing this approach. See 75 FR 32021, 32029. The EPA addressed comments received on this approach in the final rule (76 FR 15621–23). Therefore, the EPA is denying the petition.

Issue: Revise approach to establish MACT floors where there is non-detect data.

The petitioner (Sierra Club) requested that the EPA not use the approach it used in the final rule based on the representative detection level (RDL) to establish MACT floors because it does not reflect actual emissions of any source within the subcategory. Further, the petitioner questioned the basis of the selected detection level, and whether or not other variability adjustments (e.g., UPL analysis) sufficiently account for measurement imprecision. The EPA is denying the petition. The three times representative detection level approach was subject to notice and comment. The EPA explained its rationale for this approach in the proposed rule (75 FR 32021) and responded to comments received in the final rule (76 FR 15623, 76 FR 80611).

Issue: The approach used to set MACT floor limits for dioxin/furan emissions is flawed and the EPA should establish an isomer-specific approach.

The petitioner (WEPCO) requested that the EPA establish an isomer-specific approach for dioxin/furan emissions because the three times detection level approach for dioxin/furan emissions is flawed. The EPA is denying the petition. This approach was subject to notice and comment. Rationale and responses to comments on this approach were provided at (75 FR 32021, 32041, 76 FR 15623). Further, the methods for establishing a representative detection level for dioxin/furan have been revised to account for the sensitivity of individual isomers, see rationale provided at (76 FR 80606).

Issue: Incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units.

The petitioners (WEPCO, CIBO) requested that the EPA incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units. The MACT floor methodology was explained in the June 4, 2010 proposal which included fuel variability factors that did not reflect the ash content of the fuel. Therefore, the petitioner could have commented recommending that the EPA do so, and, in fact, comments were provided on this issue. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. Responses to comment on this topic were provided in RTC document, Volume 1, EPA–HQ–OAR–2002–0058–3289, see section ''MACT Floor Methodology: Fuel Analysis Variability''.

Issue: Allow energy assessors to determine the time needed to conduct assessment.

The petitioner (Washington Dept. of Ecology) requested that the EPA allow the energy assessor to determine the time needed to conduct the energy assessment. The EPA is denying the petition. The duration of energy assessments was subject to notice and comment and the duration remains up to the affected source. Specific concerns with maximum duration requirements included in the March 21, 2011 final rule were clarified in the December 23, 2011 proposed notice of reconsideration. (76 FR 80615)

Issue: The unit designed to burn gas 1 subcategory should allow for limited use of liquid fuels.

The petitioners (ACC, CEG, API, NPRA) requested that the EPA allow units in the Gas 1 subcategory for limited use of liquid fuels; for example, units with a federally enforceable permit on back up fuels or units burning 10 percent or less of its heat input from liquid fuels should qualify as gas 1 units. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed definitions of the various subcategories, and petitioners had the opportunity to comment on those definitions, including the proposed definition of the Gas 1 subcategory which did allow for the limited use of liquid fuels. The EPA addressed comments received on this issue in the final rule (76 FR 15620).

Issue: The unit designed to burn gas 1 subcategory should automatically include other gaseous fuels such as petrochemical process gas and landfill gas.

The petitioners (ACC, AIF, WM) requested that the EPA redefine the unit designed to burn gas 1 subcategory to automatically include other gaseous fuels such as petrochemical process gas and LFG, especially when the LFG is routed to a treatment system prior to use or sale. The EPA proposed definitions of units designed to burn gas 1 and units designed to burn gas 2 (other), and therefore the petitioner had the opportunity to comment on these definitions and to recommend that other gases be included in the definition of the Gas 1 subcategory (75 FR 32017, 32065). The EPA addressed comments received on this issue in the final rule (76 FR 15638). Therefore, the EPA is denying the petition.

Issue: Reconsider the emission standards established for the unit designed to burn gas 2 subcategory.

Petitioners (AIF, CIBO, WM, CEG) requested that the EPA reconsider the emission standards for the unit designed to burn gas 2 subcategory in light of what they feel was a limited dataset and lack of data from a diverse set of fuel types. The EPA is denying the petition. The MACT floor methodology was open to notice and comment in the June 4, 2010 proposal. The EPA proposed emissions standards for this subcategory and the petitioners had an opportunity to comment on the proposed standards and the data on which the standards were based. The EPA further notes that the CAA requires that the MACT standards be based on the best performing sources for which the Administrator has emissions information.

Issue: Adjust the ''metal process furnaces'' subcategory definition to include any gas-fired process furnace.

The petitioners (AISI, ACCCI) requested that the EPA adjust the ''metal process furnaces'' subcategory definition to include any gas-fired process furnace. The EPA is denying the petition. The definition of the subcategory for metal process furnaces was subject to notice and comment. (75 FR 32064, 76 FR 15620).

Issue: The designed to burn rationale for subcategorization is arbitrary.

The petitioner (Sierra Club) alleged that the designed to burn rationale for subcategorization is arbitrary, especially considering the large number of co-fired units in the inventory. The EPA proposed subcategories based on boiler design, and the petitioner has not demonstrated that it was impracticable to comment on the issue. In fact, the petitioner did submit comments on the proposed rule opposing the EPA's proposed subcategorization approach. Therefore, the EPA is denying the petition.

Issue: The EPA should consider exempting units from NSR.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA consider exempting units from NSR who switch fuels, install pollution controls, or construct energy efficiency projects to meet the requirements of this rule because complying with the rule requirements will trigger NSR. The EPA is denying the petition. The applicability of NSR is outside the scope of this rulemaking. Moreover, it was not impracticable to comment on this issue during the 2011 rulemaking, in fact, comments were submitted on this issue, to which the EPA responded. See RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2729.1, excerpt 17.

Issue: Remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative.

The petitioners (AMP, MSU, PSU, Purdue, RPU, U.S. Sugar, Citizens Thermal Energy) requested that the EPA remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative. The EPA is denying the petition. The EPA proposed an emissions averaging approach that included the 10 percent adjustment factor. (75 FR 32035) Therefore, the petition does not demonstrate that it was impracticable to comment on this issue. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section ''Emissions Averaging.''

Issue: Allow emissions averaging across subcategories.

The petitioners (MSU, PSU, Purdue, RPU, Citizens Thermal Energy) requested that the EPA allow emissions averaging across subcategories. The EPA is denying the petition. The EPA proposed an emissions averaging approach that did not allow averaging across subcategories, and petitioners therefore had the opportunity to comment recommending that the EPA allow such averaging. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–3213.1, excerpt 175.

Issue: Allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions.

The petitioner (CIBO) requested that the EPA allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions of the final rule. The EPA proposed an emissions averaging approach that was based on the maximum rated heat input capacity, and petitioners therefore had the opportunity to comment recommending that the EPA base the averaging on actual heat input. Therefore, the EPA is denying the petition.

Issue: Reduce stack testing frequency to once every five years to reduce burden on facilities.

The petitioners (ACC, CIBO, JELD–WEN) requested that the EPA reduce stack testing frequency to once every 5 years and rely on the extensive set of continuous parameter monitoring in order to reduce burden on facilities. The EPA is denying the petition. The EPA proposed to require stack testing every year. The petition does not demonstrate that it was impracticable to comment on this issue, and the petitioners could have submitted comments requesting less frequent stack testing.

Issue: Incorporate detailed fuel sampling procedures using incorporation by reference mechanisms instead of detailing sampling procedures in the regulatory language.

The petitioner (CIBO) requested that the EPA incorporate detailed fuel sampling procedures using incorporation by reference mechanisms and citing credible literature (e.g., American Society for Testing and Materials) instead of detailing sampling procedures in the regulatory language since sampling procedures are subject to change over time. The EPA is denying the petition because the petitioner has not demonstrated that it was impracticable to comment on this issue. The EPA proposed fuel sampling procedures in the regulatory text in the June 4, 2010 proposal, and the petitioner therefore had the opportunity to comment recommending its preferred approach.

Issue: Remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis.

The petitioner (UARG) requested that the EPA remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis, especially if monthly frequency is maintained. If the fuel monitoring plan requirement remains, the petitioner requests that the EPA remove the requirement to report things that might change, such as unanticipated fuel use (based on unanticipated fuel changes). The EPA is denying the petition and disagrees with the commenter. First, the EPA proposed a fuel monitoring plan, and petitioners had the opportunity to comment on the plan requirement. The final rule requires submittal of a fuel monitoring plan 60 days before demonstrating initial compliance. The rule does not require re-submittal of this plan before each monthly analysis, see 40 CFR section 63.7521(b)(1).

Issue: Allow EPA Method 5B to demonstrate compliance with PM emission limits.

The petitioner (UARG) requested that the EPA allow EPA Method 5B to demonstrate compliance with PM emission limits. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to allow Method 5B for PM compliance demonstrations. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA allow the use of this method. For this

reason, the EPA is denying the petition on this issue.

Issue: Remove or make references to Methods 2, 2F, 2G and 4 optional.

The petitioner (UARG) requested that the EPA remove or make references to EPA Methods 2, 2F, 2G and 4 optional. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to make EPA Methods 2, 2F, 2G and 4 optional. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA make the use of these methods optional. For this reason, the EPA is denying the petition on this issue.

Issue: Allow sources to petition for alternative PM monitoring requirements based on source-specific limitations.

The petitioner (CEG) requested that the EPA allow sources to petition for alternative PM monitoring requirements based on source-specific limitations (e.g., common stacks with more than one subcategory). The EPA is denying this petition because it is not of central relevance to this rulemaking. The General Provisions at 40 CFR 63.8 allow sources to petition the EPA for alternative monitoring plans. Therefore, no such provision is needed in this final rule.

Issue: Allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B.

The petitioners (CIBO, CMI) requested that the EPA allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B. The EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: No justification or discussion was provided on why the EPA selected 12 hours as the averaging time period and also why the EPA selected block averages instead of rolling averages.

The petitioner (Sierra Club) alleges that the EPA provided no justification or discussion explaining why the EPA selected 12 hours as the averaging time period and why the EPA selected block averages instead of rolling averages for parameter monitor. The petitioner requested that the EPA clarify that the averaging times for continuous parameter monitoring should be the same as the averaging times during the most recent performance test. Averaging times were open to notice and comment in the June 4, 2010 proposal. In the June 2010 proposal, we required that parameters be set based on 4-hour block averages during the compliance test, and that continuous compliance be demonstrated by monitoring 12-hour block average values for most parameters. We selected this averaging period to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits. Therefore, the EPA is denying the petition.

Issue: The EPA position regarding treatment of ''out-of-control'' and ''maintenance'' periods as deviations is not supported or explained.

The petitioner (UARG) alleges that the EPA position regarding treatment of ''out-of-control'' and ''maintenance'' periods as deviations is not supported or explained. The petitioner requested that the EPA revise the definition of ''deviation'' to be consistent with how deviation is treated with respect to CO CEMS and CPMS. The EPA is denying the petition. The definition of deviations was open to notice and comment in the June 4, 2010 proposal.

Issue: Require checks of pressure monitoring taps only if reading is abnormal.

The petitioner (CMI) requested that the EPA require checks of pressure monitoring taps only if reading is abnormal. The requirement to check pressure tap pluggage daily was open to notice and comment in the June 2010 proposal. In addition, the EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: The EPA has not sufficiently correlated emission limits to operating parameters and should not set enforceable limits on maximum and minimum control device operating parameters.

The petitioners (UARG, AMP, CIBO) alleges that the EPA has not sufficiently correlated emission limits to operating parameters and requested the EPA not to set enforceable limits on maximum and minimum control device operating parameters. One petitioner (CIBO) requested that the rule should allow sources to set their own ESP secondary voltage requirement based on load and coal quality since power consumption by an ESP is influenced by factors other than operating load, including ESP design, amount of PM collected, and resistivity of the PM. Other petitioners (UARG and AMP) also indicate that the limits set on control devices inhibit the flexibility to operate control devices with a margin of safety. The EPA is denying the petition. Operating limits were open to notice and comment in the June 4, 2010 proposal.

Issue: The EPA should delay incorporating PS 17 in this rule until the revisions for PS 17 are completed.

The petitioner (UARG) requested that the EPA delay incorporating PS 17 in this rule, which outlines how to select and install CPMS, until the revisions for PS 17 are completed.

The EPA is denying this petition. The final rule did not incorporate PS 17, or any other PS, in the provision regarding selection and installation of CPMS and ongoing quality assurance of data from CPMS. Comments related to revising PS 17 are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2960.1, excerpt 150).

Issue: The EPA should not set an enforceable operating limit on opacity.

The petitioner (UARG) alleged that there is insufficient correlation between opacity and PM emissions and requested that the EPA not set an enforceable operating limit on opacity. The EPA is denying the petition. The EPA proposed opacity limits in the June 4, 2010 proposal and the petitioner therefore had the opportunity to comment on the proposed limits, including comments requesting that no limit be established.

Issue: Update outdated BLDS Guidance.

The petitioner (UARG) requested that the EPA update the outdated BLDS Guidance that is currently incorporated by reference. The EPA is denying this petition. The current guidance document is the most recent guidance available and comments related to revising the guidance document are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2997.1, excerpt 10).

Issue: The EPA should reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control. The petitioners are unaware of any HCl control devices that are compatible with a hot-side ESP. The EPA is denying the petition. The basis for subcategorization was subject to notice and comment. The EPA did not propose a separate subcategory for such units, and the petitioner could have commented recommending that the agency do so. (75 FR 32012, 76 FR 15617–18, 76 FR 80607) Further, the EPA disagrees with the petitioner that the subcategories

could be based on the level of controls installed on the unit.

Issue: The EPA should change electronic reporting requirements to avoid WebFIRE and ERT shortcomings.

The petitioner (UARG) requested that the EPA change the electronic reporting requirements to avoid WebFIRE and ERT shortcomings. The petitioner requested that to meet the EPA's obligations under the Paperwork Reduction Act the EPA specify each individual data item requested in the ERT. The petitioner also requests that the EPA explain how the ERT electronic signature mechanisms will meet the requirements of the Cross-Media Electronic Reporting Rule.

The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed to require the use of the ERT and WebFIRE, and the petitioner therefore had the opportunity to comment on any concerns with the proposed approach.

Issue: Eliminate gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the reporting requirements in the Title V program.

The petitioner (AIF) requested that the EPA eliminate the gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the semi-annual reporting requirements in the Title V program. The EPA is denying the petition. Reporting requirements were open to notice and comment in the June 4, 2010 proposal.

Issue: Allow facilities to become area or synthetic minor sources instead of installing controls.

The petitioner (GPSP) requested that the EPA allow facilities to become area or synthetic minor sources instead of installing controls. The EPA is denying the petition. Whether or not sources elect to become area or synthetic minor sources is not of central relevance to this rulemaking, as nothing in this rule affects whether or how a source can become a synthetic minor source (RTC document, EPA–HQ–OAR–2002–0058–3289, Volume 1, DCN EPA–HQ–OAR–2002–0058–3176.2, excerpt 4).

VI. Impacts of This Final Rule

A. What are the incremental air impacts?

Table 4 of this preamble illustrates, for each basic fuel subcategory, the total emissions reductions achieved by the final amended rule (i.e., the difference in emissions between a boiler or process heater controlled to the amended floor level of control and boilers or process heaters at the current baseline) for new and existing sources. Nationwide emissions of selected HAP (i.e., HCl, HF, mercury, metals, and VOC) will be reduced by 44,300 tpy. This is an incremental increase of 4,000 tpy in HAP reductions compared to the estimates in the March 2011 final rule. This increase is due mainly to changes in the inventory (336 units were added since the March 2011 inventory). Excluding the changes in the inventory, the amendments to the regulatory provisions themselves resulted in a decrease of 1,100 tpy of estimated reductions, part of this incremental reduction in HAP is contributed to edits to the baseline emission data received since the March 2011 final rule, as well as changes to the subcategories and emission limits as a result of this amended rule. The amendments to the final rule are expected to result in an additional 4,600 tpy of reductions in HCl emissions. The amendments are also expected to have a modest effect on mercury, estimated to range from a slight decrease of 0.12 tpy up to a slight increase of 0.96 tpy in emission reductions as a result of the changes to the regulatory requirements. Reductions in emissions of filterable PM will decrease by 18,500 tpy due to the final amended rule. Reductions in emissions of non-mercury metals (i.e., antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will decrease by 260 tpy. In addition, the amendments are estimated to result in an additional 50,100 tpy of reductions in SO_2 emissions. A discussion of the methodology used to estimate emissions, emissions reductions, and incremental emission reductions is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

TABLE 4—SUMMARY OF TOTAL EMISSIONS REDUCTIONS FOR THE FINAL AMENDED RULE

[tons/yr]

Source	Subcategory	HCl	PM	Non mercury metals [a]	Mercury [b]	VOC
Existing Units	Limited Use	1	2	0.42	2.1E–04	0.48
	Solid units	36,737	21,367	147	0.4 to 1.5	1,619
	Liquid units	2,143	9,434	2,315	0.9 to 1	620
	Non-Continental Liquid units	35	3	1	0.01 to 0.02	23
	Gas 1 (NG/RG) units	20	117	0.3	0.01	88
	Gas 1 Metallurgical Furnaces	0.4	3	0.02	0.001	27
	Gas 2 (other) units	4	8	0.06	3.8E–03 to 4.6E–03.	40
New Units	Solid units	0	351	5	0.02	0
	Liquid units	0	0	0	0	0
	Gas 1 units	0	0	0	0	0
	Gas 1 Metallurgical Furnaces	0	0	0	0	0
	Gas 2 (other) units	0	0	0	0	0

[a] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[b] Mercury reductions are presented as a range due to adjustments on reported fractions and limits of detection. See memorandum entitled ''Revised (March 2012) Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source'' for a description of the two methods for estimating mercury reductions.

B. What are the incremental water and solid waste impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the amended emission limits for HCl would be 556 million gallons per year for existing sources compared to the current baseline. In addition to the increased water usage, an additional 160 million gallons per year of wastewater would be produced for existing sources. Only half of these incremental changes are due to changes in the regulatory provisions. The other half is due to changes in the number of identified existing units and projected new units. The annual costs of treating the additional wastewater are $1.2 million. These additional costs are accounted for in the incremental control cost estimates.

The EPA estimated the additional solid waste that would result due to the amendments to be 138,000 tpy, with nearly all due to changes in the regulatory provisions. Solid waste is generated from flyash and dust captured in PM and mercury controls as well as from spent carbon that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are $5.8 million. These costs are also accounted for in the incremental control costs estimates.

A discussion of the methodology used to estimate incremental impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

C. What are the incremental energy impacts?

The EPA estimated that the March 2011 final rule would result in an increase of about 1.4 billion kWh/yr in national energy usage from the electricity required to operate control devices, such as wet scrubbers, electrostatic precipitators and fabric filters which are expected to be installed to meet the final rule. The amendments are expected to decrease energy usage by a net 143 million kWh/yr compared to the March 2011 rule. These reductions are driven by the regulatory provisions of these amendments. Additionally, the EPA expects these amendments will result in a decrease of 4.4 million MMBtu/yr in fuel savings, compared with the estimates in the March 2011 final rule.

D. What are the incremental cost impacts?

For these final amendments, we estimated the incremental difference between the national costs impacts for the final amended rule and the March 2011 final rule. First, we determined the control measures, work practices, and monitoring and testing requirements that would be required by boilers and process heaters located at major source facilities to comply with the final amended rule. To estimate the national cost impacts of the final amended rule for existing sources, we used the identical methodology used to estimate the cost impacts for the March 2011 final rule with one exception. In this revised analysis, it was assumed that several liquid fuel units that reported natural gas firing capability would switch to natural gas as a compliance option instead of installing add-on controls to demonstrate compliance with the emission limits. Thus, the only costs to these units would be the tune-up work practice costs. A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

The resulting total national cost impact of the final amended rule is $4.7 billion in capital expenditures and $1.5 billion per year in total annual costs, considering fuel savings. The total capital expenditures are slightly lower than estimated for the March 2011 final rule, but the total annual costs are slightly higher than estimated for the March 2011 final rule. See 76 FR 15651. The total capital and annual costs include costs for control devices, work practices, testing and monitoring.

In order to determine the incremental cost impacts of the amended requirements and emission limits, we first estimated the cost impacts of the additional existing boilers and process heaters added to the Boiler MACT inventory database since promulgation of the March 2011 final rule and the revised number of new boilers and process heaters that could be potentially constructed. Since the March 2011 final rule, we became aware of 72 major source facilities that were not previously in the Boiler MACT inventory database. Adding the boilers and process heaters located at these newly identified major source facilities resulted in 73 additional coal-fired units, 32 additional biomass-fired units, 82 additional oil-fired units, and 149 additional gas-fired units. Our revised number of new boilers and process heaters included 82 additional biomass units, 1,728 additional gas 1 units and 13 fewer liquid units.

The resulting cost impact for these additional existing and new boilers and process heaters is $1.0 billion in capital expenditures and $0.31 billion per year in total annual costs, considering fuel savings.

Therefore, discounting the added costs for the additional boilers and process heaters included in the costs analysis, the estimated incremental cost impacts for these amended requirements on existing and new boilers and process heaters are $1.0 billion in capital expenditures and $0.13 billion per year in total annual costs less than the costs estimated in the March 2011 rule.

Table 5 of this preamble shows the total capital and annual cost impacts of the final amended rule for each subcategory. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE

Source	Subcategory	Estimated/ projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
Existing Units	Coal units	621	2,554	46	904
	Biomass units	502	405	29	109
	Heavy Liquid units	319	761	5.4	221
	Light Liquid units	615	712	4.2	166
	Non-Continental Liquid units	21	62	0.8	17
	Gas 1 (NG/RG) units	11,929	77	0.9	(295)

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE—Continued

Source	Subcategory	Estimated/ projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
	Gas 2 (other) units	129	138	2.3	58
Energy Assessment	ALL	1,700 (Facilities).	N/A	N/A	28
New Units	Coal units	0	0	0	0
	Biomass units	82	381	5.6	[a] 99
	Liquid units	0	0	0	0
	Gas 1 (NG/RG) units	1,762	11	0	[a] 5.1
	Gas 2 (other) units	0	0	0	0

[a] Total annualized costs for new units do not account for fuel savings since no fuel savings are estimated in the first year for new units.

Potential control device cost savings and increased recordkeeping and reporting costs associated with the emissions averaging provisions in the final rule are not accounted for in either the capital or annualized cost estimates.

A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

E. What are the economic impacts?

The EPA analyzed the economic impacts of this final amended rule using the methodology that was discussed in the March 2011 final rule RIA and in the preamble to the March 2011 final rule. See FR 76 15651. The market impact results are very similar to the results presented in the March 2011 final rule and the RIA. The agency's economic model suggests the average national price increases for industrial sectors are less than 0.01 percent, while average annual domestic production may fall by less than 0.01 percent.

Because of higher domestic prices, imports slightly rise. The results for sales tests for small businesses were somewhat reduced than those calculated for the March 2011 final rule. For the sales tests using small companies identified in the Combustion Survey, the mean cost to receipts dropped from 4 percent in the RIA to 3 percent for this final amended rule and the median was 0.2 percent for the RIA and also 0.2 percent for this final amended rule. The number of parent companies with sales tests exceeding 3 percent dropped from 8 in the RIA to 5 for this final amended rule. There was no change in the results for small public entities. Median cost is still about $1.1 million and representative small major public entities would have cost-to-revenue ratios above 10 percent. The change in employment estimates between the RIA and the final amended rule is minimal. In the RIA for the March 2011 final rule, we estimated employment changes ranging between −3,100 to +6,500 employees, with a central estimate of +1,700. For this final amended rule we estimate employment changes ranging between −2,600 to +5,400 employees, with a central estimate of +1,400. These estimated annual employment changes compared to the baseline employment, and are for the time period for which the annualized cost applies (2015 to 2029).

F. What are the benefits of this final rule?

We calculated health benefits using the methodology described in the RIA prepared for the March 21, 2011 final rule. We incorporated the revised emission reductions estimated for this reconsideration final rule into the analysis. We were unable to estimate the benefits from reducing exposure to HAP and ozone, ecosystem impairment and visibility impairment, including reducing 180,000 tons of carbon monoxide, 39,000 tons of HCl, 500 tons of HF, 2,500 tons of other metals and 3,100 to 5,300 pounds of mercury. Please refer to the full description of the unquantified benefits as well as technical details of the analysis and its limitations and uncertainties in the final Boiler RIA (March 2011). These monetized benefits are approximately 23 percent higher than the March 2011 final rule benefits due to the increase in SO_2 emission reductions associated with the additional units affected by the rule and the revised HCl limit. We estimate the total monetized benefits of this final regulatory action to be $27 billion to $67 billion at a 3 percent discount rate and $25 to $61 billion at a 7 percent discount rate. All estimates are for the implementation year (2015) in 2008$. A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is provided in Table 6 of this preamble. A summary of the avoided health incidences is provided in Table 7 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT

[millions of 2008$] [a b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
$PM_{2.5}$-related benefits			
Direct $PM_{2.5}$	14,139	$1,200 to $2,900	$1,100 to $ $2,700
SO_2	572,000	$26,000 to $64,000	$24,000 to $61,000

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT—Continued

[millions of 2008$] [a b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
Total		$27,000 to $67,000	$25,000 to $61,000.

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing hazardous air pollutants (HAP) are not included. These estimates do not include energy disbenefits valued at $24 million (using a 3 percent discount rate). These benefits reflect existing boilers and new boilers anticipated to come on-line by 2015.

[b] There are some slight differences in the emission reductions used in the RIA and those used in the air impacts section of this preamble due to some late changes in the data that were received after the RIA was completed. Refer to the memoranda ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' for a discussion of the differences.

TABLE 7—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT [a]

	Avoided health incidences
Premature Mortality	3,000–7,900
Morbidity	
Chronic Bronchitis	2,000
Acute Myocardial Infarction	5,000
Hospital Admissions, Respiratory	750
Hospital Admissions, Cardiovascular	1,600
Emergency Room Visits, Respiratory	3,000
Acute Bronchitis	4,600
Work Loss Days	390,000
Asthma Exacerbation	51,000
Minor Restricted Activity Days	2,300,000
Lower Respiratory Symptoms	55,000
Upper Respiratory Symptoms	41,000

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing HAP are not included. These benefits reflect existing boilers and new boilers anticipated to come online by 2015.

G. What are the incremental secondary air impacts?

For units adding controls to meet the amended emission limits, we anticipate very minor secondary air impacts. The combustion of fuel needed to generate additional electricity would yield slight increases in emissions, including NO_X, CO, PM and SO_2 and an increase in CO_2 emissions. Since NO_X and SO_2 are covered by capped emissions trading programs and methodological limitations prevent us from quantifying the change in CO and PM, we do not estimate an increase in secondary air impacts for this final rule from additional electricity demand. We do estimate greenhouse gas impacts, which result from increased electricity consumption, to be 859,200 tpy from existing units and 79,700 tpy from new units. This is 19,200 tpy less than the estimated greenhouse gas impacts associated with the March 2011 final rule.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to the OMB recommendations have been documented in the docket for this action.

The EPA did prepare a new RIA for this action. The EPA prepared an assessment of the changes in the costs and benefits of this final rule compared to the costs and benefits associated with the March 21, 2011, final rule. Overall, the costs and impacts are estimated to be similar to the costs and impacts associated with the previous final rule, although the distribution is somewhat different and the number of affected units in the inventory has increased by about 302 units. When comparing the costs using only those sources that were part of the final rule inventory, the costs have decreased. The EPA re-ran the multimarket model to assess changes in economic impacts, and this analysis confirmed that the overall economic impacts are similar to the previous final rule. The benefits are projected to increase by about 20 percent because of the increase in the estimated SO_2 reductions. A summary of the costs and benefits of the previous final rule is provided in the preamble to the previous final rule (*see* 76 FR 15658) and the detailed analysis for the previous final rule is provided in the RIA for the previous final rule. In addition, memoranda are provided in the docket to document the changes in costs, economic impacts, and benefits associated with this final rule, shown in Table 8.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$24,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,200 to $59,000.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015—Continued

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of mercury, and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.
[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the ''social cost of carbon'', which is discussed further in the RIA.
[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

B. Paperwork Reduction Act

The OMB has approved the information collection requirements contained in the March 21, 2011 final rule under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0551. The EPA has updated the supporting statement to reflect the final inventory and burden estimates associated with this action since some of the monitoring, recordkeeping and reporting requirements have changed since the March 21, 2011 final rule. These revised estimates have been sent to OMB for review and approval.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

This final rule will require maintenance inspections of the control devices but will not require any notifications or reports beyond those required by the General Provisions aside from a notification of intent to commence burning solid waste materials and notification of alternative fuel use for those units that are in the Gas 1 subcategory but burn liquid fuels for periodic testing, or during periods of gas curtailment or gas supply emergencies. The recordkeeping requirements require only the specific information needed to determine compliance.

The revised annual monitoring, reporting and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $95.3 million which is about the same as estimated for the March 2011 final rule. This includes 323,130 labor hours per year at a total labor cost of $30.6 million per year, and total non-labor capital costs of $64.7 million per year. This estimate includes initial and annual performance test, conducting and documenting an energy assessment, conducting fuel specifications for Gas 1 units, repeat testing under worst-case conditions for solid fuel units, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications and recordkeeping. Monitoring, testing, tune-up and energy assessment costs and cost were also included in the cost estimates presented in the control costs impacts estimates in section VI.D of this preamble. The total burden for the federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 100,608 hours per year at a total labor cost of $5.3 million per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. In addition, the EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information requirements contained in this final rule.

C. Regulatory Flexibility Act

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.[1] The RFA also allows an agency to ''consider a series of closely related rules as one rule for the purposes of sections'' 603 (initial regulatory flexibility analysis) and 604 (final regulatory flexibility analysis) in order to avoid ''duplicative action.'' 5 U.S.C. § 605(c). This final rule is closely related to the final major source rule, which the EPA signed on February 21, 2011. The EPA prepared a final regulatory flexibility analyses in connection with the major source rule. Therefore,

[1] Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business according to Small Business Administration (SBA) size standards by the North American Industry Classification System category of the owning entity. The range of small business size standards for the affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

pursuant to § 605(c), the EPA is not required to complete a final regulatory flexibility analysis for this rule.

The EPA has been concerned with potential small entity impacts since it began developing the major source rule. The EPA conducted outreach to small entities and, pursuant to § 609 of RFA, convened a Small Business Advocacy Review Panel to obtain advice and recommendations from small entity representatives.

Pursuant to the RFA, the EPA used the Panel's report and prepared both an initial regulatory flexibility analysis and a final regulatory flexibility analysis in connection with the closely related major source rule. Convening an additional Panel and preparing an additional final regulatory flexibility analysis would be procedurally duplicative and is unnecessary given that the issues here are within the scope of those considered by the Panel. In addition, this final action would decrease capital and annualized costs on small entities by about 3 percent and 10 percent, respectively, relative to the closely related final rule.

D. Unfunded Mandates Reform Act

Title II of the UMRA of 1995, 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local and tribal governments and the private sector. Federal agencies must also develop a plan to provide notice to small governments that might be significantly or uniquely affected by any regulatory requirements. The plan must enable officials of affected small governments to have meaningful and timely input in the development of the EPA regulatory proposals with significant Federal intergovernmental mandates and must inform, educate, and advise small governments on compliance with the regulatory requirements.

Both this rule and the March 21, 2011 final rule contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA prepared under section 202 of the UMRA a written statement for the final rule. This final rule also contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. The discussion below has been updated to reflect the changes.

1. Statutory Authority

As discussed in the March 21, 2011, final rule, the statutory authority for this final rulemaking is section 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

Section 112(d) of the CAA directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all boilers and process heaters located at major sources of HAP emissions.

2. Social Costs and Benefits

The regulatory impact analysis prepared for the March 21, 2011 final rule, which we have revised for this final rule, including the agency's assessment of costs and benefits, is detailed in the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' and in the ''Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources'' in the docket. Based on estimated compliance costs associated with this final rule and the predicted change in prices and production in the affected industries, the estimated social costs of this rule are $1.4 to 1.6 billion (2008 dollars).

It is estimated that 3 years after implementation of this final rule, HAP would be reduced by 45,000 tpy, including reductions in HCl, hydrogen fluoride, metallic HAP including mercury, and several other organic HAP from boilers and process heaters. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, the agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, there are significant annual reductions in fine particulate matter ($PM_{2.5}$) and in SO_2 that would occur, including 25 thousand tons of $PM_{2.5}$ and 558 thousand tons of SO_2. These reductions occur within 3 years after the implementation of the final regulation and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) are a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks and work-lost days (i.e., days when employees are unable to work). While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2015 associated with the implementation of the final regulatory action range from $27 billion (2008 dollars) to $67 billion (2008 dollars) when using a 3 percent discount rate (or from $25 billion (2008 dollars) to $61 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about $25 billion (2008 dollars) to $65 billion (2008 dollars) higher than the estimated social costs shown earlier in this section. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the rulemaking, refer to the RIA and the memos updating the impacts and benefits in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this final rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the rule are discussed previously in this preamble.

We do not believe that there will be any disproportionate budgetary effects of this final rule on any particular areas of the country, state or local governments, types of communities (e.g., urban, rural) or particular industry segments. See the results of the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).''

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this final rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this final rule is presented in the

''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' and a memoranda that are included in the docket, entitled ''Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources which update the RIA analyses. This analysis provides estimates of the effect of this rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a small impact on prices and output, and little impact on communities that may be affected by this final rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products and electricity). Hence, the potential impacts on the categories mentioned above should be small.

5. Consultation With Government Officials

The UMRA requires that we describe the extent of the agency's prior consultation with affected state, local and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a final rule. We consulted with state and local air pollution control officials during the development of the final rule. We have also held meetings on this final rule with many of the stakeholders from numerous individual companies, institutions, environmental groups, consultants and vendors, labor unions and other interested parties. We have added materials to the docket to document these meetings.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the emission limits in this final rule are based represents the MACT floors for all subcategories and, as a result, it is the least costly and least burdensome alternative.

This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by this final rule, the impacts are not expected to be significant. Therefore, this final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This final rule will not impose direct compliance costs on state or local governments, and will not preempt state law. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it is based solely on technology performance.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For the March 21, 2011, final rule, we estimated a 0.05 percent price increase for the energy sector and a −0.02 percent percentage change in production. We estimated a 0.09 percent increase in energy imports. For more information on the estimated energy effects, please refer to the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).'' The analysis is available in the public docket. While we did not recreate the RIA for this final action, the energy impacts for existing sources decreased slightly, and the energy impacts for new source increased due to the increased number of new sources that is now projected. Overall, the projected energy use increased slightly but would not change the analysis that was conducted for the previous final rule. Therefore, we conclude that this final rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through the OMB, explanations when the agency decides not to use available and applicable VCS.

This action does not involve any new technical standards from those contained in the March 21, 2011 final rule. Therefore, the EPA did not consider the use of any VCS. See 76 FR 15660–15662 for the NTTAA discussion in the March 21, 2011 final rule.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

For the March 2011 final rule, the EPA determined that the rule would not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the

level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. Compared to the previous final rule, while the amendments are somewhat less stringent for some subcategories of units and more stringent for some others, the overall increased health benefits demonstrate that the conclusions from the environmental justice analysis conducted for the previous final rule are still valid. Therefore, the EPA has determined this final rule will not have disproportionately high and adverse human or environmental effects on minority or low-income populations.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). With the exception of the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) being lifted January 31, 2013, this rule will be effective April 1, 2013.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and Recordkeeping requirements.

Dated: December 20, 2012

Lisa P. Jackson,

Administrator.

For the reasons cited in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 2. Effective January 31, 2013, the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted.

Subpart A—[Amended]

■ 3. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(19), (b)(23), (b)(35), (b)(40), (b)(69), and (b)(70).
■ b. Removing and reserving paragraph (b)(53).
■ c. Adding paragraphs (b)(46), (b)(55), and (b)(76) through (83).
■ d. Adding paragraphs (p)(12) through (20).
■ e. Adding paragraph (r).

The revisions and additions read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(19) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(23) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(35) ASTM D6784–02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD, table 11 to subpart DDDDD of this part, table 12 to subpart DDDDD of this part, table 13 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

* * * * *

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575 and § 63.11237.

* * * * *

(46) ASTM D4606–03 (2007), Standard Test Method for Determination of Arsenic and Selenium in Coal by the Hydride Generation/Atomic Absorption Method, approved October 1, 2007, IBR approved for table 6 to subpart DDDDD.

* * * * *

(55) ASTM D6357–11, Test Methods for Determination of Trace Elements in Coal, Coke, and Combustion Residues from Coal Utilization Processes by Inductively Coupled Plasma Atomic Emission Spectrometry, approved April 1, 2011, IBR approved for table 6 to subpart DDDDD.

* * * * *

(69) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

(70) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(76) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, approved July 15, 2011, IBR approved for § 63.7575 and § 63.11237.

(77) ASTM D975–11b, Standard Specification for Diesel Fuel Oils, approved December 1, 2011, IBR approved for § 63.7575.

(78) ASTM D5864–11 Standard Test Method for Determining Aerobic Aquatic Biodegradation of Lubricants or Their Components, approved March 1, 2011, IBR approved for table 6 to subpart DDDDD.

(79) ASTM D240–09 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD.

(80) ASTM D4208–02 (2007) Standard Test Method for Total Chlorine in Coal by the Oxygen Bomb Combustion/Ion Selective Electrode Method, approved May 1, 2007, IBR approved for table 6 to subpart DDDDD.

(81) ASTM D5192–09 Standard Practice for Collection of Coal Samples from Core, approved June 1, 2009, IBR approved for table 6 to subpart DDDDD.

(82) ASTM D7430–11ae1, Standard Practice for Mechanical Sampling of Coal, approved October 1, 2011, IBR approved for table 6 to subpart DDDDD.

(83) ASTM D6883–04, Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, approved June 1, 2004, IBR approved for table 6 to subpart DDDDD.

* * * * *

(p) * * *

(12) Method 5050 (SW–846–5050), Bomb Preparation Method for Solid Waste, Revision 0, September 1994, in

EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition IBR approved for table 6 to subpart DDDDD.

(13) Method 9056 (SW–846–9056), Determination of Inorganic Anions by Ion Chromatography, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(14) Method 9076 (SW–846–9076), Test Method for Total Chlorine in New and Used Petroleum Products by Oxidative Combustion and Microcoulometry, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(15) Method 1631 Revision E, Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Absorption Fluorescence Spectrometry, Revision E, EPA–821–R–02–019, August 2002, IBR approved for table 6 to subpart DDDDD.

(16) Method 200.8, Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma—Mass Spectrometry, Revision 5.4, 1994, IBR approved for table 6 to subpart DDDDD.

(17) Method 6020A (SW–846–6020A), Inductively Coupled Plasma-Mass Spectrometry, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(18) Method 6010C (SW–846–6010C), Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(19) Method 7060A (SW–846–7060A), Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(20) Method 7740 (SW–846–7740), Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

* * * * *

(r) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, *http://www.tappi.org.*

(1) TAPPI T 266, Determination of Sodium, Calcium, Copper, Iron, and Manganese in Pulp and Paper by Atomic Absorption Spectroscopy (Reaffirmation of T 266 om-02), Draft No. 2, July 2006, IBR approved for table 6 to subpart DDDDD.

(2) [Reserved]

Subpart DDDDD—[Amended]

■ 4. Section 63.7485 is revised to read as follows:

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

■ 5. Section 63.7490 is amended by adding paragraph (e) to read as follows:

§ 63.7490 What is the affected source of this subpart?

* * * * *

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

■ 6. Section 63.7491 is amended by:
■ a. Revising the introductory text.
■ b. Revising paragraph (a).
■ c. Revising paragraph (c).
■ d. Revising paragraph (h)
■ e. Revising paragraph (i).
■ f. Revising paragraph (m).
■ g. Revising paragraph (n).

The revisions read as follows:

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

* * * * *

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

* * * * *

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

* * * * *

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

* * * * *

■ 7. Section 63.7495 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b).
■ c. Adding paragraphs (e), (f), and (g).

The revisions and additions read as follows:

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

* * * * *

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of § 60.2145(a)(2) and (3) or § 60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must

be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

■ 8.Section 63.7499 is amended by revising paragraphs (d) and (f) through (l) and adding paragraphs (p) through (u) to read as follows:

§ 63.7499 What are the subcategories of boilers and process heaters?

* * * * *

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

* * * * *

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

* * * * *

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

■ 9. Section 63.7500 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (c).
■ c. Adding paragraph (d).
■ d. Adding paragraph (e).
■ e. Adding paragraph (f).

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

* * * * *

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

■ 10. Section 63.7501 is revised to read as follows:

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in

any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 11. Section 63.7505 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (c).
■ c. Revising paragraphs (d) introductory text, (d)(1) introductory text, and (d)(1)(iii).

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

* * * * *

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

* * * * *

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

* * * * *

■ 12. Section 63.7510 is revised to read as follows:

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to

§ 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

■ 13. Section 63.7515 is revised to read as follows:

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to

demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

■ 14. Section § 63.7520 is amended by revising paragraphs (a), (c), (d), and (e) and adding paragraph (f) to read as follows:

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

* * * * *

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

■ 15. Section 63.7521 is revised to read as follows:

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in

Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

■ 16. Section § 63.7522 is revised by:
■ a. Revising paragraphs (a) through (d).
■ b. Revising paragraphs (e)(1) and (2).
■ c. Revising paragraphs (f) introductory text and (f)(1) and (2).
■ d. Revising paragraphs (g) introductory text, (g)(2)(i), (g)(2)(iv), (g)(2)(vi)(B), (g)(3) introductory text, (g)(4) introductory text, and (g)(4)(ii).
■ e. Revising paragraph (h).
■ f. Revising paragraph (i).
■ g. Revising paragraph (j)(1).
■ h. Revising paragraph (k).

The revisions read as follows:

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on

January 31, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) * * *

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1a)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 1b)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 1c)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.
Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.
1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.
Hb = The heat input for that calendar month to unit, i, in units of million Btu.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 3c)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \qquad \text{(Eq. 4)}$$

Where:
AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million

Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

* * * * *

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

* * * * *

(2) * * *

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

* * * * *

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

* * * * *

(vi) * * *

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

* * * * *

(3) The Administrator shall review and approve or disapprove the plan according to the following criteria:

* * * * *

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

* * * * *

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

* * * * *

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategories, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) * * *

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

* * * * *

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

■ 17. Section 63.7525 is amended by:
■ a. Revising paragraph (a)
■ b. Revising paragraph (b).
■ c. Revising paragraph (c) introductory text.
■ d. Revising paragraphs (d) introductory text and paragraphs (d)(1) through (d)(4).
■ e. Revising paragraph (e)(2).
■ f. Revising paragraph (e)(3).
■ g. Revising paragraph (f)(2).
■ h. Revising paragraph (j).
■ i. Revising paragraph (k).
■ j. Adding paragraph (l).
■ k. Adding paragraph (m).

The revisions and additions read as follows:

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and

according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A–4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19–19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A–7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A–3 or Method 17 at 40 CFR part 60, appendix A–6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the

initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

* * * * *

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

* * * * *

(e) * * *

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

* * * * *

(f) * * *

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

* * * * *

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA–454/R–98–015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A–7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide

(SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

■ 18. Section 63.7530 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b) introductory text.
■ c. Redesignating paragraph (b)(3) as paragraph (b)(4) and adding new paragraph (b)(3).
■ d. Revising newly designated paragraph (b)(4).
■ e. Revising paragraph (c), (c)(2) through (4).
■ f. Adding paragraph (c)(5).
■ g. Revising paragraphs (d), (e), (g), and (h).
■ h. Adding paragraph (i).

The revisions and additions read as follows:

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

* * * * *

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and

pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (*e.g.,* when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 \, , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM

CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (''back half'') of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run. (iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in § 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

* * * * *

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard

deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028 \right) \qquad \text{(Eq. 16)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

* * * * *

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by

collecting the minimum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

■ 19. Section 63.7533 is amended by:
■ a. Revising the section heading.
■ b. Revising paragraph (a).
■ c. Revising paragraphs (b)(1) and (4).
■ d. Revising paragraphs (c) introductory text, (c)(1)(i) and (ii), (c)(2)(i), and (c)(3).
■ e. Revising paragraph (d) through (f).
■ f. Adding paragraph (g).

The revisions and addition read as follows:

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

(b) * * *

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

* * * * *

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) * * *

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

* * * * *

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

■ 20. Section 63.7535 is amended by revising the section heading and paragraphs (b), (c), and (d) to read as follows:

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

* * * * *

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

■ 21. Section 63.7540 is revised to read as follows:

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the

procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

■ 22. Section 63.7541 is amended by revising paragraphs (a)(3) and (4) to read as follows:

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

* * * * *

(a) * * *

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling

average parameter values consistent with the approved monitoring plan.

* * * * *

■ 23. Section 63.7545 is amended by:
■ a. Revising paragraphs (a) through (c).
■ b. Revising paragraphs (e) introductory text, (e)(1), (e)(2), (e)(3), (e)(4), (e)(5) introductory text, and (e)(5)(i).
■ c. Adding paragraph (e)(5)(ii).
■ d. Revising paragraphs (e)(8)(i) and (iii).
■ e. Revising paragraph (f) introductory text.
■ f. Revising paragraphs (g)(1) and (2).
■ g. Revising paragraphs (h) introductory text and (h)(1) and (3).
■ h. Removing paragraph (h)(4).

The revisions and addition read as follows:

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

* * * * *

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

* * * * *

(8) * * *

(i) ''This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi).''

* * * * *

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: ''No secondary materials that are solid waste were combusted in any affected unit.''

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

* * * * *

(g) * * *

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

* * * * *

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

* * * * *

(3) The date upon which the fuel switch or physical change occurred.

■ 24. Section 63.7550 is revised to read as follows:

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission

limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or

may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) [Reserved]

(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

■ 25. Section 63.7555 is amended by:

■ a. Revising paragraphs (d) introductory text and (d)(2) through (6).

■ b. Adding paragraphs (d)(9) through (11).

■ c. Revising paragraphs (f) through (h).

■ d. Adding paragraphs (i) and (j).

The revisions and additions read as follows:

§ 63.7555 What records must I keep?

* * * * *

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

* * * * *

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

* * * * *

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 14 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

* * * * *

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

■ 26. Section 63.7570 is amended by revising paragraph (a) and paragraph (b) introductory text to read as follows:

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this

subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

* * * * *

■ 27. Section 63.7575 is amended by:

■ a. Adding in alphabetical order definitions for ''10-day rolling average,'' ''30-day rolling average,'' ''Annual capacity factor,'' ''Average annual heat input rate,'' ''Benchmark,'' ''Biodiesel,'' ''Daily block average,'' ''Efficiency credit,'' ''Energy management program,'' ''Fluidized bed boiler with an integrated fluidized bed heat exchanger,'' ''Heavy liquid,'' ''Light liquid,'' '' ''Major source for oil and natural gas production facilities,'' ''Minimum oxygen level,'' ''Other combustor'', ''Oxygen analyzer system'', ''Oxygen trim system'', ''Pile burner'', ''Regulated gas stream'', ''Residential boiler,'' ''Residual oil'', ''Secondary material,'' ''Shutdown'', ''Sloped grate'', ''Startup'', ''Stoker/sloped grate/other unit designed to burn kiln dried biomass,'' Stoker/sloped grate/other unit designed to burn wet biomass,'' ''Suspension burner,'' ''Total selected metals (TSM),'' ''Traditional fuel,'' ''Ultra low sulfur liquid fuel,'' ''Unit designed to burn heavy liquid subcategory,'' ''Unit designed to burn light liquid subcategory,'' and ''Vegetable oil.''

■ b. Revising the definitions for ''Boiler,'' ''Boiler system,'' ''Coal,'' Commercial/institutional boiler,'' ''Deviation,'' ''Distillate oil,'' ''Dry scrubber,'' ''Dutch oven,'' ''Electric utility steam generating unit,'' ''Energy assessment,'' ''Energy use system,'' ''Equivalent,'' ''Federally enforceable,'' ''Fluidized bed boiler'', ''Fuel cell,'' ''Fuel type,'' ''Gaseous fuel,'' ''Heat input,'' ''Hot water heater,'' ''Hybrid suspension grate boiler,'' ''Industrial boiler,'' ''Limited-use boiler or process heater,'' ''Liquid fuel,'' ''Load fraction,'' ''Metal process furnaces,'' ''Minimum activated carbon injection rate,'' ''Minimum scrubber liquid flow rate,'' ''Minimum sorbent injection rate,'' ''Natural gas,'' ''Other gas 1 fuel,'' ''Period of natural gas curtailment or supply interruption,'' ''Process heater,'' ''Qualified energy assessor,'' ''Residual oil,'' ''Solid fossil fuel,'' ''Steam output,'' ''Stoker,'' ''Temporary boiler,'' ''Tune-up,'' ''Unit designed to burn gas 1 subcategory,'' ''Unit designed to burn gas 2 (other) subcategory,'' ''Unit designed to burn liquid subcategory,'' ''Unit designed to burn liquid fuel that is a non-continental unit,'' ''Unit designed to burn solid fuel,'' ''Waste heat boiler,'' ''Waste heat process heater.''

■ c. Removing the definitions for ''Benchmarking,'' ''Emission credit,'' ''Liquid fuel subcategory,'' and ''Suspension boiler.''

The revisions read as follows:

§ 63.7575 What definitions apply to this subpart?

* * * * *

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

* * * * *

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

* * * * *

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

* * * * *

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

* * * * *

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of ''coal'' includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

* * * * *

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

* * * * *

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

Deviation.

(1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751–11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

* * * * *

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

* * * * *

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite

consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an ''as received'' basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

* * * * *

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

* * * * *

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

* * * * *

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

* * * * *

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

* * * * *

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

* * * * *

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

* * * * *

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.

* * * * *

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

* * * * *

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

* * * * *

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396–10 (incorporated by reference, *see* § 63.14(b)).

* * * * *

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

* * * * *

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7\ MMBtu/Mwh \quad (Eq.\ 21)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2\ MMBtu/Mwh \quad (Eq.\ 22)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9\ MMBtu/Mwh \quad (Eq.\ 23)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_T \times 13.8\ MMBtu/Mwh \quad (Eq.\ 24)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other)

subcategory, use Equation 25 of this section:

$$EL_{OBE} = EL_T \times 10.4\ MMBtu/Mwh \quad (Eq.\ 25)$$

Where:
EL_{OBE} = Emission limit in units of pounds per megawatt-hour.
EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

* * * * *

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

* * * * *

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn

liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

* * * * *

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

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■ 28. Table 1 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.28 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E–07 [a] lb per MMBtu of heat input.	8.7E–07 [a] lb per MMBtu of steam output or 1.1E–05 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	1.1E–03 lb per MMBtu of steam output or 1.4E–02 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 2.9E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.2E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	5.8E–01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 3.7E–04 lb per MWh).	Collect a minimum of 2 dscm per run.

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TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (4.2E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.2E–01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E–04 [a] lb per MMBtu of steam output or 1.2E–03 [a] lb per MWh).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	3.1E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	3.5E–01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	4.3E–03 lb per MMBtu of steam output or 4.5E–02 lb per MWh; or (5.2E–05 lb per MMBtu of steam output or 5.5E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 [a] lb per MMBtu of heat input).	3.0E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (5.1E–05 lb per MMBtu of steam output or 4.1E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	3.3E–02 lb per MMBtu of steam output or 3.7E–01 lb per MWh; or (5.5E–04 lb per MMBtu of steam output or 6.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	4.8E–04 lb per MMBtu of steam output or 6.1E–03 lb per MWh.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input.	5.3E–07 [a] lb per MMBtu of steam output or 6.7E–06 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	1.5E–02 lb per MMBtu of steam output or 1.8E–01 lb per MWh; or (8.2E–05 lb per MMBtu of steam output or 1.1E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	1.2E–03 [a] lb per MMBtu of steam output or 1.6E–02 [a] lb per MWh; or (3.2E–05 lb per MMBtu of steam output or 4.0E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	2.5E–02 lb per MMBtu of steam output or 3.2E–01 lb per MWh; or (9.4E–04 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

■ 29. Table 2 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.27 lb per MWh.	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	5.7E–06 lb per MMBtu of heat input.	6.4E–06 lb per MMBtu of steam output or 7.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	4.0E–02 lb per MMBtu of heat input; or (5.3E–05 lb per MMBtu of heat input).	4.2E–02 lb per MMBtu of steam output or 4.9E–01 lb per MWh; or (5.6E–05 lb per MMBtu of steam output or 6.5E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.3E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E–02 lb per MMBtu of heat input; or (2.4E–04 lb per MMBtu of heat input).	4.3E–02 lb per MMBtu of steam output or 5.2E–01 lb per MWh; or (2.8E–04 lb per MMBtu of steam output or 3.4E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.7E–01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	4.6E–01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–01 lb per MMBtu of heat input; or (1.2E–03 lb per MMBtu of heat input).	1.4E–01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E–03 lb per MMBtu of steam output or 1.7E–02 lb per MWh).	Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
10. Suspension burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	5.2E–02 lb per MMBtu of steam output or 7.1E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	8.4E–01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E–01 lb per MMBtu of heat input; or (2.0E–03 lb per MMBtu of heat input).	3.9E–01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E–03 lb per MMBtu of steam output or 2.8E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid.	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.4 lb per MMBtu of steam output or 12 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (5.8E–03 lb per MMBtu of heat input).	5.5E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (1.6E–02 lb per MMBtu of steam output or 8.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E–01 lb per MMBtu of heat input; or (4.5E–04 lb per MMBtu of heat input).	5.5E–01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E–04 lb per MMBtu of steam output or 6.3E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	1.1E–03 lb per MMBtu of heat input.	1.4E–03 lb per MMBtu of steam output or 1.6E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E–06 lb per MMBtu of heat input.	2.5E–06 lb per MMBtu of steam output or 2.8E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b] collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E–02 lb per MMBtu of heat input; or (2.0E–04 lb per MMBtu of heat input).	7.5E–02 lb per MMBtu of steam output or 8.6E–01 lb per MWh; or (2.5E–04 lb per MMBtu of steam output or 2.8E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E–03 lb per MMBtu of heat input; or (6.2E–05 lb per MMBtu of heat input).	9.6E–03 lb per MMBtu of steam output or 1.1E–01 lb per MWh; or (7.5E–05 lb per MMBtu of steam output or 8.6E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.7E–01 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	3.3E–01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E–03 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

■ 30. Table 3 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable work practice standards:

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575: a. A visual inspection of the boiler or process heater system.

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS—Continued

If your unit is . . .	You must meet the following . . .
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup.	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas. If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose. You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown.	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

■ 31. Table 4 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the applicable operating limits:

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler not using a PM CPMS.	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS—Continued

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS.	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS.	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not using a PM CPMS.	a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS.	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2 CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS, maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the most recent HCl performance test, as specified in Table 8.

■ 32. Table 5 to subpart DDDDD of part 63 is amended by:
■ a. Revising the entry for ''1. Particulate matter.''
■ b. Remove the entry for ''5. Dioxins/Furans''.
■ c. Redesignating the entries for ''2. Hydrogen chloride,'' ''3. Mercury,'' and ''4. CO'' as ''3. Hydrogen chloride,'' ''4. Mercury,'' and ''5. CO,'' respectively.
■ d. Revising the newly redesignated entries for ''4. Mercury'' and ''5. CO.''
■ e. Add entry for ''2. Total selected metals.''

The revisions and addition read as follows:

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
1. Filterable PM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the TSM emission concentration ...	Method 29 at 40 CFR part 60, appendix A–8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. HCl	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the HCl emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the mercury emission concentration.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine oxygen concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A–4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

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■ 33. Table 6 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323[a] (for solid), or EPA 821–R–01–013 (for liquid or solid), or ASTM D4177[a] (for liquid), or ASTM D4057[a] (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or EPA 3050[a] (for solid fuel), or EPA 821–R–01–013[a] (for liquid or solid), or equivalent.

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a], ASTM E871[a], or ASTM D5864[a], or ASTM D240, or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722[a] (for coal), EPA SW–846–7471B[a] (for solid samples), or EPA SW–846–7470A[a] (for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content.	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 12 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M§[a] (for coal), or ASTM D5198§[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), ASTM D5864, ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871[a], or D5864[a], or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250[a], ASTM D6721[a], ASTM D4208[a] (for coal), or EPA SW–846–5050[a] or ASTM E776[a] (for solid fuel), or EPA SW–846–9056[a] or SW–846–9076[a] (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content.	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter.	Method 30B (M30B) at 40 CFR part 60, appendix A–8 of this chapter or ASTM D5954[a], ASTM D6350[a], ISO 6978–1:2003(E)[a], or ISO 6978–2:2003(E)[a], or EPA–1631[a] or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784[a] or equivalent.
4. TSM for solid fuels	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), or ASTM D4177[a],(for liquid fuels)or ASTM D4057[a] (for liquid fuels),or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] or TAPPI T266[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871[a], or D5864, or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample ..	ASTM D3683[a], or ASTM D4606[a], or ASTM D6357[a] or EPA 200.8[a] or EPA SW–846–6020[a], or EPA SW–846–6020A[a], or EPA SW–846–6010C[a], EPA 7060[a] or EPA 7060A[a] (for arsenic only), or EPA SW–846–7740[a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content.	Equation 9 in § 63.7530.
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

■ 34. Table 7 to subpart DDDDD of part 63 is amended by:
■ a. Revising the entry for ''1. Particulate matter or mercury,''.
■ b. Revising the entry for ''2. Hydrogen Chloride,''.
■ c. Revising the entry for ''3. Mercury,''.
■ d. Revising the entry for ''4. Carbon monoxide''.

The revisions read as follows:

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b).	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test.	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. HCl	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
	c. Alternative Maximum SO_2 emission rate.	i. Establish a site-specific maximum SO_2 emission rate operating limit according to § 63.7530(b).	(1) Data from SO_2 CEMS and the HCl performance test.	(a) You must collect the SO_2 emissions data according to § 63.7525(m) during the most recent HCl performance tests.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(b) The maximum SO_2 emission rate is equal to the lowest hourly average SO_2 emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury performance test.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (*e.g.,* actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen analyzer system specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
*	*	*	*	*	*	*

■ 35. Table 8 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and b. Reduce the data to 12-month rolling averages; and c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2). b. Reducing the data to 30-day rolling averages; and c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the minimum hourly SO_2 rate measured during the most recent HCl performance test according to § 63.7530.

■ 36. Table 9 to subpart DDDDD of part 63 is amended by revising the entry for ''1. Compliance report'' to read as follows:

As stated in § 63.7550, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
* * * * * * *		

■ 37. Table 10 to subpart DDDDD of part 63 is amended by:
■ a. Revising the entry for ''§ 63.6(i)''.
■ b. Revising the entry for ''§ 63.7(e)(1)''.
■ c. Revising the entry for ''63.8(g)''.
■ d. Revising the entry for ''§ 63.10(e) and (f)''.
■ e. Adding an entry for ''§ 63.10(e)''.
The revisions and addition read as follows.

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

Citation	Subject	Applies to subpart DDDDD
* * * * * * *		
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

Citation	Subject	Applies to subpart DDDDD
*	* * *	* * *
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
*	* * *	* * *
§ 63.8(g)	Reduction of monitoring data	Yes.
*	* * *	* * *
§ 63.10(e)	Additional reporting requirements for sources with CMS.	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements.	Yes.
*	* * *	* * *

■ 38. Add Table 11 to subpart DDDDD of part 63 to read as follows:

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Mercury	8.0E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Mercury	2.0E–06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
4. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run
12. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	8.0E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel ..	a. HCl	4.4E–04 lb per MMBtu of heat input ...	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input ...	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input ...	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.
[b] Incorporated by reference, see § 63.14.

■ 39. Add Table 12 to subpart DDDDD of part 63 to read as follows:

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E–06 [a] lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E–04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote ''a'', your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

■ 40. Add Table 13 to subpart DDDDD of part 63 to read as follows:

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.8E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.8E–02 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.6E–02 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel ..	a. HCl	1.2E–03 lb per MMBtu of heat input ...	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel.	a. CO (or CEMS)	130 [a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average)..	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average).	1 hr minimum sampling time.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

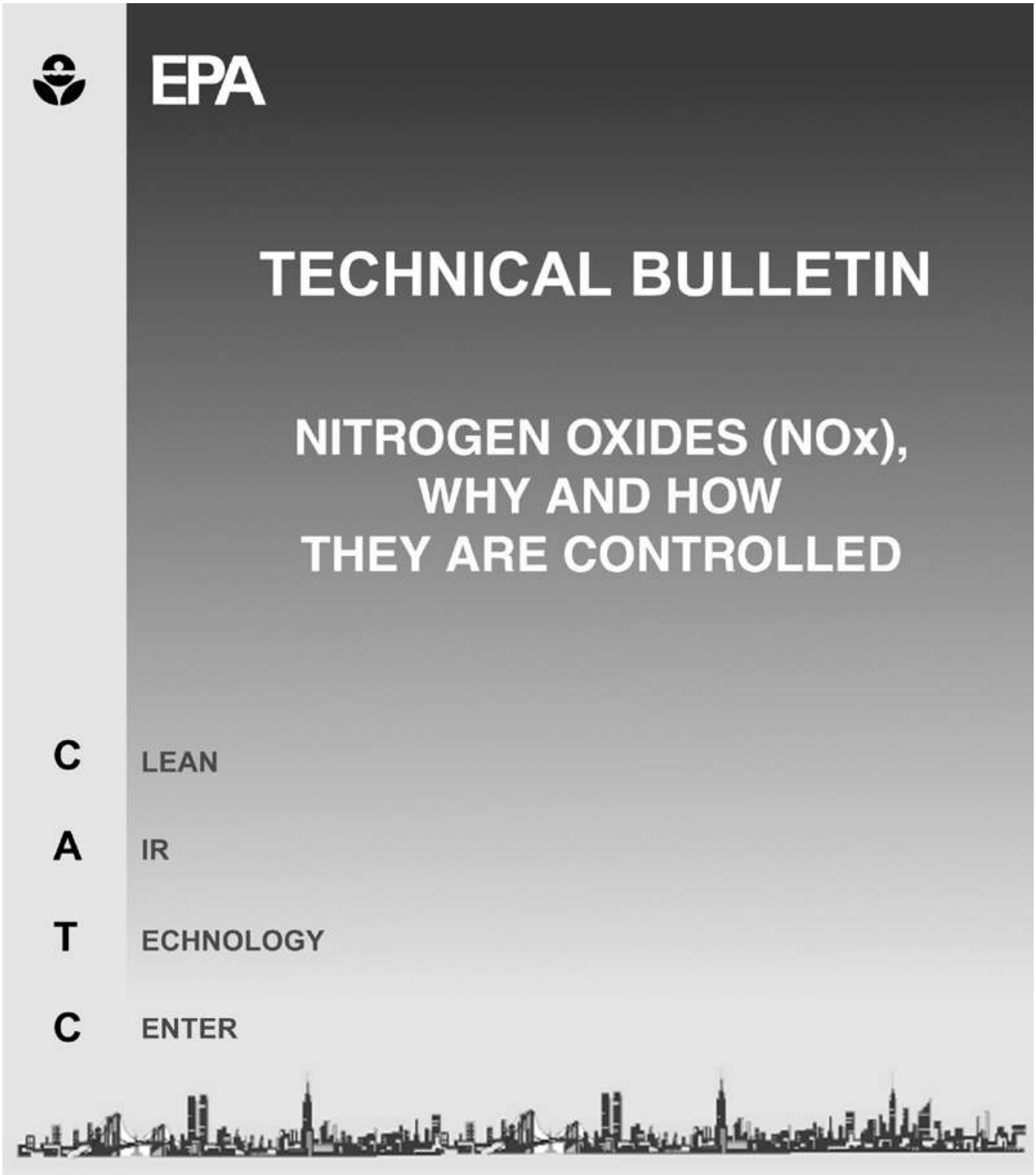
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Research Triangle Park, NC 27711

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Nitrogen Oxides (NOx), Why and How They Are Controlled

Prepared by

Clean Air Technology Center (MD-12)
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U.S. Environmental Protection Agency
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DISCLAIMER

This report has been reviewed by the Information Transfer and Program Integration Division of the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency and approved for publication. Approval does not signify that the contents of this report reflect the views and policies of the U.S. Environmental Protection Agency. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available form the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, Virginia 22161, telephone number (800) 553-6847.

CORRECTION NOTICE

This document, EPA-456/F-99-006**a**, corrects errors found in the original document, EPA-456/F-99-006. These corrections are:

Page 8, fourth paragraph: "Destruction or Recovery Efficiency" has been changed to "Destruction or Removal Efficiency;"

Page 10, Method 2. Reducing Residence Time: This section has been rewritten to correct for an ambiguity in the original text.

Page 20, Table 4. Added Selective Non-Catalytic Reduction (SNCR) to the table and added acronyms for other technologies.

Page 29, last paragraph: This paragraph has been rewritten to correct an error in stating the configuration of a typical cogeneration facility.

Page30, Internal Combustion Reciprocating Engines: A sentence has been added to the end of this section to refer the readers to Table 13 for more information;

Page 41, third through seventh paragraphs: These paragraphs were renumbered to correct for a numbering error (numbers 6 and 7 were used twice).

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FORWARD

The **Clean Air Technology Center (CATC)** serves as a resource on all areas of emerging and existing air pollution prevention and control technologies, and provides public access to data and information on their use, effectiveness and cost. In addition, the CATC will provide technical support, including access to EPA's knowledge base, to government agencies and others, as resources allow, related to the technical and economic feasibility, operation and maintenance of these technologies.

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In addition, the CATC thanks the individuals, companies and institutions who supplied information on nitrogen oxide abatement technology used to prepare this Technical Bulletin. Contributors are indicated in the REFERENCES section of this bulletin.

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Nitrogen Oxides (NOx), Why and How They Are Controlled

When we try to look only at one thing in Nature,
we find it connected to everything else.
John Muir

Nitrogen oxides (NOx) are a very interesting and important family of air polluting chemical compounds. This bulletin explains why NOx are important air pollutants and how NOx are formed and react in the atmosphere. This bulletin also discusses the principles on which all NOx control and pollution prevention technologies are based; available NOx technologies for various combustion sources; and performance and cost of NOx technologies..

WHY SHOULD WE CONTROL NOx?

NOx represent a family of seven compounds. Actually, EPA regulates only nitrogen dioxide (NO_2) as a surrogate for this family of compounds because it is the most prevalent form of NOx in the atmosphere that is generated by anthropogenic (human) activities. NO_2 is not only an important air pollutant by itself, but also reacts in the atmosphere to form ozone (O_3) and acid rain. It is important to note that the ozone that we want to minimize is tropospheric ozone; that is, ozone in the ambient air that we breathe. We are not talking about stratospheric ozone in the upper atmosphere that we cannot breathe. Stratospheric ozone protects us and the troposphere from ionizing radiation coming from the sun.

EPA has established National Ambient Air Quality Standards (NAAQS) for NO_2 and tropospheric ozone. The NAAQS define levels of air quality that are necessary, with a reasonable margin of safety, to protect public health (primary standard) and public welfare (secondary standard) from any known or anticipated adverse effects of pollution. The primary and secondary standard for NO_2 is 0.053 parts per million (ppm) (100 micrograms per cubic meter), annual arithmetic mean concentration.

Tropospheric ozone has been and continues to be a significant air pollution problem in the United States and is the primary constituent of smog. Large portions of the country do not meet the ozone NAAQS and thereby expose large segments of the population to unhealthy levels of ozone in the air. NO_2 reacts in the presence of air and ultraviolet light (UV) in sunlight to form ozone and nitric oxide (NO). The NO then reacts with free radicals in the atmosphere, which are also created by the UV acting on volatile organic compounds (VOC). The free radicals then recycle NO to NO_2. In this way, each molecule of NO can produce ozone multiple times.[40] This will continue until the VOC are reduced to short chains of carbon compounds that cease to be photo reactive (a reaction caused by light). A VOC molecule can usually do this about 5 times.

In addition to the NO_2 and Ozone NAAQS concerns, NOx and sulfur oxides (SOx) in the

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atmosphere are captured by moisture to form acid rain. Acid rain, along with cloud and dry deposition, severely affects certain ecosystems and directly affects some segments of our economy. All of these facts indicate an obvious need to reduce NOx emissions. However, to successfully do so, we must understand the generation and control of the NOx family of air pollutants.

WHAT IS A NITROGEN OXIDE?

Diatomic molecular nitrogen (N_2) is a relatively inert gas that makes up about 80% of the air we breathe. However, the chemical element nitrogen (N), as a single atom, can be reactive and have ionization levels (referred to as valence states) from plus one to plus five. Thus nitrogen can form several different oxides. Using the Niels Bohr model of the atom, valence state relates to the number of electrons which are either deficient (positive valence) or surplus (negative valence) in the ion when compared with the neutral molecule. The family of NOx compounds and their properties are listed in Table 1.

Table 1. Nitrogen Oxides (NOx)

Formula	Name	Nitrogen Valence	Properties
N_2O	nitrous oxide	1	colorless gas water soluble
NO N_2O_2	nitric oxide dinitrogen dioxide	2	colorless gas slightly water soluble
N_2O_3	dinitrogen trioxide	3	black solid water soluble, decomposes in water
NO_2 N_2O_4	nitrogen dioxide dinitrogen tetroxide	4	red-brown gas very water soluble, decomposes in water
N_2O_5	dinitrogen pentoxide	5	white solid very water soluble, decomposes in water

Oxygen ions are always at valence minus 2. Depending upon the number of oxygen ions (always balanced by the valence state of nitrogen), NOx can react to either deplete or enhance ozone concentrations. The nitrogen ion in these oxides really does a dance in which it has (at different times) various numbers of oxygen ions as partners. Nitrogen changes its number of partners when it changes its ionization energy level. This happens whenever NOx: (1) is hit with a photon of ionizing radiation (UV or a shorter wavelength light); (2) is hit with enough photons that together transfer enough energy to change its ionization level; (3) is catalyzed; (4) is stimulated sufficiently by thermal (IR) energy; (5) reacts with a chemically oxidizing or reducing radical (an ionized fragment of a molecule); or (6) reacts with a chemically oxidizing or reducing

ion (an atom with unbalanced electrical charge).

When any of these oxides dissolve in water and decompose, they form nitric acid (HNO_3) or nitrous acid (HNO_2). Nitric acid forms nitrate salts when it is neutralized. Nitrous acid forms nitrite salts. Thus, NOx and its derivatives exist and react either as gases in the air, as acids in droplets of water, or as a salt. These gases, acid gases and salts together contribute to pollution effects that have been observed and attributed to acid rain.

Nitrous oxide (N_2O), NO, and NO_2 are the most abundant nitrogen oxides in the air. N_2O (also known as laughing gas) is produced abundantly by biogenic sources such as plants and yeasts. It is only mildly reactive, and is an analgesic (i.e., unlike an anaesthetic you still feel pain, but you feel so good that you just don't mind it). N_2O is an ozone depleting substance which reacts with O_3 in both the troposphere (i.e., below 10,000 feet above sea level) and in the stratosphere (50,000 - 150,000 feet). N_2O has a long half-life, estimated at from 100 to 150 years.

Oxidation of N_2O by O_3 can occur at any temperature and yields both molecular oxygen (O_2) and either NO or two NO molecules joined together as its dimer, dinitrogen dioxide (N_2O_2). The NO or N_2O_2 then oxidizes quickly (in about two hours) to NO_2. The NO_2 then creates an ozone molecule out of a molecule of oxygen (O_2) when it gets hit by a photon of ionizing radiation from sunlight. N_2O is also a "Greenhouse Gas" which, like carbon dioxide (CO_2), absorbs long wavelength infrared radiation to hold heat radiating from Earth, and thereby contributes to global warming.

Emissions of NOx from combustion are primarily in the form of NO. According to the Zeldovich equations, NO is generated to the limit of available oxygen (about 200,000 ppm) in air at temperatures above 1,300°C (2,370°F). At temperatures below 760°C (1,400°F), NO is either generated in much lower concentrations or not at all. Combustion NO is generated as a function of air to fuel ratio and is more pronounced when the mixture is on the fuel-lean side of the stoichiometric ratio[50] (the ratio of chemicals which enter into reaction). The Zeldovich equations are:

$$N_2 + O \rightarrow NO + N$$
$$N + O_2 \rightarrow NO + O$$
$$N + OH \rightarrow NO + H$$

Except for NO from soils, lightning and natural fires, NO is largely anthropogenic (i.e., generated by human activity). Biogenic sources are generally thought to account for less than 10% of total NO emissions. NO produces the same failure to absorb oxygen into the blood as carbon monoxide (CO). However, since NO is only slightly soluble in water, it poses no real threat except to infants and very sensitive individuals.

NO_2 is present in the atmosphere and in acid rain. It produces nitric acid (HNO_3) when dissolved in water. When NO_2 reacts with a photon to make O_2 become O_3, NO_2 becomes NO. This NO is then oxidized within hours to NO_2 by radicals from the photo reaction of VOC. Therefore, our

present ozone concentration is the product of both NOx and VOC pollution.

Dinitrogen trioxide (N_2O_3) and dinitrogen tetroxide (N_2O_4) exist in very small concentrations in flue gas. However, they exist in such low concentrations in the atmosphere that both their presence and their effect are often ignored. N_2O_4 is two NO_2 molecules joined together (another dimer) and reacts like NO_2; so, the presence of N_2O_4 may be masked by the more abundant NO_2.

Dinitrogen pentoxide (N_2O_5) is the most highly ionized form of nitrogen oxide. It is generated in air in a very small concentration, unless it is emitted from a process (such as a nitric acid production facility) that is specifically designed to generate it. N_2O_5 is highly reactive, and forms nitric acid (HNO_3) when it decomposes in water.

Some experts feel that NO_2 is a good surrogate for NOx because NO is rapidly converted to NO_2, and N_2O has such a long life because it is not highly reactive. Others feel that due to their role in forming ozone, both NO and NO_2 should be considered NOx. Still others feel that all nitrogen oxides (including N_2O) need to be regulated. NO and NO_2 are certainly the most plentiful forms of NOx and they are largely (but not exclusively) from anthropogenic sources. N_2O is largely biogenic, and as such is not subject to regulation. For environmental purposes, using the concentration of NO_2 as a surrogate for the concentration of NOx has seemed to suffice, for it is the precursor for ozone.

WHERE DOES NOx COME FROM?

Automobiles and other mobile sources contribute about half of the NOx that is emitted. Electric power plant boilers produce about 40% of the NOx emissions from stationary sources.[34] Additionally, substantial emissions are also added by such anthropogenic sources as industrial boilers, incinerators, gas turbines, reciprocating spark ignition and Diesel engines in stationary sources, iron and steel mills, cement manufacture, glass manufacture, petroleum refineries, and nitric acid manufacture. Biogenic or natural sources of nitrogen oxides include lightning, forest fires, grass fires, trees, bushes, grasses, and yeasts.[1] These various sources produce differing amounts of each oxide. The anthropogenic sources are approximately shown as:

Mobile Sources	Electric Power Plants	Everything Else
50%	20%	30%

This shows a graphic portrayal of the emissions of our two greatest sources of NOx. If we could reduce the NOx emissions from just these two leading categories, we might be able to live with the rest. However, don't expect either of these categories to become zero in the foreseeable future. We cannot expect the car, truck, bus, and airplane to disappear. The zero-emission car is still on the drawing board and not on the production line. Also, social customs will have to change before consumption of electricity can be reduced.

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In all combustion there are three opportunities for NOx formation. They are:

1. Thermal NOx - The concentration of "thermal NOx" is controlled by the nitrogen and oxygen molar concentrations and the temperature of combustion. Combustion at temperatures well below 1,300°C (2,370°F) forms much smaller concentrations of thermal NOx.

2. Fuel NOx - Fuels that contain nitrogen (e.g., coal) create "fuel NOx" that results from oxidation of the already-ionized nitrogen contained in the fuel.

3. Prompt NOx - Prompt NOx is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions which exist, to some extent, in all combustion. This nitrogen then oxidizes along with the fuel and becomes NOx during combustion, just like fuel NOx. The abundance of prompt NOx is disputed by the various writers of articles and reports - probably because they each are either considering fuels intrinsically containing very large or very small amounts of nitrogen, or are considering burners that are intended to either have or not have fuel-rich regions in the flame.

HOW DOES NOx AFFECT THE ENVIRONMENT?

Because NOx are transparent to most wavelengths of light (although NO_2 has a brownish color and the rare N_2O_3 is black), they allow the vast majority of photons to pass through and, therefore, have a lifetime of at least several days. Because NO_2 is recycled from NO by the photo reaction of VOC to make more ozone, NO_2 seems to have an even longer lifetime and is capable of traveling considerable distances before creating ozone. Weather systems usually travel over the earth's surface and allow the atmospheric effects to move downwind for several hundred miles. This was noted in EPA reports more than twenty years ago. These reports found that each major city on the East coast has a plume of ozone that extends more than a hundred miles out to sea before concentrations drop to 100 parts per billion (ppb). Another report cited the same phenomenon for St. Louis. Therefore, this problem was not just on the sea coast. Since ozone in clean air has a lifetime of only a few hours, this phenomenon is a measure of the effect and the persistence of both VOC and NOx.

Differences in the distance estimates between the emission of NOx and the generation of ozone may be related to differences in plume transport (wind) speeds as well as other meteorological and air quality factors. It is important to note that, under the right conditions, power plant plumes may travel relatively long distances overnight with little loss of VOC, NO and NO_2 . These pollutants can thus be available to participate in photochemical reactions at distant locations on the following day.[41] Figure 1 shows a map of NOx concentration drawn by the Center for Air Pollution Impact and Trend Analysis (CAPITA) at Washington University in St. Louis and reported to the Ozone Transport Assessment Group, a national workgroup that addressed the problem of ground-level ozone (smog) and the long-range transport of air pollution across the Eastern United States. OTAG was a partnership among the EPA, the Environmental Council of the States (ECOS) and various industry and environmental groups with the goal of developing a thoughtful assessment and a consensus agreement for reducing ground-level ozone and the

pollutants that cause it. The animated version of Figure 1 shows the trajectory of NOx emissions moving with the weather over an 8 day period.

Figure 2 is a map of ozone concentration that shows the same trajectory over the 8 day period. The animated version shows concentrations of both NOx and ozone moving with the weather for several hundred miles.[5]

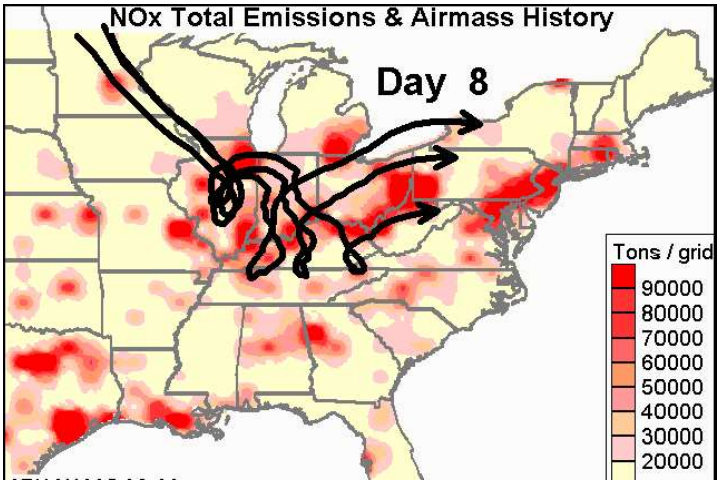


Figure 2 NOx Map

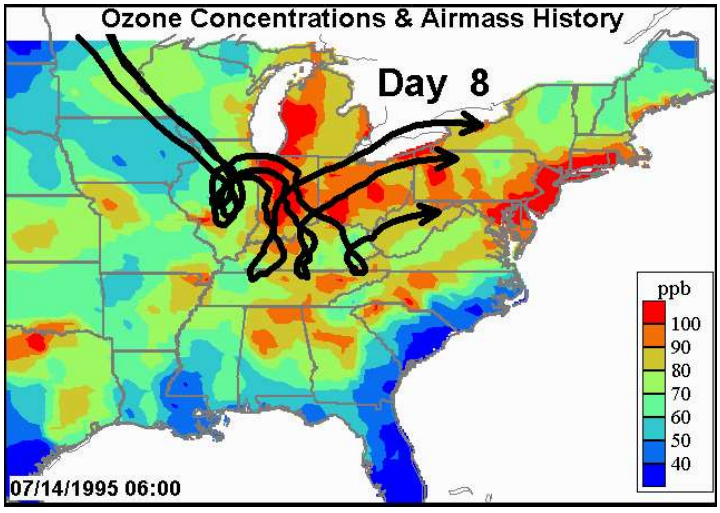


Figure 3 Ozone Map

Ozone is the primary constituent of smog. Between 1970 and 1990, we in the United States have tried to control ozone primarily by controlling the emissions of VOC. However, we have had mixed results, for although some areas reduced their VOC emissions and attained their ozone goals, others have not. It now appears that the communities that failed to meet their ozone goals

may not be completely at fault, for they appear to be affected by NOx and VOC emissions in the air coming to them. To meet the ozone NAAQS, EPA must now regulate emissions of NOx regionally.

ARE THERE OTHER NOx RELATED ISSUES?

Yes. Nutrient enrichment problems (eutrophication) occur in bodies of water when the availability of either nitrates or phosphates become too large. As a result, the ratios of nitrogen to phosphorus, silicon, and iron and other nutrients are altered. This alteration may induce changes in phytoplankton, produce noxious or toxic brown or red algal blooms (which are called "red tides"), or stimulate other plant growth. The algal blooms and plant growth produce a shadow and cause the death of other plants in the water, which depletes the oxygen content of the water (hypoxia) when the plants die, sink, and decay. Such eutrophication can make the bottom strata of water unihabitable for both marine animals (such as fish and shellfish) and aquatic plants. It can progress to virtually the complete depth of the water. It is estimated that between 12% and 44% of the nitrogen loading of coastal water bodies comes from the air.[40] Inland lakes are also affected in this way.

Another dimension of the problem is that high temperature combustion can convert sulfur in fuel to SO_2 and SO_3. While SO_2 is toxic and forms sulfurous acid when dissolved in water, SO_3 is both toxic and hygroscopic (moisture absorbing) and forms sulfuric acid by combining with moisture in the atmosphere. SO_2 and SO_3 form sulfites and sulfates when their acids are neutralized. Both of these acids can form solid particles by reacting with ammonia in air. SO_2 and SO_3 also contribute to pH (acidity) changes in water, which can adversely affect both land and aquatic life. Therefore, both NOx and SOx from combustion can kill plants and animals.

CAPITA has shown that there are about equal amounts by weight of sulfate/sulfite, nitrate and organic particles making up 90% of Particulate Matter less than 2.5 microns in aerodynamic diameter (PM-2.5). This was confirmed by Brigham Young University researchers. The Six Cities Study, published in the *New England Journal of Medicine* in 1990, has shown that illness and premature death are closely correlated with the amount of PM-2.5 in the air. Therefore, there is epidemiological data indicting nitrogen oxides, sulfur oxides, and/or organic compounds as PM-2.5 aerosols. There is currently no evidence that separately examines the health effects of each of these substances. PM-2.5 usually appear as smog, smoke, white overcast, haze, or fog which does not clear when air warms up. Brown smog is colored by nitrogen dioxide.

Because the nitric acid, sulfurous acid and sulfuric acid react with ammonia in air to form solid crystals that are much smaller than 2.5 microns and can be nucleation sites for particle growth, we need to be concerned about each of these pollutants. Some research indicates that even insoluble particles much smaller than 2.5 microns in size can exhibit severe toxic effects.[38] The smallest particles that have shown toxicity have a diameter of about 3% to 5% of the wavelength of any color of visible light. Therefore, these particles are too small to even scatter light and cannot even be detected optically.

Acid deposition occurs from airborne acidic or acidifying compounds, principally sulfates (SO_4^{-2}) and nitrates (NO_3^{-1}), that can be transported over long distances before returning to earth. This occurs through rain or snow (wet deposition), fog or cloud water (cloud deposition), or transfer of gases or particles (dry deposition). While severity of damage depends on the sensitivity of the receptor, acid deposition and NOx "represent a threat to natural resources, ecosystems, visibility, materials, and public health."(section 401(a)(1) of the Clean Air Act).[40]

WHAT ABATEMENT AND CONTROL PRINCIPLES APPLY?

NOx abatement and control technology is a relatively complex issue. We shall try to provide a structure to the spectrum of NOx pollution prevention and control technologies by first giving the principles that are used. Then we shall describe the more successful pollution prevention and emission control technologies and strategies.

Please note that abatement and control of NOx from nitric acid manufacturing and "pickling" baths differs from abatement and control at combustion sources. Combustion sources all have NOx in a large flow of flue gas, while nitric acid manufacturing plants and pickling baths try to contain the NOx. Wet scrubbers (absorbers) can control NOx emissions from acid plants and pickling, and can use either alkali in water, water alone, or hydrogen peroxide as the liquid that captures the NOx.[3] The wet scrubber operates by liquid flowing downward by gravity through a packing medium, opposed by an upward flow of gas. Scrubbers operate on the interchange of substances between gas and liquid. This requires that the height of the absorber, type of packing, liquid flow, liquid properties, gas properties, and gas flow should collectively cause a scrubber to have the desired control efficiency. Chapter 9 of the OAQPS Control Cost Manual provides guidance on the application, sizing, and cost of these scrubbers (referred to as gas absorbers). Also, Table 16 in this Bulletin presents some information for non-combustion NOx sources. Other then that, non-combustion NOx sources are not addressed in this Bulletin.

For combustion sources, this Bulletin defines abatement and emission control principles and states the Destruction or Removal Efficiency (DRE) that each successful technology is capable of achieving. The effectiveness of pollution prevention measures in reducing NO and NO_2 generation also is expressed in terms of relative DRE; i.e., the amount NOx generation is reduced by using a prevention technology compared to NOx generation when not using that technology. Then, specific boiler types and combustion systems and applicable NOx technologies for each system are discussed. Finally, the cost of these technologies is considered.

Many new combustion systems incorporate NOx prevention methods into their design and generate far less NOx then similar but older systems. As a result, considering DRE (even a relative DRE) for NOx may be inappropriate. Comparing estimated or actual NOx emissions from a new, well-designed system to NOx emitted by a similar well-controlled and operated older system may be the best way of evaluating how effectively a new combustion system minimizes NOx emissions.

Table 2 lists principles or methods that are used to reduce NOx. Basically there are six

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principles, with the seventh being an intentional combination of some subset of the six.

Table 2. NOx Control Methods [6,7]

Abatement or Emission Control Principle or Method	Successful Technologies	Pollution Prevention Method (P2) or Add-on Technology (A)
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning Low NOx Burners (LNB) Combustion Optimization Burners Out Of Service (BOOS) Less Excess Air (LEA) Inject Water or Steam Over Fire Air (OFA) Air Staging Reduced Air Preheat Catalytic Combustion	P2 P2 P2 P2 P2 P2 P2 P2 P2 P2 P2
2.Reducing residence time at peak temperature	Inject Air Inject Fuel Inject Steam	P2 P2 P2
3. Chemical reduction of NOx	Fuel Reburning (FR) Low NOx Burners (LNB) Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)	P2 P2 A A
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor Inject Oxidant	A A
5. Removal of nitrogen	Oxygen Instead Of Air Ultra-Low Nitrogen Fuel	P2 P2
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	A A
7. Combinations of these Methods	All Commercial Products	P2 and A

Method 1. Reducing Temperature -- Reducing combustion temperature means avoiding the stoichiometric ratio (the exact ratio of chemicals that enter into reaction). Essentially, this technique dilutes calories with an excess of fuel, air, flue gas, or steam. Combustion controls use different forms of this technique and are different for fuels with high and low nitrogen content.

Control of NOx from combustion of high nitrogen content fuels (e.g., coal) can be understood by the net stoichiometric ratio. Control of the NOx from combustion of low nitrogen fuels (such as gas and oil) can be seen as lean versus rich fuel/air ratios. Either way, this technique avoids the ideal stoichiometric ratio because this is the ratio that produces higher temperatures that generate higher concentrations of thermal NOx.

Combustion temperature may be reduced by: (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit temperature by diluting energy input; (3) injecting cooled oxygen-depleted flue gas into the combustion air to dilute energy; (4) injecting cooled flue gas with added fuel; or (5) injecting water or steam. Low-NOx burners are based partially on this principle.[8,9,10] The basic technique is to reduce the temperature of combustion products with an excess of fuel, air, flue gas, or steam. This method keeps the vast majority of nitrogen from becoming ionized (i.e., getting a non-zero valence).

Method 2. Reducing Residence Time -- Reducing residence time at high combustion temperatures can be done by ignition or injection timing with internal combustion engines. It can also be done in boilers by restricting the flame to a short region in which the combustion air becomes flue gas. This is immediately followed by injection of fuel, steam, more combustion air, or recirculating flue gas. This short residence time at peak temperature keeps the vast majority of nitrogen from becoming ionized. This bears no relationship to total residence time of a flue gas in a boiler.

Method 3. Chemical Reduction of NOx – This technique provides a chemically reducing (i.e., reversal of oxidization) substance to remove oxygen from nitrogen oxides. Examples include Selective Catalytic Reduction (SCR) which uses ammonia, Selective Non-Catalytic Reduction (SNCR) which use ammonia or urea, and Fuel Reburning (FR). Non-thermal plasma, an emerging technology, when used with a reducing agent, chemically reduces NOx. All of these technologies attempt to chemically reduce the valence level of nitrogen to zero after the valence has become higher.[11] Some low-NOx burners also are based partially on this principle.

Method 4. Oxidation of NOx -- This technique intentionally raises the valence of the nitrogen ion to allow water to absorb it (i.e., it is based on the greater solubility of NOx at higher valence). This is accomplished either by using a catalyst, injecting hydrogen peroxide, creating ozone within the air flow, or injecting ozone into the air flow. Non-thermal plasma, when used without a reducing agent, can be used to oxidize NOx. A scrubber must be added to the process to absorb N_2O_5 emissions to the atmosphere. Any resultant nitric acid can be either neutralized by the scrubber liquid and then sold (usually as a calcium or ammonia salt), or collected as nitric acid to sell to customers.[12, 49]

Method 5. Removal of nitrogen from combustion -- This is accomplished by removing nitrogen as a reactant either by: (1) using oxygen instead of air in the combustion process; or (2) using ultra-low nitrogen content fuel to form less fuel NOx. Eliminating nitrogen by using oxygen tends to produce a rather intense flame that must be subsequently and suitably diluted. Although Method 2 can lower the temperature quickly to avoid forming excessive NOx, it cannot

eliminate nitrogen oxides totally if air is the quench medium. Hot flue gas heats the air that is used to quench it and this heating generates some thermal NOx. This method also includes reducing the net excess air used in the combustion process because air is 80% nitrogen. Using ultra-low-nitrogen content fuels with oxygen can nearly eliminate fuel and prompt NOx.[13]

Method 6. Sorption, both adsorption and absorption -- Treatment of flue gas by injection of sorbents (such as ammonia, powdered limestone, aluminum oxide, or carbon) can remove NOx and other pollutants (principally sulfur). There have been successful efforts to make sorption products a marketable commodity. This kind of treatment has been applied in the combustion chamber, flue, and baghouse. The use of carbon as an adsorbent has not led to a marketable product, but it is sometimes used to limit NOx emissions in spite of this. The sorption method is often referred to as using a dry sorbent, but slurries also have been used. This method uses either adsorption or absorption followed by filtration and/or electrostatic precipitation to remove the sorbent.

Method 7. Combinations of these methods -- Many of these methods can be combined to achieve a lower NOx concentration than can be achieved alone by any one method. For example, a fuel-rich cyclone burner (Method 1) can be followed by fuel reburn (Method 3) and over-fire air (Method 1). This has produced as much as a 70% reduction in NOx.[55] Other control technologies that are intended to primarily reduce concentrations of sulfur also strongly affect the nitrogen oxide concentration. For example, the SOx-NOx-ROx-Box (SNRB) technology uses a limestone sorbent in the flue gas from the boiler to absorb sulfur. This is followed by ammonia injection and SCR using catalyst fibers in the baghouse filter bags. The sulfur is recovered from the sorbent and the sorbent regenerated by a Claus process. This has demonstrated removal of up to 90% of the NOx along with 80% of the SOx.[39, 42] EBARA of Japan reported that an electron beam reactor with added ammonia removed 80% of the SO_2 and 60% of the NOx for a utility boiler in China.[54] FLS Milo and Sons reported at the same symposium that 95% of the SO_2 and 70%-90% of the NOx were removed in several demonstrations of their SNAP technology, which is based upon an aluminum oxide adsorber with Claus regeneration.[56]

WHAT ABATEMENT TECHNOLOGIES ARE AVAILABLE?

In this report existing NOx abatement technologies are divided into two categories, external combustion applications (e.g., boilers, furnaces and process heaters) and internal combustion applications (e.g., stationary internal combustion engines and turbines). These categories are further subdivided into pollution prevention (which reduces NOx generation) and add-on control technologies (which reduces NOx emissions).

EXTERNAL COMBUSTION

For external combustion applicable technologies are shown in Table 3 (based on Table 2 in Select the Right NOx Control Technology, Stephen Wood, Chemical Engineering Progress, January 1994).

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Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Less Excess Air (LEA)	Reduces oxygen availability	Easy modification	Low NOx reduction	High CO Flame length Flame stability	All fuels
Off Stoichiometric a. Burners Out of Service (BOOS) b. Over Fire Air (OFA)	staged combustion	Low cost No capital cost for BOOS	a. Higher air flow for CO b. high capital cost	Flame length Fan capacity Header pressure	All fuels Multiple burners for BOOS
Low NOx Burner (LNB)	Internal staged combustion	Low operating cost Compatible FGR	Moderately high capital cost	Flame length Fan capacity Turndown stability	All fuels
Flue Gas Recirculation (FGR)	<30% flue gas recirculated with air, decreasing temperature	High NOx reduction potential for low nitrogen fuels	Moderately high capital cost and operating cost Affects heat transfer and system pressures	Fan capacity Furnace pressure Burner pressure drop Turndown stability	All fuels Low nitrogen fuels
Water/Steam Injection	Reduces flame temperature	Moderate capital cost NOx reduction similar to FGR	Efficiency penalty Fan power higher	Flame stability Efficiency penalty	All fuels as Low nitrogen fuels
Reduced Air Preheat	Air not preheated, reduces flame temperature	High NOx reduction potential	Significant efficiency loss (1% per 40°F)	Fan capacity Efficiency penalty	All fuels Low nitrogen fuels
Selective Catalytic reduction (SCR) (add-on technology)	Catalyst located in the air flow, promotes reaction between ammonia and NOx	High NOx removal	Very high capital cost High operating cost Catalyst siting Increased pressure drop Possible water wash required	Space requirements Ammonia slip Hazardous waste Disposal	All fuels

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Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Selective Non-Catalytic Reduction (SNCR) (add-on technology) a. urea b. ammonia	Inject reagent to react with NOx	a. Low capital cost Moderate NOx removal Non-toxic chemical b. Low operating cost Moderate NOx removal	a. Temperature dependent NOx reduction less at lower loads b. Moderately high capital cost Ammonia storage, handling, injection system	a. Furnace geometry Temperature profile b. Furnace geometry Temperature profile	All fuels
Fuel Reburning	Inject fuel to react with NOx	Moderate cost Moderate NOx removal	Extends residence time	Furnace temperature profile	All fuels (pulverized solid)
Combustion Optimization	Change efficiency of primary combustion	Minimal cost	Extends residence time	Furnace temperature profile	Gas Liquid fuels
Catalytic Combustion	Catalyst causes combustion to be at low temperature	Lowest possible NOx	Very high capital cost High operating cost Catalyst siting	Space requirements Disposal	Gas Liquid fuels
Non-Thermal Plasma	Reducing agent ionized or oxidant created in flow	Moderate cost Easy siting High NOx removal	Fouling possible Ozone emission possible	Uses electrical power	All fuels
Inject Oxidant	Chemical oxidant injected in flow	Moderate cost	Nitric acid removal	Add-on	All fuels
Oxygen instead of Air	Uses oxygen to oxidize fuel	Moderate to high cost Intense combustion	Eliminates prompt NOx Furnace alteration	Equipment to handle oxygen	All fuels
Ultra-Low Nitrogen Fuel	Uses low -nitrogen fuel	Eliminates fuel NOx No capital cost	Slight rise in operating cost	Minimal change	All ultra-low nitrogen fuels

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Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Use Sorbents (add-on technology) in: a. Combustion b. Duct to Baghouse c. Duct to Electrostatic Precipitator	Use a chemical to absorb NOx or an adsorber to hold it	Can control other pollutants as well as NOx Moderate operating cost	Cost of handling sorbent Space for the sorbent storage and handling	Add-on	All fuels
Air Staging	Admit air in separated stages	Reduce peak combustion temperature	Extend combustion to a longer residence time at lower temperature	Adds ducts and dampers to control air Furnace modification	All fuels
Fuel Staging	Admit fuel in separated stages	Reduce peak combustion temperature	Extend combustion to a longer residence time at lower temperature	Adds fuel injectors to other locations Furnace modification	All fuels

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EXTERNAL COMBUSTION: POLLUTION PREVENTION METHODS

LESS EXCESS AIR (LEA)

Excess air flow for combustion has been correlated to the amount of NOx generated. Limiting the net excess air flow to under 2% can strongly limit NOx content of flue gas. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.[43]

BURNERS OUT OF SERVICE (BOOS)

Multiple-burner equipment can have part of an array of burners with some "burners out of service" (not feeding fuel, but supplying air or flue gas). This allows the burners around them to supply fuel and air to air or flue gas flowing from the BOOS. The result is combustion by stages with temperature always lower than when all burners are in service. Thus, thermal NOx is lower. The degree to which NOx generation is reduced depends upon the spatial relationship of the BOOS to the other burners.[44]

OVER FIRE AIR (OFA)

When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the temperature is held down. After all other stages of combustion, the remainder of the fuel is oxidized in the over fire air. This is usually not a grossly excessive amount of air.

LOW NOx BURNERS (LNB)

A LNB provides a stable flame that has several different zones. For example, the first zone can be primary combustion. The second zone can be Fuel Reburning (FR) with fuel added to chemically reduce NOx. The third zone can be the final combustion in low excess air to limit the temperature. There are many variations on the LNB theme of reducing NOx. The LNB has produced up to 80% DRE.[17,18, 32, 33] This can be one of the least expensive pollution prevention technologies with high DRE. LNB have had problems with designs that had flame attaching to the burners, resulting in a need for maintenance. We believe that these design problems should now be a thing of the past.

FLUE GAS RECIRCULATION (FGR)

Recirculation of cooled flue gas reduces temperature by diluting the oxygen content of combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the NOx concentration that is generated. If combustion temperature is held down to below 1,400 °F, the thermal NOx formation will be negligible.[50]

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WATER OR STEAM INJECTION

Injection of water or steam causes the stoichiometry of the mixture to be changed and adds steam to dilute calories generated by combustion. Both of these actions cause combustion temperature to be lower. If temperature is sufficiently reduced, thermal NOx will not be formed in as great a concentration.

REDUCED AIR PREHEAT

Air is usually preheated to cool the flue gases, reduce the heat losses, and gain efficiency. However, this can raise the temperature of combustion air to a level where NOx forms more readily. By reducing air preheat, the combustion temperature is lowered and NOx formation is suppressed. This can lower efficiency, but can limit NOx generation.

FUEL REBURNING (FR)

Recirculation of cooled flue gas with added fuel (this can be natural gas, pulverized coal, or even oil spray) causes dilution of calories, similar to FGR, and primary combustion temperature can be lowered. Also, when added as a secondary combustion stage, the presence of added fuel chemically reduces newly generated NOx to molecular nitrogen. Added fuel is only partially consumed in reducing NOx and burning is completed in a later stage using either combustion air nozzles or over-fire-air. This technique has been demonstrated to be effective with residence times from 0.2 seconds to 1.2 seconds and has achieved up to 76% DRE. [17]

COMBUSTION OPTIMIZATION

Combustion optimization refers to the active control of combustion. In a natural gas fired boiler, by decreasing combustion efficiency from 100% to 99%, NOx generation dropped to a much more acceptable level.[14,15] For coal-fired boilers a 20% to 60% reduction in NOx has been experienced. These active combustion control measures seek to find an optimum combustion efficiency and to control combustion (and hence emissions) at that efficiency. Another approach uses a neural network computer program to find the optimum control point.[16] Still another approach is to use software to optimize inputs for the defined output.[52,53]

One vendor decreases the amount of air that is pre-mixed with fuel from the stoichiometric ratio (ratio that produces the hottest flame) to lengthen the flame at the burner and reduce the rate of heat release per unit volume. This can work where the boiler tubes are far enough away from the burner. Carbon monoxide, unburned fuel, and partially burned fuel that result can then be subsequently oxidized in over-fire-air at a lower temperature. Combustion must be optimized for the conditions that are encountered. 50% DRE has been reported.[14]

AIR STAGING

Combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that

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produces a reducing flame. The second stream is injected downstream of the flame and makes the net ratio slightly excess air compared to the stoichiometric ratio. DRE up to 99% have been reported.[51]

FUEL STAGING

This is staging of combustion using fuel instead of the air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel to air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be only slightly oxidizing. Excess fuel in primary combustion dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NOx to N_2. This is reported to achieve a 50% DRE.[51]

OXYGEN INSTEAD OF AIR FOR COMBUSTION

An example of this is a cyclone burner where the flame is short and intense. Excess fuel air or steam, injected just after the combustion chamber per Method 2 is sufficient to rapidly quench the flue gas to below NOx formation temperature. Combustion can then be completed in over-fire air. Oxygen can now be separated from air at a low enough cost to make this economical.[13] This technique has reduced NOx by up to 20%[23] in burners using conventional fuel. This technique also is usable with low-NOx burners to prevent the prompt NOx from being formed.

INJECTION OF OXIDANT

The oxidation of nitrogen to its higher valence states makes NOx soluble in water. When this is done a gas absorber can be effective. Oxidants that have been injected into the air flow are ozone, ionized oxygen, or hydrogen peroxide. Non-thermal plasma generates oxygen ions within the air flow to achieve this. Other oxidants have to be injected and mixed in the flow. Nitric acid can be absorbed by water, hydrogen peroxide, or an alkaline fluid. Calcium or ammonia dissolved in the water can make an alkaline fluid that will react with nitric and sulfuric acids to produce a nitrate or sulfate salt that can be recovered. Alternatively, using water or hydrogen peroxide to absorb NOx can provide nitric acid for the commercial market.

CATALYTIC COMBUSTION

Use of a catalyst to cause combustion to occur below NO formation temperatures can provide a suitable means of limiting temperature. This technique is not used often because it is very load sensitive. However, where it is used, catalytic combustion can achieve less than a 1 ppm concentration of NOx in the flue gas.

ULTRA-LOW NITROGEN FUELS

These fuels can avoid NOx that results from nitrogen contained in conventional fuels. The result can be up to a 70% reduction in NOx emissions.[43] Now there are ultra-low-nitrogen liquid fuel

oils. These oils contain 15-20 times less nitrogen than standard No. 2 fuel oil. This oil is now commercially available and competitively priced. Ultra-low-nitrogen oil is most frequently used in Southern California where the air pollution is particularly a problem. Natural gas can be considered a low-nitrogen fuel. Coke (the quenched char from coal) can also be an ultra-low-nitrogen fuel because nitrogen in the volatile fraction of the coal is removed in making coke.

NON-THERMAL PLASMA

Using methane and hexane as reducing agents, non-thermal plasma has been shown to remove NOx in a laboratory setting with a reactor duct only 2 feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NOx and achieved a 94% DRE. There are indications that an even higher DRE can be achieved. A successful commercial vendor uses ammonia as a reducing agent to react with NOx in an electron beam generated plasma. Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor could also be used without reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid.

EXTERNAL COMBUSTION: ADD-ON CONTROL TECHNOLOGY

Add-on controls are applicable to a broad range of sources and fuels. This differs from the pollution prevention techniques listed above in that the prevention techniques must be adapted to the circumstances of their use.

SELECTIVE CATALYTIC REDUCTION (SCR)

SCR uses a catalyst to react injected ammonia to chemically reduce NOx. It can achieve up to a 94% DRE[34] and is one of the most effective NOx abatement techniques. However, this technology has a high initial cost. In addition, catalysts have a finite life in flue gas and some ammonia "slips through" without being reacted. SCR has historically used precious metal catalysts, but can now also use base-metal and zeolite catalysts. The base-metal and zeolite catalysts operate at much different temperatures then the precious metal catalysts.[11]

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR ammonia or urea is injected within a boiler or in ducts in a region where temperature is between 900°C and 1100°C. This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst or non-thermal plasma. This temperature "window" – which is reported differently by various authors -- is important because outside of it either more ammonia "slips" through or more NOx is generated than is being chemically reduced. The temperature "window" is different for urea and ammonia. Reduction of the NOx by SNCR can have up to a 70% DRE.[23,35,43]

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SORPTION – BOTH ADSORPTION AND ABSORPTION

Several methods are used to inject and remove adsorbent or absorbent. One method sprays dry powdered limestone into the flue gas. The limestone then reacts with both sulfuric acid and nitric acid. There also is a spray dryer approach that sprays a slurry of powdered limestone and aqueous ammonia into the flue gas. The limestone preferentially reacts with the sulfur while the ammonia preferentially reacts with the NOx. In-duct injection of dry sorbents is another example of this technique and can reduce pollutants in three stages: (1) in the combustion chamber, (2) in the flue gas duct leading to the baghouse, and (3) in the flue gas duct leading to the electrostatic precipitator. The by products formed by sorption are gypsum (calcium sulfate) that is sold to make wallboard, and ammonium nitrate that can be sold to make either an explosive or a fertilizer. Sorption is reported to have up to a 60% DRE.[23, 31] Another version uses carbon injected into the air flow to finish the capture of NOx. The carbon is captured in either the baghouse or the ESP just like other sorbents. There are many absorbents and adsorbents available.

COMBINED TECHNOLOGY APPROACHES

Very seldom is only one method or principle used alone. The choice depends upon the type of combustion system, type of boiler or other energy conversion device, and type of fuel used. Available technologies will be narrowed by consideration of turndown ratio, stability of combustion, availability or access to burners, air supply controls, fuel impurities, and cost among other factors.

There are many examples and here are a few of them. Selective catalytic reduction of NOx to N_2 can be followed by selective oxidation of sulfur dioxide to sulfur trioxide. Then sulfuric acid is formed followed by scrubbing sulfuric acid from the flue gas.[30]

LNB can be used in conjunction with SCR or SNCR to achieve a greater overall DRE than any of these can achieve alone. Water/steam injection can be used with SCR to achieve a DRE greater than SCR can achieve alone. Fuel reburning and SCR can be used together as well as separately, to get the maximum NOx reduction.[57]

INTERNAL COMBUSTION

Now we turn to internal combustion, which usually occurs at elevated pressures. Again, we divide the technologies between pollution prevention techniques and add-on technologies. This is shown in Table 4.

These techniques can be used in combination. Pollution prevention techniques do not have to be used separately. Add-on techniques could be used sequentially after a pollution prevention technique when they do not impose conflicting demands on the process.

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Table 4. Internal Combustion NOx Limiting Technologies

Pollution Prevention	Add-On Control
Low-NOx Burners (LNB)	Selective Catalytic Reduction (SCR)
Steam/Water Injection	Selective Non-Catalytic Reduction (SNCR)
Catalytic Combustion	Non-Selective Catalytic Reduction (NSCR)
Air-Fuel Ratio and Ignition Type	Non-Thermal Plasma
Pre-Stratified Charge	
Lean Burn	

INTERNAL COMBUSTION: POLLUTION PREVENTION METHODS

LOW NOx BURNERS (LNB)

Combining the use of LNB with closely controlled air/fuel ratio and water/steam injection can yield emissions as low as 10 ppm from gas turbines.[46]

STEAM/ WATER INJECTION

To reduce combustion temperature, steam or water can be mixed with the air flow. This lowers combustion temperature to below 1,400°F to limit NOx generation to about 40 ppm.[46] This can cause the concentration of CO and unburned hydrocarbons emitted from a turbine to be increased. However, these can be burned by either a catalyst bed, afterburner, or another stage of combustion. This otherwise wasted fuel and heat can also be recovered in co-generation boilers.

CATALYTIC COMBUSTION

A catalyst is used to react fuel with air at a lower temperature than normal combustion at which generation of significant amounts of NOx does not occur. Emissions under 1 ppm NOx have been reported.[46] However, if this combustion is for a turbine, turbine efficiency may depend upon achieving a higher temperature. When a catalyst is present, you also need to assure that NOx will not be formed at the combustion temperature that results.

This technology has a relatively high capital and operation and maintenance cost because there is both a substantial initial investment and a replacement cost for the catalyst. The need for replacement and, therefore, replacement cost are usually driven by impurities in the fuel. However, catalytic combustion generates possibly the lowest level of thermal NOx.

AIR-FUEL RATIO AND IGNITION TYPE

For internal combustion reciprocating engines, retardation of injection or spark ignition, or an air-fuel ratio that departs from stoichiometric conditions will reduce peak temperature. Lower peak temperature will limit the amount of NOx formation. This technique can achieve up to 50% control efficiency.[19, 48]

When a three-way catalyst is used for spark ignition engines, exhaust gas must have no more than 0.5% oxygen. This technique can be up to 98% effective.

The use of plasma ignition (an alternating current or AC system) instead of a direct current (DC) spark ignition system can also allow a greater fuel-lean departure from the stoichiometric ratio. NOx emissions from internal combustion engines using plasma ignition have been reported to be reduced by up to 97%.[20,21, 45]

Delaying injection of fuel in a compression ignition (diesel) engine can reduce the NOx emissions. The amount of this reduction will depend upon the engine, valving, and fuel. Excessive timing retard can cause combustion instability or misfire.[48] However, some claims of high effectiveness are to be found with ostensibly excessive retard.

PRE-STRATIFIED CHARGE (PSC)

PSC refers to an engine equipped with a pre-combustion chamber that receives a rich enough air/fuel mixture to ignite dependably. This pre-combustion chamber fires a jet of flame into the main combustion chamber (cylinder). The main combustion chamber has a fuel-lean mixture that needs pre-combustion flame to ignite it reliably. The injected flame also produces a swirl in the main combustion chamber that acts like stratified charge combustion. This dependably ignites the lean main cylinder mixture. The PSC can achieve NOx emissions of 2 grams/horsepower-hour (g/hp-hr) or 140 ppm.[48]

LEAN BURN

Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NOx emissions. These can achieve less than 1.0 gram/brake horsepower-hour according to the RACT-BACT-LAER Clearinghouse (RBLC) (http://www.epa.gov/ttn/catc, then select RBLC).

INTERNAL COMBUSTION ADD-ON CONTROL TECHNOLOGY

SELECTIVE CATALYTIC REDUCTION (SCR)

As with boilers, SCR can be used to obtain up to a 90% DRE of NOx. When used with a LNB or steam/water injection, NOx can be reduced to 5-10 ppm.[46] With compression ignition engines, zeolite catalysts achieve a DRE of 90+%, while base-metal catalysts can achieve a 80% to 90% DRE.[48]

NON-SELECTIVE CATALYTIC REDUCTION (NSCR)

NSCR is the same technique used in automobile applications as a three-way catalytic converter. It does not require injection of a reducing agent because it uses unburned hydrocarbons as a reducing agent. The catalyst requires that exhaust have no more than 0.5% oxygen. This technique uses a fuel rich mixture that, combined with back pressure from exhaust flow through the catalyst, increases the brake specific fuel consumption of the engine. However, NOx control of 90% to 98% can be achieved.[48]

NON-THERMAL PLASMA REACTORS

This approach uses a non-thermal plasma to ionize ammonia, urea, hexane, methane or other reducing agents injected into a flue gas. Combined with the effect of temperature, non-thermal plasma ionizes the reducing agent that reacts with nitrogen oxides achieving a 94% DRE. This decreases the amount of reducing chemicals that "slips" through unreacted.[20,44] The use of non-thermal plasma was developed to ionize pollutants and act as a catalyst to control NOx in diesel exhaust.[36]

DO FUELS AND COMBUSTION TYPE AFFECT ABATEMENT?

Yes they do. Here again, we find a spectrum of types, almost enough to make every gas turbine, internal combustion engine, boiler, or furnace seem unique. The type of fuel can vary with the vein of the mine from which coal was obtained, the well in the oilfield from which crude oil came, the refinery for petroleum based fuels, or the supplier of natural gas. Thus the concentration of impurities will vary between sources, refineries, and suppliers. Even "natural gas" (methane) may contain some "supplier gas" (propane, butane, and carbon monoxide) which will cause the composition of "natural gas" to vary.

The type of combustion system (low-NOx burner, over-fire air, tangential firing, wall firing, etc) also will sometimes limit options. Each type of boiler, each type of fuel, each combustion system, and each construction of a boiler puts constraints on what is possible. It is not possible to treat each combination of combustion system and fuel in detail in this Technical Bulletin; however, we will try to show the picture while painting with broad strokes.

The choice of fuel and combustion system often depends upon: (1) what can or cannot be adjusted; (2) whether ducts are suitable for sorption; (3) what the effect on boiler maintenance will be; (4) the temperature profile in the flow: (5) how the combustion system can be modified; (6) what types of burners can be used; and (7) what can either be added or modified. The list does not end there, but continues. Let us consider some fuels with these limitations in mind.

SOLID FUELS

In burning a solid fuel (such as coal), combustion control is achieved by first getting the primary burner to gasify the volatile fraction of a fuel. The volatile fraction is carried away from char by

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air flow, oxidized in the air flow, and becomes flue gas. Char needs more combustion air to burn and provide further heat, part of which is used to volatilize additional fuel. To control combustion temperature, you traditionally would limit combustion air through the char fraction. The volatile fraction is oxidized in over-fire-air or a secondary stage of burner and must have its air separately controlled. The balance of combustion air between these stages must be adjusted for composition of fuel being used, boiler loading, and transient loads. Because all of these parameters will vary continually, provisions to make balancing adjustments dynamically are recommended.

Pulverized coal can be burned similar to oil. The flame is usually well defined and, depending on particle size, char may remain in suspension in flue gas throughout burning. The volatile fraction burns in air even as char is burned. If the particles are too coarse, char will continue burning on its trajectory after leaving the flame, but will stop burning at some point. The trade jargon for this is " unburned carbon (UBC)," "carbon in the ash (CIA)," or "loss of ignition (LOI)." These terms refer to carbon in char that does not burn along the trajectory. UBC is minimized by grinding particles finer and classifying particles so that larger ones are returned to the roller mill or grinder. Particles will become fly ash if they are small enough. UBC ranging from 0.5% to 5% is considered acceptable. Therefore, particle size at ignition is important. The major concerns are to control stoichiometry and combustion temperature to minimize unburned carbon in ash.

Biomass is another solid fuel, but burning biomass char is less of a concern than with coal. Biomass cannot be pulverized to small particles, but can burn to ash in a short time. As with the burning of all char, ash and fly ash are problems, but can be treated with a slag tap or ash pit, baghouse, and/or electrostatic precipitator.

LIQUID FUELS

Liquid fuels burn like the volatile fraction of solid fuel provided that the droplets are small enough. Liquid fuels usually have less nitrogen content than solid fuels. Combustion of liquids and gases can be controlled much more readily than char from solid fuel because combustion is less dependent on the history of the past few minutes of demand. Combustion is also completed essentially without residual ash. The fuel-air ratio can be used to control combustion temperature and can be adjusted to minimize NOx generation. The flame can be well-defined and combustion is essentially completed within the flame. Therefore, burning oil or liquid-from-coal or liquid-from-gas is different from burning coal because there is usually less nitrogen in the fuel, a lack of char, complete burning within the flame and a lack of ash.

SEMI-SOLID FUELS

Semi-solid fuels are residuals from refineries. They are not clean burning like distillates and often are not even liquid at room temperature. Many impurities typically found in crude oil are concentrated in semi-solid residual fuel. These fuels can contain more nitrogen than coal, but usually contain less sulfur.[50] Therefore, semi-solid fuels are intermediate between coal and oil. They often have somewhat less impurities than coal (although they can have more impurities),

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but they do produce ash.

GAS FUEL

Natural gas is desulfurized before it is sent in a pipeline. Therefore, natural gas has almost no sulfur, essentially no impurities, and no ash. The only thing that varies is heat content per cubic meter. This variance is caused by natural gas producers supplementing natural gas with propane, liquified petroleum gas (butane), carbon monoxide, or other gaseous fuel. As a result, air to fuel ratio must be controllable to allow for changes in the stoichiometric ratio.

COMBUSTION SYSTEMS

To take advantage of a specific NOx abatement technology, a combustion system must either have certain features in place, or needed system modifications must be technically and economically feasible. Therefore, when identifying applicable pollution prevention and emission control technologies, we must first consider combustion system design. The major types of combustion systems are shown in Table 5.[23]

Table 5. Common Combustion Systems

Type of Combustion Unit	Fuel
Dry bottom boilers - wall-fired, front-fired or opposed-fired	pulverized coal, gas, or liquid
Dry bottom boilers - tangentially fired	pulverized coal, gas, or liquid
Wet bottom (slag tap) boilers - cyclone-type burners	pulverized coal, gas, or liquid
Fluidized bed	coal
Stokers with traveling grate.	crushed coal
Stokers with spreader grate	crushed coal.
Gas turbines	gas and liquid
Internal combustion engines	gas and liquid

Each NOx abatement technology has different implementations, development histories, and, therefore, commercial status. Selection of a technology must occur after an engineering study to determine technical and economic feasibility of each NOx technology. This includes how each technology can be implemented and its cost. Options may be limited by inability to adjust combustion system air flow appropriately, ducts that are at the wrong temperature, or ducts that

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are too short to provide adequate mixing. These problems can be solved, but may require too much modification to make them economical.

DRY BOTTOM BOILERS - WALL-FIRED, FRONT-FIRED or OPPOSED-FIRED

Dry bottom pulverized coal, gas, and liquid fuel wall-fired boilers have used low-NOx burners to inject fuel and air from lower walls. Front-fired boilers have burners on one wall. Opposed-fired boilers have burners on front and back walls. These boilers typically use methods that reduce peak temperature, reduce residence time at peak temperature, or chemically reduce NOx (Methods 1, 2 & 3). These methods are used for large utility boilers in which combustion efficiency is all-important. NOx oxidation with absorption and removal of nitrogen (Methods 4 and 5) represent newer technologies that may be applied in the future. Using a sorbent (Method 6) is already in use for some boilers. See Table 6 for NOx technologies used for dry bottom wall-fired, front-fired or opposed-fired boilers.

Table 6: NOx technologies currently used for dry bottom wall-fired, front-fired or opposed-fired boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Low NOx Burners (LNB) Combustion Optimization Burners Out Of Service (BOOS) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR) Low NOx Burners (LNB)	35-90%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

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DRY BOTTOM BOILERS - TANGENTIALLY FIRED

Dry bottom pulverized coal, gas, or liquid fuel tangentially-fired boilers use jets from each corner of a furnace to inject fuel and combustion air in a swirl. The injected mix of fuel and combustion air forms a fireball in the center of the boiler. This firing configuration is used in medium sized utility and large industrial boilers. This combustion technique holds flame temperatures down (Method 1). In addition, chemical reduction of NOx (Method 3) is frequently used. NOx oxidation (Method 4) techniques may be used in the future. Sorbents (Method 6) are already used for some boilers. See Table 7 for NOx technologies used for dry bottom tangentially fired boilers.

Table 7: NOx technologies currently used for dry bottom tangentially fired boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

WET BOTTOM (SLAG TAP) BOILERS

Wet bottom (slag tap) boilers use cyclone burners to create an intense flame. The flame is so hot that it melts ash, which then becomes slag that must be removed via a slag tap. These boilers are known to have higher NOx generation because combustion temperature is so high. As a result, this high temperature combustion technique is not widely used because the NOx concentration necessarily must be greater. Removal of non-fuel nitrogen as a reactant from the combustion process (Method 5) applies here. Reducing residence time at peak temperature, chemical

reduction of NOx, and NOx oxidation with absorption (Methods 2, 3 & 4) also apply to this combustion system. In addition, some slag tap boilers may be using sorbents (Method 6). There are recent reports that reducing peak temperature (Method 1) so that ash just melts has been used. See Table 8 for NOx technologies used for slag tap boilers.

Table 8: NOx technologies currently used for wet bottom (slag tap) boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	30-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	20-50%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Use Oxygen Instead Of Air Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

FLUIDIZED BED

Fluidized bed combustion occurs in a bed of crushed coal that has air flowing upward through it to make coal particles behave like a fluid. Boiler pipes can be either submerged in the bed or exposed to the hot gases after they leave the bed. The fluidized bed is temperature controlled (Method 1). The bed also is a chemically reducing region in which available oxygen is consumed by carbon (Method 3) that reduces ionization of nitrogen. Excess air is injected (Method 2) over the fluidized bed to complete combustion of CO and other burnables. This allows for the addition of pulverized limestone (Method 6) to coal in the fluidized bed. Sulfur oxides then react with the limestone to form gypsum, a marketable product. Gypsum must be separated from the ash. As a result, NOx generation can be essentially limited to prompt NOx and fuel NOx. See Table 9 for NOx technologies used for fluidized bed combustion units.

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Table 9: NOx techniques currently used for fluidized bed combustion.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Reduced Air Preheat	No Data
2.Reducing residence time at peak temperature	Inject Steam	No Data
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction(SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

STOKERS WITH TRAVELING GRATE

Stokers with traveling grate cause the coal to move as it burns. Thus, char combustion is in one zone while volatiles are liberated and combusted in another zone. These stokers are commonly used with industrial boilers that are smaller than utility boilers. Reducing peak temperature, chemical reduction of NOx, and sorbents (Methods 1, 3 & 6) usually are applied. Perhaps NOx oxidation (Method 4) also will apply in the future. See Table 10 for NOx technologies used for stokers with traveling grates.

STOKERS WITH SPREADERS

Stokers with spreaders throw coal over the grate in a controlled manner. Coal is crushed, but particles are typically larger than pulverized coal. Therefore, combustion of volatiles begins while coal is in flight and combustion of char occurs on the grate. This system is used with somewhat larger boilers than stokers with traveling grates. It can be used in power plants, but this combustion system is used mainly for industrial boilers. Like stokers with traveling grates, reducing peak temperature, chemical reduction of NOx, and sorbents (Methods 1, 3, and 6) usually are applied. Perhaps NOx oxidation (Method 4) also will apply in the future. See Table 11 for NOx technologies used for stokers with Spreader grates.

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Table 10: NOx technologies currently used for stokers with traveling grates.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Combustion Optimization Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	35-50%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	55-80%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

GAS TURBINES

Gas turbines use the Brayton Cycle with a burner to raise temperature of gas after compression and before expansion through the turbine. Turbines mainly use reducing peak temperature and reducing residence time (Methods 1 and 2) approaches to limit NOx emissions. Because addition of particles to air flow entering the turbine would accelerate erosion of turbine blades, sorbents (Method 6) could only be applied after the expansion in the turbine. NOx reduction (Method 3) has been used to treat exhaust gases. Many turbine operators claim that they use "good combustion practices" that do reduce the particles that produce visible emissions (which they equate with pollution), but say nothing about the NOx emissions which are not visible.

Cogeneration units use a gas turbine to generate electricity and provide preheated combustion air for a boiler. Gas turbine exhaust is typically 10-15% oxygen and can be used to provide combustion air for a low pressure boiler. That boiler can be used to provide steam for another turbine, a process heater, a space heater, or some combination of these. If a steam turbine is used to generate electricity, it may constrain what can be done. Sorbent particles can be introduced to a flow after it leaves a gas turbine in order to control NOx. There has also been some success in reducing NOx concentrations when burning biomass fuels in a boiler. See Table 12 for NOx technologies used for gas turbines.

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Table 11: NOx technologies currently used for stokers with spreader grates.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Low NOx Burners (LNB) Combustion Optimization Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-65%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-65%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-80%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

INTERNAL COMBUSTION RECIPROCATING ENGINES

Internal combustion engines use air-to-fuel ratio and ignition/injection timing to control maximum temperature and residence time. This can reduce the concentration of NOx that is generated by reducing peak temperature (Method 1). Valve timing adjustments can reduce residence time at peak temperature (Method 2) to control NOx formation. Chemical reduction of NOx (Method 3) is used in catalytic converters to reduce NOx to N_2. Some stationary engines use both Method 3 and NOx oxidation (Method 4). A non-thermal plasma reactor was developed for treatment of diesel exhaust, but is not yet marketed to our knowledge. A plasma ignition system allows greater freedom in the air-fuel ratio and the ignition timing of spark ignition engines. See Table 13 for NOx technologies used for stationary internal combustion engines.

WHAT DOES NOx ABATEMENT AND CONTROL COST?

The cost of NOx abatement and control has been changing rapidly with dramatic reductions in recent years. Table 14 gives the 1993 cost as given in the Alternative Control Techniques

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Table 12: NOx technologies currently used for gas turbines.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Natural Gas Reburning (NGR) Low NOx Burners (LNB) Inject Water or Steam Reduced Air Preheat Catalytic Combustion	70-85%
2.Reducing residence time at peak temperature	Air Staging of Combustion Inject Steam	70-80%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR) Low NOx Burners (LNB)	70-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	No Data
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Ducts	60-90%

Table 13: NOx technologies currently used for stationary internal combustion engines.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Air/fuel Ratio Timing of Ignition/Type of Ignition Pre-Stratified Combustion	20-97%
2.Reducing residence time at peak temperature	Valve Timing	No Data
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Non-Selective Catalytic Reduction (NCSR)	80-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	80-95%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Exhaust Ducts Adsorber in fixed Bed	60-90%

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Table 14. 1993 Costs of NOx Controls

	Cost of NOx Controls in 1993 Dollars					
Control Device	Low -Cap. $/MMBTU	High -Cap. $/MMBTU	Low - Oper. $/MMBTU	High -Oper. $/MMBTU	Low $/ton	High $/ton
LNB	650	8,300	340	1,500	240	4,300
LNB + FGR					650	7,630
SNCR	1,600	3,300	680	1,200	N/A	N/A
(1994 ESTIMATE)					700	1,300
SCR	2,400	20,000	1,500	5,800	1,810	10,900
(1994 ESTIMATE)					500	2,800

Document NOx Emissions from Industrial/Commercial/Institutional Boilers (EPA 453/R-94-022).
The EPA Region III Low-NOx Control Technology Study in 1994 said that low-NOx burners had both beneficial effects on operating costs and detrimental effects on the burners, their life expectancy, and the boilers in which they were installed. Coal quality and some boiler designs caused NOx to remain high even after low-NOx burners were in place. Capital costs ranged from $1.91 to $54.24 per kW. Operating costs ranged from $-23,000 (a profit) to $1,113,750 per year. Thus, no reliable cost estimates could be obtained regarding low-NOx burner operation. Coal quality, boiler capacity, and burner design were among the variables influencing this cost. Many plants could not even give an estimate. SNCR cost between $700 and $1,300 per ton of NOx reduced. SCR cost between $500 and $2,800 per ton of NOx reduced.[25] However, cost per ton of NOx removed for all technologies is apparently becoming smaller.

These costs vary by control technique; type of fuel; grade of fuel; size of boiler, engine or turbine; type of boiler, or turbine; and other factors. Other costs were also changing with time. Therefore you need to examine the costs of these NOx control technologies for a specific application and at a particular time.

These preliminary cost estimates will also be further reduced as operating experience is gained, competition sharpens, and design iterations eliminate the high-maintenance or life-shortening features. Confidence in this view of the future is based upon reports that some users of low-NOx burners had already seen in 1994 that operating costs could be reduced to make the changeover yield a net profit. SCR and SNCR costs may also have declined further, since there is now competition for these technologies.

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This analysis was supported by 1997 cost figures. These are presented in Table 15. This table is from the Analyzing Electric Power Generation Under the CAAA [26]. It appears that competition and improved designs are still driving the costs downward. The Table was presented in that publication and is presented here for your convenience.

Table 15. 1997 Costs of NOx Controls

Analyzing Electric Power Generation Under the CAAA -- Cost Estimates[26]					
Boiler Type	Control Type	Capital Cost	Fixed O & M	Variable O& M	% Control
		$/kW	$/kW/yr	mils/kWh	
Wall Fired	LNB w/o OFA	16.8	0.25	0.05	67.5
Wall Fired	LNB w/ OFA	22.8	0.35	0.07	67.5
Tang-Fired	LNB w/ OFA	32.3	0.49	0	47.3
Tang-Fired LNB w/ SOFA		34.7	0.53	0	52.3
Tang Fired LNB w/ BOFA		46.7	0.71	0.02	57.3
Cell Burners	Non Plug-In Comb. Ctl.	22.8	0.34	0.07	60
Cyclone	Coal Reburning	70.7	1.07	0.25	50
Wet Bottom	NOx Comb. Ctl.	9.6	0.14	0.05	50
Vert. Fired	NOx Comb. Ctl.	10.8	0.17	0.05	40
	SCR -Low NOx Rate	69.7	6.12	0.24	70
	SCR- High NOx Rate	71.8	6.38	0.4	80
	SNCR-Low NOx Rate	16.6	0.24	0.82	40
	SNCR-Cyclone	9.6	0.14	1.27	35
	SNCR-High NOx Rate	19	0.29	0.88	35
	Nat.Gas Reburn-Low	32.4	0.49		40
	Nat.Gas Reburn-High	32.4	0.49		50

Note that in Table 8 the following acronyms are used:

LNB is low-NOx burner
OFA is closed coupled overfire air
SOFA is separate over fire air
BOFA is both close coupled and over fire air
Comb. Ctl. is combined controls

The Institute of Clean Air Companies also suggests that in 1999 SCR will cost $50 - $80 per kW for retrofit to units, which relates to $400-$1800 per ton of NOx that is destroyed.[34] Their cost estimate for SNCR ranges from $5-$15 per kW, which relates to $400-$2000 per ton of NOx that is destroyed.[35] Cost-effectiveness does not correlate with boiler capacity alone - other variables such as type and quality of fuel, type of boiler, SNCR/SCR design, etc enter into the analysis.

While the "Performance of Selective Catalytic Reduction on Coal-fired Steam Generating Units" study was for Germany, it cited a recent cost range for SCR from $52 to $77 per kW with retrofit units tending to have lower costs. Thus, the costs in Germany were very similar to costs in the U.S.A., except that retrofit costs usually are greater in the United States.

Table 16, Unit Costs for NOx control Technologies for Non-Utility Stationary Sources, is from the report "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis." The report was prepared for EPA by the Pechan-Avanti Group. It indicates efficiencies and cost estimates for various NOx technologies for the year 2007. This appears to be a conservative estimate of efficiency and cost. Efficiencies indicated in the table tend to be lower than currently demonstrated efficiencies. Costs were based on historical information and, therefore, should be high estimates because NOx technology costs appear to be declining over time. The table was included here to indicate the relative efficiency and cost of NOx technologies for specific types of combustion systems.

The Alternative Control Techniques Document NOx Emissions from Stationary Reciprocating Internal Combustion Engines contains cost algorithms for the pollution prevention techniques and control technology applied to internal reciprocating engines. Costs for NOx elimination run from $250/ton to $1,300/ton for engines larger than 1,000 horsepower. For smaller engines the cost runs from $400/ton to over $3,500/ton.

ARE THESE METHODS SUFFICIENT?

YES, these methods are sufficient to meet the present goal of reducing NOx emissions 2 million tons below 1980 emissions.[47] The goal appears to be set at a level that can be achieved based on the state of NOx technology in 1996. However, we will have to see whether achieving our present goal provides the needed relief. A still more stringent set of standards may become necessary at sometime in the future.

As a high-technology nation and with a large urban and suburban population, we depend on automobiles, buses, airplanes, railroads, and trucks for transportation. We also depend upon electric power for computers, lights, air conditioning, and commerce. Therefore, we seem caught in a dilemma, for, while we depend on transportation, vehicles produce most of our NOx. While we also consume electric power as part of our market economy, electric power generation also generates over 40% of our NOx from stationary sources in 1995.[34]

We also need to generate less NOx without regard to the ionization level of the nitrogen. In 1999, we are currently not capable of doing that. Therefore, we must do the best that we can,

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Table 16: Unit Costs for NO_x Control Technologies for Non-Utility Stationary Sources

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
ICI Boilers - Coal/Wall	SNCR	40	1,870	1,380
ICI Boilers - Coal/Wall	LNB	50	3,490	2,600
ICI Boilers - Coal/Wall	SCR	70	2,910	2,450
ICI Boilers - Coal/FBC	SNCR - Urea	75	1,220	910
ICI Boilers - Coal/Stoker	SNCR	40	1,810	1,350
ICI Boilers - Coal/Cyclone	SNCR	35	1,480	1,110
ICI Boilers - Coal/Cyclone	Coal Reburn	50	3,730	710
ICI Boilers - Coal/Cyclone	NGR	55	3,730	710
ICI Boilers - Coal/Cyclone	SCR	80	1,840	1,560
ICI Boilers - Residual Oil	LNB	50	940	1,020
ICI Boilers - Residual Oil	SNCR	50	5,600	1,950
ICI Boilers - Residual Oil	LNB + FGR	60	2,670	920
ICI Boilers - Residual Oil	SCR	80	3,460	1,840
ICI Boilers - Distillate Oil	LNB	50	2,810	4,950
ICI Boilers - Distillate Oil	SNCR	50	10,080	3,520
ICI Boilers - Distillate Oil	LNB + FGR	60	5,960	1,810
ICI Boilers - Distillate Oil	SCR	80	6,480	3,460
ICI Boilers - Natural Gas	LNB	50	1,950	1,560
ICI Boilers - Natural Gas	SNCR	50	8,400	2,930
ICI Boilers - Natural Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Natural Gas	OT + WI	65	1,620	760
ICI Boilers - Natural Gas	SCR	80	5,190	2,770
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	55	2,090	1,430
ICI Boilers - Wood/Bark/FBC	SNCR - Ammonia	55	1,660	1,210
ICI Boilers - MSW/Stoker	SNCR - Urea	55	2,610	1,830
ICI Boilers - Process Gas	LNB	50	1,950	1,560
ICI Boilers - Process Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Process Gas	OT + WI	65	1,620	760
ICI Boilers - Process Gas	SCR	80	4,990	2,570
ICI Boilers - Coke	SNCR	40	1,870	1,380
ICI Boilers - Coke	LNB	50	3,490	2,600
ICI Boilers - Coke	SCR	70	2,910	2,450
ICI Boilers - LPG	LNB	50	2,810	4,950
ICI Boilers - LPG	SNCR	50	10,000	3,440
ICI Boilers - LPG	LNB + FGR	60	5,960	1,810
ICI Boilers - LPG	SCR	80	6,240	3,220
ICI Boilers - Bagasse	SNCR - Urea	55	2,090	1,430
ICI Boilers - Liquid Waste	LNB	50	940	1,020
ICI Boilers - Liquid Waste	SNCR	50	5,560	1,910
ICI Boilers - Liquid Waste	LNB + FGR	60	2,670	920
ICI Boilers - Liquid Waste	SCR	80	3,320	1,710
Internal Combustion Engines - Oil	IR	25	1,840	1,160

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Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Internal Combustion Engines - Oil	SCR	80	4,690	1,850
Internal Combustion Engines - Gas	IR	20	2,430	1,320
Internal Combustion Engines - Gas	AF RATIO	20	3,730	900
Internal Combustion Engines - Gas	AF + IR	30	3,430	1,080
Internal Combustion Engines - Gas	L-E (Medium Speed)	87	890	N/A
Internal Combustion Engines - Gas	L-E (Low Speed)	87	4,000	1,500
Internal Combustion Engines - Gas	SCR	90	5,547	1,075
IC Engines - Gas, Diesel, LPG	IR	25	1,840	1,160
IC Engines - Gas, Diesel, LPG	SCR	80	4,690	1,850
Gas Turbines - Oil	Water Injection	68	3,080	1,540
Gas Turbines - Oil	SCR + Water Injection	90	4,240	1,860
Gas Turbines - Natural Gas	Water Injection	76	3,590	1,750
Gas Turbines - Natural Gas	Steam Injection	80	2,490	1,190
Gas Turbines - Natural Gas	LNB	84	1,170	240
Gas Turbines - Natural Gas	SCR + LNB	94	4,850	1,140
Gas Turbines - Natural Gas	SCR + Steam Injection	95	3,750	1,570
Gas Turbines - Natural Gas	SCR + Water Injection	95	5,040	2,060
Gas Turbines - Jet Fuel	Water Injection	68	3,080	1,540
Gas Turbines - Jet Fuel	SCR + Water Injection	90	4,240	1,860
Process Heaters - Distillate Oil	LNB	45	8,290	2,320
Process Heaters - Distillate Oil	LNB + FGR	48	10,130	4,000
Process Heaters - Distillate Oil	SNCR	60	6,210	3,230
Process Heaters - Distillate Oil	ULNB	74	5,110	1,450
Process Heaters - Distillate Oil	SCR	75	18,970	12,520
Process Heaters - Distillate Oil	LNB + SNCR	78	7,160	3,630
Process Heaters - Distillate Oil	LNB + SCR	92	18,770	10,910
Process Heaters - Residual Oil	LNB + FGR	34	8,330	3,290
Process Heaters - Residual Oil	LNB	37	6,010	1,690
Process Heaters - Residual Oil	SNCR	60	3,730	2,050
Process Heaters - Residual Oil	ULNB	73	3,080	860
Process Heaters - Residual Oil	LNB + SNCR	75	4,730	2,510
Process Heaters - Residual Oil	SCR	75	10,560	7,170
Process Heaters - Residual Oil	LNB + SCR	91	11,170	6,550
Process Heaters - Natural Gas	LNB	50	5,250	4,290
Process Heaters - Natural Gas	LNB + FGR	55	7,610	5,890
Process Heaters - Natural Gas	SNCR	60	5,560	3,740
Process Heaters - Natural Gas	ULNB	75	3,580	2,870
Process Heaters - Natural Gas	SCR	75	24,840	16,760
Process Heaters - Natural Gas	LNB + SNCR	80	6,960	5,080
Process Heaters - Natural Gas	LNB + SCR	88	23,880	16,500
Process Heaters - Process Gas	LNB	50	5,250	4,290
Process Heaters - Process Gas	LNB + FGR	55	7,610	5,890
Process Heaters - Process Gas	SNCR	60	5,560	3,740
Process Heaters - Process Gas	ULNB	75	3,580	2,870
Process Heaters - Process Gas	SCR	75	24,840	16,760
Process Heaters - Process Gas	LNB + SNCR	80	6,960	5,080
Process Heaters - Process Gas	LNB + SCR	88	23,880	16,500

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Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Process Heaters - LPG	LNB	45	8,290	2,320
Process Heaters - LPG	LNB + FGR	48	10,130	4,000
Process Heaters - LPG	SNCR	60	6,210	3,230
Process Heaters - LPG	ULNB	74	5,110	1,450
Process Heaters - LPG	SCR	75	18,970	12,520
Process Heaters - LPG	LNB + SNCR	78	7,160	3,630
Process Heaters - LPG	LNB + SCR	92	18,770	10,910
Process Heaters - Other Fuel	LNB + FGR	34	8,330	3,290
Process Heaters - Other Fuel	LNB	37	6,010	1,690
Process Heaters - Other Fuel	SNCR	60	3,730	2,050
Process Heaters - Other Fuel	ULNB	73	3,080	860
Process Heaters - Other Fuel	LNB + SNCR	75	4,730	2,510
Process Heaters - Other Fuel	SCR	75	10,560	7,170
Process Heaters - Other Fuel	LNB + SCR	91	11,170	6,550
Adipic Acid Manufacturing	Thermal Reduction	81	1,000	1,000
Adipic Acid Manufacturing	Extended Absorption	86	210	210
Nitric Acid Manufacturing	Extended Absorption	95	840	840
Nitric Acid Manufacturing	SCR	97	1,010	1,010
Nitric Acid Manufacturing	SNCR	98	940	940
Glass Manufacturing - Container	Electric Boost	10	17,050	17,050
Glass Manufacturing - Container	Cullet Preheat	25	2,240	2,240
Glass Manufacturing - Container	LNB	40	4,040	4,040
Glass Manufacturing - Container	SNCR	40	3,320	3,320
Glass Manufacturing - Container	SCR	75	4,550	4,550
Glass Manufacturing - Container	OXY-Firing	85	10,960	10,960
Glass Manufacturing - Flat	Electric Boost	10	5,540	5,540
Glass Manufacturing - Flat	LNB	40	1,660	1,660
Glass Manufacturing - Flat	SNCR	40	1,380	1,380
Glass Manufacturing - Flat	SCR	75	1,490	1,490
Glass Manufacturing - Flat	OXY-Firing	85	4,530	4,530
Glass Manufacturing - Pressed	Electric Boost	10	20,910	20,910
Glass Manufacturing - Pressed	Cullet Preheat	25	1,930	1,930
Glass Manufacturing - Pressed	LNB	40	3,570	3,570
Glass Manufacturing - Pressed	SNCR	40	3,080	3,080
Glass Manufacturing - Pressed	SCR	75	5,170	5,170
Glass Manufacturing - Pressed	OXY-Firing	85	9,310	9,310
Cement Manufacturing - Dry	Mid-Kiln Firing	30	1,110	1,110
Cement Manufacturing - Dry	LNB	30	1,340	1,340
Cement Manufacturing - Dry	SNCR - Urea Based	50	1,280	1,280
Cement Manufacturing - Dry	SNCR - NH3 Based	50	1,490	1,490
Cement Manufacturing - Dry	SCR	80	6,850	6,850
Cement Manufacturing - Wet	Mid-Kiln Firing	30	1,010	1,010
Cement Manufacturing - Wet	LNB	30	1,260	1,260
Cement Manufacturing - Wet	SCR	80	5,840	5,840
Iron & Steel Mills - Reheating	LEA	13	3,160	3,160
Iron & Steel Mills - Reheating	LNB	66	720	720
Iron & Steel Mills - Reheating	LNB + FGR	77	900	900

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Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Iron & Steel Mills - Annealing	LNB	50	1,350	1,350
Iron & Steel Mills - Annealing	LNB + FGR	60	1,790	1,790
Iron & Steel Mills - Annealing	SNCR	60	3,130	3,130
Iron & Steel Mills - Annealing	LNB + SNCR	80	3,460	3,460
Iron & Steel Mills - Annealing	SCR	85	8,490	8,490
Iron & Steel Mills - Annealing	LNB + SCR	90	9,070	9,070
Iron & Steel Mills - Galvanizing	LNB	50	1,170	1,170
Iron & Steel Mills - Galvanizing	LNB + FGR	60	1,370	1,370
Municipal Waste Combustors	SNCR	45	2,140	2,140
Medical Waste Incinerators	SNCR	45	8,570	8,570
Space Heaters - Distillate Oil	LNB	50	2,810	4,950
Space Heaters - Distillate Oil	SNCR	50	10,000	3,440
Space Heaters - Distillate Oil	LNB + FGR	60	5,960	1,810
Space Heaters - Distillate Oil	SCR	80	6,240	3,220
Space Heaters - Natural Gas	LNB	50	1,950	1,560
Space Heaters - Natural Gas	SNCR	50	8,330	2,860
Space Heaters - Natural Gas	LNB + FGR	60	6,110	1,420
Space Heaters - Natural Gas	OT + WI	65	1,620	760
Space Heaters - Natural Gas	SCR	80	4,990	2,570
Ammonia - NG-Fired Reformers	LNB	50	1,950	1,560
Ammonia - NG-Fired Reformers	SNCR	50	8,330	2,860
Ammonia - NG-Fired Reformers	LNB + FGR	60	6,110	1,420
Ammonia - NG-Fired Reformers	OT + WI	65	1,620	760
Ammonia - NG-Fired Reformers	SCR	80	4,990	2,570
Ammonia - Oil-Fired Reformers	LNB	50	940	1,020
Ammonia - Oil-Fired Reformers	SNCR	50	5,560	1,910
Ammonia - Oil-Fired Reformers	LNB + FGR	60	2,670	920
Ammonia - Oil-Fired Reformers	SCR	80	3,320	1,710
Lime Kilns	Mid-Kiln Firing	30	1,110	1,110
Lime Kilns	LNB	30	1,340	1,340
Lime Kilns	SNCR - Urea Based	50	1,280	1,280
Lime Kilns	SNCR - NH3 Based	50	1,490	1,490
Lime Kilns	SCR	80	6,850	6,850
Comm./Inst. Incinerators	SNCR	45	2,140	2,140
Indust. Incinerators	SNCR	45	2,140	2,140
Sulfate Pulping - Recovery Furnaces	LNB	50	1,950	1,560
Sulfate Pulping - Recovery Furnaces	SNCR	50	8,330	2,860
Sulfate Pulping - Recovery Furnaces	LNB + FGR	60	6,110	1,420
Sulfate Pulping - Recovery Furnaces	OT + WI	65	1,620	760
Sulfate Pulping - Recovery Furnaces	SCR	80	4,990	2,570
Ammonia Prod; Feedstock Desulfurization	LNB + FGR	60	6,110	1,420
Plastics Prod-Specific; (ABS) Resin	LNB + FGR	55	7,610	5,890
Starch Mfg; Combined Operations	LNB + FGR	55	7,610	5,890

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Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
By-Product Coke Mfg; Oven Underfiring	SNCR	60	3,130	3,130
Pri Cop Smel; Reverb Smelt Furn	LNB + FGR	60	1,790	1,790
Iron Prod; Blast Furn; Blast Htg Stoves	LNB + FGR	77	900	900
Steel Prod; Soaking Pits	LNB + FGR	60	1,790	1,790
Fuel Fired Equip; Process Htrs; Pro Gas	LNB + FGR	55	7,610	5,890
Sec Alum Prod; Smelting Furn/Reverb	LNB	50	1,350	1,350
Steel Foundries; Heat Treating Furn	LNB	50	1,350	1,350
Fuel Fired Equip; Furnaces; Natural Gas	LNB	50	1,350	1,350
Asphaltic Conc; Rotary Dryer; Conv Plant	LNB	50	5,250	4,290
Ceramic Clay Mfg; Drying	LNB	50	5,250	4,290
Coal Cleaning-Thrml Dryer; Fluidized Bed	LNB	50	3,490	2,600
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	LNB	40	4,040	4,040
Sand/Gravel; Dryer	LNB + FGR	55	7,610	5,890
Fluid Cat Cracking Units; Cracking Unit	LNB + FGR	55	7,610	5,890
Conv Coating of Prod; Acid Cleaning Bath	LNB	50	5,250	4,290
Natural Gas Prod; Compressors	SCR	20	5,547	1,075
In-Process; Bituminous Coal; Cement Kiln	SNCR - urea based	50	1,280	1,280
In-Process; Bituminous Coal; Lime Kiln	SNCR - urea based	50	1,280	1,280
In-Process Fuel Use;Bituminous Coal; Gen	SNCR	40	1,420	1,060
In-Process Fuel Use; Residual Oil; Gen	LNB	37	6,010	1,690
In-Process Fuel Use; Natural Gas; Gen	LNB	50	5,250	4,290
In-Proc;Process Gas;Coke Oven/Blast Furn	LNB + FGR	55	7,610	5,890
In-Process; Process Gas; Coke Oven Gas	LNB	50	5,250	4,290
Surf Coat Oper;Coating Oven Htr;Nat Gas	LNB	50	5,250	4,290
Solid Waste Disp;Gov;Other Incin;Sludge	SNCR	45	2,140	2,140

NOTE: *Small source cost per ton values are used to estimate control costs for all sources with 1995 NO_x emissions below 1 ton per day. If the ozone season daily 1995 baseline NO_x value is 1 ton or more, the cost per ton value for large sources is used.
N/A = not applicable. The population of medium speed gas-fired IC engines are all considered small.

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and hope that we can endure while looking for the discovery and cost-reduction of the "better technology" that is capable of meeting the goal of sustainability. The reference literature suggests that the leading edge of pollution prevention and control technology in 1999 is capable of about 94%-99% control of NOx or 1 ppm-5 ppm of NOx.[27,28]

As we all know, the leading edge technology always costs more because engineering has not yet shifted from feasibility to cost-reduction, and competition in the technology is not fully developed. Therefore, we can expect technology to be more affordable with time and to also improve its capability. We should expect to see the goal change with time as the technology advances, and as the achievable goal becomes both more stringent and more economically feasible. At one time, the capabilities that we now have seemed beyond imagining, and the costs seemed prohibitive. We live in an interesting time when the NOx pollution prevention, abatement, and control technology is becoming more capable and more affordable.

CONCLUSIONS

1. Different fuels require different combustion, abatement and control techniques. Different coals have a varying content of volatile ingredients. The nitrogen content of fuel is important, as are the content of sulfur, lead, mercury and other contaminants. Ultra-low nitrogen content fuels have been developed and are already cost competitive. Thus, we can achieve some control of NOx from the lowered concentration of nitrogen in the fuel without investing in changed burner designs.[29]

2. The design of the boiler, internal combustion engine, or gas turbine has a major effect on the operation. NOx formation tends to increase with an increase in boiler capacity, because larger boilers tend to have more intense combustion with higher combustion temperatures and longer residence time for flue gases. The same appears to be true of engines and turbines.

3. Staging of the combustion is implicit in several pollution prevention techniques. Tandem application (or use of hybrid control technology) of NOx control techniques (first SNCR, then SCR in the duct, and then sorption before the ESP which is referred to as "polishing") have been used to achieve an overall reduction of 90+% in NOx and 80% in SOx, even without using low-NOx burners to lower NOx generation.

4. Combustion of natural gas and petroleum distillates can be controlled in much the same way as pulverized coal. The major differences between coal and natural gas or oil are that gas and oil: (1) generally are lower in sulfur and ash; (2) usually are lower in nitrogen; and (3) probably are lower in lead and mercury. Thus, gas and oil do not deactivate a catalyst used in Selective Catalytic Reduction (SCR) at the same rate that coal or semi-solid fuels do.

5. The semi-solid petroleum products can actually have higher levels of sulfur, nitrogen and other impurities than coal. They do not have as much char or ash as coal, but have more than the lighter distillates.

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6. We should expect the declining cost trend of control technology to continue as operating experience is gained, firing techniques are adapted to fuels, design flaws are corrected, and new designs appear. We should expect to see costs become less as they are driven down by competition between suppliers of successful technologies.

7. NOx control technology appears capable of more than just meeting EPA's present goal and this should provide emission credits that can be traded to those firms that choose to continue emitting poorly controlled emissions. The sale of these credits by those that over-corrected for the present goal should further offset any net costs in adopting these control technologies.

8. Commercially available NOx control systems are already available. The availability of these technologies was part of the basis of the recent NOx SIP Call and Title IV regulations.

9. There has been an economic incentive to make combustion more efficient and to innovate ways to control nitrogen oxides. However, the amount of time and money that must be invested for a full-scale test of a strategy is significant. Acceptance requires that a technology be tried and succeed before a larger scale test is even contemplated. This delays acceptance of improved techniques.

10. There seems to be no control technology which is clearly superior for all combustion systems, boilers, engines, or fuels. Lacking a clear winner, one must select fuels and control technology either from among those already proven, or from a growing number of new and promising ideas.

11. The end of the search for control technologies is not yet in sight, and the search must continue. Past research must of necessity give ambivalent answers, because there are so many conflicting factors. However, at under $150 per ton of NOx prevented and with up to 80% control efficiency, the low-NOx burner, where applicable, appears to be among the least expensive emission control technologies. SCR is more expensive, but can obtain up to 94% control efficiency. SNCR can be adopted without the initial cost of catalyst, although it is somewhat less effective. LNB, SCR and SNCR are all viable technologies across a wide spectrum of applications.

12. Research and development will have to continue to seek more effective answers and try to balance them against cost and efficiency. The cost will decrease as technology advances, operating experience is gained, competition becomes sharper, design flaws are corrected, and better designs become available. Reliability can only be gained with time. Cost will be reduced with time and experience. We also must expect that the level of pollution prevention and control technology effectiveness will improve with time.

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TECHNICAL REPORT DATA

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For more information, call the CATC Information Line at (919) 541-0800 or access the CATC Web page at www.epa.gov/ttn/catc

16. ABSTRACT

The purpose of this document is to educate people about nitrogen oxides, how they are formed, the danger that they represent, and how emissions can be controlled. This knowledge is needed to make an informed choice of the control technology that is to be used.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
nitrous oxide, nitric oxide, nitrogen dioxide, dinitrogen pentoxide, nitrous acid, nitric acid, ozone, volatile organic compounds, VOC, generation, pollution prevention, control technology, control technologies, emission control, acid rain, combustion, boilers, gas turbines, internal combustion engines, cost of emission controls, air pollution	air pollution control technology, combustion, pollution prevention, nitrogen oxides, boilers, internal combustion engines, diesel engines	

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Utah Admin. Code 307-504-4

Current through Bulletin 2021-13, July 1, 2021

Section R307-504-4 - Tank Truck Loading Requirements

(1) Tanker trucks used for intermediate hydrocarbon liquid or produced water shall be loaded using bottom filling or a submerged fill pipe.

(2) VOC emissions during truck loading operations shall be controlled at all times using a vapor capture line. The vapor capture line shall be connected from the tanker truck to a control device or process, resulting in a minimum 95 percent VOC destruction efficiency.

(a) Well sites in operation on January 1, 2018 shall comply with R307-504-4(2) no later than July 1, 2019.

Utah Admin. Code R307-504-4

Adopted by Utah State Bulletin Number 2014-21, effective 10/7/2014

Amended by Utah State Bulletin Number 2018-7, effective 3/5/2018

IN THE UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF PENNSYLVANIA

UNITED STATES OF AMERICA, and COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION, Plaintiffs, v. MARKWEST LIBERTY MIDSTREAM & RESOURCES, L.L.C., and OHIO GATHERING COMPANY, L.L.C., Defendants.	Civil Action No. 2:18-cv-00520-LPL CONSENT DECREE

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WHEREAS, Plaintiffs the United States of America ("United States"), on behalf of the United States Environmental Protection Agency ("EPA"), and the Commonwealth of Pennsylvania, Department of Environmental Protection ("PADEP"), simultaneously with the lodging of this Consent Decree, filed a complaint pursuant to Section 113(b) of the Clean Air Act ("Act"), 42 U.S.C. § 7413(b). The complaint seeks injunctive relief and civil penalties for violations of the Clean Air Act's Prevention of Significant Deterioration ("PSD") provisions, 42 U.S.C. §§ 7490-7492; the Non-Attainment New Source Review ("NSR") provisions, 42 U.S.C. §§ 7501-7515; and the state implementation plans ("SIPs") adopted thereunder by the Commonwealth of Pennsylvania and the State of Ohio, and approved by EPA pursuant to Section 110 of the Act, 42 U.S.C. § 7410, at certain compressor stations and at stand-alone pigging stations ("stand-alone facilities") owned and operated by Defendants MarkWest Liberty Midstream & Resources, L.L.C. and Ohio Gathering Company, L.L.C., (collectively, "MarkWest") in the Marcellus Shale and Utica Shale formations in Pennsylvania and Ohio;

WHEREAS, PADEP is the agency of the Commonwealth of Pennsylvania charged with the implementation and enforcement of the Air Pollution Control Act, 35 P.S. § 4001 *et seq.*;

WHEREAS, MarkWest is engaged in natural gas gathering operations in western Pennsylvania and eastern Ohio;

WHEREAS, this is the first civil enforcement action brought by the United States or PADEP concerning emissions from natural gas pig launchers and receivers at compressor stations or at stand-alone facilities;

WHEREAS, MarkWest has investigated and evaluated the development, design, fabrication, and testing of new technologies for sampling and estimating volatile organic

compound ("VOC") emissions from pig launcher and receiver operations and alternatives for reducing VOC emissions from natural gas pig launchers and receivers at compressor stations and stand-alone facilities;

WHEREAS, MarkWest has undertaken numerous design enhancements of launchers and receivers at compressor stations and stand-alone facilities in Pennsylvania and Ohio that have substantially reduced VOC, methane, and ethane emissions, including the design, installation and/or operation of high-to-low pressure natural gas transfer lines, pig ramps, and liquid drains;

WHEREAS, MarkWest expressly denies and does not admit any liability to the United States or PADEP arising out of the conduct, transactions or occurrences alleged in the Complaint; and

WHEREAS, the Parties acknowledge that this Consent Decree has been negotiated by all Parties in good faith and will avoid litigation among the Parties, and the Court, by entering this Consent Decree, finds that this Consent Decree is fair, reasonable, and in the public interest.

NOW, THEREFORE, before the taking of any testimony, without the adjudication or admission of any issue of fact or law except as provided in Section I, and with the consent of the Parties,

IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and over the Parties, pursuant to 28 U.S.C. §§ 1331, 1345, 1355 and 1367, and Section 113(b) of the Act, 42 U.S.C. § 7413(b). Venue is proper in this judicial district pursuant to Section 113(b) of the Act, 42 U.S.C. § 7413(b), and 28 U.S.C. §§ 1391(b) and (c), and 1395(a), because violations alleged

in the Complaint are alleged to have occurred, and MarkWest conducts business, in this judicial district. MarkWest consents to and shall not challenge entry of this Consent Decree or this Court's jurisdiction to enter and enforce this Decree, and further consents to venue in this judicial district solely for the purpose of entering and enforcing this Consent Decree.

2. For purposes of this Consent Decree, MarkWest agrees that the Complaint states claims upon which relief may be granted.

II. APPLICABILITY AND SALES OR TRANSFERS OF OWNERSHIP AND OPERATION INTERESTS

3. The obligations of this Consent Decree apply to and are binding upon the United States, PADEP, and MarkWest, and any of their respective successors or assigns, or other entities or persons otherwise bound by law.

4. In the event that MarkWest proposes to sell or transfer ownership or operation, in whole or in part, of any of the Covered Facilities, to an entity unrelated to MarkWest ("Third Party"), MarkWest shall notify the Third Party in writing of the existence of this Consent Decree prior to the closing of such sale or transfer. MarkWest shall send a copy of this written notification to the United States and PADEP pursuant to Section XVIII (Notices) prior to the proposed closing.

5. MarkWest shall condition any sale or transfer, in whole or part, of ownership or operation of any of the Covered Facilities upon the execution by the Third Party of a modification to this Consent Decree to make the terms and conditions of this Consent Decree related to the ownership or operation of the transferred Covered Facilities applicable to the Third Party. No earlier than thirty (30) Days after giving notice to a successor in interest pursuant to Paragraph 4, MarkWest may file a motion to modify this Consent Decree with the Court to make

the terms and conditions of the Consent Decree related to the ownership or operation of the transferred Covered Facilities applicable to the Third Party. MarkWest shall be released from the requirements of this Consent Decree with respect to the transferred Covered Facilities unless the Court finds that the Third Party does not have the financial or technical ability to comply with the requirements of this Consent Decree.

6. This Consent Decree shall not be construed to impede the sale or transfer of any asset or interest between MarkWest and any Third Party so long as the requirements of this Consent Decree are met.

7. Paragraphs 3-5 shall not be construed to affect or apply to mergers or other corporate transactions in which MarkWest is acquired by a Third Party and the surviving entity, by operation of law, assumes all of MarkWest's assets and liabilities pursuant to the Consent Decree relating to the Covered Facilities.

8. MarkWest shall (a) provide a copy of this Consent Decree to all officers of MarkWest and managers who will be responsible for implementation of the terms of this Consent Decree, and ensure that any employees and contractors whose duties might reasonably include compliance with any provision of this Consent Decree are made aware of those requirements of this Consent Decree that fall within such persons' duties; and (b) place an electronic version of the Consent Decree on its internal environmental website. MarkWest shall be responsible for ensuring that all employees and contractors involved in performing any work pursuant to this Consent Decree perform such work in compliance with the requirements of this Consent Decree.

9. In any action to enforce this Consent Decree, MarkWest shall not raise as a defense to liability or stipulated penalty the failure by any of its officers, directors, employees, agents, or contractors to take any actions necessary to comply with the provisions of this Consent Decree. This Section does not preclude MarkWest from holding any employee, agent, or contractor who is alleged to have not complied with this Consent Decree liable for their actions. Nothing herein shall preclude MarkWest, in an action to enforce this Consent Decree pursuant to Paragraph 78, from raising the failure of any contractor to take any actions necessary to comply with the provisions of this Consent Decree as a mitigating factor with regard to any non-injunctive relief sought.

III. DEFINITIONS

10. For purposes of this Consent Decree, every term expressly defined by this Section shall have the meaning given that term herein. Every other term used in this Decree that is defined in the Act, 42 U.S.C. § 7401 *et seq.*, or in the regulations promulgated pursuant to the Act, but not defined in this Section, shall mean in this Decree what such term means under the Act or those regulations.

a. "CD Emissions Reductions" shall mean any VOC emissions reductions that result from any projects, controls, or any other actions used to comply with this Consent Decree at any of the facilities listed on Appendices 1, 3 (with the exception of Route 18), or 4.

b. "Commercially and Operationally Appropriate" shall mean that: (1) fewer than 50% of anticipated pigging events at the pig launcher or receiver will be for pipeline inspection purposes; and (2) the costs of installing a shorter barrel at the pig launcher or receiver

would not be unreasonably disproportionate to the benefits of VOC emissions reductions achieved by use of a shorter barrel.

c. "Commercially Reasonable and Technically Feasible" shall mean that connection of a high pressure launcher or receiver to a low pressure line does not require MarkWest to: (1) use more than 100 feet of piping to achieve such a connection; (2) connect to a low pressure line located outside the fenceline of the facility where the high pressure launcher or receiver will be located; or (3) incur costs that would be unreasonably disproportionate to the benefits of VOC emissions reductions achieved by the installation and operation of such a connection to a low pressure line.

d. "Complaint" shall mean the complaint filed by the United States and PADEP in this action.

e. "Compressor Stations" shall mean the compressor stations identified in Appendices 1 and 4 to this Consent Decree.

f. "Consent Decree" or "Decree" shall mean this Decree and all appendices attached hereto (listed in Section XXVII (Appendices)).

g. "Covered Facilities" shall mean all MarkWest facilities identified in Appendices 1-5.

h. "Day" shall mean a calendar day unless expressly stated to be a business day. In computing any period of time under this Decree, where the last day would fall on a Saturday, Sunday, or federal holiday, the period shall run until the close of business of the next business day.

i. "EPA" shall mean the United States Environmental Protection Agency and any of its successor departments or agencies.

j. "Effective Date" shall have the definition provided in Section XIX (Effective Date).

k. "Flare" shall mean a combustion device used to control emissions from equipment in VOC service.

l. "Jumper Line" shall mean an enclosed piping system attached to the vent line of a pig launcher or receiver that routes the contents of a pig launcher or receiver into a lower pressure gathering system.

m. "Liquid or Residue Gas Service" shall refer to any pipelines downstream of a MarkWest processing plant that convey natural gas liquids or processed natural gas (residue gas).

n. "MarkWest" shall mean Ohio Gathering Company, L.L.C., and MarkWest Liberty Midstream & Resources, L.L.C.

o. "Mobile Flare" shall mean a trailer-mounted flare.

p. "Ohio SIP" shall mean the federally-approved State Implementation Plan ("SIP") adopted by the State of Ohio.

q. "Ohio VOC Permitting Threshold" shall mean, for Ohio air contaminant sources, actual VOC emissions exceeding 10 pounds per day from an air contaminant source, or potential VOC emissions from an air contaminant source alone or in combination with similar sources at the same facility in excess of 25 tons per year.

r. "PADEP" shall mean the Commonwealth of Pennsylvania, Department of Environmental Protection.

s. "Paragraph" shall mean a portion of this Decree identified by an Arabic numeral.

t. "Parties" shall mean the United States, PADEP, and MarkWest.

u. "Party" shall mean the United States, PADEP, or MarkWest.

v. "Pennsylvania SIP" shall mean the federally-approved State Implementation Plan ("SIP") adopted by the Commonwealth of Pennsylvania.

w. "Pigging" shall mean the process of introducing and subsequently removing a specialized device (called a "pig") into a natural gas pipeline to push liquids through the pipeline into a slug catcher and/or designated system.

x. "Pig Ramp" shall mean a device installed inside the barrel of a pig receiver designed and intended to prevent liquid accumulation in the barrel and minimize release of volatile liquids into the environment during retrieval of the pig.

y. "Project Dollars" shall mean MarkWest's direct costs incurred in implementing the Supplemental Environmental Projects identified in subparagraphs b. and c. of Paragraph 28 to the extent that such costs: (i) comply with the requirements set forth in Section VI and (ii) constitute MarkWest's direct payments associated with such projects or MarkWest's external costs for contractors, vendors, and equipment. Project Dollars shall not include MarkWest's internal personnel costs incurred to oversee the implementation of the Supplemental Environmental Projects identified in subparagraphs b. and c. of Paragraph 28.

z. "Real Gas Law" shall mean $PV = (m/M_w)RTZ$ where:

P = pressure inside the pipe (psfa) pound per square foot actual

V = actual volume of pipe (ft^3)

m = mass of material (lb)

M_w = molecular weight of the mixture (lb/lbmol)

R = universal gas constant (1545 psfa*ft3/lbmol*°R^{-1})

T = temperature of mixture (°R)

Z = compressibility factor (unitless)

Solving for mass yields: $m = PVM_w/(RTZ)$.

aa. "Section" shall mean a portion of this Decree identified by a Roman numeral.

bb. "Stand-Alone Facilities" shall mean the MarkWest sites where natural gas pig launchers and/or receivers are located that are identified in Appendices 3, 5, and 6.

cc. "System" shall mean all of MarkWest's pig launchers and receivers in Pennsylvania and Ohio.

dd. "United States" shall mean the United States of America, acting on behalf of EPA.

ee. "VOC" or "VOCs" shall mean volatile organic compounds, as defined in 40 C.F.R. § 51.100(s), and which does not include methane or ethane.

IV. INJUNCTIVE RELIEF

11. Emission Calculations. For purposes of compliance with the Consent Decree, MarkWest shall calculate the mass of VOC emissions from pigging operations at facilities listed in Appendices 1 through 5 using the Real Gas Law multiplied by a factor of 1.2.

12. Pennsylvania Compressor Stations. No later than the Effective Date, at the MarkWest Compressor Stations identified in Appendix 1, MarkWest shall:

a. connect each high pressure pig launcher and receiver by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch; and

c. install and use Pig Ramps in pig receivers.

13. Pennsylvania Compressor Station Dehydrator Flares. At the MarkWest Compressor Stations identified in Appendix 2, MarkWest shall replace existing dehydrator flares with enclosed air-assisted flares. The replacement enclosed air-assisted flare system shall include a 3 horsepower blower (with a variable frequency drive), a single point burner tip, a gas enrichment stream and shutdown/startup control logic panels, and shall raise regenerator off-gas Btu value to ensure a clean burn. These flares shall achieve a minimum 98% destruction and removal efficiency ("DRE").

14. Pennsylvania Stand-Alone Facilities. No later than the Effective Date, MarkWest shall implement those elements of injunctive relief identified in this Paragraph that apply, as specified in Appendix 3, to each specific pig launcher and receiver located at each of the MarkWest Stand-Alone Facilities identified in Appendix 3. Where applicable, MarkWest shall:

a. connect high pressure pig launchers and receivers by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch; and

c. install and use Pig Ramps in pig receivers.

15. Pennsylvania Launcher/Receiver Smith Tee Emissions Flare Replacement. At the Smith Tee Stand-Alone Facility (the location of which is identified in Appendix 3) in Pennsylvania**,** MarkWest shall replace the existing flare with a new "candlestick" flare. The replacement candlestick flare system shall be designed to (a) provide smokeless and low heat radiation flaring, (b) maintain its pilot light in winds up to 50 mph, and (c) generate a hydrocarbon gas-air mixture using an air inspirator ignition.

16. Loffert (Joe Cain) Pennsylvania Stand-Alone Facility. At the Loffert (Joe Cain) Stand-Alone Facility (the location of which is identified in Appendix 3)**,** MarkWest shall continue to operate the redesigned and modified discharge piping installed in 2016.

17. Closure of Drugmand, Stewart Route 50, and Graham Header Stations. No later than twelve (12) months after the Effective Date, MarkWest shall permanently close and cease operations of all launchers and receivers located at the Drugmand Station (located at 40.32917258600, -80.28226258100) and Stewart Route 50 Station (located at 40.28446667, -80.35458611) and all high pressure launchers and receivers located at the Graham Header Station (located at 40.83600748440, -80.08065377390). MarkWest shall permanently remove all pig launchers and receivers that are subject to this Paragraph. Until MarkWest permanently ceases operations of the referenced launchers and receivers, MarkWest shall continue to use the existing Pig Ramps, Jumper Lines, and Flares to reduce VOC emissions during pigging operations.

18. Ohio Compressor Stations. No later than the Effective Date, MarkWest shall implement those elements of injunctive relief identified in this Paragraph that apply, as specified

in Appendix 4, to each specific pig launcher and receiver located at each of the MarkWest Compressor Stations identified in Appendix 4. Where applicable, MarkWest shall:

a. connect high pressure pig launchers and receivers by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch;

c. install and use Pig Ramps in pig receivers; and

d. when necessary to ensure that VOC emissions do not exceed the Ohio VOC Permitting Threshold, use a Mobile Flare to control VOC emissions.

19. Ohio Stand-Alone Facilities. No later than the Effective Date, MarkWest shall implement those elements of injunctive relief identified in this Paragraph that apply, as specified in Appendix 5, to each specific high pressure launcher and receiver located at each of the MarkWest Stand-Alone Facilities identified in Appendix 5. Where applicable, MarkWest shall:

a. connect high pressure pig launchers and receivers by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch;

c. install and use Pig Ramps in pig receivers; and

d. when necessary to ensure compliance with the Ohio SIP, use a Mobile Flare to control VOC emissions.

20. New Launchers and Receivers. For pig launchers and receivers constructed in Pennsylvania and Ohio after the Effective Date and prior to Termination, MarkWest shall, subject to the exception in subparagraph e., below:

a. connect each high pressure pig launcher or receiver by Jumper Lines to a low pressure gathering line where such connection is Commercially Reasonable and Technically Feasible;

b. use Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch;

c. at each new receiver, install and use a Pig Ramp or, with prior EPA written approval, technology that achieves equivalent emissions reductions;

d. at high pressure pig launchers and receivers, use shorter barrels than those presently used in the System, provided that the high pressure pig launcher or receiver is not in Liquid or Residue Gas Service and use of a shorter barrel is Commercially and Operationally Appropriate; and

e. in the event that MarkWest determines that any of the requirements in subparagraphs a., b., or d. above would pose a material adverse risk to worker safety, MarkWest may inform EPA of such risk and the reasons therefore, and upon written approval by EPA be excused from that requirement.

21. Existing Receivers. MarkWest shall install Pig Ramps in all pig receivers located at the Stand-Alone Facilities identified in Appendix 6.

22. At each high pressure pig launcher and receiver that MarkWest currently operates in Pennsylvania and Ohio that is not located at a Covered Facility, MarkWest shall connect such

high pressure pig launcher and receiver by pipe to a low pressure gathering line where such connection is Commercially Reasonable and Technically Feasible and operate such Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch.

23. Liquid Containment Enhancement. For each launcher or receiver located at any MarkWest Compressor Station or Stand-Alone Facility identified in Appendices 1, 3, 4, 5, or 6, and each new launcher or receiver constructed after the Effective Date but prior to Termination in Pennsylvania and Ohio, MarkWest shall install and use liquid containers with grounded steel receptacles that are covered at all times when not in use.

V. CIVIL PENALTY

24. No later than thirty (30) Days after the Effective Date, MarkWest shall pay as a civil penalty $610,000. MarkWest shall pay 80% of this penalty to the United States, and 20% to PADEP. MarkWest shall pay interest on any amount past due, at the rate specified in 28 U.S.C. § 1961.

25. Federal Payment Instructions. MarkWest shall make the penalty payment to the United States at https://www.pay.gov to the U.S. Department of Justice account, in accordance with instructions provided to MarkWest by the Financial Litigation Unit ("FLU") of the United States Attorney's Office for the Western District of Pennsylvania after the Effective Date. The payment instructions provided by the FLU will include a Consolidated Debt Collection System ("CDCS") number that MarkWest shall use to identify this payment, as well as any others required to be made in accordance with this Consent Decree. The FLU will provide payment instructions to MarkWest to:

Christopher L. Rimkus
Managing Counsel – Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Christopher.rimkus@markwest.com

MarkWest may change the individual to receive payment instructions on its behalf by providing written notice of such change in accordance with Section XVIII (Notices). At the time of payment, MarkWest shall send notice that payment has been made to the United States and EPA in accordance with Section XVIII (Notices). Such notice shall state that it is for the civil penalty owed pursuant to the Consent Decree, and shall reference the CDCS number, the civil action number, and DOJ Case No. 90-5-2-1-11374.

26. Pennsylvania Payment Instructions. The MarkWest penalty payment to Pennsylvania shall be made by Electronic Funds Transfer in accordance with instructions to be provided to MarkWest by PADEP. The payment instructions will include ABA and Account numbers that MarkWest shall use to identify all payments required to be made to PADEP in accordance with this Consent Decree. PADEP will provide the payment instructions to:

Christopher L. Rimkus
Managing Counsel – Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Christopher.rimkus@markwest.com

MarkWest may change the individual to receive payment instructions on its behalf by providing written notice of such change in accordance with Section XVIII (Notices). At the time of payment, MarkWest shall send notice that payment has been made to PADEP. This notice shall include (a) the name, address, phone number and entity making payment, (b) the civil action

number of this case, (c) the reference/confirmation number and advice number of the transmittal, (d) the amount of the payment, (e) the date of the payment, and (f) the sending bank's Federal identification number.

27. Not Tax Deductible. MarkWest shall not deduct any penalties paid under this Section or Section XII (Stipulated Penalties) in calculating its federal, state, or local income tax.

VI. SUPPLEMENTAL ENVIRONMENTAL PROJECTS

28. MarkWest shall perform the following Supplemental Environmental Projects in accordance with all provisions of this Section:

a. Innovation Transfer and Emission Control Education. MarkWest will disseminate and make available for use by other oil and gas companies its proprietary design for Pig Ramps, which has been shown to reduce liquid accumulation and emissions from pig launcher and receiver operations. In order to promote the rapid adoption of this innovative device, MarkWest will make available on a public website, no later than six (6) months after the Effective Date, a royalty-free license and information on the Pig Ramp design. MarkWest will also provide educational presentations and host four demonstration or training sessions per year over a three-year period (for a total of 12 sessions), with technical staff available in-person at each session, to demonstrate and encourage the installation and adoption of the technologies developed by MarkWest to reduce VOC emissions from pig launchers and receivers throughout the oil and gas industry. In conjunction with such presentations and demonstrations, MarkWest will develop comprehensive and detailed educational materials on the effective installation, maintenance, and use of Pig Ramps and Jumper Lines to reduce VOC emissions from pig launchers and receivers. Within twelve (12) months of the Effective Date, MarkWest will make

any such materials available on the same website provided for in this Paragraph for the publication of a royalty-free Pig Ramp license and information on Pig Ramp design.

b. Humphreys Compressor Station Ambient Air Monitoring SEP. In accordance with Appendix 7, MarkWest shall install and operate, for a period of at least seven hundred twenty (720) days, one (1) meteorological station and two (2) air sampling stations for sampling and analyzing speciated and total VOCs and reduced sulfur compounds ("RSCs"). One air sampling station will be located upwind and the other downwind of the Humphreys Compressor Station ("HCS") in Barnesville, Ohio. Within one hundred twenty (120) days of the Effective Date, MarkWest shall submit a plan ("Humphreys Monitoring Plan") to EPA for approval to conduct an ambient air monitoring SEP ("Humphreys SEP") near the HCS in accordance with the requirements of this subparagraph and Appendix 7. Following EPA approval of the Humphreys Monitoring Plan, MarkWest shall install and operate the meteorological and air sampling stations in accordance with the approved Humphreys Monitoring Plan and Appendix 7. MarkWest shall submit quarterly information reports and annual reports to EPA as required by the approved Humphreys Monitoring Plan and Appendix 7.

c. Harmon Creek Ambient Air Monitoring SEP. In accordance with Appendix 8, MarkWest shall install and operate, for a period of at least seven hundred twenty (720) days, one (1) meteorological station and three (3) VOC air sampling stations located around the proposed Harmon Creek Gas Processing Plant ("Harmon Creek") in Smith Township, Washington County, Pennsylvania. Within one hundred twenty (120) days of the Effective Date, MarkWest shall submit a plan ("Harmon Creek Monitoring Plan") to EPA and PADEP, for approval by EPA in consultation with PADEP, to conduct an ambient air monitoring SEP near

Harmon Creek in accordance with the requirements of this subparagraph and Appendix 8. Following EPA approval (in consultation with PADEP) of the Harmon Creek Monitoring Plan, MarkWest shall install and operate the meteorological and air sampling stations in accordance with the approved Harmon Creek Monitoring Plan and Appendix 8. MarkWest shall submit quarterly information reports and annual reports to EPA and PADEP as required by the approved Harmon Creek Monitoring Plan and Appendix 8.

d. MarkWest shall spend not less than $2,000,000 in Project Dollars to implement the SEPs described in subparagraphs b. and c.

29. With regard to the SEPs identified in Paragraph 28, MarkWest certifies the truth and accuracy of each of the following:

a. That all cost information provided to EPA in connection with EPA's approval of the SEPs is complete and accurate and that MarkWest in good faith estimates that the cost to implement the SEPs is $2,400,000;

b. That, as of the date of executing this Consent Decree, MarkWest is not required to perform or develop the SEPs by any federal, state or local law, or regulation and is not required to perform or develop the SEPs by agreement, grant, or as injunctive relief awarded in any other action in any forum;

c. That the SEPs are not projects that MarkWest was planning or intending to construct, perform or implement other than in settlement of the claims resolved in this Decree;

d. That MarkWest has not received and will not receive credit for the SEPs in any other enforcement action;

e. That MarkWest will not receive any reimbursement for any portion of the SEPs from any other person;

f. That MarkWest is not a party to any open federal financial assistance transaction that is funding or could fund the same activity as the SEPs. For purposes of these certifications, the term "open federal financial assistance transaction" refers to a grant, cooperative agreement, loan, federally-guaranteed loan guarantee, or other mechanism for providing federal financial assistance whose performance period has not yet expired.

30. SEP Completion Report. Within thirty (30) Days after completion of a SEP, MarkWest shall submit a SEP Completion Report to the United States and PADEP in accordance with Section XVIII (Notices) of this Consent Decree. Each SEP Completion Report shall contain the following information:

a. A detailed description of the SEP as implemented;

b. A description of any problems encountered in completing the SEP and solutions thereto;

c. An itemized list of all eligible SEP costs expended;

d. Certification that the SEP has been fully implemented pursuant to the provisions of this Decree; and

e. To the extent feasible, a description of the environmental or public health benefits resulting from implementation of the SEPs.

31. The United States may, in its sole discretion, require MarkWest to provide information in addition to that described in Paragraph 30 ("SEP Completion Report") in order to evaluate MarkWest's SEP Completion Report.

32. After receiving a SEP Completion Report, the United States will notify MarkWest whether or not MarkWest has satisfactorily completed the SEP. If MarkWest has not completed the SEP in accordance with this Consent Decree, stipulated penalties may be assessed under Section XII (Stipulated Penalties) of this Consent Decree.

33. MarkWest may invoke dispute resolution under Section XIV of the Decree (Dispute Resolution) regarding EPA's determination of (i) whether MarkWest has satisfactorily performed a SEP and (ii) the amount of eligible SEP costs. No other disputes arising under this Section are subject to Dispute Resolution.

34. MarkWest shall ensure that each submission required under this Section is signed by a MarkWest official with knowledge of the SEP and bears the certification language set forth in Paragraph 63.

35. If MarkWest references the SEPs under this Consent Decree in any press conference, press release, or similar formal public statement, MarkWest shall include language in substantially the following form: "This project was undertaken in connection with the settlement of an enforcement action under the Clean Air Act brought by the United States and PADEP against certain MarkWest entities."

36. For federal income tax purposes, MarkWest agrees that it will neither capitalize into inventory or basis nor deduct any costs or expenditures incurred in performing the SEPs.

VII. COMMONWEALTH-ONLY COMMUNITY ENVIRONMENTAL PROJECT

37. In order to settle the matters contained herein, and in addition to the PADEP portion of the civil penalty identified in Section V (Civil Penalty), MarkWest shall, as a Commonwealth-Only Community Environmental Project ("CEP"), permanently transfer

ownership to PADEP of the equipment used in the Harmon Creek Ambient Air Monitoring SEP, identified in Paragraph 38, below (hereinafter "Monitoring Equipment CEP").

38. Within sixty (60) days of the completion of the Harmon Creek Ambient Air Monitoring SEP (Paragraph 28.c), MarkWest shall permanently transfer ownership of the following equipment ("Equipment") to PADEP, for PADEP's use within Pennsylvania:

Compound Analyzer	Consolidated Analytical Systems (CAS) AirmOzone Auto-Gas Chromatograph (GC) (along with ancillary equipment needed to operate it (i.e. stuff in the box))
Wind Speed/Direction	R.M. Young Model 05305 Wind Monitor AQ
Temperature and Delta Temperature	R.M. Young Platinum RTD Model 41342 ambient temperature sensor
Temperature and Delta Temperature	R.M. Young Model 43502 aspirated radiation shield
Relative Humidity	Campbell Scientific Inc (CSI) EE181 relative humidity/temperature probe
Solar Radiation	Hukseflux LP02
Net Radiation	Kipp & Zonen NR-LITE net radiometer
Barometric Pressure	CS106 Vaisala PTB110 barometer
10-Meter Tower	Model UT30 10-meter guyed aluminum tower
Telecommunications	Sierra Wireless RV50 modem (Verizon)
Data Acquisition System	Campbell Scientific, Inc. CR1000x data acquisition system

39. The Monitoring Equipment CEP falls within the definition of CEP in PADEP's "Policy for the Acceptance of Community Environmental Projects in Conjunction with Assessment of Civil Penalty" (Technical Guidance Document Number 012-4180-001).

40. PADEP has determined that the Monitoring Equipment CEP will provide a substantial public health and environmental benefit to Pennsylvania and that the Monitoring Equipment CEP is not something that MarkWest is otherwise legally required to do.

41. MarkWest shall not deduct any costs incurred in connection with or in any way associated with the Monitoring Equipment CEP for any tax purpose or otherwise obtain favorable tax treatment for those costs. If requested to do so by PADEP, MarkWest shall submit an affidavit of the corporate officer responsible for the financial affairs of MarkWest certifying that MarkWest has not deducted or otherwise obtained favorable tax treatment of any of the costs of the Monitoring Equipment CEP.

42. MarkWest agrees that whenever it publicizes, in any press conference, press release, or similar formal public statement, the Monitoring Equipment CEP, it will state that the Monitoring Equipment CEP was undertaken as part of the settlement of an enforcement action with PADEP.

VIII. PERMITS

43. Pennsylvania Appendix 1 and Appendix 3 Facilities. For each Pennsylvania Compressor Station identified on Appendix 1 with the exception of Baker, Redd, and Tupta Day, and each Pennsylvania Stand-Alone Facility identified on Appendix 3 with the exception of Route 18, MarkWest will submit complete applications to PADEP, using PADEP application forms, seeking to incorporate as "applicable requirements" the injunctive relief listed in Paragraphs 12 through 16 of this Consent Decree into non-Title V state-only operating permits ("SOOPs") for those Covered Facilities that are federally enforceable and will survive termination of this Consent Decree. VOC emissions from pigging operations in the SOOP

applications shall be determined in accordance with Paragraph 11. If, after the Effective Date, PADEP issues a revised version of its January 2015 General Plan Approval and/or General Operating Permit BAQ-GPA/GP-5 (Natural Gas Processing Stations, Processing Plants, and Transmission Stations) ("GP-5"), MarkWest will submit complete applications to PADEP, using PADEP application forms, seeking authorization to operate Baker, Redd, and Tupta Day Compressor Stations under the revised GP-5.

44. Permits to be Issued by PADEP. PADEP will review and act on such permit applications submitted by MarkWest. Any challenges to PADEP's issuance or denial of a permit application must be filed with the Pennsylvania Environmental Hearing Board.

45. Ohio Compressor Stations. For each Ohio Compressor Station identified on Appendix 4, MarkWest will submit complete applications to the Ohio Environmental Protection Agency ("OEPA") seeking to incorporate as "applicable requirements" the injunctive relief identified in Paragraph 18 (Ohio Compressor Stations) of the Consent Decree into non-Title V Permits to Install and Operate that are federally enforceable and will survive termination of this Consent Decree.

46. Other Covered Ohio Stand-Alone Facilities. For each pig launcher and receiver identified in Appendix 5, MarkWest will submit complete applications to OEPA seeking coverage under Ohio General Permit GP 21.1 (Pigging at an Oil and Gas Compressor Station/Other Site).

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IX. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

47. Prohibitions. MarkWest shall neither generate nor use any CD Emissions Reductions: (i) as netting reductions; (ii) as emissions offsets; or (iii) to apply for, obtain, trade, or sell any emission reduction credits in any permit application.

48. Outside the Scope of the Prohibitions. Nothing in this Section is intended to prohibit MarkWest from seeking to, nor PADEP or Ohio EPA from denying MarkWest's request to:

a. Use or generate emission reductions from emissions units that are covered by this Consent Decree to the extent that the proposed emissions reductions represent the difference between CD Emissions Reductions and more stringent control requirements that MarkWest may elect to accept for those emissions units in a permitting process, except as provided in this Paragraph;

b. Use or generate emissions reductions from emissions units that are not subject to an emission limitation or control requirement pursuant to this Consent Decree; or

c. Use CD Emissions Reductions for compliance with any rules or regulations designed to address regional haze or the non-attainment status of any area (excluding Prevention of Significant Deterioration and non-attainment New Source Review rules, but including, for example, Reasonably Achievable Control Technology ("RACT") rules that apply to MarkWest); provided, however, that MarkWest shall not be allowed to trade or sell any CD Emissions Reductions.

X. THIRD PARTY VERIFICATION

49. Third-Party Audit. MarkWest will retain, at its expense, a qualified third-party consultant, not employed by MarkWest or any of its subsidiary or affiliated companies (a "Third Party Auditor"), to lead an audit team to perform the audit described in this Section. The audit team shall include, for coordination of onsite inspection activities only, at least one MarkWest employee or contractor familiar with the Compressor Stations and Stand-Alone Facilities being audited. MarkWest shall make available to the Third-Party Auditor all of MarkWest's non-privileged records requested by the Third-Party Auditor that are reasonably related to the scope of the audit required under this Section. MarkWest may, however, require that the Third-Party Auditor execute a confidentiality agreement prior to providing any documents or records containing Confidential Business Information. MarkWest shall provide the Third-Party Auditor with access to those Compressor Stations and Stand-Alone Facilities that are the subject of the audit required by this Section and shall provide all reasonable assistance to allow the Third-Party Auditor to conduct the audit required by this Section, including making employees, affiliates, or contractors available to answer questions or provide information.

50. Third-Party Auditor Selection Process. Within sixty (60) Days after the Effective Date, MarkWest shall notify the United States and PADEP in writing of MarkWest's recommended Third-Party Auditor and provide statements of qualification for that consultant for performance of the services as Third-Party Auditor. Such statements of qualification shall identify those other services, in addition to those to be performed as Third-Party Auditor, that may be performed for MarkWest in the foreseeable future. EPA, in consultation with PADEP, may disapprove of MarkWest's recommended Third-Party Auditor if it determines that the

consultant lacks the necessary qualifications to serve as Third-Party Auditor. EPA shall state the reasons for its disapproval of the consultant as Third-Party Auditor in writing, and the MarkWest recommendation and EPA approval process will be repeated with MarkWest having thirty (30) Days from the date of disapproval to propose an alternate consultant and provide statements of qualification. In the event a consultant is not approved within thirty (30) Days of MarkWest's first submission under this Paragraph, all deadlines in this Section shall be extended by the total number of Days it takes to approve the consultant minus thirty (30) Days. For example, if it takes forty-five (45) Days to approve the consultant, MarkWest's deadlines would be extended by fifteen (15) Days (*i.e.*, 45 – 30 = 15).

51. MarkWest shall ensure that the Third-Party Auditor complies with the following terms: (a) the Third-Party Auditor shall provide written advance notice as soon as practicable to MarkWest, the United States, and PADEP in the event that the Third-Party Auditor is unable to continue to serve as the Third-Party Auditor under this Consent Decree; (b) the Third-Party Auditor shall provide EPA and PADEP with a written advance schedule of any facility visits, telephone calls, or other meetings with MarkWest or its agents or contractors and shall invite EPA and PADEP to participate in person or by teleconference; (c) the Third Party Auditor shall use the Real Gas Law, as defined herein, and calculate VOC emissions consistent with Paragraph 11 (Emission Calculations); (d) the Third-Party Auditor shall promptly disclose to the United States and PADEP any conflicts of interests for it or its subcontractors that may arise with respect to its performance of the audit and, in the event of a conflict, the Third-Party Auditor shall take any and all action to resolve such conflict; and (e) the individual Third-Party audit team personnel who conducted or otherwise participated in auditing services pursuant to this

Consent Decree shall not accept employment by MarkWest for a period of at least one (1) year following completion of the audit.

52. Scope of Audit. Within eighteen (18) months of the Effective Date, the Third-Party Auditor shall conduct an audit of the installation and operation of the injunctive relief required pursuant to Section IV to determine compliance with this Consent Decree at a total of five (5) of the Compressor Stations or Stand-Alone Facilities identified in Appendices 1 and 3, except the Baker, Redd, and Tupta Day Compressor Stations, and a total of five (5) Compressor Stations or Stand-Alone Facilities identified in Appendices 4 and 5.

53. Third-Party Audit Report. Within twenty-one (21) months of the Effective Date, the Third-Party Auditor shall simultaneously provide a draft Audit Report to MarkWest, EPA, and PADEP. Within forty-five (45) Days after receipt of the draft Audit Report, MarkWest shall provide comments on the draft Audit Report, if any, to the Third-Party Auditor, EPA, and PADEP. As part of such comments, MarkWest shall, if needed, identify within the draft Third-Party Audit Report any Confidential Business Information ("CBI"), and such information shall be designated by the Third-Party Auditor as CBI in the final Third-Party Audit Report submitted to EPA and PADEP. EPA and PADEP shall treat the draft Third-Party Audit Report, in its entirety, as CBI. The Third-Party Auditor shall provide in writing its basis for accepting or rejecting the comments of MarkWest on the draft Third-Party Audit Report. Within twenty-four (24) months of the Effective Date, the Third-Party Auditor shall submit a Third-Party Audit Report to MarkWest, EPA and PADEP. The Third-Party Audit Report shall identify any requirement of the injunctive relief specified in Section IV where MarkWest is not in compliance and, for each such requirement: (i) provide a detailed description of the basis for this conclusion

regarding noncompliance, including a summary of any relevant oral communications between the Third-Party Auditor and any of MarkWest's officers, agents, or employees; and (ii) attach relevant supporting documentation.

54. Response to Third-Party Audit Report. Within one hundred twenty (120) Days after receiving the Third-Party Audit Report, MarkWest shall (1) serve on the United States and PADEP a schedule for remedying any deficiencies identified in the Third-Party Audit Report, and/or (2) serve a notice on the United States and PADEP that MarkWest disputes the Third-Party Auditor's findings, in whole or part, and specifies the factual, technical, or legal basis of that disagreement. Any disagreement between the United States and MarkWest and/or PADEP and MarkWest over MarkWest's response to the Third-Party Audit Report shall be resolved according to the Dispute Resolution provisions of the Consent Decree in Section XIV.

55. The United States and PADEP shall not be bound by any Third-Party Audit Report generated pursuant to this Consent Decree. The United States and/or PADEP may accept or reject, in whole or in part, the Third-Party Auditor's findings, conclusions, and/or recommendations. If the United States or PADEP determines that MarkWest is in violation of any Consent Decree requirement for which stipulated penalties are provided under Section XII (Stipulated Penalties), MarkWest shall be subject to the assessment of such penalties, regardless of the Third-Party Audit Report, in accordance with the provisions of Section XII (Stipulated Penalties), and subject to MarkWest's right to invoke the provisions of Section XIV (Dispute Resolution).

56. MarkWest may terminate its contract with the Third-Party Auditor only for good cause shown and with the consent of the United States, in consultation with PADEP; such

consent not to be unreasonably withheld. For the purposes of this Paragraph, "good cause" includes, but is not limited to, incompetence, fraudulent actions, and any failure by the Third-Party Auditor to comply with all applicable laws and MarkWest policies relating to (1) worker health and safety, or (2) environmental compliance and protection. In the event MarkWest terminates its contract with the Third-Party Auditor, MarkWest shall select a new consultant consistent with the process in Paragraph 50.

57. Except as otherwise provided herein, the Third-Party Audit Report shall not be subject to any privilege or the attorney work product doctrine. Nothing in this Section shall prevent MarkWest from designating as CBI portions of the Third-Party Audit Report or other documents prepared by the Third-Party Auditor.

XI. RECORDKEEPING AND REPORTING

58. Status Reports. After the Effective Date and until termination of the Consent Decree, MarkWest shall submit periodic reports ("Status Reports") on the status of the injunctive relief and SEPs required by the Consent Decree. The first such Status Report shall cover the first six-month period after the Effective Date and shall be due within sixty (60) Days after the end of the six-month period. Each subsequent Status Report shall cover a one (1) year period and shall be due within sixty (60) Days after the end of annual period covered. Each Status Report shall contain the following information:

a. The date(s) of replacement of any Dehydrator Flares at compressor stations listed in Appendix 2 of this Decree, as required by Paragraph 13.

b. The date of the replacement of the candlestick flare at the Smith Tee facility, as required by Paragraph 15.

c. The status of the closure of launchers and receivers located at the Drugmand, Stewart Route 50, and Graham Header facilities. If the facility is closed, provide the date the facility ceased operation, as required by Paragraph 17.

d. The date of any SEP Completion Reports submitted under Paragraph 30. Also, identify for which SEP the completion report was submitted.

e. For any new launcher or receiver constructed after the Effective Date but prior to the Termination Date of this Decree, as provided in Paragraph 20, provide the date(s) and location of any:

i. Jumper Lines installed;

ii. Pig Ramps installed;

iii. An explanation for not installing Jumper Lines or Pig Ramps;

iv. Any instances where a Jumper Line was not used prior to opening the hatch;

v. An explanation for not using shorter barrels at high pressure launchers and receivers.

f. For each launcher or receiver subject to the requirements of Paragraphs 12, 14, 18 and 19, provide, as applicable to each specific pig launcher or receiver, the date(s) and locations of:

i. Jumper Lines installed;

ii. Pig Ramps installed; and

iii. Liquid Containment Vessels installed.

g. Copies of each permit application submitted to PADEP pursuant to Paragraph 43.

h. Copies of each permit application or application seeking coverage under a general permit submitted to OEPA pursuant to Paragraphs 45 and 46.

i. Date on which OEPA granted any permit or approval to operate under a general permit in response to applications submitted pursuant to Paragraphs 45 and 46.

j. Date that any Jumper Line was installed pursuant to the requirements of Paragraph 22.

k. Dates that Pig Ramps were installed for each receiver as required by Paragraph 21.

l. Dates that a Mobile Flare was operated as required by Paragraphs 18 and 19.

m. Status update for the HCS and Harmon Creek monitoring SEPs as set forth in Paragraph 28.b. and c. until those SEPs are completed.

59. Maintenance of Consent Decree Records. MarkWest shall maintain records necessary to demonstrate compliance with this Consent Decree.

60. Pigging Event Records. For each pigging event that occurs at a launcher or receiver subject to the requirements of Paragraphs 12, 14, 18, and 19, MarkWest shall maintain records of the following information:

a. Identification number of the launcher or receiver;

b. Location of the launcher or receiver;

c. Date and time of pigging;

d. The launcher or receiver pressure prior to venting to the atmosphere, and prior to routing emissions to a flare, where applicable;

e. Gas composition data representative of the composition of gas at the facility. This data shall be updated at least annually;

f. In the case of pig launchers and receivers identified in Appendices 4 and 5, whether a Mobile Flare was used as required by Paragraphs 18 and 19; and

g. In the case of pig launchers and receivers identified in Appendices 4 and 5, any additional records necessary to demonstrate that the emissions from each launcher and receiver did not exceed the emissions threshold applicable to each launcher and receiver under Paragraphs 18 and 19.

61. Whenever any violation of this Consent Decree, or any other event affecting MarkWest's performance under this Decree, may pose an immediate threat to public health or welfare or the environment, MarkWest shall notify EPA and PADEP orally or by electronic transmission as soon as possible, but no later than 24 hours after MarkWest first knew of the violation or event.

62. All reports pursuant to this Section shall be submitted to the persons designated in Section XVIII of this Consent Decree (Notices).

63. Certification. Each report submitted by MarkWest under this Decree shall be signed by an official of MarkWest and include the following certification:

> I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I have no personal knowledge that the information submitted is other than true, accurate, and complete. I am aware that there are significant

> penalties for submitting false information, including the possibility of fine and imprisonment for knowingly and willfully submitting a material false statement.

This certification requirement does not apply to emergency or similar notifications where compliance would be impractical.

64. The reporting requirements of this Consent Decree do not relieve MarkWest of any reporting obligations required by the Act or implementing regulations, or by any other federal, state, or local law, regulation, permit or requirement.

65. Any information provided pursuant to this Consent Decree may be used by the United States or PADEP in any proceeding to enforce the provisions of this Consent Decree and as otherwise permitted by law.

XII. STIPULATED PENALTIES

66. MarkWest shall be liable for stipulated penalties for violations of this Consent Decree as specified below, unless excused under Section XIII (Force Majeure) of the Decree, or reduced or waived by the United States or the United States and PADEP (in the case of violations at Facilities located in Pennsylvania) pursuant to Paragraph 72. For violations occurring at Facilities in Pennsylvania, stipulated penalties are due to both the United States and PADEP, with fifty percent (50%) of the total amount of stipulated penalties paid to the United States, and fifty percent (50%) to PADEP. For violations occurring at Facilities in Ohio, one hundred percent (100%) of the penalty shall be paid to the United States.

67. Tier 1 Stipulated Penalties. The following stipulated penalties shall accrue per violation per Day for each violation of the following requirements of this Consent Decree: (1) connection of high pressure to low pressure Jumper Lines under Paragraphs 12.a., 14.a., 18.a.,

and 19.a.; (2) use of Jumper Lines before depressurizing under Paragraphs 12.b., 14.b., 18.b., and 19.b; (3) installation of dehydrator flares at Compressor Stations pursuant to Paragraph 13; (4) replacement of the flare at the Smith Tee Stand-Alone Facility under Paragraph 15; (5) operation of the redesigned and modified discharge piping at Loffert (Joe Cain) Pennsylvania Stand-Alone Facility pursuant to Paragraph 16; and (6) closure of pig launchers and receivers at the Drugmand, Stewart Route 50, and Graham Header Stations pursuant to Paragraph 17.

Penalty Per Violation Per Day	Period of Noncompliance
$2,250	1st through 14th Day
$3,500	15th through 30th Day
$5,000	31st Day and beyond.

68. Tier 2 Stipulated Penalties. The following stipulated penalties shall accrue per violation per Day for each violation of each of the following requirements of this Consent Decree: (1) installation and use of Pig Ramps under Paragraphs 12.c., 14.c., 18.c., and 19.c.; and (2) timely submission of Status Reports under Paragraph 58:

Penalty Per Violation Per Day	Period of Noncompliance
$500	1st through 14th Day
$1,000	15th through 30th Day
$1,500	31st Day and beyond.

69. Stipulated Penalties for SEPs. The following stipulated penalties shall accrue per Day for each violation of the following SEP requirements, as set forth in Paragraph 28.a-c. of this Consent Decree: (1) failure to timely submit SEP work plans required by Paragraph 28.b and .c. (2) failure to timely make available on a public website a royalty-free license and/or

information on the Pig Ramp design; (3) failure to timely make available on a public website materials on the effective installation, maintenance, and use of Pig Ramps and Jumper Lines; (4) failure to install the air sampling or meteorological stations at HCS and Harmon Creek as required by Paragraph 28.b. and c.; (5) material failure to operate the monitoring or meteorological stations as required by Paragraph 28.b. and c.; (6) failure to timely provide the meteorological data and/or sampling data as set forth in Paragraph 28.b. and c.; and (7) failure to timely submit a SEP Completion Report pursuant to Paragraph 30:

Penalty Per Day of Violation	Period of Noncompliance
$500	1st through 14th Day
$1,000	15th through 30th Day
$2,500	31st Day and beyond.

70. Stipulated penalties under this Section shall begin to accrue on the Day after performance is due or on the Day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree. The penalties that accrue for each violation or failure to perform an obligation do not increase from one period of noncompliance to the next unless the violations or failures to perform are continuous.

71. MarkWest shall pay stipulated penalties to the United States and PADEP within thirty (30) Days of a written demand by the United States and/or PADEP.

72. Either the United States or PADEP may, in the unreviewable exercise of their respective discretion, reduce or waive stipulated penalties otherwise due them under this Consent Decree.

73. Stipulated penalties shall continue to accrue during any Dispute Resolution, but need not be paid until the following:

a. If the dispute is resolved by agreement or MarkWest does not seek judicial review of EPA's written position provided pursuant to Paragraph 87, MarkWest shall pay the stipulated penalties determined to be owing, together with interest, to the United States and PADEP within thirty (30) Days of the effective date of the agreement or the expiration of Paragraph 88's period for seeking judicial resolution of a dispute.

b. If the dispute is appealed to the Court and the United States and/or PADEP prevail, MarkWest shall pay all penalties determined by the Court to be owing, together with interest, within sixty (60) Days of receiving the Court's decision or order, except if the District Court's decision is appealed, and then as provided in Subparagraph c., below.

c. If any Party appeals the District Court's decision, MarkWest shall pay all penalties determined to be owing by the final decision of the appellate court, together with interest, within thirty (30) Days of receiving the final appellate court decision.

74. If MarkWest fails to pay stipulated penalties according to the terms of this Consent Decree, MarkWest shall be liable for interest on such penalties, as provided in 28 U.S.C. § 1961, accruing from the date payment became due until full payment is made.

75. MarkWest shall pay stipulated penalties owing to the United States in accordance with the procedures for payment of civil penalties specified in Paragraph 25. The transmittal letter required by Paragraph 25 shall specify that the payment is for stipulated penalties.

76. MarkWest shall pay stipulated penalties due under this Consent Decree to PADEP in accordance with the procedures for payment of civil penalties specified in Paragraph 26.

77. The payment of stipulated penalties and interest, if any, shall not alter in any way MarkWest's obligation to complete the performance of the requirements of this Consent Decree.

78. Subject to the provisions of Section XVI (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States and PADEP for MarkWest's violations of this Consent Decree or applicable law. Where a violation of this Decree is also a violation of relevant statutory or regulatory requirements, MarkWest shall be allowed a credit for any stipulated penalties paid against any statutory penalties imposed for such violation under the applicable federal or state requirement.

XIII. FORCE MAJEURE

79. "Force majeure," for purposes of this Consent Decree, is defined as any event arising from a cause or causes beyond the control of MarkWest, of any entity controlled by MarkWest, or of MarkWest's contractors, that delays or prevents the performance of any obligation under this Decree despite MarkWest's best efforts to fulfill the obligation. The requirement that MarkWest exercise "best efforts to fulfill the obligation" includes using reasonable efforts to anticipate any potential force majeure event and best efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred in order to minimize

delay and any adverse effects of the delay to the greatest extent possible. Force majeure does not include MarkWest's financial inability to perform any obligation under this Decree.

80. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree, for which MarkWest intends or may intend to assert a claim of force majeure, MarkWest shall provide notice orally or by electronic transmission within three (3) Days of when MarkWest first knew that the event might cause a delay to the addresses provided in Section XVIII of this Consent Decree (Notices). Within fifteen (15) Days of this initial notification, MarkWest shall provide in writing to EPA and, if the event involves a facility in Pennsylvania, PADEP, to the extent available: an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to mitigate the delay or the effect of the delay; and MarkWest's rationale for attributing such delay to a force majeure event if it intends to assert such a claim. MarkWest shall include with any notice all available documentation necessary to support the claim that the delay was attributable to a force majeure. Any material failure to comply with the above requirements that prejudices EPA's ability to assess MarkWest's claim of force majeure shall preclude MarkWest from asserting any claim of force majeure for that event for the period of time of such failure to comply.

81. If EPA agrees that the delay or anticipated delay is attributable to a force majeure, the time for performance of the obligations under this Consent Decree that are affected by the force majeure event will be extended by EPA for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the force

majeure event shall not, of itself, extend the time for performance of any other obligation. EPA will notify MarkWest in writing of the length of the extension, if any, for performance of the obligations affected by the force majeure.

82. If EPA does not agree that the delay or anticipated delay has been or will be caused by a force majeure event, EPA will notify MarkWest in writing of its decision.

83. If MarkWest elects to invoke the dispute resolution procedures set forth in Section XIV (Dispute Resolution) of this Consent Decree with regard to a force majeure event, it shall do so no later than thirty (30) Days after receipt of EPA's notice. In any such proceeding, MarkWest bears the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a force majeure, that the duration of the delay or the extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that MarkWest complied with the requirements of Paragraphs 79 and 80. If MarkWest carries this burden, the delay at issue shall be deemed not to be a violation of the affected obligation of this Decree.

XIV. DISPUTE RESOLUTION

84. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Section shall be the exclusive mechanism to resolve any dispute arising under or with respect to this Consent Decree.

85. Informal Dispute Resolution. Any dispute subject to dispute resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when MarkWest disputes a decision of the United States and sends the United States and PADEP a written Notice of Dispute. Such Notice of Dispute shall state clearly

the matter in dispute. The period of informal negotiations shall not exceed ninety (90) Days from the date the dispute arises, unless that period is modified by written agreement. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the United States, after consultation with PADEP, shall be considered binding unless, within ninety (90) Days after the conclusion of the informal negotiation period, MarkWest invokes formal dispute resolution procedures as set forth below.

86. Formal Dispute Resolution. MarkWest shall invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph, by serving on the United States and PADEP a written Statement of Position regarding the matter in dispute. The MarkWest Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting MarkWest's position and any supporting documentation relied upon by MarkWest.

87. The United States, after consultation with PADEP, shall serve its Statement of Position within forty-five (45) Days of receipt of MarkWest's Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that position and any supporting documentation relied upon by the United States. The United States' Statement of Position shall be binding on MarkWest unless MarkWest files a motion for judicial review of the dispute in accordance with the following Paragraph.

88. MarkWest may seek judicial review of the dispute by filing with the Court and serving on the United States, in accordance with Section XVIII of this Consent Decree (Notices), a motion requesting judicial resolution of the dispute. The motion must be filed within thirty (30) Days of receipt of the United States' Statement of Position pursuant to the preceding Paragraph.

The motion shall contain a written statement of MarkWest's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

89. The United States shall respond to MarkWest's motion within the time period allowed by the Local Rules of this Court for responses to dispositive motions. MarkWest may file a reply memorandum to the extent permitted by the Local Rules.

90. Standard of Review.

a. Disputes Concerning Matters Accorded Record Review. Except as otherwise provided in this Consent Decree, in any dispute brought under Paragraph 85 and 86 above pertaining to a matter that involves EPA's exercise of discretion under this Consent Decree, MarkWest shall have the burden of proof based on the administrative record (including the Parties' Statements of Position) and the applicable standard of review as set forth in the Administrative Procedure Act, 5 U.S.C. § 500 *et seq*.

b. Other Disputes. Except as otherwise provided in this Consent Decree, in any other dispute brought under Paragraphs 85 and 86 above, MarkWest shall bear the burden of demonstrating that its position complies with this Consent Decree.

91. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of MarkWest under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first day of noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 73 above. If

MarkWest does not prevail on the disputed issue, subject to the Court's order, stipulated penalties shall be assessed and paid as provided in Section XII (Stipulated Penalties).

XV. INFORMATION COLLECTION AND RETENTION

92. The United States and PADEP, and their respective representatives, including attorneys, contractors, and consultants, shall have the right of entry into any facility identified on Appendices 1-6, at all reasonable times, upon presentation of proper credentials, to:

a. monitor the progress of activities required under this Decree;

b. verify any data or information submitted to the United States or PADEP in accordance with the terms of this Decree;

c. obtain samples and, upon request, splits of any samples taken by MarkWest or its representatives, contractors, or consultants related to MarkWest's performance of its obligations under this Decree;

d. obtain documentary evidence, including photographs and similar data; and

e. assess MarkWest's compliance with this Decree.

93. Upon request, MarkWest shall provide EPA, PADEP, or their authorized representatives, splits or duplicates of any samples taken by MarkWest in performing its obligations under this Decree. EPA or PADEP shall provide MarkWest splits of any samples taken by EPA or PADEP or their authorized representatives.

94. Until two (2) years after the termination of this Consent Decree, MarkWest shall retain, and shall instruct its contractors and agents performing work under this Consent Decree to preserve all non-identical copies of all documents, records, or other information (including documents, records, or other information in electronic form) in its or its contractors' or agents'

possession or control, or that come into its or its contractors' or agents' possession or control, and that relate in any manner to MarkWest's performance of its obligations under this Decree. This information-retention requirement shall apply regardless of any contrary corporate or institutional policies or procedures. At any time during this information-retention period, upon request by the United States or PADEP, MarkWest shall provide copies of any non-privileged documents, records, or other non-privileged information required to be maintained under this Paragraph to the United States or PADEP.

95. At the conclusion of the information-retention period provided in the preceding Paragraph, MarkWest shall notify the United States and PADEP at least sixty (60) days prior to the destruction of any records subject to the requirements of this Section and, upon request by the United States or PADEP, MarkWest shall deliver any such documents, records, or other information to EPA and PADEP.

96. MarkWest may assert that certain documents, records, or other information are privileged under the attorney-client privilege or any other privilege recognized by federal law. If MarkWest asserts such a privilege, it shall provide the following: (1) the title of the document, record, or information; (2) the date of the document, record, or information; (3) the name and title of each author of the document, record, or information; (4) the name and title of each addressee and recipient; (5) a description of the subject of the document, record, or information; and (6) the privilege asserted by MarkWest. However, no documents, records, or other information created or generated in order to comply with the requirements of this Consent Decree shall be withheld on grounds of privilege.

97. MarkWest may also assert that information required to be provided under this Section is protected as Confidential Business Information ("CBI") under 40 C.F.R. Part 2 or applicable state law. As to any information that MarkWest seeks to protect as CBI, MarkWest shall follow the procedures set forth in 40 C.F.R. Part 2 or applicable state law.

98. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States or PADEP pursuant to applicable federal or state laws, regulations, or permits, nor does it limit or affect any duty or obligation of MarkWest to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

XVI. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

99. This Consent Decree resolves the civil and administrative claims that the United States may have against MarkWest for the following violations of the Clean Air Act through the date of lodging:

a. With respect to the Pennsylvania Compressor Stations identified on Appendix 1, the Pennsylvania Stand-Alone Facilities (with the exception of Route 18) identified in Appendix 3, and the Drugmand, Stewart Route 50, and Graham Header Stations identified in Paragraph 17, failure to comply with (i) the PSD provisions, 42 U.S.C. §§ 7490-7492; (ii) the NSR provisions, 42 U.S.C. §§ 7501-7515; (iii) the Title V provisions, 42 U.S.C. §§ 7661-7661f; and (iv) provisions of the Pennsylvania SIP implementing Pennsylvania's PSD permitting program, NSR permitting program, Title V permitting program, and Plan Approval and Operating Permit programs;

b. With respect to the Pennsylvania Stand-Alone Facilities identified in Appendix 6 and the Route 18 Stand-Alone Facility identified in Appendix 3, failure to comply with the provisions of the Pennsylvania SIP implementing Pennsylvania's Plan Approval and Operating Permit programs;

c. With respect to the Ohio Compressor Stations identified on Appendix 4, failure to comply with (i) the PSD provisions with respect to VOC, 42 U.S.C. §§ 7490-7492; (ii) the Title V provisions, 42 U.S.C. §§ 7661-7661f; and (iii) the provisions of the Ohio SIP implementing Ohio's Title V operating permit program and Ohio's permit to install and operate program;

d. With respect to the Ohio Stand-Alone Facilities identified in Appendix 5, failure to comply with the provisions of the Ohio SIP implementing Ohio's minor source permit to install and operate program; and

e. With respect to the Ohio Stand-Alone Facilities identified in Appendix 6, failure to comply with the provisions of the Ohio SIP implementing Ohio's minor source permit to install and operate program, and failure to comply with the recordkeeping provisions of the Ohio SIP.

100. This Consent Decree resolves all of PADEP's civil claims against MarkWest pursuant to Sections 9.1 and 13.6(a) of the Air Pollution Control Act ("APCA"), 35 P.S. §§ 4009.1 and 4013.6(a), through the date of lodging for the following violations of the APCA and its implementing regulations:

a. With respect to the Pennsylvania Compressor Stations identified in Appendix 1, the Pennsylvania Stand-Alone Facilities (with the exception of Route 18) identified

in Appendix 3, and the Drugmand, Stewart Route 50, and Graham Header Stations identified in Paragraph 17, failure to comply with (i) the Plan Approval and Operating Permit programs; (ii) the PSD permitting program; (iii) the NSR permitting program; and (iv) the Title V permitting program.

b. With respect to the Pennsylvania Stand-Alone Facilities identified on Appendix 6 and the Route 18 Stand-Alone Facility identified in Appendix 3, failure to comply with the Plan Approval and Operating Permit programs.

101. The United States and PADEP reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree, except as expressly stated in Paragraphs 78, 99 and 100. This Consent Decree does not limit the rights of the United States or PADEP to obtain penalties or injunctive relief under the Act or implementing regulations, or under other federal or state laws, regulations, or permit conditions, except as expressly specified in Paragraphs 99 and 100. The United States and PADEP further retain all legal and equitable remedies to address any imminent and substantial endangerment to the public health or welfare or the environment arising at, or posed by, any MarkWest facility, whether related to the violations addressed in this Decree or otherwise.

102. In any subsequent administrative or judicial proceeding initiated by the United States or PADEP for injunctive relief, civil penalties, or other appropriate relief relating to the facilities subject to this Consent Decree or MarkWest's alleged violations, MarkWest shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States or PADEP in the

subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraphs 99 and 100.

103. This Consent Decree is not a permit, or a modification of any permit, under any federal, state, or local laws or regulations. MarkWest is responsible for achieving and maintaining complete compliance with all applicable federal, state, and local laws, regulations, and permits; and MarkWest's compliance with this Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States and PADEP do not, by their consent to the entry of this Decree, warrant or aver in any manner that MarkWest's compliance with any aspect of this Decree will result in compliance with provisions of the Act, the APCA, or with any other provisions of federal, state, or local laws, regulations, or permits.

104. This Consent Decree does not limit or affect the rights of MarkWest, of the United States, or of PADEP against any third parties not party to this Decree, nor does it limit the rights of third parties not party to this Decree against MarkWest, except as otherwise provided by law.

105. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not party to this Decree.

106. MarkWest expressly denies and does not admit any liability to the United States or PADEP arising out of the conduct, transactions or occurrences alleged in the Complaint. Nothing in this Consent Decree shall be construed as an admission of MarkWest's liability, nor shall MarkWest's performance of any obligation under this Decree be considered any admission

of liability. This Consent Decree shall not be admissible against MarkWest in any administrative or judicial proceeding, except in a proceeding initiated by the Parties to enforce this Decree.

XVII. COSTS

107. The Parties shall bear their own costs of this action, including attorneys' fees, except that the United States and PADEP shall be entitled to collect the costs (including attorneys' fees) incurred in any action necessary to collect any portion of the civil penalty or any stipulated penalties due, but not paid, by MarkWest.

XVIII. NOTICES

108. Unless otherwise specified herein, whenever notifications, submissions, statements of position, or communications are required by this Consent Decree (referred in this Paragraph as a "notice" or "notices"), they shall be made electronically as described below, unless such notices are unable to be uploaded to the CDX electronic system (in the case of EPA) or transmitted by email (in the case of any other party). For all notices to EPA, MarkWest shall register for the CDX electronic system and upload such notices at https://cdx.epa.gov/epa_home.asp. Any notice that cannot be uploaded or electronically transmitted via email shall be provided in writing to the addresses below:

As to the United States by email:	eescdcopy.enrd@usdoj.gov Re: DJ# 90-5-2-1-11374
As to the United States by mail:	EES Case Management Unit Environment and Natural Resources Division U.S. Department of Justice Box 7611 Ben Franklin Station Washington, D.C. 20044-7611 Re: DOJ No. 90-5-2-1-11374

As to EPA:

Director, Air Enforcement Division
Office of Civil Enforcement
U.S. EPA Headquarters, MC 2242A
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

And

For notices relating to Ohio facilities:

U.S. EPA Region V
77 W. Jackson Boulevard
Chicago, IL 60604
Attn: Compliance Tracker
R5airenforcement@epa.gov

And

For notices relating to Pennsylvania facilities:

Director, Air Enforcement
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19103

As to PADEP:

Mark R. Gorog, P.E.
Regional Manager
Department of Environmental Protection
Air Quality Program
Southwest Regional Office
400 Waterfront Drive
Pittsburgh, PA 15222
Phone: 412.442.4150
Fax: 412.442.4194
mgorog@pa.gov

And

Lori McNabb
Environmental Group Manager
Department of Environmental Protection – Field Operations
Air Quality Program

Northwest Regional Office
230 Chestnut Street
Meadville, PA 16335
Phone: 814.332.6634
Fax: 814.332.6121
lmcnabb@pa.gov

As to MarkWest:

General Counsel
MPLX LP
200 East Hardin Street
Findlay, Ohio 45840
lawdepartment.notices@markwest.com

Managing Counsel – Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Christopher.rimkus@markwest.com

And

Environmental Director – Northeast Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Robert.mchale@markwest.com

109. Any Party may, by written notice to the other Parties, change its designated notice recipient or notice address provided above.

110. Notices submitted pursuant to this Section shall be deemed submitted upon electronic transmission or mailing, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

XIX. EFFECTIVE DATE

111. The Effective Date of this Consent Decree is the date upon which this Consent Decree is entered by the Court or a motion to enter the Decree is granted, whichever is first, as recorded by the Court's docket.

XX. RETENTION OF JURISDICTION

112. The Court shall retain jurisdiction over this case, until termination of this Consent Decree pursuant to Section XXII (Termination), for the purpose of (a) resolving disputes arising under this Decree pursuant to Section XIV (Dispute Resolution), (b) entering orders modifying this Decree pursuant to Section XXI (Modification), or (c) effectuating or enforcing compliance with the terms of this Decree.

XXI. MODIFICATION

113. The terms of this Decree, including any attached appendices, may be modified only by a subsequent written agreement signed by all the Parties. Where the modification constitutes a material change to this Decree, it shall be effective only upon approval by the Court.

114. Any disputes concerning modification of this Consent Decree shall be resolved pursuant to Section XIV (Dispute Resolution). The Party seeking the modification bears the burden of demonstrating that it is entitled to the requested modification in accordance with Federal Rule of Civil Procedure 60(b).

XXII. TERMINATION

115. After MarkWest has fulfilled its obligations to (a) pay the civil penalty in Paragraph 24, (b) implement all injunctive relief, (c) obtain permits pursuant to Section VIII (Permits); (d) implement the Third Party Verification program and submit a satisfactory Third-Party Audit Report; (e) complete all SEPs, (f) complete the Commonwealth-only Community Environmental Project, and (g) pay any stipulated penalties not waived or reduced by the United States or PADEP under Section XII (Stipulated Penalties) pursuant to Paragraph 72, MarkWest

may send to the United States and PADEP a Request for Termination, which shall be certified in accordance with Paragraph 63, stating that MarkWest has satisfied those requirements, together with all reasonably necessary supporting documentation.

116. Following receipt by the United States and PADEP of MarkWest's Request for Termination, the Parties shall confer informally concerning the Request and any disagreement that the Parties may have as to whether MarkWest has satisfactorily complied with the requirements for termination of this Consent Decree. If the United States, after consultation with PADEP, agrees that the Decree may be terminated, the Parties shall submit for the Court's approval a joint stipulation terminating the Decree.

117. If the United States, after consultation with PADEP, does not agree that the Decree may be terminated, MarkWest may invoke Dispute Resolution under Section XIV of this Decree (Dispute Resolution). However, MarkWest shall not seek Dispute Resolution of any dispute regarding termination until sixty (60) Days after service of its Request for Termination.

XXIII. PUBLIC PARTICIPATION

118. This Consent Decree will be lodged with the Court for a period of not less than thirty (30) Days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding the Consent Decree disclose facts or considerations indicating that the Decree is inappropriate, improper, or inadequate. MarkWest consents to entry of this Decree without modification without further notice and agrees not to withdraw from or oppose entry of this Decree by the Court or to challenge any provision of the Decree, unless the United States has notified MarkWest in writing that it no longer supports entry of the Decree or has modified the Decree.

XXIV. SIGNATORIES/SERVICE

119. Each undersigned representative of MarkWest, PADEP, and the Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

120. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis.

121. MarkWest agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree. MarkWest agrees to accept service in that manner and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons. MarkWest need not file an answer to the Complaint in this action unless or until the Court expressly declines to enter this Decree.

XXV. INTEGRATION

122. This Consent Decree and its Appendices constitute the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Decree. There are no representations, agreements, or understandings relating to the settlement other than those expressly contained in this Consent Decree.

XXVI. FINAL JUDGMENT

123. Upon approval and entry of this Consent Decree by the Court, this Decree shall constitute a final judgment of the Court as to the United States, PADEP, and MarkWest under Fed. R. Civ. P. 54 and 58.

XXVII. 26 U.S.C. SECTION 162(f)(2)(A)(ii) IDENTIFICATION

124. For purposes of the identification requirement of Section 162(f)(2)(A)(ii) of the Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), performance of Section II (Applicability), Paragraph 8, Section IV (Injunctive Relief), Paragraphs 11 – 23, Section VIII (Permits), Paragraphs 43 - 46, Section X (Third Party Verification), Paragraphs 49 – 54, Section XI (Recordkeeping and Reporting), Paragraphs 58(a)-(c) and (e) – (l), 59 – 60, and 62 – 63, and Section XIV (Information Collection and Retention), Paragraphs 92 - 95, is restitution or required to come into compliance with law.

XXVIII. APPENDICES

125. The following appendices are attached to and part of this Consent Decree:

"Appendix 1" is a list of MarkWest compressor stations in Pennsylvania subject to Paragraph 12;

"Appendix 2" is a list of MarkWest compressor stations in Pennsylvania subject to Paragraph 13;

"Appendix 3" is a list of MarkWest Stand-Alone Facilities in Pennsylvania subject to Paragraph 14;

"Appendix 4" is a list of MarkWest Compressor Stations, and specific launchers and receivers at each of those Compressor Stations, in Ohio subject to Paragraph 18;

"Appendix 5" is a list of MarkWest Stand-Alone Facilities, and specific launchers and receivers at each of those Stand-Alone Facilities, in Ohio subject to Paragraph 19;

"Appendix 6" is a list of MarkWest Stand-Alone Facilities in Pennsylvania and in Ohio subject, as applicable, to Paragraphs 21 and 23;

"Appendix 7" is the Humphreys Ambient Air Monitoring SEP for the Humphreys Compressor Station in Ohio; and

"Appendix 8" is the Harmon Creek Ambient Air Monitoring SEP for the Harmon Creek Gas Processing Plant in Pennsylvania.

Dated and entered this _____ day of _____, 2018.

_____

UNITED STATES DISTRICT JUDGE
Western District of Pennsylvania

THE UNDERSIGNED PARTY enters this Consent Decree in this action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR PLAINTIFF UNITED STATES OF AMERICA:

Date: 4/20/18

[redacted]

JEFFREY H. WOOD
Acting Assistant Attorney General
Environment & Natural Resources Division
United States Department of Justice
950 Pennsylvania Avenue, NW
Washington, DC 20530

Date: 4/20/18

[redacted]

MARK C. ELMER
Senior Counsel
Environmental Enforcement Section
Environment & Natural Resources Division
United States Department of Justice
999 18th Street, South Terraces, Suite 370
Denver, Colorado 80202

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY:

Date: April 16, 2018

[redacted]
ROSEMARIE KELLEY
Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC 20460

Date: April 16, 2018

[redacted]
APPLE CHAPMAN
Deputy Director, Air Enforcement Division
Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC 20460

Date: April 16, 2018

[redacted]
KATHRYN PIRROTTA CABALLERO
Senior Attorney, Air Enforcement Division
Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC 20460

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 3:

4/16/2018
Date

[redacted]
COSMO SERVIDIO
Regional Administrator
United States Environmental Protection Agency, Region III

4/15/18
Date

[redacted]
MARY B. COE
Regional Counsel
Office of Regional Counsel
United States Environmental Protection Agency, Region III
Philadelphia, PA 19103

4/16/18
Date

[redacted]
DOUGLAS J. SNYDER
Assistant Regional Counsel
Office of Regional Counsel
United States Environmental Protection Agency, Region III
Philadelphia, PA 19103

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 5:

4/19/2018
Date

[redacted]

T. LEVERETT NELSON
Regional Counsel
Office of Regional Counsel
United States Environmental Protection
Agency, Region V
Chicago, IL 60604

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR PLAINTIFF COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION:

4/11/18
Date

[redacted]
GEORGE HARTENSTEIN
Deputy Secretary for Waste Air
Radiation and Remediation
Department of Environmental Protection
Rachel Carson State Office Building
400 Market Street
Harrisburg, PA 17101

Ap. 14, 2018
Date

[redacted]
ALEXANDRA C. CHIARUTTINI
Chief Counsel
Department of Environmental Protection
Rachel Carson State Office Building
400 Market Street
Harrisburg, PA 17101

April 19, 2018
Date

[redacted]
MICHAEL J. HEILMAN
Assistant Regional Counsel
Department of Environmental Protection
Office of Chief Counsel
400 Waterfront Drive
Pittsburgh, PA 15222

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR DEFENDANT MARKWEST LIBERTY MIDSTREAM & RESOURCES, L.L.C.

Date: April 13, 2018

[redacted]

MICHAEL J. HENNIGAN
President
MarkWest Liberty Midstream & Resources, L.L.C.

FOR DEFENDANT OHIO GATHERING COMPANY, L.L.C.

Date: April 13, 2018

[redacted]

MICHAEL J. HENNIGAN
President
Ohio Gathering Company, L.L.C.

APPENDIX 1

Pennsylvania Compressor Stations Subject to Paragraph 12

Compressor Station	Coordinates
1. 3 Brothers	40.33119792490, -80.38033471710
2. Baker	40.08051389, -80.222575
3. Brigich	40.28964213860, -80.23951772010
4. Carpenter	40.11364210760, -80.48247261960
5. Dryer	40.24287923210, -80.46833245070
6. Fulton	40.28485243400, -80.30122700440
7. Godwin	40.24572395910, -80.31131155010
8. Hoskins	40.17991189320, -80.41232597640
9. Johnston	40.27515606030, -80.23270970570
10. Lowry	40.24932187010, -80.36840279130
11. Redd	40.14328889, -80.19907778
12. Royal Oak	40.76560317060, -80.03657298740
13. Shaw	40.23917195340, -80.28146975710

Compressor Station	Coordinates
14. Smith	40.41698982380, -80.35687488560
15. Stewart	40.28269070850, -80.34980728680
16. Trillith	40.85454091700, -80.10256057730
17. Tupta Day	40.11326944, -80.22364167
18. Voll	40.83941511830, -80.05602366480
19. Welling	40.19014693410, -80.35981800720

Appendix 2

Pennsylvania Compressor Stations Subject to Paragraph 13

Compressor Station	Coordinates
1. 3 Brothers	40.33119792490, -80.38033471710
2. Carpenter	40.11364210760, -80.48247261960
3. Royal Oak	40.76560317060, -80.03657298740
4. Smith	40.41698982380, -80.35687488560
5. Trillith	40.85454091700, -80.10256057730
6. Welling	40.19014693410, -80.35981800720

Appendix 3

Applicability of Injunctive Relief in Paragraph 14 to Launchers and Receivers at Pennsylvania Stand-Alone Facilities

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
1. Huntington Farms			40.24179301380, -80.31836096160
a. Godwin to Huntington Farms HP Receiver	Yes	Yes	
b. Huntington Farms to Houston HP Launcher	Yes	No	
c. Huntington Farms to Welling HP Launcher	Yes	No	
d. Huntington Farms to Shaw HP Launcher	Yes	No	
e. Lowry to Huntington Farms HP Receiver	Yes	Yes	
f. Lowry Meter to Huntington Farms LP Receiver	No	Yes	

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
2. Loffert (Joe Cain)			40.35937332930, -80.31124654080
a. 3 Bros to Loffert (Joe Cain) HP Receiver	Yes	Yes	
b. Loffert (Joe Cain) to Drugmand HP Launcher	Yes	No	
c. Smith to Loffert (Joe Cain) HP Receiver	Yes	Yes	
d. Airport to Loffert (Joe Cain) LP Receiver	No	Yes	
e. Malinky LP Receiver	No	Yes	
3. Post Road			40.16793683830, -80.39937478710
a. Hoskins to Post Road HP Receiver	No	Yes	
4. Route 18			40.33220420730, -80.36049705900
a. Stewart to Rt 18 HP Receiver	No	Yes	

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
b. Carns to Rt 18 LP Receiver	No	Yes	
c. Inches to Rt 18 LP Receiver	No	Yes	
5. Smith Tee			40.22352411360, -80.45690851150
a. Dryer to Smith Tee HP Receiver	No	Yes	
b. Smith Tee to Hoskins HP Launcher	No	No	
c. Smith Tee to Lowry HP Launcher	No	No	
6. Wilhelm			40.10854085660, -80.44762638940
a. Welling to Wilhelm HP Receiver	Yes	Yes	
b. Wilhelm to Carpenter HP Receiver	Yes	Yes	
c. Wilhelm to Majorsville HP Launcher	Yes	No	

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
d. Claysville to Wilhelm LP Receiver	No	Yes	
e. Greathouse to Wilhelm LP Receiver	No	Yes	
f. Hamilton to Wilhelm LP Receiver	No	Yes	

Appendix 4

Applicability of Injunctive Relief in Paragraph 18 to Launchers and Receivers at Ohio Compressor Stations

Compressor Station	¶ 18.a.-b. Apply? (Install and Use Jumper Line)	¶ 18.c. Applies? (Install and Use Pig Ramp)	¶ 18.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
1. Arrowhead				40.175580, -81.073237
a. 70T to Arrowhead HP Receiver	Yes	Yes	Yes	
b. Arrowhead to Cadiz Launcher	Yes	No	Yes	
c. Wagner to Arrowhead Receiver	No	Yes	No	
d. Darla to Arrowhead Receiver	No	Yes	No	
e. Miller Road to Arrowhead Receiver	No	Yes	No	
2. Barnesville West				40.009219, -81.181596
a. Barnesville West 12” Launcher	Yes	No	Yes	
b. Magee to Barnesville West Receiver	No	Yes	No	
c. 70T to Barnesville West Receiver	No	Yes	No	
3. Harrison West				40.209936, -81.217978
a. Harrison West to Cadiz Launcher	Yes	No	Yes	
b. Scott Hill to Harrison West Receiver	No	Yes	No	
c. Clay 20” Receiver	No	Yes	No	
4. Humphreys				39.906906, -81.188574
a. Humphreys to Tri-County Launcher	Yes	No	Yes	
b. Wheatley to Humphreys Receiver	No	Yes	Yes	

Compressor Station	¶ 18.a.-b. Apply? (Install and Use Jumper Line)	¶ 18.c. Applies? (Install and Use Pig Ramp)	¶ 18.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
c. Stronz Receiver	No	Yes	No	
d. Stuzman Receiver	No	Yes	No	
5. Lake				40.278232, -81.181580
a. Lake to Cadiz Launcher	Yes	No	Yes	
b. Central to Lake Receiver	No	Yes	No	
c. Kinsey Receiver	No	Yes	No	
d. Boy Scout Receiver	No	Yes	No	
6. Morristown				40.058737, -81.096102
a. Morristown 12” Launcher	Yes	No	Yes	
b. Morristown 20” Receiver	No	Yes	No	
7. Tri-County				39.939357, -81.227774
a. Shannon to Tri-County Receiver	Yes	Yes	Yes	
b. Tri-County to Seneca Launcher	Yes	No	Yes	
c. Tri-County to McCort 20” Launcher	No	No	Yes	
d. Humphreys to Tri-County Receiver	Yes	Yes	Yes	
e. Tri-County to Magee Launcher	No	No	Yes	

Appendix 5

Applicability of Injunctive Relief in Paragraph 19 to Launchers and Receivers at Stand-Alone Facilities in Ohio

Stand-Alone Facility	¶ 19.a.-b. Apply? (Install and Use Jumper Line)	¶ 19.c. Applies? (Install Pig Ramp)	¶ 19.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
1. 70T				40.047342, -81.143914
a. Shannon to 70T Receiver	Yes	Yes	Yes	
b. 70T to Arrowhead Launcher	Yes	No	Yes	
c. Morristown 12" Receiver	Yes	Yes	Yes	
2. 513 Station				40.002087, -81.301192
a. 513 to Magee Launcher	No	No	Yes	
b. Neff Receiver	No	Yes	Yes	
c. Flesher Receiver	No	Yes	Yes	
3. BK Stevens Station				40.195014, -81.172019
a. BK Stevens Launcher	No	No	Yes	
b. Michael 12" Receiver	No	Yes	No	
4. Blaze Station				40.109623, -81.296475
c. Blaze Road Launcher	No	No	Yes	
d. Lawson Receiver	No	Yes	No	
5. Marshall Road Station				40.109600, -81.333299
a. Guernsey 20" Launcher	No	No	Yes	
b. Blaze Road Receiver	No	Yes	Yes	
c. Guernsey 12" Receiver	No	Yes	No	
6. Smyrna McClelland Station				40.199200, -81.245391
a. Guernsey 20" Receiver	No	Yes	Yes	
b. Clay 12" Receiver	No	Yes	No	
c. Clay 20" Launcher	No	No	No	
7. Boston McCort Receiver Station				39.921722, -81.207956
a. McCort to Wheatley	No	No	Yes	

Stand-Alone Facility	¶ 19.a.-b. Apply? (Install and Use Jumper Line)	¶ 19.c. Applies? (Install Pig Ramp)	¶ 19.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
Launcher				
b. Tri-County to McCort 20" Receiver	No	Yes	Yes	
c. McCort 12" Receiver	No	Yes	No	
8. McGee Station				39.945758, -81.234022
a. 513 to McGee Receiver	No	Yes	Yes	
b. McGee to Barnsville West Launcher	No	No	Yes	
c. Tri-County to McGee Receiver	No	Yes	Yes	
d. Brothers Receiver	No	Yes	No	
9. Neff Station				39.994326, -81.385291
a. Neff Launcher	No	No	Yes	
b. Shugert Daddy Receiver	No	Yes	No	
c. Onega Receiver	No	Yes	No	
d. Detweiler Receiver	No	Yes	No	
10. Oxford Siefert Station				40.028938, -81.305076
a. Flesher Launcher	No	No	Yes	
b. Karen Receiver	No	Yes	No	
11. Shannon				40.015606, -81.191986
a. Shannon to Tri-County Receiver	Yes	Yes	Yes	
b. Shannon to 70T Launcher	Yes	No	Yes	
Barnesville West 12" Receiver	Yes	Yes	Yes	
12. Scott Hill Station				40.213707, -81.199295
a. Scott Hill to Harrison West Launcher	No	No	No	

Stand-Alone Facility	¶ 19.a.-b. Apply? (Install and Use Jumper Line)	¶ 19.c. Applies? (Install Pig Ramp)	¶ 19.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
b. BK Stevens Receiver	No	Yes	No	
c. Scott Hill to Yoder Launcher	No	No	No	
13. Wheatley Station				39.910131, -81.201674
a. McCort to Wheatley Receiver	No	Yes	Yes	
b. Wheatley to Humphreys Launcher	No	No	Yes	

Appendix 6

Pennsylvania and Ohio Stand-Alone Facilities Subject to Paragraph 21

Pennsylvania

	Stand-Alone Facility	Coordinates	
1.	Airport L/R Site	40.37395927760,	-80.30305865130
2.	Amwell Meter Site	40.14614613440,	-80.20302966240
3.	Best Site L/R Site	40.23147156770,	-80.33893228910
4.	Brenckle Header	40.84400668670,	-80.01438657980
5.	Bowen Rd L/R Site	40.35620228600,	-80.29091780790
6.	Drugmand L/R Site	40.32121915270,	-80.30277507650
7.	Meter Site Greco	40.09104915880,	-80.20974335020
8.	Houston National Fuel M&R Site	40.24940452070,	-80.34876507660
9.	Lowry Meter Station & L/R Site	40.24942497510,	-80.34873637460
10.	Mounts Road L/R Site	40.13289991020,	-80.31682797040
11.	Hoskins L/R Station	40.24945714620,	-80.26379790300
12.	Patterson Rd (Avella) L/R Site	40.27381420040,	-80.42744742360
13.	ROW Bame	40.81714493130,	-80.08961472930
14.	ROW Bare	40.41178582760,	-80.35589611000
15.	ROW Behm	40.79583936330,	-80.04148611180
16.	ROW Best	40.23164739230,	-80.33641676650
17.	ROW Breakneck	40.77764731670,	-80.08564275290
18.	Claysville Taylorstown Rd L/R Site	40.14849469170,	-80.40984054650

	Stand-Alone Facility	Coordinates	
19.	Fallen Timber Rd L/R Site	40.27072933350,	-80.49157469860
20.	Hillcrest Ln L/R Site	40.21167059680,	-80.34995610710
21.	Scenic Dr (Chase) L/R Site	40.19905575650,	-80.44969751100
22.	Fox Road (Cravat Coal) L/R Site	40.20519747190,	-80.42570011420
23.	Oakleaf Rd L/R Site	40.25409971610,	-80.37131701950
24.	Lynn Portal Rd L/R Site	40.25874697060,	-80.36964903040
25.	Grimes L/R Site	40.13299991620,	-80.43109470140
26.	McGowan Rd L/R Site	40.14279324820,	-80.22140131220
27.	Buck Run Rd L/R Site	40.18536844860,	-80.44308026640
28.	Brush Run Rd L/R Site	40.20720289960,	-80.37080643150
29.	Scenic Dr (Falconi) L/R Site	40.26595604250,	-80.46084767610
30.	Deerfield Rd L/R Site	40.11630590800,	-80.27285940870
31.	ROW Hamilton	40.85929594380,	-80.14286462350
32.	Pleasant Valley Rd (Hanes) L/R Site	40.16377825080,	-80.34140927220
33.	Buck Run Rd (Hercules) L/R Site	40.13837364120,	-80.42497159930
34.	Toll Gate Rd L/R Site	40.10314260290,	-80.46782350840
35.	ROW JRGL	40.84398338570,	-80.10487271690
36.	Hackney Station Rd L/R Site	40.03182652570,	-80.21131940660
37.	Valleyview Rd L/R Site	40.40304581570,	-80.33243646710
38.	Sugar Run Rd	40.23188521750,	-80.47933489330
39.	Meddings Rd (Little) L/R Site	40.26507985420,	-80.23774634660

	Stand-Alone Facility	Coordinates	
40.	ROW LL Property	40.84029348320,	-80.08598831230
41.	Walker Rd L/R Site	40.35085903180,	-80.42689905960
42.	Strope Rd L/R Site	40.33513883610,	-80.44326981090
43.	Nickolay Rd L/R Site	40.30167354440,	-80.40734222390
44.	McMaster L/R Site	40.31124638210,	-80.30097450590
45.	Caldwell Rd L/R Site	40.28261382140,	-80.35555972230
46.	ROW Pallack	40.85004087970,	-80.08157787530
47.	ROW Parees	40.38722027540,	-80.30502008320
48.	Scenic Dr (Pete Zappi) L/R Site	40.20364205010,	-80.44809086520
49.	McAdams Rd (Phelan) L/R Site	40.09539268620,	-80.22951699520
50.	Carns Lane L/R Site	40.32423905170,	-80.36576671750
51.	ROW Powell	40.74363745330,	-79.9604929242(
52.	Patterson Rd (R. Margaria) L/R Site	40.28723537050,	-80.43589296710
53.	Agape Rd (Rukavina) L/R Site	40.26725418690,	-80.36329205560
54.	Fox Rd (Rush) L/R Site	40.22866432510,	-80.42395307960
55.	Patterson Ln (L/R) Site	40.22064084750,	-80.33797828550
56.	Joffre Cherry Valley Rd L/R Site	40.35359238190,	-80.33301815770
57.	ROW Schilling	40.75341364380,	-79.99506226040
58.	Dille Rd (Strawn) L/R Site	40.04603091090,	-80.24107217480
59.	ROW Varner	40.17378970270,	-80.46539519780
60.	Lynn Rd L/R Site	40.22840547500,	-80.32462392150

	Stand-Alone Facility	Coordinates	
61.	ROW Warner	40.84397086940,	-80.11171987180
62.	ROW West	40.75104115670,	-79.97716026150
63.	Dille Rd (Whitmer) L/R Site	40.04048742890,	-80.23640364280
64.	Sharp Meter Site (Ridge Ave L/R Site)	40.26769369990,	-80.21010761160
65.	Swain Hill	40.81898776310,	-80.08484177090
66.	Temple T L/R Site	40.22417625130,	-80.44906886280
67.	Agape Rd (Triple) L/R Site	40.26804165920,	-80.36563975230
68.	Well Pad Bare	40.40342650950,	-80.37723290090
69.	Well Pad Behm	40.79672204020,	-80.03451440360
70.	Well Pad BNBC	40.77079850210,	-80.10355358670
71.	Well Pad Breakneck	40.77075318260,	-80.10355581720
72.	Well Pad Burgh	40.87569389260,	-80.12625895460
73.	Well Pad Carol Baker	40.23009012030,	-80.27796334060
74.	Well Pad Carson B	40.84625933330,	-80.03219656250
75.	Well Pad Chase	40.20175530230,	-80.46770417890
76.	Durkacs L/R Site	40.283977778,	-80.229130555
77.	Well Pad Eleanor West	40.20710177410,	-80.38557015700
78.	Well Pad Ferree	40.72843685230,	-79.90603378450
79.	Well Pad Franklin 2	40.14094073750,	-80.26221722840
80.	Well Pad Gilliland	40.84241439010,	-80.03392781810
81.	Well Pad John Miller	40.21521587750,	-80.31559765760

Stand-Alone Facility		Coordinates	
82.	Well Pad Kraeer	40.21816609360,	-80.45752184520
83.	Well Pad Lynn	40.82164973840,	-79.96377223130
84.	Well Pad MCC	40.34397056500,	-80.43256951140
85.	Well Pad McElhinney	40.77986241940,	-80.01889964030
86.	Well Pad Meyer	40.77357077330,	-80.08385907690
87.	Well Pad Midler A	40.29650600530,	-80.41270793020
88.	Well Pad Paxton	40.25621631280,	-80.24725325410
89.	Well Pad Plesniak	40.87216680500,	-80.08007954920
90.	Well Pad Pollana	40.30559829300,	-80.36009428140
91.	Well Pad R. Margaria	40.28531146480,	-80.43233486240
92.	Well Pad Stebbins	40.79463038620,	-79.96722033100
93.	Well Pad Stefkovich	40.27733921230,	-80.45377227360
94.	Well Pad Talarico	40.79264245230,	-80.08005861390
95.	Well Pad Worstell	40.27474883780,	-80.21630888150
96.	Well Pad Aloe	40.36361111,	-80.2692444
97.	Well Pad Imperial East	40.38121944,	-80.25612778
98.	Well Pad Imperial North	40.3847611,	-80.27874444
99.	Well Pad Charelli	40.3543667,	-80.28129722
100.	Well Pad Drugmand	40.32065,	-80.3023578
101.	Well Pad Franklin 1	40.15145556,	-80.25371667
102.	Well Pad June Hoskins	40.24821111,	-80.2627001

Stand-Alone Facility		Coordinates	
103.	Well Pads Wylie	40.26177222,	-80.27190833
104.	Well Pad Avella Lands	40.27136944,	-80.43052778
105.	Well Pad Breese	40.14353611,	-80.39037778
106.	Well Pad Campbell	40.27816389,	-80.48513611
107.	Well Pad Chappel	40.21136111,	-80.35252778
108.	Well Pad Cravit Coal	40.20503611,	-80.42930833
109.	Well Pad CC 41-44	40.25441944,	-80.37799167
110.	Well Pad CC 6-9, 25	40.25972778,	-80.38564167
111.	Well Pad Old McDonald	40.12071111,	-80.43345013
112.	Well Pad Earl Redd	40.14277778,	-80.22141111
113.	Well Pad Falconi	40.26966389,	-80.50097221
114.	Well Pad Folly Hollow	40.11380833,	-80.26863056
115.	Well Pad Georgetti	40.24512222,	-80.48410833
116.	Well Pad McAdoo	40.21458333,	-80.49498056
117.	Well Pad Goettle	40.23987778,	-80.46559444
118.	Well Pad Kennedy	40.23206389,	-80.48385556
119.	Well Pad Hanes	40.16891944,	-80.35004722
120.	Well Pad Hercules	40.14573611,	-80.42516944
121.	Well Pad Hunter	40.09600278,	-80.47336945
122.	Well Pad Kearny	40.02977222,	-80.21465833
123.	Well Pad Kendall	40.40645556,	-80.32643333
124.	Well Pad MCC West	40.33761389,	-80.44501944

Stand-Alone Facility		Coordinates	
125.	Well Pad McIntyre	40.29370278,	-80.39157778
126.	Well Pad Minichi	40.30496389,	-80.32689444
127.	Well Pad McMasters	40.31078056,	-80.30234722
128.	Well Pad Ohio Valley	40.27660556,	-80.34920833
129.	Well Pad Johnston	40.27631389,	-80.23965278
130.	Well Pad Painter	40.27277222,	-80.25871111
131.	Well Pad Parees	40.39088611,	-80.299152778
132.	Well Pad Pete Zappi	40.20325556,	-80.44185833
133.	Well Pad Phelan	40.09114722,	-80.24646389
134.	Well Pad Rukavina	40.26523333,	-80.36197501
135.	Well Pad Rush	40.22270556,	-80.41881111
136.	Well Pad R. Carslise	40.21708056,	-80.33216389
137.	Well Pad Sasso	40.36851111,	-80.35763889
138.	Well Pad Strawn	40.04582222,	-80.25218888
139.	Well Pad Varner	40.172416667,	-80.46723056
140.	Varner to E. Zappi Launcher	40.17558889,	-80.46682503
141.	Well Pad Ward	40.22967003,	-80.32365278
142.	Well Pad Whitmer	40.02379167,	-80.24307502
143.	Well Pad Costanzo	40.26727222,	-80.35452778
144.	Well Pad Yanavich	40.21778333,	-80.26991667
145.	Well Pad Dorothy Green	40.19993611,	-80.47827501
146.	Well Pad Troyer Farms	40.28809722,	-80.21635833

Stand-Alone Facility		Coordinates	
147.	Well Pad Khouri	40.20993889,	-80.40015015
148.	Well Pad Kopko	40.21137778,	-80.29239724
149.	Well Pad Kraeer West	40.21553333,	-80.46209722
150.	Well Pad Carnes Donald	40.28363889,	-80.38654723
151.	Well Pad Lehman	40.29895555,	-80.37828333
152.	Well Pad Kancel	40.28785556,	-80.41620278
153.	Well Pad W. Cowden	40.30847503,	-80.37043611
154.	Well Pad CC 17-19, 45-47	40.26315002,	-80.40854722
155.	Well Pad Photon	40.26468333,	-80.21717505
156.	Well Pad L. Smith	40.12773611,	-80.34577801
157.	ROW L. Smith L/R	40.11939442,	-80.34563611
158.	Well Pad A&D Ferguson	40.29096667,	-80.24841667
159.	Well Pad Engle	40.30635278,	-80.23452504
160.	Well Pad Bloom	40.84400691,	-80.01438658
161.	Well Pad Bricker	40.85586944,	-80.02126111
162.	Well Pad Graham	40.83919444,	-80.05586667
163.	Well Pad Shipley	40.82048333,	-80.00895556
164.	Well Pad Ballie Trust	40.76065556,	-80.08748065
165.	Well Pad Lamperski	40.80330833,	-80.02951111
166.	Well Pad R. Knauf	40.80346111,	-80.06258889
167.	Well Pad Burr-Brennan	40.87219167,	-80.04880833
168.	Well Pad Ceasar	40.88700833,	-80.09868889

Stand-Alone Facility		Coordinates	
169.	Well Pad Flinner	40.89144167,	-80.07206667
170.	Well Pad Hamilton	40.85896944,	-80.14835005
171.	Well Pad L&L Properties	40.83417502,	-80.08932503
172.	Well Pad Pallack	40.85868333,	-80.09930556
173.	Well Pad Schilling	40.75428334,	-79.99429722
174.	Well Pad Reno	40.73497781,	-79.89145278
175.	Well Pad West	40.74006111,	-79.99027503
176.	Well Pad R. Double	40.79726112,	-80.08143056
177.	Well Pad JRGL	40.81681389,	-80.12953611
178.	Well Pad Powell	40.76466944,	-79.94619167
179.	Well Pad Perry	40.87980556,	-80.18103611
180.	Well Pad Warner	40.84784722,	-80.11418333
181.	Well Pad Bell	40.76255556,	-80.13437222
182.	Well Pad Bame	40.80087222,	-80.09644278
183.	Well Pad Alex Paris	40.29338333,	-80.46162222
184.	Well Pad Bedillion Day	40.11590833,	-80.22677222
185.	Well Pad Bigley	40.13135833,	-80.18826388
186.	Well Pad Burkett	40.32740555,	-80.45561111
187.	Well Pad Carns	40.32583888,	-80.37212777
188.	Well Pad Clingerman	40.25311388,	-80.32005833
189.	Well Pad Farabee	40.06371666,	-80.20518888
190.	Well Pad Gillett	40.18281666,	-80.36071067

Stand-Alone Facility		Coordinates	
191.	Well Pad Godwin	40.24441389,	-80.30912499
192.	Well Pad Noble-Greathouse	40.10858889,	-80.44535564
193.	Well Pad Inches	40.34806667,	-80.36915556
194.	Well Pad John Day	40.12205834,	-80.21701670
195.	Well Pad Kearns	40.20641389,	-80.41984722
196.	Well Pad Lindley	40.03942778,	-80.29100833
197.	Well Pad Lois Miller	40.24075833,	-80.36516944
198.	Well Pad O'Donnell	40.23306944,	-80.35092230
199.	Well Pad Mele	40.25098889,	-80.29406944
200.	Buffalo Creek Launcher	40.17696388,	-80.40658333
201.	Prospect Road Launcher	40.80188333,	-80.05266944
202.	Well Pad Malinky	40.36193889,	-80.30718611
203.	Cowden Pad	40.329463888,	-80.282280555
204.	Elm Rd.	40.283461111,	-80.314280555
205.	Well Pad Constance Zappi	40.179097222,	-80.406086111
206.	Well Pad Little	40.255397222,	-80.236719444

Ohio

	Stand-Alone Facility	Coordinates
1.	Bolton Launcher Station	39.938144, -81.206353
2.	Wright Station	39.933098, -81.208784
3.	Caston Miller Receiver Station	40.130142, -81.323137
4.	Coal Run Eagle Creek Station	40.067335, -81.099467
5.	Eagle Creek Receiver Station	40.080931, -81.115004
6.	Groh Receiver Station	40.112375, -81.366465
7.	Heavillin Road Station	40.268289, -81.148645
8.	Inherst Station	39.889863, -81.177801
9.	Leatherwood Station	39.966288, -81.273205
10.	Greenlawn Road Station	39.985663, -81.287137
11.	Jones Station	39.79069, -81.059774
12.	Kinsey Station	40.289319, -81.279951
13.	Crum Road Station	39.861991, -81.045932
14.	National OCO Road Station	40.083685, -81.016877
15.	Miller Road Station	40.109296, -81.070266
16.	Eldon Road Station	39.950794, -81.259223
17.	Oak Hill Road Station	40.100566, -81.021299
18.	Old Piedmont Kimble Station	40.197874, -81.193600
19.	Ripley Station-2	40.144020, -81.305489
20.	Buskirk Lane Detweiler Station	39.994646, -81.393084

	Stand-Alone Facility	Coordinates
21.	Stutzman Station-2	39.891061, -81.171815
22.	Mt. Olivett Shugert Station - 3	40.038708, -81.146225
23.	Tyson Receiver Station	40.187745, -81.162444
24.	Westhawk Station	39.843335, -81.030991
25.	Wagner Station	40.1735277, -81.07825
26.	Boyscout Station	40.25867025, -81.21354888
27.	Mt. Olivett Shugert Station	40.04909476, -81.12826697
28.	BK Stephens-2	40.18575333, -81.1665594
29.	Stout Station	40.18622222, -81.20461111
30.	Clay Station	40.17324326, -81.22616504
31.	Noble Station	39.94673422, -81.28760737
32.	Marshall Road Station	40.1072222, -81.3307222
33.	Clark South Station	39.893337, -81.145224
34.	Shriver Station	39.840238, -81.046996
35.	Ohio 556 Station	39.856315, -80.996473
36.	Hudson Road Station	39.861175, -81.017864
37.	Trembly Ridge Road Station	39.809928, -81.040442
38.	Vozar Station	40.198232, -81.207992
39.	Caston Station	40.133954, -81.326833
40.	Lawson LND Station	40.127986, -81296972
41.	Bedway Station	40.076193, -81.024371
42.	McGee Station	39.94562771, -81.23406919

	Stand-Alone Facility	Coordinates
43.	Miller Station	40.12941667, -81.31125
44.	Puskarich Station	40.202308, -81.16281
45.	Bahmer Station	39.94816886, -81.20429452
46.	Red Hill Tarbert Station	40.201221, -81.179773
47.	Lake LND Stattion	40.148834, -81.297728
48.	Brothers Station	39.95147891, -81.21878497
49.	Triple B Station	40.06924617, -81.07527801
50.	Hayes Station	40.044293, -81.121239
51.	Shugert Daddy Station	40.00523641, -81.41198983
52.	Jones Launcher Station	40.25474023, -81.16676636
53.	Amanda Station	39.8886365, -81.17061957
54.	Wesley Station	39.89328118, -81.15947025
55.	Michael Station	40.19500259, -81.17202306
56.	Darla Station	40.17793958, -81.07410902
57.	Karen Station	40.02580771, -81.29045958
58.	Detweiler Station	39.98857029, -81.38588845
59.	Groh Station	40.11030961, -81.37014543
60.	Onega Station	39.99941027, -81.43802381
61.	Cadiz Road Piedmont Clay Station	40.17769444, -81.23427778
62.	J Anderson Station	39.974759, -81.270049
63.	J Hall Station	39.991753, -81.260724
64.	Stiers Station	39.951932, -81434505

	Stand-Alone Facility	Coordinates
65.	Swallie Station	40.039191, -81.139875
66.	Milliken Station	40.174307, -81.239336
67.	Stronz Station	39.931337, -81.123607

APPENDIX 7

HUMPHREYS AMBIENT AIR MONITORING SEP FOR THE HUMPHREYS COMPRESSOR STATION IN OHIO

A. General Requirements

1. Pursuant to Section VI of the Consent Decree, and in accordance with the specifications and provisions in this Appendix, MarkWest will install, operate, and maintain an ambient air monitoring system ("AAMS") at the Humphreys Compressor Station and provide data as required by this Appendix and the Consent Decree.

2. Within 120 Days of the Effective Date, MarkWest shall submit to EPA for review and approval a plan (the "Humphreys Monitoring Plan") that shall include, at a minimum:

   a. An identification of the location of the meteorological station required by this Appendix and how this location meets this Appendix's requirements.

   b. Compliance with the monitoring requirements in 40 C.F.R. Part 58, Appendix E, and in accordance with the NATTS guidance document available at https://www3.epa.gov/ttnamti1/files/ambient/airtox/NATTS%20TAD%20Revision%203_FINAL%20October%202016.pdf

   c. A Quality Assurance Project Plan ("QAPP") that describes the Quality Assurance/Quality Control procedures, specifications, and other technical activities to be implemented to ensure: (i) that the results of this SEP meet project specifications; and (ii) the accuracy, validity, representativeness, and usability of the data obtained by all monitoring equipment, including the stationary equipment and systems identified in Section B of this Appendix (Stationary Equipment Requirements). The QAPP shall follow the outline and guidance in the EPA publication entitled "QA Handbook for Air Pollution Measurement Systems, Volume II, Ambient Air Quality Monitoring Program," EPA-454/B-13-003, May 2013.

   d. A description of the implementation of Data Availability (Paragraph 17) requirements of this Appendix.

   e. A schedule, with a start date contingent upon approval of the Humphreys Monitoring Plan, for expeditiously purchasing, installing, upgrading, and commencing operation of specifically-identified systems and equipment that met all requirements of this Appendix.

3. Upon EPA approval of the Humphreys Monitoring Plan, in compliance with the

schedule in the approved Humphreys Monitoring Plan, MarkWest shall purchase or lease all equipment specified in the Humphreys Monitoring Plan, shall complete the installation of all such equipment, and shall upgrade all systems or stations as set forth in the approved Humphreys Monitoring Plan.

4. MarkWest shall promptly correct deficient implementation of its Humphreys Monitoring Plan. Any disputes related to the Humphreys Monitoring Plan or this Appendix shall be resolved pursuant to the procedures set forth in Section XIII (Dispute Resolution) of the Consent Decree.

5. MarkWest may seek EPA approval to modify the Humphreys Monitoring Plan at any time during the effective period of this Consent Decree.

B. Stationary Equipment Requirements

6. Overview. The AAMS shall include:

   a. A meteorological station to monitor meteorological parameters (Paragraph 7);

   b. Upwind and downwind stations to monitor air pollutants (Paragraphs 8-12); and

   c. A Data Acquisition System for all upwind, downwind, and meteorological stations (Paragraph 13).

7. Instruments for Measuring and Recording Wind Speed, Wind Direction, Ambient Temperature, and Barometric Pressure. Specific meteorological parameters will be continuously monitored to obtain data representative of the meteorological conditions at each facility. The data set produced shall be adequate to correlate hourly block average conditions and thirty-minute rolling average conditions (collected on a five-minute basis) with pollutant measurements and transport.

   a. Continuously measured meteorological parameters shall include hourly block average and thirty-minute rolling average horizontal wind speed and wind direction, the standard deviation of horizontal wind direction (sigma theta), air temperature, and barometric pressure. Wind speed and direction shall be measured at a height of approximately 10 meters. Temperature and barometric pressure shall be measured at a height of 2 to 3 meters. The sensors shall, to the extent practicable, be positioned away from, or above, obstructions such as buildings, trees, and process units that may interfere with wind direction measurements.

   b. Wind direction and sigma theta measurement data shall be auto-corrected to True North, rounded to the nearest whole degree. Wind speed data shall be reported in meters per second, rounded to the nearest tenth.

c. Air temperature data shall be reported in degrees Fahrenheit or Celsius, rounded to the nearest tenth of a degree.

d. Barometric pressure data may be in any unit of pressure.

8. Air Pollutant Monitoring Stations: Equipment and Pollutant Measurement Capability. MarkWest shall install continuous auto-gas chromatographs for VOCs and separate continuous instruments for reduced sulfur compounds at each upwind and downwind monitoring station so that each station has each of the following:

a. Instruments capable of measuring and recording the concentrations of the following compounds in the air at a minimum detection level of 1.0 part per billion by volume (ppbV): propane, butane, pentane, hexane, benzene, toluene ethylbenzene, xylene and all of its isomers, and total VOCs. The data will be recorded as hourly block averages.

b. Instruments capable of measuring and recording the concentrations of reduced sulfur compounds at a minimum detection level of 1.0 ppbV. The data will be recorded as hourly block averages.

c. The continuous measurement of the compounds listed in Subparagraph 8.a. above, shall be accomplished using an auto-Gas Chromatograph ("GC"). The automated GCs shall be operated and maintained in accordance with the manufacturer's recommendations and shall have a measurement range of 1.0 to 500 ppbV for all gases.

d. The continuous measurement of reduced sulfur compounds, listed in Subparagraph 8.b. above, shall be accomplished using Teledyne API T102 Total Reduced Sulfur (TRS) analyzers. The instruments shall be operated and maintained in accordance with the manufacturer's recommendations, shall be operated in high sensitivity mode, and shall have a measurement range of 1.0 to 50 ppbV.

9. Air Pollutant Monitoring Stations: Temperature-Controlled Shelter: Each air pollutant monitoring station shall be operated inside a temperature-controlled equipment shelter.

a. The temperature within each shelter shall be continuously monitored and recorded using a calibrated resistance temperature detector ("RTD") and microprocessor or PC-based data acquisition system.

b. The climate control system for each monitoring shelter will be capable of maintaining a stable temperature within the range of 20ºC to 30ºC.

c. The monitoring shelters shall measure approximately 8 feet wide by 12 feet

long by 8 feet high.

d. Each shelter shall be anchored to the ground and be electrically grounded for safety.

e. The shelter walls and roofs will have a minimum insulation rating of R11.

f. Each shelter will be equipped with electrical service panels, interior electrical distribution circuits, lighting, workbench and sufficient space for housing, operating, and maintaining the monitoring instruments. All electrical wiring and appurtenances will conform to the National Electric Code (NEC).

10. Air Pollutant Monitoring Station Locations. The air pollutant monitoring stations shall be located at the following coordinates and identified as follows:

a. Humphreys Facility Upwind: Latitude: Longitude

b. Humphreys Facility Downwind: Latitude: Longitude

11. Air Pollutant Monitoring Systems Sampler Inlet Requirements. The sampler inlets for each monitoring station shall comply with the following requirements:

a. The sampler inlets should be 2 to 5 meters above ground and have unrestricted airflow 270 degrees around the sample inlet or 180 degrees if the sampler is on the side of a building.

b. The sampler inlets should be >20 meters from the dripline of any tree(s).

c. The sampler inlets should be >1 meter away from supporting structures and walls.

d. The distance from a sampler probe to an obstacle, such as a building, should be at least twice the height the obstacle protrudes above the sampler, probe, or monitoring path.

e. The sampler inlets should be away from minor sources, to avoid undue influences from minor sources. The separation distance is dependent on the height of the minor source's emission point, the type of fuel or waste burned, and the quality of the fuel.

12. Air Pollutant Monitoring Stations – Prohibition on Moving. MarkWest shall not move the pollutant monitoring stations to a new location without prior written approval by EPA. Movement of the pollutant monitoring station components for maintenance shall not be restricted by this Paragraph.

13. Data Acquisition System (DAS). A DAS will be used to log all numerical data generated by the air pollutant analyzers and weather instruments using a common time-stamp. The DAS also will be programmed to correct pollutant concentration data to standard temperature and pressure, and to automatically correlate pollutant data with wind direction. The DAS outputs shall be in a file format that can be used in common spreadsheet programs.

14. Nothing in this Appendix shall preclude the use of any other, additional fence line monitoring equipment and/or of monitoring other, additional pollutants at the fence line.

C. Operation of AAMS

15. MarkWest shall comply with all terms of this Appendix and the Humphreys Monitoring Plan, including but not limited to operating and maintaining the monitors, equipment, and systems described herein, for a period of no less than a total of 720 days.

16. Quality Assurance/Quality Control (QA/QC). MarkWest shall ensure that all data collected by the AAMS are subjected to the approved QA/QC procedures on a quarterly basis. The QA/QC procedures for a given quarter's data shall be completed by no later than the end of the quarter following the quarter within which the data were collected.

17. Data Submission. MarkWest shall provide Relevant Data on a quarterly basis, within 45 days of the end of each calendar quarter. For purposes of this Paragraph, "Relevant Data" shall mean the hourly block averages of propane, butane, pentane, hexane, benzene, toluene ethylbenzene, xylene and all of its isomers, total VOCs, and reduced sulfur compounds, wind speed, and wind direction that are collected during periods at all times. MarkWest shall submit the data in a manner that allows pollutant concentrations, wind speed, and wind direction to be viewed concurrently and indicate that these data meet the QA/QC procedures in Subparagraph C.16 of this Appendix. All numerical data shall be presented in a format that can be used in common spreadsheet programs. MarkWest shall maintain the Relevant Data collected through the AAMS as required by the Consent Decree.

18. Annual Reports. MarkWest shall prepare and submit at least two annual reports. These reports will detail the operation of the VOC, RSC, and meteorological equipment as well as any maintenance and service work performed at each monitoring location. These reports will contain data summaries, a summary of any problems encountered in the monitoring project and the status of any current problems and corrective actions performed, a summary of any meetings or correspondence addressing the monitoring program, a synopsis of percent recovery including brief explanations of missing data, overall data recovery, quality control, and all quality assurance documentation. Each report will include a fully quality□ assured hourly data file in Excel format and an Adobe Acrobat PDF copy of the

formalized report. Each report will be provided within 45 days of the end of each year-long monitoring period.

APPENDIX 8

AMBIENT AIR MONITORING SEP FOR THE HARMON CREEK GAS PROCESSING PLANT IN THE VICINITY OF SMITH TOWNSHIP, WASHINGTON COUNTY, PENNSYLVANIA

A. General Requirements

1. Pursuant to Section VI of the Consent Decree, and in accordance with the specifications and provisions in this Appendix, MarkWest will install, operate, and maintain an ambient air monitoring system in the vicinity of the proposed Harmon Creek Gas Processing Plant ("HC") in Smith Township, Washington County, Pennsylvania and provide data as required by this Appendix and the Consent Decree (hereinafter the "Harmon Creek Monitoring System").

2. Within 120 Days of the Effective Date, MarkWest shall submit to EPA and PADEP for review and, following consultation with PADEP, approval by EPA a plan (the "Harmon Creek Monitoring Plan") that shall include, at a minimum:

   a. The proposed location of the meteorological station required by this Appendix, a discussion of how the location meets the siting criteria discussed below, the specifications of the station, a discussion of how these specifications meet the data measurement criteria discussed below, and the proposed date for installation and operation. Before submitting the complete Harmon Creek Monitoring Plan, MarkWest may submit a separate plan for installing the meteorological station in order to speed installation and operation of the station.

   b. A description of the three VOC monitors to be installed, how this monitoring equipment meets the criteria discussed below, and a schedule for proposing the specific locations of this monitoring equipment.

   c. Compliance with the monitoring requirements in 40 C.F.R. Part 58, Appendix E, and in accordance with the NATTS guidance document available at https://www3.epa.gov/ttnamti1/files/ambient/airtox/NATTS%20TAD%20Revision%203_FINAL%20October%202016.pdf

   d. A Quality Assurance Project Plan ("QAPP") that describes the Quality Assurance/Quality Control procedures, specifications, and other technical activities to be implemented to ensure: (i) that the results of this SEP meet project specifications; and (ii) the accuracy, validity, representativeness, and usability of the data obtained by all monitoring equipment, including the stationary equipment and systems identified in Section B of this Appendix (Stationary Equipment Requirements). The QAPP shall follow the outline and guidance in the EPA publication entitled "QA Handbook for Air

Pollution Measurement Systems, Volume II, Ambient Air Quality Monitoring Program," EPA-454/B-13-003, May 2013.

e. A description of the implementation of Data Availability (Paragraph 17) requirements of this Appendix.

f. A schedule, with a start date contingent upon approval of the Harmon Creek Monitoring Plan, for (i) expeditiously purchasing, installing, upgrading, and commencing operation of specifically-identified systems and equipment that meet all requirements of this Appendix and (ii) completing the monitoring and submitting a final report to EPA and PADEP.

3. Upon EPA approval, after consultation with PADEP, of the Harmon Creek Monitoring Plan, MarkWest shall purchase all equipment specified in the plan, shall complete the installation of all such equipment, and shall upgrade all systems or stations as set forth in the schedule in the approved plan.

4. MarkWest shall promptly correct deficient implementation of its Harmon Creek Monitoring Plan. Any disputes related to the plan or this Appendix shall be resolved pursuant to the procedures set forth in Section XIII (Dispute Resolution) of the Consent Decree.

5. MarkWest may seek EPA approval to modify the Harmon Creek Monitoring Plan at any time during the effective period of this Consent Decree. EPA will consult with PADEP on any such request.

B. Stationary Equipment Requirements

6. Overview. The Harmon Creek Monitoring System shall include:

a. A meteorological station to monitor meteorological parameters (Paragraph 7);

b. Three air pollutant monitoring stations: one located a short distance upwind of HC ("Upwind Station"), one located a short distance downwind of HC ("Near Downwind Station"), and one located further downwind (approximately 1 – 3 km) of HC ("Far Downwind Station") (collectively referred to as "Air Pollutant Monitoring Stations") (Paragraphs 8-12); and

c. A Data Acquisition System for all Air Pollutant Monitoring Stations and the meteorological station (Paragraph 13).

7. Instruments for Measuring and Recording Wind Speed, Wind Direction, Ambient Temperature, and Barometric Pressure. Specific meteorological parameters will be continuously monitored to obtain data representative of the meteorological conditions at HC. The data set produced shall be adequate to correlate hourly block

average conditions and thirty-minute rolling average conditions (collected on a five-minute basis) with pollutant measurements and transport.

a. Continuously measured meteorological parameters shall include hourly block average and thirty-minute rolling average horizontal wind speed and wind direction, the standard deviation of horizontal wind direction (sigma theta), air temperature, and barometric pressure. Wind speed and direction shall be measured at a height of approximately 10 meters. Temperature and barometric pressure shall be measured at a height of 2 to 3 meters. The sensors shall, to the extent practicable, be positioned away from, or above, obstructions such as buildings, trees, and process units that may interfere with wind direction measurements.

b. Wind direction and sigma theta measurement data shall be auto-corrected to True North, rounded to the nearest whole degree. Wind speed data shall be reported in meters per second, rounded to the nearest tenth.

c. Air temperature data shall be reported in degrees Fahrenheit or Celsius, rounded to the nearest tenth of a degree.

d. Barometric pressure data may be in any unit of pressure.

8. Air Pollutant Monitoring Stations: Equipment and Pollutant Measurement Capability. MarkWest shall install the following equipment at each of the Air Pollutant Monitoring Stations:

a. Instruments capable of measuring and recording the concentrations of the following compounds in the air at a minimum detection level of 1.0 part per billion by volume (ppbV): C_2 to C_6 (i.e. from ethane through 1,3-butadiene up to benzene) and up to 32 compounds from C_6 to C_{12} (hexane, dimethylbutane, diethylbenzene, naphthalene, dodecane, BTEX, and halogen compounds), and total VOCs. The VOC data will be recorded as hourly averages.

b. An auto gas chromatograph ("GC") shall be employed to accomplish the continuous measurement of the compounds listed in Subparagraph 8.a. above. The automated GC shall be operated and maintained in accordance with the manufacturer's recommendations and shall have a measurement range of 1.0 to 500 ppbV for all gases.

9. Air Pollutant Monitoring Stations: Temperature-Controlled Shelter: Each air pollutant monitoring station shall be operated inside a temperature-controlled equipment shelter.

a. The temperature within each shelter shall be continuously monitored and recorded using a calibrated resistance temperature detector ("RTD") and

microprocessor or PC-based data acquisition system.

b. The climate control system for each monitoring shelter will be capable of maintaining a stable temperature within the range of 20ºC to 30ºC.

c. The monitoring shelters shall measure approximately 8 feet wide by 8 feet long by 8 feet high.

d. Each shelter shall be anchored to the ground and be electrically grounded for safety.

e. The shelter walls and roofs will have a minimum insulation rating of R11.

f. Each shelter will be equipped with electrical service panels, interior electrical distribution circuits, lighting, workbench and sufficient space for housing, operating, and maintaining the monitoring instruments. All electrical wiring and appurtenances will conform to the National Electric Code (NEC).

10. Air Pollutant Monitoring Systems Sampler Inlet Requirements. The sampler inlets for each monitoring station shall comply with the following requirements:

a. The sampler inlets should be 2 to 5 meters above ground and have unrestricted airflow 270 degrees around the sample inlet or 180 degrees if the sampler is on the side of a building.

b. The sampler inlets should be >20 meters from the dripline of any tree(s).

c. The sampler inlets should be >1 meter away from supporting structures and walls.

d. The distance from a sampler probe to an obstacle, such as a building, should be at least twice the height the obstacle protrudes above the sampler, probe, or monitoring path.

e. The sampler inlets should be away from minor sources, to avoid undue influences from minor sources. The separation distance is dependent on the height of the minor source's emission point, the type of fuel or waste burned, and the quality of the fuel.

f. Each Air Pollutant Monitoring System shall be housed in a climate controlled monitoring shelter and shall draw air through a sampling tube that meets the criteria at https://www3.epa.gov/ttn/amtic/files/ambient/pams/newtad.pd.

11. Air Pollutant Monitoring Stations – Prohibition on Moving. MarkWest shall not

move the pollutant monitoring stations to a new location without prior written approval by EPA, following consultation with PADEP. Movement of the pollutant monitoring station components for maintenance shall not be restricted by this Paragraph.

12. Data Acquisition System ("DAS"). A DAS will be used to log all numerical data generated by the air pollutant analyzers and weather instruments using a common time-stamp. The DAS also will be programmed to correct pollutant concentration data to standard temperature and pressure, and to automatically correlate pollutant data with wind direction. The DAS outputs shall be in a file format that can be used in common spreadsheet programs.

13. Nothing in this Appendix shall preclude the use of any other, additional fence line monitoring equipment and/or of monitoring other, additional pollutants at the fence line.

C. Operation of Harmon Creek Monitoring System

14. MarkWest shall comply with all terms of this Appendix and the Harmon Creek Monitoring Plan, including but not limited to operating and maintaining the monitors, equipment, and systems described herein, for a period of no less than a total of 720 days.

15. Quality Assurance/Quality Control ("QA/QC"). MarkWest shall ensure that all data collected by the Harmon Creek Monitoring System are subjected to the approved QA/QC procedures on a quarterly basis. The QA/QC procedures for a given quarter's data shall be completed by no later than 45 days following the end of the quarter in which the data were collected.

16. Quarterly Submissions. MarkWest shall provide Relevant Data on a quarterly basis, within 45 days of the end of each calendar quarter. For purposes of this Paragraph, "Relevant Data" shall mean the quality assured hourly block averages of compounds identified in Table A, attached, and all meteorological data collected (see Paragraph 7). MarkWest shall submit the data in a manner that allows pollutant concentrations and meteorological data to be viewed concurrently and indicate that these data meet the QA/QC procedures in Paragraph 15 of this Appendix. All numerical data shall be presented in a format that can be used in common spreadsheet programs. MarkWest shall maintain and retain the Relevant Data collected through the Harmon Creek Monitoring System as required by the Consent Decree. In addition to the Relevant Data, MarkWest shall provide the following information on a quarterly basis: a summary of any problems encountered in the monitoring project and the status of any current problems and corrective actions performed, a summary of any meetings or correspondence addressing the monitoring program, a synopsis of percent recovery including brief explanations of missing data, overall data recovery, quality control, and all quality assurance documentation, as well the results of any Performance Audits performed during the

quarter.

17. Final Report. Within 90 days of the conclusion of the monitoring period, MarkWest shall prepare and submit a Final Report. The Final Report shall describe the Harmon Creek Monitoring System sampling, compile all data collected, including meteorology, chemical compounds, and QA/QC, and interpret and analyze the data collected by the Harmon Creek Monitoring System.

TABLE A

Compound	Parameter Code
Carbon disulfide	42153
Dodecane	43141
Ethane	43202
Ethene	43203
Propane	43204
Propene	43205
Ethyne	43206
Butane	43212
Isobutane	43214
trans-2-Butene	43216
cis-2-Butene	43217
Pentane	43220
Isopentane	43221
1-Pentene	43224
trans-2-Pentene	43226
cis-2-Pentene	43227
3-methylpentane	43230
n-hexane	43231
n-heptane	43232
Octane	43233
Nonane	43235
Decane	43238
Cyclopentane	43242
Isoprene	43243
2,2,-Dimethylbutane	43244
1-Hexene	43245
2,4-Dimethylpentane	43247
Cyclohexane	43248
3-Methylhexane	43249
2,2,4-Trimethylpentane	43250
2,3,4-Trimethylpentane	43252
3-Methylheptane	43253
Methylcyclohexane	43261
Methylcyclopentane	43262
2-methylhexane	43263

Compound	Parameter Code
1-Butene	43280
2,3-Dimethylbutane	43284
2-methylpentane	43285
2,3-Dimethylpentane	43291
Acrolein	43505
Acetone	43551
2-Butanone (MEK)	43552
2-Hexanone	43559
Chloromethane	43801
Chloroform	43803
Carbon tetrachloride	43804
Trichlorofluoromethane	43811
1,1,1-Trichloroethane	43814
Tetrachloroethene (PERC)	43817
1,1,2-Trichloro-1,2,2-trifluoroethane	43821
Dichlorodifluoromethane	43823
Trichloroethylene (TCE)	43824
Methylene chloride	43860
Undecane	43954
2-Methylheptane	43960
m&p-Xylene	45109
Benzene	45201
Toluene	45202
Ethylbenzene	45203
o-Xylene	45204
1,3,5-Trimethylbenzene	45207
1,2,4-Trimethylbenzene	45208
Propylbenzene	45209
Isopropylbenzene	45210
1-Ethyl-2-Methylbenzene	45211
1-Ethyl-3-Methylbenzene	45212
1-Ethyl-4-methylbenzene	45213
m-Diethylbenzene	45218
p-Diethylebenzene	45219
Styrene	45220
1,2,3-Trimethylbenzene	45225

Compound	Parameter Code
Tetrahydrofuran (THF)	46401

GENERAL PERMIT 21.1 TEMPLATE

PIGGING OPERATION

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTI to be issued to a **Title V** facility

1. All the facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

   a) B.2.

2. Modeling to demonstrate compliance with the “Toxic Air Contaminant Statute”, ORC 3704.03(F)(4)(b), is not necessary if/when the maximum annual emissions for each toxic air contaminant, as defined in OAC rule 3745-114-01, from all sources in the project, is less than 1.0 ton per year (or are subject to a standard under 40 CFR Part 63). OAC Chapter 3745-31 requires permittees to apply for and obtain a new or modified PTIO prior to making a "modification" as defined by OAC rule 3745-31-01. The permittee is hereby advised that changes in the composition of the materials or use of new materials that would cause the emissions of any toxic air contaminant to increase to above 1.0 ton per year may require the permittee to apply for and obtain a new PTIO.

3. Records related to this permit may be maintained at an off-site location (e.g. regional office), provided they are made accessible when the need arises, otherwise by the next business day upon Ohio EPA request (or made viewable electronically on-site and submitted to Ohio EPA within 24 hours).

C. Emissions Unit Terms and Conditions

1. Emissions Unit: Pigging Operation: P020

Operations, Property and/or Equipment Description:

One discrete pig launcher or receiver.

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) b)(1)b., b)(1)c., and b)(2)b.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	Volatile organic compound (VOC) emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit. See b)(2)a., b)(2)c. and c) below.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the VOC emissions from this air contaminant source since the calculated annual emissions rate is less than 10 tons/year, taking into account the voluntary restrictions from OAC rule 3745-31-05(E). See b)(2)b. below.
c.	OAC rule 3745-31-05(E) June 30, 2008	VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		See b)(2)b., b)(2)c. and c) below.

(2) Additional Terms and Conditions

a. This Best Available Technology (BAT) emissions limit applies until U.S. EPA approves OAC rule 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio SIP.

b. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

c) Operational Restrictions

(1) Access openings to the receivers shall be kept closed at all times, except when a pig is being placed into or removed from the receiver, or during active maintenance operations.

(2) The permittee shall install and operate add-on control (vapor recovery, flare/combustor or equivalent) for the control of VOC emissions as needed to comply with this permit's emission limits.

(3) In the event any needed add-on control is not operating in accordance with the manufacturer's recommendations, instructions, or operating manual, with any modifications deemed necessary by the permittee, add-on control shall be expeditiously repaired or otherwise returned to these documented operating conditions.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall collect the following information for each pigging event venting:

a. Date and time of the venting;

b. The calculated mass of the resulting VOC emissions where the mass is calculated using the following equation[1]:

VOC Mass = [(mw*PV/(RTZ)) * VOC Wt% + L + C] * (1 - capture efficiency * control efficiency) * (1 ton/2000 pounds)

Where:

mw = the molecular weight of the gas vented;

P = the absolute gas pressure of the gas in the pigging vessel prior to venting;

V = the actual volume of the pigging vessel and piping vented;

T = the temperature of the vented gas;

[1] Representative values may be used for this calculation as long as the values are updated with actual data at least on an annual basis.

Z = the gas compressibility factor of the vented gas;

R = the gas constant;

L = the chamber liquid phase released and volatilized (flash) as VOCs; and

C = the VOCs emitted in the re-sealed chamber purge gas flush.

(2) The permittee shall maintain monthly records of the following information:

a. the ton of VOC per month emitted from the pigging events (using the calculation provided in d)(1)), and

b. the ton of VOC per month emitted from all pigging events, averaged over a rolling, 12-month period (using the calculation provided in d)(1) and summing the current month with the previous 11 months and then dividing by 12 months).

(3) The permittee shall maintain documentation of the manufacturer's recommendations, instructions, or operating manuals for add-on control, along with documentation of any modifications deemed necessary by the permittee. These documents shall be maintained at the facility and shall be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(4) The permittee shall conduct periodic inspections of the add-on control to determine whether it is operating in accordance with the manufacturer's recommendations, instructions, or operating manuals with any modifications deemed necessary by the permittee or operator.

(5) The permittee shall document each inspection (periodic and annual) of the add-on control and shall maintain the following information:

a. the date of the inspection;

b. a description of each/any problem identified and the date it was corrected;

c. a description of any maintenance and repairs performed; and

d. the name of person who performed the inspection.

These records shall be maintained at the facility for not less than five years from the date the inspection and any necessary maintenance or repairs were completed and shall be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(6) The permittee shall maintain records that document any time periods when the add-on control was not in service when the emissions unit(s) was/were in operation, as well as, a record of all operations during which add-on control was not operated according to the manufacturer's recommendations with any documented modifications made by the permittee. These records shall be maintained for a period of not less than five years and shall be made available to the Ohio EPA upon request.

e) Reporting Requirements

(1) The permittee shall submit deviation reports that identify any of the following occurrences:

a. All exceedances of the ton of VOC per month, averaged over a rolling, 12-month period, and the other requirements under sections c)(1) through (3) and d)(1) through (6).

(2) The deviation reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(3) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

Emission Limitation:

VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period.

Applicable Compliance Method:

Compliance shall be determined based on the records found in terms d)(1) and d)(2) above.

g) Miscellaneous Requirements

(1) None.

GENERAL PERMIT 21.1 TEMPLATE

PIGGING OPERATION

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTIO to be issued to a **non-Title V** facility

1. This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

   a) For the purpose of a permit-to-install document, the facility-wide terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

      (1) B.2.

   b) For the purpose of a permit-to-operate document, the facility-wide terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

      (2) None.

2. Modeling to demonstrate compliance with the “Toxic Air Contaminant Statute”, ORC 3704.03(F)(4)(b), is not necessary if/when the maximum annual emissions for each toxic air contaminant, as defined in OAC rule 3745-114-01, from all sources in the project, is less than 1.0 ton per year (or are subject to a standard under 40 CFR Part 63). OAC Chapter 3745-31 requires permittees to apply for and obtain a new or modified PTIO prior to making a "modification" as defined by OAC rule 3745-31-01. The permittee is hereby advised that changes in the composition of the materials or use of new materials that would cause the emissions of any toxic air contaminant to increase to above 1.0 ton per year may require the permittee to apply for and obtain a new PTIO.

3. Records related to this permit may be maintained at an off-site location (e.g. regional office), provided they are made accessible when the need arises, otherwise by the next business day upon Ohio EPA request (or made viewable electronically on-site and submitted to Ohio EPA within 24 hours).

C. Emissions Unit Terms and Conditions

1. Emissions Unit: Pigging Operation: P020

Operations, Property and/or Equipment Description:

One discrete pig launcher or receiver.

a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

(1) For the purpose of a permit-to-install document, the emissions unit terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

a. b)(1)b., b)(1)c., and b)(2)b.

(2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

a. None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	Volatile organic compound (VOC) emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit. See b)(2)a., b)(2)c. and c) below.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the VOC emissions from this air contaminant source since the calculated annual emissions rate is less than 10 tons/year, taking into account the voluntary restrictions from OAC rule 3745-31-05(E). See b)(2)b. below.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
c.	OAC rule 3745-31-05(E) June 30, 2008	VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit. See b)(2)b., b)(2)c. and c) below.

(2) Additional Terms and Conditions

a. This Best Available Technology (BAT) emissions limit applies until U.S. EPA approves OAC rule 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio SIP.

b. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

c) Operational Restrictions

(1) Access openings to the receivers shall be kept closed at all times, except when a pig is being placed into or removed from the receiver, or during active maintenance operations.

(2) The permittee shall install and operate add-on control (vapor recovery, flare/combustor or equivalent) for the control of VOC emissions as needed to comply with this permit's emission limits.

(3) In the event any needed add-on control is not operating in accordance with the manufacturer's recommendations, instructions, or operating manual, with any modifications deemed necessary by the permittee, add-on control shall be expeditiously repaired or otherwise returned to these documented operating conditions.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall collect the following information for each pigging event venting:

a. Date and time of the venting;

b. The calculated mass of the resulting VOC emissions where the mass is calculated using the following equation[1]:

[1] Representative values may be used for this calculation as long as the values are updated with actual data at least on an annual basis.

VOC Mass = [(mw*PV/(RTZ)) * VOC Wt% + L + C] * (1 - capture efficiency * control efficiency) * (1 ton/2000 pounds)

Where:

mw = the molecular weight of the gas vented;

P = the absolute gas pressure of the gas in the pigging vessel prior to venting;

V = the actual volume of the pigging vessel and piping vented;

T = the temperature of the vented gas;

Z = the gas compressibility factor of the vented gas;

R = the gas constant;

L = the chamber liquid phase released and volatilized (flash) as VOCs; and

C = the VOCs emitted in the re-sealed chamber purge gas flush.

(2) The permittee shall maintain monthly records of the following information:

a. the ton of VOC per month emitted from the pigging events (using the calculation provided in d)(1)), and

b. the ton of VOC per month emitted from all pigging events, averaged over a rolling, 12-month period (using the calculation provided in d)(1) and summing the current month with the previous 11 months and then dividing by 12 months).

(3) The permittee shall maintain documentation of the manufacturer's recommendations, instructions, or operating manuals for add-on control, along with documentation of any modifications deemed necessary by the permittee. These documents shall be maintained at the facility and shall be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(4) The permittee shall conduct periodic inspections of the add-on control to determine whether it is operating in accordance with the manufacturer’s recommendations, instructions, or operating manuals with any modifications deemed necessary by the permittee or operator.

(5) The permittee shall document each inspection (periodic and annual) of the add-on control and shall maintain the following information:

a. the date of the inspection;

b. a description of each/any problem identified and the date it was corrected;

c. a description of any maintenance and repairs performed; and

d. the name of person who performed the inspection.

These records shall be maintained at the facility for not less than five years from the date the inspection and any necessary maintenance or repairs were completed and shall

be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(6) The permittee shall maintain records that document any time periods when the add-on control was not in service when the emissions unit(s) was/were in operation, as well as, a record of all operations during which add-on control was not operated according to the manufacturer's recommendations with any documented modifications made by the permittee. These records shall be maintained for a period of not less than five years and shall be made available to the Ohio EPA upon request.

e) Reporting Requirements

(1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit.

(2) The reports required by this permit may be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal; or they may be mailed as a hard copy to the appropriate district office or local air agency.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

Emission Limitation:

VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period.

Applicable Compliance Method:

Compliance shall be determined based on the records found in terms d)(1) and d)(2) above.

g) Miscellaneous Requirements

(1) None.

Recover Gas from Pipeline Pigging Operations



Technology/Practice Overview

Description

Gases rich in recoverable hydrocarbons tend to condense liquids in gathering systems upstream of gas gathering and processing plants. These systems are frequently pigged with spherical or bullet-shaped pigs to remove accumulated liquids and reduce the gathering system pressure drop. This improves gas flow and pipeline efficiency. The pigged liquids are separated from the gas ahead of the processing plant compressors, stored temporarily at gathering system pressure, and then sent to a low pressure storage tank. The liquids, recovered at pipeline pressure, flash and vent light hydrocarbon gases from the storage tanks.

Much of the gas that is vented can be recovered by installing a dedicated vapor recovery system. Recovering the flash gas resulting from the pressure drop between the pressurized liquid storage tanks and the atmospheric storage tanks can reduce emissions and add more gas to the sales line.

Operating Requirements

The required equipment to be installed includes an electric or a gas engine driven vapor recovery compressor. A liquid/vapor flash vessel and low pressure liquid pump may also be required depending on system design and/or ambient temperature and pressure. It is assumed that a pig launcher and receiver on gathering lines, vapor/liquid separation and pressurized liquid storage vessels, and low pressure liquid storage tanks would already be

- ☐ Compressors/Engines
- ☐ Dehydrators
- ☐ Directed Inspection & Maintenance
- ■ Pipelines
- ☐ Pneumatics/Controls
- ■ Tanks
- ☐ Valves
- ☐ Wells
- ☐ Other

Applicable Sector(s)

- ■ Production
- ■ Processing
- ■ Transmission
- ☐ Distribution

Other Related PROs:

Use Inert Gases and Pigs to Perform Pipeline Purges, PRO No. 403

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*21,400 Mcf per year*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	21,400 Mcf	$159,400	$24,000	$1,000	2 Month
$5.00/Mcf	21,400 Mcf	$113,800	$24,000	$1,000	3 Month
$3.00/Mcf	21,400 Mcf	$68,300	$24,000	$1,000	5 Months

** Whole gas savings are calculated using a conversion factor of 94% methane in pipeline quality natural gas.*

Additional Benefits

- Addition of gas to the sales line (or plant fuel system)
- Recovery of valuable hydrocarbon liquids
- Safer operations

Recover Gas from Pipeline Pigging Operations (Cont'd)

present on site. Vapor recovery compressor sizing is affected by the variance of pigging operations; colder temperatures in the winter can require extra capacity that is not necessary in the summer months. This is because colder temperatures result in more condensation at constant pressure. Pipelines would therefore have to be pigged more often. In general, gathering lines that must be pigged frequently and recover a large volume of liquid at moderate to high pressure (150 to 300 psig or greater) are best suited for vapor recovery.

Applicability

Gas and condensate recovery is possible at any gas gathering station and processing plant that frequently must remove condensed liquids from its upstream gathering lines.

Methane Emissions

The methane emission savings are based on the design flow rate and operating time of a single vapor recovery compressor dedicated to the compression of the flash vapor from the pigged liquid (pressurized) storage tanks.

Economic Analysis

Basis for Costs and Emissions Savings

For example reported savings are based on a gathering system at 200-300 psig (pounds per square-inch, gage) that is pigged 30-40 times per year and collects approximately 3,000 barrels of condensate per year. A small vapor recovery system was installed with an electric compressor for $24,000 and has an annual operating and maintenance cost in excess of $1,000 per year.

Discussion

Gathering system pigging frequency depends on the gas composition as well as the ambient temperature conditions, and can vary greatly from one location to another and from season to season. The economics of recovering gas from pigging operations are dependent upon the methane through butane composition of the hydrocarbon liquid, which directly impact the energy content and value of the gas, and the amount of liquid collected.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

NMED Exhibit 87 - 0002

EPA United States Environmental Protection Agency

Office of Enforcement and Compliance Assurance

Enforcement Alert

Publication no. EPA 325-F-19-001

SEPTEMBER 2019

EPA Observes Air Emissions from Natural Gas Gathering Operations in Violation of the Clean Air Act

Purpose

EPA and state investigations have identified Clean Air Act (CAA) non compliance caused by unauthorized and/or excess emissions from depressurizing pig launchers and receivers in natural gas gathering operations. For example, EPA and Pennsylvania resolved CAA violations by MarkWest (described at the end of this Alert) in a consent decree in April 2018. The settlement provides an example of potential compliance issues that operators may experience if Volatile Organic Compound (VOC) emissions from depressurizing pig launchers and receivers in natural gas gathering operations are not properly controlled. This Alert discusses engineering, design, operations, and maintenance practices that EPA and state inspectors have found that can cause non-compliance and summarizes engineering solutions to reduce emissions and help alleviate potential safety issues. While this Alert provides information intended to help operators and state regulators identify and address compliance concerns, the solutions discussed in this Alert do not guarantee compliance with federal and state regulations, including, but not limited to requirements to obtain an air permit, keep records, and/or control emissions.

Non-Compliance Concerns

State and federal laws require owners and operators of certain facilities to register air emission sources, obtain authorization to emit from a registered source, including natural gas gathering operations, and design, install, operate, and maintain effective emission control measures. Such laws include state permitting and air pollution regulations—many of which are federally-enforceable and collectively referred to as the State Implementation Plan or "SIP"—and the federal New Source Review (NSR) air permitting regulations including the Prevention of Significant Deterioration (PSD) requirements.



Infrared Image of Compressor Station Pig Receiver Depressurization Event

EPA and state inspectors have observed numerous instances where depressurizing pig launchers and receivers in natural gas gathering operations emit unauthorized or excess VOC emissions, due to the company's failure to obtain an air permit for the pigging

NMED Exhibit 88 - 0001

equipment, to address deficiencies in the design of the pigging equipment, or to operate the pigging equipment in accordance with an air permit, air permit application or air permit registration.

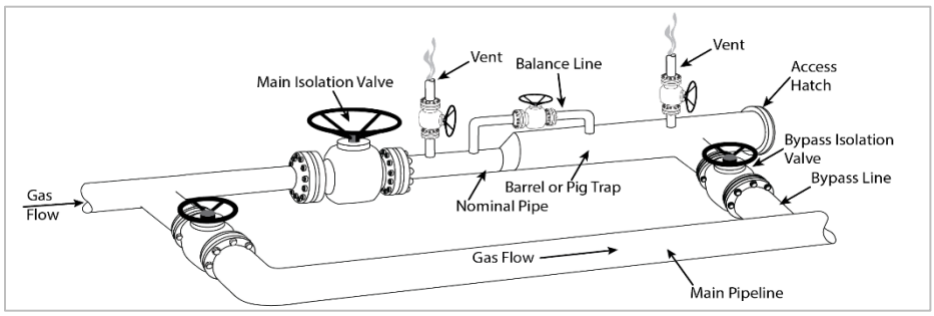


Figure 1. Conventional pig receiver.

In most jurisdictions, a company must determine the mass emissions of pollutants when registering a source, applying for an air permit, and/or claiming an air permit exemption; which are prerequisites to constructing a source. Failing to calculate the potential for VOC or HAP emissions from pigging operations or otherwise underestimating the mass of the pollutants released may result in a misrepresentation to the permit authority when the company applies for a permit or permit exemption. Depending on the state and local air permitting rules and regulations, a company's misrepresentation to the permit authority may mean that the emissions from the pigging operations are considered unauthorized or excess. In this situation, the non-compliance is caused by a company's failure to comply with federal and state permitting requirements, including, but not limited to: failure to register an air emission source, failure to obtain an air permit or obtain the correct air permit, or failure to adhere to representations in the air permit registration, failure to maintain records, and/or failure to control emissions. *See, e.g.,* 40 C.F.R. §§ 51.165 and 70.7(b); 25 Pa. Code §§ 127.11 and 127.402(a); Ohio Admin. Code 3745-31-02(A)(1)(a)-(b) and 3745-15-05(B), (D) and (E).

Emissions from Pigging Operations

Raw natural gas is transported from production wells to processing plants through networks of gathering pipelines. Although liquid separation may occur at the well pad, much of the raw natural gas passing through the gathering pipelines is saturated with hydrocarbons other than methane and may contain other components such as water, carbon dioxide, and hydrogen sulfide. During the transportation of this gas through gathering pipeline systems, the gas often experiences a temperature drop and pressure change that causes the hydrocarbons and other components to condense to a liquid phase. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of the gathering pipelines, operators mechanically push these condensates out of the low elevations and down the pipeline by an operation called "pigging," which involves first inserting a device called a pig into a pig launcher upstream of the pipeline segment where condensates have accumulated. The gas flowing through the pipeline then pushes the pig through the pipeline, allowing the pig to sweep along the accumulated condensates. The pig is removed from the pipeline segment when it is caught in a pig receiver.

A conventional pig receiver is shown in Figure 1. Pig launchers are very similar in design. The pipeline at the rear of the barrel is called a "kicker line" on pig launchers and a "bypass line" on pig receivers; these lines direct the main gas flow through the barrel to launch or receive a pig, respectively.

Before a pig can be inserted or removed through the hatch of a pig launcher or a pig receiver, the pipeline gas in the launcher or receiver barrel must be removed, leading to potential emissions. This gas is under the same pressure as the pipeline and contains methane, ethane, and VOCs including benzene, toluene, ethylbenzene, and xylene. Pig receivers can also contain collected condensate liquid that had accumulated in the pipeline.

When the launcher and receiver barrels are depressurized (via a vent as shown in Figure 1) prior to opening the hatch for pig insertion or removal, the depressurization gases contain mixtures of methane, ethane, VOCs and hazardous air pollutants (HAPs). The barrel depressurization gases are often vented to the atmosphere but can be controlled or recovered to reduce emissions. When the hatch is opened, additional gas is released, and any liquids collected in a pig receiver that did not volatilize in the depressurization process may be spilled from the open hatch as the pig is withdrawn. These spilled liquids can fall to the ground or be collected in an open tub, either of which allow for further evaporation that contributes to emissions.

The amount of potential emissions from pigging operations depends on several factors including the launcher or receiver volume, pipeline pressure (higher pressure correlating with higher potential emissions), amount of liquid trapped in the pig receiver barrel prior to depressurization, frequency of pigging, and gas composition.

Depending on these system characteristics, the pigging operation may emit VOCs or HAPs in excess of federal or state limits.

Engineering Solutions

EPA inspectors have identified general characteristics of a pig launcher and receiver system that control and reduce emissions of air pollutants and may require less management. These systems: (1) minimize the total volume between the kicker and/or bypass isolation valves and the main isolation valve, so that less gas is trapped in the barrel; and (2) minimize the potential for liquid accumulation or hold-up in the receiver, and include features such as sloped receiver barrels and piping so that liquids collected in the barrel are gravity-drained through the bypass piping into the main pipeline for collection downstream. However, depending on the quantity of emissions released, a company may be required to implement additional design measures, and emissions capture and control approaches to comply with federal and state regulations.

The following sections discuss design alternatives to the conventional launcher/receiver system (i.e., pig ball valves and multi-pig launcher systems), considerations for receiver barrel design (i.e., condensate drains and pig ramps), and additional site modifications to capture or control emissions (i.e., jumper lines, combustion devices, rerouting low pressure systems, barrel pump-down systems, and enhanced liquid containment). In addition to reducing potential VOC emissions to alleviate potential non-compliance, application of these solutions reduces methane (a potent greenhouse gas) and generally improves safety of the pigging operation. The applicability and effectiveness of these engineering solutions are site-specific; solutions can generally be combined to effectively reduce emissions.

Install Pig Ball Valves

Pig ball valves are a design alternative to conventional launcher/receiver systems that result in fewer emissions

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from pigging operations due to a smaller sized barrel (or chamber) that launches and receives the pig. A conventional pig launcher or receiver system can be retrofitted by replacing the conventional launcher and receiver barrels with special ball valves used to insert and remove the pig directly from the main pipeline. Figure 2 shows a pig ball valve installed in a pipeline, with a bypass loop around the pig ball valve for use when the pig ball valve is closed. By replacing the large volume barrel with the much smaller volume ball valve, the volume of gas vented during each pigging operation can be reduced by as much as 80% to 95% with a corresponding reduction in emissions and other risks associated with pipeline pigging operations.

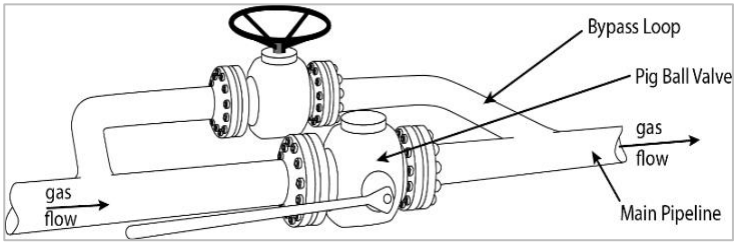


Figure 2. Pig Ball Valve Installation

Install Multi-Pig Launcher Systems

Multi-pig launcher systems are a design alternative to conventional launcher/receiver systems and reduce pigging emissions by reducing the frequency that launchers and receivers must be vented prior to pig insertion and removal. An example manufacturer design for a multi-pig launcher system is shown in Figure 3. The launcher barrel is designed to hold multiple spherical pigs, which are each held in place by gates or pins prior to release. Emission reductions are approximately proportional to the reduction in frequency of opening the launcher and receiver hatch.

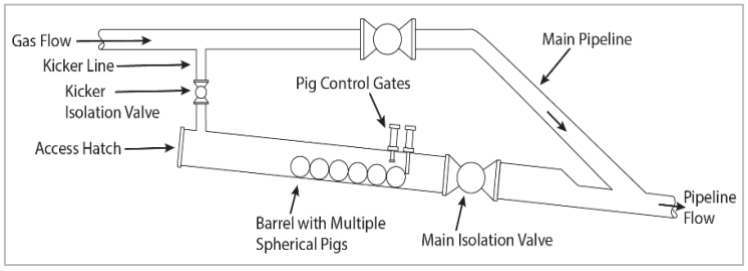


Figure 3. Multi-Pig Launcher System

Receiver Barrel Design: Condensate Drains

Drains can be installed in the bottom of receiver barrels and pig ball valves to ensure that all condensate is drained from the system prior to depressurization. These drains generally route the condensate back into the main pipelines, to onsite storage tanks, or to onsite processes via enclosed piping. Two drains are shown in Figure 4 which depicts a conventional receiver design, but additional drains can be used. These drains can be retrofitted to existing systems.

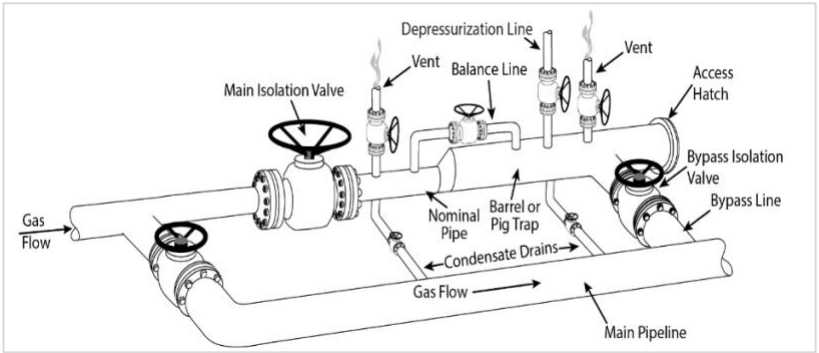


Figure 4. Conventional Pig Receiver with Condensate and Vapor Recovery

The effectiveness of condensate drains in controlling pigging emissions is based on the quantity of condensate trapped in the receiver system, and the subsequent ability of the drain to recover the full quantity of this condensate during each pigging operation, thereby preventing its volatilization during pig receiver depressurization or hatch opening.

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Receiver Barrel Design: Pig Ramps

A pig ramp is a device that can be installed inside a receiver barrel to minimize the accumulation of condensate, or VOCs in the condensed liquid phase, in the receiver by directing the movement of the pig and liquid in the barrel. The pig ramp promotes the flow of liquid through the barrel and into the bypass line by preventing the pig from creating blockages in the receiver. By promoting the flow of liquid back into the pipeline system while the receiver is under pressure, pig ramps reduce the amount of condensed VOCs trapped in the barrel prior to depressurization which reduces the air emission that occur during depressurization and removal of the pig from the receiver. As part of MarkWest's recent settlement with EPA, pig ramps were installed at hundreds of barrels in its wet gas midstream pipeline systems. As discussed below, MarkWest will provide a royalty-free license to others interested in using their proprietary pig ramp design.

Route High Pressure Systems to Lower Pressure Lines (Install Jumper Lines)

The depressurization emissions from high pressure launchers and receivers can be reduced by routing the gases to a lower pressure system before venting the remaining gases to the atmosphere or to control equipment. Routing to a lower pressure system is achieved with a depressurization line (or, "jumper line") exiting the top of the barrel, as shown in Figure 4, or exiting the top of the pig ball valve. Compressor stations and gas plants have low pressure lines on the site that can receive these depressurization gases and recycle them through the process. Similarly, launchers and receivers along high pressure pipelines are occasionally located near low pressure pipelines that can receive depressurization gases exiting the barrel or pig ball valve.

Route Depressurization Gases to Combustion Devices

Depressurization gases from barrels and pig ball valves can be routed through the depressurization line (see Figure 4) to onsite combustion devices. Well-designed and operated combustion devices can achieve vapor destruction efficiencies as high as 95% to 98%. Combustion devices can be used in conjunction with engineering solutions discussed above that first reduce accumulation of or recover as much natural gas and condensate as possible before destroying the remaining vapors in the combustion device. An example would be to route high pressure systems to low pressure lines and drain barrel condensate, then route the remaining vapors to a combustion device. Large, high capacity combustion devices are typically available at compressor stations and processing plants and can be used to control pigging gases while meeting the other flaring needs of the facility. There are also numerous low capacity combustion devices available for serving remote launcher/receiver sites.

Route Low-Pressure Systems into Fuel Gas Systems or Vapor Recovery Unit (VRU)

Gases that remain in high pressure barrels after venting to low pressure systems and gases in low pressure barrels can be recovered during depressurization by discharging the gases to very low-pressure systems at the site (e.g., 10-15 psig). Two examples of very low-pressure systems at compressor stations are a fuel gas system and a condensate tank vapor recovery unit (VRU). Applying such an approach can reduce the gas pressure in the barrels to the pressure of the very low-pressure system (e.g., 10 psig), with a corresponding reduction in depressurization emissions.

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Barrel Pump-down Systems

In barrel pump-down systems, small fixed or portable compressors are used to pump vapors in the receiver or a launcher barrel back into the main pipeline prior to venting and opening the barrel hatch. In barrel pump-down systems, the inlet of a gas compressor is connected to the receiver or launcher depressurization line, and the compressor discharge is connected into the main pipeline. Vapors exiting the depressurization line are pulled into the compression system and recovered back into the pipeline at system pressure. These control systems can recover greater than 99% of the depressurization vapors from pig launchers and receivers.

Enhanced Liquid Containment

Covering containers that collect liquids remaining in a receiver barrel after depressurization with a fitted impermeable material will reduce emissions from evaporation. Use of grounded steel receptacles additionally helps ensure safety.

Estimating Potential Emissions from Pigging Activities in Natural Gas Gathering Operations

The Real Gas Law has been used to estimate the emissions from depressurizing launcher and receiver barrels, where a gas compressibility factor is applied to account for non-ideal gas initial conditions (e.g., high pressure).

However, the fundamental assumption of the methodology guiding this approach is that the average pipeline gas profile accurately characterizes the contents of the barrel prior to depressurization. This assumption neglects changes in physical conditions along the pipeline which lead to compositional changes and potential formation of condensate liquid that can accumulate in and/or is swept into the pig receiver during pigging.

Therefore, when considering emissions from pig receivers, the Real Gas Law methodology accounts for depressurizing the natural gas mixture from pressurized conditions to atmospheric; however, the equation does not address the potential flash emissions from volatilization of condensates during depressurization. Using the Real Gas Law alone in circumstances with liquid accumulation can result in an underestimation of the calculated VOC emissions from the receiver.

A complete emissions estimation methodology for receivers would account for the impact of any liquid accumulation in receivers, as a supplement to estimates based on the Real Gas Law.

Enforcement Settlement with MarkWest

On April 24, 2018, the U.S. EPA, the U.S. Department of Justice, and the Pennsylvania Department of Environmental Protection announced a settlement with MarkWest that requires innovative solutions designed to evaluate and address VOC emissions from pigging operations at gathering compressor stations and stand-alone pigging stations. This settlement resulted from joint inspections conducted by the EPA and the Commonwealth of Pennsylvania. MarkWest failed to apply for, and comply with, the required permits and/or recordkeeping requirements under the Nonattainment New Source Review, Prevention of Significant Deterioration and Title V programs, and the Pennsylvania and Ohio State Implementation Plans, for natural gas pigging and venting activities that released excess VOC emissions. MarkWest is undertaking measures to help

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ensure compliance with federal and state regulations and reduce emissions including:

- Operating jumper lines to depressurize launchers and receivers.
- Installing pig ramps in receivers.
- Using a mobile flare to control emissions during depressurization.
- Using shorter (smaller volume) barrels than those presently used in the system.
- Using liquid containers with grounded steel receptacles that are covered at all times when not in use.
- Using an estimation methodology that accounts for the flash emissions from condensates that accumulate in the pig barrel.

MarkWest additionally is performing the following environmental projects to further EPA's goal of protecting and enhancing the public health and the environment:

- Innovation transfer and emission control education: MarkWest will provide a royalty-free license and public educational sessions to promote rapid adoption of its proprietary pig ramp design. This project is aimed at increasing awareness of the emissions from pigging operations and sharing cost-effective methods to reduce these emissions. The adoption of this technology by other midstream operators will further benefit the environment by reducing emissions from pigging operations.
- Ambient air monitoring: MarkWest will install and operate air sampling stations to analyze VOCs downstream of two compressor stations over a period of at least two years. Air monitoring at these facilities is not required by law, but MarkWest agreed to conduct these supplemental environmental projects as part of the settlement to provide local communities, industry, regulators, and other stakeholders valuable information about air emissions generated during midstream operation and maintenance activities, and their impacts on local air quality.

For more information, visit https://www.epa.gov/enforcement/markwest-clean-air-act-settlement-information-sheet

DISCLAIMER: This document aims to explain the application of certain EPA regulatory provisions using plain language. Nothing in this Alert revises or replaces any regulatory provisions, any other part of the Code of Federal Regulations, the Federal Register, or the Clean Air Act. Following the approaches as discussed in this Alert do not equate to or guarantee compliance with the Clean Air Act, its implementing regulations, and associated state/local requirements. For more information, visit: www.epa.gov/compliance.

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Vapor Recovery and Gathering Pipeline Pigging

Lessons Learned from Natural Gas STAR

Chevron Corporation,
New Mexico Oil and Gas Association,
Texas Oil and Gas Association

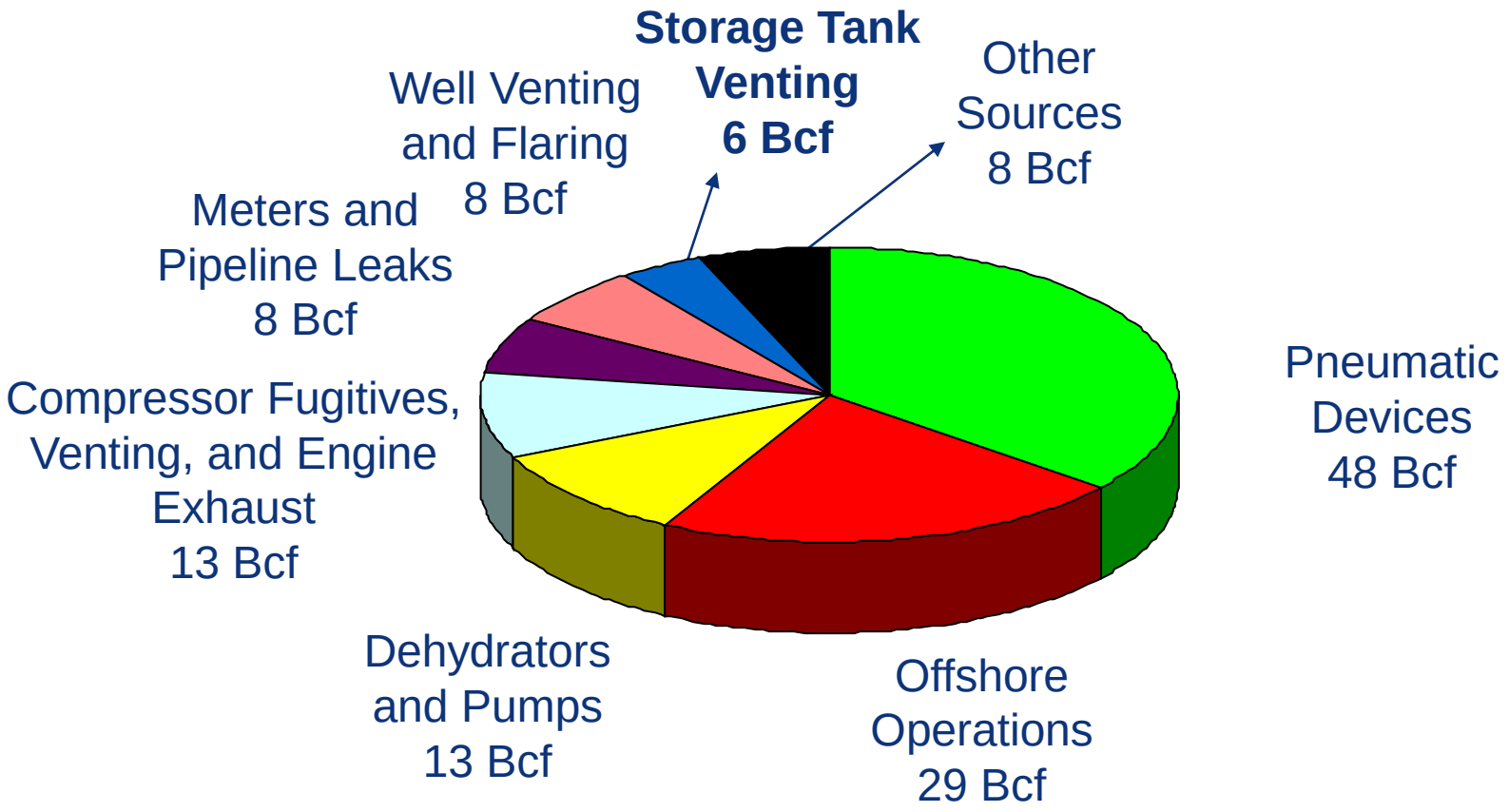
Producers and Processors Technology Transfer Workshop
Midland, Texas
July 23, 2008

epa.gov/gasstar

Reduction Opportunities: Agenda

- Industry Emissions
- Selected Methane Saving Opportunities
  - Vapor Recovery Units
  - Pipeline Pigging
- Discussion

Industry Emissions: Production, Gathering, and Boosting



Source: EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2006.* April, 2008. Available on the web at: epa.gov/climatechange/emissions/usinventoryreport.html

Note: Natural Gas STAR reductions from gathering and boosting operations are reflected in the production sector.

Vapor Recovery Units

- Methane Losses
- Methane Savings
- Is Recovery Profitable?
- Industry Experience
- Lessons Learned

Sources of Methane Losses

- A storage tank battery can vent 5,000 to 500,000 thousand cubic feet (Mcf) of natural gas and light hydrocarbon vapors to the atmosphere each year
  - Vapor losses are primarily a function of oil or condensate throughput, gravity, and gas-oil separator pressure
- Flash losses
  - Occur when crude oil or condensate is transferred from a gas-oil separator at higher pressure to a storage tank at atmospheric pressure
- Working losses
  - Occur when crude or condensate levels change and when liquid in tank is agitated
- Standing losses
  - Occur with daily and seasonal temperature and barometric pressure changes

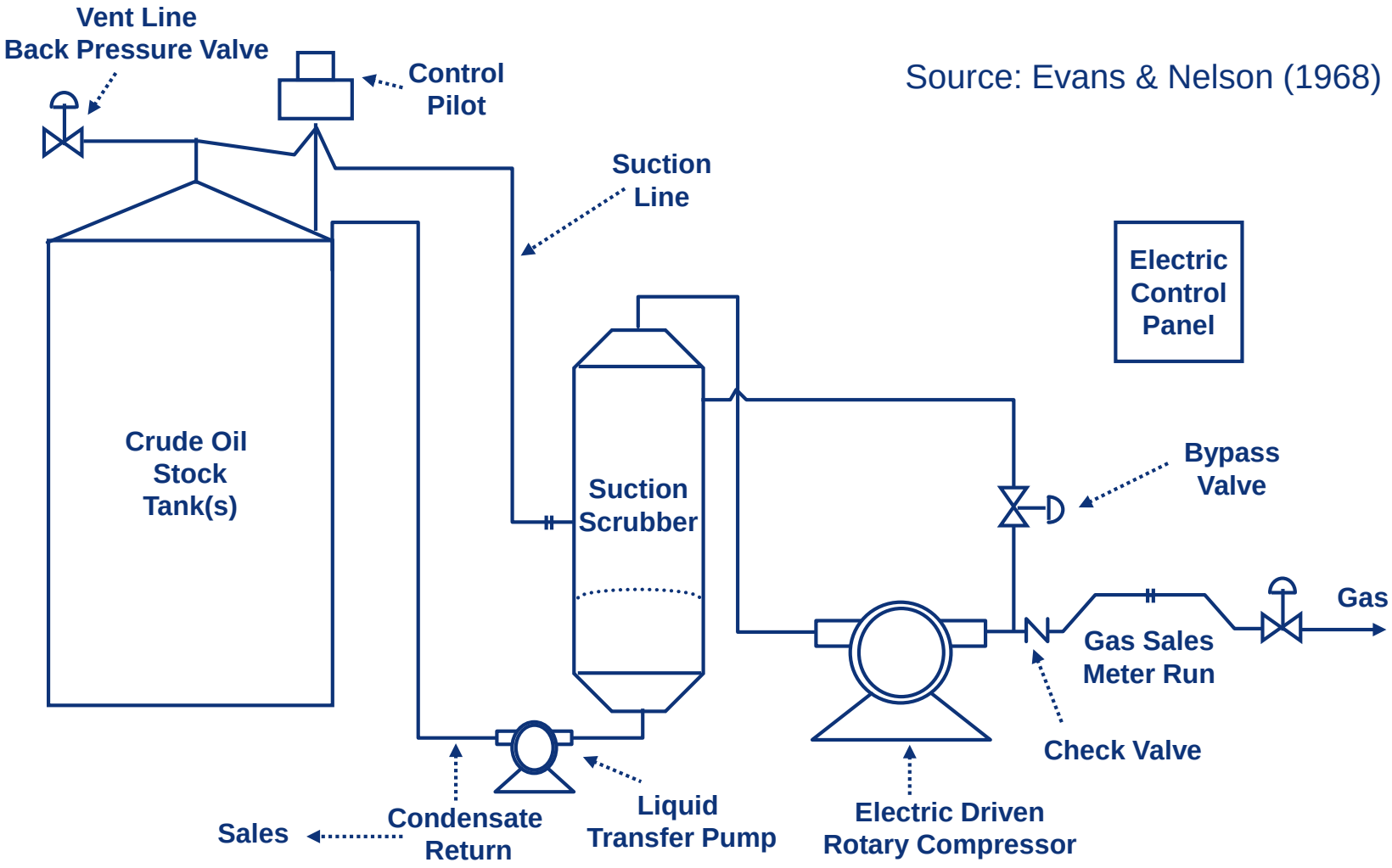
Methane Savings: Vapor Recovery

- Vapor recovery can capture up to 95% of hydrocarbon vapors from tanks
- Recovered vapors have higher heat content than pipeline quality natural gas
- Recovered vapors are more valuable than natural gas and have multiple uses
  - Re-inject into sales pipeline
  - Use as on-site fuel
  - Send to processing plants for recovering valuable natural gas liquids

Types of Vapor Recovery Units

- Conventional vapor recovery units (VRUs)
  - Use screw or vane compressor to suck vapors out of atmospheric pressure storage tanks
  - Scroll compressors are new to this market
  - Require electrical power or engine driver
- Venturi ejector vapor recovery units (EVRU™) or Vapor Jet
  - Use Venturi jet ejectors in place of rotary compressors
  - Contain no moving parts
  - EVRU™ requires a source of high pressure motive gas and intermediate pressure discharge system
  - Vapor Jet requires a high pressure water motive

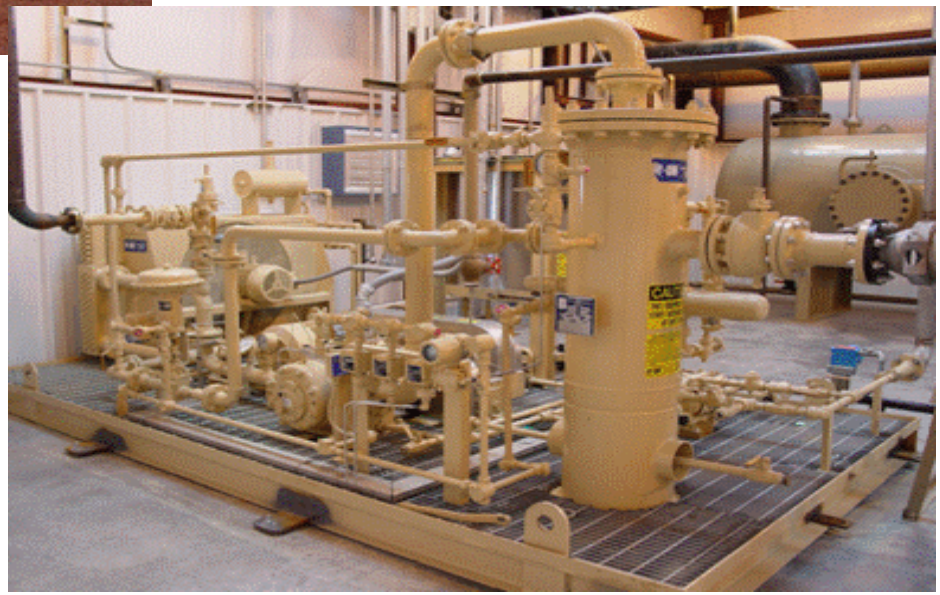
Conventional Vapor Recovery Unit



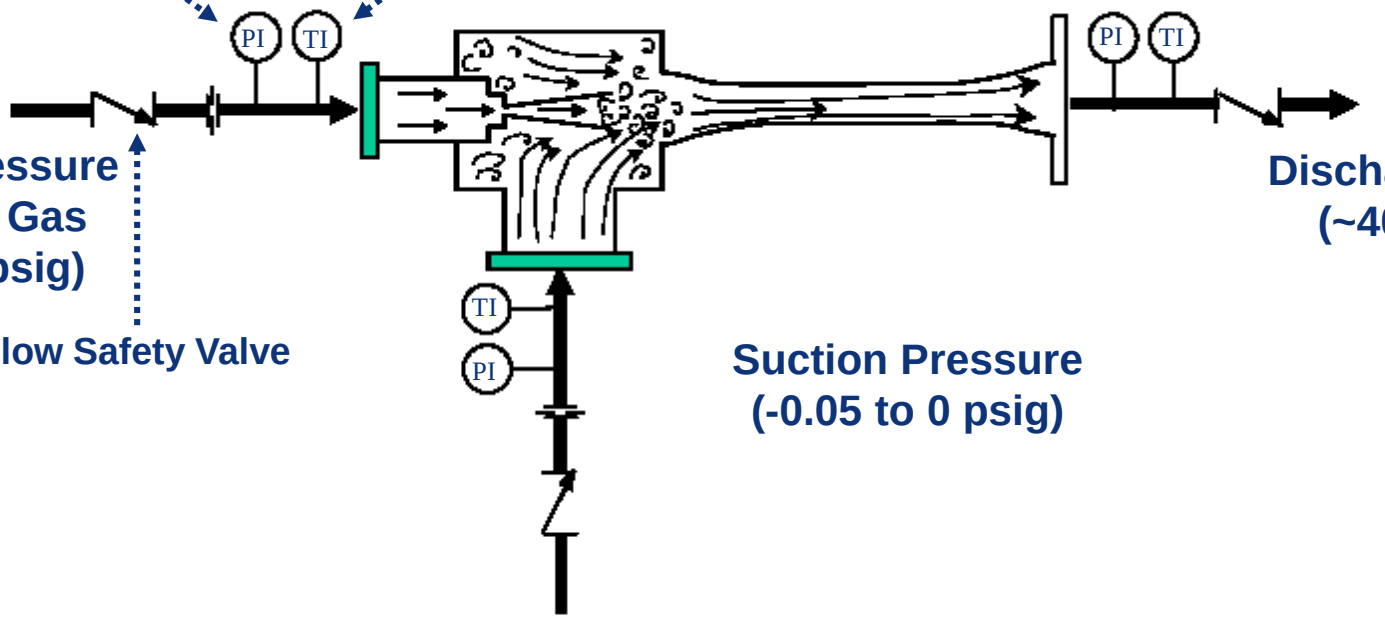
Source: Evans & Nelson (1968)

Vapor Recovery Installations





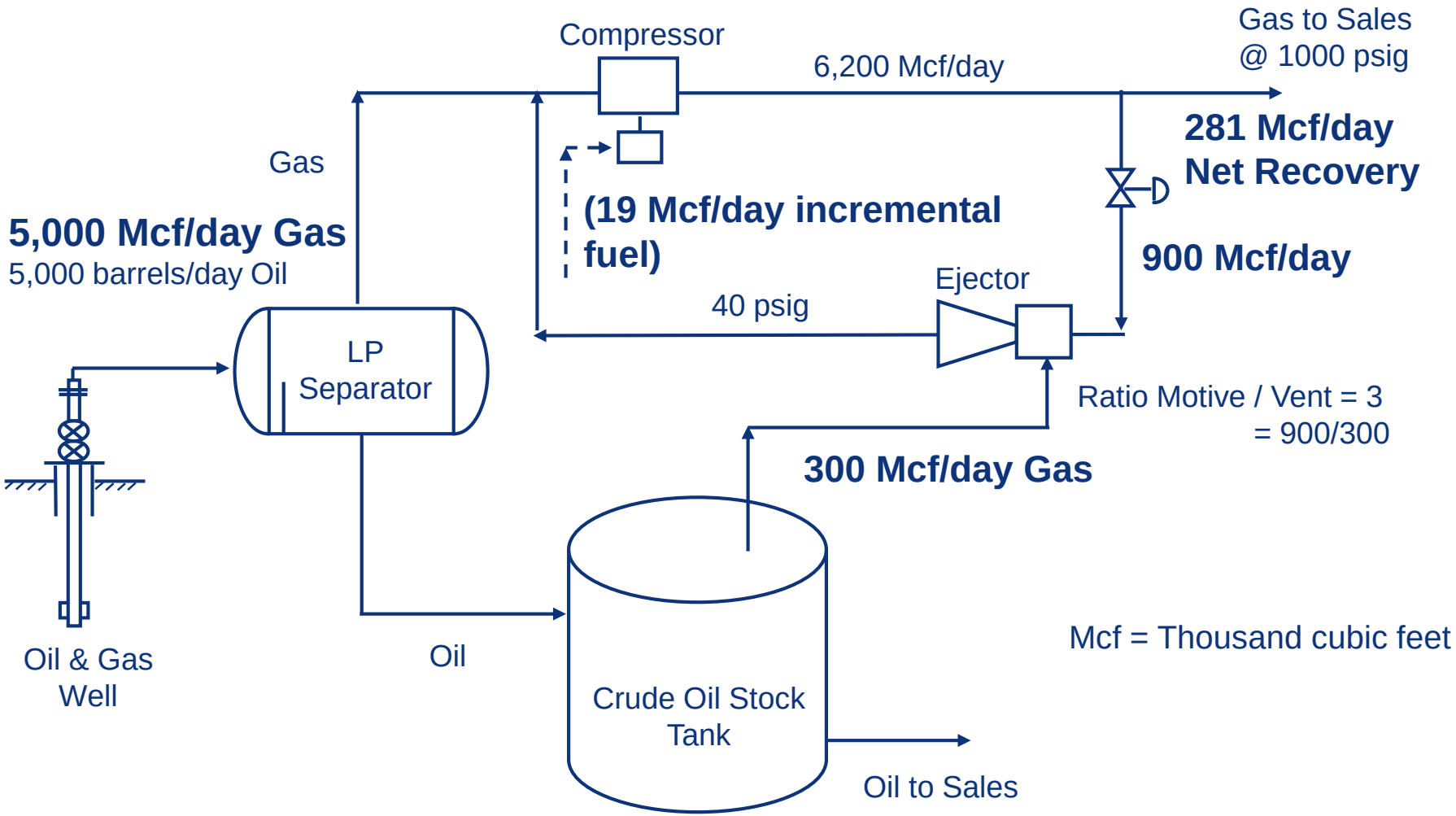
Venturi Jet Ejector*



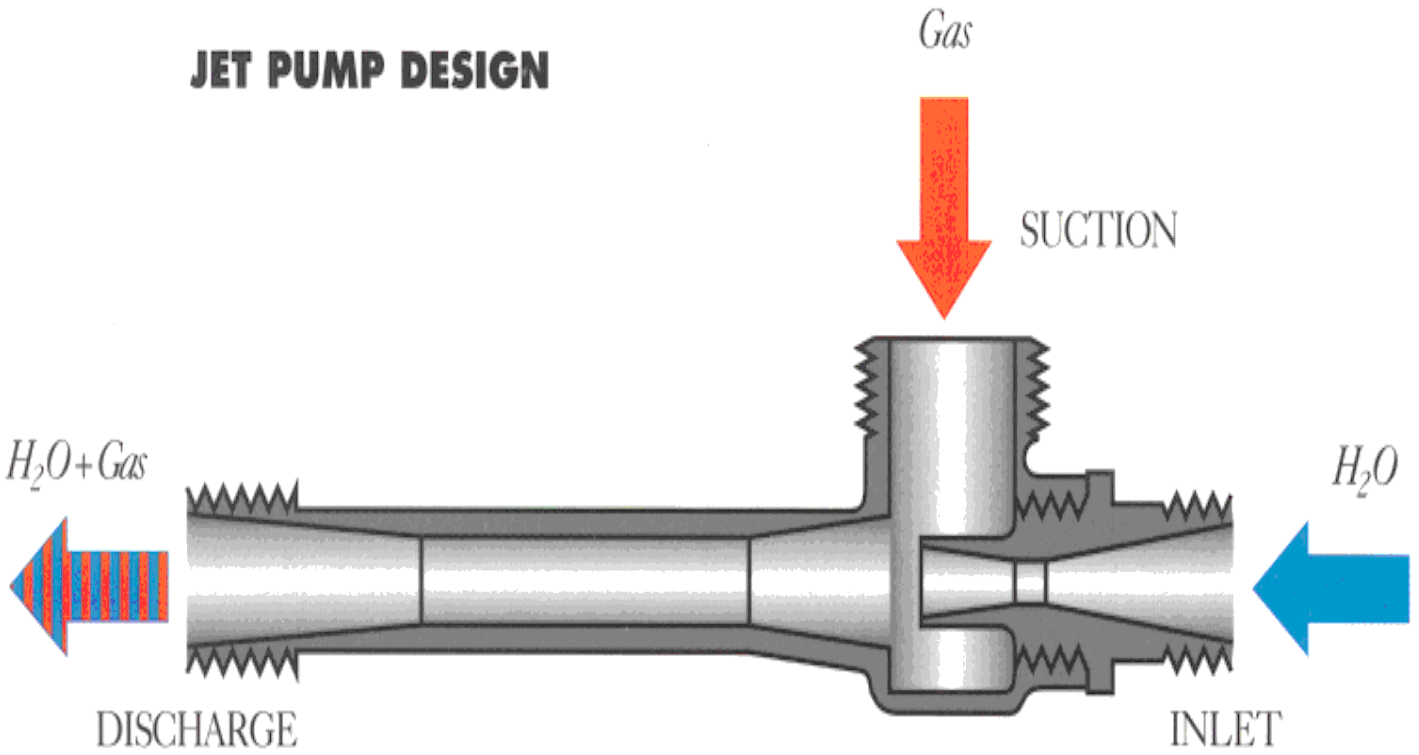
*EVRU™ Patented by COMM Engineering

Adapted from SRI/USEPA-GHG-VR-19
psig = pound per square inch, gauge
psia = pounds per square inch, absolute

Vapor Recovery with Ejector

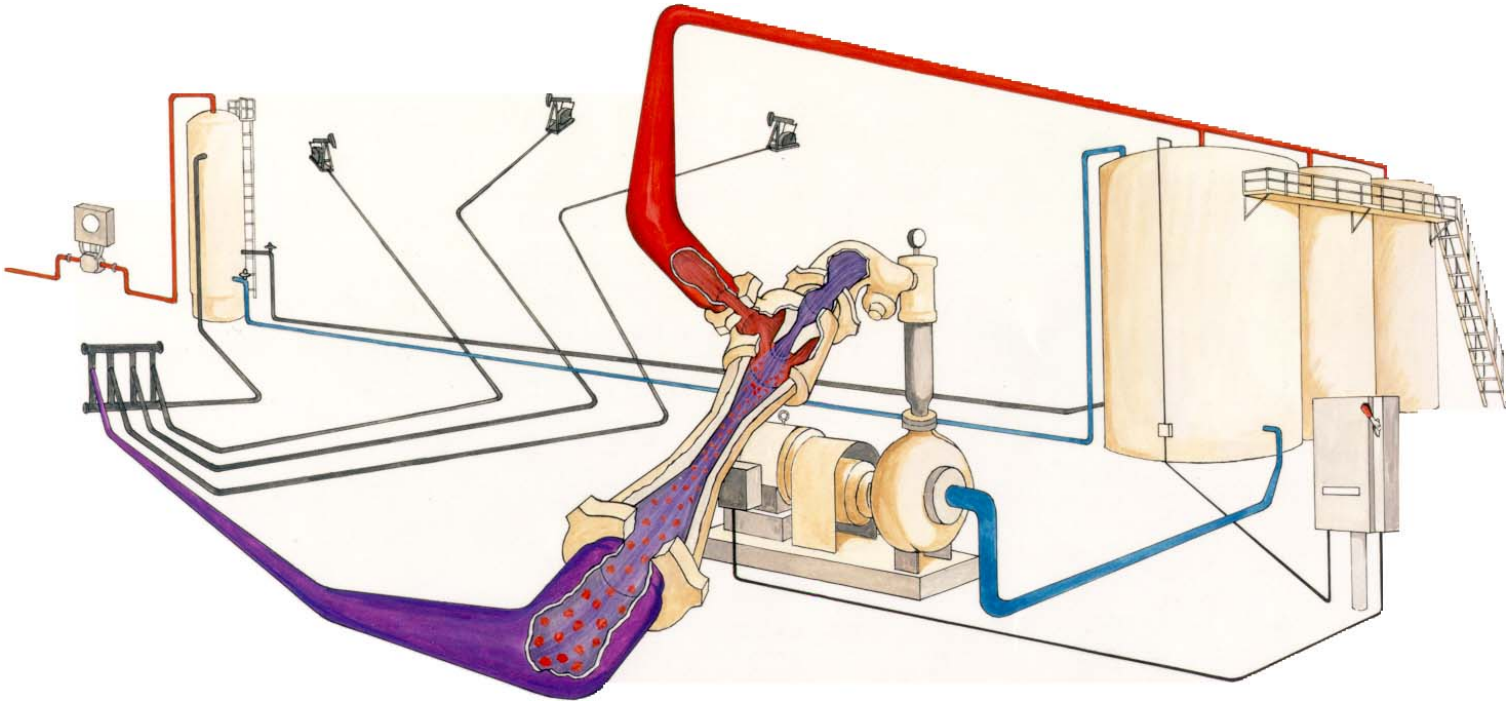


Vapor Jet System*



*Patented by Hy-Bon Engineering

Vapor Jet System*



- Utilizes produced water in closed loop system to effect gas gathering from tanks
- Small centrifugal pump forces water into Venturi jet, creating vacuum effect
- Limited to gas volumes of 77 Mcf/day and discharge pressure of 40 psig

*Patented by Hy-Bon Engineering

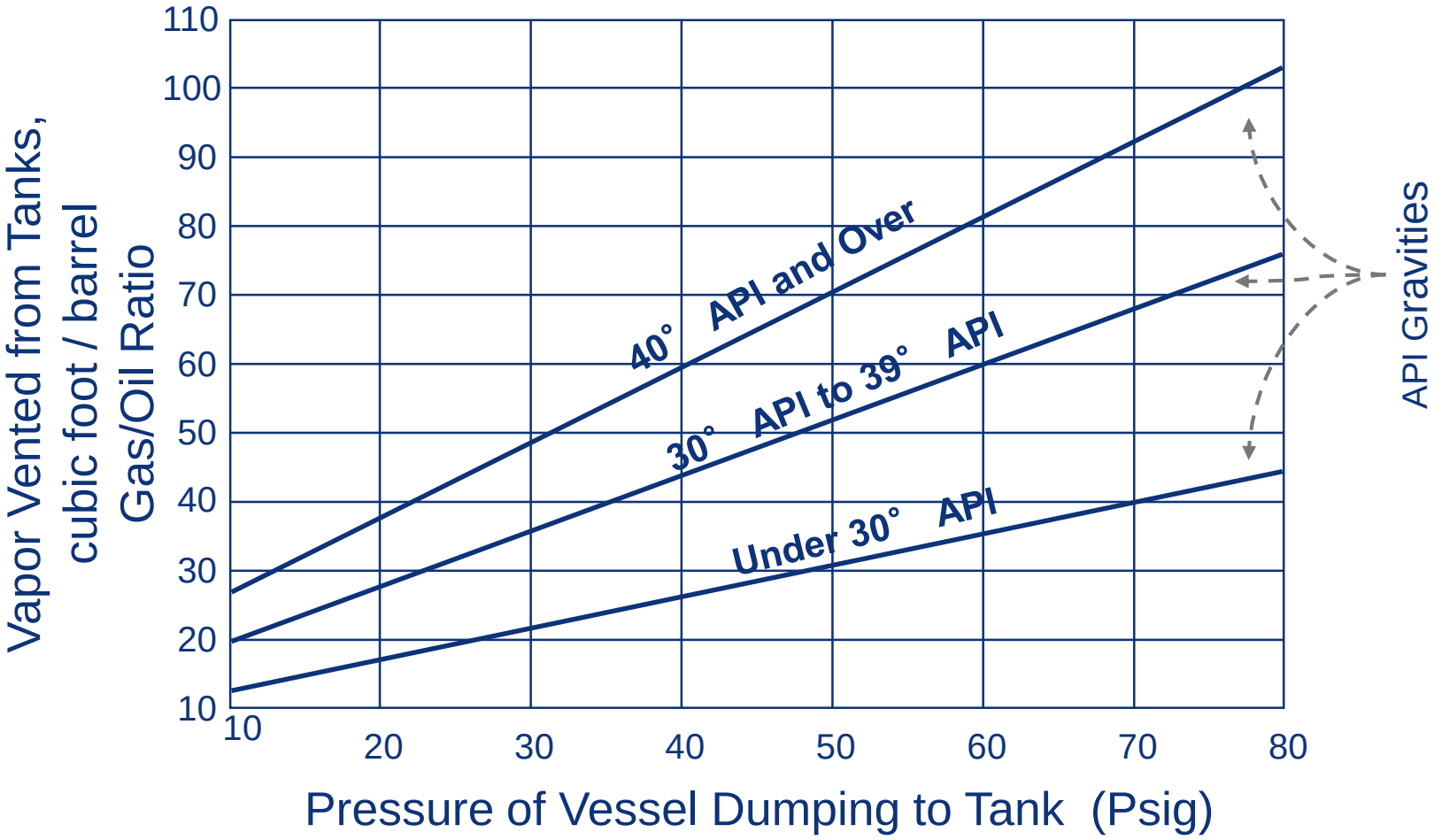
Criteria for Vapor Recovery Unit Locations

- Steady source and sufficient quantity of losses
  - Crude oil stock tank
  - Flash tank, heater/treater, water skimmer vents
  - Gas pneumatic controllers and pumps
  - Dehydrator still vent
  - Pig trap vent
- Outlet for recovered gas
  - Access to low pressure gas pipeline, compressor suction, or on-site fuel system
- Tank batteries not subject to air regulations

Quantify Volume of Losses

- Estimate losses from chart based on oil characteristics, pressure, and temperature at each location (± 50%)
- Estimate emissions using the E&P Tank Model (± 20%)
- Engineering Equations – Vasquez Beggs (± 20%)
- Measure losses using recording manometer and well tester or ultrasonic meter over several cycles (± 5%)
  - This is the best approach for facility design

Estimated Volume of Tank Vapors



° API = API gravity

Estimated Volume of Tank Vapors

- Atmospheric tanks may emit large amounts of tank vapors at relatively low separator pressure

Vasquez-Beggs Equation

$$GOR = A \times (G_{flash\ gas}) \times (P_{sep} + 14.7)^{B} \times \exp\left(\frac{C \times G_{oil}}{T_{sep} + 460}\right)$$

where,

GOR	=	Ratio of flash gas production to standard stock tank barrels of oil produced, in scf/bbl oil (barrels of oil corrected to 60°F)
$G_{flash\ gas}$	=	Specific gravity of the tank flash gas, where air = 1. A suggested default value for $G_{flash\ gas}$ is 1.22 (TNRCC; Vasquez, 1980)
G_{oil}	=	API gravity of stock tank oil at 60°F
P_{sep}	=	Pressure in separator, in psig
T_{sep}	=	Temperature in separator, °F

For $G_{oil} \leq 30$°API: A = 0.0362; B = 1.0937; and C = 25.724

For $G_{oil} > 30$°API: A = 0.0178; B = 1.187; and C = 23.931

psig – pounds per square inch, gauge
scf – standard cubic feet
bbl – barrels

What is the Recovered Gas Worth?

- Value depends on heat content of gas
- Value depends on how gas is used
  - On-site fuel
    - Valued in terms of fuel that is replaced
  - Natural gas pipeline
    - Measured by the higher price for rich (higher heat content) gas
  - Gas processing plant
    - Measured by value of natural gas liquids and methane, which can be separated
- Gross revenue per year = (Q x P x 365) + NGL
  - Q = Rate of vapor recovery (Mcf per day)
  - P = Price of natural gas
  - NGL = Value of natural gas liquids

Value of Natural Gas Liquids

	1 Btu/gallon	2 MMBtu/ gallon	3 $/gallon	4 $/MMBtu[1,2] (=3/2)
Methane	59,755	0.06	0.43	7.15
Ethane	74,010	0.07	1.51	21.57
Propane	91,740	0.09	1.99	22.11
n Butane	103,787	0.10	2.48	24.80
iso Butane	100,176	0.10	2.49	24.90
Pentanes+*	105,000	0.11	3.08	28.00

	5 Btu/cf	6 MMBtu/Mcf	7 $/Mcf (=4*6)	8 $/MMBtu	9 Vapor Composition	10 Mixture (MMBtu/Mcf)	11 Value ($/Mcf) (=8*10)
Methane	1,012	1.01	$7.22	7.15	82%	0.83	$5.93
Ethane	1,773	1.77	$38.18	21.57	8%	0.14	$3.05
Propane	2,524	2.52	$55.71	22.11	4%	0.10	$2.23
n Butane	3,271	3.27	$81.09	24.80	3%	0.10	$2.43
iso Butane	3,261	3.26	$80.90	24.90	1%	0.03	$0.81
Pentanes+	4,380	4.38	$122.64	28.00	2%	0.09	$2.45
Total						1.289	$16.90

1 – Natural Gas Price assumed at $7.15/MMBtu as on Mar 16, 2006 at Henry Hub
2 – Prices of Individual NGL components are from Platts Oilgram for Mont Belvieu, TX July 11, 2008

Cost of a Conventional VRU

Vapor Recovery Unit Sizes and Costs				
Capacity (Mcf/day)	Compressor Horsepower	Capital Costs ($)	Installation Costs ($)	O&M Costs ($/year)
25	5 to 10	20,421	10,207 to 20,421	7,367
50	10 to 15	26,327	13,164 to 26,327	8,419
100	15 to 25	31,728	15,864 to 31,728	10,103
200	30 to 50	42,529	21,264 to 42,529	11,787
500	60 to 80	59,405	29,703 to 59,405	16,839
Cost information provided by United States Natural Gas STAR companies and VRU manufacturers, 2006 basis.				

Is Recovery Profitable?

Financial Analysis for a Conventional VRU Project						
Peak Capacity (Mcf/day)	Installation & Capital Costs[1] ($)	O&M Costs ($/year)	Value of Gas[2] ($/year)	Annual Savings ($)	Simple Payback (months)	Internal Rate of Return
25	$35,738	$7,367	$77,106	$69,739	10	121%
50	$46,073	$8,419	$154,213	$145,794	6	204%
100	$55,524	$10,103	$308,425	$298,322	4	352%
200	$74,425	$11,787	$616,850	$605,063	3	537%
500	$103,959	$16,839	$1,542,125	$1,525,286	2	974%

1 – Unit cost plus estimated installation of 75% of unit cost
2 – $16.90 x ½ peak capacity x 365, Assumed price includes Btu enriched gas (1.289 MMBtu/Mcf)

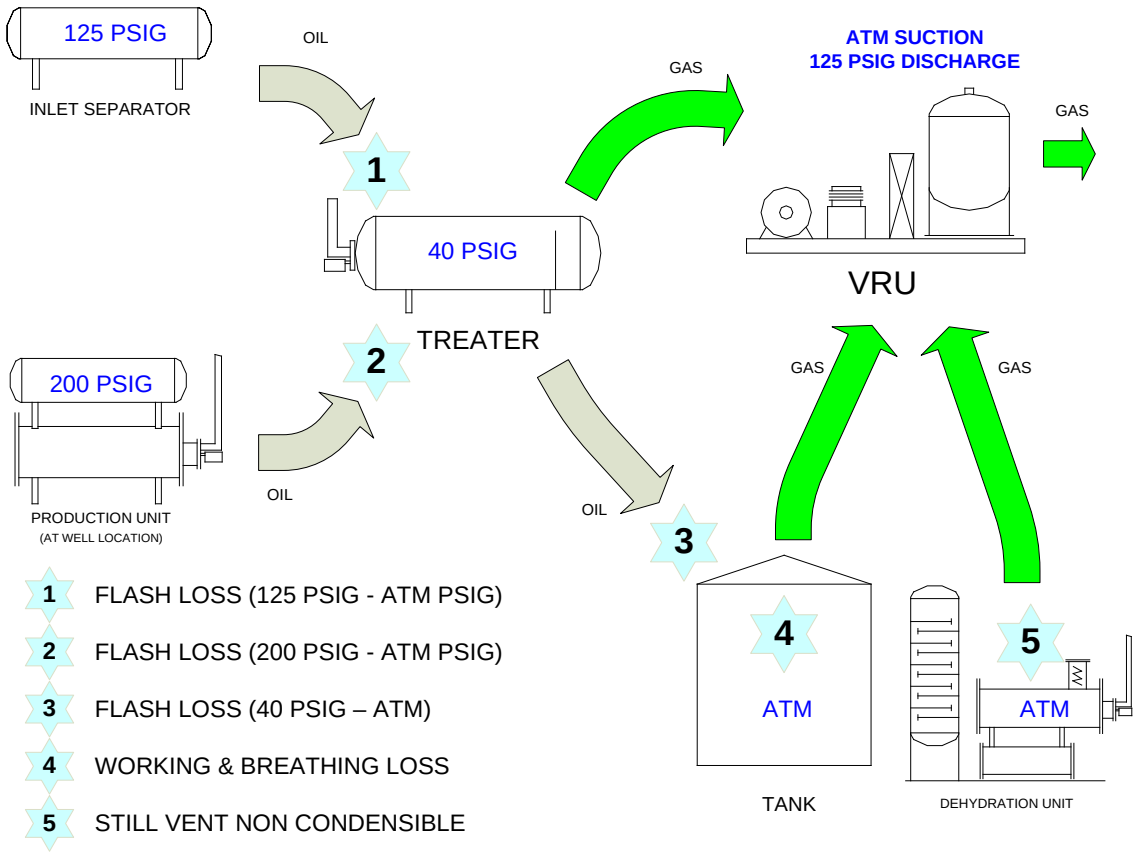
Industry Experience: EnCana Oil & Gas

- Vapor recovery unit installed in Frenchie Draw, WY
- Captures vapors from
  - Separators
  - Crude oil storage tank
  - Non-condensable dehydrator still gas
- VRU designed to handle 500 Mcf/day
  - Additional capacity over the estimated 284 Mcf/day of total gas from all emission sources

Industry Experience: EnCana Oil & Gas

- Quantify the volume of vapor emissions

Total Emissions-
284 MSCFD



Source: EnCana Oil & Gas (USA) Inc.

EnCana Oil & Gas: Project Costs

- Determine the cost of VRU project

Installation

VRU Unit (500 Mcfd) -	$90,000
Generator-	$85,000
Vent Header-	$25,000
Labor-	$200,000
TOTAL	$400,000

O & M

VRU Unit (500 Mcfd) -	$15,000
Generator-	$18,000
Fuel-	$73,000
TOTAL	$106,000

EnCana Oil & Gas: Project Economics

- Evaluate VRU economics

Capacity–	500 Mcfd
Installation Cost -	$400,000
O&M-	$106,000/year
Value of Gas*-	$788,400/year
Payback-	7 months
Return on Investment-	170%

*Gas price assumed to be $ 7.60 by Encana

Industry Experience: Anadarko

- Vapor Recover Tower (VRT)
  - Add separation vessel between heater treater or low pressure separator and storage tanks that operates at or near atmospheric pressure
    - Operating pressure range: 1 psi to 5 psi
  - Compressor (VRU) is used to capture gas from VRT
  - Oil/Condensate gravity flows from VRT to storage tanks
    - VRT insulates the VRU from gas surges with stock tank level changes
    - VRT more tolerant to higher and lower pressures
    - Stable pressure allows better operating factor for VRU

Industry Experience: Anadarko

- VRT reduces pressure drop from approximately 50 psig to 1-5 psig
  - Reduces flashing losses
  - Captures more product for sales
  - Anadarko netted between $7 to $8 million from 1993 to 1999 by utilizing VRT/VRU configuration
- Equipment Capital Cost: $11,000
- Standard size VRTs available based on oil production rate
  - 20” x 35’
  - 48” x 35’
- Anadarko has installed over 300 VRT/VRUs since 1993 and continues on an as needed basis

VRT/VRU Photos





Courtesy of Anadarko

Lessons Learned

- Vapor recovery can yield generous returns when there are market outlets for recovered gas
  - Recovered high heat content gas has extra value
  - Vapor recovery technology can be highly cost-effective in most general applications
  - Venturi jet models work well in certain niche applications, with reduced operating and maintenance costs
- Potential for reduced compliance costs can be considered when evaluating economics of VRU, EVRU™, or Vapor Jet

Lessons Learned (continued)

- VRU should be sized for maximum volume expected from storage tanks (rule-of-thumb is to double daily average volume)
- Rotary vane, screw or scroll type compressors recommended for VRUs where Venturi ejector jet designs are not applicable
- EVRU™ recommended where there is a high pressure gas compressor with excess capacity
- Vapor Jet recommended where there is produced water, less than 75 Mcf per day gas and discharge pressures below 40 psig

Methane Losses from Pipeline Pigging

- Gas lost when launching and receiving a pig
- Fugitive emissions from pig launcher/receiver valves
- Gas lost from storage tanks receiving condensate removed by pigging
- Gas vented from pipeline blowdowns

Pigging Pipelines

- Hydrocarbons and water condense inside pipelines, causing pressure drop and reducing gas flow
- Periodic line pigging removes liquids and debris to improve gas flow
  - Also inspect pipeline integrity
- Efficient pigging:
  - Keeps pipeline running continuously
  - Keeps pipeline near maximum throughput by removing debris
  - Minimizes product losses during launch/capture

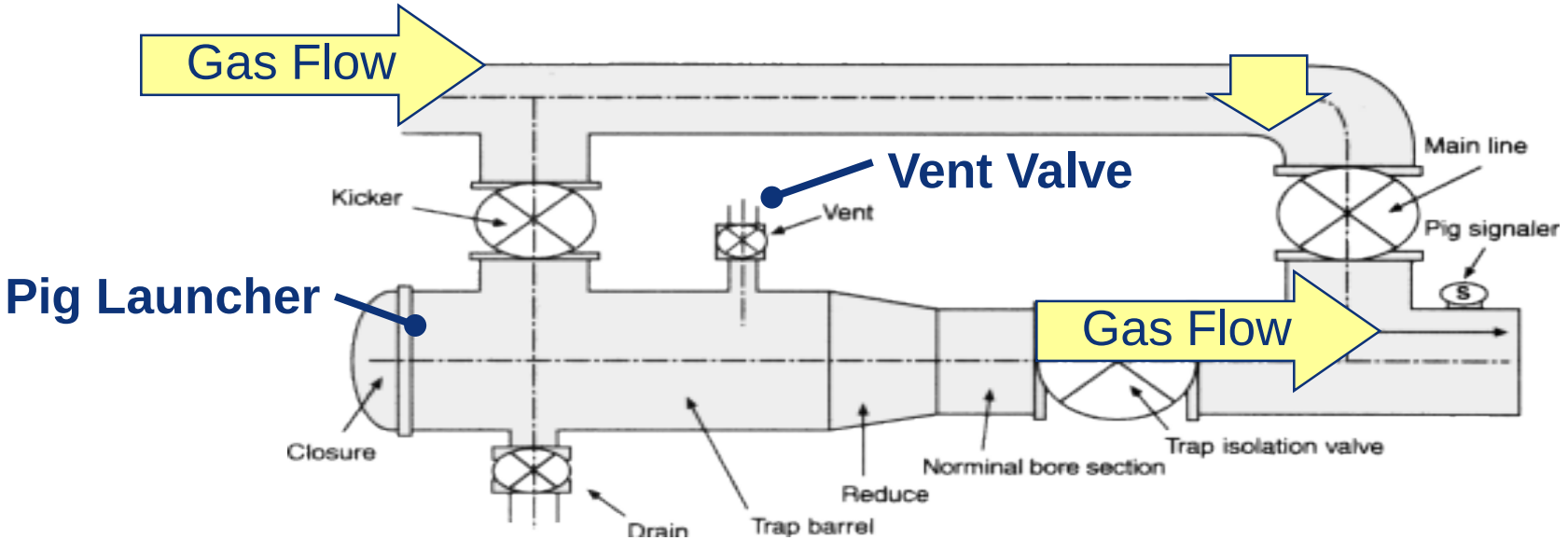




Source: www.girardind.com/

How Does Pigging Vent Methane?

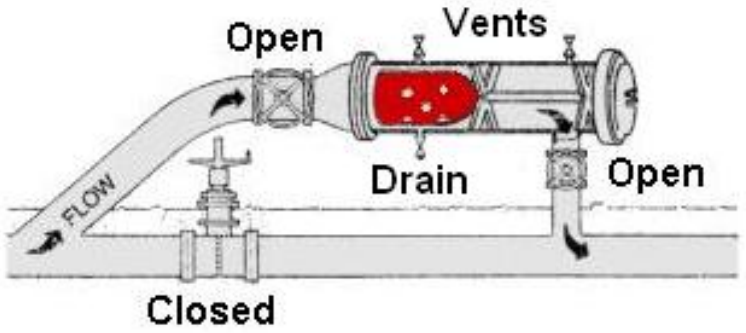
- Pig launchers have isolation valves for loading pigs, pressurizing pigs, and launching pigs with gas bypassed from the pipeline
- Launcher pressuring/depressuring loses methane out the vent valve



Source: www.girardind.com/

Pigging Vents Methane Twice

- Methane lost through vent valve on the launcher and again through vent valve on the receiver
  - Once receiver is isolated from the line, it must be depressured to remove the pig
  - Liquids ahead of the pig drain to a vessel or tank
- *MORE than twice:* isolation valve leaks may cause excessive venting to depressure



Source: www.girardind.com/

Methane Recovery

- Pipeline maintenance requires pipe section blowdown before work can begin
- Gas in pipeline is usually vented to the atmosphere
- Use inert gas and pig
- Route vent to vapor recovery system or fuel gas
  - One Partner reported connecting pig receiver vent to fuel gas to recover gas while working a tight isolation

Is Recovery Profitable?

- One partner pigged gathering lines 30 to 40 times per year, collecting several thousand barrels of condensate per application
- Partner reported saving 21,400 Mcf/year from recovering flash gases
- Dedicated vapor recovery unit (VRU) was installed with an electric compressor at an installation cost of $24,000 and an annual operating cost of $40,000 mostly for electricity
- Large gas savings and increasing gas prices will offset costs

Gas Price ($/Mcf)	$7.00
Gas Saved (Mcf/year)	21,400
Annual Savings ($/year)	$149,800
Installed Cost	$24,000
Operating Cost	$40,000
Payback Period (years)	0.3

Discussion

- Industry experience applying these technologies and practices
- Limitations on application of these technologies an practices
- Actual costs and benefits

Install Flares



Technology/Practice Overview

Description

Remote, unmanned production sites and compressor stations may vent low-pressure natural gas and vapors from storage tanks and other onsite equipment to the atmosphere. These gases, which contain methane and often volatile organic compounds (VOC), hydrogen sulfide, and hazardous air pollutants (HAP), can pose an environmental, health, and safety hazard. In order to reduce these emissions, Partners have reported installing flares to combust these gases instead of venting them to the atmosphere.

Partners have applied flaring technology typically consisting of a small flare stack with one or two pilots. Emissions sources, such as tank vents, compressor blowdown lines, low-pressure separator vents, overpressure relief valves, and other vent streams are piped directly to the flare.

Operating Requirements

If the heat content of the stream is below 300 Btu per scf, auxiliary fuel is needed. The average pilot gas consumption is 70 scf per hour per pilot burner.

Applicability

Flares can be applied to all point source vented emissions of combustible gas with minimal sulfur content.

Methane Emissions

The methane emissions reduction is uniquely dependent on the types and sizes of sources and the methane content of the flared gas. Wellhead gas may range from 70 to 90 percent methane while crude oil production tank vapors

- ☐ Compressors/Engines
- ☐ Dehydrators
- ☐ Directed Inspection & Maintenance
- ☐ Pipelines
- ☐ Pneumatics/Controls
- ☐ Tanks
- ☐ Valves
- ☐ Wells
- ■ Other

Applicable Sector(s)

- ■ Production
- ☐ Processing
- ■ Transmission
- ☐ Distribution

Other Related PROs:

Install Electronic Flare Ignition Devices, PRO No. 903

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*2,000 Mcf per flare (with a single pilot)*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	2,000 Mcf	N/A	$21,000	$4,200	None
$5.00/Mcf	2,000 Mcf	N/A	$21,000	$3,000	None
$3.00/Mcf	2,000 Mcf	N/A	$21,000	$1,800	None

** Because the natural gas is flared, there are no economic gas savings associated with this activity.*

Additional Benefits

- Safer operations

Install Flares (Cont'd)

may be as low as 50 percent methane. Partners have reported production site application for tank vents, relief valves, and compressor blow-down at 2,000 Mcf per year, low-pressure separators at 4,000 Mcf per year, and condensate tanks at 36,000 Mcf per year.

Economic Analysis

Basis for Costs and Emissions Savings

Methane emissions reductions of 2,000 Mcf per year apply to a single flare with a single pilot. Costs for a flare are estimated to be $3,000 based on partner experiences (which vary significantly and are often between $1,000 and $5,000). In addition, and there is a fuel cost of $1,800 per year for each pilot (at $3 per Mcf of gas).

Discussion

Flares are commonly installed on higher-pressure blowdown or emergency pressure relief valves for safety reasons. Low-pressure gas installations have been justified by environmental emissions control. There are no revenues from the gas as it is destroyed through combustion.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

Oil and Natural Gas Sector Pneumatic Devices

Report for Oil and Natural Gas Sector Pneumatic Devices

Review Panel

April 2014

Prepared by

U.S. EPA Office of Air Quality Planning and Standards (OAQPS)

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PREFACE

On March 28, 2014 the Obama Administration released a key element called for in the President's Climate Action Plan: a Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

This technical white paper is one of those steps. The paper, along with four others, focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. The Agency is seeking input from independent experts, along with data and technical information from the public. The EPA will use these technical documents to solidify our understanding of these potentially significant sources, which will allow us to fully evaluate the range of options for cost-effectively cutting VOC and methane waste and emissions.

The white papers are available at:

www.epa.gov/airquality/oilandgas/whitepapers.html

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1.0 INTRODUCTION

The oil and natural gas exploration and production industry in the U.S. is highly dynamic and growing rapidly. Consequently, the number of wells in service and the potential for greater emissions from oil and natural gas sources is also growing. There were an estimated 504,000 producing gas wells in the U.S. in 2011 (U.S. EIA, 2012a), and an estimated 536,000 producing oil wells in the U.S. in 2011 (U.S. EIA, 2012b). It is anticipated that the number of gas and oil wells will continue to increase substantially in the future because of the continued and expanding use of horizontal drilling combined with hydraulic fracturing (referred to here as simply hydraulic fracturing).

Due to the growth of this sector and the potential for increased air emissions, it is important that the U.S. Environmental Protection Agency (EPA) obtain a clear and accurate understanding of emerging data on emissions and available mitigation techniques. This paper presents the Agency's understanding of emissions and available emissions mitigation techniques from a potentially significant source of emissions in the oil and natural gas sector.

1.1 Definition of the Source

The focus of this white paper is natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps. Such pneumatic controllers and pumps are widespread in the oil and natural gas industry and emit natural gas, which contains methane and VOCs. In some applications, pneumatic controllers and pumps used in this industry may be driven by gases other than natural gas and, therefore, do not emit methane or VOCs.

1.1.1 Pneumatic Controllers

For the purposes of this white paper, a *pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, pressure difference and temperature. Based on the source of power, two types of pneumatic controllers are defined for this paper:

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- *Natural gas-driven pneumatic controller* means a pneumatic controller powered by pressurized natural gas.
- *Non-natural gas-driven pneumatic controller* means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this white paper, they are characterized primarily by their emissions characteristics:

- *Continuous bleed pneumatic controllers* are those with a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator. For the purposes of this paper, continuous bleed controllers are further subdivided into two types based on their bleed rate:
    - *Low bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).
    - *High bleed*, having a bleed rate of greater than 6 scfh.
- *Intermittent pneumatic controller* means a pneumatic controller that vents non-continuously. These natural gas-driven pneumatic controllers do not have a continuous bleed, but are actuated using pressurized natural gas.
- *Zero bleed pneumatic controller* means a pneumatic controller that does not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

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1.1.2 Pneumatic Pumps

Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers. Pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available (GRI/EPA, 1996d). The supply gas for these pumps can be compressed air, but most often these pumps use natural gas from the production stream (GRI/EPA, 1996e).

1.2 Background

1.2.1 Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations, across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these natural gas-driven pneumatic controllers, natural gas is released with every actuation of the valve, i.e., valve movement. In some designs, natural gas is also released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs of natural gas-driven pneumatic controllers: (1) continuous bleed controllers are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) intermittent controllers release gas only when they open or close a valve or as they throttle the gas flow; and (3) zero bleed controllers, which are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere (EPA, 2011a).

As noted above, intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. Thus, the actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Continuous bleed controllers also vent an additional volume of gas during

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actuation, in addition to the device's continuous bleed stream. Thus, actual emissions from a continuous bleed device also depend, in part, on the frequency of activation and the amount of gas vented during activation. As the name implies, zero bleed controllers are considered to emit no natural gas to the atmosphere (EPA, 2011a).

In general, intermittent controllers serve functionally different purposes than bleed controllers and, therefore, cannot replace bleed controllers in most (but not all) applications. Furthermore, zero bleed controllers are "closed loop" systems that can be used only in applications with very low pressure and therefore may not be suitable to replace continuous bleed pneumatic controllers in many applications.

Non-natural gas-driven pneumatic controllers can be used in some applications. These controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Instrument air systems are feasible only at oil and natural gas locations that have electrical service sufficient to power an air compressor. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic controllers can be used. Non-natural gas-driven controllers do not directly release methane or VOCs, but may have secondary impacts related to generation of required electrical power (EPA, 2011a).

1.2.2 Pneumatic Pumps

There are two types of pneumatic pumps that are commonly used in the oil and natural gas sector: piston and diaphragm (GRI/EPA, 1996d). These pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas (GRI/EPA, 1996d).

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The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation (GRI/EPA, 1996d). Pneumatic pumps used for chemical injection are needed in oil and natural gas production to inject small amounts of chemicals to limit processing problems and protect equipment. Typical chemicals that are injected into the process include: biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers and hydrogen sulfide scavengers (GRI/EPA, 1996d). These chemicals are normally injected using pneumatic pumps at the wellhead, and into gathering lines or at production separation facilities (GRI/EPA, 1996d). Pneumatic pumps, commonly referred to as "Kimray" pumps, used for glycol circulation recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber (GRI/EPA, 1996e).

1.3 Purpose of the White Paper

This white paper provides a summary of the EPA's understanding of the emissions from natural gas-driven pneumatic controllers and pumps in the oil and natural gas sector, the mitigation techniques available to reduce these emissions, the efficacy of these techniques and the prevalence of these techniques in the field. Section 2 of this document provides the EPA's understanding of emissions from pneumatic controllers and pumps, and Section 3 provides our understanding of available mitigation techniques. Section 4 summarizes the EPA's understanding based on the information presented in Sections 2 and 3, and Section 5 presents a list of charge questions for reviewers to assist the EPA with obtaining a more comprehensive understanding of pneumatic controller and pump VOC and methane emissions and emission mitigation techniques.

2.0 AVAILABLE EMISSIONS DATA AND ESTIMATES

There are a number of studies that have been published that have estimated VOC and methane emissions from pneumatic controllers and pneumatic pumps in the oil and natural gas sector. These studies have used different methodologies to estimate these emissions including the use of equipment counts and emission factors and direct measurement of emissions. Section 2.1 discusses the studies relevant to pneumatic controllers, and Section 2.2 discusses the studies

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relevant to pneumatic pumps. These studies are listed in Table 2-1, along with an indication of the type of information contained in the study.

Table 2-1. Summary of Major Sources of Pneumatic Controller and Pump Information

Report Name	Affiliation	Year of Report	Activity Factor	Pneumatic Controllers	Pneumatic Pumps
Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)	Gas Research Institute / EPA	1996	Nationwide	X	X
Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)	EPA	1999	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)	EPA	2014	Nationwide/ Regional	X	X
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	EPA	2013	Basin	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	Nationwide	X	
Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino, 2013)	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)	ICF International	2014	Nationwide	X	X

2.1 Discussion of Data Sources for Pneumatic Controllers

This section presents and discusses pertinent studies and data sources that estimate emissions from pneumatic controllers.

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2.1.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)

This report's main objective was to quantify annual methane emissions from pneumatic controllers from the natural gas production, processing, transmission, and distribution sectors. The methane emissions were determined by developing average annual emissions factors for the various types of pneumatic controllers used in each of the natural gas segments. The annual emission factors were then extrapolated to a national estimate using activity factors for each of the natural gas segments.

Production

The data used to develop emission factors for pneumatic controllers in the natural gas production sector were obtained from a study performed by the Canadian Petroleum Association (CPA)[1], manufacturers' data, measured emission rates[2], data collected from site visits, and literature data for methane composition.

The CPA study consisted of methane and VOC emission measurements from pneumatic controllers in two types of service: 19 in on/off service and 16 in throttling service.[3] The CPA study determined the average natural gas emission rate for on/off controllers was 213 standard cubic feet per day per device (scfd/device), and the average natural gas emission rate for throttling controllers was 94 scfd/device. For throttling controllers, the CPA study did not distinguish between the throttling controllers with intermittent bleed rates and throttling controllers with continuous bleed rates. In addition, only one throttling controller actuated during the emission measurement. Therefore, these measurements are lower in comparison to field measurements of similar devices in the U.S. (GRI/EPA, 1996c).

---

[1] Picard, D.J., B.D. Ross, and D.W.H. Koon, *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta*. Canadian Petroleum Association, Calgary, Alberta, 1992.

[2] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.

[3] Controllers in on/off service wait until a specific set point is reached before actuating (e.g., a high or low liquid level). Controllers in throttling service maintain a desired set point (e.g., pressure).

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The manufacturers' data were obtained from four manufacturers of pneumatic controllers and were based on laboratory testing of new controllers. The manufacturers' noted that emissions in the field can be higher due to operating condition, age, and wear of the device. The gas consumption rates for the manufacturers' pneumatic controllers ranged from 0 to 2,150 scfd. The manufacturers noted that the emissions from these controllers in the field may be higher than the reported maximum value (GRI/EPA, 1996c).

The measured emissions data[4] were collected by connecting a flow meter to the supply line between the pressure regulator and the controller to measure the gas consumption of the controller. The duration of the test depended on the operating conditions. For steady operating conditions, one data point was measured for 15-20 minutes. For variable operating conditions, several one-hour measurements were taken. The data set contained a total of 41 measurements from a combination of continuous bleed controllers from offshore and onshore production sites and transmission stations. The average gas emissions rates for continuous bleed controllers were determined to be 872 scfd/device for onshore and offshore production sites and 1,363 scfd/device for transmission stations.

The measured emission data[5] also provided data for intermittent bleed controllers that were measured using the same techniques that were used for the continuous bleed pneumatic controllers. A total of seven measurements were performed on intermittent bleed controllers located at onshore natural gas production sites. No measurements were available for intermittent bleed controllers in the offshore or transmission segments. The average natural gas emission rate for the intermittent pneumatic controllers was determined to be 511 scfd/device.

Site visit data were collected from a total of 22 sites to determine the number of pneumatic controllers located at natural gas production sites, and to determine the fraction of these controllers that were intermittent or continuous bleed. The study determined that 65% of

[4] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.
[5] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.

the pneumatic controllers were intermittent bleed and 35% of the pneumatic controllers were continuous bleed.

The measured emission data, the CPA study emissions data, and the pneumatic controller counts were used to develop a single emission factor for a "generic" pneumatic device. For the production segment, the "generic" pneumatic controller emission factor was calculated using:

- 323 scfd/device for intermittent bleed controllers,
- 654 scfd/device for continuous bleed controllers,
- a methane content of 78.8%, and
- the ratio of intermittent bleed to continuous bleed controllers at natural gas production sites.

The "generic" emission factor was determined to be 345 scfd/device of methane for a pneumatic controller at natural gas production sites.

Transmission

The transmission "generic" emission factor was calculated using data from three types of gas-operated pneumatic controllers: continuous bleed controllers and two types of intermittent bleed controllers used to operate isolation valves[6] (isolation valves with turbine operators and isolation valves with displacement-type pneumatic/hydraulic operators). The continuous bleed emission factor was obtained from the transmission station measured emission data, which was determined to be 1,363 scfd/device. The isolation valve with displacement-type pneumatic/hydraulic operators emission factor was determined using data provided by Shafer Valve Operating Systems[7,8] and the count of the isolation valves at four sites. Using these data,

[6] Isolation valves at transmission stations are very large and are most often actuated either pneumatically or by electric motor. Isolation valve pneumatic controllers only discharge gas when they are actuated and are considered to be intermittent.

[7] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-00693. June 1993.

the average annual emission factor was determined to be 5,627 standard cubic feet per year per device (scfy/device). For turbine-operated isolation valves, the natural gas emissions were estimated using information provided by Limitorque Corporation[9] and information from two transmission sites. This information was used to calculate an emission factor of 67,599 scfy/device. The above emission factors, a methane content of 93.4% and proportions of each of these controllers at transmission sites was used to calculate a "generic" emission factor of 162,197 scfy/device of methane for pneumatic controllers at transmission stations.

Processing

The site visit information from nine natural gas processing plants found that plants used compressed air to operate the majority of pneumatic controllers at the plants. Only one of the plants used natural gas-powered continuous bleed controllers, and five had natural gas-driven pneumatic controllers for the isolation valves on the main pipeline emergency shutdown system or isolation valves used for maintenance. The same type of pneumatic controllers used in the transmission sector are used at natural gas processing sites; therefore, the same emission factors were used to calculate a facility pneumatic emission factor. Using the survey data and the transmission sector pneumatic controller emission factors, the annual methane emissions were determined to be 165 thousand standard cubic feet per facility (Mscfy/facility).

Summary

A summary of the pneumatic controller emission factors, activity factors, and annual methane emission rates estimated by this report are provided in Table 2-2 for the natural gas production, processing and transmission segments. The total methane emissions from pneumatic controllers was estimated to be 45,634 million standard cubic feet per year (MMscfy) or 861,704 metric tons (MT).

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[8] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-2-00394. March 1994.

[9] Personal correspondence with Belva Short of Limitorque Corporation, Lynchburg, VA, April 5, 1994.

Table 2-2 GRI Nationwide Pneumatic Controller Methane Emissions in the United States (1992 Base Year)

Natural gas Segment	Methane Emission Factor	Activity Factor	Annual Methane Emission Rate (MMscf/yr)	Annual Methane Emission Rate (MT)
Production	125,925 scfy/device	249,111 controllers	31,369	592,349
Processing	165,000 scfy/facility	726 facilities	120	2,262
Transmission	162,197 scfy/device	87,206 controllers	14,145	267,093
Total			45,634	861,704

2.1.2 Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)

ICF Consulting (ICF Consulting, 1999) prepared a report for the EPA that estimated methane emissions from crude oil production, transportation and refining, identified potential methane mitigation techniques and provided an analysis of the economics of reducing methane emissions. The report estimated that 97% of the annual methane emissions occur during crude oil production (59.1 billion cubic feet, Bcf or 1,116,000 MT) in 1995. The transportation and refining sectors generate 0.3 Bcf (5,700 MT) and 1.3 Bcf (24,500 MT) of the annual methane emissions, respectively. The annual methane emissions were estimated using methane emission factors and activity factors to calculate the annual methane emissions from the oil industry.

In the production segment, annual vented methane emissions from 13 sources account for 91% (53.8 Bcf or 1,016,000 MT) of the total 1995 methane emissions from crude oil production. Two of these sources: high bleed pneumatic controllers and low bleed pneumatic controllers account for 37% (19.9 Bcf or 376,000 MT) and 7% (3.7 Bcf or 69,900 MT) of the annual vented methane emissions, respectively.

The high bleed pneumatic controller methane emissions were calculated using an emission factor of 345 scfd (GRI/EPA, 1996c). The activity factor for high bleed pneumatic controllers was determined to be 157,581 and assumes that tank batteries with heater treaters have four pneumatic controllers (three level controllers and one pressure controller). Tank batteries without heater treaters were assumed to have three pneumatic controllers. In addition, it was assumed that 35% of the total pneumatic controllers were high bleed, which is based on the percentage of continuous bleed pneumatic controllers determined in the GRI/EPA study (GRI/EPA, 1996c).

The low bleed pneumatic controller methane emission factor was estimated to be 10% of the high bleed methane emission factor or 35 scfd.[10] The activity factor for low bleed controllers was calculated to be 292,650 controllers and was determined using the assumption that 65% of the total pneumatic controllers are intermittent bleed (GRI/EPA, 1996c), which this report assumed to be low bleed pneumatic devices.

No methane emissions from pneumatic controllers were estimated in this report for the transportation and refining segments of the oil industry.

2.1.3 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

The EPA leads the development of the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). This report tracks total U.S. greenhouse gas (GHG) emissions and removals by source and by economic sector over a time series, beginning with 1990.

The U.S. submits the GHG Inventory to the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The GHG Inventory includes estimates of methane and carbon dioxide for natural gas systems (production through distribution) and petroleum systems (production through refining).

[10] EPA Natural Gas STAR default value for low bleed pneumatic controllers.

Table 2-3 summarizes the 2014 GHG Inventory's (published in 2014; containing emissions data for 1990-2012) estimates of 2012 national methane emissions from pneumatic controllers in the natural gas production, processing, transmission and storage segments and the petroleum production segment. Where presented in the GHG Inventory, the table includes potential emissions (i.e., emissions that would be released in the absence of controls), emission reductions and net emissions. For pneumatic controllers, the emission reductions reported to the Natural Gas STAR program are deducted from potential emission to calculate net emissions. In future years, the GHG Inventory will also account for regulatory reductions impacting emissions from pneumatic controllers that result from subpart OOOO.

Table 2-3. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Controllers

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas and petroleum production[a]	1,642,622	873,100	769,522
Natural gas processing	1,923	[b]	[b]
Natural gas transmission and storage	263,561	14,078	249,483

[a] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

[b] The GHG Inventory does not include a specific emission reduction for pneumatic controllers in the natural gas processing sector resulting from the Natural Gas STAR program although it is likely non-zero.

The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors. The following sections provide greater detail on the estimates given in Table 2-3.

2.1.3.1 Natural gas and petroleum production industry segment

Table 2-4 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas and petroleum production industry segment. The table

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presents the population of pneumatic controllers, methane emission factors, potential methane emissions, and the estimated national total of pneumatic controllers and potential methane emissions. The natural gas production data are broken down by the Energy Information Agency's (EIA's) National Energy Modeling System (NEMS) regions. The table also presents the national total of methane emission reductions compiled from Natural Gas STAR reports and the resulting estimated national net methane emissions from pneumatic controllers.

Table 2-4. Estimated 2012 National and Regional Methane Emissions from Pneumatic Controllers in the Natural Gas and Petroleum Production Segment

NEMS Region	Population of Pneumatic Controllers[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Potential Emissions-Natural Gas Systems			
North East	77,261	373	202,696
Midcontinent	167,589	362	426,133
Rocky Mountain	122,127	339	291,166
South West	55,095	353	136,534
West Coast	2,098	402	5,933
Gulf Coast	53,436	386	145,057
Total	477,606		1,207,519
Potential Emissions-Petroleum Systems			
High Bleed	145,179	330	336,692
Low Bleed	269,618	52	98,411
Total	414,797		435,103
Combined Natural Gas and Petroleum Systems			
Total	892,403		1,642,622
Voluntary Emission Reductions-Natural Gas and Petroleum			873,100
Net Emissions-Natural Gas and Petroleum[b]			769,522

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
[b] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

Recent national activity data on pneumatic controllers are not available. To calculate national emissions for these sources for the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data. For the natural gas production segment, pneumatic controllers were estimated each year by applying a regional factor for the number of pneumatic controllers per well to annual regional data on gas well population. These factors ranged from 0.5 to 1.6 pneumatic controllers per well. For the petroleum production segment, pneumatic controllers were estimated each year by applying a factor for the number of pneumatic controllers per heater/treater (4), and pneumatic controller per battery without a heater/treater (3).

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas and petroleum production industry segment is the 1996 GRI/EPA report. The factor for natural gas systems represents a mix of the average emissions from continuous bleed and intermittent natural gas-driven pneumatic controllers in the 1996 GRI/EPA report. The region-specific factors are developed using the GRI/EPA factor and regional gas composition data. For petroleum systems, it was then assumed that 65% of pneumatic controllers in the petroleum production segment are low bleed pneumatic controllers, and 35% of controllers are high bleed. The GRI/EPA factors for low and high bleed controllers are applied to these populations

According to the GHG Inventory, the 1996 GRI/EPA report "still represents the best available [emissions] data in many cases, [but] using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. For this reason, 'potential emissions' are calculated using the [1996 GRI/EPA report] data, and then current data on voluntary and regulatory emission reduction activities are deducted to calculate actual emissions."

In the case of pneumatic controllers in the natural gas production industry segment, the GHG Inventory reduces the calculated potential emissions using voluntary emission reductions reported by industry partners to the Natural Gas STAR Program. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before

being incorporated into the GHG Inventory. Future inventories are expected to reflect the subpart OOOO requirements for pneumatic controllers as they are implemented.

2.1.3.2 Natural gas processing industry segment

Table 2-5 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas processing industry segment.

Table 2-5. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Processing Segment

Activity Factor	CH_4 Potential Emission Factor (scfy/plant)[b]	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
606 gas plants[a]	164,721	1,923	[c]	[c]

[a] *Oil and Gas Journal*, with available 2012 activity data.
[b] 1996 GRI/EPA report.
[c] Although voluntary Natural Gas STAR emission reductions are reported for this industry segment in the aggregate, no value is given specifically for pneumatic controllers.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas processing segment is the 1996 GRI/EPA report. This potential emission factor is expressed in terms of standard cubic feet per year per processing plant (scfy/plant). The associated activity factor is the number of U.S. gas plants, which comes from the *Oil and Gas Journal*.

The GHG Inventory does not report emissions reductions specific to pneumatic controllers in this industry segment and, thus, there is no reported net emissions figure.

2.1.3.3 Natural gas transmission and storage segment

Table 2-6 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas transmission and storage industry segment.

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Table 2-6. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Transmission and Storage Segment

Subsegment	Activity Factor (# of controllers)	CH_4 Potential Emission Factor (scfy/device)	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Transmission	70,827	162,197[a]	221,257		
Storage	13,542	162,197[a]	42,304		
Total	84,369		263,561	-14,078[b]	249,483

[a] 1996 GRI/EPA report.
[b] Voluntary Natural Gas STAR emission reductions are reported for all pneumatic controllers in this industry segment, not split out by transmission and storage.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas transmission and storage segment is the 1996 GRI/EPA report. In this case, the potential emission factor is expressed in terms of scfy/device. The associated activity factor is the number of pneumatic controllers. For transmission, the number of pneumatic controllers is calculated based on transmission pipeline length. For storage, the number of pneumatic controllers is calculated based on number of compressor stations in the storage segment.

The 2014 GHG Inventory includes voluntary emission reductions reported by industry partners to the Natural Gas STAR Program for pneumatic controllers in the natural gas transmission and storage industry segment.

2.1.4 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

In October 2013, the EPA released 2012 GHG data for Petroleum and Natural Gas Systems collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.

When reviewing this data and comparing it to other data sets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. The GHGRP covers a subset of national emissions from Petroleum and Natural Gas Systems; a facility in the Petroleum and Natural Gas Systems source category is required to submit annual reports if total emissions are 25,000 MT of CO_2 equivalent (MT CO_2e) or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement. In some cases, facilities have a choice of calculation methods for an emission source.

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rules define three segments of the oil and natural gas industry sector that are required to report GHG emissions from pneumatic controllers: (1) onshore petroleum and natural gas production, (2) onshore natural gas transmission compression, and (3) underground natural gas storage. Facilities calculate emissions from pneumatic controllers by determining the number of each type of controller at the facility and applying emission factors. In the petroleum and natural gas production segment, facilities must apply facility-specific gas composition factors for methane and CO_2. In the natural gas transmission and storage segments, default gas composition factors are used. Subpart W emission factors for pneumatic controllers are located at 40 CFR Part 98, subpart W, Table W-1A (Onshore Petroleum and Natural Gas Production), Table W-3 (Onshore Natural Gas Transmission Compression), and Table W-4 (Underground Natural Gas Storage). These emission factors are based on the 2009 document *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* published by the American Petroleum Institute (API), which in turn is based on the 1996 GRI/EPA report.

Table 2-7 shows the number of reporting facilities[11] in each of the three industry segments, along with reported pneumatic controller methane emissions.

Table 2-7. Facilities and Reported Emissions from Pneumatic Controllers, 2012

Segment	Number of Reporting Facilities	Reported Methane Emissions (MT)[a]
Petroleum and NG Production	417	861,224
Transmission	330	7,582
Storage	38	4,493

[a] The reported methane MT CO2e emissions were converted to methane emissions in MT by dividing by a global warming potential (GWP) of methane (21).

2.1.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)

A study completed by multiple academic institutions and consulting firms was conducted to gather methane emissions data at onshore natural gas sites in the U.S. and compare those emission estimates to the 2011 estimates reported in the 2013 GHG Inventory. The sources or operations tested included 305 pneumatic controllers located at 150 distinct natural gas production sites in four production regions (Appalachian, Gulf Coast, Midcontinent, and Rocky Mountain).

Testing was carried out using a Hi-Flow Sampler, which is a portable, battery-powered instrument designed to determine the rate of gas leakage around various pipe fittings, valve packings and compressor seals found in natural gas production, transmission, storage and processing facilities. To allow the quantity of methane to be separated out from other chemical

[11] In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed a specialized facility definition for onshore production. For onshore production, the "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon-producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

species, gas composition data were collected for each natural gas production site, typically provided by the site owner. The 305 sampled pneumatic controllers represented an estimated 41% of all the controllers associated with the wells that were sampled. The sampling time for each controller was not specified in the study. Table 2-8 shows the emission rates determined by the testing.

Table 2-8. Pneumatic Controller Methane Emission Rates Reported in the Allen Study

	Methane Emissions per Pneumatic Controller				
	Appalachian	Gulf Coast	Midcontinent	Rocky Mtn.	Total
Number sampled[a]	133	106	51	15	305
Emissions rate (scf methane/min/device)[b]	0.126 ± 0.043	0.268 ± 0.068	0.157 ± 0.083	0.015 ± 0.016	0.175 ± 0.034
Emissions rate (scf whole gas/min/device, based on site-specific gas composition)[b]	0.130 ± 0.044	0.289 ± 0.071	0.172 ± 0.086	0.021 ± 0.022	0.187 ± 0.036

[a] Intermittent and low bleed controllers are included in the total; no high bleed controllers were reported by companies providing controller type information

[b] Uncertainty characterizes the variability in the mean of the data set, rather than an instrumental uncertainty in a single measurement

The Allen study reports that the average whole gas emission rate was 11.2 scfh per pneumatic controller for the tested population, which consisted of a mix of intermittent and low bleed controllers. No high bleed controllers were reported by the companies that provided controller type information. The study also reports whole gas emission factors of 5.1 scfh for low bleed controllers and 17.4 scfh for intermittent controllers. These emission factors are based on measured emissions at the 24 sites where the site operators reported only low bleed controllers and the 55 sites reporting only intermittent controllers, where potential misidentification of controller type is less likely to be a confounding factor.

The study notes that there is significant geographical variability in the emissions rate from pneumatic controllers between production regions. Emissions per controller from the Gulf Coast are highest and are statistically different than emissions from controllers in the Rocky Mountain and Appalachian regions. The difference in average values is more than a factor of 10

between Rocky Mountain and Gulf Coast regions. The study provided the following discussion of these differences:

> Some of the regional differences in emissions may be explained by differences in practices for utilizing low bleed and intermittent controllers. For example, new controllers installed after February 1, 2009 in regions in Colorado that do not meet ozone standards, where most of the Rocky Mountain controllers were sampled, are required to be low bleed (or equivalent) where technically feasible (Colorado Air Regulation XVIII.C.1; XVIII.C.2; technical feasibility criterion under review as this is being written). However, observed differences in emission rates between intermittent and low bleed devices (roughly a factor of 3) are not sufficient to explain all of the regional differences. A number of additional hypotheses were examined to attempt to explain the differences in emissions. For datasets consisting entirely of intermittent or entirely of low-bleed devices, the volume of oil produced was not a good predictor of emissions. Wellhead and separator pressure were also not good predictors of emissions. The definition of low-bleed controllers may be [an] issue, however. All low bleed devices are required to have emissions below 6 scf/hr (0.1 scf/m), but there is not currently a clear definition of which specific controller designs should be classified as low bleed and reporting practices among companies can vary. Other possibilities for explaining the low-bleed emission rates observed in this work, that have not yet been investigated, but that may be pursued in follow-up work, include operating practices for the use of the controllers.

The study estimated 2011 national methane emissions from pneumatic controllers in the natural gas production industry segment at 570,000 MT (with a range of 510,000 – 812,000 MT based on the 95% confidence bounds of the emission factor) using the same number of controllers (447,379) used in the 2013 GHG Inventory for 2011. This estimate was computed using a regionally weighted emission factor of 67,400 scfy methane/device.

2.1.6 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

A study completed by the Prasino Group was conducted to determine the average bleed rate of pneumatic controllers when operating under field conditions in British Columbia (BC). Bleed rates were sampled from pneumatic controllers using a positive displacement bellows meter at upstream oil and gas facilities across a variety of producing fields in the Fort St. John, BC and surrounding areas. For this study, bleed rate was defined as "the amount of fuel gas released to the atmosphere per hour," including both continuous bleed (where applicable) and emissions during activation. The study centered on high bleed controllers, including both continuous bleed and intermittent controllers with emissions greater than 0.17 cubic meters per hour ($m^{3/}$hr) (e.g, > 6 scfh).[12] The study aimed to identify the most common high bleed pneumatic controllers in the field and test emissions from at least 30 units of each model. In identifying controllers to test, the study used a manufacturer-supplied emission rate of 0.119 m^3/hr as a cutoff to explore whether some models identified by manufacturers as low bleed perform at that level in the field.

Field measurements were carried out with a Calscan Hawk 9000 Vent Gas Meter, which uses a positive displacement diaphragm meter that detects flow rates down to zero, and can also effectively measure any type of vent gas (methane, air, or propane). (A few sampled devices ran on air at large sites using compressed air, or propane at sour sites using compressed propane; such samples were corrected using a density ratio to equivalent natural gas emissions rates.) This device uses "a precision pressure sensor, an external temperature probe, and industry standard gas flow measurement algorithms to accurately measure the gas rates and correct for pressure and temperature differences." The report notes that metering a device can affect the operation of the device when hooked up due to back pressure, adding that it is possible that certain controllers did not produce enough pressure when hooked up to overcome the back pressure, resulting in a

[12] This definition of "high bleed" is slightly different than the definition presented in Section 1.1.1 of this paper, because "intermittent bleed controllers" are included as "high bleed controllers" if their emissions are above the specified threshold. The definition presented in Section 1.1.1 places "intermittent bleed controllers" in their own category.

zero reading. The sample time for each controller was 30 minutes, so there was variability in the number of actuation events captured for each controller depending on operating conditions.

In addition to emission factors for individual models of pneumatic controllers, the study generated emission factors for "generic high bleed controllers" and "generic high bleed intermittent controllers." The study also included a regression analysis of the relationship between bleed rate and the pressure of the supply gas routed to the controller. Based on the analysis, the study found that the positive relationship between these parameters was strong enough to recommend use of a supply pressure coefficient to calculate the bleed rate for several controller models and for generic controllers. The generic emission factors and supply pressure coefficients are shown in Table 2-9.

Table 2-9. Generic Natural Gas Emission Factors and Supply Pressure Coefficients for High Bleed Pneumatic Controllers

Type of Pneumatic Controller	Average Bleed Rate (m^3/hr)[a]	Average Bleed Rate (scfh)[b]	Coefficient Related to Supply Pressure[c]
Generic High Bleed Controller	0.2605	9.199	0.0012
Generic High Bleed Intermittent Controller	0.2476	8.744	0.0012

[a] "Bleed rate" defined to include actuation emissions as well as continuous bleed.
[b] Calculated.
[c] Supply pressure apparently in kPa, although not clearly stated in the report.

Based on what it termed a "positive correlation," the Prasino study recommended the use of the supply pressure coefficients above for calculating emission rates for generic high bleed controllers and generic high bleed intermittent controllers. It should be noted that the coefficients of determination (R^2 values) for these supply pressure coefficients are 0.41 and 0.35 for high bleed and high bleed intermittent controllers, respectively.

2.1.7 Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)

A study by the Center for Atmospheric Particle Studies at Carnegie Mellon University was conducted to develop an emission inventory for the development, production, and processing of natural gas in the Marcellus Shale region for 2009 and 2020. (Note: The focus of this white paper is current emissions, therefore, the 2020 projections are not discussed further.) The inventory includes estimates for emissions of nitrogen oxides, VOC, and particulate matter less than 2.5 micrometers in diameter from major activities, including VOC emissions from pneumatic controllers associated with "wet" and "dry" gas wells. The study estimated VOC emissions from pneumatic controllers associated with Marcellus Shale natural gas wells to be on the order of 10 tons/day in 2009.

This study developed these emissions estimates by estimating the number of wet and dry wells in the region and establishing per-well emission factors for 2009. The per-well emission factors are shown in Table 2-10.

Table 2-10. Per-Well VOC Emissions from Pneumatic Controllers in 2009 (95% confidence interval)

Type of Well	VOC Emissions, 2009 (tons/producing well)
Dry Gas	0.5 (0.08 – 0.8)
Wet Gas	3.5 (2.4 – 4.4)

The per-well emission factors were based on assumptions regarding the type, number, and emission factors for pneumatic controllers associated with each natural gas well, which were drawn primarily from a 2008 ENVIRON report.[13] Table 2-11 shows these assumptions.

[13] Bar-Ilan, Amnon et al., ENVIRON International Corporation. *Recommendations for Improvement to the CENRAP States' Oil and Gas Emissions Inventories*. Prepared for the Central States Regional Air Partnership. November 13, 2008. This report also includes emission factors for positioners (15.2 scfh) and transducers

Table 2-11. Assumed Type, Number, and Emission Factors for Pneumatic Controllers Associated with Each Natural Gas Well

Type of Device	Number of Controllers	Emission Factor (scfh)[a]
Liquid Level Controller	2	31 (2009)
Pressure Controller	1	17 (2009)

[a] 2009 emission factors are from the 2008 ENVIRON report.

The emission factors from this study and the ENVIRON report are not comparable to the emission factors discussed above because they are provided for different classifications of pneumatic controllers. In addition, these emission factors differ from those discussed previously in that they are based on bleed rates provided by manufacturers rather than measured emissions.

2.1.8 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The Environmental Defense Fund (EDF) commissioned ICF International (ICF) to conduct an economic analysis of methane emission reduction opportunities from the oil and natural gas industry to identify the most cost-effective approach to reduce methane emissions from the industry. The study projects the estimated growth of methane emissions through 2018 and focuses its analysis on 22 methane emission sources in the oil and natural gas industry (referred to as the targeted emission sources). These targeted emission sources represent 80% of their projected 2018 methane emissions from onshore oil and gas industry sources. Pneumatic devices are several of the 22 emission sources that are included in the study and include: high bleed pneumatic controllers, intermittent bleed pneumatic controllers, Kimray pumps, intermittent bleed pneumatic controllers – dump valves, and chemical injection pumps. The

(13.6 scfh). The emission factors in the report "were obtained from data gathered as part of the EPA's Natural Gas STAR program." Examination of Natural Gas STAR program materials clearly shows that these emission factors were derived from the manufacturer-supplied natural gas bleed rates for high bleed pneumatic controllers listed in Appendix A to *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. The ENVIRON report also includes the number of controllers of each type associated with each gas well, said to be drawn from survey data in the CENRAP states. The numbers for liquid level controllers and pressure controllers are reflected in Table 2-15; the report found zero positioners and transducers per well.

methodology that was used for this analysis is based on the 2013 GHG Inventory and uses data from the GHGRP and the University of Texas/EDF gas production measurement study (Allen et al., 2013).

The study relied on the 2013 GHG Inventory for 1990-2011 for methane emissions data for the oil and natural gas sector. These emissions data were revised to include updated information from the GHG Inventory and the *Measurements of Methane Emissions at Natural Gas Production Sites in the United States* study (Allen et al., 2013). The revised 2011 baseline methane emissions estimate was used as the basis for projecting onshore methane emissions to 2018. (Note: The focus of this white paper is current emissions, therefore, the 2018 projections are not discussed further.)

The study used the 2013 GHG Inventory estimates for 2011 to develop new activity and emission factors for pneumatic controllers. The count of pneumatic controllers was calculated using the well counts and assuming 0.94 pneumatic controllers per well. The study did find that there are an additional 8.6 pneumatic controllers per gathering/boosting station that were not accounted for in the 2013 GHG Inventory. The study also used emission factors from subpart W, which reported pneumatic controllers in three categories: low bleed, intermittent bleed and high bleed controllers. To break out the number of pneumatic controllers in each of these categories, the emission data from subpart W were analyzed, and the study determined that the percentage of pneumatic controllers were 10% high bleed, 50% intermittent bleed and 40% low bleed. These percentages were applied to the pneumatic controller counts and the respective emission factor was used to calculate the emissions from these controllers. Intermittent pneumatic controllers were further segregated into two categories: dump valves and non-dump valve intermittent controllers. The dump valves represent intermittent controllers that do not continuously bleed and only emit during actuation. The study estimated that 75% of the total intermittent pneumatic controllers were dump valves. Based on the subpart W data and the assumptions above, the study used the following emission factors for each of the controllers: 320 Mcf/yr/device for high bleed, 120 Mcf/yr/device for non-dump intermittent, 20 Mcf/yr/device for dump intermittent and 11 Mcf/yr/device for low bleed pneumatic controllers. Using these factors, the study estimated an

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increase of 41% (26 Bcf or 491,000 MT) in methane emissions in comparison to the 2013 GHG Inventory.

Further information included in this study on the replacement of high bleed and intermittent bleed pneumatic controllers with low bleed pneumatic controllers, and the replacement of pneumatic pumps with electric pumps as mitigation or emission reduction techniques, methane control costs, and their estimates for the potential for VOC emissions co-control benefits from the replacement of these pneumatic controllers are presented in Section 3 of this document.

2.2 Discussion of Data Sources for Pneumatic Pumps

Many of the data sources for pneumatic pumps are the same as those for pneumatic controllers, therefore, the overall descriptions of these data sources are not repeated in this section and only the information relevant to pneumatic pumps is discussed.

2.2.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c) (GRI/EPA, 1996e)

The methane emission estimates for pneumatic pumps are separated into two categories for the GRI/EPA reports; chemical injection pumps (GRI/EPA, 1996d) and gas-assisted glycol pumps (GRI/EPA, 1996f). A summary of each of these reports and the methane calculation methodologies are provided in the following sections.

2.2.1.1 Methane Emissions from the Natural Gas Industry – Chemical Injection Pumps (GRI/EPA, 1996c)

This report estimates emissions from two types of pumps that the oil and natural gas industry uses for chemical injection into process streams: piston pumps and diaphragm pumps. Four sources of information were used to develop an emission factor for chemical injection

pumps: a study by the CPA[14], data collected from site visits, literature data for methane composition, and data from pump manufacturers.

The CPA study provided natural gas emissions from five diaphragm chemical injection pumps using the "bagging" method. This method involves enclosing the pump and measuring the flow rate and concentration of the natural gas emissions from the pump. The measurements from this study reported natural gas emissions ranging from 254 to 499 standard cubic feet per day per pump (scfd/pump) with an average of 334 scfd/pump.

Data from site visits included: the total number of chemical injection pumps for a particular site, number of chemical injection pumps used in natural gas production, the energy source for the pump (e.g., natural gas, instrument air, electricity), frequency of operation (e.g., pumping rate in strokes per minute), number of pumps that are active or idle, pump operation schedule, size of the unit (e.g., volume displacement of the motive chamber), manufacturer and model number of the pump, and supply gas pressure. Table 2-12 provides a summary of the site visit data. The methane emission factor in Table 2-12 was calculated using a methane composition of 78.8% (GRI/EPA, 1996d).

Table 2-12. Summary of Chemical Injection Pump Site Visit Data

Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Percent of Total Pumps	49.8 ± 38%	50.2 ± 38%	4.5 ± 678%	95.5 ± 32%
Pump Actuation Rate (strokes/min)	26.32 ± 29%	13.64 ± 49%	3.57 ± 42%	14.75 ± 61%
Number of Pump Actuation Measurements	32	8	15	5
Number of Sites with	7	5	2	4

[14] Canadian Petroleum Association. A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta, March 1992.

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Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Pump Actuation Measurements				
Percent of Pumps Operating	44.6 ± 62%	40.0 ± 52%	77.5 ± 148%	58.0 ± 39%
Number of Sites with Pumps Operating	7	10	4	6
Methane Emissions Factor (scfd/pump)	248 ± 83%		668 ± 88%	

Manufacturers' data and the CPA data were used to determine the volume of gas released per pump stroke. This was done by using the natural gas usage data (amount of natural gas required to pump one gallon of liquid), stroke length, and stoke diameter to calculate volume of natural gas per pump stoke. For diaphragm pumps, the average natural gas usage was calculated to be 0.0719 standard cubic feet per stroke (scf/stroke). The piston pump average natural gas usage was calculated to be 0.0037 scf/stroke. These averages were then used to determine the emission factor for each of the pump types by multiplying the average frequency (strokes per day) by the operating time percentage. Note that the report uses the "all data" frequency and operating percentage to calculate the emission factor for each type of pump. The emission factor for diaphragm pumps was calculated to be 446 scfd/pump and the emission factor for piston pumps was calculated to be 48.9 scfd/pump.

The percentage of piston and diaphragm pumps and their respective emission factors were then used to calculate an average emission factor for chemical injection pumps. The average emission factor was determined to be 248 scfd/pump. The 1992 national emissions were then calculated using the average chemical injection pump emission factor (248 scfd/pump) and the activity factor for chemical injection pumps of 16,971 (GRI/EPA, 1996a). The resulting 1992 national emissions from chemical injection pumps for the natural gas production segment was calculated to be 1,536 MMscf/yr (29,008 MT).

2.2.1.2 Methane Emissions from the Natural Gas Industry – Gas-Assisted Glycol Pumps (GRI/EPA, 1996e)

For many glycol dehydrators in the natural gas industry, small gas-assisted pumps are used to circulate the glycol. These pumps use energy from the high-pressure rich glycol/gas mixture leaving the absorber to pump the low-pressure lean glycol back to the absorber. Natural gas is entrained in the rich glycol stream feeding the pump and is discharged from the pump at a lower pressure to the regenerator. If the glycol unit has a flash tank, most of the natural gas in the low-pressure stream can be recovered and used as a fuel or stripping gas. If the natural gas from the pump is used as a stripping gas, or if there is no flash tank, all of the pump exhaust gas will be vented through the regenerator's atmospheric vent stack (GRI/EPA, 1996e).

Methane emissions from these gas-assisted pumps were calculated using technical information from Kimray, a manufacturer of gas-assisted pumps. No direct measurements of pump gas usage were used in the calculations. Kimray reported that the natural gas usage ranges from 0.081 actual cubic feet per gallon of glycol pumped (acf/gal) for high-pressure pumps (>400 psig) to 0.130 acf/gal for low-pressure pumps (< 400 psig). These values convert to 3.73 standard cubic feet per gallon (scf/gal) at an operating pressure of 800 psig and 83 mole percent methane for high-pressure pumps and 2.31 scf/gal at an operating pressure of 300 psig and 83 mole percent methane for low-pressure pumps.

The gas usage rates were then converted to an amount of natural gas treated by assuming a typical high-pressure dehydrator would remove 53 pounds of water per million cubic feet of gas (lbs/MMscf), and a typical low-pressure dehydrator would remove 127 lbs/MMscf. The design glycol-to-gas ratio was assumed to be three gallons of glycol per pound of water removed and an overcirculation ratio of 2.1 was used to determine the emission factors for the pumps for the natural gas production segment. Using these factors and the fraction of dehydrators without flash tanks (0.735) and the fraction of dehydrators without combustion vent controls (0.988), the emission factor for the gas-assisted pumps in the natural gas production segment were calculated to be 904.5 standard cubic feet of methane per million standard cubic feet of natural gas treated (scf/MMscf) for high-pressure pumps, and 1342.2 scf/MMscf for low-pressure pumps. The final

emission factor for methane from an average gas-assisted glycol pump was determined assuming that 80% of these pumps are high-pressure and 20% are low-pressure. The average emission factor was calculated to be 992.0 scf/MMscf and was used to estimate methane emissions from the natural gas production segment.

For natural gas processing, the study assumed that only high-pressure gas-assisted glycol pumps are used. The emission factor was calculated using the high-pressure pump gas usage (3.73 scf/gal), the design glycol-to-gas ratio (3 gal glycol/lb water), the water removal rate for a high-pressure system (53 lbs/MMcsf), an overcirculation ratio of 1.0, the fraction of dehydrators without flash tanks (0.333) and the fraction of dehydrators without combustion vent controls (0.900). These values were used to calculate a methane emission factor of 177.8 scf/MMscf for gas-assisted pumps for the natural gas processing segment. The natural gas transmission and storage segments do not use gas-assisted glycol pumps.

The 1992 national methane emissions were calculated using data from site surveys to determine the natural gas throughput of dehydrators with gas-assisted pumps. The natural gas throughput of dehydrators with gas-assisted pumps was estimated to be 11.1 trillion standard cubic feet per year (Tscf/yr) for the natural gas production segment and 0.958 Tscf/yr for the natural gas processing segment. The 1992 national methane emissions from gas-assisted pumps were calculated to be 10,962 MMscf/yr (206,989 MT) for the natural gas production segment and 170 MMscf/yr (3,215 MT) for the natural gas processing segment.

2.2.2 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

Table 2-13 summarizes the 2014 GHG Inventory estimates of 2012 national methane emissions from pneumatic pumps in the natural gas production and processing segments. (Note: The GHG inventory does not include estimates of emissions from pneumatic pumps in the natural gas transmission and storage segments.) The pneumatic pumps described in the GHG Inventory include: chemical injection pumps and Kimray pumps. The table includes potential emissions, emission reductions and net emissions. For pneumatic pumps, the emission reductions

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in this report are voluntary reductions through the Natural Gas STAR program. In future years, the GHG Inventory will also account for regulatory reductions that result from subpart OOOO.

Table 2-13. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Pumps

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas production	455,719	2,771	452,948
Petroleum Production	49,973	N/A	
Natural gas processing	5,011	N/A	

The 2014 GHG Inventory data estimates that pneumatic pump emissions are around 16% of overall methane emissions from the natural gas production and processing sectors.

Tables 2-14 and 2-15 show the 2014 GHG Inventory's estimates of 2012 methane emissions from chemical injection pumps and gas-assisted pumps (Kimray pumps) in the natural gas and petroleum production and processing industry segments. The tables present population of chemical injection and Kimray pumps, methane emission factors and potential methane emissions from these devices in each of the EIA's NEMS regions, and the estimated national total of chemical injection pumps, Kimray pumps and potential methane emissions. The activity factors for chemical injection pumps are based on the estimated count of chemical injection pumps in operation. For the production sector, a regional factor for pumps per well (ranging from 0.01 to 0.68) is applied to annual regional well counts to calculate chemical injection pumps each year for natural gas, and for petroleum systems it is estimated that around 20% of wells have pumps (based on 1996 GRI/EPA) and that 25% of pumps use gas. For the production sector, the activity factors for Kimray pumps are based on the total throughput of natural gas multiplied by the fraction of dehydrators using gas-driven pumps (0.9 for the production segment). For the processing segment, the activity factor for Kimray pumps is based the total processing plant throughput multiplied by the fraction of natural gas treated by dehydrators at

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gas plants (0.5) and then multiplied by the fraction of dehydrators that use a gas-driven pump (0.1 for the processing segment).

Table 2-14. Estimated 2012 National and Regional Methane Emissions from Chemical Injection Pumps in the Natural Gas Production Segment

NEMS Region	Population of Chemical Injection Pumps[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	795	268	1,499
Midcontinent	15,343	260	28,045
Rocky Mountain	14,849	244	25,448
South West	2,531	253	4,508
West Coast	1,422	289	2,890
Gulf Coast	2,537	278	4,951
Total Natural Gas	37,477		67,341
Voluntary Emission Reductions			-2,771
Net Emissions-Natural Gas			64,570
Petroleum Production	28,702	248	49,973

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.

Table 2-15. Estimated 2012 National and Regional Methane Emissions from Kimray Pumps in the Natural Gas Production and Processing Segments

NEMS Region	Total Natural Gas using Kimray Pumps[a]	CH_4 Potential Emission Factor (scfd/MMscf)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	6,487,241	1,073	134,073
Midcontinent	4,409,271	1,040	88,322
Rocky Mountain	3,404,114	975	63,934
South West	1,692,957	1,014	33,050
West Coast	85,450	1,157	1,904
Gulf Coast	3,137,482	1,110	67,095
Production Total	19,216,515		388,378
Natural Gas Processing			

All Regions	1,463,675	178	5,011
Total Potential Emissions			393,389

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
Note: The GHG Inventory did not list any Kimray pumps in the natural gas transmission or distribution sectors.

The basis for the GHG Inventory's potential methane emission factors for pneumatic pumps in the natural gas production and processing segments is the 1996 GRI/EPA report.

The region-specific factors used in the production segment are developed using the GRI/EPA factor and regional gas composition data.

2.2.3 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rule requires facilities in the onshore petroleum and natural gas production segment to report GHG emissions from pneumatic pumps. Facilities calculate emissions from pneumatic pumps by determining the number of pneumatic pumps at the facility and applying an emission factor of 13.3 scf/hour/pump. Facilities also apply a facility-specific gas composition factor for calculating emissions. For 2012, 343 facilities in the onshore petroleum and natural gas production industry segment reported emissions from pneumatic pumps, with total methane emissions of 135,227 metric tons.

2.2.4 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

The study used data from the Canadian Association of Petroleum Producers (2008), Pacific Carbon Trust (2011), Cap-Op Energy's Distributed Energy Efficiency Project Platform (DEEPP) database to compile a list of pneumatic pumps. The study notes that the total number of pneumatic pumps is unknown and the list only comprises a subset of the total population. In total, 184 samples were taken from chemical injection pumps. From the data collected, the study determined the average bleed rate for a piston-type pneumatic pumps to be 0.5917 m^3/hr

(approximately 20.9 scfh). For diaphragm-type pneumatic pumps, the bleed rate was calculated to be 1.0542 m^3/hr (approximately 37.2 scfh).

2.2.5 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The analysis developed by ICF includes an inventory of methane emissions for 2011 using data from the 2013 GHG Inventory and the GHGRP (U.S. EPA, 2013), in addition to data from the EIA and GRI.

For pneumatic chemical injection pumps in the natural gas production segment, the 2011 ICF inventory updated the count of chemical injection pumps to reflect changes made to the well counts and applied the Natural Gas STAR estimated reductions associated with pneumatic pumps. These changes resulted in a 2011 methane estimate of 3 Bcf (56,600 MT) from chemical injection pumps in the natural production segment. Kimray pumps (gas-assisted glycol pumps) were estimated to be 17 Bcf (321,000 MT).

3.0 AVAILABLE PNEUMATIC DEVICE EMISSIONS MITIGATION TECHNIQUES

The following sections describe the different available emissions mitigations techniques that the EPA is aware of for pneumatic controllers and pneumatic pumps. The primary sources of information for mitigations techniques was the EPA's Natural Gas STAR Lessons Learned documents and the ICF economic analysis (ICF, 2014).

3.1 Available Pneumatic Controller Emissions Mitigation Techniques

Several techniques to reduce emissions from pneumatic controllers have been developed over the years. Table 3-1 provides a summary of these techniques for reducing emissions from pneumatic controllers including replacing high bleed controllers with low bleed or zero bleed

models, driving controllers with instrument air rather than natural gas, using non-gas-driven controllers, and enhanced maintenance.

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Install Zero Bleed Controller in Place of Continuous Bleed Controller (U.S. EPA, 2011a, GE Energy Services, 2012)	Zero bleed controllers are self-contained natural gas-driven devices that vent to the downstream pipeline, not the atmosphere. Provide the same functional control as continuous bleed controllers, where applicable (U.S. EPA, 2011a, GE Energy Services, 2012).	Applicable only for relatively low-pressure control valves, e.g., in gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution applications (U.S. EPA, 2011a).	The EPA does not have cost information on this technology.	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field, however, it is the EPA's understanding that applicability is limited.
Install Low Bleed Controller in Place of High Bleed Controller (U.S. EPA, 2006b)	Low bleed controllers provide the same functional control as a high bleed devices, while emitting less continuous bleed emissions (U.S. EPA, 2006b).	Applicability depends on the function of instrumentation for an individual device and whether the device is a level, pressure, or temperature controller. Not recommended for control of very large valves that require fast and/or precise response to process changes. These are found most frequently on large compressor discharge and bypass pressure controllers (U.S. EPA, 2006b).	Based on information from Natural Gas STAR (U.S. EPA, 2006b) and supplemental research conducted for subpart OOOO, low bleed devices cost, on average, around $165 more than high bleed versions. ICF report assumed a cost of $3,000 per replacement based on industry comments (ICF, 2014).	Estimated average reductions (U.S. EPA, 2011a): *Production segment:* 6.6 tpy methane *Transmission:* 3.7 tpy methane The EPA does not have information on the prevalence of this technology in the field.

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Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Convert to Instrument Air (U.S. EPA, 2006c)	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel (U.S. EPA, 2006c).	Most applicable at facilities where there are a high concentration of pneumatic control valves and an operator present. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2006c).	System costs are dependent on size of compressor, power supply needs, labor and other equipment (U.S. EPA, 2006c). A cost analysis is provided in Section 3.1.3 below.	100% emission reduction, where applicable. There are secondary emissions associated with electrical power generation. The EPA does not have information on the prevalence of this technology in the field.
Mechanical and Solar-Powered Systems in Place of Bleed Controller (U.S. EPA, 2006a, U.S. EPA, 2006b)	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar-powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability (U.S. EPA, 2006a).	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric-powered valves are only reliable with a constant supply of electricity (U.S. EPA, 2006a).	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems (U.S. EPA, 2006a).	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field.

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Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Enhanced Maintenance (U.S. EPA, 2006a)	Instrumentation in poor condition typically bleeds 5 to 10 scfh more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear; or loose control tube fittings. This may not impact operations but does increase emissions. Proper methods of maintaining a device are highly variable (U.S. EPA, 2006a).	Enhanced maintenance to repair and maintain pneumatic controllers periodically can reduce emissions at many controllers (U.S. EPA, 2006a).	Variable based on labor, time, and fuel required to travel to many remote locations.	Natural gas emission reductions of 5 to 10 scfh (U.S. EPA, 2006a). The EPA does not have information on the prevalence of this practice in the field.

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The mitigation techniques summarized in Table 3-1 are discussed in more detail in the following sections.

3.1.1 Zero Bleed Pneumatic Controllers

Zero bleed pneumatic controllers are self-contained, "closed loop" natural gas-driven controllers that vent to the downstream pipeline rather than to the atmosphere (U.S. EPA, 2011a). These closed loop devices are considered to emit no natural gas to the atmosphere. However, they can be used only in applications with very low pressure and, therefore, may not be suitable to replace continuous bleed pneumatic controllers in many applications. Some applications where they may suitable include gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution (U.S. EPA, 2011a). To date, the EPA has not obtained any information on the cost of zero bleed controllers or their prevalence in the field.

3.1.2 Low Bleed Pneumatic Controllers

Description

Low bleed controllers provide similar functional control as high bleed controllers, but have lower continuous bleed emissions. It has been estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low bleed device in place of a high bleed device (U.S. EPA, 2011a). In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively (U.S. EPA, 2011a). As defined in this white paper, a low bleed controller can emit up to 6 scfh, but this is higher than the expected emissions from the typical low bleed controllers available on the current market.

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Applicability

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved.

Replacing high bleed pneumatic with low bleed controllers is infeasible in situations where a process condition may require a fast or precise control response so that it does not stray too far from the desired set point (U.S. EPA, 2011a). A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic controllers monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Another scenario where fast and precise control is necessary includes transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably (U.S. EPA, 2011a). In this case, a responsive high bleed device may be required to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes may be appropriate for control from a low bleed device, which is slower acting and less precise.

Safety concerns can limit the appropriateness of low bleed controllers in specific situations where any amount of bleeding is unacceptable. Emergency valves are often not controlled with bleeding controllers (e.g., neither low bleed nor high bleed), because it may not be acceptable to have any amount of bleeding in emergency situations (U.S. EPA, 2011a). Pneumatic controllers are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[15] the equipment in place for such an event is spring-loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic

[15] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

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gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

Costs

The costs described in this section are based on vendor research and information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers (U.S. EPA, 2006a). As Table 3-2 indicates, the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338.[16] Thus, the incremental cost of installing a low bleed device instead of a high bleed device is on the order of $165 per device. (Note: The ICF report assumed a cost of $3,000 to replace an existing high bleed pneumatic controller with a low bleed pneumatic controller based on industry comments (ICF, 2014).)

Table 3-2. Cost Projections for the Representative Pneumatic Controllers[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low Bleed Incremental Cost ($)
High bleed controller	366	7,000	2,388	$165
Low bleed controller	524	8,852	2,553	

[a] Major pneumatic controllers vendors were surveyed for costs, emission rates and any other pertinent information that would give an accurate picture of the present industry.

Monetary savings associated with additional gas captured to the sales line were estimated based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).[17] The representative low bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high bleed device per year. Assuming production quality gas is 82.8% methane by volume, this equals 385.5 Mcf natural gas recovered

[16] Costs are estimated in 2008 U.S. Dollars.

[17] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

per year (EC/R, 2011). Therefore, the value of recovered natural gas from one pneumatic controller in the production segment equates to approximately $1,500. While the owner of the transmission system is generally not the owner of the natural gas, the potentially lost gas still has value. The total value of the recovered gas from one pneumatic controller in the transmission segment is $1,375 assuming a natural gas value of $4.00 per Mscf and transmission natural gas is 92.8% methane by volume (EC/R, 2011).

3.1.3 Instrument Air Systems

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document (U.S. EPA, 2006c), *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.
- A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of

electric power can be difficult to ensure. In some instances, solar-powered battery-operated air compressors can be effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. A diagram of a natural gas pneumatic controller is presented in Figure 3-1. A diagram of a compressed instrument air system is presented in Figure 3-2.

Applicability

The use of instrument air eliminates natural gas emissions from the natural gas-driven pneumatic controllers; however, these systems may only be used in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning (U.S. EPA, 2006c).

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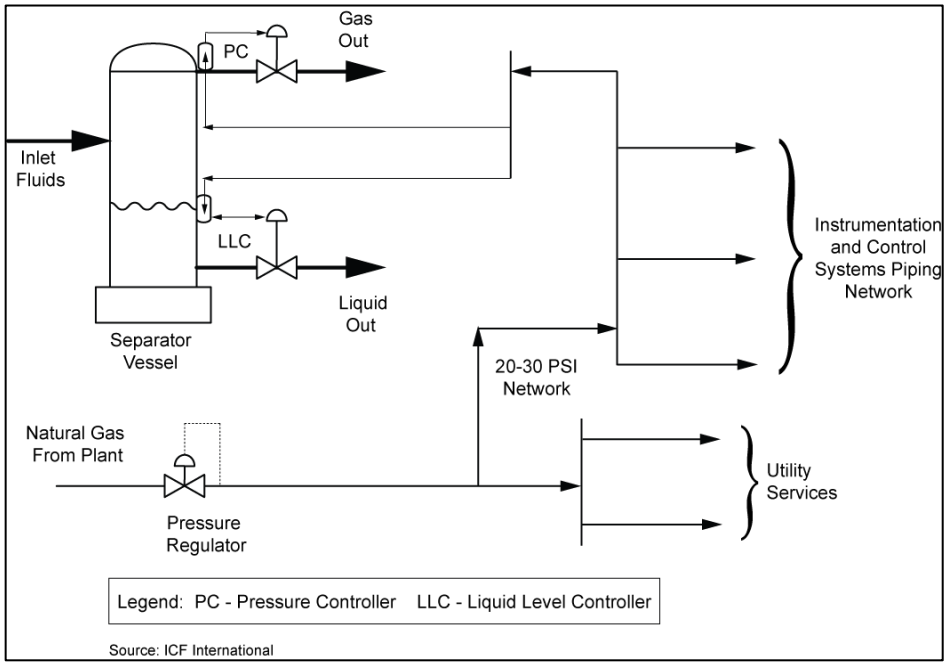


Figure 3-1 Natural Gas Pneumatic Control System

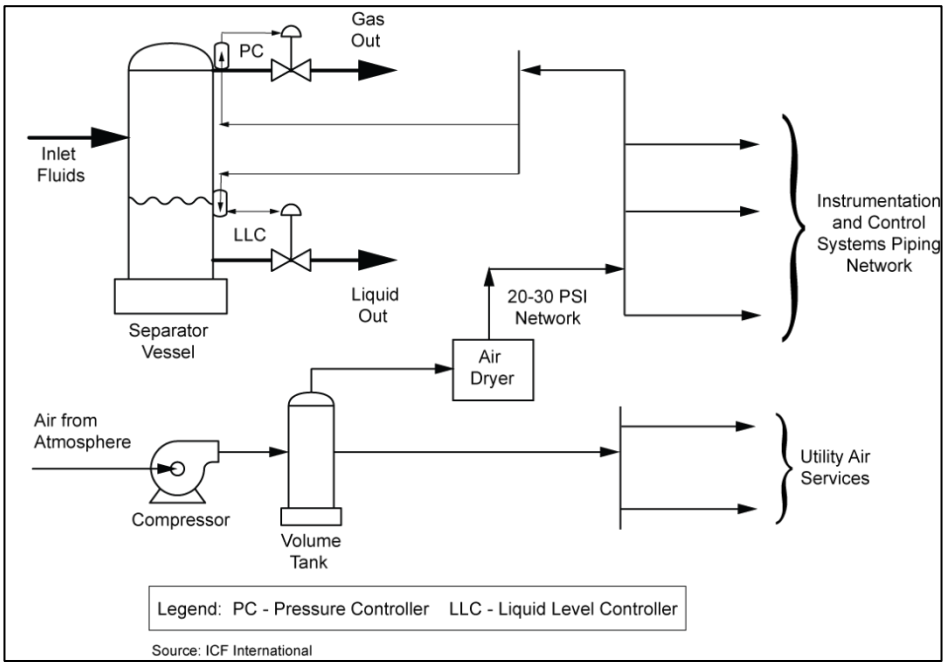


Figure 3-2. Compressed Instrument Air System

Costs

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation—adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is 1 cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power or a backup pneumatic device. Table 3-3 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 3-3. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate	Control Loops
Size of Unit	Hp	kW	(cfm)	Loops/Compressor
Small	10	13.3	30	15
Medium	30	40	125	63
Large	75	100	350	175

[a] Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air.*

[b] Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50% of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors based on assumptions found in the Natural Gas STAR

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document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air” are summarized in Table 3-4.

3.1.4 Mechanical and Solar-Powered Systems in Place of Bleed Controller

Description

Mechanical controls have been widely used in the natural gas and petroleum industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages (U.S. EPA, 2006a). Another device that is increasing in use is electronic control instrumentation. Electricity or small electrical motors (including solar-powered) have been used to operate valves and therefore do not bleed natural gas into the atmosphere (U.S. EPA, 2006a). Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Applicability

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations (U.S. EPA, 2006c). Electric-powered valves are only reliable with a constant supply of electricity. These controllers can achieve 100% reduction in emissions where applicable.

Costs

Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems (U.S. EPA, 2006a).

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Table 3-4 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

[a] Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

[b] The annualized cost was estimated using a 7% interest rate and 10-year equipment life.

[c] Annual Costs include the cost of electrical power as listed in Table 3-3 and labor.

3.1.5 Maintenance of Natural Gas-Driven Pneumatic Controllers

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age, and wear of the device (U.S. EPA, 2006a). Examples of circumstances or factors that can contribute to this increase include:

- Nozzle corrosion resulting in more flow through a larger opening.
- Broken or worn diaphragms, bellows, fittings, and nozzles.
- Corrosives in the gas leading to erosion or corrosion of control loop internals.
- Improper installation.
- Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals).
- Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle.
- Foreign material lodged in the pilot seat.
- Wear in the seal seat.

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device (U.S. EPA, 2006a).

However, proper methods of maintaining a device are highly variable, thus, costs are variable based on labor, time, and fuel required to travel to many remote locations.

3.2 Available Pneumatic Pump Emissions Mitigation Techniques

There are several techniques that are currently being used to reduce emissions from pneumatic pumps. Table 3-5 provides a summary of these techniques for reducing emissions

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from pneumatic pumps, which include chemical injection pumps and natural gas-assisted recirculation pumps.

3.2.1 Instrument Air Pump

Description

Circulation pumps in glycol dehydration processes and chemical injection pumps are often powered by pressurized natural gas at remote locations. As a result, these pumps vent natural gas to the atmosphere as part of their normal operation. To mitigate VOC and methane emissions, some companies are using instrument air to power these pumps. These companies have found that the use of instrument air increased operational efficiency, decreased maintenance and decreased costs, while eliminating emissions of methane and VOC (U.S. EPA, 2011b).

Applicability

Converting chemical injection pumps and glycol dehydration circulation pumps to instrument air can be applied to natural gas hydration operations across all gas industry sectors with excess capacity of its instrument air system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2011b).

Costs

The total cost to convert a natural gas pneumatic circulation pump to instrument air includes the installation of piping and an appropriate control system between the existing instrument air system and the glycol pump if the driver is independent of the circulation pump. If the driver is separated from the pump by O-rings, then the pump would need to also be replaced. The implementation capital costs are estimated to be $1,000 to $10,000, and the incremental operating costs are estimated to be $100 to $1,000 (U.S. EPA, 2011b). The potential annual

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Table 3-5. Summary of Alternative Mitigation Techniques for Pneumatic Pumps

Option	Description	Applicability	Costs	Efficacy and Prevalence
Replace natural gas-assisted pump with instrument air pump (U.S. EPA, 2011b)	Circulation pumps in glycol dehydration units and chemical injection pumps are retrofitted with instrument air to drive the pumps (U.S. EPA, 2011b).	Facilities with excess capacity of instrument air or facilities that can install an air compressor system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic pump (U.S. EPA, 2011b).	The installation of the piping from the air compressor system to the pump accounts for the bulk of the capital cost and typically ranges from $100 to $1,000 (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 2,500 Mcf for glycol circulation pumps and 183 Mcf for chemical injection pumps (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.
Replacement of natural gas-assisted pump with solar-charged direct current pump (U.S. EPA, 2011b)	In field settings, low volume natural gas pneumatic pumps can be replaced with solar-charged DC pumps (U.S. EPA, 2011b).	Low volume solar-charged pneumatic pumps are limited to approximately 5 gallons per day discharge at 1,000 psig. Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b).	The reporting partners for Natural Gas STAR stated a replacement cost of $2,000 per pump, including the solar panels, storage batteries and pump (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 182.5 Mcf per chemical injection pump conversion (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.

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Option	Description	Applicability	Costs	Efficacy and Prevalence
Replacement of natural gas-assisted pump with electric pump (ICF, 2014)	In settings where a constant supply of electricity is available, natural gas pneumatic pumps can be replaced with electric pumps (ICF, 2014).	These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity (U.S. EPA, 2011b).	Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year. (ICF, 2014)	100% emission reduction, where applicable. The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014). The EPA does not have information on the prevalence of this technology in the field.

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natural gas savings are estimated to be 2,500 Mcf (U.S. EPA, 2011b) or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf per pump conversion (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.2 Solar Power Pump

Description

Solar power can be used to operate pumps located at remote sites where electricity is not available. These solar-powered pumps use electric power captured by solar panels to operate a DC-charged pump. Solar injection pumps can handle a range of throughputs and injection pressures. Low volume solar-charged DC pumps are limited to approximately 5 gallons per day discharge at 1,000 psig (U.S. EPA, 2011b). Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b). These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These solar-powered pumps are generally used to replace low volume natural gas pneumatic pumps if sufficient sunlight is available to power the pumps and backup power is not required. These low volume pumps are typically used to inject methanol or corrosion inhibiters into producing wells and other field equipment. These chemical injection pumps are typically sized for 6 to 8 gallons of methanol injection per day. The large volume pumps can be used to replace gas-assisted circulation pumps for glycol dehydrators.

Costs

The Natural Gas STAR program reported the cost of replacing pneumatic pumps with solar-charged electric pumps to be approximately $2,000 per pump (U.S. EPA, 2011b). The solar

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panels and storage batteries are nearly maintenance free, and the solar panels have a life span of up to 15 years and the electric motors last approximately 5 years in continuous use (U.S. EPA, 2011b). The potential annual natural gas savings are estimated to be 2,500 Mcf or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010) for recirculation pumps (U.S. EPA, 2011b). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). The ICF report estimates the cost of replacing chemical injection pneumatic pumps with solar-powered pumps to be $5,000 per pump with a natural gas savings of 180 Mcf per year (ICF, 2014) or $720 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.3 Electric Power Pumps

Description

Electric power pumps are used to replace natural gas-assisted pneumatic used to recirculate glycol in gas dehydrators. These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity.

Costs

Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year (ICF, 2014). The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014) or $20,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

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4.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of emissions from pneumatic controllers and pumps and the emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding these sources of VOC and methane emissions.

4.1 Pneumatic Controllers

- The majority of recent emissions estimates for pneumatic controllers have focused on methane emissions and not VOC emissions.
- The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors.
- Recent emission measurement studies have resulted in a wide range of methane emission factors for natural gas-driven pneumatic controllers. The studies all show that emissions can vary depending on sector (e.g., production, transmission, or storage) and the type of gas-driven pneumatic controller.
- Natural gas-driven pneumatic controllers are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Low bleed gas-driven controllers can replace high bleed gas-driven controllers in many, but not all, applications.
- Where a reliable source of electrical power is available, instrument air systems can replace natural gas-driven pneumatic controllers, and result in no methane or VOC emissions.
- Zero bleed, mechanical, and solar-powered controllers can replace continuous bleed controllers in certain applications, but are not broadly applicable to all segments of the oil and natural gas industry.

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4.2 Pneumatic Pumps

- Pneumatic pumps in the oil and natural gas industry are used as chemical injection pumps and circulation pumps for glycol dehydrators. Pressure from the natural gas line is used to power these pumps and the natural gas is vented to the atmosphere.
- There are several mitigation techniques that can be used to reduce or eliminate emissions from pneumatic pumps and they include: instrument air pumps and electric pumps (both AC and DC powered).
- The 2014 GHG Inventory data estimates that pneumatic pump emissions are 16% of overall methane emissions from the natural gas production and processing sectors. The 2014 GHG Inventory estimated methane emissions from these sources to be 64,570 MT of methane for chemical injection pumps and 393,389 MT of methane for natural gas-assisted Kimray pumps. Chemical injection pumps at petroleum systems emitted 49,973 MT of methane, or around 3% of emissions from petroleum production.
- Natural gas-driven pneumatic pumps are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Where a reliable source of electrical power is available, instrument air systems are an effective replacement for natural gas-driven pneumatic pumps.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Did this paper appropriately characterize the different studies and data sources that quantify emissions from pneumatic controllers and pneumatic pumps in the oil and gas sector?
2. Please discuss explanations for the wide range of emission rates that have been observed in direct measurement studies of pneumatic controller emissions (e.g., Allen et al., 2013 and Prasino 2013). Are these differences driven purely by the design of the monitored controllers or are there operational characteristics, such as supply pressure, that play a crucial role in determining emissions?

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3. Did this paper capture the full range of technologies available to reduce emissions from pneumatic controllers and pneumatic pumps oil and gas facilities?

4. Please comment on the pros and cons of the different emission reduction technologies. Please discuss efficacy, cost and feasibility for both new and existing pneumatics.

5. Please comment on the prevalence of the different emission control technologies and the different types of pneumatics in the field. What particular activities require high bleed pneumatic controllers and how prevalent are they in the field?

6. What are the barriers to installing instrument air systems for converting natural gas-driven pneumatic pumps and pneumatic controllers to air-driven pumps and controllers?

7. Are there situations where it may be infeasible to use air driven pumps and controllers in place of natural gas-driven pumps and controllers even where it is feasible to install an instrument air system?

8. Did this paper correctly characterize the limitations of electric-powered pneumatic controllers and pneumatic pumps? Are these electric devices applicable to a broader range of the oil and gas sector than this paper suggests?

9. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from pneumatic controllers and pneumatic pumps and available techniques for increased product recovery and emissions reductions?

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Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry



Executive Summary

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Methane emissions from pneumatic devices, which have been estimated at 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector and <1 Bcf per year in the processing sector, are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable.

Natural Gas STAR Partners have achieved significant savings and methane emission reductions through replacement, retrofit, and maintenance of high-bleed pneumatics. Partners have found that most retrofit investments pay for themselves in little over a year, and replacements in as little as 6 months. To date, Natural Gas STAR Partners have saved 36.4 Bcf by retrofitting or replacing high-bleed with low-bleed pneumatic devices, representing a savings of $254.8 million worth of gas. Individual savings will vary depending on the design, condition and specific operating conditions of the controller.

Technology Background

The natural gas industry uses a variety of control devices to automatically operate valves and control pressure, flow, temperature or liquid levels. Control devices can be powered by electricity or compressed air, when available and economic. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas.

Natural gas powered pneumatic devices perform a variety of functions in all three sectors of the natural gas industry. In the production sector, an estimated 400,000 pneumatic devices are used to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector, about 13,000 gas pneumatic devices are used for compressor and glycol dehydration control in gas gathering/booster stations and isolation valves in processing plants (process control in gas processing plants is predominantly instrument air).

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/year)	Value of Natural Gas Savings ($/year)			Implementation Cost ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Replacement								
Change to low-bleed device at end of life.	50 to 200	$150 to $600	$250 to $1,000	$350 to $1,400	$210 to $340[a]	4 to 27	3 to 17	2 to 12
Early-replacement of high-bleed unit.	260	$780	$1,300	$1,820	$1,850	29	17	13
Retrofit	230	$690	$1,150	$1,610 per year	$675	12	7	5
Maintenance	45 to 260	$135 to $780	$225 to $1,300	$315 to $1,820	Negligible to $500	Immediate to 8	Immediate to 5	Immediate to 4

General Assumptions:
[a] Incremental cost of low-bleed over high-bleed equipment.

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Definition of High-Bleed Pneumatic

Any pneumatic device that bleeds in excess of 6 scfh (over 50 Mcf per year) is considered a high-bleed device by the Natural Gas STAR Program.

In the transmission sector, an estimated 85,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at distribution company gate stations for regulating flow, pressure, and temperature.

As part of normal operation, pneumatic devices release or bleed natural gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The actual bleed rate or emissions level largely depends on the design of the device.

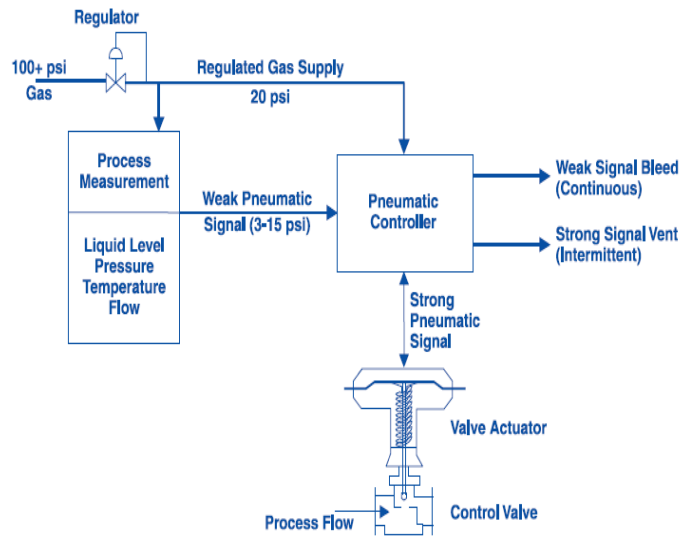
Exhibit 1 shows a schematic of a gas pneumatic control system. Clean, dry, pressurized natural gas is regulated to a constant pressure, usually around 20 psig. This gas supply is used both as a signal and a power supply. A small stream is sent to a device that measures a process condition (liquid level, gas pressure, flow, temperature). This device regulates the pressure of this small gas stream (from 3 to 15 psig) in proportion to the process condition. The stream flows to the pneumatic valve controller, where its variable pressure is used to regulate a valve actuator.

To close the valve pictured in Exhibit 1, 20-psig pneumatic gas is directed to the actuator, pushing the diaphragm down against the spring, which, through the valve stem, pushes the valve plug closed. When gas is vented off the actuator, the spring pushes the valve back open. The weak signal continuously vents (bleeds) to the atmosphere. Electro-pneumatic devices use weak electric current instead of the weak gas stream to signal pneumatic valve actuation.

In general, controllers of similar design usually have similar steady-state bleed rates regardless of brand name. Pneumatic devices come in three basic designs:

- ★ **Continuous** bleed devices are used to modulate flow, liquid level, or pressure and will generally vent gas at a steady rate;
- ★ **Actuating or intermittent** bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed or as they throttle gas flows; and

Exhibit 1: Pneumatic Device Schematic



- ★ **Self-contained** devices release gas into the downstream pipeline, not to the atmosphere.

To reduce emissions from pneumatic devices the following options can be pursued, either alone or in combination:

1. Replacement of high-bleed devices with low-bleed devices having similar performance capabilities.
2. Installation of low-bleed retrofit kits on operating devices.
3. Enhanced maintenance, cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings, and seals.

Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. Exhibit 2 lists the generic options applicable for different controller requirements.

In general, the bleed rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years.

Exhibit 2: Options for Reducing Gas-Bleed Emissions by Controller Type

Action	Pneumatic Types		
	Level Controllers	Pressure Controllers	Positioners/ Transducers
Replacements			
High-bleed with low-bleed	X	X	X (electro-pneumatic)
Retrofits			
Install retrofit kits	X	X	X
Maintenance			
Lower gas supply pressure/replace springs/re-bench	X	X	X
Repair leaks, clean and tune	X	X	X
Change gain setting	X	X	
Remove unnecessary positioners			X

Economic and Environmental Benefits

Reducing methane emissions from high-bleed pneumatic devices through the options presented above will yield significant benefits, including:

- ★ **Financial return from reducing gas-bleed losses.** Using a natural gas price of $7.00 per thousand cubic feet (Mcf), savings from reduced emissions can range from $315 to $1,820 or more per year per device. In many cases, the cost of implementation is recovered in less than a year.

- ★ **Increased operational efficiency.** The retrofit or complete replacement of worn units can provide better system-wide performance and reliability and improve monitoring of parameters such as gas flow, pressure, or liquid level.

- ★ **Lower methane emissions.** Reductions in methane emissions can range from 45 to 260 Mcf per device per year, depending on the device and the specific application.

Decision Process

Operators can determine the gas-bleed reduction option that is best suited to their situation, by following the decision process laid out below. Depending on the types of devices that are being considered, one or more options for reducing pneumatic gas bleed may be appropriate.

Step 1: Locate and describe the high-bleed devices.

Partners should first identify the high-bleed devices that are candidates for replacement, retrofit, or repair. The identification and description process can occur during normal maintenance or during a system-wide or facility-specific pneumatics survey. For each pneumatic device, record the location, function, make and model, condition, age, estimated remaining useful life, and bleed rate characteristics (volume and whether intermittent or continuous).

The pneumatic device's bleed rate can be determined through direct measurement or from data provided by the manufacturer. Direct measurement might include bagging studies at selected instruments, high-volume sampler measurements (see "Directed Inspection and Maintenance at Compressor Stations" Lessons Learned) or the operator's standard leak measurement approach. Operators will find it unnecessary to measure bleed rates at each device. In most cases, sample measurements of a few devices are sufficient. Experience suggests that manufacturers' bleed rates are understated, so measurement data should be used when it can be acquired.

Appendix A lists brand, model, and gas bleed information—as provided by manufacturers—for various pneumatic devices. This is not an exhaustive list, but it covers the most commonly used devices. Where available, actual field data on bleed rates are included.

Step 2: Establish the technical feasibility and costs of alternatives.

Nearly all high-bleed pneumatic devices can be replaced or retrofitted with lower-bleed equipment. Consult your pneumatic device vendor or an instrumentation specialist for availability, specifications and costs of suitable devices. Low-bleed devices can be requested by specifying bleed rates less than 6 standard cubic feet per hour (scfh). It is important to note that not all manufacturers report bleed rates in the same manner, and companies should exercise

Five Steps for Reducing Methane Emissions from Pneumatic Devices:
1. Locate and describe the high-bleed devices;
2. Establish the technical feasibility and costs of alternatives;
3. Estimate the savings;
4. Evaluate the economics; and
5. Develop an implementation plan.

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caution when making purchases of low-bleed devices.

Appendix B lists cost data for many low-bleed pneumatic devices and summarizes the compatibility of retrofit kits with various controllers. This is not an exhaustive list, but it covers the most commonly used devices.

Maintenance of pneumatics is a cost-effective method for reducing emissions. All companies should consider maintenance as an important part of their implementation plan. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device.

Some high-bleed devices, however, should not be replaced with low-bleed devices. Control of very large valves that require fast and/or precise response to process changes often require high-bleed controllers. These are found most frequently on large compressor discharge and bypass pressure controllers. EPA recommends contacting vendors for new fast-acting devices with lower bleed rates.

Step 3: Estimate the savings.

Determine the quantity of gas that can be saved with a low-bleed controller, using field measurement of the high-bleed controller and a similar low-bleed device in service. If these actual bleed rates are not available, use bleed specifications provided by manufacturers.

Gas savings can be monetized to annual savings using $7.00 per Mcf and multiplying bleed reduction, typically specified in scfh, by 8,670 hours per year.

Gas Savings = (High-bleed, scfh) — (Low-bleed, scfh)

Annual Gas Savings = Gas Savings (scfh) * 8,760 hrs/yr * 1 Mcf/1000scf * $7.00/Mcf

Step 4: Evaluate the economics.

The cost-effectiveness of replacement, retrofit, or maintenance of high-bleed pneumatic devices can be evaluated using straightforward economic analysis. A cost-benefit analysis for replacement or retrofit is appropriate unless high-bleed characteristics are required for operational reasons.

Exhibit 3 illustrates a cost-benefit analysis for replacement of a high-bleed liquid level controller. Cash flow over a five-year period is analyzed by showing the magnitude and timing of costs (shown in parenthesis) and benefits. In this example, a $513 initial investment buys a level controller that saves 19 scfh of gas. At $7.00 per Mcf, the low-bleed device saves $1,165 per year. Annual maintenance costs for the new and old controllers are shown. The maintenance cost for the older high-bleed controller is shown as a benefit because it is an avoided cost. Net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. Internal rate of return (IRR) is the discount rate at which the NPV generated by the investment equals zero.

Exhibit 3: Cost-Effectiveness Calculation for Replacement

Type of Costs	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Implementation Costs, $ (Capital Costs)[a]	(513)					
Annual Savings, $ (New vs. Old)[b]		1,165	1,165	1,165	1,165	1,165
Maintenance Costs, $ (New Controller)[c]		(34)	(34)	(34)	(34)	(34)
Avoided Maintenance, $ (Replaced Controller)[c]		70	70	70	70	70
Net Benefit	(513)	1,202	1,202	1,202	1,202	1,202
NPV[d] = $4,042 IRR = 234%						

Notes:
[a] Quoted cost of a Fisher 2680 device. Adjusted to 2006 equipment costs. See Appendix B.
[b] Annual savings per device calculated as the change in bleed rate of 19 scfh x 8,760 hrs/hr = 167 Mcf/yr at $7/Mcf.
[c] Maintenance costs are estimated.
[d] Net Present Value (NPV) based on 10% discount rate for 5 years.

Exhibit 4 illustrates the range of savings offered by proven methods for reducing gas bleed emissions. For simplicity, it is assumed that the cost of maintenance of the pneumatic device will be the same before and after the replacement, retrofit, or enhanced maintenance activity.

As seen in Exhibit 4, sometimes more than one option to reduce gas bleed may be appropriate and cost-effective for a given application. For the listed options, please note that the payback period with respect to implementation cost can range from less than one month to two years.

Exhibit 4: Economic Benefits of Reducing Pneumatic Device Emissions

Action	Cost[a] ($)	Bleed Rate Reductions[b] (Mcf/yr/device)	Annual Savings[c] ($/year)	Payback Period (months)	IRR[d] (%)
Replacement					
Level Controllers					
High-bleed to low-bleed	513	166	1,165	6	226
Pressure Controllers					
High-bleed to low-bleed	1,809	228	1,596	14	84
Airset metal to soft-seal	104	219	1,533	<1	>1,400
Retrofit					
Level Controllers					
Mizer	675	219	1,533	6	226
Large orifice to small	41	184	1,288	<1	>3,100
Large nozzle to small	189	131	917	3	>450
Pressure Controllers					
Large orifice to small	41	184	1,288	<1	>3,100
Maintenance					
All types					
Reduce supply pressure	207	175	1,225	3	>500
Repair leaks, retune	31	44	308	2	>900
Level Controllers					
Change gain setting	0	88	616	Immediate	—-
Positioners					
Remove unnecessary	0	158	1,106	Immediate	—-

[a] Implementation costs represent average costs for Fisher brand pneumatic instruments installed.
[b] Bleed rate reduction = change in bleed rate scf/hr x 8,760 hr/yr.
[c] Savings based on $7.00/Mcf cost of gas.
[d] Internal rate of return (IRR) calculated over 5 years.

The case studies in Exhibit 5 on the next page present analyses performed and savings achieved by two Natural Gas STAR Partners who installed retrofit kits at gas production facilities.

Step 5: Develop an implementation plan.

After identifying the pneumatic devices that can be profitably replaced, retrofitted or maintained, devise a systematic plan for implementing the required changes. This can include modifying the current inspection and maintenance schedule and prioritizing replacement or retrofits. It may be most cost-effective to replace all those devices that meet the technical and economic criteria of your analysis at one time to minimize labor costs and disruption of operation.

Where a pneumatic device is at the end of its useful life and is scheduled for replacement, it should be replaced with a low-bleed model instead of a new high-bleed device whenever possible.

When assessing options for replacement of high-bleed pneumatic devices, natural gas price may influence the decision making process. Exhibit 6 shows an economic analysis of early replacement of a high bleed pneumatic device with a lower bleed device at different natural gas prices.

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Exhibit 5: Case Studies on Retrofit To Reduce Gas Leaks at Natural Gas STAR Partner Sites

Study	Implementation Costs ($)	Emissions Reductions (Mcf/yr)	Annual Savings ($/year)	Payback (months)	IRR (%)
Company 1:					
Platform 1	8,988	2,286	16,002	7	177
Platform 2	13,892	3,592	25,144	7	180
Retrofit Liquid-level controllers	5,452	1,717	12,019	6	220
Company 2:					
Per device	702	219	1,533	6	218

Exhibit 6: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$780	$1,300	$1,820	$2,080	$2,600
Payback Period (months)	29	18	13	11	9
Internal Rate of Return (IRR)	31%	64%	95%	110%	139%
Net Present Value (i=10%)	$1,107	$3,078	$5,049	$6,035	$8,006

Other Technologies

Instrument air, nitrogen gas, electric valve controllers, and mechanical control systems are some of the alternatives to gas powered pneumatics implemented by Partners.

★ **Instrument Air.** These systems substitute compressed, dried air in place of natural gas in pneumatic devices, and thus eliminate methane emissions entirely. Instrument air systems are typically installed at facilities where there is a high concentration of pneumatic control valves and fulltime operator presence (for example, most gas processing plants use instrument air for pneumatic devices). The major costs associated with instrument air systems are capital and energy. Instrument air systems are powered by electric compressors, and require the installation of dehydrators and volume tanks to filter, dry and store the air for instrumentation use. Generally, Partners have found that cost-effective implementation of instrument air systems is limited to field sites with available utility or self-generated electrical power. The Lessons Learned study, "Covert Gas Pneumatic Controls to Instrument Air," provides a detailed description of the technical and economic decision process required to evaluate conversion from gas pneumatic devices to instrument air.

★ **Nitrogen Gas.** Unlike instrument air systems that require capital expenditures and electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, that is replaced periodically, and a liquid nitrogen vaporizer. The system uses a pressure regulator to control the expansion of the nitrogen gas (i.e., the gas pressure) as it enters the control system. The primary disadvantage of these systems stems from the cost of liquid nitrogen and the potential safety hazard associated with using cryogenic liquids.

★ **Electric Valve Controllers.** Due to advances in technology, the use of electronic control instrumentation is increasing. These systems use small electrical motors to operate valves and therefore do not bleed natural gas into the atmosphere. While they are reliant on a constant

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

supply of electricity, and have high associated operating costs, they have the advantage of not requiring the utilization of natural gas or a compressor to operate.

★ **Mechanical Control Systems.** These devices have been widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. While they are simple in design and require no natural gas or power supply to operate, their application is limited due to the need for the control valve to be in close proximity to the process measurement. Also, these systems are unable to handle large flow fluctuations and lack the sensitivity of pneumatic systems.

Each of these options has specific advantages and disadvantages. Where Natural Gas STAR Partners do install these systems as replacements to gas powered pneumatic devices, they should report the resulting emissions reductions and recognize the savings.

One Partner's Experience

Union Pacific Resources replaced 70 high-bleed pneumatic devices with low-bleed pneumatic devices and retrofitted 330 high-bleed pneumatic devices. As a result, this Partner has estimated a total reduction of methane emissions of 49,600 Mcf per year. Assuming a gas price of $7 per Mcf, the savings corresponds to $347,200. The costs of replacing and retrofitting all the devices, including materials and labor, is $166,300 at 2006 costs, resulting in a payback period of less than one year.

One Partner's Experience

Marathon Oil Company surveyed 158 pneumatic control devices at 50 production sites using the Hi-Flow Sampler to measure emissions. Half of these controllers were identified as non-bleed devices (e.g., weighted dump valves, spring operated regulators, enclosed capillary temperature controllers, non-bleed pressure switches). High-bleed devices accounted for 35 of 67 level controllers, 5 of 76 pressure controllers, and 1 of 15 temperature controllers. Measured gas emissions were 583 scfh total; 86 percent of emissions came from level controllers, with leaks up to 48 scfh, and averaging 7.6 scfh. Marathon concluded that "control devices with higher emissions can be identified qualitatively by sound prior to leak measurement, making it unnecessary to quantitatively measure methane emissions using technologically advanced equipment."

Lessons Learned

Natural Gas STAR Partners offer the following Lessons Learned:

★ Hear it; feel it; replace it. Where emissions can be heard or felt, this is a sign that emissions are significant enough to warrant corrective action.

★ Control valve cycle frequency is another indicator of excessive emissions. When devices cycle more than once per minute, they can be replaced or retrofitted profitably.

★ Manufacturer bleed rate specifications are not necessarily what users will experience. Actual bleed rates will generally exceed manufacturer's specifications because of operating conditions different from manufacturer's assumptions, installation settings and maintenance.

★ Combine equipment retrofits or replacements with improved maintenance activities. Do not overlook simple solutions such as replacing tubes and fittings or rearranging controllers.

★ The smaller orifices in low-bleed devices and retrofit kits can be subject to clogging from debris in corroded pipes. Therefore, pneumatic supply gas piping and tubing should be flushed out before retrofitting with

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smaller orifice devices, and gas filters should be well maintained.

- ★ When replacing pneumatic control systems powered by pressurized natural gas with instrument air or other systems, do not forget to account for the savings from the resulting methane emission reductions.

- ★ Include methane emission reductions from pneumatics in annual reports submitted as part of the Natural Gas STAR Program.

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Appendix A

The following chart contains manufacturer-reported bleed rates. Actual bleed rates have been included whenever possible. Discrepancies occur due to a variety of reasons, including:

- ★ Maintenance.
- ★ Operating conditions.
- ★ Manufacturer vs. operating assumptions.

It is important to note that manufacturer information has not been verified by any third party and there may be large differences between manufacturer-reported bleed rates and those found during operations. Until a full set of information is available, companies should be careful to compare bleed rates in standard units (CFH) when comparing manufacturers and models. During this study we found that manufacturers reported information in a wide range of different units and operating assumptions.

Gas Bleed Rate for Various Pneumatic Devices

Controller Model	Type	Consumption Rate (CFH)	
		Manufacturer Data	Field Data (where available)
High-Bleed Pneumatic Devices			
**Fisher 4100 Series	Pressure controller (large orifice)	35	
**Fisher 2500 Series	Liquid-level controllers (P.B. in mid range)	10-34	44-72
*Invalco AE-155	Liquid-level controller		44-63
*Moore Products—Model 750P	Positioner	42	
*Invalco CT Series	Liquid-level controllers	40	34-87
**Fisher 4150/4160K	Pressure controller (P.B. 0 or 10)	2.5-29	
**Fisher 546	Transducer	21	
**Fisher 3620J	Electro-pneumatic positioner	18.2	
Foxboro 43AP	Pressure controller	18	
**Fisher 3582i	Electro-pneumatic positioner	17.2	
**Fisher 4100 Series	Pressure controller (small orifice)	15	
**Fisher DVC 6000	Electro-pneumatic positioner	14	
**Fisher 846	Transducer	12	
**Fisher 4160	Pressure controller (P.B. 0.5)	10-34	
**Fisher 2506	Receiver controller (P.B. 0.5)	10	
**Fisher DVC 5000	Electro-pneumatic positioner	10	
**Masoneilan 4700E	Positioners	9	
**Fisher 3661	Electro-pneumatic positioner	8.8	
**Fisher 646	Transducer	7.8	
**Fisher 3660	Pneumatic positioner	6	
**ITT Barton 335P	Pressure controller	6	
*Ametek Series 40	Pressure controllers	6	
Low- or No-Bleed Pneumatic Devices			
**Masoneilan SV	Positioners	4	
**Fisher 4195 Series	Pressure controllers	3.5	
**ITT Barton 273A	Pressure transmitter	3	
**ITT Barton 274A	Pressure transmitter	3	
**ITT Barton 284B	Pressure transmitter	3	
**ITT Barton 285B	Pressure transmitter	3	
**Bristol Babcock Series 5457-70F	Transmitter	3	
**Bristol Babcock Series 5453-Model 624 -II	Liquid-level controllers	3	
**Bristol Babcock Series 5453-Model 10F	Pressure controllers	3	
**Bristol Babcock Series 5455 Model 624 -III	Pressure controllers	3	
**ITT Barton 358	Pressure controller	1.8	

**ITT Barton 359	Pressure controller	1.8	
**Fisher 3610J	Pneumatic positioner	16	
**Bristol Babcock Series 502 A/D	Recording pneumatic controllers	<6	
**Fisher 4660	High-low pressure pilot	<5	
**Bristol Babcock Series 9110-00A	Transducers	0.42	
Fisher 2100 Series	Liquid-level controllers	1	
**Fisher 2680	Liquid-level controllers	<1	
*Norriseal 1001 (A) (snap)	Liquid-level controller	0.2	0.2
*Norriseal 1001 (A) ('Envirosave')	Liquid-level controller	0	0
*Norriseal 1001 (A) (throttle)	Liquid-level controller	0.007	0.007
**Becker VRP-B -CH	Double-acting pilot pressure control system (replaces controllers and positioners)	0-10	
**Becker HPP-5	Pneumatic positioner (Double-acting)	0-10	
**Becker EFP-2.0	Electro-pneumatic positioner	0	
**Becker VRP-SB	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker VRP-SB GAP Controller	Replaces pneumatic "gap" type controllers	0	
**Becker VRP-SB-PID Controller	Single-acting pilot pressure control system specifically designed for power plant type feeds (replaces controllers and positioners)	0	
**Becker VRP-SB-CH	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker HPP-SB	Pneumatic positioner (Single-acting)	0	

Actuator Model	Size	Manufacturer Data	Field Data
*Shafer RV-Series Rotary Vane Valve Actuators	33" x 32"	1,084	
	36" x 26"	768	
	26" x 22"	469	
	25" x 16"	323	
	20" x 16"	201	
	16.5" x 16"	128	
	14.5" x 14"	86	
	12.5" x 12"	49	
	12" x 9"	22	
	11" x 10"	32	
	9" x 7"	12	
	8" x 6.5"	8	
	6.5" x 3.5"	6	
	5" x 3"	6	

Actuator Model	Size	Number of Snap-acting Strokes per CF	Number of Throttling Strokes per CF
**Fisher Valve Actuators	20	21	39
**Fisher Valve Actuators	30	12	22
**Fisher Valve Actuators	34/40	6	10
**Fisher Valve Actuators	45/50	3	5
**Fisher Valve Actuators	46/50	2	3

* Last updated in 1996.
** Last updated in 2001.

Appendix B

Controllers Compatible with MIZER Retrofits	
Type	**Brand/Model Number**
Liquid-level controllers	C.E. Invalco — 215, 402, AE-155
	Norriseal — 1001, 1001A
Pressure controllers	Norriseal — 4300
Suggested Retail Prices for Various Brand Low-Bleed Pneumatic Devices (Estimates Based on Best Information Available at Time of Publication)	
Brand/Model	**Price per Device**
**ITT Barton 335P (pressure controller)	$920
**ITT Barton 273A (pressure transmitter)	$1,010
**ITT Barton 274A (pressure transmitter)	$1,385
**ITT Barton 284B (pressure transmitter)	$1,605
**ITT Barton 285B (pressure transmitter)	$1,990
**ITT Barton 340E (recording pressure controller)	$1,400
**ITT Barton 338E (recorder controller)	$2,800
**Ametek Series 40 (pressure controllers)	$1,100 (average cost)
**Becker VRP-B-CH	$1,575.00
**Becker HPP-5	$1,675.00
**Becker VRP-SB	$1,575.00-$2,000.00
**Becker VRP-SB-CH-PID	$2,075.00
**Becker VRP-SB-CH	$1,575.00
**Becker HPP-SB	$1,675.00
**Mizer Retrofit Kits	$400-$600
**Fisher 67AFR (airset regulators)	$80
**Fisher 2680 (liquid-level controllers)	$380
**Fisher 4195 (pressure controllers)	$1,340
**Bristol Babcock Series 9110-00A (transducers)	$1,535-$1,550
**Bristol Babcock Series 5453 (controllers)	$1,540
**Bristol Babcock 5453 40 G (temperature controllers)	$3,500
**Bristol Babcock Series 5457-624 II (controllers)	$3,140
**Bristol Babcock Series 502 A/D (recording controllers)	$3,000
**Bristol Babcock Series 5455-624 III (pressure controllers)	$1,135
**Bristol Babcock Series 5453-624 II (liquid level controllers)	$2,345
**Bristol Babcock Series 5453-10F (pressure controllers)	$1,440

* Last updated in 1996.
** Last updated in 2001.

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

October 2006

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

COLORADO

Air Pollution Control Division

Department of Public Health & Environment

Dedicated to protecting and improving the health and environment of the people of Colorado

Pneumatic Controller Task Force Report to the Air Quality Control Commission

Pneumatic Controller Field Study and Recommendations

June 1, 2020

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1 Introduction

This report was developed in response to a December 2017 rulemaking, in which the Colorado Air Quality Control Commission (AQCC) established a pneumatic controller (PC) 'Find and Fix' program for oil and gas well production facilities and natural gas compressor stations located in the ozone non-attainment area (NAA). The AQCC recognized that continuous bleed and intermittent pneumatic controllers are designed to have emissions but these emissions can be excessive when the controllers are not operating properly. The AQCC adopted the Find and Fix program to reduce excess emissions from such natural gas-driven pneumatic controllers.

As part of the Statement of Basis and Purpose (SBAP), and at the request of industry and other stakeholders, the AQCC adopted a "reassessment" provision for the Find and Fix program. The reassessment was to follow an Air Pollution Control Division (Division) led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also directed that more information on "good engineering and maintenance practices" should be gathered during the pneumatic controller study and implementation of the Find and Fix program to inform the reassessment. As part of the reassessment, industry agreed to participate in a study focused on the Denver-Julesburg (DJ) Basin that would collect data on the types of PCs in service, those PCs determined to be operating improperly, what caused the PCs to not operate properly, and the repairs taken to return the PCs to proper operation across a representative cross section of well production facilities and natural gas compressor stations in the NAA.

The AQCC directed the creation of a Pneumatic Controller Task Force (PCTF) comprised of representatives of the Division, operators and industry trade groups, local governments, and conservation groups. The PCTF was to brief the AQCC annually and make recommendations in this report, and each participant was to have the opportunity to contribute to the briefings and report. The AQCC also recognized that the pneumatic controller study and inspection program might inform the strategies for cost-effective hydrocarbon emission reductions for pneumatic controllers, including zero emission pneumatic controllers, under consideration by the Statewide Hydrocarbon Emission Reduction (SHER) team. The AQCC also established the SHER team through the SBAP for the December 2017 rulemaking.

The PCTF convened for the first time on January 25, 2018. The group held bi-weekly meetings for several months to develop and design the study. Field inspections of production facilities selected for the study started on May 1, 2018. Afterwards, meetings were held bi-monthly to check on the progress of field inspections and updates on data management until the data was submitted to the Division in December 2018. The group met in January 2019 to discuss initial data analysis, finalize the project plan, and revisit goals. The PCTF briefed the AQCC on February 21, 2019 on its progress. Throughout the spring of 2019, industry PCTF members developed and responded to questionnaires to document and assess the effectiveness and costs of inspection techniques as well as to understand opportunities for expanded use of no-bleed PCs. The PCTF and the SHER team held a joint meeting on June 11, 2019, to hear presentations on Canadian regulation of pneumatic controllers.

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In April 2019, the legislature adopted Senate Bill 19-181, which directs the AQCC to "review its rules for oil and natural gas well production facilities and compressor stations and specifically consider adopting more stringent provisions, including . . . a requirement to reduce emissions from pneumatic devices. The AQCC shall consider requiring oil and gas operators, under appropriate circumstances, to use pneumatic devices that do not vent natural gas." The PCTF was effectively put on hold in the summer of 2019 to allow its members to focus on regulatory proposals to be addressed during the December 2019 SB 19-181 Rulemaking. In that rulemaking, the AQCC adopted the SHER team's proposal to (1) expand the Find and Fix program statewide, (2) include language in the SBAP directing continued work to evaluate the use of zero-bleed pneumatic devices, and (3) provide for a compliance assistance approach for operators outside the nonattainment area while those operators get up to speed on the Find and Fix program. In the SBAP, the AQCC directed the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the AQCC in 2020 their recommendations on the use of zero-bleed pneumatic devices.

Members of the PCTF were requested in April 2020 to review and complete this report.

1.1 2017 AQCC Reg 7 Oil and Gas CTG Rulemaking and Pneumatic Inspection Program

Below is a summary from the Statement of Basis and Purpose prepared for the 2017 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2017 rulemaking and the direction given to the Division to convene a PCTF.

1.1.1 Background

On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that Colorado's Marginal ozone NAA failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate NAA requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate NAA, Colorado revised its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guidelines ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a NAA's attainment date. EPA finalized the CTG for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado needed to further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado had similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions were not currently in Colorado's Ozone SIP. Therefore, on November 16, 2017, the AQCC adopted RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP. In order to make additional progress towards attainment of the NAAQS, the AQCC also adopted State Only revisions to require owners or operators of oil and gas well production facilities and

compressor stations with natural gas-driven PCs in the DMNFR area to inspect and maintain these PCs.

1.1.2 PC Find and Fix program

The AQCC adopted an inspection and enhanced response (*e.g.*, maintenance) program for natural gas-driven PCs. While the Oil and Gas CTG notes the value of PC inspection and maintenance, the Oil and Gas CTG does not specify PC inspection and maintenance as presumptive RACT. The AQCC therefore created a new program that requires that natural gas-driven PCs at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the PC is operating properly. The program requires that owners or operators inspect PCs for proper operation as part of routine LDAR regulatory programs at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

This PC inspection and enhanced response process was intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven PC using an approved instrument monitoring method (AIMM) to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those PCs with detected emissions. Second, the owner or operator must determine whether the PCs with detected emissions are operating properly. Use of an AIMM is not required during this second step; the AQCC did not lay out a process for how owners or operators are to determine if their PCs are operating properly. During this second step, if an owner or operator determines that the PC is operating properly, no further action is necessary. Third, where an owner or operator determines the PC is not operating properly, the owner or operator must take actions to return an improperly operating PC to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those PCs that the owner or operator determined not to be operating properly. Similar to the LDAR records, owners or operators must keep records of the date the PC was returned to proper operation and a description of the types of actions taken.

1.1.3 Reassessment Provision

The reassessment provision is explained as follows in the SBAP for the 2017 Reg 7 CTG rulemaking.

The AQCC adopted a "reassessment" provision for this inspection and enhanced response program following a Division led study of PC emission reduction options, including the rate, type, application, and causes of PCs found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also recognized that owners and operators may have limited information on "good engineering and maintenance practices" for PCs and intended that more information on these practices are gathered during the pneumatic study and implementation to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry's proposal, a task force was directed to convene by January 30, 2018, consisting of

representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection was scheduled to commence no later than by May 1, 2018. The task force *will* brief the AQCC annually and make any recommendations on its findings in a report (this document) to the AQCC due May 1, 2020. The AQCC *intends* that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the AQCC. The AQCC intended that this information be used to reassess the natural gas-driven PC requirements of Regulation Number 7 that will remain in effect until rescinded, superseded, or revised.

1.1.4 2019 Rulemaking Directives

Below is an excerpt from the Statement of Basis and Purpose prepared for the 2019 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2019 rulemaking and the direction given to the PCTF and SHER Team:

> "Pneumatic Controllers (Part D, Section III.)
>
> SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.
>
> The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.
>
> The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

> The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings."

2 Pneumatic Controllers

This section provides some basic information regarding PCs, with a focus on the PCs studied recently in Colorado.

2.1 What is a PC, what does it do?

PCs are found widely on oil and natural gas production facilities in Colorado. PCs are used to automate and regulate process control variables such as temperature, pressure, liquid level, and to maintain critical safety fail-safe functions. PCs operate by sensing a condition and then sending a signal to a valve actuator that in turn controls a valve that controls the process parameter in question. For instance, a liquid level controller will sense liquid levels in a separator and send a signal (in the form of natural gas pressure) to a valve actuator on a dump valve which in turn opens the dump valve and lowers the liquid level in the separator. It is important to note that the PC, the valve actuator, and the valve are all different components of the control system. It is not uncommon for the PC to be located several feet away from the valve actuator and the valve it is controlling. Finally, it is important to realize that the valve being controlled by the PC is a component that is already subject to the LDAR provisions of Regulation Number 7. Similarly, there are many connectors associated with PCs and valve actuators - each of which is also a component subject to the LDAR provisions. As such, it is important to distinguish emissions from leaking components that are routinely found and repaired in an LDAR program, from emissions caused by an improperly operating PC.

2.2 Types of PCs

As part of their normal function, PCs emit natural gas when they actuate, either intermittently or continuously. Continuous and intermittent PCs are the two broad categorizations of PCs that were the focus of the 2018 PCTF field study. The categorization refers to how the PC is expected to emit under normal operation. A continuous PC is designed to emit at a steady rate, commonly referred to as a bleed rate. The bleed rate may change during actuation. Contrastingly, an intermittent PC is only expected to emit above a de minimis level during actuations and hence they do not have a bleed rate per se. Some intermittent PCs actuate very frequently and some only rarely. For instance, a liquid-level

controller on a new high producing well may actuate many times within an hour. There may be significant emissions associated with this normal, intended operation.[1]

There are also non-emitting controllers, often referred to as "no-bleed," "zero-bleed" or "zero-emitting"[2] PCs. These devices do not emit natural gas to the atmosphere during any phase of normal operation. Many of these devices are inherently non-emitting because they are driven by electricity or pressurized air, rather than pressurized natural gas. Since the intent of this field study was to examine emissions associated with natural gas-driven PCs, non-emitting PCs were not included in the scope of the 2018 PCTF field study.

Contained within the continuous PC category are high-bleed and low-bleed PCs. High-bleed PCs are designed to emit over 6 standard cubic feet per hour (scf/hr) of gas between actuations. Low-bleed devices emit less than 6 scf/hr. As of 2020, the Division believes that there are no high-bleed devices in use within the State of Colorado and all continuous-bleed PCs reported during this study were low-bleed.

2.3 Improper operation

Numerous studies have identified that a small number of improperly operating PCs are typically responsible for the majority of emissions from the PC population[3,4,5]. This information is what originally prompted the AQCC to adopt a PC find and fix program. The PCTF took a similar approach with the field study by focusing on "proper" vs "improper" operation.

2.3.1 Causes

Improper operation could be caused by any number of issues affecting a PC. These causes range from small amounts of debris keeping the controller from reseating properly to broken internal parts or defects in the housing for the PC. The causes specifically identified in the field study included: abnormal operation parameters, corrosion, debris, diaphragm failure, seal failure, spring failure, and wet supply gas.

2.3.2 Effects and Indicators

Operator personnel utilize AIMM (typically an OGI camera) to detect emissions from production facilities during LDAR inspections. Identification of a PC that is not operating properly requires additional knowledge regarding the types of PCs and their emission characteristics during normal operation in order to distinguish improper operation with an OGI camera.

Common tell-tale signs of PC improper operation include: loss of or improper control of the process parameter the PC is supposed to control; continuous emissions from an intermittent PC; excess emissions, as compared to normal operation, as identified via audio, visual, and olfactory (AVO) inspections or AIMM, from a controller; or obvious signs of significant staining

[1] Stovern, 2020: Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging, Journal of the Air & Waste Management Association.
[2] Simpson, 2014. Pneumatic controllers in upstream oil and gas. Oil Gas Facil. 3(5):83–96.
[3] Allen, 2014. CH4 emissions from process equipment at natural gas production sites in the United States: Pneumatic controllers. Environ. Sci. Technol. 49 (1):633–40.
[4] Luck, 2019. Multi-day measurements of pneumatic controller emissions reveal frequency of abnormal emissions behavior at natural gas gathering stations. Environ. Sci. Technol. Letters 6:348–52.
[5] Thoma, 2017. Assessment of Uinta basin oil and natural gas well pad pneumatic controller emissions. J. Environ. Prot. 8:394.

or corrosion. A subset of improperly operating PCs may also be able to be identified by field personnel using their AVO senses; however, all inspections in this study used AIMM and did not solely rely on AVO observations.

3 PC Task Force

3.1 PCTF Goals

The PCTF members established the following goals for the PC study:

- Identify and collect natural gas-actuated PC data from a representative subset of well production facilities and compressor stations in the NAA
    - Set parameters of "improper operation" for each type of PC
    - Develop, document, and assess the effectiveness and costs of inspection techniques
    - Document malfunction rates and causes for types, makes, and models of PCs in different types of service
    - Document the effectiveness and costs of repair techniques and preventative maintenance
    - Estimate the number of PCs typically associated with a separator or other grouping of equipment

- Gather information regarding "good engineering and maintenance" practices

- Evaluate the appropriateness of the definitions in Regulation No. 7 for enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller

- Gather information about the current applications, cost, effectiveness, current applications and opportunities for expanded use for no-bleed and self-contained PCs

- Produce timely annual presentations and a report to the AQCC

3.2 Implementation Plan

The PCTF formed three distinct groups to address different elements of designing the field study: a main core group and two subgroups. One subgroup selected representative facilities and the second subgroup developed a field data form. Members of the PCTF provided several technical presentations to grow the shared knowledge base during the study development phase.

Once the field inspection campaign commenced on May 1, 2018, bimonthly meetings were held to check on the progress of field inspection and subsequent data management until the compiled and blinded data was submitted to the Division in December 2018. The two subgroups disbanded once 2018 sampling began while the main core group continued to meet.

4 PC Field Study

4.1 Participating Stakeholders

The field study was designed with the help of all PCTF stakeholders. These stakeholders include: the Division, the American Petroleum Institute (API), the Colorado Oil and Gas

Association (COGA), nine upstream oil and gas well production operators, one midstream operator, the Clean Air Task Force (CATF), Earthjustice (EJ), the Environmental Defense Fund (EDF), Boulder County Public Health (BCPH), Denver Public Health and Environment (DDPHE), Colorado Communities for Climate Action (CC4CA), and the Regional Air Quality Council (RAQC).

The field study was implemented and conducted with the participation of nine upstream oil and gas well production facility operators in the DJ Basin. The study also surveyed PCs at the only two known natural gas compressor stations within the DJ Basin that operate natural gas-actuated PCs.

4.2 Study Design

4.2.1 PC Inspection Method Utilized

All PC inspections conducted at the facilities selected for this field study utilized an OGI camera to monitor and identify improperly operating PCs. Some operators also noted whether an improperly operating PC could have been identified using only AVO methods (e.g. visible staining or corrosion or audible hissing when not actuating).

4.2.2 Field Data Form Development

A subgroup was formed to develop the field data forms (Attachment A) that would be used by operators during PC inspections of the selected facilities to collect consistent metadata across operators and facilities. These forms were based on forms utilized by the Stovern et al (2020) study and amended to reflect the different data collection goals of the PCTF inspection process. The final data forms include general, inventory, inspection, and repair information. The data form options include PC type (including manufacturer and model), function, application, depressurization method, and type of service. The forms determine "improper operation" causes, including description(s). The forms note primary causes of improper operation such as debris, corrosion, equipment failures, broken or missing parts, or abnormal operational parameters; there is also an option for other causes.

Industry representatives provided extensive instructions (Attachment B) for field staff that detailed each item on the form step-by-step. The final data forms were available in paper and electronic form. Operators that utilized paper forms tabulated the data into the electronic form once the paper forms were returned to office staff. All data was submitted to the Division in electronic form.

4.2.3 Facility Selection

The PCTF extensively examined appropriate cross-sectional data for well production facilities and natural gas compressor stations. For well production facilities, the Division initially estimated about 7,000 well production facilities in the NAA counties. The group discussed how to appropriately divide the facilities into cohorts in order to identify which facilities should be sampled for the study. The factors discussed included type of drilling (horizontal vs. vertical), operation size based on production levels, facility age, and separator types. Ultimately, the subgroup decided that production level (barrels/day) was most appropriate and representative of the other variables being considered.

Industry then provided "snapshot" daily average production data from December 2017 for each of the nine participating operators to the Division on February 21, 2018, with subsequent updates based on stakeholder meeting discussions. This snapshot dataset for the nine participating operators represented approximately 80% of all well production facilities located

in the NAA. The original dataset was grouped by level of production (barrels/day), and a 50 percent "Plug and Abandon" (P&A) rate for wells in the 0 - 10 bbls production level cohort was assumed, as these wells were largely older vertical wells likely to be shut-in or scheduled for P&A. This P&A rate assumption is based on multiple factors including, but not limited to, line pressure, economic considerations, lease agreement issues, and land use matters.

Industry updated the dataset on March 21, 2018, with more accurate information from the two largest participating operators, which decreased the P&A rate and provided a conservatively low estimate of the number of PCs to be surveyed at each well production facility, based on its level of production. This analysis was conducted to demonstrate that the study would sample a sufficient number of selected facilities in each production cohort, to provide an adequate data set for the study.

After further meetings and discussion, the PCTF decided on the following cross-sectional sample of well production facilities to be subject to PC inspections starting May 1, 2018, shown in Table 1:

Table 1: Preliminary DMNFR Ozone NAA Well Production Facility Dataset (2018 Sampling Estimate)

Production Buckets	Estimated number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Estimated # of controllers
>250 bbls/day	50	104	13	14	700
10-250 bbls/day	20	553	7	39	780
0-10 bbls/day	5	2,509	5	125	625
TOTAL		**3,166**		**178**	**2,105**

The actual sampling that took place resulted in one extra facility inadvertently being surveyed by one of the operators. Additionally, because operator PC count estimates were intentionally conservative, a significantly higher number of controllers were actually surveyed during the study. The actual final 2018 well sampling facility and PC numbers inspected are shown below in Table 2.

Table 2: Final DMNFR Ozone NAA Well Production Facility Dataset (May - October 2018)

Production Buckets	Average number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Final # of controllers
>250 bbls/day	98	104	13	14	1,378
10-250 bbls/day	34	553	7	39	1,319
0-10 bbls/day	9	2,509	5	126	1,141
TOTAL		**3,166**		**179**	**3,838**

For natural gas compressor stations, the Division initially requested industry feedback on potential data for inclusion in the May 2018 sampling. After further stakeholder discussion, the Division conducted an independent analysis using its databases to determine the number of active natural gas compressor stations in the NAA and gathered industry feedback by facility. The final analysis showed 58 active natural gas compressor stations operated by eight companies. The Division received feedback on 86% of the stations (50 stations) by June 2018 (four out of eight operators). Of these, 48 stations are currently operating or under construction to operate on instrument air, or have been depressurized and are not included in the field inspections. Two natural gas compressor stations were confirmed to use natural gas-driven PCs and were included in the study. These two natural gas compressor stations were sampled in the summer of 2018. Nine compressor stations are operated by non-participating operators and are of an unknown status at the time of the study. It is likely that at least some of these natural gas compressor stations are operated on instrument air since 4% (two out of 50) of the participating stations use natural gas-driven PCs; however, this is assumed and not verified.

4.3 Field Campaign Summary

The PCTF field study began in May 2018 and data collection was finished by October 2018. On August 1, 2018, and September 11, 2018, Patrick Murphy (formerly of Boulder County) and Jeramy Murray (APCD) attended field surveys at four Noble Energy and two PDC Energy facilities to observe how industry field staff were implementing the study design.

4.3.1 Field Data Compilation

Spirit Environmental (Spirit) was retained by COGA to assist with implementation of the PCTF study plan, including facility selection, field data form development, and data validation and compilation. Once the representative cross-section criteria was developed, Spirit generated a randomly selected list of facilities to be inspected by participating operators. If a facility was not available for inspection, Spirit randomly chose a replacement facility that met the original criteria for that operator. Reasons for assigning a designating a site as unavailable included: depressurized, shut-in, P&A, divested sites, sites operating with instrument air, sites with landowner access restrictions, or incorrectly categorized sites.

4.3.2 Completeness and Consistency Review

All data collected by operators was compiled and blinded by Spirit Environmental before electronic submission to the Division. The data also went through a completeness and consistency check performed by Spirit, where operators were consulted to complete missing

data fields and to better account for information provided, thereby improving field data reporting consistency between operators. For transparency, industry provided the compiled field data in both uncorrected and corrected spreadsheets that were made available to all stakeholders in the PCTF.

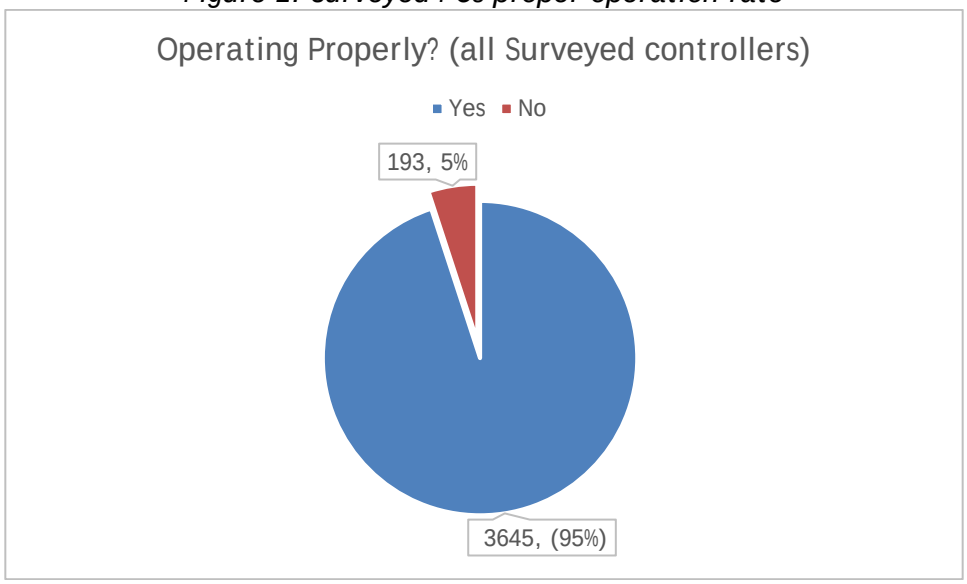
4.4 PCTF Study Data

The following sections contain summaries of key data collected during the PCTF field study. A full spreadsheet with all data collected in the program is available to stakeholders for analysis through the Division.

4.4.1 Oil and Gas Production Facility Data

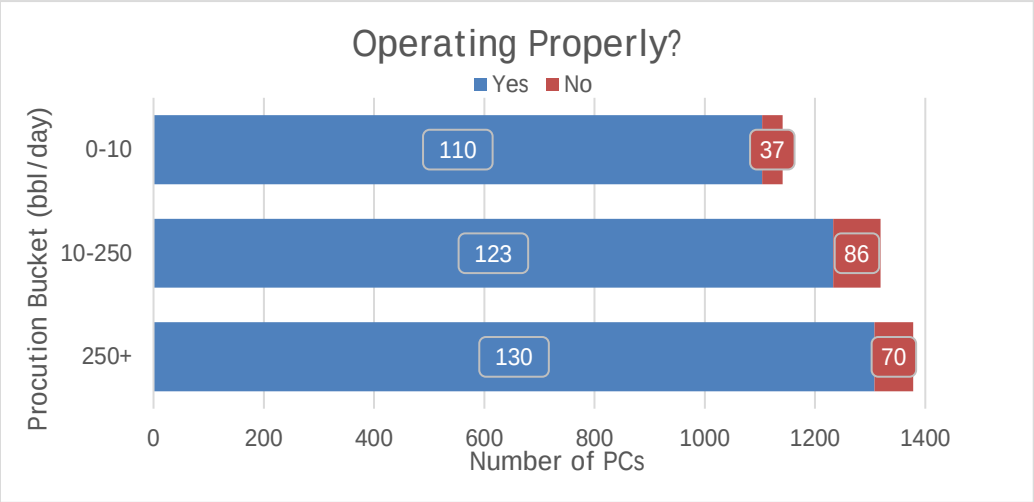
The study resulted in data points based on inspections for over 3800 PCs in the DJ Basin. Of the PCs observed, approximately 5% were observed to be improperly operating.

Figure 1. Surveyed PCs proper operation rate



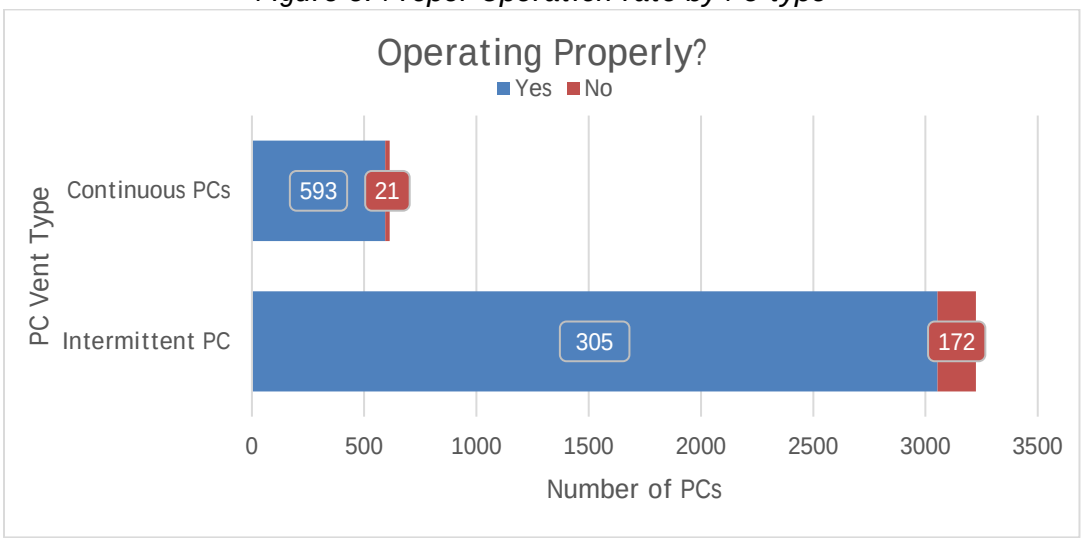
This data was also broken down by the three predetermined inventory production buckets. In the 0-10 bbl/day production bucket, 3.2% of all PCs were improperly operating. In the 10-250 and 250+ bbl/day buckets, 6.5 and 5.1% of PCS respectively were found to be improperly operating.

Figure 2. Proper Operation rate by inventory production bucket



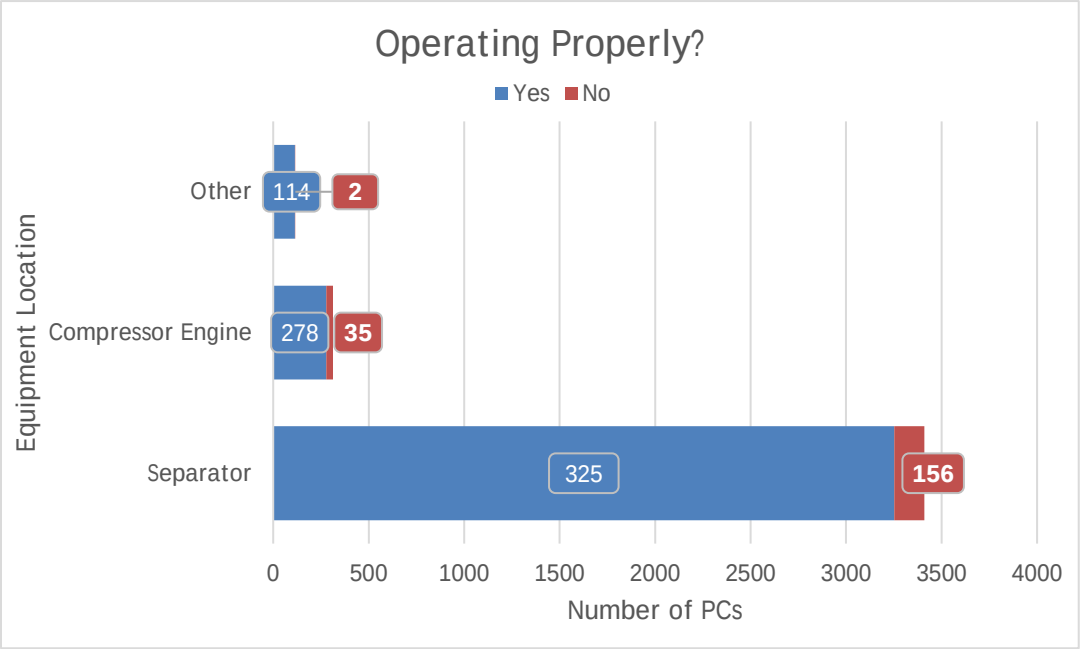
Breaking down the data by PC type (continuous vs. Intermittent) is also a useful way to look at the data. Continuous PCs were found to have an improper operation rate of 3.5% and intermittent controllers had a rate of 5.6%.

Figure 3. Proper Operation rate by PC type



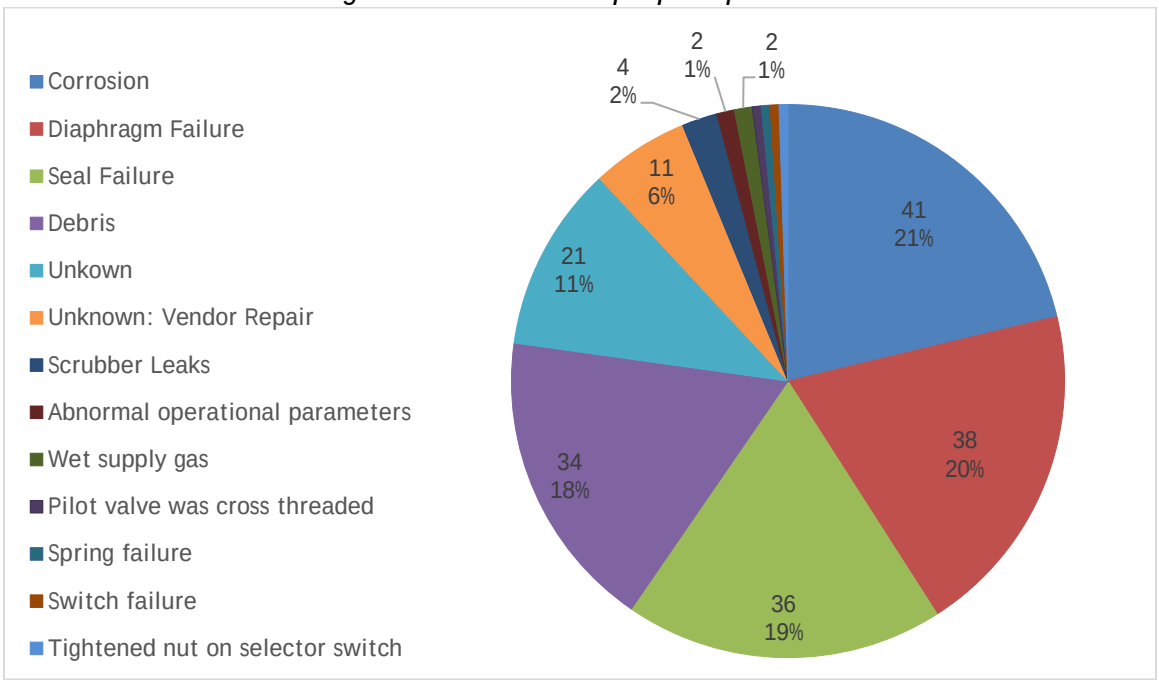
Operators tracked the facility equipment associated with each PC in the study. The majority of PCs are in-service on separation vessels. About 5% of PCs on separators were found to be improperly operating. The second most common PC equipment location was on the compressor engines. PCs on compressor engines had a relatively high improper rate of 12.3%. PCs found on all other equipment had a 2% improper operation rate.

Figure 4. Proper Operation rate by equipment location



The study revealed that there were a myriad of reasons that a PC might operate in an improper manner. The four largest causes were attributed to corrosion, diaphragm failure, seal failure, and debris blocking the internal mechanism from reseating.

Figure 5. Causes of improper operation

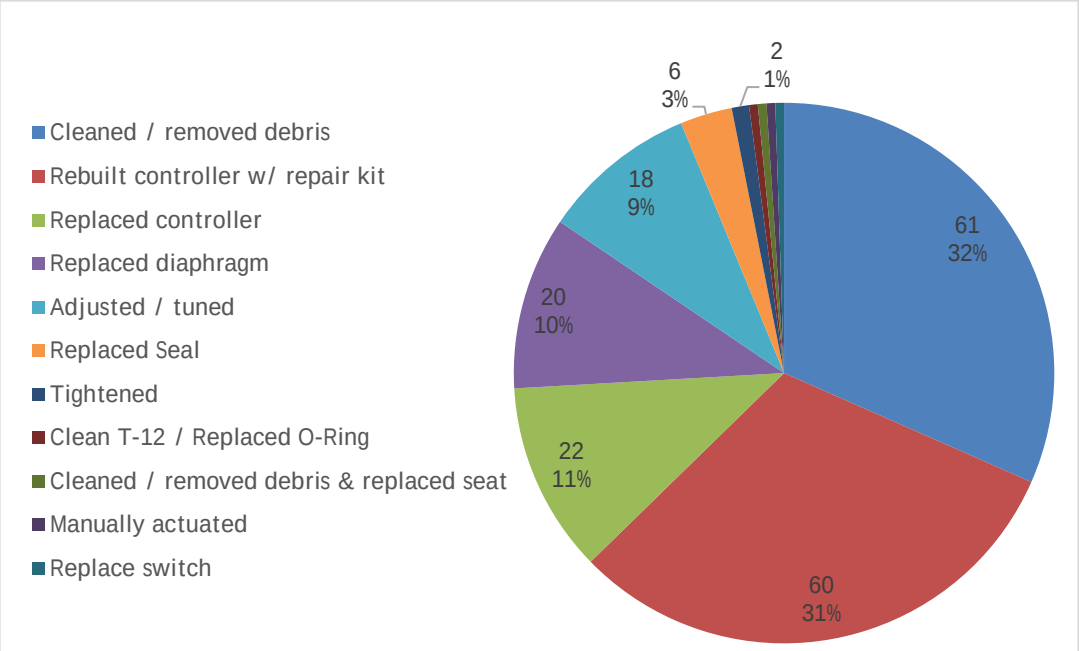


Operators made attempts to return all PCs to proper operation at the time of inspection if possible. Fifty (26%) of the 193 improperly operating PCs were repaired immediately. Ninety-

two PCs that needed repair were done on the same day of the inspection. 101 of the repairs were made at least a day later, with an average lag time of 4 days later.

Some repairs required a shut down or replacement of the PC. Those types of repairs take longer to complete and may have to be scheduled for repair soon thereafter or during the next planned shutdown of the facility. The majority of repairs were simply cleaning the PC and/or removing debris. Another common repair was to rebuild the PC with spare parts provided in a manufacturer repair kit.

Figure 6. PC repair actions



4.4.2 Midstream Data

As discussed previously, only two natural gas compressor stations of the 50 operated by participating companies use natural gas-driven PCs and were surveyed by the participating operator. All other natural gas compressor stations in the NAA owned by these participating operators utilized air-driven controllers and so therefore were not part of this study. The inspections of the two subject natural gas compressor stations occurred over two days in late August and early September. A total of 23 PCs were inspected. Four (4) models of PCs were documented. None of the surveyed PCs were found to be operating improperly. The PCs were used to monitor and control liquid levels and pressure.

4.5 PCTF Study Findings and Conclusions

The key findings and conclusions from the PCTF study are summarized below in narrative form. Additional findings are provided in the industry surveys of PC inspection costs and effectiveness, and use of no-bleed PCs, provided in Section 5.

4.5.1 Key Findings

PC Survey

- The most common manufacturers of PCs surveyed for this study were Kimray (43%), Wellmark (36%), and Fisher (15%).

- The most common models of PCs surveyed for this study were Wellmark 7400 Snaptrol (32%), Kimray T-12 (21%), Fisher 4660 (14%), Kimray 230 SGT (7%), Murphy LS200N (3%), and Norriseal 1001A (2%).
- Intermittent PCs comprise 84% and low bleed, continuous PCs comprise 16% of the 3838 PCs surveyed for this study.
- For equipment location, the PCs surveyed were found as follows:
    - 89% on separators
    - 8% on compressor engines
    - 1.4% on liquid knockouts
    - <1% on various equipment

PC Improper Operation

- The rate of PC improper operation varied:
    - by facility production:
        - Ranging from 5.1% for greater than 250 bbl/day, to 6.5% for 10-250 bbl/day, and 3.2% for 0-10 bbl/day.
    - by controller type:
        - 4.3% for pilot PCs and 8.0% for integrated PCs.
    - by controller vent type:
        - 5.3% for intermittent PCs and 3.4% for continuous PCs.
    - by controller enclosure:
        - 3.1% for enclosed PCs and 7.9% for non-enclosed PCs
    - by equipment location:
        - 4.9% for separators, 11% for compressor engines, 0% for liquid knockouts, and varying percentages for those few PCs that serviced various types of equipment.
- Overall, the observed rate of improper operation for all surveyed PCs was 5%.
- Actuations of PCs were observed only for 33% of the PCs surveyed.
- PC emissions were observed at the following locations and frequencies:
    - Vent port – 79%
    - Body – 20%
    - Vent port and body – 1%
- The following frequencies of common indicators of PC improper operations were reported.
    - 86% - Continuous bleed from vent port of intermittent PC
    - 11% - More venting than normal from continuous PC based on inspector's judgement
    - 1% - Continuous bleed from vent port of intermittent PC and PC was making unusual sound

Causes of PC Improper Operation

- The following frequencies of common causes of PC improper operations were reported:
    - Corrosion – 21%
    - Diaphragm failure - 20%
    - Seal failure – 19%
    - Debris – 18%
    - Other: Unknown - - 11%
    - Other: Vendor repair – 6%

- Other: Scrubber leaks – 2%
- Abnormal operations parameters – 1%
- Other: Wet supply gas – 1%
- Various - <1%

PC Repairs

- The following frequencies of common types of repairs of PCs that were not operating properly were reported:
  - Cleaned/removed debris – 32%
  - Rebuilt PC – 31%
  - Replaced PC – 11%
  - Replaced diaphragm – 10%
  - Adjusted/tuned PC – 9%
  - Replaced seal – 3%
  - Tightened – 1%
  - Various - <1%
- Double block and bleed was performed for 36% of the PC repairs.
- Equipment shutdown was performed for 37% of the PC repairs. Shutdown of a well was performed for 24% of the repairs.
- The time to make a PC repair varied by the type of repair, yet the average time for all types of repairs was less than 30 minutes.

4.5.2 Conclusions

This PCTF study represents the largest sample set of PC inspections in the nation to date, with 3838 PCs surveyed during the facility inspections conducted during the spring and summer of 2018. The 5% rate of improper PC operation found in the 3838 PCs inspected for this study based on emissions observed using an OGI camera demonstrates that typically (~95% of the time) PCs sampled in this study were found to be operating properly.

This study also demonstrated that an OGI camera can identify improperly operating natural gas-driven PCs. Detection of improper operation of an intermittent PC is largely determined by the observation of continuous emissions between actuations. Given that 84% of the PCs surveyed consist of intermittent PCs, the use of an IR camera is particularly effective in identifying excess emissions from intermittent PCs. Discerning improper operation of a low bleed continuous PC is less straightforward and is subject to the experience and judgement of the inspector in discerning excess emissions from improper operation.

Additionally, where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven PCs to the inspections adds minimal incremental inspection costs. Repairs of improperly operating PCs are readily made by cleaning the PC of corrosion and debris, replacing broken parts and adjusting/tuning the PC and the supply gas pressure.

4.6 Separate EPA/CDPHE Study on PCs in Denver-Julesburg Basin

4.6.1 Overview

Over a similar time period as the PCTF inspection study, EPA and CDPHE conducted a parallel study on natural-gas actuated PC emissions in the DJ Basin. The results of this parallel study were published in early 2020 in the Journal of the Air and Waste Management Association in a

paper by Stovern et al. entitled "Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging."

Briefly, the Stovern et al. paper focused on a smaller sample size of PCs (500 controllers servicing 102 wells at 31 facilities operated by seven different companies) and included counts and observations of intermittent and continuous low bleed PCs. The PCs were inspected with OGI, and the emission rate from a small subset of the inspected PCs was quantified using high-volume sampling. Although measurements required to quantify actuation volumes were outside the scope of this study, the OGI camera survey provided limited information on the frequency of occurrence for actuations. This study was performed in the spring 2018 over a period of 10 field days.

4.6.2 Study Design

Stovern et al identify two objectives for this study: 1) gather information on the types and uses of PCs employed by randomly selecting facilities representative of the overall basin and 2) investigate the use of an expeditious and less invasive PC emissions survey approach based on optical gas imaging (OGI) camera that could help inform PC operational and maintenance states.

An important aspect of the PC survey was to confirm that the exhaust port of the PC was visible during the OGI inspection so that any continuous emission through the PC pilot could be assessed. A FLIR GF320 camera was utilized to monitor emission profiles of PC for this study, which has a normal or "auto" imaging mode and a high sensitivity mode (HSM), where onboard differential image processing can enhance an operator's ability to identify lower emission rates approaching 0.5 scf/hr natural gas or even lower under ideal conditions. Comparisons between the auto and high sensitivity mode imaging were made in monitoring PC emissions to explore their differences in detection capability as a rough indicator of emission level. An extended OGI observation time of 60 sec for each PC was used to enhance detection capability, to look for anomalous temporal emission profiles indicative of potential malfunctions, and to document short time duration PC actuation events as activity data where possible. If an actuation event or unusual temporal profile was observed, the observation time was increased to 120 seconds to bound actuation frequency and further diagnose potential malfunction issues.

The well production facilities ranged in production and complexity from small facilities with minimal equipment (such as one wellhead, one separator, and one or two tanks) to larger facilities with multiple wellheads, separators including second and third stage separation vessels, complex tank batteries with vapor capture systems, multiple control devices, gas lift compressor engines, and vapor recovery units. Of the 31 well production facilities selected, the wells were 50.0% vertical, 33.3% horizontal and 16.7% directional. This distribution is consistent with the overall well type distribution for the 24,220 actively producing wells in the basin of 42.1% vertical, 38.9% horizontal, and 19% directional.

Information gathered for each pneumatic system (PS)/PC included: process working status (in use or shut-in), PS/PC identification (make/model), motive gas type, PC configuration and operational mode, process function (control, safety, or both), process equipment application (separator, combustor, compressor, etc.), and sensed process variables (e.g. temperature, pressure, and liquid level). PC-specific information such as model configuration variables, retrofit status, installation date, actuator components, and supply line pressures were also documented to the extent possible.

4.6.3 Findings

Stovern et al. (2020) reported the following findings for the EPA/CDPHE PC study:

Survey of PCs at Facilities

- A total of 615 process control pneumatic systems (PSs) were found at the 31 facilities with 59 of these being of the electronic variety that does not use gas-emitting PC pilots.
- Of the 556 PSs with gas-emitting PC pilots, 38 of these were instrument air-driven. Natural gas was found to be the exclusive motive gas type at 30 of the 31 facilities surveyed. One facility used instrument air on 38 out of 52 PCs with the natural gas models at that facility primarily serving back pressure regulation functions. Operations of instrument air-driven PCs were not further studied by Stovern et al.
- Of the 518 natural gas-driven PCs, 18 (3.5%) of these comprised a "no-vent" design where the natural gas emitted from the pilot is fully captured. These integrated pilot-actuator PCs have the potential to emit natural gas only by diaphragm or connector leaks that would be classified as equipment leaks and therefore were not further studied by Stovern et al.
- A total of 500 natural gas emitting PCs were found at 31 facilities servicing 102 wells (average of 4.9 PCs/well).
- A total of 453 of the 500 natural gas-driven PCs were found to be in service (i.e. not shut-in or depressurized); this number represents the primary count of the PCs assessed for proper operation. Of this total, 377 (83%) of the PCs were intermittent and 76 (17%) were continuous.
- A total of 447 PCs were monitored with an OGI camera for emissions as six intermittent PCs were not surveyed due to wind speeds exceeding the 9 m/s method limit.

PCs with Maintenance Issues

- Of the 371 intermittent PCs monitored, 42 (11.3%) were observed with continuous emissions and 22 were observed with actuations (5.9%). This 11.3% represent intermittent PCs experiencing some level of maintenance issue. The severity of the maintenance issues is unknown without emission rate measurement. The authors note that due to the fact that some controllers were observed in the less sensitive "auto" mode of the OGI camera (see below), the true level of maintenance issues among the intermittent PCs they surveyed was probably higher. They estimate that the true frequency of maintenance issues in this population was 11.6 to 13.6%.
- Of the 76 continuous PCs, 28 (37%) were found to have continuous emissions. Yet, it is unknown what portion of these emitting continuous PCs reflect a potential maintenance issue, since they may have been operating as designed. As described below, at least one continuous PC had measured emissions above the State regulatory standard (6 scf/hr).
- It was critical to determine the design type of the PC (intermittent or continuous) during the on-site survey because the type assignment played a role in the assessment of potential maintenance issue conditions.

PC Emission Measurements

- Emission measurements were conducted on 18 total PCs (14 intermittent PCs and 4 continuous PCs) with continuous emissions detected during the OGI camera survey. In general, the measurements were conducted on PCs that appeared to have the most significant gas signature.
- 36.8% of continuous low-bleed PCs (28 controllers) had continuous emissions that were observable with the OGI camera. Emissions were measured from four of these continuous PCs with a high-flow sampler. Measured emission rates ranged from 0.7 to 9.9 scf/hr with an average ER of 4.2 scf/hr. Three of the continuous PCs exhibited emission rates above 1.39 scf/hr; one was considered to be malfunctioning as it was emitting in excess of the 6 scf/hr State regulatory limit. Two of the measured continuous PCs had measured emissions above 1.39 scf/hr and below 6 scf/hr.
- Snapshot measurements were conducted on 14 intermittent PCs that were observed using an OGI camera to have continuous emissions (not including actuations). Three of the measurements were near or below the estimated method detection limit of the technique at (0.1 scf/hr). Observed emissions rates ranged from 0.1 up to 31.3 scf/hr (mean = 2.8 scf/hr).
- In two cases, the intermittent PCs were cycling between actuations with the OGI camera video showing steadily increasing emissions prior to actuating, followed by a sharp drop in emissions below the OGI detection threshold. These significantly variable (heavy ramping and temporally sustained) emissions were categorized as maintenance issues for these snap-acting intermittent PCs.
- The highest measured intermittent PC emission rate (31.3 scf/hr) was caused by a process issue. This PC managed back pressure on the low-pressure side of a high-low pressure separator. A suspected process control issue was identified where a bleeding valve upstream of the low-pressure vessel caused the PC to continuously actuate because the low-pressure vessel was continually exceeding the pressure set point of the PC. In this situation, the intermittent PC itself was not malfunctioning.

Auto vs. High Sensitivity Mode

- The initial protocol for the OGI camera included evaluating only auto imaging mode (the less-sensitive mode for the OGI camera used in the study) at 85 PCs that serviced 26 wells at 9 facilities. Later, both high sensitivity mode (HSM) imaging and auto mode (HSM/auto) were used for most of the PC assessments (N= 362 PCs, 22 facilities, and 76 wells).
- The continuous PC emission detection rates for the auto-only versus the HSM/auto subgroups differed significantly. For the auto-only mode subgroup, 1 of 16 continuous PC (6.3%) and 1 of the 69 intermittent PCs (1.4%) exhibited continuous emissions. For the HSM/auto subgroup, 27 of 60 continuous PCs (45%) and 41 of 302 intermittent PCs (13.6%) exhibited continuous emissions.
- OGI camera imaging modes were observed to have a significant effect on emission detectability with HSM mode detection rates being approximately 2 times higher compared to auto mode.

Actuations

- A total of 33 actuation events (AEs) were observed from 22 different PCs in the 447 monitored for this study. Based on observed emissions, only a few percent of intermittent PCs in this basin appear to have actuation frequencies greater than 1/min, with many PCs (e.g. safety category) very infrequently actuating.
- AEs were observed at only 9 of 31 facilities with the top two highest oil producing facilities accounting for 54.5% (12 of 22) of the PCs with actuations. The highest producing facilities had five separate intermittent PCs exhibiting AEs with a total of 13 observed, whereas the second-highest producing facilities had 7 PCs and 8 total AEs. There were a total of six PCs surveyed that had multiple actuations observed during the OGI survey (extended up to 2 min). Three of those PCs were located at the highest producing facility, and one PC with multiple actuations was located at the second, fifth, and sixteenth highest producers.
- The OGI camera survey indicates an expected relationship between normalized oil production and observed actuations. At a high producing facility, the same PC and process will require more actuations than at a lower producing facility. However, PCs with a maintenance issue do not show the same correlation with facility production.
- Estimated actuation volumes ranged from 0.005 to 0.185 scf per actuation event, which indicates that potential emissions from continuous emissions due to a maintenance issue may often be the dominant factor in overall emission rates for infrequently actuating PC populations. At lower producing facilities, the continuous emission component of emissions for intermittent PCs with maintenance issues becomes a more significant factor affecting average PC emissions rates for lower producing facilities.

4.6.4 Conclusions

- Although the findings of this study are representative of the DJ Basin, they are not intended to be representative of PC operating characteristics at a national level and therefore should be used with caution at that scale.
- The observed PCs per well are reasonably consistent with the 2018 data from EPA's Greenhouse Gas Reporting program for the Denver Basin with an average of 3.1 PCs per well and are significantly higher than the national average of 1.6 PCs per well (U.S. EPA 2019c).
- 83% of the PCs surveyed for this study were intermittent PCs, which is consistent with the 91% reported by Allen et al. (2014) for PCs in the Rocky Mountain region.
- The use of an OG camera to profile PC emissions was found to be a helpful approach to inform PC maintenance issues.
- Observing continuous emissions from a PC with an OGI camera on a snap-acting intermittent PC is indicative of emissions beyond the designed shut-off rate and is indicative of a maintenance issue.
- The identification of actuation events for continuous PCs and throttling process control applications was more challenging than those for intermittent PCs in snap acting applications.
- For a low bleed CPC, continuous emissions observed with an OGI camera was not informative to detect a potential maintenance issue unless in the OGI operator's judgment the emission appeared abnormally large compared to typical operation.
- 11.3% of intermittent PCs surveyed were directly observed with OGI to have continuous emissions. Due to an issue with the use of the OGI camera at some sites, this figure probably represents an underestimate of the frequency of continuous

emissions from these controllers. Stovern et al. estimate that the true frequency of continuous emissions in this population was 11.6% to 13.6%. These observations may reflect maintenance issues since these emissions were likely above the designed seepage rate of these intermittent PCs.

- As opposed to intermittent PCs, it is unknown what portion of continuous PCs were experiencing a potential maintenance issue, without measurement. One of the four continuous PCs measured was classified as malfunctioning with a measured emission rate of 9.9 scf/hr, above the 6.0 scf/hr State regulatory limit.
- The type of imaging mode (i.e. auto vs high sensitivity) utilized during the OGI camera survey was observed to significantly affect the detection rate of continuous emissions. The detection rate of continuous emissions using high sensitivity mode was 1.6 and 2.1 times higher than when using auto-mode imaging for intermittent PCs and continuous PCs, respectively. The difference between observation capabilities in high sensitivity vs. auto modes could be used in an inspection approach to approximately separate the PC populations (e.g. minor maintenance issues and significant malfunctions), so that repairs can be prioritized to minimize unnecessary emissions.
- PC actuations from process control-based PCs correlate with facility production. Facilities with lower production will have lower actuation emissions rates among its PC population and continuous emissions from PCs with maintenance issues will therefore be the controlling factor for the average operational PC emission rate. For higher producing facilities that cause PCs to actuate much more frequently, actuations will be a significant contributor to the overall average operational PC emission rate

4.7 Comparison of PCTF Study and EPA/CDPHE Study Findings and Conclusions

The following statements offer key comparisons between the findings and conclusions for the PCTF Study and EPA/CDPHE Study.

4.7.1 Findings

- Both field inspections of PCs were conducted in the DJ Basin during the spring/summer of 2018.
- Both studies focused on identifying improper operation (aka maintenance issues) of PCs using an OGI camera by trained and experienced personnel during facility inspections.
- Facility selection for each of these studies was done randomly for the operators participating in each study.
- Both studies found that the majority of natural gas-driven PCs observed consisted of intermittent PCs (PCTF – 84% vs EPA – 83%)
- The EPA/CDPHE study estimated that 11-14% of the intermittent PCs inspected were not operating properly, while the PCTF study found 5.3% of intermittent PCs were not operating properly.
- The EPA/CDPHE study found that using a camera in high sensitivity mode was more effective in finding smaller emissions from intermittent PCs.
- The EPA/CDPHE study did not evaluate whether continuous PCs were operating properly based on emissions observed with an OGI camera. The PCTF study found 3.4% of continuous PCs were not operating properly. Emissions measurements were performed by EPA/CDPHE on four continuous PCs, finding one of these PCs to have emissions in excess of the 6 scf/hr regulatory limit.
- The EPA/CDPHE study measured 14 intermittent PCs that were observed using an OGI camera to have continuous emissions. Observed emissions rates ranged from 0.1 up to

31.3 scf/hr. The elevated reading of 31.3 scf/hr was attributed to a process issue and not PC improper operation.

A significant contrast between the PCTF study and the EPA/CDPHE study is related to how integrated pilot-actuator devices were classified. Simpson (2014)[6] defines an *integral* PC as a PC that is built into an end device (i.e. valve) and does not require an external source of gas, nor does it release actuation gas to the atmosphere. Rather, it releases actuation gas into the process downstream. Similarly, Simpson defines a *local* controller is also defined as one built into the end device, but it exhausts gas to the atmosphere to move the process valve toward closed. In contrast, remote pilot controllers are PCs that are not integrated into the end device.

Note that "integral" controllers, as defined by Simpson, would be considered "Self-contained PCs" under Regulation 7. Additionally, note that Stovern et al. refer to both integral and local PCs as "integrated" PCs, and they use the term "no-vent" for PCs that Simpson defines as "integral" – those that release gas into a process downstream. The discussion below uses Simpson's terminology.

- The EPA/CDPHE study did not include integral devices in their assessment of PCs. EPA stated in its report that integral PCs have the potential to emit natural gas only by diaphragm or connector leaks and that any such leakage should be classified as an LDAR component leak, rather than as a PC that is operating improperly.
- For the PCTF study, integral devices were classified as a type of PC. 59 (8%) of the 740 integral PCs surveyed were determined to be not operating properly, compared to 134 (4.3%) of the 3,098 pilot PCs surveyed. Presumably, these devices were leaking from the diaphragm or connector, as described above.
- Since the PCTF study included integral controllers, while the EPA/CDPHE study did not, and integral controllers were operating improperly at a relatively *high* rate in the PCTF study, this suggests that the inclusion of integral controllers in the PCTF study skewed the improper operation rate slightly higher.
- Regardless if classified as a PC or not, integral controllers are included as a component in a LDAR program for equipment leaks and will therefore be assessed for leakage and repaired as needed to ensure proper operation.

4.7.2 Conclusions

- The Stovern et al. study found that using the high sensitivity mode of the OGI camera resulted in a nearly 2 times higher emission detectability compared to the auto mode. This might explain why Stovern et al found more than twice the percentage of intermittent PCs that were not operating properly compared to the PCTF study (11-14% vs 5%).
- The Stovern et al. study used a set observation time of 60-120 seconds for every PC/PS. The PCTF study did not have this requirement and if the OGI camera operator did not detect emissions within a few seconds, they would move on with the inspection. These varying approaches were utilized because each study had a different objective. The PCTF study set out, in part, to determine the effectiveness of the find and fix program, so inspection protocols were adapted to current industry practices.

[6] Simpson (2014), *Pneumatic Controllers in Upstream Oil and Gas*. https://pubs.spe.org/en/ogf/ogf-article-detail/?art=238.

The longer observation time used by Stovern et al. may also be a contributing factor to the discrepancy between the proper operation rates.

- Both studies concluded that using an OGI camera to profile PC emissions was an effective method to inform possible improper operation of intermittent PCs. However, the use of this method for identifying improper operation of continuous PCs is more challenging, except when the emissions appear to be abnormally large compared to normal operation.

5 Industry Surveys

In order to achieve the goals established by the PCTF for reassessment of the Find and Fix program, additional information needed to be gathered on the effectiveness and costs related to inspection of PCs under the find and fix program and to better understand the use of self-contained and no bleed PCs. A series of questions were developed and incorporated into survey questionnaires that operators were requested to complete. A total of three surveys were developed:

1. The effectiveness and costs of PC inspection techniques
2. The effectiveness and costs of PC repairs
3. The use of self-contained and no bleed PCs.

The surveys were completed in confidence, and then blinded and compiled by API and COGA to address industry anti-trust concerns before being shared with the PCTF in presentations that summarized the survey responses. The first two surveys were to be completed by the nine operators participating in the PCTF study within the ozone NAA. The third survey was distributed to COGA and API members with oil and gas production operations in the state. As described below, the second survey was developed but not completed.

5.1 Effectiveness and Costs of Inspection Techniques (NAA only)

Highlights from the results of survey questions provided to the nine operators participating in the PCTF study on the effectiveness and costs of PC inspection techniques are provided in the following bullets.

- The majority of operators use a combination of employees and contractors to conduct PC inspections. Some operators use employees only.
- The majority of operators use the same party for both LDAR and PC inspections.
- Operators typically conduct LDAR and PC inspections during the same facility visit.
- Operators generally replied that it can be helpful to know in advance whether the PC is an intermittent or low bleed in order to understand if emissions are expected between actuations (low bleed) or not (intermittent).
- Operators also indicated that understanding the process the PC is controlling is beneficial in making a determination whether a PC is operating properly or not.
- For intermittent PCs, operators typically look for continuous emissions between actuations. For continuous bleed PCs, operators typically look for emissions that appear abnormal for that type and application of controller.
- Operators found using OGI camera inspections along with AVO indicators was effective, although OGI cameras are more effective at finding smaller leaks. Soapy water may be used to further pinpoint a leak location.

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- AVO indicators such as the presence of liquids at or around/below the vent and whether dependent processes are operating properly can be useful to determine whether a PC is operating properly or not.
- Safety limitations in the use of OGI cameras are largely driven by whether the OGI camera is intrinsically safe or not. An intrinsically safe camera does not pose a potential ignition source and can be used in Class 1 Division 2 areas as defined by OSHA in CFR 1926.449. OGI cameras that are not intrinsically safe may require a hot work permit to be allowed on site at a facility or the camera operator may have to maintain a minimum safe distance from the equipment being observed.
- Responses on the average time to inspect a PC varied depending on the experience of the inspector and included various caveats including weather conditions. The inspection time varies and is dependent on the type of PC and if emissions are observed. If no emissions are observed, then only a few to several seconds is generally sufficient to determine that the controller is operating properly. If emissions are observed, then the time to make this determination is dependent on whether the controller is actuating or not, the type of controller, and the characteristics of emissions observed. It could take up to several minutes to make this determination.
- The costs to conduct PC inspections are variable and likely highly dependent on the size and makeup of facilities of operators and internal programs and processes. Some operators indicated that the incremental equipment costs are not significant since this equipment is required for LDAR inspections. Other operators estimated that incremental annual equipment costs for PC inspections represent a small percent of LDAR related equipment costs. Ultimately, incremental annual equipment costs for PC inspections are dependent on the number of PC inspections performed.

5.2 Effectiveness and Costs of Repairs (NAA only)

Due to the need to focus on regulatory proposals to be considered for the December 2019 AQCC rulemaking, and the willingness of operators to expand the PC "find and fix program" statewide, it was not necessary to complete the planned repair cost survey.

Separately, the PCTF study results indicated that those PCs found to be improperly operating were successfully repaired and the majority of repairs were completed either immediately, the same day of the inspection, or within a few days of the inspection.

Operators seek to repair PCs in order to return them to proper operation since it is in their interest to maintain and optimize production operations. The cost of repairs is considered a normal operation and maintenance cost. The ability to more readily identify PCs that are not operating properly using an OGI camera allows earlier detection of those PCs needing repair that would otherwise eventually fail to control their intended process function and need subsequent repair.

The repair costs range in regard to the extent of the repair. These repairs can range from cleaning the PC of debris or residue that collects over time, replacing worn parts, or replacing the entire controller. Operators stock spare parts, repair kits or extra PCs that are then used to repair or replace the defective PC as a means to promptly make a repair.

The costs of repairs was not considered an impediment to supporting expansion of the PC "find and fix" program from the NAA to statewide during the AQCC December 2019 rulemaking.

5.3 Use of Self-contained and No-Bleed PCs (State-wide survey)

COGA developed and distributed a survey to better understand the use of self-contained and no-bleed PCs. The survey utilized the following definitions in order to establish a common understanding in completing the questions.

- Instrument air-driven PC: Any PC that is uses compressed air as the valve's actuating gas. Known as "no-bleed" under CO Regulation 7.
- Natural gas-driven PC with exhaust routed to process/sales: Any PC that directs gas to a process or sales line instead of to the atmosphere. Known as "self-contained" under CO Regulation 7.
- Natural gas-driven PC with exhaust routed to combustion control: Any PC that directs gas to a combustion control device instead of to the atmosphere.
- Non-pneumatic mechanical controllers: Any controller that uses mechanical force (not a pressurized gas) to trigger actuation.
- Non-pneumatic electric controllers: Any controller that uses an electrical signal (not a pressurized gas) and motor to trigger actuation.

The survey results are summarized below:

- 12 Operator Responses for production facilities
  - 3 Operators in Piceance, 9 in DJ.
    - >5,400 Total Production Facilities: ~4,200 DJ NAA, ~100 DJ AA & ~1,200 Piceance
    - >22,400 total wells: ~15,700 DJ NAA, ~500 DJ AA & ~6,200 Piceance
    - Percentage of facilities where on-site electrical grid power is used:
      - 19% DJ NAA
      - 63% DJ AA
      - 4% Piceance
- Operator Responses for compressor stations
  - 4 Operators in Piceance, 1 in DJ responded.
    - 16 Compressors stations in DJ NAA, 38 in Piceance
    - Percentage of compressor stations where on-site electrical grid power is used:
      - 100% in DJ NAA
      - 76% in Piceance
  - DJ NAA - 1 operator
    - 16 compressor stations
    - All use instrument air-driven PCs (11 new, 5 retrofitted)
  - DJ AA - No compressor station operator responded
  - Piceance Basin - 4 operators responded
    - 38 compressor stations
    - 9 new stations use instrument air-driven PCs
- Summary of Usage
  - The majority of PCs in use in Colorado are conventional natural gas-driven PCs
  - Most of the non-conventional controllers in use in the state are located
    - In the DJ NAA
    - At new facilities receiving production from horizontal wells
  - The most commonly used non-conventional controllers are air-driven PCs
  - Other non-conventional controller technologies usually only replace a fraction of the PCs at a site

- Consideration for Use
  - Safety
    - Instrument air-driven PCs
      - Some operators expressed concern with facilities using both instrument air-driven and natural gas-driven PCs: potential risk of flammable mixtures or explosion
      - One operator noted that fail-safe close valves need to be used so the site/well can shut-in in case of power loss or air compressor malfunction
    - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
      - The required additional piping/plumbing could significantly complicate work areas
      - There are backpressure issues with remote PCs preventing exhaust vapors from reaching process/sales or combustion control
      - Backpressure can also slow actuation and affect operation
    - Non-pneumatic mechanical controllers
      - Some operators indicated mechanical dumps are more prone to failure due to erosion.
      - One operator noted that mechanical dumps may not have emergency shut down ability.
    - Non-pneumatic electric controllers
      - It was noted electrical controllers may not have a fail-safe capability and do not return to a safe position when power is lost, unlike conventional natural gas-driven PCs. Electric fail safe close valves require programming.
      - Electrical classification determines safe location on site.
    - Overall
      - Non-conventional have a positive impact on safety by reducing the quantity of hydrocarbon vapors in the atmosphere at facilities.
  - Costs
    - Instrument air-driven PCs
      - New facilities: incremental capital cost of $70K - $140K (depending on production/number of wells)
        - Additional piping, air compressor, supporting infrastructure, grid power/generator.
        - Use of grid power is critical for most, generators also used by some.
        - Additional maintenance costs required for air compressor and a desiccant air dryer.
        - One operator reported reduced maintenance on instrument air-driven PCs themselves.
        - One operator mentioned a backup instrument gas may be required, increasing costs.
      - Existing facilities: incremental capital cost of $90K - $180K (depending on production/number of wells)

        - Several operators reported that, due to declining production, retrofits are not cost effective and have primarily been done under compliance order.
        - Loss of production for retrofit, in addition to reasons listed above.
        - Additional incremental cost is on top of the initial cost to run instrument gas line.
        - One operator reported the need to hydro vacuum instrument air lines before retrofitting
    - Natural gas-driven PC with exhaust routed to process/sales
        - Significant cost associated with design of a complex vapor capture system.
        - Cost associated with compression to safely and reliably get emissions into process lines.
        - Additional maintenance on vapor control system (VCS) lines.
    - Natural gas-driven PC with exhaust routed to combustion control
        - Cost associated with re-piping equipment. May be do-able for PCs in close proximity to control device, very high cost otherwise.
        - VCS: Additional maintenance on lines and may require updates to the VCS analysis.
        - Some compressor stations are not equipped with ECD: high cost for low reductions.
    - Non-pneumatic mechanical controllers
        - Some mechanical dumps usually have lower upfront cost but higher maintenance cost.
        - For retrofits, cost of new controllers when natural gas-driven controllers are already in use.
    - Non-pneumatic electrical controllers
        - One operator reported an incremental cost of $7K - $10K per well.
        - Controllers have a higher upfront cost and higher maintenance cost.
        - Several operators reported that retrofits are not cost effective.
- Technical
    - Instrument air-driven PC
        - Sufficient grid power availability (true for new and potential retrofits).
        - Very frequent maintenance on air compressors required to ensure reliability.
            - One operator noted liquid collection and freezing may require backup compressors.
        - Considerations for power loss:
            - Some operators do not have back up options and site shuts in.
            - One operator reported using natural gas powered back up air compressors.
            - One operator reported using pressurized air bottles.
    - Natural gas-driven PC with exhaust routed to process/sales

        - Low pressure and low volume gas needing compression to process/sales.
        - Concerns with vapor collection lines such as air intrusion through components, debris and/or condensate build up, freezing, and backpressure concerns.
        - Not all exhaust from natural gas-driven PCs can be captured.
    - Natural gas-driven PCs with exhaust routed to combustion control
        - Low pressure and low volume may make it difficult for gas to reach combustor.
        - One operator mentioned experience indicating back pressure which affects valve actuation and maintaining stable stream to the combustor.
    - Non-pneumatic mechanical controllers
        - Generally can only replace a specific type of PC: dump valves/liquid level.
        - Experience shows that mechanical controllers are not as precise or as reliable as natural gas-driven PCs for process control.
    - Non-pneumatic electric controllers
        - Need for reliable electrical power (e.g. solar with battery and generator/grid as backup).
        - There are no electric replacement options for some natural gas-driven PCs.
        - There are limitations on where those controllers can be located (e.g. not compressors).
        - Electric fail safe close valves requires programming knowledge.
- Land/Leasehold
    - Instrument air-driven PCs
        - Ability to bring grid power may be limited: landowner restrictions, BLM land & FS land with approval requirements, remote/mountainous locations.
        - Pad size needs to be sufficient to accommodate air compressor and additional infrastructure in an area that is safe for electrical equipment.
            - Especially challenging for existing facilities where land has already been reclaimed.
    - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
        - None identified
    - Non-pneumatic mechanical controllers
        - None identified
    - Non-pneumatic electric controllers
        - None identified
- Other
    - Instrument air-driven PCs
        - Pros:
            - Instrument air-driven PCs are a proven technology and usually use same/similar PCs.
            - Instrument air-driven PCs are not subject to the find and fix program.

        - Reg. 7 requires the use of no-bleed (instrument air-driven PCs) at facilities that use grid power.
    - Cons:
        - Grid power availability is utility dependent and can be very complex (permitting and approvals for new lines, proximity to power line does not mean availability).
        - Electric generators, if used, require permitting through APCD and have extra emissions.
        - Retrofits are not cost effective and primarily been done under compliance order.
- Natural gas-driven PC with exhaust routed to process/sales
    - Reliability (operation and maintenance very complex). Other options are more desirable.
    - Required by Reg. 7 once grid power is used on site and if technically and economically feasible.
    - Process/sales gas line occasional downtime may require redundancy.
    - Emissions associated with required additional compression.
- Natural gas-driven PC with exhaust routed to combustion control
    - Not considered as no-bleed or self-contained under Reg. 7 definitions.
    - Reliability is a major concern: other options are more desirable.
- Non-pneumatic mechanical controllers
    - None identified
- Non-pneumatic electric controllers
    - One operator reported less maintenance needed for such controllers.
    - Not a proven technology, cannot cover all functions usually covered by natural gas-driven PCs.
    - Use and maintenance requires staff with knowledge related to electrical systems.

- Survey Takeaways
    - Fail-safe options a concern for non-natural gas-driven technologies
    - Instrument air-driven PCs
        - Electrical grid power use is crucial, upfront cost is high
        - Proven technology, familiar make/model of PCs, less training
        - Safety and cost effectiveness concerns for retrofits
    - Natura gas-driven PCs with exhaust routed to process/sales/control
        - Operationally burdensome, reliability issues
        - Only feasible for a small subset of PCs
    - Mechanical controllers
        - Can only replace very specific functions (dump valves)
        - Cheaper upfront
        - Reliability and precision concerns
    - Electrical controllers
        - Require reliable power
        - Require trained staff
        - Only feasible for a small subset of controllers

According to the industry survey on zero-emitting PCs, the practice of capturing gas and routing emissions from a self-contained PC to emission control devices (ECD) is relatively uncommon and is highly dependent upon the distance between the vent port of the PC and the ECD. The PCTF study identified 50 PCs where PC vented emissions were routed to a nearby ECD. All of these PCs that were routed to an ECD were operating properly. The majority of these 50 PCs serviced a level control for a liquid condensate burner knockout pot which was located within a few feet of the ECD. In most cases, these knockout pots are drained by gravity or manually and are not controlled by a PC.

Routing to a process is relatively uncommon due to pressure differences between the vent port and the process. In general, the gas pressure from the vent port is too low to route to a facility process.

The category of no-bleed PCs can be considered a misnomer as all "pneumatic" controllers bleed or vent as part of their normal operation. The term "no-bleed" usually refers to those PCs that use instrument air as a motive force, rather than natural gas. In order to utilize instrument air, an air compressor, desiccants and filters, and pressure regulators are typically installed. The power to operate the air compressor is either provided using an electrical generator that is fueled by natural gas or diesel, or by a connection to an accessible utility line that provides adequate electrical power to the facility. The use of a natural gas or diesel fuel powered generator may result in a net emissions disbenefit in providing instrument air in lieu of natural gas for operating PCs. However, the net emissions benefit or disbenefit would vary on a case-by-case basis.

(Note that low power air compressors designed driving pneumatics using solar-battery systems for electricity,[7] and hybrid solar-gas powered electric compression systems,[8] are both available on the market in Canada.)

For new development of multi-well pads, operators pursue commitments from electric utilities to provide a connection and adequate power to a planned facility for electrification of equipment including air compressors for instrument air. A number of factors, many of which are beyond the operator's control, dictate whether the utility can provide an accessible connection and adequate power when the facility is being constructed. If the utility is not capable of meeting the requested commitment, then the operator will typically either rely on a natural gas or diesel-fired generator to power an air compressor, or utilize natural gas pressure as a conventional power source for PC operation.

5.4 Electrical Infrastructure for Oil and Gas Development

As part of the joint effort with the SHER work group, information was collected from API and COGA operators regarding the availability and planning for the use of electrical power from the grid or the use of natural gas or diesel oil powered generators to provide electrical power at oil and gas production facilities. A presentation was given during the July 12, 2019, SHER meeting which included the following talking points:

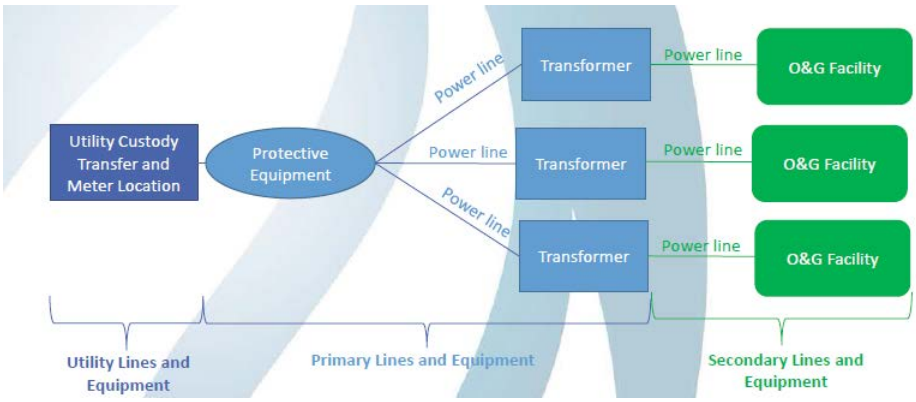
- Urban growth and development is an issue and impacts infrastructure availability

[7] See https://lcotechnologies.com/crossfire-compressor.html.
[8] See https://westgentech.com/.

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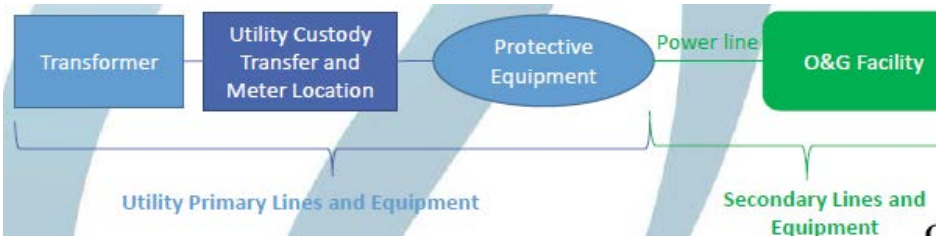
- Federal Lands and The National Environmental Policy Act (NEPA)/ The Federal Land Policy and Management Act (FLPMA) processes in remote areas are also obstacles to the use of electrical grid power
- Colorado has public utilities and cooperatives that provide power:
    - Each utility has different power drop timelines (1-3 years)
    - Each utility has different requirements on ownership and installation requirements between primary and secondary power lines and equipment
    - Primary lines are typically higher voltage lines while secondary lines are supplying power to a location (480-120 volts)
- Primary Meter – primary and secondary lines and equipment after custody transfer are installed, owned, operated and maintained by the company. In this case the O&G Facilities owner.

Figure 7. Primary Meter Ownership



- Secondary Meter –Only secondary lines and equipment after custody transfer are owned, operated and maintained by the O&G Facility owner. Everything upstream of custody transfer is installed, owned and operated by the utility.

Figure 8. Secondary Meter Ownership



- Primary Metering
    - The company has the staffing and technical ability to install, own, operate and maintain all the electrical equipment
    - Shorter lead times for power drop because less line and equipment needs to be installed by the utility
    - Higher costs for companies that only have a few O&G facilities in an area that requires power
    - Lower cost for companies with many O&G facilities in an area that requires power
    - Might not be an option because of right-of-way and surface user agreements

- Secondary Metering
    - Longer lead times for power drop to wait for utility to install primary lines and equipment
    - Costs may be higher depending on the location and amount of power needed
    - Some utilities require companies to perform primary metering so this might not be an option
- Challenges include:
    - Slowdowns from utility companies due to increased residential development
    - Changes in schedule from drilling permit issuance delays, operator agreement challenges with local governments, or right-of-way changes
    - Can be limited by proximity and capacity of grid power depending on utility
    - Power plant expansions dependent on air and other permitting
    - Cost may be prohibitive for operators in limited development areas
    - Small operators may not be able to effectively negotiate cost and availability
    - Contractual third party agreements may limit operator access
    - Timing often uncertain and power generation needed as backup

6 Good Engineering and Maintenance Practices

In 2017, the AQCC adopted Regulation 7 Part D, Section III.F.1. (formerly Section XVIII.F.1), requiring operators to operate and maintain PCs consistent with manufacturer's specifications, if available, or utilize good engineering and maintenance practices. The SBAP recognizes the need to more fully develop and document those practices, which include but are not necessarily limited to, ensuring proper operation. Data collected by the PCTF can be used to develop and document good engineering and maintenance practices.

Due to the unavailability of documentation from PC manufacturers, there are no widely agreed upon routine or preventive maintenance schedules. Individual operators have developed their own maintenance and operating plans in accordance with industry best practices and Regulation Number 7 requirements. While individual operators may have company-specific protocols for their PC program, all operators are in agreement on some key practices. The use of OGI cameras as the proper inspection tool to identify improperly operating PCs is universally accepted, at this time, by all industry members of the PCTF. However, identification of improper operation from a continuous low-bleed PC may require additional training/experience for the OGI camera operator. The findings above from the survey results on PC inspections also reflect key practices.

There are some barriers to developing prescriptive PC protocols because of the wide variability in how these devices function and the wide variety of designs and specific applications that are employed. More work needs to be done if developing prescriptive maintenance protocols is a goal of the AQCC.

6.1.1 The Environmental Partnership

API established The Environmental Partnership (TEP) in 2017 to "continuously improve the industry's environmental performance by taking action, learning about best practices and technologies, and fostering collaboration in order to responsibly develop our nation's essential natural gas and oil resources." TEP's initial focus is to further reduce the industry's air emissions in continuing to reduce methane, a greenhouse gas, and VOCs, which is one precursor to the formation of ground-level ozone. TEP hosted their first annual conference in

2018 as described in their 2019 Annual Report[9]. The conference focused on PCs and brought together producers, manufacturers, researchers, and regulators to discuss PC technology and how it might be improved.

In addition to periodically checking for proper operation of the controller through AVO and AIMM inspections, operators participating in this study concur with the "Pneumatic Controller Maintenance Work Practices" published by TEP as a wallet card for its members to provide to field personnel responsible for inspecting and maintaining PCs for proper operation of oil and gas production facilities. This wallet card is shown below:



7 Recommendations

The PCTF offers the following recommendations for consideration by the AQCC. Where there was not consensus on specific elements assigned to the PCTF, individual stakeholder positions are presented as such.

7.1 Effectiveness of current program (NAA only)

Pursuant to AQCC Reg 7 CTG rulemaking in November 2017, the PC find and fix program that applied only to the ozone NAA took effect on June 30, 2018, which was during the same summer of the PC field surveys performed for the PCTF study. The PC find and fix program has proven effective as demonstrated in the Division's 2018 LDAR Annual Report[10], which included the results of the PC find and fix program for the NAA, as described below. The AQCC extended the PC find and fix program state-wide effective May 1, 2020, as part of the AQCC SB-181 Reg 7 rulemaking in December 2019.

[9] See https://www.api.org/~/media/Files/Policy/Environment/TEP/The-Environmental-Partnership-Annual-Report-2019.pdf

[10] See https://www.colorado.gov/pacific/cdphe/2018-ldar-annual-reports-regulation-7-section-xii-xvii-and-xviii

The Division's 2018 LDAR Annual Report (pp. 4-6) summarizes the results of PC inspections performed for the PC find and fix program. Although the report does not break out the number of PC inspections using AIMM at well production facilities that were performed in the NAA in 2018, a total of 4,053 PCs were found to need repair and of these 4,015 (99%) were returned to proper operation. For natural gas compressor stations subject to PC inspections using AIMM in the NAA in 2018, a total of 7 PCs were needed to be repaired and 6 (86%) were returned to proper operation. Upon discovery of an improperly operating PC, repairs must begin no later than five working days and the PC must be returned to proper operation no later than 30 working days. A delay in a repair may be attributed to unavailability of parts, the equipment requires a scheduled shutdown to complete the repair, or other good cause. The Division developed a list of standardized enhanced response actions to repair PCs with input from the oil and gas industry to be used for recordkeeping and annual reporting purposes. These include the following options to return a natural gas-driven PC to proper operation:

1. adjusted/tuned;
2. cleaned/removed debris;
3. tightened;
4. heated/insulated;
5. replaced part(s) of controller;
6. rebuilt controller with repair kit;
7. replaced controller; and
8. other.

Below is Figure 2 from the Division's 2018 LDAR Annual Report that shows the distribution of each type of response action, with a total of 4,060 actions reported. The two most common types of response action were to clean/remove debris, and to rebuild the pneumatic controller with a repair kit.

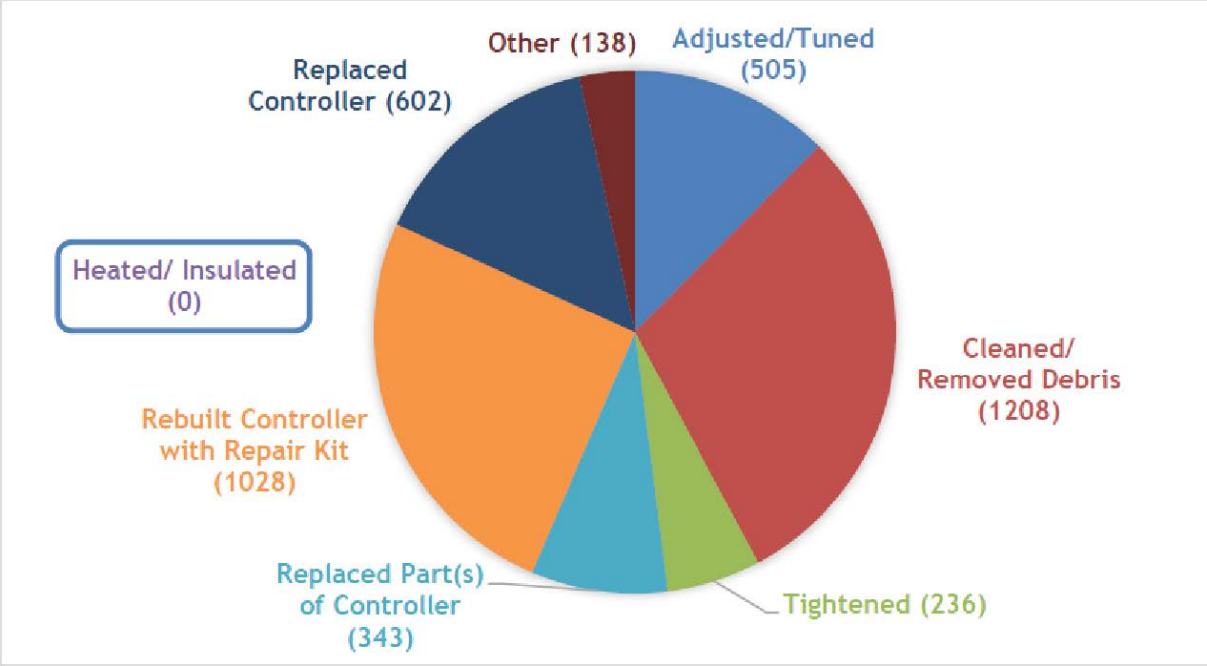


Figure 2: Enhanced response actions taken to return pneumatic controllers to proper operation, by enhanced response action category

Although not specific to natural gas-fired PCs, the Division's 2018 LDAR Annual Report on p.4 indicated that the use of an OGI camera was more effective than AVO observations during facility inspections for emission leaks from components. On page 4, the report states:

"Based on the data reported by owners/operators, more than 90% of leaks were identified through AIMM inspections despite AIMM inspections constituting only 3% of the total number of inspections at WPFs. While AVO inspections are valuable for operations and maintenance purposes, as well as being required by other sections of Regulation No. 7, the data from this year's LDAR annual reporting indicate that AIMM is a more effective monitoring method than AVO for detecting leaks."

Given the results from the 2018 PCTF field inspections, and the 2018 LDAR program and PC find and fix results, the PCTF believes the use of AIMM inspections using an OGI camera is an effective means for identifying both those emissions from PCs that indicate improper operation and from leaky LDAR components.

7.2 Definition Appropriateness

As discussed previously, due to the need to focus on regulatory proposals for consideration during the AQCC December 2019 rulemaking hearing, the PCTF did not complete its evaluation of the appropriateness of the current Reg 7 definitions related to PCs. However, revisions to these definitions will be included in the regulatory proposal specific to the use of no-bleed PCs (aka zero-bleed PCs). Currently, industry is developing a proposal that may be further modified through a future stakeholder and rulemaking process.

Stakeholder meetings will be scheduled and facilitated by the Division staff to review and solicit comments on the no-bleed PC regulatory proposal, which will include the need to make

appropriate revisions to PC-related definitions. As such, for the purposes of completing this report, the PCTF does not recommend making any changes at this time to the definitions for "enhanced response", "intermittent pneumatic controller", "no-bleed pneumatic controller", "self-contained pneumatic controller", or "pneumatic controller". Changes to these definitions will be considered separate from this report in vetting the regulatory proposal with stakeholders.

7.3 No-bleed and Self-contained PCs

As defined by Regulation 7 Part D Section III., a no-bleed PC is "any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas." Alternative actuating gases include compressor air or nitrogen, but in practice such PCs in Colorado are mainly compressed air, also known as instrument air. Instrument air systems utilize a skid-mounted compressor and often come with a dryer system to remove moisture from the air prior to compression. Once compressed, the air is routed through the same supply gas system that would otherwise contain pressurized natural gas to actuate the PCs.

As defined in Regulation 7 Part D Section III., a self-contained PC is "a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere." Such PCs utilize natural gas as the actuating gas, but have minimal emissions to atmosphere because the vent port of the controller is routed back to a process line. Likewise, although not addressed in the current Regulation 7 rule language, emissions from the vent port of the PC can be routed to a control device in some limited applications. As previously mentioned and further discussed below, the use of self-contained PCs is very limited due to technical infeasibility, safety concerns, and cost.

Additionally, mechanical or electric controllers (non-pneumatic) can be used in some very limited applications as described below. These controllers are neither no-bleed or self-contained as defined by Regulation 7 and because they have no emissions, are not subject to the regulatory requirements. However, the PCTF included these controllers in the operator survey so they are also addressed below.

BCPH, DDPHE, and CC4CA Position:

SB181 directed the AQCC to consider a requirement to reduce emissions from pneumatic devices and in 2019 the AQCC directed the PCTF to develop recommendations on the use of zero-bleed pneumatic devices for rulemaking in 2020. Because the PCTF was unable to reach consensus on a recommendation, we believe the AQCC should direct the Division to continue its research and develop a proposal for the planned December 2020 rulemaking. Specifically, the Division should continue to research and put forth recommendations based on the information provided below by Earthjustice and CATF. No-bleed and self-contained PCs are a proven technology that should be implemented in Colorado. Furthermore, the successful implementation of solar-powered PCs in Canada points to the need for serious consideration of this technology in Colorado.

7.3.1 Current applications

As discussed above in Section 5.3, most of the no-bleed PCs in use in Colorado are in the DJ basin NAA and at newer multi-horizontal well pad facilities producing significant volumes of oil and gas. The PC field study also demonstrates that the majority of compressor stations in the NAA are currently operating or under construction to operate on instrument air.

Industry Position:

No-bleed controllers can generally be utilized on any piece of equipment that utilizes a natural gas actuated PC, but as detailed below, technical feasibility, safety concerns, other regulatory requirements, contractual obligations, and cost can all limit the ability of an owner or operator to utilize no-bleed PCs on some or all pieces of equipment at a facility.

Solar-powered PCs have recently been utilized in Alberta, Canada under specific operating conditions for where they are included in the design for a separator equipment package. However, industry believes that the array of solar batteries and battery storage has not yet been fully demonstrated to be sufficient and reliable for the power demands of well pads with multiple horizontal wells that produce significant volumes of oil and gas. As technology advances and costs decrease, the use of solar panels and battery storage to provide electrical power at large oil and gas production facilities may become feasible.

Industry is currently working on a regulatory proposal regarding the use of no-bleed PCs to be considered for a future AQCC rulemaking. This regulatory proposal will build on the work developed for a no-bleed PC emission mitigation strategy proposed under the SHER stakeholder process.

CATF/EJ Position:

Regulations currently in force in Alberta and British Columbia (BC) will significantly limit the use of venting gas-driven PCs moving forward. In BC, new facilities cannot use venting gas-driven PCs after January 1, 2021. Large compressor stations will require retrofit of all venting gas-driven PCs by January 1, 2022.[11] In Alberta, no new gas-driven venting PCs can be installed after January 1, 2022 (this regulation was very recently tightened – previously operators were to be allowed to use gas-driven venting controllers for up to 10% of new controllers after January 1, 2022).[12] Both provinces also will subject existing PCs, including intermittent PCs, to various emission limits.

Solar-powered PCs have been utilized for a number of years in Alberta where they are included in the design for separator equipment packages from certain manufacturers. Other operators have utilized similar solar-powered systems in custom configurations (for example to provide more electrical power and storage than is available in standard packages). Solar systems are used on both low-production wellsites and modern, high-production tight/shale wells.

This technology has proven reliable in Alberta north of 55°N latitude, where sunlight on a clear winter day is far weaker than in Colorado, snowfall is higher, winter cloud cover is much more common, and winter temperatures are much lower (affecting battery capacity). In short, CATF and EJ believe that there is no reason that this technology cannot succeed in Colorado.

[11] See BC Regulation 282/2010, §52.05.
http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018
[12] See Alberta Energy Regulator (2020), "Directive 060 - Upstream Petroleum Industry Flaring, Incinerating, and Venting," §8.6.1. https://www.aer.ca/documents/directives/Directive060_2020.pdf

As noted above, there are also air compression systems designed for solar-powered sites on the market.

7.3.2 Effectiveness of devices

Industry Position:

Industry believes that the effectiveness of a no-bleed or self-contained PC is highly dependent on the application of the controller. The scope of the PCTF study did not evaluate the effectiveness of no-bleed PCs so no conclusions can be offered in this report. The consideration of the use of no-bleed PCs is being addressed under a SHER work group regulatory proposal as directed by SB 19-181.

CATF/EJ Position:

CAFT and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers;[13] this approach will be one of the key technologies allowing operators in Alberta and BC to comply with the provincial rules mentioned above.

7.3.3 Costs for new and retrofit facilities

Industry Position:

Based on operator survey results, the cost of instrument air systems (no-bleed pneumatic controllers) is highly variable and significantly higher for retrofits versus new installations.
The cost of self-contained PCs was not able to be ascertained through this study. However, industry has estimated that the cost to design the large and intricate vapor recovery system to capture these small emissions is significant and not cost-effective in most cases.

Likewise, industry estimates that the cost of routing controllers to a combustion device is prohibitively expensive unless the controller is located in close proximity to the control device (e.g. on the inlet to the control device itself).

Mechanical controllers, which can only be used for liquid level control in specific applications, were reported to have low capital costs, but higher maintenance costs than PCs based on operator survey results. Electric controllers were reported to cost significantly more, and also have higher maintenance costs, than PCs.

CATF/EJ Position:

The Conservation Groups' pneumatics proposal from the 2017 oil and gas rulemaking (which was also included as a SHER team proposal) was supported by an Economic Impact Assessment (EIA) documenting the cost-effectiveness of using zero-emitting approaches instead of gas-driven venting controllers. All cost calculations included in the Conservation Group's 2017 EIA include full costs for solar-powered electric systems, including: solar panels, batteries, and control panels and electronics; over-

[13] See Carbon Limits (2016), *Zero emission technologies for pneumatic controllers in the USA: Applicability and cost effectiveness.* https://www.catf.us/wp-content/uploads/2019/09/CL2016-ZeroEmitting-Pneumatics-Alts-1Aug2016.pdf

capacity for solar panels and batteries to ensure power will be available during (for example) extended cloudy periods in winter; electric actuators; installation; and maintenance. Operators report lower maintenance costs with electric systems than gas-driven systems when only wet gas is available to operate PCs, due to deleterious effects of wet gas on some PC components.[14]

In the 2017 rulemaking and as part of the SHER team, the Conservation Groups made available spreadsheets listing parameters for calculating cost-effectiveness, such as cost estimates for various components and labor, and engineering design assumptions such as the appropriate oversizing of solar panels and maximum allowable discharge from batteries.

7.3.4 Limitations and Barriers to expanded use

Industry Position:

In addition to cost, industry believes that there are technical, safety, regulatory, and land/leasehold concerns that limit the use of no-bleed and self-contained pneumatic controllers.

In terms of instrument air systems, operators must have sufficient grid or other power to run the instrument air skid and associated equipment. Further, some facilities will not have sufficient area at the facility to install the instrument air skid and associated infrastructure or may have landowner or regulatory restrictions on the grid power right of way or installation of additional equipment at the facility. Additionally, even where some controllers can be converted to instrument air there may be some processes that need to be controlled with natural gas-driven PCs for safety or technical reasons.

The biggest limitations to utilizing self-contained PCs or routing the vent port of the controller to a control device, aside from cost, are related to pressures. If there is not a process that is operating at a relatively low pressure then the pressure released from the vent port will not be sufficient to push the gas into the process line, potentially creating a safety hazard if a safety valve is not able to actuate against the process pressure. Additionally, beyond the cost of the amount of tubing that is required the route emissions from controllers that are located throughout a facility to a process line or control device, the longer that tubing is the more pressure differential (higher than the process or control device backpressure) is required to overcome the backpressure created by the tubing itself.

As mentioned previously, industry claims that mechanical and electric controllers can only be used to control liquid level and can only be used in certain applications (such as liquid level control). Additionally, mechanical controllers have been shown to be less accurate than PCs and electric controllers cannot typically be located on compressors due to vibration and require more technical knowledge to ensure safe application.

CATF/EJ Position:

[14] See Carbon Limits (2016) at p. 15.

As noted above, air compressors designed for solar-powered sites are on the market, as are packages systems that provide compressed air using hybrid electrical systems utilizing solar and batteries for the majority of the power they consume, with a gas-fired generator available as backup for the solar generation and battery. CATF and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers.[15]

7.3.5 Opportunities for expanded use

Industry Position:

Given the current state of technology, the use of electric and mechanical controllers is limited due to the limitation outlined in the section above. Industry believes that electric and mechanical controllers have very limited applications and cannot be used in the place of all traditional PCs at a facility. While there are extensive barriers that exist for retro-fitting existing facilities with instrument air, opportunity exists to expand the use of instrument air at new larger horizontal facilities that have sufficient grid power. Many of the land use and spacing limitations can be avoided if these systems are included during the planning phase. Additionally, there is a lower cost associated with installing a new system compared to retrofitting a location.

The ability to be able to plan for and allow utilities to commit to providing access to electrical grid power with sufficient power in advance of constructing new oil and gas production facilities represents a significant opportunity to expand the use of no-bleed PCs.

CATF/EJ Position:

CATF and EJ believe that zero-emitting technology can cost-effectively reduce emissions in Colorado at both new and existing sites. The CATF and EJ recommend that the AQCC consider requiring operators to utilize zero emitting pneumatic controllers statewide at all natural gas compressor stations and all well production facilities with four or more wells producing hydrocarbons so long as it is technically feasible to do so. CATF and EJ have previously offered this proposal in the 2017 oil and gas rulemaking and through the SHER team process. CATF and EJ believe that it is supported by the EIA and supporting spreadsheets, as well as the documented use of zero-emitting technology in Canada and the fact that venting PCs are being phased out for new facilities in British Columbia and Alberta.

8 Acknowledgments

The Division would like to thank all of the members of the PCTF for all of their time and hard work over the last two and a half years. The input from all stakeholders was vital to develop and implement what was the largest study of PCs to date. The information contained in this report is the culmination of thousands of hours of effort. The Division would also like to recognize the high level of engagement, collaboration, and resource expenditure from the industry members on the PCTF.

[15] Carbon Limits (2016).

ATTACHMENT A

Pneumatic Controller (PC) Task Force Data Collection Form

General Information

Inspector

Pad/Battery/Facility/Location

Blinded ID

Date

Time

Ambient Temperature

Wind Speed (MPH)

Inventory Information

Manufacturer*

Other:

Family (If Applicable)

Model*

Other:

Sensed Variable*

Other:

Type*

Other:

Supply Pressure (If Available) & Source

(psig) Enter 'None' if no gauge

Source:

Other:

Function*

Vent Type*

Vent Control Type*

Equipment Location*

Other:

Service Type*

Name/Description

Is PC Enclosed?*

Enclosure Type, If Not Exposed to Elements*

Additional Notes:

Inspection Information

Operating Properly*

Actuation Observed*

Detection Method*

Emissions Location*

Other:

If not operating properly provide the following:

Indicator 1

Indicator 2

Other:

Additional Notes:

Repair Information

Primary Cause of Improper Operation*

Other:

Repair Date

PC Repair Method*

Other:

Did the Repair Require:*

Double block and bleed

Shutdown and purge equip. to atmosphere

Shutdown of the well

Repair Time (Mins)

Repair travel time (if required)

Additional Notes:

Re-inspection Date

PC Repair Re-inspection Method*

An asterik (*) indicates that a field has a dropdown list

ATTACHMENT B

INSTRUCTIONS FOR COMPLETING THE DATA COLLECTION FORM FOR APCD PNEUMATIC CONTROLLER STUDY

MAY 9, 2018

These instructions serve to assist operators participating in the APCD's Pneumatic Controller (PC) Study specific to selected oil and gas facilities in the Front Range/Denver Metro Area Ozone Nonattainment Area (NAA) in the collection of data related to whether PCs in service at these facilities are operating properly.

It is important the persons conducting these inspections understand the focus of this study is limited to assessing the proper operation of PCs that are actuated using pressurized natural gas as a motive force and have the ability to vent to the atmosphere during normal operation. Leaks found to be originating from a component are not considered to represent improper operation of a PC. Instead, these observations should be considered leaks of components subject to a Leak Detection and Repair Program (LDAR).

Operators conducting these inspections of PCs at facilities selected for the purposes of this study will utilize concurrently an Audio, Visual and Olfactory (AVO) method along with an Approved Instrument Monitoring Method (AIMM) for each PC being inspected. Although other potential methods may be used to detect whether a PC is operating properly or not, these methods are not utilized by participating operators with facilities in the NAA and therefore will not be considered in the scope for Phase 1 of this study. Persons conducting these inspections of PCs for this study should strive to identify and document insights that were gained in applying methods in the field to determine whether a PC is properly operating or not. Although this form serves a purpose to document a specific inspection of a PC, the real value will be in being able to accurately describe what was done, observed or evaluated to determine if a PC was operating properly, along with any repairs necessary to a PC that was not operating properly.

General Instructions

- This form is to be used by an operator in conducting an inspection at a facility selected for the PC Study to document whether a PC is properly operating or not. As an option, the inspection data can also be captured using a flat table.
- If an inspector uses the form for data entry, one form is to be completed by the operator for each PC inspected at a facility. If the inspector uses the flat table rather than the form for data entry, one row in the table is to be completed for each PC inspected at a facility.
- PCs are not considered to be in service if the supply gas is depressurized; therefore, these out of service PCs are not to be inventoried or inspected for this study.
- For a PC that is found to be operating properly, the form or table row must be completed through the Inspection Information section.
- For PC that is found to be operating improperly, the entire form or table row must be completed including the Repair Information section. Neither the repair nor the Repair Information section must be completed at the time of the inspection. If the repair is not successfully completed at the time of the inspection, the details of the successful repair must be added to the form or flat table once completed.

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- The confirmation of successful repair does not need to be completed at the time of the repair. The details of the repair confirmation must be added to the form or flat table once completed.
- The data collection form is provided in an Excel format tied to a flat table that can be used to compile the data for each PC inspected at a facility. Although the use of the electronic version of this form is encouraged, a hard copy of the form can be used in the field if the dropdown options are used appropriately and consistently with those in the electronic form. However, this will require that the data in the hard copy of the form be re-entered into the Excel form or flat table so that the data can be compiled for subsequent reporting.

Specific Instructions

- The specific instructions herein address the completion of individual subject fields in the data collection form or flat table.
- An asterisk symbol (*) next to the data field indicates that a dropdown menu of options exists for this specific field. To open the dropdown menu, click on the data field until the down arrow symbol is highlighted to the right of the data field and then click on this symbol. Select by clicking the option that correctly describes the characteristic specific to the PC inspected. Only one option can be selected for each data field with a dropdown menu.
- The "Other" option for a specific data field is to be used when none of the options in the dropdown menu applies to the PC. When none of the specific dropdown options apply, select the "other" option from the dropdown menu and enter as text the information in the separate "Other" data field.
- Use the additional notes data field provided in each section of the form to add free form text describing noteworthy information relevant to the inventory, inspection, or repair sections.

General Information Section

Inspector – Enter the first and last name of the person performing the inspection of the PC.

Pad/Battery/Facility/Location – Enter the operator's designated name of the facility.

Facility ID – Enter the blinded ID designated by Spirit Env. for the facility being inspected. Each operator will be provided a list of facilities randomly selected for inspection by Spirit Env. and each facility selected will have a Blinded ID.

Date – Enter the date when the inspection of the PC was conducted using the numerical month/day/year format (xx/xx/xxxx).

Time – Enter the approximate time that the inspection of the PC started in a numerical format (xx:xx) with an AM or PM designation.

Ambient Temperature - Enter the approximate temperature at the time that the inspection started in Fahrenheit degrees.

Wind Speed - Enter the approximate wind speed at the time that the inspection started in miles per hour.

Inventory Information Section

Manufacturer* – Select the manufacturer of the PC if known. The dropdown options represent PC manufacturers that are believed to be common in the DJ Basin, yet may not cover all makes. If not listed, select "Other" as a dropdown option and enter the full manufacturer name using text in the separate "Other" data field. If the manufacturer is unknown or not certain, take a photograph of the PC and later attempt to confirm the manufacturer of the PC using available information.

Family – This data field is to be completed, as applicable, if the manufacturer of the PC uses a family classification to describe its line of PCs. If no family classification exists, leave this data field blank.

Model* – Select the model of the PC if known. The dropdown options represent PC models that are believed to be common in the DJ Basin, yet may not cover all models. If not listed, select "Other" as a dropdown option and enter the model as text in the separate "Other" data field. If the model is unknown or not certain, take a photograph of the PC and later attempt to confirm the model of the PC using available information. Please be careful in selecting the correct model as some model designations may vary slightly in their labeling.

Sensed Variable* – This data field describes the process variable that the PC is controlling. Dropdown options include pressure, temperature, position, differential pressure, and level. If the process variable is not listed, select "Other" as a dropdown option and describe the variable using text in the separate "Other" data field.

Type* – This data field distinguishes the type of PC being inspected in terms of its configuration. Only three options exist: integrated, pilot or other. An integrated PC refers to a PC that has both the sensing and actuating components contained in one housing. A pilot PC describes a PC that senses a signal and remotely actuates a device that is not contained in the same housing. If the type is not listed, select "Other" as a dropdown option and describe the type by entering text in the separate "Other" data field.

Supply Pressure & Source

- This data field records the pressure of the natural gas being applied as a motive force to the PC being inspected. If a pressure gauge exists on the supply line to the PC being inspected, record the pressure reading of the gauge. If no pressure gauge is present, then enter "None" in this data field. Do not enter "zero" or "0" instead of "None" as this suggests that there is zero pressure, or the gauge is broken.
- The data field for "Source" refers to where the source of the natural gas as a motive force originates from and the dropdown options include wellhead, separator, pipeline quality or "Other". To confirm the source of the gas, the supply tubing to the PC being inspected may have to be followed to its point of origin. If the source of the natural gas is not listed, select "Other" as a dropdown option and describe the source using text in the separate "Other" data field.

Primary Function* – This data field describes the primary function that the PC being inspected. Only two options apply to this data field: process control or safety. An "Other" option is not

available. The safety option should be selected where the PC is used to isolate a pressure source or cease operation of a process.

Vent Type* – This data field describes how the PC being inspected vents during an actuation cycle. Three dropdown options are available: a continuous high bleed (> 6scf/hr); a continuous low bleed (< 6 scf/hr); and an intermittent bleed. An "Other" option is not available. To determine the correct vent type, the operators should research the vent type classified by the manufacturer for the model of the PC being inspected. Measurement of the actual vent rate is not required for this study.

Vent Control Type* – This data field describes whether the vent from the PC being inspected is captured and routed. Three dropdown options are available: vented to atmosphere; captured and routed to sales or process; or captured and routed to a flare/combustor header. An "Other" option is not available. To determine the correct option, the operator may need to follow the vent tubing to the point where it connects to piping and determine whether the piping connects to a process or sales line, or a flare/combustion device.

Equipment Location* – This data field describes the equipment associated with the PC being inspected in terms of its purpose to control the equipment's operation. Available dropdown options include: wellhead, separator, heater, combustor, compressor engine, generator, dehydrator (dehydration unit), and other. If the type of equipment is not listed, select "Other" as a dropdown option and enter the type of equipment using text in the separate "Other" data field.

Service Type* – This data field describes the service of the PC being inspected in terms of how the process variable is controlled. The dropdown options are: on/off, throttling, or unknown. An "Other" option is not available. If the inspector is unsure of whether a PC is on/off or throttling, the inspector should select unknown.

Name/Description – This data field provides a more specific description of the piece of equipment so that the PC being inspected can be identified and located, especially at facilities where there is more than one of the same equipment type (i.e. heater treater 4, water dump). No dropdown menu is available.

Is PC Enclosed? – This data field provides a yes or no answer to whether the PC is located within some type of enclosure that shields the PC from the elements such as a hinged case, a cabinet, or building. Answer "No" if no enclosure exists around the PC being inspected.

Enclosure Type (If Not Exposed to Elements) – This data field is to be completed only if the PC is enclosed as indicated by a "Yes" response to the previous data field. Three dropdown options exist for a "Yes" response: inside separator cabinet, inside compressor enclosure, or inside other enclosure? An "Other" option is not available.

Additional Notes – This data field is a text box that allows additional information to be provided that are worth noting to describe conditions specific to the facility, equipment or PC being inspected.

Inspection Information Section

Operating Properly – This data field identifies whether the PC being inspected is operating properly. Two dropdown options exist: Yes or No. An "Other" option is not available. If the "Yes" option is selected because the PC is found to be operating properly, ~~then~~ then do not complete the Detection Method data field below ~~must be completed~~. If the "No" option is selected because the PC is found to not be operating properly, then ~~do not~~ complete the Detection Method data field below.

Actuation Observed – This data field identifies whether the PC being inspected was observed to actuate during the inspection. Three dropdown options exist: Yes, No or Unknown. An "Other" option is not available.

Detection Method – This data field identifies the method used to detect whether a PC is not operating properly ~~or not~~. This data field must be completed only if the "No~~Yes~~" option is selected for the "Operating Properly" data field above. Three dropdown options exist: Audio-Visual-Olfactory (AVO) Only, Approved Instrument Monitoring Method (AIMM) Only, and AVO/AIMM. An "Other" option is not available.

- AVO refers to hearing, seeing or smelling something that indicates a PC is not operating properly. Indicators associated with hearing may include hissing or clicking. Detection of a hydrocarbon odor near a PC may not be telltale yet could still indicate a process is not being controlled properly due to an improper operation of a PC. AVO to be selected as a dropdown option when this method was able to independently determine that a PC was not operating properly.
- AIMM refers to methods approved for use by APCD under Reg 7 such as an optical gas imaging (OGI) camera. For the purposes of this PC study for the NAA, an OGI camera will be the only AIMM used. AIMM is to be selected as a dropdown option when this method was able to identify that a PC was not operating properly and AVO was not able to independently make this determination.
- AVO/AIMM is to be selected as a dropdown option when both methods in concert were required to detect that a PC was not operating properly.

Emissions Location – This data field identifies where emissions are detected from a PC being inspected that is not operating properly. Three dropdown options exist: Vent Port, Body or "Other". If the emission location is other than the Vent Port of Body, then select "Other" as a dropdown option and enter a description using text in the separate "Other" data field. Emissions from supply tubing connections or other components do not represent improper operation of a PC.

Indication of Proper Operation – This data field describes what indicator(s) were found that led to a determination that the PC being inspected was not operating properly. Two data fields with dropdown menus with options are provided including an "Other" option. If the indicator is not listed in the dropdown menu, then select "Other" as a dropdown option and enter a description using text in the separate "Other" data field. If there are more than two indicators, use the Other field to enter text describe any additional indicators.

Additional Notes – This data field is a text box that allows additional information worth noting specific to the PC being inspected. These notes can be used to provide further insight into what was done, observed or evaluated during the inspection to determine whether the PC was operating properly or not.

Repair Information Section

Primary Cause of Improper Operation – This data field identifies the primary cause of improper operation of the PC being inspected. Ten dropdown options are provided including an "Other" option. Select the option that is believed to be the primary cause. If the primary cause is not listed in the dropdown menu, then select "Other" as an option and enter a description using text in the separate "Other" data field.

Repair Date - Enter the date when the repair of the PC that was found to be operating improperly was successfully completed using the numerical month/day/year format (xx/xx/xxxx).

PC Repair Method – This data field identifies the method(s) applied to repair the PC that was inspected and found to be operating improperly. Eleven dropdown options are provided including an "Other" option. Select the option that best represents the repair method necessary to return the PC to proper operation. If the repair method applied is not listed in the dropdown menu, then select "Other" as an option and enter a description using text in the separate "Other" data field.

Did the Repair Require a double block and bleed? Shutdown and purge equipment to atmosphere? Shutdown of the well? - These data fields describe whether any of the listed actions were necessary to make the repair of the PC that was found to be operating improperly. A Yes or No response is needed for each of the three actions listed. An "Other" option is not available.

PC Repair Confirmation Method – This data field identifies the method used to confirm that the PC repair was successful to restore the PC to proper operation. Five dropdown options exist: AIMM, AVO, Soapy Water, Method 21, and Physical Inspection. Select the method used to confirm a successful repair. An "Other" option is not available.

Repair Time Onsite – This data field documents the amount of time needed once onsite to complete the successful repair of a PC found to be operating improperly. Enter the amount of time in hours using 15-minute increments (i.e. 0.25, 0.5, 0.75, 1.0, 1.25, 1.50, etc.). Repair Travel Time (if required) – This data field documents the travel time needed to visit the facility to make a necessary repair of a PC found to be improperly operating. This travel time information is only required if a separate trip is needed to make the repair separate from the trip made to conduct the inspection for this study. Enter the amount of time in hours using 15-minute increments (i.e. 0.25, 0.5, 0.75, 1.0, 1.25, 1.50, etc.)

Re-Inspection Date – Enter the date when re-inspection of a PC that was subject to repair was completed to confirm its proper operation using the numerical month/day/year format (xx/xx/xxxx).

PC Repair Re-Inspection Method – This data field identifies the method used to re-inspect a PC that was subject to repair. Three dropdown options are provided – AIMM, AVO or soapy water. Select the method used to confirm the successful repair. An "Other" option is not available.

Additional Notes - This data field is a text box that allows additional information worth noting specific to the PC being repaired and re-inspected. These notes can be used to provide further insight into what was done, observed or evaluated to successfully complete the repair and confirm the repair during the re-inspection to demonstrate that the PC was returned to proper operation.

PLEASE CHECK THAT THE FORM IS COMPLETE AFTER EACH INSPECTION AND IF A REPAIR IS REQUIRED.

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Part V

Environmental Protection Agency

40 CFR Part 98
Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2014–0831; FRL–9935–50–OAR]

RIN 2060–AS37

Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing revisions and confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule. These revisions include the addition of calculation methods and reporting requirements for greenhouse gas (GHG) emissions from gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing, and blowdowns of natural gas transmission pipelines between compressor stations. The revisions also include the addition of well identification reporting requirements to improve the EPA's ability to verify reported data and enhance transparency. This action also finalizes confidentiality determinations for new data elements contained in these amendments.

DATES: This final rule is effective on January 1, 2016.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2014–0831. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343–9263; fax number: (202) 343–2342; email address: *GHGReportingRule@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Rule Web site, *http://www.epa.gov/ghgreporting/.* To submit a question, select Help Center, followed by ''Contact Us.''

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on the EPA's Greenhouse Gas Reporting Rule Web site at *http://www.epa.gov/ghgreporting/index.html.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. This final rule adds calculation methods, monitoring, and data reporting requirements and finalizes confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule (40 CFR part 98). The Administrator determined that 40 CFR part 98 is subject to the provisions of Clean Air Act (CAA) section 307(d). See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine''). Entities affected by this final rule are owners and operators of petroleum and natural gas systems that directly emit GHGs, which include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS [a]	Examples of affected facilities
Petroleum and Natural Gas Systems	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.
	221210	Natural gas distribution.
	486210	Pipeline transportation of natural gas.

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Types of facilities other than those listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A and 40 CFR part 98, subpart W. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

What is the effective date? The final rule is effective on January 1, 2016.

Judicial Review. Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit (the Court) by December 21, 2015. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Section 307(d)(7)(B) of the CAA also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note that under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

AGR acid gas removal

API American Petroleum Institute
BAMM best available monitoring methods
CAA Clean Air Act
CBI confidential business information
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e carbon dioxide equivalent
e-GGRT Electronic Greenhouse Gas Reporting Tool
EPA U.S. Environmental Protection Agency
FERC Federal Energy Regulatory Commission
FR Federal Register
ft^3 cubic feet
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GOR gas to oil ratio
GRI Gas Research Institute
ICR information collection request
ID identification
LDC local distribution company
N_2O nitrous oxide
NAICS North American Industry Classification System
NGO non-government organization
NGPA Natural Gas Policy Act
NTTAA National Technology Transfer and Advancement Act
O&M operation and maintenance
OMB Office of Management and Budget
PHMSA Pipeline and Hazardous Materials Safety Administration
psi/ft pounds per square inch per foot
REC reduced emissions completion
RFA Regulatory Flexibility Act
scf standard cubic feet
scf/STB standard cubic feet per stock tank barrel
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
WWW worldwide web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Background
A. Organization of This Preamble
B. Background on This Action
C. Legal Authority
D. How do these amendments apply to 2015 and 2016 reports?
II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment
A. Summary of Final Amendments for Oil Wells With Hydraulic Fracturing
B. Summary of Final Amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment
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III. Final Confidentiality Determinations
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F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. Background

A. Organization of This Preamble

Section I of this preamble provides background information regarding the origin of the final amendments. This section also discusses the EPA's legal authority under the CAA to promulgate and amend 40 CFR part 98 of the Greenhouse Gas Reporting Rule (hereafter referred to as ''part 98'') as well as the legal authority for making confidentiality determinations for the data to be reported. Section II of this preamble contains information on the final amendments to part 98, subpart W (Petroleum and Natural Gas Systems) (hereafter referred to as ''subpart W''), including a summary of the major comments that the EPA considered in the development of this final rule. Section III of this preamble discusses the final confidentiality determinations for new data reporting elements. Section IV of this preamble discusses the impacts of the final amendments to subpart W. Finally, Section V of this preamble describes the statutory and executive order requirements applicable to this action.

B. Background on This Action

The EPA's Greenhouse Gas Reporting Program (GHGRP) requires annual reporting of GHG data and other relevant information from large sources and suppliers in the United States. On October 30, 2009, the EPA published part 98 for collecting information regarding GHG emissions from a broad range of industry sectors (74 FR 56260). Although reporting requirements for petroleum and natural gas systems were originally proposed to be part of part 98 (75 FR 16448; April 10, 2009), the final October 2009 rule did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA re-proposed subpart W in 2010 (79 FR 18608; April 12, 2010), and a subsequent final rule was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458) (hereafter referred to as ''the final subpart W rule''). Following promulgation, the EPA finalized actions revising subpart W (76 FR 22825, April 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 80554, December 23, 2011; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014).

On December 9, 2014, the EPA proposed ''2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (79 FR 76267) to require the reporting of GHG emissions from several sources that had not previously been included in subpart W. These sources include completions and workovers of oil wells with hydraulic fracturing, petroleum and natural gas gathering and boosting systems, and transmission pipeline blowdowns between compressor stations. The reporting requirements for completions and workovers of oil wells with hydraulic fracturing were proposed to be included as part of the existing Onshore Petroleum and Natural Gas Production industry segment. For the other sources, the EPA proposed two new industry segments: The Onshore Petroleum and Natural Gas Gathering and Boosting segment for petroleum and natural gas gathering and boosting facilities, and the Onshore Natural Gas Transmission Pipeline segment for transmission pipeline blowdowns between compressor stations. The EPA also proposed to require the reporting of a well identification number for oil and gas wells covered in the Onshore Petroleum and Natural Gas Production segment. In addition, the EPA proposed confidentiality determinations for new data elements contained in the proposed amendments. The public comment period for these proposed rule amendments ended on February 24, 2015, following a 2-week extension of the original comment period end date (80 FR 6495; February 5, 2015).

In this action, the EPA is finalizing additions and revisions to the subpart W calculation, monitoring, and reporting requirements for new sources, with some changes made in response to public comments. Responses to comments submitted on the proposed amendments can be found in sections II, III, and IV of this preamble as well as in ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. As noted in the preamble to the proposed amendments (79 FR 73148; December 9, 2014), these additions and revisions further the EPA's goals of improving the completeness, quality, accuracy, and transparency of data from this sector, and improving the ability of agencies and the public to use these GHG data to analyze emissions and understand emission trends.

The *Strategy to Reduce Methane Emissions* in the President's *Climate Action Plan* summarizes the sources of methane (CH_4) emissions, commits to new steps to cut emissions of this potent GHG, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut CH_4 emissions from several sectors, including the oil and natural gas sector. In the strategy, the EPA was tasked to review regulatory requirements to address potential gaps in coverage, improve methods, and help ensure high quality data reporting.[1] The final revisions to subpart W covered in this action are responsive to this task by addressing data gaps in subpart W, specifying methods for measuring CH_4 emissions, and providing data that can be used to further analyze CH_4 emissions in this industry.

This action also addresses a petition the EPA received from a group of non-government organizations (NGOs) requesting that the EPA collect data from emissions sources not currently included in subpart W, including well completion emissions from oil wells that co-produce natural gas, facilities and pipelines in the gathering and boosting segment, and transmission pipeline blowdown events (''Petition for Rulemaking'').[2] Table 2 of this preamble summarizes how the EPA has responded to the Petition for Rulemaking. These revisions, and previously finalized revisions where noted in Table 2, reflect the EPA's complete response to the Petition for Rulemaking. It is our position that we have fully responded to the NGO petition, however, any requests included in the petition that have not been responded to in Table 2 are considered denied.

TABLE 2—EPA RESPONSE TO PETITION FOR RULEMAKING

Request in petition	EPA's response	Final rule citations (40 CFR)
Clarify that oil wells that co-produce natural gas (''co-producing wells''), specifically wells in tight-oil formations like the Bakken and Eagle Ford, are subject to the completion reporting requirements as currently written. Expand the well completion reporting requirements to all wells, ensuring co-producing wells in any formation type are required to report completion emissions.	The EPA is not changing the definition of ''gas well'' or ''oil well.'' Instead, the EPA is amending subpart W to require the reporting of GHG emissions from completions and workovers with hydraulic fracturing for wells in the Onshore Petroleum and Natural Gas Production segment, regardless of whether their primary product is oil or natural gas.	98.232(c)(6) 98.232(c)(8) 98.236(g)
Require reporting from facilities and pipelines in the gathering and boosting segment of the natural gas industry.	The EPA is finalizing the proposal to amend subpart W to add a new industry segment, Onshore Petroleum and Natural Gas Gathering and Boosting, which covers emissions from equipment used by gathering pipeline systems that move petroleum and natural gas from the well to either larger gathering pipeline systems, natural gas processing plants, natural gas transmission pipelines, or natural gas distribution pipelines.	98.230(a)(9) 98.232(j) 98.233 (various) 98.236(a)(9)
Require reporting from transmission pipeline blowdown events.	The EPA is finalizing the proposal to add reporting requirements for emissions from natural gas transmission pipeline blowdowns between compressor stations in a new Onshore Natural Gas Transmission Pipeline segment.	98.230(a)(10) 98.232(m) 98.236(aa)(11)
Require reporters to include API well identification numbers along with their submissions to help the public and policymakers understand which sources are reporting and how the threshold may be adjusted to most effectively provide emissions information.	The EPA is requiring the reporting of well identification numbers for the Onshore Petroleum and Natural Gas Production segment for information related specifically to wells.	98.236(f), (g), (h), (l), and (m) 98.238
Phase out the use of best available monitoring methods (BAMM), which will further help to ensure Subpart W data are rigorous, and comprehensive.	Prior to these amendments, BAMM was discontinued for all sources except specific sources that were affected by the amendments finalized on November 25, 2014 (79 FR 70352); those BAMM provisions will be unavailable after December 31, 2015. Reporters will be allowed to use BAMM for the 2016 reporting year for only the new industry segments and emission sources included in this action. The EPA is not allowing the use of BAMM beyond 2016.	98.234(f) and (g)

[1] *Climate Action Plan—Strategy to Reduce Methane Emissions.* The White House, Washington, DC, March 2014. Available at *http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.*

[2] *Petition for Rulemaking and Interpretive Guidance Ensuring Comprehensive Coverage of Methane Sources Under Subpart W of the Greenhouse Gas Reporting Rule—Petroleum And Natural Gas Systems;* Submitted by Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club; March 19, 2013. Docket Item No. EPA–HQ–OAR–2014–0831–0005.

TABLE 2—EPA RESPONSE TO PETITION FOR RULEMAKING—Continued

Request in petition	EPA's response	Final rule citations (40 CFR)
Consider including advanced innovative monitoring methods as a way to accelerate development and deployment of real-time continuous CH_4 emission monitoring in the oil and natural gas sector.	The agency is assessing the potential opportunities for application of remote sensing technologies and other innovations in measurement or monitoring technology to identifying and calculating emissions from affected sources under subpart W and requested comment in the proposal. The EPA received multiple comments in response to the request for comments on the feasibility, possible regulatory approaches, and provisions necessary to incorporate or allow the use of advanced measurement or monitoring methods in subpart W. All of the comments received are included in "Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" in Docket ID No. EPA–HQ–OAR–2014–0831. The EPA is not including provisions related to advanced measurement or monitoring methods in this rule and is not responding to these comments in this rulemaking. Instead, following review of the data and information received in comments, the EPA may propose amendments related to the use of innovative technologies in reporting to the GHGRP in a future rulemaking.	

Legal Authority

The EPA is finalizing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 final GHG reporting rule (74 FR 56260; October 30, 2009), CAA section 114(a)(1) provides the EPA broad authority to require the information to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out a wide variety of CAA provisions. See the preambles to the proposed (74 FR 16448; April 10, 2009) and final GHG reporting rule (74 FR 56260; October 30, 2009) for further information.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing final confidentiality determinations for the new data elements required by these amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information that qualifies for confidential treatment. The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA.

D. How do these amendments apply to 2015 and 2016 reports?

These amendments are effective on January 1, 2016. Thus, beginning on January 1, 2016, facilities must follow the revised methods in subpart W, as amended, to calculate emissions occurring during the 2016 calendar year (*i.e.,* reporting year 2016). The first annual reports of emissions calculated using the amended requirements will be those submitted by March 31, 2017, covering reporting year 2016. For reporting year 2015, reporters will continue to calculate emissions and other relevant data for the reports that are submitted according to the requirements in part 98 that are applicable to reporting year 2015 (*i.e.,* the requirements in place until the effective date of this final rule).

For reporting year 2016 only, we are allowing the use of best available monitoring methods (BAMM) on a short-term transitional basis for facilities new to reporting under subpart W as well as reporters of facilities subject to new monitoring requirements associated with these revisions. Reporters have the option of using BAMM for only the new industry segments and emission sources included in this action from January 1, 2016, to December 31, 2016, without seeking prior EPA approval. The EPA will not accept requests for an extension for the use of BAMM beyond the time periods listed above. The EPA is not allowing the use of BAMM for the new well identification number provisions in the Onshore Petroleum and Natural Gas Production segment because the well identification number is not a parameter that requires monitoring equipment to be measured and, therefore, does not meet the requirements for BAMM. In addition, reporters should already have well identification numbers readily available for all wells and associated equipment to which this reporting requirement applies. See section II.E of this preamble for more information.

II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment

In this action, the EPA is amending subpart W to require the reporting of GHG emissions from completions and workovers of oil wells with hydraulic fracturing as part of the existing Onshore Petroleum and Natural Gas Production industry segment. The EPA is also adding requirements for two new industry segments: the Onshore Petroleum and Natural Gas Gathering and Boosting segment for petroleum and natural gas gathering and boosting systems, and the Onshore Natural Gas Transmission Pipeline segment for transmission pipeline blowdowns between compressor stations. Finally, the EPA is requiring the reporting of well identification numbers for oil and gas well-specific information (*e.g.,* completions and workovers, associated gas venting and flaring) reported in the Onshore Petroleum and Natural Gas Production segment. The comments received on this rule generally did not dispute the merit of adding these new segments and sources to subpart W, but they did provide a number of suggestions regarding the technical details of monitoring, reporting, and applicability.

Sections II.A through II.E of this preamble describe the requirements and other amendments that we are finalizing in this rulemaking. Section II.A describes the final amendments for the

reporting of GHG emissions from completions and workovers of oil wells with hydraulic fracturing. Section II.B describes the final amendments for the reporting of GHG emissions from sources in the new Onshore Petroleum and Natural Gas Gathering and Boosting segment. Section II.C describes the final amendments for the reporting of GHG emissions from sources in the new Onshore Natural Gas Transmission Pipeline segment. Section II.D describes the requirements for reporting well identification numbers for the Onshore Petroleum and Natural Gas Production segment. Finally, section II.E provides a summary of the final amendments to the best available monitoring method requirements. The amendments described in each section are followed by a summary of the major comments on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and the EPA's responses.

Finally, in the preamble to the proposed rule, the EPA stated that the agency is ''assessing the potential opportunities for applying remote sensing technologies and other innovations in measurement or monitoring technology to identifying and calculating emissions from affected sources under subpart W'' (79 FR 73148; December 9, 2014). The EPA did not propose, and therefore is not finalizing, any amendments to subpart W to this effect, but the EPA did request comment on the feasibility, possible regulatory approaches, provisions necessary to incorporate or allow the use of advanced measurement or monitoring methods in subpart W, and methods to ensure compliance with those provisions in an efficient manner. The EPA also requested comment on the memorandum ''Discussion Paper on Potential Implementation of Alternative Monitoring under the GHGRP'' in Docket ID No. EPA–HQ–OAR–2014–0831. All of the comments received are included in ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. The EPA will consider these comments in the context of any future action related to alternative monitoring.

The amendments in this action will advance EPA's goal of maximizing rule effectiveness. For example, these amendments provide clear monitoring, calculation and reporting requirements for new segments and sources in subpart W, thus enabling government, regulated entities, and the public to easily identify and understand rule requirements. In addition, specific changes such as increasing the flexibility and time period for transitional BAMM will make compliance easier than non-compliance.

These amendments will also improve the EPA's ability to assess compliance by adding reporting elements that allow the EPA to more thoroughly verify greenhouse gas data and understand trends in emissions. For example, the requirement for the Onshore Petroleum and Natural Gas Production segment to report well identification numbers will allow the EPA to link GHGRP data with other data sources and assess the completeness and representativeness of the data collected relative to all activity in the U.S. oil and gas production sector. Lastly, these amendments further advance the ability of the GHGRP to provide access to quality data on greenhouse gas emissions by adding key petroleum and natural gas emission sources to this program. One example is the addition of the Onshore Petroleum and Natural Gas Gathering and Boosting segment, a significant greenhouse gas emissions segment that had not been previously covered under the GHGRP.

A. Summary of Final Amendments for Oil Wells With Hydraulic Fracturing

1. Summary of Final Amendments

The EPA is amending subpart W to require the reporting of GHG emissions from completions and workovers with hydraulic fracturing for wells in the Onshore Petroleum and Natural Gas Production segment, regardless of whether their primary product is oil or natural gas. In general, commenters supported inclusion of emissions from completions and workovers of oil wells with hydraulic fracturing in subpart W, and a few commenters provided targeted technical edits and suggestions for this source. Consistent with the requirements for completions and workovers of gas wells with hydraulic fracturing, and consistent with the proposed requirements, the new provisions include the reporting of activity data on the number of completions and workovers of oil wells with hydraulic fracturing and on the use of flaring and reduced emission completions (RECs). In response to public comments, the final monitoring and reporting amendments do not apply to completions and workovers of oil wells with hydraulic fracturing that have a gas to oil ratio (GOR) of less than 300 standard cubic feet per stock tank barrel (scf/STB).

The EPA is also amending the equations and definitions in 40 CFR 98.233(g) to reflect applicability to completions and workovers of all gas and oil wells with hydraulic fracturing. As in the proposal, the final amendments require the use of either Equation W–10A or W–10B for calculating GHG emissions from completions and workovers of oil wells with hydraulic fracturing. Equation W–10A is used to calculate emissions from wells using inputs obtained from a representative sample of wells within a sub-basin and the ratio of the gas flowback rate to the production flow rate, and Equation W–10B is used to calculate emissions using inputs obtained from all wells within a sub-basin and the flow rate and flow volume of the gas vented or flared. As proposed, the EPA is finalizing that emissions be calculated and reported separately for gas wells and oil wells by sub-basin and well type combination.[3] Furthermore, as proposed, the final amendments require the use of Calculation Method 1 for calculating inputs to Equations W–12A and W–12B for oil wells. Calculation Method 1 relies on direct measurement of gas flow rate during flowback to develop calculation inputs; the requirements for the location of the flow meter used to measure the gas flow rate for oil wells are the same as the location requirements for gas wells. Other provisions that apply to completions and workovers of gas wells with hydraulic fracturing also apply to completions and workovers of oil wells with hydraulic fracturing, including the determination of wells that constitute a representative sample for use in Equation W–10A.

For oil wells that do not meter gas production, such as some wells with a relatively low GOR, the EPA is adding a new Equation W–12C as proposed to calculate, rather than measure, the value of $PR_{s,p}$ (the average gas production flow rate during the first 30 days of production after the completion or workover), which is used as an input to Equation W–10A. In this Equation W–12C, the value of $PR_{s,p}$ is calculated by multiplying the GOR of the well by the measured oil production rate over the

[3] Within subpart W, an individual well is labeled an ''oil well'' or ''gas well'' depending on the formation type reported for that well. If wells produce from more than one formation type, then the well is classified into only one type based on the formation type with the most contribution to production as determined by the reporter's engineering knowledge. See the definition of ''Sub-basin category, for onshore natural gas production'' in 40 CFR 98.238.

first 30 days of production after the completion or workover.

2. Summary of Comments and Responses

Comment: Several commenters responded to the EPA's request for comment on whether to establish a minimum GOR threshold such that oil wells with a very low GOR would not be subject to the monitoring and reporting requirements for GHG emissions from completions and workovers with hydraulic fracturing. Most of these commenters supported establishment of a cutoff for wells with very low emissions. One commenter urged the EPA to require monitoring and reporting for all completions and workovers with hydraulic fracturing but stated that if a threshold is set, it should be set at a level that ensures that all significant emissions sources are included and that sources are able to clearly determine whether they are required to report. Three commenters supported setting a minimum GOR threshold. One commenter suggested a minimum GOR threshold of 300 and stated that, based on industry experience, oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. The second commenter agreed that operators should only have to monitor and report emissions if the GOR is great enough to operate a separator and direct measurement is possible. The third commenter supporting a minimum GOR threshold did not provide a suggestion for a specific numeric threshold but stated that the emissions from wells with a low GOR are insignificant, and the time and resources involved in measuring the flowback and reporting emissions for wells expected to have minimal emissions would outweigh any contribution of these emissions to the overall source category totals. This commenter supported the inclusion of a threshold so that only significant sources of emissions would be included.

Response: The EPA agrees that including a minimum GOR threshold will help minimize reporting burden while still capturing most of the emissions from this source. Energy Information Administration data show that the number of ''oil only'' wells drilled from 2007–2012 was less than 20 percent of all new wells.[4] These wells would have a GOR approaching zero and, therefore, would be expected to have low emissions. We believe that having no threshold may create an unnecessary burden for operators to report emissions for these wells with just a trace of gas. Given that the EPA is finalizing the proposed requirement that the oil well flow meter be located downstream of the separator, the separator must be operating for the owner or operator to be able to measure the flow rate and estimate emissions from completions and workovers of oil wells with hydraulic fracturing. One commenter, an industry trade association, suggested a threshold of 300 scf/STB based on the industry trade association's experience that separators typically do not operate at a GOR less than 300 scf/STB.

The primary concern when determining the level for a threshold is volatility; the threshold must be low enough that the oil produced is considered non-volatile. Non-volatile ''black oils'' (*i.e.,* oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900 scf/STB.[5] Oil wells with a GOR less than the 300 scf/STB suggested by the commenter are at the lower end of this range, and completions and workovers with hydraulic fracturing of these wells will not likely have enough gas associated that can be separated. Therefore, the final monitoring and reporting requirements do not apply to completions and workovers of oil wells with hydraulic fracturing that have a GOR of less than 300 scf/STB.

Comment: Several commenters responded to the EPA's request for comment on whether to establish a minimum well pressure threshold such that oil wells with a very low well pressure would not be subject to the monitoring and reporting requirements for GHG emissions from completions and workovers with hydraulic fracturing. Most of these commenters supported establishment of a cutoff for wells with very low well pressure. One commenter urged the EPA to require monitoring and reporting for all completions and workovers with hydraulic fracturing but stated that if a threshold is set, it should be set at a level that ensures that all significant emissions sources are included and that sources are able to clearly determine whether they are required to report. Three commenters supported setting a minimum well pressure threshold. One commenter suggested a minimum well pressure threshold of 0.4645 pounds per square inch per foot (psi/ft) because this is the vertical pressure gradient needed for a well to flow back, based on experience with the Natural Gas STAR program. The second commenter suggested that operators should only have to monitor and report emissions if the pressure of the reservoir during oil well completions and workovers is greater than the pressure gradient of 0.433 psi/ft and noted that the pressure needed varies based on the density of the materials in the column and the depth of the well. The third commenter supporting a minimum well pressure threshold did not provide a suggestion for a threshold but supported the inclusion of a threshold so that only significant sources of emissions would be included.

Response: The EPA evaluated the commenters' suggestions and has decided not to include a minimum well pressure threshold. Both commenters who suggested a specific value noted in their comments that these pressure gradients are the minimum needed for the well to produce. In other words, according to the commenters' rationale, wells with pressures below the suggested pressure thresholds would not have any production, regardless of whether a threshold is included in the final rule. As a result, specifying that reporting of emissions from completions and workovers of oil wells with hydraulic fracturing is not required below those pressures is redundant. Therefore, the final rule does not include a minimum well or reservoir pressure threshold for completions and workovers of oil wells with hydraulic fracturing.

B. Summary of Final Amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment

The EPA is amending subpart W to add a new industry segment, Onshore Petroleum and Natural Gas Gathering and Boosting, that covers emissions from equipment used by gathering pipeline systems that move petroleum and natural gas from the well to either larger gathering pipeline systems, natural gas processing plants, natural gas transmission pipelines, or natural gas distribution pipelines. A gathering and boosting system is a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more well-defined connection points to gas and oil production and a well-defined downstream endpoint, typically a gas

[4] In this analysis, all hydrocarbon production in the liquid state at the wellhead was considered oil. J. Lieskovsky and S. Gorgen. ''Drilling often results in both oil and natural gas production.'' *Today in Energy,* U.S. Energy Information Administration, October 29, 2013. *http://www.eia.gov/todayinenergy/detail.cfm?id=13571.* Accessed June 9, 2015.

[5] M.P. Walsh. ''Oil Reservoir Primary Drive Mechanisms.'' In *Petroleum Engineering Handbook, Volume V: Reservoir Engineering and Petrophysics,* E.D. Holstein (Ed.), L.W. Lake (Ed. in Chief), pp. V–895–980. Society of Petroleum Engineers, 2007.

processing plant or transmission pipeline. Gathering pipelines are pipelines used to transport gas from the furthermost downstream point in an onshore production facility to certain endpoints, generally either a gas processing facility or point of connection to a transmission pipeline. Compressors located along the gathering and boosting system are used to control or ''boost'' the pressure of the gas in the pipeline and keep the gas moving downstream. Commenters generally supported inclusion of gathering and boosting system emissions in subpart W, and many commenters suggested targeted revisions concerning definitions, what emission sources should be included in the segment and methods for individual emission sources.

The remainder of this section describes the final reporting requirements for this new industry segment, including the segment description, definitions, calculation methods, and information to be reported. The amendments described in each section are followed by a summary of the major comments, if any, on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and the EPA's responses.

1. Segment Description for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment

a. Summary of Final Amendments

The EPA is finalizing the definition of the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230 as gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to, gathering pipelines, separators, compressors, acid gas removal (AGR) units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. The Onshore Petroleum and Natural Gas Gathering and Boosting segment does not include equipment and pipelines that are reported under any other industry segment defined in subpart W. The segment definition is being finalized as proposed, except that the final amendments provide two clarifications regarding gathering pipelines. First, gathering pipelines operating on a vacuum are not included because they would not be expected to have emissions. Second, to address comments regarding the inclusion of liquid and multiphase streams in the segment, the definition clarifies that gathering pipelines with a GOR less than 300 scf/STB are not a part of the segment.

b. Summary of Comments and Responses

Comment: Commenters requested that the EPA remove ''Petroleum and'' from the proposed segment name, ''Onshore Petroleum and Natural Gas Gathering and Boosting.'' The commenters asserted that the removal would provide a clear demarcation between onshore petroleum and natural gas production and onshore natural gas gathering and boosting. They also stated that such a change would be more consistent with the segment definition, which includes pipelines and equipment ''used to compress, dehydrate, sweeten, or transport the gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline.'' The commenter stated that the type of equipment included in the gathering and boosting segment is ''synonymous'' with gas gathering and boosting systems, not liquid or petroleum, and they noted that the emission factor for equipment leaks from gathering pipelines is not applicable to gathering pipelines that carry mostly liquid.

Commenters also specifically requested that the EPA exclude petroleum gathering pipelines from the gathering and boosting segment because the fugitive gas emissions from these gathering pipelines would be negligible. Both commenters stated that the proposed emission factor for gathering pipeline leaks is only applicable to gas gathering pipelines. Two commenters also requested that multi-phase flow lines from wells to a centralized production facility where initial separation occurs be retained in the Onshore Petroleum and Natural Gas Production segment rather than included in the new gathering and boosting segment.

Response: The EPA is finalizing the segment name as proposed and not removing ''Petroleum and'' from the segment name or moving multiphase gathering pipelines to the Onshore Petroleum and Natural Gas Production segment. We proposed including ''Petroleum and'' in the segment name to reflect the complex nature of upstream operations where wells can produce oil, natural gas, or a mixture of both and to signify the inclusion of GHG emissions from gathering and boosting systems moving high volatility liquids in this new segment. Even in wells that produce primarily liquids at surface temperature and pressure conditions, there is often a volatile gaseous component. This associated gas is usually considered wet due to the high content of natural gas liquids (volatile components) to go along with gaseous CH_4. Similarly, the inclusion of all petroleum gathering pipelines in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, including multiphase pipelines, is appropriate, because gathering lines are a key component to gathering and boosting systems. Therefore, all gathering pipelines that collect petroleum and/or natural gas from onshore production gas or oil wells and transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline are considered part of the final Onshore Petroleum and Natural Gas Gathering and Boosting segment.

However, the EPA does agree that gathering pipelines carrying mostly oil have a low potential for GHG emissions. We note that the ratio of CH_4 to volatile components increases as the GOR increases. Therefore, to clarify our intent to exclude gathering pipelines containing oil, the final rule clarifies that the Onshore Petroleum and Natural Gas Gathering and Boosting segment does not include gathering pipelines with a GOR of less than 300 scf/STB. Operators of gathering pipelines below that threshold are not required to include those pipelines in their gathering and boosting facility. See section II.B.5 of this preamble for additional discussion.

Finally, as part of evaluating this comment, the EPA reviewed the proposed definitions related to the Onshore Petroleum and Natural Gas Gathering and Boosting segment and recognizes that two of them referred to ''the gas'' rather than ''the petroleum and/or natural gas.'' One was the proposed description of the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230, as identified by the commenters, and the other was the definition of ''gathering and boosting system owner or operator'' in 40 CFR 98.238. For consistency throughout the final rule with the intent stated in this response, the final description of the Onshore

Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230 refers to ''petroleum and/or natural gas'' and the final definition of ''gathering and boosting system owner or operator'' in 40 CFR 98.238 refers to ''the petroleum or natural gas transported.''

Comment: One commenter stated that there may be confusion regarding which equipment should be reported in the different industry segments, which could lead to emissions being mistakenly excluded or double-counted. For example, gathering and boosting equipment located on a single well pad or associated with a single well pad could be double-counted, especially if it is operated by one entity but owned by another. The commenter also noted that confusion over the proper segment for this type of equipment could make the difference between reporting emissions or not reporting emissions if a facility is close to the reporting threshold of 25,000 metric tons carbon dioxide equivalent (CO_2e). Therefore, the commenter requested that the EPA incorporate by reference the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) federally defined boundaries of production, gathering and boosting, and transmission segments to ensure state/federal transparency and consistency.

Response: The EPA is not changing the segment description for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3). As stated at proposal, the EPA decided not to make any changes to the existing segment descriptions to provide consistency for reporters in that segment. This decision allows the EPA to ensure that the data gap in subpart W related to gathering and boosting systems is addressed while minimizing confusion over changes to other segments. Instead, the EPA is reiterating the intention for the Onshore Petroleum and Natural Gas Gathering and Boosting segment to cover equipment and emission sources not included in reporting for the existing Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments.

The EPA does not agree that emissions from the same equipment will be reported under more than one industry segment in a given reporting year; however, we acknowledge that similar equipment may exist in adjacent industry segments as defined in subpart W. The owner or operator of the equipment in question should first determine if that equipment is subject to reporting in another segment of subpart W, such as the Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments. If the equipment is not subject to reporting in another segment of subpart W, then the owner or operator should evaluate whether or not the equipment is included in the Onshore Petroleum and Natural Gas Gathering and Boosting source category. For example, if a gathering and boosting owner or operator also owns or operates equipment on or associated with a single well pad (40 CFR 98.230(a)(2)), that equipment is part of the Onshore Petroleum and Natural Gas Production segment, not the Onshore Petroleum and Natural Gas Gathering and Boosting segment. Therefore, emissions from that equipment should not be included when determining if the gathering and boosting facility exceeds the reporting threshold.

Comment: One commenter requested that the EPA clarify the proper segment for AGR units and revise the rule accordingly. The commenter suggested that the Natural Gas Processing segment should explicitly exclude sulfur dioxide and carbon dioxide (CO_2) removal units, so that it is clear that those units do not report under both the Natural Gas Processing segment and the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The commenter stated that this revision would be more consistent with the definition of gas processing plant in other EPA rules. If the EPA does not make this change, the commenter stated that AGR units should not be included in the Onshore Petroleum and Natural Gas Gathering and Boosting segment because they are already included in the Natural Gas Processing segment. The commenter noted that AGR units are specifically defined in 40 CFR 98.238 as a process unit that separates hydrogen sulfide and/or CO_2 from sour natural gas using liquid or solid absorbents or membrane separators.

Response: The EPA agrees that emissions from a particular acid gas removal unit should not be reported under both the Natural Gas Processing segment and the Onshore Petroleum and Natural Gas Gathering and Boosting segment. However, as noted previously in this preamble, the EPA is not changing the segment description for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3). Instead, the EPA is reiterating the intention for the Onshore Petroleum and Natural Gas Gathering and Boosting segment to cover equipment and emission sources not included in reporting for the Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments. The final segment description for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230(a)(10) specifies that gathering and boosting equipment does not include equipment reported under any other industry segment defined in 40 CFR 98.230(a), which should address the commenter's concern about reporting under multiple segments.

Regarding the commenter's suggestion to exclude AGR units from the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA believes AGR units should be reported under subpart W and that the current requirements, coupled with the revisions in this rulemaking, allow for a clear demarcation of where they should be included and reported. While most AGR units will be included in the Onshore Natural Gas Processing segment, the EPA does not agree that the Onshore Natural Gas Processing segment includes all AGR vents, particularly those in processes that do not fractionate gas liquids with an annual average throughput of less than 25 million scf per day. Therefore, the final Onshore Petroleum and Natural Gas Gathering and Boosting segment includes AGR vents that do not meet the segment descriptions for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3) but do meet the Onshore Petroleum and Natural Gas Gathering and Boosting segment description in 40 CFR 98.230(a)(10).

2. Definitions

a. Summary of Final Amendments

The EPA is finalizing the definition of ''gathering and boosting system'' as proposed and is finalizing the definition of ''gathering and boosting system owner or operator'' as proposed with a clarification that the fluid being transported may be petroleum or natural gas. Specifically, a gathering and boosting system is a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, local distribution company (LDC) pipeline, or other gathering and boosting system. A gathering and

boosting system owner or operator is any person that: (1) Holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline; or (2) is responsible for custody of the petroleum or natural gas transported. In complex ownership scenarios, the owner/operator assigns a designated representative responsible for reporting consistent with 40 CFR 98.4.

The EPA is also finalizing the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting'' in 40 CFR 98.238 as proposed. A facility with respect to onshore petroleum and natural gas gathering and boosting is all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in 40 CFR 98.238. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting systems and equipment that the person owns or operates in the basin are considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system. Emissions from an onshore petroleum and natural gas gathering and boosting facility only need to be reported if the collection of emission sources emits 25,000 metric tons CO_2e or more per year.

b. Summary of Comments and Responses

Comment: Multiple commenters provided comments on the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting.'' Some commenters supported the basin-level approach that the EPA proposed, although a few asked the EPA to clarify how to report their emissions if their gathering and boosting system is in more than one basin. Other commenters disagreed with the basin-level approach and suggested that the EPA should use the definition of facility in 40 CFR 98.6. These commenters asserted that the basin-level approach would result in an expansive definition of facility that includes huge numbers of emissions sources and that this approach is not consistent with how a facility is defined elsewhere in the GHGRP or with traditional notions of aggregation under the CAA. One commenter asserted that defining a facility in a way that is not consistent with other CAA programs will make it difficult for the EPA to use the GHGRP data to inform future policy decisions. The commenter also stated that the EPA has not provided any explanation of why basin-wide aggregation is a reasonable data request under section 114 of the CAA.

Commenters opposing the basin-level facility definition noted that the Onshore Petroleum and Natural Gas Gathering and Boosting segment has very different characteristics from the Onshore Petroleum and Natural Gas Production segment, which also uses the basin-level approach to defining a facility. One commenter specifically noted that production sources are located at well-defined, discrete locations, owners and operators of production sites know where the wells are physically located and how many operate in a single production basin. In contrast, the commenter stated, the gathering and boosting operations of one owner or operator in a single hydrocarbon basin may include hundreds or thousands of miles of pipelines with multiple sites, including interconnects, meter stations, scrubber stations, pigging stations, compressor stations, and gas treating plants. Another commenter stated that gathering and boosting sites have the ability to boost and move gas from multiple basins within the same site, whereas production typically maintains operations and moves gas within one basin.

Another commenter also disagreed with the basin-level approach, noting that the term ''basin'' is not common terminology that is used in the gathering and boosting industry segment. The commenter suggested that the EPA use a county- or parish-level approach with an equipment threshold (to determine which equipment should be counted when determining if the 25,000 metric tons CO_2e reporting threshold has been exceeded).

Response: The EPA is finalizing the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as proposed. As noted in the preamble to the proposed amendments, the basin-level approach to defining a facility for the Onshore Petroleum and Natural Gas Gathering and Boosting segment is expected to achieve a balance of providing geographically specific information while also reducing burden on reporters. This approach also recognizes the fact that gathering and boosting facilities are more dispersed than processing facilities and are geographically similar to the Onshore Petroleum and Natural Gas Production segment in size and number of sources because, by their nature, they are needed to process and transport the petroleum and natural gas produced in a given basin. While some gathering and boosting operations may span multiple basins or may only be present in a portion of a basin, as will some onshore production operations, the EPA has concluded that a basin-level facility definition is the best reflection of how this industry is organized operationally.

In ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' (Docket Item No. EPA–HQ–OAR–2014–0831–0018), we evaluated the option of using the definition of ''facility'' found in 40 CFR 98.6 for gathering and boosting facilities, and we found that this definition would provide limited data on the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment compared to the basin-level approach, due to the fact that fewer facilities would exceed the 25,000 metric tons CO_2e reporting threshold. It would also likely be more burdensome overall to reporters, because a larger number of facilities would have to be evaluated to determine whether they exceed the 25,000 metric tons CO_2e reporting threshold, and a larger number of ''facility'' reports would be required for each owner or operator. The commenters did not provide any new information that would enable us to re-evaluate this conclusion. A county- or parish-level approach would similarly result in a larger number of smaller facilities to be evaluated to determine whether they exceed the reporting threshold than the basin-level approach. This approach would result in fewer facilities reporting than a basin-level definition, especially if an equipment threshold were defined as requested by the commenter, as well as a higher burden for owners or operators with multiple facilities in a basin that exceed the 25,000 metric tons CO_2e reporting threshold. Therefore, the EPA concluded that these options would not achieve the goals that were articulated in the preamble to the proposed rule of ''having a thorough data set and transparent, complete information for this sector while minimizing burden to reporters'' (79 FR 73156; December 9,

2014). For more detail on this analysis, see ''Greenhouse Gas Reporting Rule: Technical Support for Final 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. We disagree with the comment that aggregation of data would not provide a data set that the EPA can use to inform future policy decisions. The purpose of this rule is to collect emissions and activity data for this industry and understand the relative emission sources, which we anticipate the aggregated data will help to promote. Therefore, the aggregated data can still inform future GHG policy. As we have pointed out previously, the EPA's definition of ''facility'' for purposes of part 98 in no way impacts the ''facility'' definition for similar sources under existing CAA programs.[6] Information collected under part 98 can inform a number of different CAA programs and the Agency's authority under CAA section 114 as the basis for part 98 is independent from the EPA's authority for other CAA programs.

To address the commenters' question about reporting a system in two basins, we are confirming in this response that reporters should submit one report per basin (*i.e.,* per facility as it is defined in subpart W) and that the 25,000 metric tons CO_2e per year reporting threshold applies to each basin/facility separately. In other words, the reporter should determine the emissions from the portion of gathering and boosting system associated with each basin. If the total emissions in each basin exceed the 25,000 metric tons CO_2e per year reporting threshold, then the reporter submits two reports. If the total emissions in one basin exceed the 25,000 metric tons CO_2e threshold, but the emissions in the other basin are below the threshold, then the reporter submits one report (for the facility that exceeds the threshold).

Regarding the commenter's question regarding the reasonableness of collecting data at the basin-level under the CAA, the EPA established its basis for collecting basin-level data in the final subpart W rule, when the EPA finalized the requirements for the Onshore Petroleum and Natural Gas Production segment. Additionally, as noted earlier in this section, more granular collection of data for this segment would result in higher burden for owners or operators with multiple operations in a basin that exceed the 25,000 metric tons CO_2e reporting threshold. See also, ''Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document (Docket Item No. EPA–HQ–OAR–2009–0923–3610) and ''Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments'' (Docket Item No. EPA–HQ–OAR–2009–0923–3608).

3. Blowdown Vent Stacks

a. Summary of Final Amendments

The EPA is finalizing the requirements for blowdowns of equipment in the Onshore Petroleum and Natural Gas Gathering and Boosting segment with some clarifications from proposal. Emissions should be calculated using the same methods that are used for the Onshore Natural Gas Processing segment. The same exemptions, including those for volumes less than 50 cubic feet (ft^3) and for desiccant dehydrator reloading, apply to the Onshore Petroleum and Natural Gas Gathering and Boosting segment. In response to comments that the segment is geographically dispersed and blowdowns may occur without personnel on-site or nearby, making it difficult to determine emissions from a blowdown event, the final amendments specify that for emergency blowdowns, reporters may use engineering estimates based on best available information to determine the temperature and pressure used in Equation W–14A.

b. Summary of Comments and Responses

Comment: Commenters stated that the EPA should not include reporting of blowdown vent stack emissions due to the large burden on the reporter. Instead, the commenters stated, blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should be treated similarly to blowdowns in the Onshore Petroleum and Natural Gas Production segment, where they are excluded because they are not located at consolidated facility sites and are not manned. Commenters also stated that blowdowns from gathering and boosting systems contribute minimally to overall GHG emissions. One commenter noted that while there is an exemption for any blowdown of a volume less than 50 ft^3, there is also a burden to determine if the physical volume meets this reporting threshold. To reduce the burden, some commenters suggested only including emissions from blowdown vent stacks located at a facility site (*e.g.,* compressor station, central tank battery). Other commenters stated if blowdowns remain in the segment, the EPA should allow reporters to use an emission factor approach to calculate emissions. Another commenter stated that the EPA's supporting documentation focuses on gathering pipeline blowdowns, but the regulatory text appears to include all the blowdowns occurring within a basin, including individual equipment blowdowns. The commenter requested that the EPA clarify its intent if blowdowns remain in the segment.

Response: The EPA has evaluated these comments and has decided to finalize the reporting requirements for blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment with some revisions to address the commenters' concerns. While the EPA does recognize that many gathering and boosting systems are geographically dispersed, as noted by the commenters, the nature of the Onshore Petroleum and Natural Gas Gathering and Boosting segment is such that the amount of fluid passing through a gathering and boosting system will be much greater than the amount of fluid at individual well pads. Therefore, the EPA has determined that the potential for emissions from blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment is higher than blowdowns in the Onshore Petroleum and Natural Gas Production segment, and they should not be excluded. However, the EPA acknowledges that the geographic dispersion of the segment, and the fact that some blowdowns occur without facility personnel on site, may make it difficult to measure emissions from blowdowns, particularly emergency blowdowns. Therefore, the final amendments include a provision specifying that for emergency blowdowns, reporters may use engineering estimates based on best available information to determine the temperature at actual conditions in the unique physical volume and absolute pressure at actual conditions in the unique physical volume for use in Equation W–14A.

To respond to the commenter's request regarding whether only gathering pipeline blowdowns or all equipment blowdowns should be included, the EPA is clarifying that the intent is to include emissions from the ''blowdown vent stacks'' source type as defined in subpart A of part 98. The focus on blowdown vent stacks located on gathering pipelines in the supporting documentation was not intended to imply that only gathering pipeline blowdowns should be reported. On the

[6] Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems, Docket Id. No. EPA–HQ–OAR–2009–0923.

contrary, the proposal supporting documentation reflects the fact that the EPA expected that blowdown vent stacks located at boosting stations would be similar to blowdown vent stacks in other industry segments and conducted a separate evaluation to determine whether the same calculation methods would be appropriate for gathering pipeline blowdown vent stacks. The final rule supporting documentation more clearly reflects this intent. The EPA also notes that while measuring equipment to determine whether it exceeds the 50 ft^3 physical volume threshold for reporting may create an initial burden on reporters, the threshold will lead to a burden reduction as reporters become familiar with the identification process.

4. Storage Tank Vented Emissions

a. Summary of Final Amendments

The EPA is finalizing the same methods for calculating emissions for atmospheric storage tanks located in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as in the Onshore Petroleum and Natural Gas Production segment, as proposed but with a few clarifications. Specifically, the EPA is clarifying some of the language within 40 CFR 98.233(j) and 40 CFR 98.236(j) that was originally written to apply to Onshore Petroleum and Natural Gas Production facilities and not proposed to be amended to also apply to storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment. In particular, references to a ''wellhead separator'' have been clarified to refer simply to a ''separator,'' which is a defined term in 40 CFR 98.238. To accommodate Onshore Petroleum and Natural Gas Gathering and Boosting storage tanks that do not receive hydrocarbon liquids from a separator or well, Calculation Methods 1 and 2 have been amended to specify how to estimate emissions if liquids are received from non-separator equipment. In addition, certain instances of ''sub-basin'' have been amended to refer to ''county'' to clarify the requirements for Onshore Petroleum and Natural Gas Gathering and Boosting reporters. All other provisions in 40 CFR 98.233(j) apply to the Onshore Petroleum and Natural Gas Gathering and Boosting segment, including the 10 barrels per day threshold for determining which calculation method may be used for estimating emissions.

b. Summary of Comments and Responses

Comment: One commenter stated that combining the requirements for storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment and the Onshore Petroleum and Natural Gas Production segment results in confusing terminology and unclear requirements. In particular, the commenter noted that the terms ''separator(s),'' ''gas-liquid separator(s),'' ''wellhead separator(s),'' and ''wellhead gas-liquid separator(s),'' appear throughout the storage tank requirements. The commenter asked whether the EPA intended all of these terms to refer to the same equipment. The commenter also noted that not all gathering and boosting system storage tanks receive liquids directly from separators, and no gathering and boosting storage tanks receive liquids directly from wellhead separators. Therefore, the commenter stated, the requirements for storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment are unclear.

The commenter also noted inconsistency between use of the terms ''oil,'' ''sales oil,'' and ''stabilized oil'' in 40 CFR 98.233(j) and 40 CFR 98.236(j). The commenter stated that Onshore Petroleum and Natural Gas Gathering and Boosting facilities may process condensate but not oil, and the commenter asked the EPA to clarify how those terms should be applied to the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

Finally, the commenter noted that Calculation Method 1 for storage tanks requires use of the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category. The commenter stated that the term ''sub-basin'' has no relevance to the Onshore Petroleum and Natural Gas Gathering and Boosting segment because the composition of condensate processed at a compressor station may have little relationship to the oil or gas formation below the compressor station.

Response: The EPA agrees that the language in 40 CFR 98.233(j) and 40 CFR 98.236(j) should be clear for all Onshore Petroleum and Natural Gas Production facilities and all Onshore Petroleum and Natural Gas Gathering and Boosting facilities to which it applies. The existing definition of ''separator'' in 40 CFR 98.238 is a vessel in which streams of multiple phases are gravity separated into individual streams of single phase. This general definition and the general term ''gas-liquid separator'' apply to both Onshore Petroleum and Natural Gas Production facilities and all Onshore Petroleum and Natural Gas Gathering and Boosting facilities. Therefore, the EPA has reviewed the language and is amending references to a ''well,'' ''well pad,'' or ''wellhead,'' which are terms that are not expected to apply to most Onshore Petroleum and Natural Gas Gathering and Boosting facilities. The final provisions in 40 CFR 98.233(j) and 40 CFR 98.236(j) refer more generally to separators or gas-liquid separators. To address the comment that not all gathering and boosting system storage tanks receive liquids directly from separators, the EPA has amended 40 CFR 98.233(j)(1) and (2) to specify how those calculation methodologies may be used for Onshore Petroleum and Natural Gas Gathering and Boosting storage tanks receiving hydrocarbon liquids from non-separator equipment (*i.e.,* without a well or separator directly upstream of the storage tank).

Regarding the particular material being stored in storage tanks, the EPA agrees that there is inconsistency in some of the terms that could cause some confusion. The EPA is clarifying in this response that for the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the intent is for ''oil'' to refer more generally to hydrocarbon liquids, which is consistent with the statement in 40 CFR 98.233(j) that reporters are required to calculate emissions ''from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids.'' The proposed separate reporting requirements for quantity of produced oil throughput and produced condensate throughput in 40 CFR 98.236(aa)(10) have been revised, and the final rule requires reporting of the hydrocarbon liquids received by the facility and the hydrocarbon liquids leaving the facility. Finally, the EPA notes that the term ''sales oil'' is already defined in Subpart A to include ''produced crude oil or condensate,'' so there is no further clarification needed.

Regarding the term ''sub-basin,'' the EPA agrees with the commenter that the definition of ''sub-basin category, for onshore natural gas production'' in 40 CFR 98.238 is not relevant for Onshore Petroleum and Natural Gas Gathering and Boosting facilities. The EPA also agrees that the operations within a section of a gathering and boosting system may not be related to the formation type below the surface of the ground at that location, especially as the material travels further from the wells supplying gas and hydrocarbon liquids to the system. As a result of this comment, the EPA reviewed the use of the term ''sub-basin'' as it was proposed to apply to Onshore Petroleum and Natural Gas Gathering and Boosting facilities. In 40 CFR 98.233(j), the calculation methods provide options to

estimate unknown parameters using information from a previous analysis of the composition in the sub-basin category. In these cases, the intent is to estimate unknown parameters from a representative unit (*e.g.,* well, separator). To reflect a similar intent for Onshore Petroleum and Natural Gas Gathering and Boosting facilities, 40 CFR 98.233(j)(1)(vii)(B) and 40 CFR 98.233(j)(1)(vii)(C) in Calculation Method 1 clarify that representative separators or non-separator equipment are located within the same county for Onshore Petroleum and Natural Gas Gathering and Boosting reporters. For Calculation Method 2, the term ''sub-basin category'' is used to describe calculation of emissions for flow to storage tanks directly from wells. The final rule includes a new paragraph 40 CFR 98.233(j)(2)(iii) to address calculation of emissions from flow to a tank from equipment other than a well or separator (such as a stabilizer or slug catcher), and this paragraph also clarifies that representative analyses should come from other non-separator equipment located within the same county. Finally, there are reporting requirements for a ''sub-basin ID'' in 40 CFR 98.236. The final rule specifies that for Onshore Petroleum and Natural Gas Gathering and Boosting, the information to be reported is the county in which the equipment is located.

5. Gathering Pipelines

a. Summary of Final Amendments

The EPA is finalizing the requirements for calculating emissions from gathering pipelines defined to be included in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as proposed. The methodology is similar to the approach used for equipment leaks in the Onshore Petroleum and Natural Gas Production segment. For gathering lines, reporters use the population count and emission factor approach in 40 CFR 98.233(r). The emission factors in Table W–1A for gathering pipelines are whole gas emission factors based on the U.S. GHG Inventory. The population count is the miles of gathering pipeline, similar to the approach used for calculating emissions from natural gas distribution pipelines in the Natural Gas Distribution segment. As noted in section II.B.1.a of this preamble, gathering pipelines with a GOR less than 300 scf/STB are not included in this segment.

b. Summary of Comments and Responses

Comment: One commenter asserted that the EPA should revise the proposed emission factor of 2.81 standard cubic feet (scf)/hour/mile for leaks from gathering pipelines to be based on characteristics of currently operating gathering pipelines rather than distribution pipelines or older data on gathering pipelines. The commenter also noted that this emission factor is not applicable to gathering pipelines that carry primarily liquids, as there is no gas stream until after separation. The commenter identified gathering pipeline-specific data from PHMSA and used the data to calculate a suggested emission factor of 2.23 scf/hour/mile.

Response: We reviewed the underlying data used to develop the proposed emission factor, and we agree with the commenter that the proposed emission factor could better account for differences between pipeline types and for currently operating gathering pipelines. In the 1996 Gas Research Institute (GRI)/EPA report that is the basis of the emission factor, material-specific emissions factors for gathering lines were developed using data from direct measurement of distribution pipelines conducted in the 1990s, not gathering pipelines. These material-specific emission factors are the same emission factors used by the commenter as the starting point for their revised emission factor.

We agree with the commenter that the emission factors should better represent currently operating gathering pipelines; however, there is significant variability in gathering pipelines and gathering system configurations. Owners and operators currently report the mileage of pipeline by gathering pipeline type to PHMSA.[7] Therefore, rather than calculate a single emission factor for gathering pipelines based on a distribution of gathering pipeline materials, as was done at proposal, the EPA determined that the most appropriate approach is to develop gathering pipeline emission factors for four pipeline material types: Protected steel, unprotected steel, plastic, and cast iron. (For more information about the development of these emission factors, see ''Greenhouse Gas Reporting Rule: Technical Support for Final 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831.) The final amendments require reporters to estimate emissions using material-specific emission factors provided in the rule and to report gathering pipeline mileage by material type.

The EPA also notes that reporters will not need to calculate emissions from gathering pipelines that carry hydrocarbon liquids if they are below the minimum GOR threshold for the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

6. Other Emission Sources

a. Summary of Final Amendments

The EPA is finalizing the requirements for natural gas pneumatic devices and pneumatic pumps located in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as proposed. Gathering and boosting reporters will use the same methods for calculating emissions as in the Onshore Petroleum and Natural Gas Production segment. The EPA is also finalizing the requirements for acid gas removal units, dehydrators, and flare stacks as proposed. The methods are the same as the methods for these sources in both the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment. The EPA is also finalizing the requirements for compressors and equipment leaks as proposed, with one clarification regarding how to count ''meters/piping'' for equipment leaks. Gathering and boosting reporters use the same method as in the Onshore Petroleum and Natural Gas Production segment. Specifically, a reporter will need to establish an inventory of the components or equipment subject to the population counts, apply the emission factors, and then update the inventory each year to account for new or retired components or equipment.

b. Summary of Comments and Responses

Comment: Two commenters stated that the major equipment categories for calculating equipment leaks by population count are not clear for the Onshore Petroleum and Natural Gas Gathering and Boosting segment. Both commenters requested that the EPA clarify how to count ''meters/piping'' for the Onshore Petroleum and Natural Gas Gathering and Boosting segment. One commenter also requested clarification regarding separators, compressors, and in-line heaters (specifically, whether small heating systems used to ensure a temperate environment for a meter are considered in-line heaters). The

[7] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. Natural and Other Gas Transmission and Gathering Pipeline Systems: Annual Report for Calendar Year. Form PHMSA F 7100.2–1 (rev 10–2014). OMB No. 2137–0522, Expires: 10/31/2016.

commenter also noted that there was limited time to evaluate the appropriateness of the emission factors in Table W–1A and the component counts in Table W–1B for gathering and boosting systems.

Response: The categories in Table W–1B represent the types of equipment that are generally expected to be found in the field for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities.[8] For the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA realizes that reporters will only use those categories that apply (*e.g.,* reporters will not include wellheads, as that equipment type is specific to Onshore Petroleum and Natural Gas Production facilities).

Most of the major equipment categories are described by function in the rule. For the example of a separator, 40 CFR 98.238 defines a separator as ''a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.'' Any device meeting this functional definition will fall into this major equipment category. Other major categories are described in the rule by their functional role, including dehydrators and compressors. For the in-line heater example for which the commenter requested clarification, the equipment described is not located in line with the fluid flow and therefore would not be considered in this equipment category.

The EPA agrees with both commenters that the measurement of meters/piping in the Onshore Petroleum and Natural Gas Gathering and Boosting segment was not clear as proposed. The final rule specifies that reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should count the number of meters in the facility and use that as the count for ''meters/piping.''

Comment: Two commenters supported the use of calculation methods that include emission factors for the Onshore Petroleum and Natural Gas Gathering and Boosting segment because they are less burdensome to the industry. However, the commenters also requested that the EPA allow reporters the option to use any available data/information that provides the best representation of emissions from their specific sources, including manufacturer data, test data, measurement and/or monitoring data. The commenters compared this option to the approach in state-level emissions inventories that require an emissions reporting hierarchy. The commenters noted that this approach will provide the EPA with more accurate emissions data that could be used to update the emission factors for the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

Response: The calculation methods provided in subpart W were selected to minimize burden on industry while maintaining the necessary quality and consistency of data to inform policy. Therefore, outside of the BAMM provisions being finalized in this rulemaking, the EPA does not agree to allow reporters to use customized, individual information for their emission sources at this time. The EPA is currently investigating additional calculation methods for subpart W sources and may propose additional calculation methods in the future.

C. Summary of Final Amendments for the Onshore Natural Gas Transmission Pipeline Segment

1. Summary of Final Amendments

The EPA is finalizing the proposal to add reporting requirements for emissions from natural gas transmission pipeline blowdowns between compressor stations in a new Onshore Natural Gas Transmission Pipeline segment. Commenters generally had no objections to the merit of including this segment in subpart W but did suggest technical edits and clarifications for targeted provisions. As noted in the preamble to the proposed amendments, a blowdown is the release of gas from transmission pipelines that causes a reduction in system pressure or a complete depressurization. The EPA is clarifying that for the purposes of the Onshore Natural Gas Transmission Pipeline segment, the blowdowns that must be reported are blowdowns of a pipeline or section of pipeline.

The EPA is finalizing clarifications to the proposed definition of onshore natural gas transmission pipeline owner or operator. For interstate pipelines, the onshore natural gas transmission pipeline owner or operator is the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, as proposed. For intrastate pipelines, the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act (NGPA). If the intrastate pipeline is not subject to section 311 of the NGPA, the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers. Finally, the owner or operator of a pipeline that falls under the ''Hinshaw Exemption'' is the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224.

The EPA is finalizing the definition of facility for the new Onshore Natural Gas Transmission Pipeline segment as proposed; the facility is the total U.S. mileage of natural gas transmission pipelines owned or operated by an onshore natural gas transmission pipeline owner or operator. If an owner or operator has multiple pipelines in the United States, the facility is considered the aggregate of those pipelines, even if they are not interconnected.

The EPA is finalizing the requirement that reporters use the methods in 40 CFR 98.233(i) to calculate or measure emissions from pipeline blowdown events as proposed. One method allows a reporter to calculate emissions based on the volume of the pipeline segment between isolation valves that is blown down and the pressure and temperature of the gas within the pipeline. The second method allows the reporter to measure the emissions from the blowdown using a flow meter on the blowdown vent stack. In both methods, the reporter calculates both CH_4 and CO_2 emissions from the volume of natural gas vented using either default gas composition or engineering estimates of composition as specified in 40 CFR 98.233(u)(2)(iii).

The EPA is not finalizing the proposed requirement to report the emissions and location (latitude and longitude) of each blowdown event. Instead, the EPA is requiring that Onshore Natural Gas Transmission Pipeline reporters report the total CH_4 and CO_2 emissions in each state, the number of blowdowns in each state, and the miles of pipeline in each state. In addition, instead of requiring Onshore Natural Gas Transmission Pipeline reporters to use the same equipment and event type categories as other industry segments reporting blowdown emissions, the EPA is including reporting categories specific to the Onshore Natural Gas Transmission Pipeline segment.

[8] See the memorandum ''Equipment-Level Population Emission Factors for Onshore Production,'' Docket Item No. EPA–HQ–OAR–2009–0923–3582, for more information regarding the derivation of this table.

NMED Exhibit 97 - 0014

2. Summary of Comments and Responses

Comment: Several commenters noted that not all intrastate pipelines are subject to section 311 of the NGPA and asked the EPA to clarify which intrastate pipelines are subject to reporting. One commenter requested that the EPA clarify that intrastate pipelines not subject to the NGPA are not required to report under subpart W. Another commenter suggested revising the definition of owner or operator to state that if section 311 of the NGPA does not apply, the intrastate transmission pipeline owner or operator is the owner or operator identified on required reports with the appropriate state agency.

Response: It was our intent to include transmission pipelines (including intrastate pipelines) that meet the already existing subpart W definition of ''transmission pipeline'' in the Onshore Natural Gas Transmission Pipeline segment. A transmission pipeline in subpart W is defined in 40 CFR 98.238 as a Federal Energy Regulatory Commission (FERC) rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the ''Hinshaw Exemption'' as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994). After reviewing the comments on the proposed rule, we re-reviewed section 311 of the NGPA and found that only operators of some intrastate pipelines, including those that transport natural gas on behalf of an interstate pipeline or sell natural gas to an interstate pipeline, are required to prepare a Statement of Operating Conditions for compliance under section 311 of the NGPA. Therefore, to clarify how to determine the owner and operator of intrastate transmission pipelines, the finalized definition of ''onshore natural gas transmission pipeline owner or operator'' specifies that for intrastate transmission pipelines not subject to section 311 of the NGPA, the owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers. The EPA also found that the proposed definition of ''onshore natural gas transmission pipeline owner or operator'' did not specify how to determine the owner or operator of pipelines that fall under the ''Hinshaw Exemption.'' The EPA notes that similar to intrastate pipelines, pipelines that fall under the ''Hinshaw Exemption'' must apply for a ''blanket certificate'' under 18 CFR 284.224 in order to transport petroleum or natural gas on behalf of interstate pipelines. Therefore, the finalized definition of ''onshore natural gas transmission pipeline owner or operator'' also specifies that for a pipeline that falls under the ''Hinshaw Exemption,'' the owner or operator is the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224.

Comment: Commenters appreciated that the EPA provided a threshold of 50 ft^3 of physical volume for blowdown emissions reporting but requested several changes. Commenters requested that the EPA include a list of ancillary equipment, such as metering and/or regulating stations, pipeline interconnects, and pig launchers and receivers, that would be excluded from reporting of blowdown emissions. One commenter suggested that, alternatively, the physical volume threshold could be increased to 3,000 thousand cubic feet to clearly exclude blowdowns of ancillary facilities along the pipeline. Another commenter stated that it is not feasible to establish a specific *de minimis* volume threshold to exclude all ancillary equipment.

Response: The EPA is finalizing the reporting threshold of 50 ft^3 of physical volume for blowdowns in the Onshore Natural Gas Transmission Pipeline segment as proposed. This threshold excludes smaller blowdown sources that have little contribution to emissions, consistent with other industry segments within subpart W that must report blowdown stack vent emissions. The EPA is not increasing the physical volume reporting threshold to account for blowdowns from ancillary equipment, as this would be inconsistent with the EPA's previous analysis in ''Equipment Threshold for Blowdowns'' (see Docket Item No. EPA–HQ–OAR–2009–0923–3581), and commenters were divided on whether increasing the threshold would even address their primary concern.

The EPA agrees that the emphasis for the Onshore Natural Gas Transmission Pipeline segment is on calculating and reporting blowdown emissions from pipeline segments, not ancillary equipment. However, any list of ancillary equipment that would be excluded from blowdown reporting could be incomplete, resulting in reporting of emissions from other equipment that is ancillary but not on the list in the rule. In addition, some of the equipment identified as ''ancillary'' in this segment is not considered ancillary in other industry segments, which could lead to confusion among reporters. Instead, the final rule clarifies that facilities in the Onshore Natural Gas Transmission Pipeline segment report pipeline blowdown emissions from blowdown vent stacks. If the blowdown does not include a pipeline segment or has a physical volume of less than 50 ft^3, then that blowdown is not required to be reported.

Comment: Several commenters stated that the blowdown equipment and event type categories in 40 CFR 98.233(i)(2) were developed for compressor station blowdowns and would not provide meaningful information regarding pipeline blowdowns in the Onshore Natural Gas Transmission Pipeline segment. The commenters provided suggestions for categories that would be more applicable to Onshore Natural Gas Transmission Pipeline blowdowns and would provide more valuable information than relying on the categories in the existing rule.

Response: The EPA agrees with the commenters that the rule should include blowdown categories specific to blowdowns in the Onshore Natural Gas Transmission Pipeline segment. The final rule specifies that blowdowns must be grouped into one of the following categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined by PHMSA, and all other pipeline segments with a physical volume greater than or equal to 50 ft^3.

Comment: Commenters requested that the EPA not finalize the requirement to report latitude and longitude for each blowdown event. The commenters indicated this requirement would be burdensome, such data are not currently collected, the requirement is inconsistent with the Paperwork Reduction Act, and the data would not be useful in determining the inventory. Some commenters also suggested aggregating emissions at the state level or only at the national/facility level.

Response: The requirement to report latitude and longitude of each blowdown was included in the proposed rule to help characterize the emissions from the new Onshore Natural Gas Transmission Pipeline segment on a more granular level than the nationwide facility. The EPA evaluated this comment and has noted the commenters' assertion that the latitude and longitude of each

blowdown is not information currently reported elsewhere and may result in additional burden. Therefore, the EPA is not finalizing the requirement to report the emissions or latitude and longitude for each individual blowdown. Instead, the EPA is finalizing requirements for reporters to aggregate blowdown emissions by state and report the number of blowdowns and mileage of pipeline per state.

Comment: Two commenters questioned the requirement to report the data elements in proposed 40 CFR 98.236(aa)(11). Two commenters noted that the quantities of natural gas in this section are duplicative of information reported to FERC annually in FERC Form 2, although the units of measure are dekatherms rather than thousand standard cubic feet. One commenter noted that for the GHGRP reporting, they would assume 1 dekatherm is equivalent to 1,000 scf of natural gas, based on the approximate heat value of natural gas. The other commenter opposed these reporting requirements because they are duplicative and inconsistent with the requirements of the PRA, which is intended to reduce the information burden imposed by the federal government by requiring that agencies ensure that reported information is not duplicative of other available data and has a practical utility. This commenter stated that the EPA has not followed the PRA. The commenter also stated that the requested information is irrelevant to assisting EPA in verifying pipeline blowdown emissions; in particular, the information cannot be used to calculate pipeline blowdown volumes.

Response: As the EPA has noted elsewhere, the data collected in the GHGRP will be used to inform future policy decisions. As such, information regarding emissions and the inputs needed to verify those emissions is only part of the information that is needed. It is important to understand that, to inform future policy, activity data is often as useful as emissions estimates. The EPA has determined that data elements in 40 CFR 98.236(aa)(11) are activity data that will be used to determine how to use the emissions data to inform future policy decisions. It is essential that reporters provide and certify the data they gather under this rule so that EPA has a complete inventory from all sources under this rule and can directly relate the activity data to the emissions data reported, which will provide for appropriate verification of the emissions data reported.

The EPA agrees with the first commenter that for purposes of reporting the data elements in 40 CFR 98.236(aa)(11), reporters may consider 1 dekatherm equal to 1,000 scf.

Comment: Several commenters asserted that the EPA has not been consistent in its decisions on whether to include pipeline leaks across the subpart W industry segments. Some commenters supported the EPA's proposal not to include leaks from transmission pipelines and noted the decision was consistent with the Onshore Petroleum and Natural Gas Production segment. Conversely, one commenter stated that transmission pipeline leaks should be reported, consistent with the new Onshore Petroleum and Natural Gas Gathering and Boosting segment. This commenter noted that accidental leaks at these facilities can be a significant source of CH_4 emissions, as evidenced by the magnitude of emissions from pipeline incidents reported to PHMSA, and leaks at remote locations may not be noticed or repaired immediately.

Response: The EPA previously considered fugitive emissions that result from leaks in transmission pipelines in the re-proposal of subpart W in April 2010 (75 FR 18616; April 12, 2010) but did not include provisions for these emissions in either the proposed or final rules. The April 2010 preamble explained that the EPA did not propose reporting requirements for fugitive emissions from leaks in natural gas pipeline segments between compressor stations due to the dispersed nature of the fugitive emissions and the fact that, once fugitives are found, the leaks causing the emissions are usually addressed quickly for safety reasons (75 FR 18616; April 12, 2010). The EPA also noted in the proposal preamble for these amendments (79 FR 76267; December 9, 2014) that larger fugitive leaks are currently reported to PHMSA as part of 49 CFR 191.3. Under this provision, any pipeline incident that results in unintentional gas loss of 3 million ft^3 or more must be reported. The commenter that noted that emissions can be significant cited the emissions reported to PHMSA under this provision, and the EPA does not find it necessary to require owners and operators to report this same information under the GHGRP. The focus of the PHMSA reporting requirements is to identify major safety-related incidents that are not a part of typical operations. Therefore, the EPA is not finalizing a requirement to report fugitive emissions from transmission pipeline leaks but will continue to review this source as part of the EPA's ongoing effort to ensure comprehensive, high quality data in subpart W.

D. Summary of Final Amendments for Well Identification Numbers

1. Summary of Final Amendments

The EPA is finalizing some of the proposed amendments to 40 CFR 98.236 to add reporting requirements for well identification numbers to improve data quality by enabling identification of wells. These well identification numbers will be reported for the first time in the report covering 2016 emissions; reporters will not be required to report well identification numbers for previous years. For the majority of wells, the well identification number reported will be the US Well Number (formerly referred to as the API Well Number, or API Number).[9] For any well that does not already have a US Well Number, the reporter will be required to provide the unique well number assigned by the permitting authority for drilling of oil and gas wells. Commenters varied in their level of support for the proposed provisions regarding well identification numbers. The EPA is adjusting the final provisions in response to concerns about these reporting provisions raised in comments.

The EPA is requiring the reporting of well identification numbers for the Onshore Petroleum and Natural Gas Production segment only for information related specifically to wells. For reporters in the Onshore Petroleum and Natural Gas Production segment that report emissions using input data that are calculated from measurements at individual wells or equipment associated with individual wells (*e.g.,* if Equation W–10A was used to calculate emissions from oil well completions and workovers with hydraulic fracturing, well testing emissions), the report must include the well identification number for which those measurements were made and the well identification number(s) of other wells to which the measurements will be applied. This includes a list of the well identification numbers by sub-basin for the producing wells at the end of the calendar year as well as lists of the well identification numbers for the wells acquired, divested, completed, and permanently taken out of production during the calendar year. The EPA is not finalizing the proposed requirement that reporters in the Onshore Petroleum and Natural Gas Production segment report a list of well identification numbers associated with different emission

[9] The Professional Petroleum Data Management Association. *The US Well Number Standard: An Identifier for Petroleum Industry Wells in the USA.* Version 2013 rev 1, published June 19, 2014. Available at *http://dl.ppdm.org/dl/1147.*

sources for all wells in a sub-basin included in the reported emissions data.

The EPA is finalizing the proposed change to update references to the ''API well number'' in subpart W to ''well identification number.'' The EPA is not otherwise changing the well identification reporting requirements finalized in 2014 (79 FR 70352; November 25, 2014). Reporters will still need to report well identification numbers for liquids unloading and for any exploratory wells for which reporting has been delayed for 2 years.

2. Summary of Comments and Responses

Comment: While one commenter supported the addition of well identification number reporting, most commenters opposed the proposal to require reporting of well identification numbers. These commenters asserted that requiring reporting of well identification numbers is an overreach of the EPA's authority for the reporting program under CAA section 114 and that the EPA has not provided a reasoned basis for the departure from the previous EPA approach that well-specific data was not necessary under Subpart W. Commenters also noted that well identification numbers are not needed to validate reported emissions. One commenter noted that the EPA has not questioned the data collected from wells thus far; nor has the EPA stated that the data already collected are insufficient to inform policy without addition of well identification numbers, so with this proposal, the EPA is no longer balancing data collection with reporting burdens. Commenters stated that mapping and maintaining a database of well identification numbers is more burdensome than the EPA estimated, and one commenter stated that it would be arbitrary and capricious to require companies to expend the resources necessary to report these data. Commenters also noted that it is not clear how to interpret the term ''associated with'' in all cases. One commenter stated that matching specific wells with emissions in the GHGRP could cause security concerns.

Response: The EPA disagrees that requiring reporting of well identification numbers is an overreach of our authority. The EPA has determined that these data elements are useful and necessary for the verification of existing data and for characterizing the emissions from the industry segment. This final revision will allow the EPA to link the GHGRP data to other databases (*i.e.* state permitting databases) to more easily match the data reported under the GHGRP with other data sources and will improve the accuracy and transparency of subpart W. Additionally, being able to match the GHGRP data to other data sources will provide the EPA with more options for analysis of the GHGRP data to better inform future policy decisions related to GHG emissions from the oil and natural gas production sector. The reporting of the well identification numbers will also allow the EPA to assess the completeness and representativeness of the data collected under the GHGRP as a portion of all activity in the oil and natural gas production sector. The EPA reiterates that CAA section 114 provides the EPA with the authority to collect emissions data, which includes information about the location of the source of emissions. Section 114 generally authorizes the EPA to gather information from any person who owns or operates an emissions source, who is subject to a requirement of the CAA, who manufactures control or process equipment, or who the Administrator believes has information necessary for the purposes of section 114(a). The EPA may gather information for purposes of establishing implementation plans or emissions standards, determining compliance, or ''carrying out any provision'' of the CAA. For these reasons, the Administrator may request that a person, on a one-time, periodic or continuous basis, establish and maintain records, make reports, install and operate monitoring equipment and, among other things, provide such information the Administrator may reasonably require. This language has been interpreted to grant the EPA broad authority. See, *e.g.,* Dow Chemical Co. v. U.S., 467 U.S. 227, 233 (1986) (''Regulatory and enforcement authority generally carries with it all modes of inquiring and investigation traditionally employed or useful to execute the authority granted.''). See, generally *Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Volume No.: 9, Legal Issues* (Docket Item No. EPA–HQ–OAR–2008–0508–2264). The requirement to report well identification numbers for well-specific data clearly fits within EPA's statutory authority. We also believe, for the reasons stated above, that we are exercising this authority reasonably in furtherance of the purposes of the Clean Air Act. Further, the EPA disagrees that this is a deviation from our previous approach to collecting data. As discussed in section II.B of this preamble, the EPA is finalizing the requirement to report Onshore Petroleum and Natural Gas Gathering and Boosting facilities at the basin-level, which is consistent with our previous approach to the Onshore Petroleum and Natural Gas Production segment.

Therefore, the EPA is finalizing the requirements to report the well identification number for well-specific data as proposed. Specifically, for reporters in the Onshore Petroleum and Natural Gas Production segment that report emissions using input data that are calculated from measurements at individual wells or equipment or operations associated with individual wells (*e.g.,* if Equation W–10A is used to calculate emissions from oil well completions and workovers with hydraulic fracturing, well testing emissions, liquids unloading), the report must include the well identification number for which those measurements were made, or for which the equipment or operations are associated. In addition, the EPA is finalizing the requirements in 40 CFR 98.236(aa)(1)(ii)(D) through (H) to include a list of the well identification numbers by sub-basin for the producing wells at the end of the calendar year and lists of the well identification numbers for the wells acquired, divested, completed, and permanently taken out of production during the calendar year. The EPA continues to expect that this is a low burden to reporters because reporters already track and maintain well identification numbers associated with measurements used for the GHGRP input data.

To respond to the comment that well identification numbers may not be available for or assigned to equipment other than wells, the EPA reviewed the permits and requirements in seven different states. Although most of the states assign unique identifiers to each emission source, the EPA found that only two of the seven states have a tracking system that links individual emission sources to specific wells and well identification numbers, and these two states are not consistent in their approach. (See ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule'' in Docket ID No. EPA–HQ–OAR–2014–0831 for more information on this analysis.) While it may be straightforward to assign some emission sources directly to one well, particularly if there is only one well on the single well pad and the reporter does not operate any other wells nearby, the EPA's review of state requirements shows that there may be multiple scenarios in which a reporter does not know which well or wells are associated with a particular emission source. For

example, there may be multiple wells on a single well pad and multiple storage tanks associated with that well pad, and the tanks may have the ability to receive hydrocarbon liquids from several of those wells. Therefore, in light of the potential burden of requiring facilities to develop new tracking systems that would assign and track emissions to well identification numbers for the purposes of part 98, the EPA is not requiring facilities in this rulemaking to report well identification numbers for every emission source in a facility in the Onshore Petroleum and Natural Gas Production segment.

E. Summary of Final Amendments to Best Available Monitoring Methods

1. Summary of Final Amendments

As proposed, reporters will be allowed to use BAMM for the 2016 reporting year for the new industry segments and emission sources included in this action. These include calculating and reporting emissions from oil well completions and workovers with hydraulic fracturing, from onshore petroleum and natural gas gathering and boosting systems, and for transmission pipeline blowdown emissions. Reporters are allowed to use BAMM to estimate inputs to emission equations for the newly finalized emission sources for cases where the monitoring of these inputs would not be possible beginning on January 1, 2016. The use of BAMM is not allowed for the reporting of well identification numbers because reporters should already have well identification numbers readily available for all wells and associated equipment to which this reporting requirement applies and because the well identification number is not a parameter that requires monitoring equipment to be measured and, therefore, does not meet the requirements for BAMM.

For these sources, the EPA is finalizing a longer timeline for BAMM than was proposed. Reporters have the option of using BAMM for the new industry segments and emission sources included in this action from January 1, 2016, to December 31, 2016, without seeking prior EPA approval. The provision providing a set amount of automatic transitional BAMM will allow reporters to prepare for data collection while automatically being able to use BAMM, which is consistent with the approach of prior part 98 rulemakings. This additional time for reporters to comply with the revised monitoring methods in subpart W will allow facilities to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions, and is responsive to comments received on the proposed rule provisions.

The EPA is not finalizing the proposed provision to allow reporters the opportunity to request an extension for the use of BAMM. The EPA will not accept requests for an extension for the use of BAMM beyond the time periods listed above. As proposed, the EPA also is not providing transitional BAMM for these new requirements beyond December 31, 2016.

The EPA is not allowing the use of BAMM beyond 2016 and does not anticipate that BAMM will be needed beyond 2016 for the new segments and emissions sources being finalized in this rule.

2. Summary of Comments and Responses

Comment: Several commenters stated that only 3 months of automatic BAMM and 1 year of transitional BAMM is not enough time to implement the monitoring and measurement requirements for facilities newly subject to subpart W and newly added emission sources. The commenter stated that adding a new segment is a significant amendment and the EPA has set the precedent of providing at least 1 year of automatic BAMM when adding a new segment to subpart W. The commenters noted that not all gathering and boosting reporters are already reporting as Onshore Petroleum and Natural Gas Production facilities, so they will not necessarily all be familiar with the monitoring and calculation methodologies. The commenters also noted that nearly all reporters will be spending the first month working on BAMM requests for the rest of 2016.

The commenters had a variety of suggestions for how long the EPA should provide BAMM for these new emission sources. Several commenters suggested 1 year (through the end of 2016) for automatic BAMM. Another commenter suggested March 31, 2017 (*i.e.,* 1 year in addition to the EPA's proposed 3 months), and another stated that 3 years would be consistent with the length of time provided when the Onshore Petroleum and Natural Gas Production segment was added to subpart W. Some commenters addressed the length of transitional BAMM with the EPA's approval. One commenter noted that a new reporter/facility could become subject to one of the new segments beyond the end of 2016, so there should be no deadline for submitting a request for BAMM to the EPA. Another requested transitional BAMM through the end of 2018.

Response: The EPA recognizes that most of the amendments being finalized in this rulemaking are new requirements rather than clarifications of existing reporting requirements for facilities already subject to subpart W and may require the development and implementation of new systems of data collection and monitoring. Therefore, the EPA is finalizing 1 year of automatic transitional BAMM in place of the proposed 3 months of automatic transitional BAMM. This additional time for reporters to comply with the revised monitoring methods in subpart W will allow facilities to install the necessary monitoring equipment and implement any new systems of data collection that may be required. Because the amount of time for which automatic BAMM is available should be sufficient time to comply with the requirements of subpart W for the new segments and emission sources, the EPA will not provide additional BAMM beyond the automatic BAMM provisions in 40 CFR 98.234(g).

We note that 40 CFR 98.235(e) and(f) provides 6 months of reporting flexibility for facilities that become subject to subpart W or acquire new sources after reporting year 2016. Reporters may also refer to the provisions of 40 CFR 98.235 after reporting year 2016 for guidance on reporting emissions if certain required data are not collected.

III. Confidentiality Determinations

A. Summary of Final Confidentiality Determinations for New Subpart W Data Elements

In the proposed rule, we assigned new data elements to the appropriate direct emitter data categories created in the 2011 Final CBI Rule based on the type and characteristics of each data element.[10] For data elements the EPA assigned to a direct emitter category with a categorical determination, the EPA proposed that the categorical determination for the category be applied to the proposed new data element. For data elements assigned to the ''Unit/Process 'Static' Characteristics that Are Not Inputs to Emission Equations'' and ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' we proposed confidentiality determinations on a case-by-case basis taking into

[10] ''Confidentiality Determinations for Data Required Under the Mandatory Greenhouse Gas Reporting Rule and Amendments to Special Rules Governing Certain Information Obtained Under the Clean Air Act'' (76 FR 30782, May 26, 2011).

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consideration the criteria in 40 CFR 2.208, consistent with the approach used for data elements previously assigned to these two data categories. We also proposed individual confidentiality determinations for six new data elements without making a data category assignment. Refer to the preamble to the proposed rule (79 FR 76267; December 9, 2014) for additional information regarding the proposed confidentiality determinations.

With consideration of the data provided by commenters, the EPA is finalizing the confidentiality determinations as proposed. Specifically, the EPA is finalizing the proposed decision to require each of the new data elements to be designated as ''not CBI.''

The EPA proposed to provide reporters with the option to delay reporting of five data elements for 2 reporting years in situations where exploratory wells are the only wells in a sub-basin. We received comment requesting that the EPA provide the same 2-year delay for additional data elements associated with exploratory wells. The comment and the EPA's response are included in section III.B of this preamble. Based on consideration of the comment and consistent with the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014), the EPA is finalizing provisions to provide reporters with the option to delay reporting of five data elements as proposed and, based on comments received, an additional two data elements for 2 reporting years in situations where exploratory wells are the only wells in a sub-basin. For a given sub-basin, in situations where wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the required measurement, the following seven data elements associated with the delineation or wildcat well may be delayed for 2 reporting years: (1) The cumulative gas flowback time, in hours, for each sub-basin, from when gas is first detected until sufficient quantities are present to enable separation (40 CFR 98.236(g)(5)(i)); (2) the cumulative flowback time, in hours, for each sub-basin, after sufficient quantities of gas are present to enable separation (40 CFR 98.236(g)(5)(i)); (3) the measured flowback rate, in standard cubic feet per hour, for each sub-basin (40 CFR 98.236(g)(5)(ii)); (4) the gas to oil ratio for the well (40 CFR 98.236(g)(5)(iii)(A)); (5) the volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing (40 CFR 98.236(g)(5)(iii)(B)); (6) the total annual gas-liquid separator oil volume that is sent to applicable onshore storage tanks, in barrels (40 CFR 98.236(j)(1)(iii)); and (7) the total annual oil throughput that is sent to all atmospheric tanks, in barrels (40 CFR 98.236(j)(2)(i)(A).

Four of the seven data elements for which reporting may be delayed by 2 years are inputs to emission equations and the EPA provided the same option in the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014). Two of the seven data elements are inputs only when the applicable data are related to a single well (the two data elements in 40 CFR 98.236(g)(5)(i)), and one data element is never an input (40 CFR 98.236(j)(2)(i)(A)). Where the EPA agrees that there are early disclosure concerns related to exploratory wells, the EPA decided to treat those early disclosure concerns consistently throughout subpart W by providing the option to delay reporting by 2 years to all seven data elements listed above.

At proposal, in cases where the two data elements in 40 CFR 98.236(g)(5)(i)) are not inputs to equations, they were assigned to the ''Unit/Process Operating Characteristics that are Not Inputs to Emission Equations'' category and were proposed to be ''not CBI.'' The EPA is finalizing this determination as proposed. Specifically, the ''not CBI'' determination applies to all situations except for when the data elements are inputs to equations.

For the situations when the data elements are used as inputs to equations, the EPA is assigning them to the ''Inputs to Emission Equations'' data category and is not making confidentiality determinations for these data. The EPA evaluated and summarized any potential disclosure concerns with the reporting of the data elements assigned to the ''Inputs to Emission Equations'' data category in the memo titled ''Review for Potential Disclosure Concerns for Inputs to Emission Equations Affected by the 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' available in Docket ID No. EPA–HQ–OAR–2014–0831. Other than the exception of the early disclosure concerns for certain data elements related to exploratory wells discussed earlier in this section, the EPA has concluded that there are no disclosure concerns with the reporting of these data elements.

The data element collected under 40 CFR 98.236(j)(2)(i)(A) was proposed as ''not CBI'' and was not assigned to a data category. The EPA is finalizing this determination as proposed as well. For the data elements reported under 40 CFR 98.236(g)(5)(i)) (in cases where they are not inputs to equations) and 40 CFR 98.236(j)(2)(i)(A), the ''not CBI'' determinations will apply once the data are reported to the EPA following the 2-year delay.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed categorical assignments and confidentiality determinations. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and responses. See the memorandum ''Final Data Category Assignments and Confidentiality Determinations for Data Elements (excluding inputs to emission equations) in the 'Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of final data category assignments and confidentiality determinations, and a discussion of changes since proposal.

Comment: One commenter requested that the EPA reconsider the determination that the quantity of produced gas throughput in the calendar year and the quantity of produced gas consumed by the facility in the calendar year are ''not CBI.'' The commenter noted that the quantity of natural gas received and the quantity of processed gas leaving processing plants was maintained as CBI in the 2014 amendments (79 FR 70352; November 25, 2014). The commenter also stated that information on fuel consumed at gathering and boosting facilities is not typically publically available, and when this information is combined with the quantity of produced gas throughput, it directly indicates the fuel efficiency of a station. The commenter noted that while the EPA is correct that the agreements are long-term for a given well, revealing information about one facility's fuel efficiency could cause competitive harm by affecting contracts for other facilities owned by that company, especially if there are smaller gathering and boosting facilities in the area that do not have to report this information to the GHGRP.

The commenter also requested that the EPA clarify a number of the reporting elements in 40 CFR

98.236(aa)(10). Specifically, the commenter requested clarification of the terms ''produced gas,'' ''produced condensate,'' ''produced oil,'' ''throughput,'' and ''consumed'' as they are used in proposed 40 CFR 98.236(aa)(10). The commenter also asserted that the data element in 40 CFR 98.236(aa)(10)(ii) (''quantity of produced gas consumed'') would be redundant with subpart C and should not be finalized. Finally, the commenter stated that the requirement to report the ''quantity of gas flared, vented and/or unaccounted for in the calendar year'' in 40 CFR 98.236(10)(aa)(v) would undermine over 5 years of rule development, public comment, reconsiderations, and petitioner negotiations because it would require reporting of emissions that are otherwise exempted (*e.g.,* blowdowns below 50 ft^3).

Response: The EPA reviewed these comments and has clarified the reporting elements in 40 CFR 98.236(aa)(10) for the final rule. The final reporting requirements include: (1) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet; (2) the quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet; (3) the quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels; and (4) the quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels. The EPA has determined that these quantities will be easily accessible for all reporters and are more consistent with the reporting requirements for the Onshore Natural Gas Processing segment. The EPA is finalizing the CBI determinations for these quantities as ''not CBI,'' as proposed.

The final reporting requirements do not include the terms ''produced gas,'' ''produced condensate,'' ''produced oil,'' ''throughput,'' or ''consumed,'' so no clarification regarding the use of those terms is needed. In particular, the final rule does not include a requirement to report the quantity of produced gas consumed by the facility. The difference between the quantities received by a gathering and boosting facility and the quantities exiting the gathering and boosting facility is expected to include the quantity of gas consumed by the facility as well as the quantity of gas flared or vented in one lump sum. Therefore, the reporting requirements do not directly indicate the fuel efficiency of the stations in a gathering and boosting facility.

Comment: One commenter reiterated previously stated concerns over the disclosure of information for exploratory wells, especially when they are located in stepout areas where no prior reporting exists for a given sub-basin. The commenter supported the EPA's proposal to defer reporting of data elements related to oil well completions and workovers with hydraulic fracturing for exploratory wells, but expressed concern that EPA has not provided such a delay in reporting for all emissions data and data elements that are associated with exploratory wells. Specifically, the commenter stated that the EPA failed to provide a necessary 2-year deferral in reporting for the following data elements, which are as business sensitive and confidential as the other information for which the EPA proposed to defer reporting for 2 years:

- 40 CFR 98.236(g)(5)(iii)(A)—If you used Equation W–12C to calculate the average gas production rate for an oil well, the gas to oil ratio for the well in standard cubic feet of gas per barrel of oil.
- 40 CFR 98.236(g)(5)(iii)(B)—If you used Equation W–12C to calculate the average gas production rate for an oil well, the volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels.
- 40 CFR 98.236(g)(6)(i)—If you used Equation W–10B to calculate annual volumetric total gas emissions for completions that vent gas to the atmosphere, the vented natural gas volume, in standard cubic feet, for each well in the sub-basin.
- 40 CFR 98.236(g)(6)(ii)—If you used Equation W–10B to calculate annual volumetric total gas emissions for completions that vent gas to the atmosphere, the flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin.
- 40 CFR 98.236(g)(7)—For each oil well completion or workover and well type combination, annual gas emissions.
- 40 CFR 98.236(g)(8)—For each oil well completion or workover and well type combination, annual CO_2 emissions.
- 40 CFR 98.236(g)(9)—For each oil well completion or workover and well type combination, annual CH_4 emissions.
- 40 CFR 98.236(g)(10)—For each oil well completion or workover and well type combination, the total N_2O emissions, if the well emissions were vented to a flare.

Response: The EPA reviewed the data elements identified by the commenter as having disclosure concerns for exploratory wells (delineation wells and wildcat wells). Consistent with the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014), the EPA has determined that, for gas well completions or workovers with hydraulic fracturing of wildcat wells and/or delineation wells, early public disclosure of some of the additional data elements identified by the commenter could reveal the well productivity of wildcat wells and/or delineation wells, thereby resulting in the loss of investment value.

The additional data elements that could reveal well productivity for wildcat and/or delineation wells are as follows:

- The gas to oil ratio for the well (40 CFR 98.236(g)(5)(iii)(A))
- The volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing (40 CFR 98.236(g)(5)(iii)(B))

As the EPA has previously noted (79 FR 70352, November 25, 2014), in the interim period before these data are reported to the EPA, the EPA will be able to verify the majority of the emissions using data elements that will be reported to the EPA. For the seven total data elements that may be delayed for 2 years, the EPA will verify emissions using other data reported to the EPA, and will conclude verification upon receipt of the data. The EPA agrees with the commenter that a 2-year delay of reporting is sufficient to prevent early public disclosure of these data and will provide sufficient time for the reporter to thoroughly conduct an assessment of the well. Given the results of this evaluation, the EPA determined that, for these data elements, in those cases where delineation wells or wildcat wells are the only wells in a sub-basin, reporters should be provided an option to delay reporting of the given data element for 2 reporting years starting in 2015. In such cases, if the 2-year delay in reporting is used, the reporter must indicate for each delayed reporting element that wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the measurement in the current reporting year. In addition, when reporters report the delayed data elements after the 2-year delay, they must also report the well identification numbers for the applicable wildcat and/or delineation wells in the sub-basin for which the reporting element was delayed. For example, if a delineation or wildcat well is completed in 2015 in a sub-basin that

has only delineation or wildcat wells or these are the only wells for which measurements can be made, then the reporter may: (1) Elect to report these seven data elements in their 2016 annual report submitted by March 31, 2017, or (2) elect to delay reporting of these data elements for up to 2 years. If the reporter elects to delay reporting, then the well identification numbers for the wildcat and delineation wells in the sub-basin for which reporting has been delayed and the data elements delayed from reporting must be reported no later than March 31, 2019.

The following inputs meet the definition of emission data in 40 CFR 2.301(a)(2)(i) because they indicate the amount or frequency of gas emitted by the facility: Volume of natural gas vented (reported under 40 CFR 98.236(g)(6)(i)) and flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation (reported under 40 CFR 98.236(g)(6)(ii)). Without corresponding activity data, such as a count of the exploratory wells in a sub-basin or production or flow rate data for a sub-basin containing only exploratory wells, there is no potential to disclose business sensitive information based on these data elements. Therefore, the EPA is not providing an option to delay reporting of these data elements for 2 reporting years.

Similarly, the data element annual gas emissions (reported under 40 CFR 98.236(g)(7)) meets the definition of emission data in 40 CFR 2.301(a)(2)(i) and is assigned to the ''Emissions'' data category because it indicates the amount of gas emitted by the facility. In addition, the following data elements meet the definition of emission data in 40 CFR 2.301(a)(2)(i) and are assigned to the ''Emissions'' data category because they are emissions of pollutants emitted by the source: annual CO_2 emissions (reported under 40 CFR 98.236(g)(8)), annual CH_4 emissions (reported under 40 CFR 98.236(g)(9)), and annual nitrous oxide (N_2O) emissions if the well emissions were vented to a flare (reported under 40 CFR 98.236(g)(10)). For these data elements that are assigned to the ''Emissions'' data category, the commenter did not claim or provide any justification for why these data elements do not meet the definition of emission data. Without corresponding activity data, such as a count of the exploratory wells in a sub-basin or production or flow rate data for a sub-basin containing only exploratory wells, there is no potential to disclose business sensitive information based on these data elements. Therefore, the EPA is not providing an option to delay reporting of these data elements for 2 reporting years.

IV. Impacts of the Final Amendments to Subpart W

A. Impacts of the Final Amendments

The final amendments to subpart W add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. The EPA is adding 213 new data elements to the reporting requirements. The new data elements impose additional burden and costs because, for each of the new data elements that are required to be reported, reporters are required to calculate the data element using readily available data and report the value to the EPA via e-GGRT as part of the annual report currently required under part 98.

The EPA calculated the increase in reporting and recordkeeping burden associated with the new data elements by adjusting labor hours upwards per reporter for all affected industry segments. For all three segments, an estimate of 10 hours per year per reporter was allotted for reporting via e-GGRT and 10 hours per year per reporter was allotted for recordkeeping.

Costs to reporters associated with this rulemaking are expressed as labor costs (*i.e.,* the cost of labor by facility staff to comply with the amendments), capital costs for equipment and travel, and operation and maintenance (O&M) costs.

Reporters in the Onshore Petroleum and Natural Gas Production segment have to monitor and report emissions and data elements associated with oil well completions and workovers with hydraulic fracturing. Reporters in this segment also have to report the well identification numbers associated with individual oil and gas wells. The addition of the requirement to report emissions associated with oil well completions and workovers with hydraulic fracturing is expected to cause an increase in the amount of emissions that count towards determining applicability under subpart W. The addition of reporting requirements for oil wells with hydraulic fracturing is expected to affect 246 existing reporters and to cause approximately 50 new reporters to exceed the reporting threshold for the onshore petroleum and natural gas production facility. These numbers have not changed from proposal.

The 50 new reporters will be required to estimate and report emissions data and related data elements associated with several different emission sources within this new industry segment, including acid gas removal units, associated natural gas venting and flaring, storage tanks, dehydrators, equipment leaks, liquids unloading, and pneumatic devices.

Reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment must estimate and report emissions data and related data elements associated with several different emission sources within this new industry segment, including acid gas removal units, storage tanks, blowdown vents, dehydrators, equipment leaks, flare stacks, and pneumatic devices. Approximately 200 new reporters are expected to be subject to subpart W due to the amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in this rulemaking. This number has not changed from proposal.

Reporters in the Onshore Natural Gas Transmission Pipeline segment will need to estimate and report emissions data and related data elements associated with transmission pipeline blowdown activities. Approximately 183 new reporters in this segment are expected to be subject to subpart W. This number increased from 150 to 183 since proposal due to public comment.

The EPA received multiple comments regarding the impacts of the proposed amendments. After evaluating these comments and reviewing other changes from proposal, the EPA revised the impacts assessment slightly from proposal. The final amendments to subpart W are not expected to significantly change the burden calculated at proposal.

The EPA has determined that the cost associated with this final action will be $7,190,235 each year and has worked to minimize burden to reporters where practicable. See the memorandum, ''Assessment of Impacts of the 2015 Final Revisions to Subpart W'' in Docket ID No. EPA–HQ–OAR–2014–0831 for additional information.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the impacts of the proposed amendments to subpart W of part 98. We note that numerous commenters asserted that the burden was underestimated, and some provided suggestions for improvement, but most of those comments did not include the detailed information the EPA needed to assess the comment

fully, such as a suggestion for a revised burden estimate, support for the suggestion, and an explanation of why the suggested value is representative of all sources subject to the same requirements. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and responses.

Comment: One commenter asked for an explanation for the estimate of 200 respondents in the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The commenter noted that the EPA estimated the number of reporters in the Onshore Natural Gas Processing industry segment as 291 reporters. The commenter stated by the nature of the industry, any company with a processing plant will most likely also have an associated gathering system subject to reporting and suggested that the number of reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment should total 291, at minimum, but potentially more.

Response: Due to differences in the definitions of the two industry segments, the EPA disagrees that the number of reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should match the number of reporters in the Onshore Natural Gas Processing segment. The EPA estimate of 200 respondents was based on the regulatory analysis for Office of Pipeline Safety (OPS) safety regulations. In the analysis, it was estimated that 50 percent of the 400 natural gas gathering pipeline operators under regulation are small entities operating small diameter, low pressure (Type B) gathering lines and fifty percent are large diameter, high pressure lines (Type A) potentially subject to the safety regulation (depending upon proximity to population centers).[11]

Comment: One commenter noted that the EPA estimated that there are 150 reporters for Onshore Natural Gas Transmission Pipeline facilities at proposal. However, the commenter stated that the EPA should expect 183 reporters in the segment based on the number of operators that are required to complete a PHMSA annual report (PHMSA F–7100–2) or are regulated by FERC under section 311 of the NGPA.

Response: The EPA agrees with the suggested change. The preamble to the final amendments, the final Supporting Statement, and the memorandum ''Assessment of Impacts of the 2015 Final Revisions to Subpart W'' (see Docket ID No. EPA–HQ–OAR–2014–0831) have been updated to reflect the change from 150 reporters to 183 reporters in the Onshore Natural Gas Transmission Pipeline segment.

Comment: Two commenters objected to the collection of well identification numbers. One commenter noted that collection would require significant resources and would be unduly burdensome on operators. The other commenter stated that the burdens associated with collecting and reporting this data far outweigh any minimal benefits in data quality.

Response: The EPA is finalizing the well identification number reporting requirements for well-specific data as proposed, but the EPA is not requiring well identification numbers to be reported in this rulemaking for equipment other than wells. See section II.D of this preamble for additional discussion responding to this comment.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

In addition, the EPA prepared an analysis of the potential costs associated with the final amendments to subpart W. This analysis is contained in the memorandum ''Assessment of Impacts of the 2015 Final Revisions to Subpart W.'' A copy of the analysis is available in the docket for this action (see Docket ID No. EPA–HQ–OAR–2014–0831) and the analysis is briefly summarized in section IV of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2300.16. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This action adds monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. Data collection complements the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) and provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments. The data can be used to complement atmospheric GHG studies and inform updates to emission inventories. Various activity data are collected that can be used to improve understanding of the occurrence of emissions from a variety of sources.

Data collected must be made available to the public unless the data qualify for CBI treatment under the CAA and EPA regulations. All data determined by the EPA to be CBI are safeguarded in accordance with regulations in 40 CFR chapter 1, part 2, subpart B.

Respondents/Affected Entities: The respondents in this information collection include owners and operators of petroleum and natural gas systems facilities that must report their GHG emissions to the EPA to comply with subpart W of part 98.

Respondent's Obligation To Respond: The respondent's obligation to respond is mandatory under the authority provided in CAA section 114.

Estimated Number of Respondents: Approximately 3,300 respondents per year.

Frequency of Response: Annual.

Total Estimated Burden: 317,100 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total Estimated Cost: $29.2 million (per year), includes $1.1 million annualized capital and 2.8 million operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities

[11] U.S. Department of Transportation. Pipeline and Hazardous Materials Safety Administration. *Draft Regulatory Evaluation, Regulated Natural Gas Gathering Lines, Regulatory Analysis,* Docket RSPA–1998–4868. Available at *www.viadata.com/pipeliner/library_docs/Gatheringanalysis.pdf.*

subject to the requirements of this action are: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

The Agency has determined that a few small businesses may experience an insignificant impact. Details of this analysis are presented in section IV.B of the preamble to the proposed amendments (79 FR 76267; December 9, 2014).

Although this final rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless has tried to reduce the impact of this rule on small entities. As part of the process of finalizing the subpart W 2010 final rule, the EPA took several steps to evaluate the effect of the rule on small entities. For example, the EPA determined appropriate thresholds that reduced the number of small businesses reporting. In addition, the EPA supports a ''help desk'' for the rule, which is available to answer questions on the provisions in the rule. Finally, the EPA continues to conduct significant outreach on the GHG reporting rule and maintains an ''open door'' policy for stakeholders to help inform the EPA's understanding of key issues for the industries.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This regulation will apply directly to petroleum and natural gas facilities that emit GHGs. Although few facilities that will be subject to the rule are likely to be owned by tribal governments, the EPA has sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final subpart W that was promulgated on November 30, 2010 (75 FR 74458).

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in section IV.F of the preamble to the re-proposal of subpart W published on April 12, 2010 (75 FR 18608), and section IV.F of the preamble to the subpart W 2010 final rule published on November 30, 2010 (75 FR 74458).

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks, that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risks.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will **not** have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because it does not affect the level of protection provided to human health or the environment. Instead, this rule addresses information collection and reporting procedures.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Reporting and recordkeeping requirements.

Dated: October 1, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 1. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart W—Petroleum and Natural Gas Systems

■ 2. Section 98.230 is amended by adding paragraphs (a)(9) and (10) to read as follows:

§ 98.230 Definition of the source category.

(a) * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR) less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil

here refers to hydrocarbon liquids of all API gravities).

(10) *Onshore natural gas transmission pipeline.* Onshore natural gas transmission pipeline means all natural gas transmission pipelines as defined in § 98.238.

* * * * *

■ 3. Section 98.231 is amended by revising paragraph (a) to read as follows:

§ 98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of § 98.2(a)(2), except for the industry segments in paragraphs (a)(1) through (4) of this section.

(1) Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year.

(2) Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(3) Facilities must report emissions from the onshore petroleum and natural gas gathering and boosting industry segment only if emission sources specified in § 98.232(j) emit 25,000 metric tons of CO_2 equivalent or more per year.

(4) Facilities must report emissions from the onshore natural gas transmission pipeline industry segment only if emission sources specified in § 98.232(m) emit 25,000 metric tons of CO_2 equivalent or more per year.

* * * * *

■ 4. Section 98.232 is amended by:
■ a. Revising paragraphs (a) and (c)(6) and (8);
■ b. Adding paragraph (j);
■ c. Revising paragraph (k); and
■ d. Adding paragraph (m).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (j) and (m) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

* * * * *

(c) * * *

(6) Well venting during well completions with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

* * * * *

(8) Well venting during well workovers with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

* * * * *

(j) For an onshore petroleum and natural gas gathering and boosting facility, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Natural gas pneumatic device venting.

(2) Natural gas driven pneumatic pump venting.

(3) Acid gas removal vents.

(4) Dehydrator vents.

(5) Blowdown vent stacks.

(6) Storage tank vented emissions.

(7) Flare stack emissions.

(8) Centrifugal compressor venting.

(9) Reciprocating compressor venting.

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(11) Gathering pipeline equipment leaks.

(12) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas gathering and boosting facility as defined in § 98.238. Stationary or portable equipment includes the following equipment, which are integral to the movement of natural gas: Natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section. Onshore petroleum and natural gas gathering and boosting facilities must report stationary and portable combustion emissions as specified in paragraph (j) of this section.

* * * * *

(m) For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks.

■ 5. Section 98.233 is amended by:
■ a. Revising the parameters ''EF_t'' and ''GHG_i'' of Equation W–1 in paragraph (a);
■ b. Revising paragraph (a)(2);
■ c. Revising the parameter ''EF'' of Equation W–2 in paragraph (c);
■ d. Revising paragraph (d)(8)(iii);
■ e. Revising paragraphs (g) introductory text, (g)(1) introductory text, (g)(1)(i), and paragraph (g)(1)(ii) heading;
■ f. Revising the parameters ''FRM_s,'' ''$FR_{s,p}$'' and ''$PR_{s,p}$'' of Equation W–12A in paragraph (g)(1)(iii);
■ g. Revising the parameters ''$FRM_{i,}$'' and ''$PR_{s,p}$'' of Equation W–12B in paragraph (g)(1)(iv);
■ h. Revising paragraphs (g)(1)(v) and (vi);
■ i. Adding paragraph (g)(1)(vii);
■ j. Revising paragraph (g)(2) introductory text;
■ k. Adding paragraph (g)(2)(iv);
■ l. Revising paragraph (g)(4) introductory text;
■ m. Revising paragraph (i)(2) introductory text;
■ n. Revising the parameters ''T_a'' and ''P_a'' of Equation W–14A in paragraph (i)(2)(i);
■ o. Revising paragraphs (j) introductory text, (j)(1) through (3), and (j)(6);
■ p. Revising paragraph (n)(2)(i);
■ q. Revising paragraphs (o) introductory text and (o)(10);
■ r. Revising paragraphs (p) introductory text and (p)(10);
■ s. Revising paragraphs (r) introductory text, (r)(2) introductory text, and (r)(2)(i);
■ t. Revising paragraphs (u)(2)(i) and (iii); and
■ x. Revising paragraphs (z) introductory text and (z)(1)(ii).

The revisions and additions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) * * *

* * * * *

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production,

onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W–1A of this subpart.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i), (iii), and (iv) of this section.

* * * * *

(2) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine ''$Count_t$'' for Equation W–1 of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine ''$Count_t$'' for Equation W–1 for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

* * * * *

(c) * * *

* * * * *

EF = Population emissions factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W–1A of this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

* * * * *

(d) * * *

(8) * * *

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas.

* * * * *

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using Equation W–10A or Equation W–10B of this section. Equation W–10A applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers and Equation W–10B applies when the gas flowback vent or flare volume is measured for each completion or workover. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use Equation W–10A, you must follow the procedures specified in paragraph (g)(1). If you elect to use Equation W–10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_{p,s} \times FRM_s \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \div 2 \times PR_{s,p} \right] \right] \quad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \div 2 \right] \right] \quad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each sub-basin and well type combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of each well p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback for each well, p, as determined by using an appropriate meter according to methods described in § 98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did

not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of vented or flared gas for each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

$FR_{p,i}$ = Flow rate vented or flared of each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in § 98.234(b).

(1) If you elect to use Equation W–10A of this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section, or Calculation Method 2 as specified in paragraph (g)(1)(ii) of this section, to determine the value of FRM_s and FRM_i. If you elect to use Equation W–10A of this section on oil wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

(i) *Calculation Method 1.* You must use Equation W–12A of this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W–12B of this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in Equations W–12A and W–12B of this section, you must use a recording flow meter (digital or analog) installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in § 98.234(b).

(ii) *Calculation Method 2 (for gas wells).* * * *

(iii) * * *

* * * * *

FRM_s = Ratio of average gas flowback rate, during the period of time when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or calculated average flowback rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured and calculated FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W–33 in paragraph (t) of this section. You may not use flow volume as used in Equation W–10B of this section converted to a flow rate for this parameter.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

* * * * *

(iv) * * *

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FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, for the period of flow to open tanks/pits.

* * * * *

$PR_{s,p}$ = Average gas production flow rate during the first 30-days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour of each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

* * * * *

(v) For Equation W–10A of this section, the ratio of gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate are applied to all well completions and well workovers, respectively, in the sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average gas production rate for each of these wells.

(vi) For Equations W–12A and W–12B of this section, calculate new flowback rates for well completions and well workovers in each sub-basin and well type combination once every two years starting in the first calendar year of data collection.

(vii) For oil wells where the gas production rate is not metered and you elect to use Equation W–10A of this section, calculate the average gas production rate ($PR_{s,p}$) using Equation W–12C of this section. If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (g)(1)(vii)(A) or (B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

$$PR_{s,p} = GOR_p * \frac{V_p}{720} \qquad \text{(Eq. W-12C)}$$

Where:

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of well p, in the sub-basin and well type combination.

GOR_p = Average gas to oil ratio during the first 30 days of production after completions of newly drilled wells or workovers using hydraulic fracturing in standard cubic feet of gas per barrel of oil for each well p, that was measured in the sub-basin and well type combination; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in barrels of each well p, that was measured in the sub-basin and well type combination.

720 = Conversion from 30 days of production to hourly production rate.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in § 98.234(b).

(2) For paragraphs (g) introductory text and (g)(1) of this section, measurements and calculations are completed separately for workovers and completions per sub-basin and well type combination. A well type combination is a unique combination of the parameters listed in paragraphs (g)(2)(i) through (iv) of this section.

* * * * *

(iv) Oil well or gas well.

* * * * *

(4) Calculate annual emissions from well venting during well completions and workovers from hydraulic fracturing where all or a portion of the gas is flared as specified in paragraphs (g)(4)(i) and (ii) of this section.

* * * * *

(i) * * *

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. For industry segments other than onshore natural gas transmission pipeline, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary other than physical volumes associated with distribution pipelines), pipeline venting (*i.e.,* physical volumes associated with distribution pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event. For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

(i) * * *

* * * * *

T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the pressure.

* * * * *

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of oil greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2 for separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last gas-liquid separator or non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator or non-separator equipment enters an atmospheric pressure storage tank. The following parameters must be determined for typical operating

conditions over the year by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from liquid transferred to tanks:

(i) Separator or non-separator equipment temperature.

(ii) Separator or non-separator equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator or non-separator equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

(i) *Flow to storage tank after passing through a separator.* Assume that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(ii) *Flow to storage tank direct from wells.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production oil and gas compositions are available through a previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(B) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(iii) *Flow to storage tank direct from non-separator equipment.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(iii)(A) or (B) of this section.

(A) If other non-separator equipment liquid and gas compositions are available through a previous analysis, select the latest available analysis that is representative of liquid and gas from non-separator equipment in the same county and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment liquid and gas compositions are not available, use default liquid and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions using Equation W–15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

* * * * *

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i,o} = \left(CF_n * \frac{E_n}{8760} * T_n \right) \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i,o}$ = Annual volumetric GHG emissions at standard conditions from each storage tank in cubic feet that resulted from the dump valve on the gas-liquid separator not closing properly.

E_n = Storage tank emissions as determined in paragraphs (j)(1), (j)(2) and, if applicable, (j)(4) of this section in standard cubic feet per year.

T_n = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_n based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_n = Correction factor for tank emissions for time period T_n is 2.87 for crude oil production. Correction factor for tank emissions for time period T_n is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

* * * * *

(n) * * *

(2) * * *

(i) For onshore natural gas production and onshore petroleum and natural gas gathering and boosting, determine the GHG mole fraction using paragraph (u)(2)(i) of this section.

* * * * *

(o) *Centrifugal compressor venting.* If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11).

* * * * *

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–25 of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from centrifugal compressor wet seals, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors that have wet seal oil degassing vents.

$EF_{i,s}$ = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (p)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) do not apply. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11).

* * * * *

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–29D of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-29D)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors.

$EF_{i,s}$ = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(r) *Equipment leaks by population count.* This paragraph (r) applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), (i)(6), (j)(10), and (j)(11) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B of this section and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \quad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \quad \text{(Eq. W-32B)}$$

Where:

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a component (*e.g.* connector, open-ended line, etc.), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations, in standard cubic feet.

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W–4 of this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W–7 of this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W–1A and W–4 through W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart.

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs, as determined in Equation W–31 of this section.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_e = Average estimated time that each emission source type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$T_{w,avg}$ = Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run, using engineering estimate based on best available data.

* * * * *

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W–1A of this subpart. Major equipment and components associated with gas wells and onshore petroleum and natural gas gathering and boosting systems are considered gas service components in reference to Table W–1A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W–1A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the calculation methods described in this paragraph (r)(2), except for miles of gathering pipelines by material type, which must be determined using Component Count Method 2 in paragraph (r)(2)(ii) of this section. The same calculation method must be used for the entire calendar year.

(i) *Component Count Method 1.* For all onshore petroleum and natural gas production operations and onshore petroleum and natural gas gathering and boosting operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B of this subpart for onshore natural gas production and onshore petroleum and natural gas gathering and boosting; and Table W–1C of this subpart for onshore oil production. Use the appropriate factor

in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

* * * * *

(u) * * *

(2) * * *

(i) *GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities.* If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

* * * * *

(iii) *GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment and the onshore natural gas transmission pipeline industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

* * * * *

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraphs (z)(3) and (4) of this section, as follows:

(1) * * *

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities will be reported according to the requirements specified in § 98.236(z) and not according to the reporting requirements specified in subpart C of this part.

* * * * *

■ 6. Section 98.234 is amended by adding paragraph (g) to read as follows:

§ 98.234 Monitoring and QA/QC requirements.

* * * * *

(g) *Special reporting provisions for best available monitoring methods in reporting year 2016*—(1) *Best available monitoring methods.* From January 1, 2016, to December 31, 2016, you must use the calculation methodologies and equations in § 98.233 but you may use the best available monitoring method as described in paragraph (g)(2) of this section for any parameter specified in paragraphs (g)(3) through (6) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2016. Starting no later than January 1, 2017, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part. For onshore petroleum and natural gas production, this paragraph (g)(1) only applies if emissions from well completions and workovers of oil wells with hydraulic fracturing cause your facility to exceed the reporting threshold in § 98.231(a)(1).

(2) Best available monitoring methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(3) *Best available monitoring methods for well-related measurement data for oil wells with hydraulic fracturing.* You may use best available monitoring methods for any well-related measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for venting during well completions and workovers of oil wells with hydraulic fracturing.

(4) *Best available monitoring methods for measurement data for onshore petroleum and natural gas gathering and boosting facilities.* You may use best available monitoring methods for any leak detection and/or measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in § 98.233(d).

(5) *Best available monitoring methods for measurement data for natural gas transmission pipelines.* You may use best available monitoring methods for any measurement data for natural gas transmission pipelines that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for blowdown vent stacks.

(6) *Best available monitoring methods for specified activity data.* You may use best available monitoring methods for activity data as listed in paragraphs (g)(6)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for well completions and workovers of oil wells with hydraulic fracturing, onshore petroleum and natural gas gathering and boosting facilities, or natural gas transmission pipelines.

(i) Cumulative hours of venting, days, or times of operation in § 98.233(e), (g), (o), (p), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in § 98.233(g) and (i).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (n), and (z).

* * * * *

■ 7. Section 98.236 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraphs (a)(9) and (10);

■ c. Revising paragraphs (d)(1)(i) and (vi);

■ d. Revising paragraphs (e)(1)(i) and (xviii);

■ e. Revising paragraphs (f)(1)(ii), (f)(1)(xi)(A), (f)(1)(xii)(A), and (f)(2)(i);

■ f. Revising paragraphs (g) introductory text, (g)(1), (g)(2), (g)(5), and (g)(6);

■ g. Revising paragraphs (h)(1)(i) and (iv), (h)(2)(i) and (iv), (h)(3)(i), and (h)(4)(i);

■ h. Revising paragraphs (i) introductory text and (i)(1) introductory text;

■ i. Adding paragraph (i)(3);

■ j. Revising paragraphs (j) introductory text and (j)(1) introductory text;

■ k. Revising paragraphs (j)(1)(i), (iii), (iv) (v), (vii), and (viii);

■ l. Revising paragraphs (j)(2)(i) introductory text, (j)(2)(i)(A) through (C), (j)(2)(ii), (j)(2)(iii) introductory text, (j)(2)(iii)(A) and (B), and (j)(3) introductory text;

■ m. Revising paragraph (l)(1) introductory text;

■ n. Redesignating paragraphs (l)(1)(ii) through (vi) as paragraphs (l)(1)(iii) through (vii), respectively;

■ o. Adding paragraph (l)(1)(ii);

■ p. Revising newly designated paragraph (l)(1)(v);

■ q. Revising paragraph (l)(2) introductory text;

■ r. Redesignating paragraphs (l)(2)(ii) through (vii) as paragraphs (l)(2)(iii) through (viii), respectively;

■ s. Adding paragraph (l)(2)(ii);

■ t. Revising newly designated paragraph (l)(2)(v);

■ u. Revising paragraph (l)(3) introductory text;

■ v. Redesignating paragraphs (l)(3)(ii) through (v) as paragraphs (l)(3)(iii) through (vi), respectively;

■ w. Adding paragraph (l)(3)(ii);

■ x. Revising newly designated paragraph (l)(3)(iv);

■ y. Revising paragraph (l)(4) introductory text;
■ a. Redesignating paragraphs (l)(4)(ii) through (vi) as paragraphs (l)(4)(iii) through (vii), respectively;
■ aa. Adding paragraph (l)(4)(ii);
■ bb. Revising newly designated paragraph (l)(4)(iv);
■ cc. Revising paragraphs (m)(1), (m)(5), (m)(6), (m)(7)(i), (m)(8)(i);
■ dd. Revising paragraph (n)(1);
■ ee. Revising paragraphs (o) introductory text and (o)(5) introductory text;
■ ff. Revising paragraphs (p) introductory text and (p)(5) introductory text;
■ gg. Revising paragraphs (r)(1) introductory text, (r)(1)(i), (r)(3) introductory text, and (r)(3)(ii) introductory text;
■ hh. Revising paragraph (z) introductory text;
■ ii. Revising paragraphs (aa) introductory text and (aa)(1)(ii)(D) through (H);
■ jj. Adding paragraphs (aa)(10) and (11); and
■ kk. Revising paragraph (cc).

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

* * * * *

(a) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10), and each applicable emission source listed in paragraphs (b) through (z) of this section.

* * * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(vi) *Storage tanks.* Report the information specified in paragraph (j) of this section.

(vii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(viii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(ix) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(x) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xi) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(10) *Onshore natural gas transmission pipeline.* For blowdown vent stacks, report the information specified in paragraph (i) of this section.

* * * * *

(d) * * *

(1) * * *

(i) A unique name or ID number for the acid gas removal unit. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

* * * * *

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the unit (for the onshore petroleum and natural gas gathering and boosting industry segment only).

* * * * *

(e) * * *

(1) * * *

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

* * * * *

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

* * * * *

(f) * * *

(1) * * *

(ii) Well tubing diameter and pressure group ID and a list of the well ID numbers associated with each sub-basin and well tubing diameter and pressure group ID.

* * * * *

(xi) * * *

(A) Well ID number of tested well.

* * * * *

(xii) * * *

(A) Well ID number.

* * * * *

(2) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin.

* * * * *

(g) *Completions and workovers with hydraulic fracturing.* You must indicate whether your facility had any well completions or workovers with hydraulic fracturing during the calendar year. If your facility had well completions or workovers with hydraulic fracturing during the calendar year, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each sub-basin and well type combination. Report information separately for completions and workovers.

(1) Sub-basin ID and a list of the well ID numbers associated with each sub-basin that had completions or workovers with hydraulic fracturing during the calendar year.

(2) Well type combination (horizontal or vertical, gas well or oil well).

* * * * *

(5) If you used Equation W–10A of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of ''$T_{p,i}$'' and sum of ''$T_{p,s}$'' values used in Equation W–10A of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number.

(ii) For the measured well(s), the flowback rate, in standard cubic feet per

hour (average of ''$FR_{s,p}$'' values used in Equation W–12A of § 98.233), and the well ID numbers of the wells for which it is measured. You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured flowback rate during well completion or workover and the well ID number(s) for the well(s) included in the measurement.

(iii) If you used Equation W–12C of § 98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil (''GOR_p'' in Equation W–12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the gas to oil ratio for the well and the well ID number for the well.

(B) Volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels (''V_p'' in Equation W–12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced during the first 30 days of production after well completion or workover and the well ID number for the well.

(6) If you used Equation W–10B of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin (''$FV_{s,p}$'' in Equation W–10B of § 98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin (''$FR_{p,i}$'' in Equation W–10B of § 98.233).

(iii) The well ID number for which vented natural gas volume was measured.

* * * * *

(h) * * *

(1) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and without flaring.

* * * * *

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all ''V_p'' used in Equation W–13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(2) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and with flaring.

* * * * *

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all ''V_p'' from Equation W–13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(3) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and without flaring.

* * * * *

(4) * * *

(i) Sub-basin ID and a list of well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and with flaring.

* * * * *

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section.

(1) *Report by equipment or event type.* If you calculated emissions from blowdown vent stacks by the seven categories listed in § 98.233(i)(2) for industry segments other than the onshore natural gas transmission pipeline segment, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each ''equipment or event type'' (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the ''equipment or event type'' (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

* * * * *

(3) *Onshore natural gas transmission pipeline segment.* Report the information in paragraphs (i)(3)(i) through (iii) of this section for each state.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) Annual number of blowdown events.

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraphs (j)(1)(ix) and (xi) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

* * * * *

(iii) The total annual oil volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total volume of oil from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

* * * * *

(vii) The minimum and maximum concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(viii) The minimum and maximum concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

* * * * *

(2) * * *

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3 of § 98.233(j). Onshore gathering and boosting facilities do not report the information specified in paragraphs (j)(2)(i)(E) and (F) of this section.

(A) The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil/condensate production less than 10 barrels per day and that send oil/condensate to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual oil/condensate throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

* * * * *

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that did not control emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that controlled emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares.

* * * * *

(3) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (iv) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting).

* * * * *

(l) * * *

(1) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual

conditions from oil wells and the emissions are not vented to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(2) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are vented to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (viii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(3) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not vented to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(4) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were vented to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (vii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(m) * * *

(1) Sub-basin ID and a list of well ID numbers for wells for which associated gas was vented or flared.

* * * * *

(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of "$V_{p,q}$" used in Equation W–18 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of "SG" values used in Equation W–18 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(7) * * *

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

* * * * *

(8) * * *

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

* * * * *

(n) * * *

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

* * * * *

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (o)(5)(i) through (iii) of this section.

* * * * *

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in

paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (p)(5)(i) through (iii) of this section.

* * * * *

(r) * * *

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W–32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by component type, service type, and geographic location (*i.e.,* Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the component type, service type and geographic location.

* * * * *

(3) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

* * * * *

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W–1B and W–1C of this subpart.

* * * * *

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by § 98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

* * * * *

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, by using best available data. If a quantity required to be reported is zero, you must report zero as the value.

(1) * * *

(ii) * * *

(D) The number of producing wells at the end of the calendar year and a list of the well ID numbers (exclude only those wells permanently taken out of production, *i.e.,* plugged and abandoned).

(E) The number of producing wells acquired during the calendar year and a list of the well ID numbers.

(F) The number of producing wells divested during the calendar year and a list of the well ID numbers.

(G) The number of wells completed during the calendar year and a list of the well ID numbers.

(H) The number of wells permanently taken out of production (*i.e.,* plugged and abandoned) during the calendar year and a list of the well ID numbers.

* * * * *

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (iv) of this section.

(i) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels.

(iv) The quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels.

(11) For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

(v) The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.

(vi) The miles of transmission pipeline for each state in the facility.

* * * * *

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (g)(5)(iii)(A), (g)(5)(iii)(B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4)(iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

■ 8. Section 98.238 is amended by adding definitions for ''Facility with respect to onshore petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements,'' ''Facility with respect to the onshore natural gas transmission pipeline segment,'' ''Gathering and

boosting system,'' ''Gathering and boosting system owner or operator,'' ''Onshore natural gas transmission pipeline owner or operator,'' and ''Well identification (ID) number'' in alphabetical order to read as follows:

§ 98.238 Definitions.

* * * * *

Facility with respect to onshore petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements means all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in this section. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in this subpart.

* * * * *

Facility with respect to the onshore natural gas transmission pipeline segment means the total U.S. mileage of natural gas transmission pipelines, as defined in this section, owned and operated by an onshore natural gas transmission pipeline owner or operator as defined in this section. The facility does not include pipelines that are part of any other industry segment defined in this subpart.

* * * * *

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

* * * * *

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act, or for pipelines that fall under the ''Hinshaw Exemption'' as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

* * * * *

Well identification (ID) number means the unique and permanent identification number assigned to a petroleum or natural gas well. If the well has been assigned a US Well Number, the well ID number required in this subpart is the US Well Number. If a US Well Number has not been assigned to the well, the well ID number is the identifier established by the well's permitting authority.

* * * * *

■ 9. Revise Table W–1A of subpart W of part 98 to read as follows:

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES—Continued

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Open-ended Line	0.006
Other [5]	0.003
Population Emission Factors—Gathering Pipelines, by Material Type [7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60
Western U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other [5]	0.003
Population Emission Factors—Gathering Pipelines by Material Type [7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emission Factor is in units of ''scf/hour/device.''
[3] Emission Factor is in units of ''scf/hour/pump.''
[4] Hydrocarbon liquids greater than or equal to 20°API are considered ''light crude.''
[5] ''Others'' category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20°API are considered ''heavy crude.''
[7] Emission factors are in units of ''scf/hour/mile of pipeline.''

■ 10. Amend Table W–1B of subpart W of part 98 by revising the table heading to read as follows:

TABLE W–1B TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING EQUIPMENT

* * * * *

[FR Doc. 2015–25840 Filed 10–21–15; 08:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2015–0764; FRL–9955–12–OAR]

RIN 2060–AS73

Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency is finalizing revisions and confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Program. In particular, this action adds new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the fugitive emissions monitoring methods in the recently finalized new source performance standards for the oil and gas industry. This action also adds emission factors for leaking equipment to be used in conjunction with these monitoring methods to calculate and report greenhouse gas emissions resulting from equipment leaks. Finally, this action finalizes reporting requirements and confidentiality determinations for nine new or substantially revised data elements contained in these amendments.

DATES: This final rule is effective on January 1, 2017.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2015–0764. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343–9334; fax number: (202) 343–2342; email address: *GHGReporting@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Rule Web site, *http://www.epa.gov/ghgreporting/.* To submit a question, select Help Center, followed by ''Contact Us.''

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on the EPA's Greenhouse Gas Reporting Rule Web site at *http://www.epa.gov/ghgreporting/index.html.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. These revisions affect entities that must submit annual greenhouse gas (GHG) reports under the Greenhouse Gas Reporting Program (GHGRP), codified in the Code of Federal Regulations (CFR) at 40 CFR part 98. This rule applies to all petroleum and natural gas systems facilities that are subject to 40 CFR part 98, regardless of the facility's location, and ensures that all these facilities across the United States (U.S.) report GHG data consistently, and therefore is ''nationally applicable'' within the meaning of section 307(b)(1) of the Clean Air Act (CAA). Further, the Administrator has determined that rules codified in 40 CFR part 98 are subject to the provisions of CAA section 307(d). (See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine'').) These are amendments to existing regulations. These amended regulations affect owners or operators of petroleum and natural gas systems that directly emit GHGs. Regulated categories and entities include, but are not limited to, those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS [a]	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution.
	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A and 40 CFR part 98, subpart W. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

What is the effective date? The final rule is effective on January 1, 2017. Section 553(d) of the Administrative Procedure Act (APA), 5 U.S.C. Chapter 5, generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**. The EPA is issuing this final rule under section 307(d)(1) of the Clean Air Act, which states: ''The provisions of section 553 through 557 * * * of Title 5 shall not, except as expressly provided in this section, apply to actions to which this subsection applies.'' Thus, section 553(d) of the APA does not apply to this rule. The EPA is nevertheless acting consistently with the purposes underlying APA section 553(d) in making the first set of amendments to this rule effective on January 1, 2017. Section 553(d) allows an effective date less than 30 days after publication for a rule that ''grants or recognizes an exemption or relieves a restriction'' or ''as otherwise provided by the agency for good cause found and published with the rule.'' As explained below, the EPA finds that there is good cause for the first set of amendments to this rule to become effective on January 1, 2017, even though this may result in an effective date fewer than 30 days from date of publication in the **Federal Register**.

While this action is being signed prior to December 1, 2016, there is likely to

be a significant delay in the publication of this rule as it contains complex equations and tables and is relatively long. As an example, the EPA Administrator signed the Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems final rule on October 1, 2015, but the rule was not published in the **Federal Register** until October 22, 2015 (80 FR 64262). The purpose of the 30-day waiting period prescribed in 5 U.S.C. 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. To employ the APA section 553(d)(3) ''good cause'' exemption, an agency must balance the necessity for immediate implementation against principles of fundamental fairness which require that all affected persons be afforded a reasonable amount of time to prepare for the effective date of its ruling.[1] Where, as here, the final rule will be signed and made available on the EPA Web site more than 30 days before the effective date, but where the publication is likely to be delayed due to the complexity and length of the rule, the regulated entities are afforded this reasonable amount of time. We balance these circumstances with the need for the amendments to be effective by January 1, 2017; a delayed effective date would result in regulatory uncertainty, program disruption, and an inability to have the amendments effective for the 2017 reporting year. Accordingly, we find good cause exists to make this rule effective on January 1, 2017, consistent with the purposes of APA section 553(d)(3).

Judicial Review. Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit (the Court) by January 30, 2017 Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Section 307(d)(7)(B) of the CAA also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note that under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

APA Administrative Procedure Act
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CH4 methane
CO_2 carbon dioxide
CRA Congressional Review Act
DOT Department of Transportation
EPA U.S. Environmental Protection Agency
FR Federal Register
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GRI Gas Research Institute
ICR Information Collection Request
LNG liquefied natural gas
NAICS North American Industry Classification System
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act
OGI optical gas imaging
OMB Office of Management and Budget
ppmv parts per million by volume
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
U.S. United States
UMRA Unfunded Mandates Reform Act
VOC volatile organic compounds
WWW Worldwide Web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Background
A. Organization of This Preamble
B. Background on This Action
C. Legal Authority
D. How do these amendments apply to 2016 and 2017 reports?
II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment
A. Summary of Final Amendments—General
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C. Summary of Final Amendments to Monitoring Methods
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E. Summary of Final Amendments to Leaker Emission Factors and the Calculation Methodology Based on Equipment Leak Surveys
F. Summary of Final Amendments to Reporting Requirements
III. Final Confidentiality Determinations
A. Summary of Final Confidentiality Determinations for New or Substantially Revised Subpart W Data Elements
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IV. Impacts of the Final Amendments to Subpart W
A. Impacts of the Final Amendments
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V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
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C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. Background

A. Organization of This Preamble

Section I of this preamble provides background information regarding the origin of the final amendments. This section also discusses the EPA's legal authority under the CAA to promulgate and amend 40 CFR part 98 of the Greenhouse Gas Reporting Rule (hereafter referred to as ''part 98'') as well as the legal authority for making confidentiality determinations for the data to be reported. Section II of this preamble contains information on the final amendments to part 98, subpart W (Petroleum and Natural Gas Systems) (hereafter referred to as ''subpart W''), including a summary of the major comments that the EPA considered in the development of this final rule. Section III of this preamble discusses the final confidentiality determinations for new or substantially revised data

[1] *Omnipoint Corp.* v. *FCC*, 78 F3d 620, 630 (D.C. Cir. 1996), quoting *U.S.* v. *Gavrilovic*, 551 F.2d 1099, 1105 (8th Cir. 1977).

reporting elements. Section IV of this preamble discusses the impacts of the final amendments to subpart W. Finally, section V of this preamble describes the statutory and executive order requirements applicable to this action.

B. Background on This Action

The EPA's GHGRP requires annual reporting of GHG data and other relevant information from large sources and suppliers in the United States. On October 30, 2009, the EPA published part 98 in the **Federal Register** (FR) for collecting information regarding GHG emissions from a broad range of industry sectors (74 FR 56260). Although reporting requirements for petroleum and natural gas systems were originally proposed to be part of part 98 (74 FR 16448, April 10, 2009), the final October 2009 rulemaking did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA re-proposed subpart W in 2010 (75 FR 18608; April 12, 2010), and a subsequent final rulemaking was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458). Following promulgation, the EPA finalized several actions revising subpart W (76 FR 22825, April 25, 2011; 76 FR 53057, August 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 80554, December 23, 2011; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 70352, November 25, 2014; 80 FR 64262, October 22, 2015).[2]

The Strategy to Reduce Methane Emissions in the President's Climate Action Plan summarizes the sources of CH_4 emissions, commits to new steps to cut emissions of this potent GHG, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut CH_4 emissions from several sectors, including the oil and natural gas sector. In the strategy, the EPA was specifically tasked with continuing to review GHGRP regulatory requirements to address potential gaps in coverage, improve methods, and ensure high quality data reporting.[3] On January 14, 2015, the Obama administration provided additional direction to the EPA to ''explore potential regulatory opportunities for applying remote sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions'' in the oil and natural gas sector, such as the emissions submitted as part of GHGRP annual reporting.[4]

Under subpart W, GHGs that must be reported by each industry segment and applicable source types are specified in 40 CFR 98.232, including equipment leaks from listed component types. In order to fulfill these equipment leak emissions reporting requirements, reporters must utilize one of two calculation methodologies [5] to calculate GHG emissions from equipment leaks as specified in 40 CFR 98.233: (1) Calculation methodology based on equipment leak surveys (40 CFR 98.233(q)), or (2) calculation methodology based on population counts (40 CFR 98.233(r).[6] For example, facilities in the Onshore Natural Gas Processing and Onshore Natural Gas Transmission Compression industry segments use the calculation methodology based on equipment leak surveys for most components at their facilities. If 40 CFR 98.233(q) specifies that an equipment leak survey is required for the subsection of listed component types in 40 CFR 98.232, reporters must use one of the monitoring methods specified in 40 CFR 98.234 when conducting those equipment leak surveys to detect leaking components at the facility. The calculation methodology based on equipment leak surveys requires that the reporter then determine the total amount of time each component was assumed to be leaking and multiply that by the concentration of the methane (CH_4) and carbon dioxide (CO_2) in the gas and the applicable emission factor (referred to as a ''leaker emission factor''), listed in Table W–1E and Table W–2 through Table W–7, to calculate emissions. Finally, 40 CFR 98.236 specifies the data elements that must be reported to the EPA.

On January 29, 2016, the EPA proposed ''Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (81 FR 4987) to add new monitoring methods for detecting leaks from oil and gas equipment, to revise which industry segments and sources use the calculation methodology based on equipment leak surveys or the calculation methodology based on population counts, to clarify how the definition of fugitive emission components in the new source performance standards (NSPS) for the oil and natural gas sector (40 CFR part 60, subpart OOOOa, at 81 FR 35824) (hereafter referred to as the ''NSPS subpart OOOOa'') aligns with the equipment components subject to subpart W, to add leaker emission factors for multiple industry segments, and to add reporting requirements and confidentiality determinations for new or substantially revised data elements. Under those proposed amendments, facilities with fugitive emissions components at a well site or compressor station subject to the NSPS subpart OOOOa would use data derived from the NSPS subpart OOOOa fugitive emissions requirements (*i.e.*, which components were determined to have fugitive emissions) along with the subpart W leaker emission factors to calculate and report GHG emissions to the GHGRP. The proposed revisions provided the opportunity for owners and operators of sources not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards (*e.g.,* sources participating in a voluntarily implemented program) and not already required to conduct leak surveys under subpart W to optionally use the calculation methodology at 40 CFR 98.233(q) to calculate and report their GHG emissions to the GHGRP. The EPA also proposed that facilities that are already required to conduct leak surveys under subpart W would be able to use the newly proposed monitoring method(s) in 40 CFR 98.234. In addition, the EPA proposed new reporting requirements for all reporters using the calculation methodology

[2] See Greenhouse Gas Reporting Program, Historical Rulemakings. Available at *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[3] Climate Action Plan—Strategy to Reduce Methane Emissions. The White House, Washington, DC, March 2014. Available at *http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.*

[4] FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions. The White House, Office of the Press Secretary, January 14, 2015. Available at *https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.*

[5] Throughout this preamble, the term ''calculation methodology'' refers to the procedures used to calculate emissions (*e.g.,* ''calculation methodology based on equipment leak surveys'' refers to the methodology described in 40 CFR 98.233(q)) and ''monitoring method'' refers to the technology, test method, or other method of determining whether an individual component is leaking (see 40 CFR 98.234(a)). The term ''leak detection method'' that is used in the 40 CFR part 98 subpart W regulatory text has the same meaning as ''monitoring method'' used in this preamble.

[6] Reporters using the calculation methodology based on population counts determine the total number of all components in the facility and multiply that count by the average estimated time of operation, the concentration of the CH_4 and CO_2 in the gas, and the applicable emission factor (referred to as a ''population emission factor'') to calculate emissions.

based on equipment leak surveys and proposed to require reporters using the calculation methodology for the first time to begin reporting the information associated with that methodology. Finally, the EPA proposed confidentiality determinations for nine new or substantially revised data elements. The public comment period for these proposed rule amendments ended on March 15, 2016, following a 15-day extension of the original comment period end date (81 FR 9797; February 26, 2016). On June 3, 2016, the EPA published the final NSPS subpart OOOOa requirements (81 FR 35824).

In this action, the EPA is finalizing revisions to subpart W largely as proposed, with some changes made after consideration of public comments. Summaries of significant comments submitted on the proposed amendments and the EPA's responses to those comments can be found in sections II, III, and IV of this preamble. All comments submitted on the proposed amendments and the EPA's additional responses to the comments can be found in ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764.

As further detailed in the preamble to the proposed amendments, these revisions advance the EPA's goal of maximizing rule effectiveness by providing a mechanism for facilities to use the NSPS subpart OOOOa monitoring results for purposes of GHGRP subpart W reporting. This alignment reduces burden for entities subject to the fugitive emissions/equipment leak detection method requirements in both programs, and, when combined with the other amendments being finalized in this revision, provides clear monitoring methods, equipment leak survey and calculation methodologies and emission factors, and reporting requirements in subpart W, thus enabling government, regulated entities, and the public to easily identify and understand regulatory requirements. These amendments also further advance the ability of the GHGRP to provide access to high quality data on GHG emissions by adding the ability for reporters to use data collected during equipment leak surveys and to perform site-specific equipment leak calculations.

C. Legal Authority

The EPA is finalizing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 final GHG reporting rule (74 FR 56260; October 30, 2009), CAA section 114(a)(1) provides the EPA broad authority to require the information to be gathered by this rule because such data will inform and are relevant to the EPA's carrying out a wide variety of CAA provisions. See the preambles to the proposed (74 FR 16448; April 10, 2009) and final GHG reporting rule (74 FR 56260; October 30, 2009) for further information.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing final confidentiality determinations for the new or substantially revised data elements required by these amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information (excluding emission data) that qualifies for confidential treatment. The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA. Section 307(d) contains a set of procedures relating to the issuance and review of certain CAA rules.

D. How do these amendments apply to 2016 and 2017 reports?

These amendments are effective on January 1, 2017. Starting with the 2017 reporting year, facilities must follow the revised methods to detect equipment leaks (if applicable) and to calculate and report their annual equipment leak emissions. The first annual reports of emissions calculated using the amended requirements will be those submitted by April 2, 2018, covering reporting year 2017. For reporting year 2016, reporters will calculate emissions according to the requirements in part 98 that are applicable to reporting year 2016 (*i.e.,* the requirements in place until the effective date of this final rule).

II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment

Sections II.A through II.F of this preamble describe the revisions that we are finalizing in this rulemaking. Section II.A provides a general summary of the final amendments to subpart W. Section II.B describes the final amendments to the requirement to use the calculation methodology based on equipment leak surveys. Section II.C describes the final amendments to the subpart W monitoring methods. Section II.D describes the final amendments for component types to be surveyed. Section II.E describes the final amendments to the subpart W leaker emission factors. Finally, section II.F provides a summary of the final amendments to the subpart W reporting requirements. The amendments described in each section are followed by a summary of the major comments on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for a complete listing of all comments and the EPA's responses.

A. Summary of Final Amendments—General

1. Summary of Final Amendments

In this action, the EPA is amending subpart W to add new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the NSPS subpart OOOOa. The EPA is also specifying that facilities with a collection of fugitive emissions components at a well site or compressor station subject to the NSPS subpart OOOOa (40 CFR 60.5397a) would be required to survey those components, except as otherwise specified in this subpart W final rule, for the subpart W calculation methodology based on equipment leak surveys using one of the new monitoring methods being added to subpart W. In practice, this means that facilities can use the results of the NSPS subpart OOOOa-required fugitive emissions monitoring survey to fulfill these subpart W requirements. The EPA is adding leaker emission factors to be used in conjunction with the calculation methodology based on equipment leak surveys to calculate and report GHG emissions. The revisions provide the opportunity for owners and operators of sources not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards (*e.g.,* sources participating in a voluntarily implemented program) and not already required to conduct leak surveys under subpart W to optionally use the calculation methodology at 40 CFR 98.233(q) to calculate and report their GHG emissions, and to use the new monitoring methods in 40 CFR 98.234 to do so.

Facilities in certain subpart W industry segments [7] that are already required to conduct leak surveys will be able to use the new monitoring methods

[7] These segments are Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment.

in 40 CFR 98.234. If they use either of the two new monitoring methods in 40 CFR 98.234(a)(6) or (7) that are consistent with the NSPS subpart OOOOa, then in addition to surveying the components currently subject to the survey requirements in subpart W, they must also survey all other components that are fugitive emissions components in the NSPS subpart OOOOa, with limited exceptions, as specified in 40 CFR 98.232 (see sections II.C and II.D of this preamble). If they use any of the monitoring methods currently in 40 CFR 98.234(a)(1) through (5), then in addition to surveying the components currently subject to the survey requirements in subpart W, they may elect to survey the other components specified in 40 CFR 98.232.

The comments received on this rule generally do not dispute the merit of allowing the use of new monitoring methods in subpart W, but they do include issues related to the adequacy of the notice and comment process, the calculation methodology based on equipment leak surveys, reporting, and applicability.

2. Summary of Comments and Responses

Comment: Numerous commenters stated that the EPA's reference to the proposed NSPS subpart OOOOa included in the subpart W proposal was premature, and substantively and procedurally flawed. According to these commenters, by relying on a proposed action, the EPA did not provide the opportunity for notice or comment on how the rule would ultimately affect stakeholders. These commenters stated that at the very least the EPA made it difficult and increased burden for stakeholders to evaluate scope and impacts and to provide comment. Commenters stated that they could only comment on the effect of the incorporation of the NSPS subpart OOOOa proposed requirements, as they could not review and comment on the effect of the finalized NSPS subpart OOOOa requirements on subpart W prior to closure of the comment period for the subpart W proposal. Specifically, the commenters expressed concern that because the EPA received so many comments on the proposed NSPS subpart OOOOa, the final NSPS subpart OOOOa provisions would likely be significantly different in certain aspects and that those details were unknowable at the time of comment. Noting that the EPA expressed intent in the preamble to the subpart W proposed amendments to incorporate the final NSPS subpart OOOOa provisions in the final subpart W rule, the commenters stated they inherently would have no formal opportunity to meaningfully comment on the effect those final NSPS subpart OOOOa provisions would have on subpart W reporters. Several commenters stated that this created substantive and procedural flaws in the proposed rule, as the EPA provided neither the ''terms or substance'' nor a ''description of the subjects and issues involved'' of the proposed rule as required for notice and comment rulemaking under the Administrative Procedure Act, 5 U.S.C. 553(b), nor did the EPA meet the more stringent notice and comment requirements of CAA section 307. Several commenters stated that EPA similarly did not consider changes that might be made to the final NSPS subpart OOOOa through the judicial review process.

Several commenters requested that the EPA either finalize, or re-propose or re-open the public comment period for, the proposed alignment of subpart W with the NSPS subpart OOOOa only after the NSPS subpart OOOOa is finalized. Other commenters requested that the EPA withdraw the proposal to amend subpart W and reconsider whether any revisions are necessary once the NSPS subpart OOOOa is in effect.

Response: The EPA disagrees that the proposed rule for this subpart W revision was premature, or substantively and procedurally flawed. This action is focused on aligning the subpart W requirements, to the extent possible, with the finalized NSPS subpart OOOOa fugitive emission requirements so that facilities may use the results of the NSPS subpart OOOOa-required fugitive emissions monitoring surveys to fulfill subpart W requirements, and does so through revisions that incorporate final NSPS subpart OOOOa monitoring methods into subpart W and make their use mandatory in subpart W surveys for most components subject to NSPS subpart OOOOa. The proposed rule for subpart W clearly specified that only a monitoring method finalized in the NSPS subpart OOOOa rule would be finalized for subpart W, which ensured that no requirement would reference any monitoring method that was merely at proposal stage. The proposed rule provided adequate notice and opportunity to comment on how the rule will affect stakeholders, and thus this final rule is in compliance with the relevant requirements of CAA section 307(d). Multiple commenters cited the Administrative Procedure Act (APA), including 5 U.S.C. 553(b)(3), which requires that a notice of proposed rulemaking shall include ''either the terms or substance of the proposed rule or a description of the subjects and issues involved.'' The EPA notes that our process is also consistent with the notice and comment requirements of the APA, 5 U.S.C. 551–559. In the preamble to the proposed and final rule, as well as in ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764, the EPA describes at length the statement and purpose of the revisions, provides explanations for any changes in the rule, and responds to all comments submitted.

Specifically, in regards to the proposed rule referencing the then proposed NSPS subpart OOOOa monitoring method(s) and fugitive emissions component definition,[8] the EPA disagrees that the proposed rule did not give adequate notice and therefore the EPA did not re-propose or re-open the comment period for this action. The proposed rule clearly laid out the EPA's proposal and requested comment regarding alternatives, as well as the detailed reasoning behind and goals of the proposal. The EPA provided this detailed explanation to ensure that commenters had ample notice of the revisions under consideration, and provided 45 days for the public comment period. This process accords with proper notice and comment procedure. Commenters posit that referencing the then proposed NSPS subpart OOOOa standard in the proposed rule renders this notice premature and inadequate, and the EPA respectfully disagrees. First, in proposing to add the NSPS subpart OOOOa equipment leak detection methods as approved monitoring methods for subpart W surveys, the EPA was not proposing to require any new collection of data under subpart W, as the data on fugitive emissions components would already be collected to meet the requirements of NSPS subpart OOOOa. Instead, the EPA proposed to add these new monitoring methods under subpart W so that reporters would be able to use, for the purpose of compliance with the proposed mandatory subpart W equipment leak survey, calculation, and reporting requirements, whatever data would already be collected as a result of complying with the monitoring method(s) that would be finalized in the NSPS subpart OOOOa. Similarly, while the EPA proposed to include all fugitive emissions components subject to the

[8] The NSPS subpart OOOOa rule has since been finalized. 81 FR 35824 (June 3, 2016).

final NSPS subpart OOOOa monitoring methods within subpart W emissions reporting requirements, with some exceptions, which would mean that additional components would fall within the scope of subpart W applicability, these data would already be collected under the NSPS subpart OOOOa, meaning that no new data would need to be collected for subpart W that was not already required by another CAA program. As such, the substance of the monitoring method(s) and fugitive emission component definition was not at issue for purposes of subpart W within these revisions, as that process took place within the NSPS subpart OOOOa rulemaking. Rather, the EPA ensured that reporters were provided notice of the proposal to add the monitoring methods and scope of components that would be finalized under the NSPS OOOOa as additional monitoring methods and applicable components for subpart W, provided notice of the proposed additional subpart W equipment leak survey, calculation, and reporting requirements for equipment components subject to the NSPS subpart OOOOa, and made clear that the intent of these revisions was to align the programs so that reporters would use the data gathered in complying with the finalized NSPS subpart OOOOa to comply with their subpart W requirements. The proposed rule further explained the purpose behind this proposed revision, as detailed in the proposed rule (81 FR 4987; January 29, 2016), including reducing burden on reporters by minimizing the potential equipment leak surveys required at a given facility across CAA programs. As noted earlier, the proposed rule for subpart W clearly specified that only a monitoring method finalized in the NSPS subpart OOOOa rule would be finalized for subpart W, which ensured that no requirement would reference any monitoring method that was merely at proposal stage. In fact, the proposed rule for subpart W clearly detailed the NSPS subpart OOOOa proposed monitoring method, and identified that the NSPS subpart OOOOa proposal included a potential alternative monitoring method, and furthermore explained that any method(s) added in this final subpart W action would be the method(s) that were finalized in the NSPS subpart OOOOa.

Furthermore, Subpart W currently includes an optical gas imaging (OGI) method (see 40 CFR 98.234(a)(1)) and Method 21 (40 CFR 98.234(a)(2)) in the subpart W list of monitoring methods. While there are differences in the application of the methods between the current subpart W and the final NSPS subpart OOOOa,[9] necessitating this revision, current use of OGI and Method 21 for purposes of subpart W provides support that the methods at issue provide reliable data for use in subpart W emissions reporting.

This final rule incorporates the monitoring methods finalized in the NSPS subpart OOOOa with some changes from proposal. To the extent the specifics of how this final subpart W rule is adding method(s) in accordance with the NSPS subpart OOOOa differ from the specifics in the subpart W proposal, as explained further in section II.C of this preamble, these changes are consistent with the purpose detailed in the proposed rule and were made to ensure only those portions of the final NSPS subpart OOOOa that are essential to the integrity of the methods are referenced within the requirements of subpart W. This final rule revises applicable components subject to subpart W to include all components subject to the final NSPS subpart OOOOa, except for the finalized as proposed exclusion of certain components, as further detailed in section II.D of this preamble. The EPA notes that while we finalized the reference to the NSPS subpart OOOOa with certain exceptions regarding applicable components as proposed, the final NSPS subpart OOOOa definition of fugitive emission components was narrower in scope than that rule's proposal. This final rule also includes revisions, with some changes from proposal as detailed in Sections II.B, II.D, II.E, and II.F of this preamble, to how reporters must use the data obtained in accordance with the methods finalized in the NSPS subpart OOOOa for subpart W reporting.

Although the EPA's own reasoned consideration and its assessment of public comment have resulted in some modifications to the final rule, as explained further in sections II.B through II.F of this preamble, such changes reflect the goals and alternatives in the EPA's original proposal, and the proposed rule ensured that interested parties were ''fairly apprised'' of the elements ultimately included in this final rulemaking. See, *e.g.,* United Steelworkers of America v. Schuylkill Metals, 828 F.2d 314 (5th Cir. 1987).

While some changes occurred to the NSPS subpart OOOOa requirements from proposal to final in that rulemaking, including changes to the substance of the monitoring methods and the fugitive emission component definition, those substantive changes are out of scope of this subpart W rulemaking that is intended to align with the final NSPS subpart OOOOa requirements; however, commenters were provided full notice and opportunity to comment within that NSPS subpart OOOOa rulemaking, as fully explained within those proposed and final preambles, the EPA's response to comments, and the docket of that action.[10]

The commenter is correct that the EPA did not consider changes that may be made to the final NSPS subpart OOOOa through the judicial review process. Any such potential, future changes are premature to consider at this time.

B. Summary of Final Amendments to the Requirement To Use the Calculation Methodology Based on Equipment Leak Surveys

1. Summary of Final Amendments

As noted in section I.B of this preamble, subpart W presently requires reporters with sources in certain industry segments to use the calculation methodology based on population counts according to 40 CFR 98.233(r). For example, reporters in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are required either to count the number of equipment components of each type (*e.g.,* valve, connector, open-ended line, or pressure relief valve) or to count the number of major equipment at the facility and then calculate the number of equipment components of each type using default average component counts for each piece of major equipment in Tables W–1B and W–1C to subpart W (40 CFR 98.233(r)(2)). The resulting equipment component counts are then multiplied by default ''population emission factors'' in Table W–1A to subpart W to calculate emissions from equipment leaks.

Other reporters are required to use the calculation methodology based on equipment leak surveys according to 40 CFR 98.233(q) using one of the monitoring methods in 40 CFR 98.234(a). For example, reporters in the Onshore Natural Gas Transmission Compression industry segment must conduct at least one equipment leak survey in a calendar year for the compressor and non-compressor components in gas service listed in Table W–3A to subpart W. These reporters then use the number of leaking

[9] See section II.C of this preamble.

[10] Docket ID No. EPA–HQ–OAR–2010–0505.

components in the calendar year, the average amount of time each component was leaking, and the default ''leaker emission factors'' in Table W–3A to subpart W to calculate emissions according to Equation W–30.

The EPA is finalizing the proposal to apply the calculation methodology based on equipment leak surveys in 40 CFR 98.233(q) to additional reporters in subpart W. Specifically, reporters in any subpart W industry segment with a well site(s) and/or compressor station(s) required to conduct fugitive emissions monitoring to comply with the NSPS subpart OOOOa will be required to use the calculation methodology based on equipment leak surveys for those components [11] under subpart W using the new monitoring methods consistent with the NSPS subpart OOOOa (see section II.C of this preamble). While these are new calculation methodology and equipment leak survey requirements for the subpart W reporting of these components, reporters may meet the survey requirements by counting the actual number of components with fugitive emissions identified through implementation of the NSPS subpart OOOOa as leaks for purposes of subpart W and use those counts with the calculation methodologies specified in 40 CFR 98.233(q) to determine equipment leak emissions for those components.

We received extensive comment regarding the proposed revisions to require facilities in the Onshore Natural Gas Processing industry segment to use the results of the leak surveys conducted to comply with the NSPS subpart OOOOa equipment leak requirements for reporting under subpart W. We are still reviewing those comments and are not taking final action on those revisions at this time.

For other sources of equipment leaks (*i.e.,* those not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards),[12] the amended subpart W requirements depend on whether the component types are currently required to be reported using the calculation methodology based on equipment leak surveys (40 CFR 98.233(q)) or the calculation methodology based on population counts (40 CFR 98.233(r)). For components at facilities in industry segments that are currently required to use the calculation methodology based on equipment leak surveys to comply with subpart W, the EPA is finalizing as proposed that reporters must continue to conduct equipment leak surveys as required by subpart W but may use any monitoring method in 40 CFR 98.234(a). If they use either of the two new monitoring methods in 40 CFR 98.234(a)(6) or (7) that are consistent with the NSPS subpart OOOOa, then in addition to surveying the components currently subject to the survey requirements in subpart W, they must also survey all other components that are fugitive emissions components in the NSPS subpart OOOOa, with limited exceptions, as specified in 40 CFR 98.232 (see sections II.C and II.D of this preamble). If they use any of the monitoring methods currently in 40 CFR 98.234(a)(1) through (5), then in addition to surveying the components currently subject to the survey requirements in subpart W, they may elect to survey the other components specified in 40 CFR 98.232.

For components at facilities in industry segments that are currently required to use the calculation methodology based on population counts, the reporter may continue to use that methodology. Alternatively, the EPA is finalizing as proposed the option that the reporter may elect to use the calculation methodology based on equipment leak surveys (40 CFR 98.233(q)(1)(iv)) in lieu of the calculation methodology based on population counts (40 CFR 98.233(r)). If this option is selected, then the reporter must use any of the monitoring methods in 40 CFR 98.234(a). If they use a monitoring method in 40 CFR 98.234(a)(6) or (7), then they must survey all components that would otherwise be subject to the calculation methodology based on population counts, and they must also survey all other components that are fugitive emissions components in the NSPS subpart OOOOa, with limited exceptions, as specified in 40 CFR 98.232. If they use any of the monitoring methods currently in 40 CFR 98.234(a)(1) through (5), then in addition to surveying the components that would otherwise be subject to the calculation methodology based on population counts, they may elect to survey the other specified in 40 CFR 98.232. The intent of the new provision in 40 CFR 98.233(q)(1)(iv) is to allow flexibility for reporters currently required to use the calculation methodology based on population counts for components that are not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards.

The burden of using the calculation methodology based on equipment leak surveys will be similar to using the existing subpart W calculation methodology based on population counts, and the results will be more representative of the number of leaks at the facility than the calculation methodology based on population counts. Table 2 of this preamble provides a summary of the equipment leak calculation methodologies and monitoring methods that will be available to each industry segment covered by subpart W under these amendments.

TABLE 2—FINAL EQUIPMENT LEAK REQUIREMENTS FOR SUBPART W

Subpart W industry segments [a]	Components subject to 40 CFR 60.5397a of the NSPS subpart OOOOa		Components not subject to 40 CFR 60.5397a of the NSPS subpart OOOOa	
	Subpart W calculation methodology [b]	Subpart W monitoring method for leak detection [c]	Subpart W calculation methodology	Subpart W monitoring method for leak detection [d]
Onshore Petroleum and Natural Gas Production.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)); OR Population count (40 CFR 98.233(r)).	Any method in 40 CFR 98.234(a). N/A.
Onshore Natural Gas Transmission Compression; Underground Natural Gas Storage: Storage stations, gas service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)) [e].	Any method in 40 CFR 98.234(a).

[11] See section II.D of this preamble.

[12] Except for onshore natural gas processing and natural gas distribution.

TABLE 2—FINAL EQUIPMENT LEAK REQUIREMENTS FOR SUBPART W—Continued

Subpart W industry segments [a]	Components subject to 40 CFR 60.5397a of the NSPS subpart OOOOa		Components not subject to 40 CFR 60.5397a of the NSPS subpart OOOOa	
	Subpart W calculation methodology [b]	Subpart W monitoring method for leak detection [c]	Subpart W calculation methodology	Subpart W monitoring method for leak detection [d]
Underground Natural Gas Storage: Storage wellheads, gas service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)); OR Population count (40 CFR 98.233(r)).	Any method in 40 CFR 98.234(a). N/A.
LNG [f] Storage: LNG Service; LNG Import and Export Equipment: LNG Service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)).	Any method in 40 CFR 98.234(a).
LNG Storage: Gas Service; LNG Import and Export Equipment: Gas Service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)); OR Population count (40 CFR 98.233(r)) [g].	Any method in 40 CFR 98.234(a). N/A.

[a] Onshore Natural Gas Processing and Natural Gas Distribution are not included in this table because we are not revising the calculation methodology and monitoring method for leak detection for these industry segments in this action. The current requirements are still applicable to components in these industry segments.

[b] The term "calculation methodology" refers to the procedures used to calculate emissions (*e.g.,* "calculation methodology based on equipment leak surveys" refers to the methodology described in 40 CFR 98.233(q)) and "monitoring method" refers to the technology, test method, or other method of determining whether an individual component is leaking (see 40 CFR 98.234(a)).

[c] OGI as specified in the NSPS subpart OOOOa is codified in subpart W at 40 CFR 98.234(a)(6) and Method 21 as specified in the NSPS subpart OOOOa is codified in subpart W at 40 CFR 98.234(a)(7).

[d] "Any method in 40 CFR 98.234(a)" means any of the following methods: OGI as specified in 40 CFR 60.18 (40 CFR 98.234(a)(1)), Method 21 with a leak definition of 10,000 parts per million by volume (ppmv)(40 CFR 98.234(a)(2)), Infrared laser beam illuminated instrument (40 CFR 98.234(a)(3)), Acoustic leak detection device (40 CFR 98.234(a)(5)), OGI as specified in the NSPS subpart OOOOa (40 CFR 98.234(a)(6)) or Method 21 with a leak definition of 500 ppmv (40 CFR 98.234(a)(7)).

[e] Reporting is required for emissions from valves, connectors, open-ended lines, pressure relief valves, and meters but is optional for instruments and other components unless the reporter elects to use either OGI or Method 21 as specified in the NSPS subpart OOOOa (40 CFR 98.234(a)(6) or (7)), in which case reporting is also required for instruments and other fugitive emissions components.[13]

[f] LNG = liquefied natural gas.

[g] Reporting is only required for emissions from vapor recovery compressors if this option is chosen.

2. Summary of Comments and Responses

Comment: Several commenters stated that facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments should not be required to use the NSPS subpart OOOOa results to calculate GHG emissions to comply with subpart W. They stated that the proposed NSPS subpart OOOOa leak detection program was limited to one monitoring method, which is inconsistent with the current flexibility for reporters conducting equipment leak surveys for subpart W to choose any monitoring method within 40 CFR 98.234(a). The commenters asserted that this requirement will result in some subpart W reporters having to manage multiple equipment leak survey programs within one facility, especially if the facility is located within a state with a different leak detection program, and this result is overly burdensome. In addition, the commenters stated that the equipment leak survey results will be internally inconsistent if they use different methods, and a facility's emissions could appear to increase one year simply because the number of sites subject to the NSPS subpart OOOOa increases, requiring the reporter to use the OGI method in the NSPS subpart OOOOa for an increased number of components. Instead, the reporters suggested, use of the calculation methodology based on equipment leak surveys, including the selection of monitoring method within 40 CFR 98.234(a), should be voluntary for all facilities not currently required to conduct leak surveys under subpart W.

In contrast, another commenter requested that the EPA require all subpart W reporters to detect leaks using direct equipment leak detection technologies such as OGI. The commenter stated that leak detection using OGI can produce more accurate data than current subpart W methods and that the EPA's approach is consistent with the EPA's stated goals to enhance the rigor and transparency of subpart W data. In addition, the commenter stated that applying OGI detection uniformly across subpart W sources will produce data that is readily comparable across facilities and will allow the EPA to assess the performance of facilities over time.

Response: For facilities that have affected sources required to conduct fugitive emissions monitoring to comply with the NSPS subpart OOOOa well site or compressor station fugitive emissions standards, the EPA is finalizing as proposed that these components must meet the subpart W calculation methodology based on equipment leak survey requirements. In practice, this means reporters can meet these requirements by counting the actual number of components with fugitive emissions identified through implementation of the NSPS subpart OOOOa as leaks for purposes of subpart W. This requirement will achieve the EPA's stated goal of alignment with the NSPS subpart OOOOa and will assist in providing the EPA with a greater understanding of emission reductions.

At this time, we are not requiring all subpart W facilities to perform a leak detection survey using direct equipment leak detection technologies such as OGI. Rather this action is focused on aligning the subpart W requirements, to the extent possible, with the NSPS subpart OOOOa fugitive emission requirements so that facilities may use the results of the NSPS subpart OOOOa-required

[13] See section II.D.1 of this preamble for the EPA's decision on the final subpart W requirements for components not subject to 40 CFR 60.5397a of the NSPS Subpart OOOOa from affected facilities in the Onshore Natural Gas Transmission Compression industry segment, and storage stations in gas service within the Underground Natural Gas Storage industry segment.

fugitive emissions monitoring surveys to fulfill subpart W requirements.

The EPA does not agree that a subpart W requirement to use the results of a previously completed leak survey within the subpart W calculation methodology based on equipment leak surveys will result in an undue burden to these reporters. For components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards, there is little to no burden associated with using the number of components found to have fugitive emissions as the number of leaking components in the subpart W calculation methodology based on equipment leak surveys. The only additional piece of information these reporters need to calculate emissions is the amount of time each component was leaking, and this is a straightforward determination based on the dates of the equipment leak surveys. See section IV.B of this preamble for information and responses to comments related to the EPA's burden estimates for these amendments.

C. Summary of Final Amendments to Monitoring Methods

1. Summary of Final Amendments

The EPA is finalizing the proposal to add OGI, as specified in the NSPS subpart OOOOa, to the list of monitoring methods in 40 CFR 98.234(a). The addition of this specific OGI method to subpart W at 40 CFR 98.234(a)(6) aligns the methods in the two rulemakings and allows subpart W facilities to directly use information derived from the implementation of the fugitive emissions monitoring conducted under the NSPS subpart OOOOa to calculate and report equipment leak emissions to the GHGRP.

The EPA has made changes to the proposed subpart W amendments after consideration of public comment and/or to be consistent with the final revisions made to the corresponding proposed NSPS subpart OOOOa specifications. The proposed subpart W amendments cross-referenced the proposed 40 CFR 60.5397a(b) through (e) and (g) through (i), which included the requirements to: (1) Develop a corporate-wide fugitive emissions monitoring plan; (2) develop a site-specific monitoring plan; (3) observe each fugitive emissions component for fugitive emissions; (4) conduct monitoring surveys semiannually; and (5) adjust the frequency of monitoring surveys based on the percent of the fugitive emissions components detected to have fugitive emissions. For the reasons described below, the final amendments to subpart W for the OGI method cross-reference a portion of the NSPS subpart OOOOa requirements to develop the fugitive emissions monitoring plan and the NSPS subpart OOOOa requirements to observe each fugitive emissions component for fugitive emissions.

The final NSPS subpart OOOOa requires an emissions monitoring plan that covers the affected sources within each company-defined area. This monitoring plan includes information about the survey frequency, monitoring method and instrument selected, repair procedures and timeframes, recordkeeping, and procedures for calibrating the monitoring instrument and verifying that it can detect fugitive emissions at the required levels.

For the final subpart W amendments, the EPA evaluated the NSPS subpart OOOOa requirements for the monitoring plan along with the level of detail in the existing monitoring methods in 40 CFR 98.234(a). The EPA determined that information about the monitoring instrument selected and procedures for calibrating the monitoring instrument and verifying that it can detect fugitive emissions at the required levels is necessary to ensure the OGI monitoring is performed correctly. Therefore, the new OGI detection method in subpart W does include the NSPS subpart OOOOa requirement to develop a monitoring plan that describes the OGI instrument (40 CFR 60.5397a(c)(3)) and how the OGI survey will be conducted to ensure that fugitive emissions can be imaged effectively (40 CFR 60.5397a(c)(7)). The EPA determined that the NSPS subpart OOOOa survey frequency should not be cross-referenced in subpart W because cross-referencing these frequencies would override the current annual survey requirement in subpart W regardless of whether the use of the new monitoring methods is voluntary or mandatory. The EPA determined that the repair procedures and timeframes should not be cross-referenced because subpart W is part of a reporting program and does not require repair of detected leaks. The EPA also determined that the NSPS subpart OOOOa recordkeeping requirements should not be cross-referenced because they include provisions that are not applicable to greenhouse gas reporting, such as records related to repairs. Applicable recordkeeping requirements for all leak detection methods in subpart W are specified at 40 CFR 98.237.

The final site-specific monitoring plan in the NSPS subpart OOOOa includes three items specific to the OGI method: (1) A sitemap; (2) a defined observation path for the operator that ensures that all fugitive emissions components are within sight of the path; and (3) a monitoring plan for difficult-to-monitor and unsafe-to-monitor fugitive emissions components. The EPA has reviewed these elements as well and determined not to cross-reference these three elements in subpart W. The observation path and the sitemap ensure that the OGI operator visualizes all of the components that must be surveyed, analogous to requirements in some rules to identify all of the equipment that must be monitored using Method 21 (*e.g.,* 40 CFR 60.486a(e)(1) and 40 CFR 63.162(c)). Subpart W does not include these identification requirements as part of the Method 21 requirements in 40 CFR 98.234(a)(2), so it would be inconsistent to require the observation path as part of the new OGI method. However, while we are not finalizing the explicit requirement to define the observation path the operator will follow during their survey, we do note that 40 CFR part 98, subpart A requires a written GHG monitoring plan for all facilities subject to the GHGRP (see 40 CFR 98.4(g)(5)). Defining an observation path is one item that could be included in the GHG monitoring plan to meet the requirement to describe ''procedures and methods that are used for quality assurance . . . of all . . . other instrumentation'' used to collect data to comply with the GHGRP (40 CFR 98.3(g)(5)(i)(C)).

The EPA is finalizing the proposed requirement to observe each fugitive emissions component for fugitive emissions (40 CFR 60.5397a(e)).[14] The EPA considers surveying all fugitive emissions components (instead of just the current list of equipment in subpart W for a particular industry segment) to be an inherent part of the NSPS subpart OOOOa OGI method.

The EPA is not cross-referencing the semi-annual (well sites) and quarterly (compressor stations) monitoring frequencies of the final NSPS subpart OOOOa. As noted above, cross-referencing these monitoring frequencies would override the current annual survey requirement in subpart W regardless of whether the use of the new monitoring methods is voluntary or mandatory. The EPA is instead clarifying that for reporters with components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and for which surveys are required or elected, the results from each equipment leak

[14] See section II.D.1 of this preamble for details regarding the specific NSPS subpart OOOOa-defined fugitive emissions components that are not considered sources of ''equipment leaks'' in subpart W.

survey must be used to calculate GHG emissions for subpart W. The EPA is further clarifying that it is not our intent to require reporters that are not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements to conduct more than one equipment leak survey in a calendar year for purposes of GHGRP reporting, solely because they choose to use the OGI method. The EPA also notes that the proposed NSPS subpart OOOOa provisions for adjusting the frequency of equipment leak surveys based on the percent of the fugitive emissions components detected to have fugitive emissions were not included in the final NSPS subpart OOOOa and therefore are not cross-referenced in the final subpart W revisions.

Finally, consistent with the final NSPS subpart OOOOa, the EPA is finalizing the use of Method 21 as an alternative monitoring method to OGI (as specified in the NSPS subpart OOOOa) at 40 CFR 98.234(a)(7). As the EPA noted in the preamble for this proposed revision to subpart W (81 FR 4989; Jan. 29, 2016), the NSPS subpart OOOOa proposal identified EPA Method 21 as a monitoring method that may also be used to conduct resurveys of repaired components when fugitive emissions are detected (80 FR 56612 (well sites) and 80 FR 56612 (compressor stations)), and the EPA requested comment on including in the final rule the use of Method 21 for fugitive emissions monitoring as well (80 FR 56638 (well sites) and 80 FR 56643 (compressor stations)). The EPA also made clear in the preamble to these proposed revisions to subpart W that, consistent with the goal of aligning the methods in the two rulemakings (subpart W and the NSPS subpart OOOOa), the EPA expected that the final amendments to subpart W for monitoring methods would reference the final version of the method(s) in the NSPS subpart OOOOa, including any changes made to the NSPS subpart OOOOa in response to comments on the proposed monitoring method(s) (81 FR 4991). Accordingly, the EPA is finalizing the use of Method 21 as an alternative monitoring method to OGI (as specified in the NSPS subpart OOOOa) at 40 CFR 98.234(a)(7).

For reporters that elect to use Method 21 as specified in 40 CFR 98.234(a)(7), either for components that are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements or voluntarily, a leak is detected if an instrument reading of 500 ppmv or greater is measured. As explained in this section regarding the NSPS subpart OOOOa OGI monitoring method, we determined that the requirements in 40 CFR 60.5397a(b) are consistent with the requirements of subpart W regarding the development of an emissions monitoring plan; this monitoring plan is required to include verification that the procedures of Method 21 are followed consistent with the requirements in 40 CFR 60.5397a(c)(8). Also, as with the NSPS subpart OOOOa OGI method, the EPA is requiring in subpart W observation of each fugitive emissions component for fugitive emissions consistent with the requirements in 40 CFR 60.5397a(e); the EPA considers surveying all fugitive emissions components to be an inherent part of the NSPS subpart OOOOa Method 21 alternative to the OGI method and is consistent with requirements in subpart W to conduct a complete equipment leak survey.

At this time, the EPA is not adding any other monitoring methods to subpart W. We will continue to evaluate equipment leak detection methods and technologies [15] and may amend subpart W to allow the use of additional methods in the future.

2. Summary of Comments and Responses

Comment: Many commenters disagreed with the EPA's proposal to add only the OGI method as specified in the NSPS subpart OOOOa to 40 CFR 98.234(a) of subpart W. They asserted that while OGI is an effective method for finding the majority of emissions more quickly than EPA Method 21, it is also a costly technology that cannot quantify emissions. The commenters stated that OGI has other limitations, especially in non-ideal weather conditions; one commenter also stated that use of the OGI camera requires a hot work permit in many instances.

Response: Due to similar comments on the proposed NSPS subpart OOOOa, the final NSPS subpart OOOOa provides owners and operators of new, modified, or reconstructed well sites or compressor stations with the option of using EPA Method 21 with a repair threshold of 500 ppmv if they elect not to use the OGI method (40 CFR 60.5397a). As discussed in section II.C.1 of this preamble, the final amendments to subpart W provide for the use of EPA Method 21 where a leak is detected for purposes of subpart W if an instrument reading of 500 ppmv or greater is measured. This amendment to subpart W maintains the alignment with the NSPS subpart OOOOa well site and compressor station fugitive emissions monitoring requirements, so that reporters can directly use the NSPS subpart OOOOa monitoring results to count the number of leaks under subpart W.

Comment: Many commenters stated that leak detection technology is a rapidly growing field and there are many alternative technologies and new technologies in development that may be more accurate and less costly than OGI. Some commenters noted that recent emphasis on CH_4 emissions has caused vendors to focus on CH_4 leak detection. Therefore, according to the commenters, some of those technologies may be better options for the purpose of reporting emissions under subpart W than other leak detection programs. The commenters stated that the EPA's proposal to limit leak surveys to a prescriptive list of methods could limit development of these new technologies.

Commenters provided a variety of suggestions for incorporation of new and emerging technologies into subpart W. Three commenters recommended that the EPA establish a clear process for industry, vendors, and/or the EPA to evaluate the efficacy and accuracy of alternative CH_4 monitoring technologies and approve the use of those technologies. One of these commenters noted that any technology evaluation process should be straightforward and more streamlined than the years-long process needed to approve emissions control devices or continuous emissions monitoring systems. Another of these commenters suggested that the EPA model a technology evaluation process after the vendor testing program for flares and combustors, in which the EPA sets testing protocols and vendors demonstrate that they can meet specific criteria. A fourth commenter suggested that the EPA develop a pilot program to incentivize the accelerated development and deployment of advanced monitoring and detection technologies and to compare the effectiveness of these approaches to periodic, OGI-based surveys.

Response: The EPA agrees with the commenters that emissions monitoring in the oil and gas sector is a field of emerging technology, and major advances are expected in the near future. We are seeing a rapidly growing push to develop and produce low-cost monitoring technologies to find fugitive CH_4 emissions sooner and at lower levels than current technology allows, thus enhancing the ability of operators to detect fugitive emissions. The EPA agrees that continued development of these cost-effective technologies is

[15] For example, the EPA has issued a voluntary request for information inviting all parties to provide information on innovative technologies to detect, measure, and mitigate emissions from the oil and gas industry. See 81 FR 46670 (July 18, 2016).

important. However, the EPA does not have enough information at this time to evaluate specific technologies to determine if they are equivalent to or better than the monitoring methods provided in and being added to 40 CFR 98.234(a). The EPA may evaluate new options as they become available and determine if they are equivalent to existing methods. For example, the final NSPS subpart OOOOa provides a process for the EPA to determine that a technology can be used as an ''alternative means of emission limitation.'' [16] As technologies are approved through this process, the EPA anticipates that it would contemporaneously incorporate these monitoring methods in subpart W to ensure continued alignment between the NSPS subpart OOOOa and subpart W through future notice and comment rulemaking.

Comment: Multiple commenters addressed the proposed requirement to consider any fugitive emissions observed using OGI during the NSPS subpart OOOOa fugitive emissions monitoring as a leak for purposes of subpart W. Most of these commenters objected to the proposal and stated that the definition of a leak for subpart W should be 10,000 ppmv, regardless of the monitoring method used. These commenters asserted that setting the leak definition consistent with the current methods in subpart W would ensure that the new methods result in new information being collected and reported consistently within a facility and consistent with the equipment leak data already in the GHGRP. One commenter noted that defining a leak as emissions at a set concentration is much less subjective than defining a leak as any emissions observed with OGI, and setting the leak definition at 10,000 ppmv rather than a lower concentration would allow operators to focus on finding (and fixing) large leaks instead of spending resources to identify many small leaks that do not contribute much to overall emissions. Another commenter noted that a leak definition of 10,000 ppmv is consistent with the leaker emission factors currently provided in subpart W as well as the proposed new leaker emission factors.

One commenter agreed with a subpart W leak being defined as any fugitive emissions observed using OGI during the NSPS subpart OOOOa fugitive emissions monitoring or emissions above 500 ppmv detected via EPA Method 21, but the commenter asserted that the leak definition for any new or emerging technologies used in a voluntary leak survey should be 5,000 ppmv. The commenter noted that these new technologies are likely to be more sensitive and detect emissions at lower concentrations than OGI, and companies that are employing more accurate instruments should not be ''penalized'' by having to report more leaks than if they used OGI.

Response: Subpart W already includes OGI and EPA Method 21 with a leak definition of 10,000 ppmv for use by reporters currently required to conduct leak surveys for subpart W. The final amendments also provide for use of these methods by reporters electing to conduct an equipment leak survey voluntarily (*i.e.,* for sources currently required to use the calculation methodology based on population counts that are not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements). The EPA is adding the methods used for fugitive emissions monitoring in the NSPS subpart OOOOa to 40 CFR 98.234(a), as approved monitoring methods for subpart W leak surveys. This addition facilitates alignment with the NSPS subpart OOOOa and will allow reporters to directly use the NSPS subpart OOOOa monitoring results to count the number of leaks under subpart W. Finally, as noted in section II.C.1 of this preamble, the EPA is not adding any other monitoring methods to subpart W at this time, so it is not necessary to consider a different leak definition for new or emerging technologies.

The EPA disagrees that using a leak definition other than 10,000 ppmv would undermine the quality of the data reported to the GHGRP. First, subpart W currently includes an OGI monitoring method in 40 CFR 98.234(a)(1). While this monitoring method allows facilities to screen the observed leaks using Method 21, it does not require it, and we do not expect that many reporters actively use dual monitoring methods in their leak surveys to screen all OGI-detected leaks using Method 21.

Second, we are also finalizing, consistent with the final NSPS subpart OOOOa rule, the ability to use Method 21 with a leak definition of 500 ppmv as an alternative to the OGI method. We agree with commenters that the average emissions rate of leaks identified using Method 21 with a leak definition of 500 ppmv would be less than the average emissions rate of leaks identified using Method 21 with a leak definition of 10,000 ppmv. To address this issue, we are also finalizing separate leaker factors that are appropriate for reporters using this alternative method (Method 21 with a leak definition of 500 ppmv). As described in further detail in section II.E.1 of this preamble and in the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' in Docket ID No. EPA–HQ–OAR–2015–0764, these additional emission factors were developed from the same data set that was used to develop the original population emission factors and the proposed leaker factors.[17] Therefore, this additional Method 21 monitoring method, which includes a different leak definition than the other Method 21-based method already available in subpart W at 40 CFR 98.234(a)(2), has been specifically considered and new emission factors are provided in the final rule to ensure that this new monitoring method's leak definition will not undermine the quality of the emissions reported under subpart W.

If the EPA did not provide the ability for reporters to use the monitoring methods required by the NSPS subpart OOOOa within subpart W, reporters would not be able to use the NSPS subpart OOOOa monitoring results directly; instead, they would have to measure each occurrence of fugitive emissions individually to determine if it is a leak for purposes of subpart W, which would increase the burden for those reporters.

D. Summary of Final Amendments for Components To Be Surveyed

1. Summary of Final Amendments

The EPA proposed to align the subpart W equipment components with the NSPS subpart OOOOa definition of ''fugitive emissions component,'' with certain exceptions.[18] After careful consideration of comments, the EPA is finalizing that provision consistent with the final NSPS subpart OOOOa definition of ''fugitive emissions component'' with certain exceptions consistent with the proposal, as described in further detail in this section below. A ''fugitive emissions component'' is defined in 40 CFR 60.5430a of the final NSPS subpart

[16] See 40 CFR 60.5398a titled ''What are the alternative means of emission limitations for GHG and volatile organic compounds from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?''

[17] This data set was developed from monitoring conducted using Method 21 with a leak definition of 10,000 ppmv.

[18] See 81 FR 4994 for a discussion of the differences between the proposed definition of ''fugitive emissions component'' and the proposed components subject to equipment leak reporting in subpart W.

OOOOa to include any component that has the potential to emit fugitive emissions of CH4 or volatile organic compounds at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to 40 CFR 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to 40 CFR 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from a location other than the vent are considered fugitive emissions.

As noted in the preamble to the proposed subpart W amendments, some of the components listed in the NSPS subpart OOOOa definition of fugitive emissions component are already included as part of the subpart W equipment leaks calculation methodologies (either based on equipment leak surveys or on population counts), while other fugitive emissions components are specifically addressed in other calculation methodologies in subpart W. As part of developing the proposed amendments for subpart W, we compared the list of components in the NSPS subpart OOOOa proposed definition of fugitive emissions component with the current methodologies in subpart W to identify which fugitive emissions components were already covered by an existing requirement in subpart W and which fugitive emissions components would be specifically covered in subpart W when using the OGI method as specified in the proposed NSPS subpart OOOOa.

Table 3 of this preamble provides a summary of the applicable subpart W calculation methodologies for components subject to the fugitive emissions standards in the final NSPS subpart OOOOa. The basis for excluding certain components that are subject to the fugitive emissions standards in the final NSPS subpart OOOOa from the final equipment leak survey requirements in 40 CFR 98.233(q) is discussed below.

TABLE 3—FINAL SUBPART W CALCULATION METHODOLOGY REQUIREMENTS FOR COMPONENTS SUBJECT TO THE FUGITIVE EMISSIONS STANDARDS IN NSPS SUBPART OOOOa

Type of component in definition of fugitive emissions component and subject to the fugitive emissions standards in NSPS subpart OOOOa	Applicable GHG emissions calculation methodology in subpart W by industry segment for components that are also subject to the fugitive emissions standards for well sites or compressor stations in the NSPS subpart OOOOa[a]		
	Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting	Underground natural gas storage, LNG storage, LNG import and export equipment	Onshore natural gas transmission compression
Thief hatches or other openings on controlled storage vessels not subject to 40 CFR 60.5395a.	• 40 CFR 98.233(j)	• 40 CFR 98.233(q) (use factor for "other" components in Tables W–4A, W–5A, and W–6A to subpart W)[b].	• 40 CFR 98.233(k).
Compressors, excluding emissions from vents that are part of normal operations (*i.e.,* wet seal oil degassing vents).	• 40 CFR 98.233(q) for blowdown valve leakage and isolation valve leakage (use factor for "open-ended line" in Table W–1E to subpart W)[b]. • 40 CFR 98.233(q) for all other leaks from the housing (use factor for "other" components in Table W–1E to subpart W)[b]. • 40 CFR 98.233(p)(10) for rod packing venting from reciprocating compressors.	• 40 CFR 98.233(o) for blowdown valve leakage and isolation valve leakage from centrifugal compressors. • 40 CFR 98.233(p) for blowdown valve leakage, isolation valve leakage, and rod packing venting from reciprocating compressors. • 40 CFR 98.233(q) for all other leaks from the housing (use factor for "other" components in Table W–4A, W–5A, and W–6A to subpart W)[b].	• 40 CFR 98.233(o) for blowdown valve leakage and isolation valve leakage from centrifugal compressors • 40 CFR 98.233(p) for blowdown valve leakage, isolation valve leakage, and rod packing venting from reciprocating compressors • 40 CFR 98.233(q) for all other leaks from the housing (use factor for "other" components in Tables W–3A, to subpart W)[b]
All other components	• 40 CFR 98.233(q) (use factors for applicable component types in Table W–1E to subpart W)[b].	• 40 CFR 98.233(q) (use factors for applicable component types in Tables W–4A, W–5A, and W–6A to subpart W)[c].	• 40 CFR 98.233(q) (use factors for applicable component types in Table W–3A to subpart W)[c].

[a] Onshore Natural Gas Processing and Natural Gas Distribution are not included in this table because we are not revising the calculation methodology and monitoring method for leak detection for these industry segments in this action. The current requirements are still applicable to components in these industry segments.

[b] The leaker emission factors for "other" components are being finalized in this revision.

[c] The leaker emission factors include both factors in the current rule and factors that are being finalized in this action, depending on the specific component and the monitoring method used to conduct the survey, as discussed in section II.E.1 of this preamble.

At proposal, we determined that the subpart W calculation methodology for storage tanks in 40 CFR 98.233(j) already includes emissions from thief hatches or other openings on storage vessels in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. However, we requested comment on whether the agency should consider separate approaches for controlled storage tanks and uncontrolled storage tanks. The final definition of "fugitive emissions component" in the NSPS subpart OOOOa (40 CFR 60.5430a) includes only thief hatches or other openings on a controlled storage vessel; it does not specifically list openings on uncontrolled storage vessels. We reviewed the subpart W calculation methodology specifically for storage tanks with a vapor recovery system (40 CFR 98.233(j)(4)) and storage tanks with a flare (40 CFR 98.233(j)(5)). The procedure for determining emissions from a tank with a vapor recovery system instructs reporters to adjust the storage tank emissions downward by the magnitude of emissions recovered using

a vapor recovery system as determined by engineering estimate based on best available data (40 CFR 98.233(j)(4)(i)). The procedure for determining emissions from a tank with a flare references 40 CFR 98.233(n), which instructs reporters to use engineering calculations based on process knowledge, company records, and best available data to determine the flow to the flare if the flare does not have a continuous flow measurement device. If a reporter sees fugitive emissions from a thief hatch or other opening on a controlled storage vessel during an equipment leak survey conducted using OGI, the reporter should consider that information as part of the ''best available data'' used to calculate emissions from that storage tank. Therefore, we have concluded that emissions from thief hatches or other openings on storage vessels in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are already included in the subpart W storage tank emission calculations in 40 CFR 98.233(j) and are finalizing, consistent with the proposal, that they are not to be considered when determining emissions from equipment leaks for purposes of subpart W.

We are also finalizing as proposed the exclusion of thief hatches and other openings on transmission storage tanks from the equipment leak reporting requirements.[19] We note that, for purposes of subpart W reporting, a leaking thief hatch or other opening is functionally a secondary vent, and thus subject to annual screening on an uncontrolled tank according to 40 CFR 98.233(k)(1). If screening shows vapors from the thief hatch or opening are continuous for 5 minutes, then a method in 40 CFR 98.233(k)(2) must be used to quantify the leak rate, and this amount must be combined with any other vent leak rates for reporting.

We are also finalizing the proposed distinction between equipment leak emissions and compressor emissions. Specifically, for centrifugal compressors, emission sources include wet seal oil degassing vents (for centrifugal compressors with wet seals), blowdown valve leakage, and isolation valve leakage. For reciprocating compressors, emission sources include reciprocating compressor rod packing vents, blowdown valve leakage, and isolation valve leakage.

For compressors in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments under subpart W, the compressor methodologies only cover emissions from centrifugal compressor wet seal oil degassing vents and from reciprocating compressor rod packing vents. Thus, the EPA is finalizing as proposed, for these industry segments, that blowdown valve leakage and isolation valve leakage are considered equipment leaks (*i.e.,* open-ended lines), and finalizing as proposed that emissions from centrifugal compressor wet seal oil degassing vents and from reciprocating compressor rod packing vents are not considered equipment leaks when using the calculation methodology based on equipment leak surveys in 40 CFR 98.233(q).[20]

For the Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment segments, subpart W requires reporters to make ''as found'' or continuous measurements for compressor emission sources, so the reporters will have either direct measurement data or site-specific emission factors by which to calculate emissions from all of the compressor sources listed above (*i.e.,* wet seal oil degassing vents for centrifugal compressors with wet seals, rod packing vents for reciprocating compressors, and blowdown valve leakage and isolation valve leakage for both centrifugal and reciprocating compressors). Therefore, we are finalizing as proposed to exclude these compressor emission sources from the requirements in the calculation methodology based on equipment leak surveys so that reporters do not double-count emissions from these sources in their GHGRP reports.

Finally, as noted in section II.C.1 of this preamble, we are finalizing the proposed determination that for purposes of subpart W, all other fugitive emissions components as defined in the NSPS subpart OOOOa not specifically identified above (*e.g.,* thief hatches or other openings on a controlled storage vessel, compressor sources with explicit calculation methodologies in subpart W) will be considered equipment components when conducting an equipment leak survey using the OGI method as specified in the NSPS subpart OOOOa or EPA Method 21 with a leak definition of 500 ppmv. In other words, we consider the provision requiring monitoring of fugitive emissions components as defined in the NSPS subpart OOOOa in 40 CFR 60.5397a(e) to be an inherent part of the NSPS subpart OOOOa OGI method and EPA Method 21 with a leak definition of 500 ppmv. Therefore, if a reporter with components not subject to the NSPS subpart OOOOa well site or compressor station fugitive emission requirements elects to use the NSPS subpart OOOOa OGI method or EPA Method 21 with a leak definition of 500 ppmv for purposes of subpart W, they are also electing to survey these additional components.

2. Summary of Comments and Responses

Comment: Several commenters stated that the NSPS subpart OOOOa proposed definition of ''fugitive emissions component'' is too expansive. Because it includes many more emission sources than a more traditional definition of equipment, the commenters asserted that it is inconsistent with current subpart W requirements. The commenters stated that aligning subpart W with the NSPS subpart OOOOa in this respect will complicate the question of which components must be monitored at subpart W facilities and will result in facilities having higher numbers of leaks than they would have if they used any other equipment leak detection method in subpart W. Some commenters stated that even for well sites and compressor station sites subject to the NSPS subpart OOOOa, component types considered to be equipment under subpart W should be consistent with a more traditional definition of equipment. Other commenters requested that equipment under subpart W only include component types for which the EPA can provide specific population factors and leaker emission factors.

Response: As noted in section II.D.1 of this preamble, the final definition of ''fugitive emissions component'' in the NSPS subpart OOOOa (40 CFR 60.5430a) does not list as many explicit individual component types, as originally proposed. The EPA is finalizing, with the exceptions discussed in section II.D.1 of this preamble and consistent with the extent proposed, this alignment with the NSPS subpart OOOOa, so that reporters may directly use the NSPS subpart OOOOa monitoring results to count the number of leaks under subpart W. Reporters using the calculation methodology based on equipment leak surveys for

[19] The exceptions to equipment leak reporting requirements were included in Tables W–1E and W–3 through W–6 of the proposal. The final rule moves these exceptions to 40 CFR 98.232, to increase clarity and reduce confusion while achieving the same purpose and effect.

[20] 40 CFR 98.233(q) specifies which subsections in 40 CFR 98.232 (*i.e.,* which components) must follow the calculation methodology based on equipment leak surveys in 40 CFR 98.233(q), and 40 CFR 98.232 subsections identify exceptions from the list of components for which equipment leak reporting is required.

components not subject to the NSPS subpart OOOOa may choose which monitoring method to use. If a reporter chooses to use one of the monitoring methods listed in 40 CFR 98.234(a)(1) through (5), that reporter would use the current list of equipment components for the appropriate industry segment in 40 CFR 98.232 (*e.g.,* the list of equipment at 40 CFR 98.232(e)(7) for the Onshore Natural Gas Transmission Compression industry segment). If a reporter chooses to use the OGI method as specified in the NSPS subpart OOOOa or EPA Method 21 with a leak definition of 500 ppmv, the reporter would use both the current list and the newly added list of equipment components for the appropriate industry segment in 40 CFR 98.232, which in conjunction include the NSPS subpart OOOOa definition of ''fugitive emissions component'' in 40 CFR 60.5430a with the exceptions discussed in section II.D.1 of this preamble (*e.g.,* the list of equipment at 40 CFR 98.232(e)(7) and (8) for the Onshore Natural Gas Transmission Compression industry segment).

E. Summary of Final Amendments to Leaker Emission Factors and the Calculation Methodology Based on Equipment Leak Surveys

1. Summary of Final Amendments

To quantify emissions from leaking equipment components, subpart W includes leaker emission factors for each component type in each industry segment currently required to use the calculation methodology based on equipment leak surveys. In contrast to the population emission factors, which are multiplied by the total facility component counts, leaker emission factors are multiplied by the actual number of leaks for each component type, as identified by the equipment leak survey. These amendments increase the component types that are required or may elect to use the calculation methodology based on equipment leak surveys, including most of the component types currently using the subpart W calculation methodology based on population counts.[21] Therefore, new leaker emission factors are being added so that reporters can calculate their GHG emissions for these new component types.

Specifically, the EPA proposed to add new sets of leaker emission factors to subpart W for: (1) The Onshore Petroleum and Natural Gas Production industry segment; (2) the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment; (3) storage wellheads in gas service in the Underground Natural Gas Storage industry segment; (4) LNG storage components in gas service in the LNG Storage industry segment; and (5) LNG terminals components in gas service for the LNG Import and Export Equipment industry segment. For industry segments that already include a set of leaker emission factors, the EPA also proposed to expand that set of leaker emission factors to include certain additional components to better align with the definition of fugitive emissions components in the NSPS subpart OOOOa. See the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket Item No. EPA–HQ–OAR–2015–0764–0028, for more information on the development of the proposed leaker emission factors.

We are finalizing the leaker emission factors for the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments as proposed, with clarifications for flanges and connectors noted below. We are also finalizing the following leaker emission factors as proposed: (1) The leaker emission factors for ''other'' components in Tables W–3A, W–4A, W–5A, and W–6A to subpart W; (2) the leaker emission factors for storage wellhead equipment in gas service within Table W–4A to subpart W; and (3) the leaker emission factors for equipment in gas service for LNG storage components within Table W–5A to subpart W and for LNG terminal components within Table W–6A to subpart W. We are also finalizing the proposal to expand the existing leaker emission factor for meters to also include instruments in Tables W–3A and W–4A to subpart W for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments, respectively. All but one of the proposed leaker factors for flanges in Tables W–3 through W–6 to subpart W (Tables W–3A, W–4A, W–5A, and W–6A to subpart W in these final amendments) were the same as the leaker factors for connectors; the exception was for flanges in gas service associated with storage wellheads at Underground Natural Gas Storage facilities, which had a proposed leaker factor that differed from the proposed leaker factor for connectors in the same service. Flanges are a type of connector, which means the proposed flange factors that were identical to the existing connector factors were redundant. Therefore, we have not finalized the proposed separate factors for flanges where the factor was the same as the factor for connectors and are finalizing that flanges must use the final connector factor, meaning the effect of the final amendments is the same as the proposal. The separate factors for connectors and flanges for storage wellheads in gas service at Underground Natural Gas Storage facilities are finalized as proposed, but to clarify that the factor for connectors applies only to all types of connectors other than flanges, the component name has been changed from ''connector'' in the proposal to ''connector (other)'' in Table W–4A of the final amendments. This change also makes the terminology in Table W–4A consistent with the terminology in Tables W–1A and W–1E, which also specify factors for flanges that differ from the factors for other types of connectors.

We are not finalizing the proposed addition of pumps to the leaker factors in Table W–2 for the Onshore Natural Gas Processing industry segment. As described in section II.B.1 of this preamble, we are not taking final action on the Onshore Natural Gas Processing revisions at this time.

In addition to finalizing nearly all of the proposed leaker factors, we are also finalizing an additional set of emission factors corresponding to the average emissions rates of components identified using Method 21 with a leak definition of 500 ppmv. The proposed leaker factors were developed based on Method 21 monitoring using a leak definition of 10,000 ppmv and were to be applied by all reporters regardless of the leak survey monitoring method used. As noted in section II.C of this preamble, the final NSPS subpart OOOOa includes an additional alternative that allows reporters to use Method 21 with a leak definition of 500 ppmv. On average, the emissions from a leak identified with a Method 21 reading above 500 ppmv are less than the emissions from a leak identified with a Method 21 reading of 10,000 ppmv or higher. Consequently, the leaker factor (which is the average emissions rate) for leaks identified when using a leak definition of 500 ppmv is smaller than the leaker factor for leaks identified when using a leak definition of 10,000 ppmv. Therefore, in order to use the NSPS subpart OOOOa survey results directly to calculate equipment leak emissions for subpart W when Method 21 with a leak definition of 500

[21] The NSPS subpart OOOOa fugitive emission requirements do not apply to fugitive emissions components in the Natural Gas Distribution industry segment.

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ppmv is used, leaker factors were developed consistent with the average emissions rate of a ''leak'' defined as a measurement reading of 500 ppmv or more using Method 21. We developed these new leaker factors using data from EPA's Protocol for Equipment Leak Emissions Estimates [22] consistent with the data used to develop the proposed leaker factors for Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. See the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' in Docket ID No. EPA–HQ–OAR–2015–0764, which provides more information on the development of the final leaker emission factors. The inclusion of leaker factors specific to Method 21 with a leak definition of 500 ppmv is consistent with our proposal to align subpart W calculation methodologies with the monitoring requirements in the NSPS subpart OOOOa.

We are also finalizing the proposed amendments to the time variable $T_{p,z}$ in Equation W–30 to clarify the total time a surveyed component found leaking is assumed to be leaking and operational. The previous language for the definition of the time variable specifically considers a first leak survey and a last leak survey in the year but does not provide specific language with respect to the duration of any ''intermediate'' survey conducted between the first and last survey. Therefore, the EPA proposed to amend the definition of the time variable to clarify how to determine the duration of a leak if more than two leak surveys are conducted in a year and to instruct reporters to sum the individual durations to determine the total time the component was leaking during the year.

The EPA is finalizing this amendment as proposed. The amendments to the time variable $T_{p,z}$ define each equipment leak survey as covering a unique, non-overlapping time period and we are clarifying our intent that a leak detected in the first or any intermediate survey is not considered to continue leaking past the date of that specific equipment leak survey. For the last survey conducted in the calendar year, the leak is assumed to continue until the end of the year. For example, if a reporter conducts three equipment leak surveys in a calendar year and a particular component is found to be leaking in the first and second surveys but not the third, the total leak duration is the sum of the time from January 1 to the date of the second survey. If a reporter conducts three equipment leak surveys in a calendar year and a particular component is found to be leaking in the first and last surveys but not the second, then the total leak duration is the sum of the time from January 1 to the date of the first survey and the time from the date of the second survey to December 31.

See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for all comments and the EPA's responses to comments on other aspects of the time variable $T_{p,z}$ in Equation W–30.

Finally, 40 CFR 98.233(q) includes a provision requiring reporters to conduct one equipment leak survey in a calendar year (which must include ''all component types'' subject to 40 CFR 98.233(q)) or multiple ''complete'' equipment leak surveys in a calendar year. In response to comments as part of the 2010 subpart W final rule, the EPA noted that subsequent equipment leak surveys should be ''conducted for an entire facility.'' [23]

The EPA has reviewed how this interpretation could interact with these final amendments for components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and finds that additional clarification is necessary. For example, a facility in the Onshore Petroleum and Natural Gas Production industry segment or the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment may have some components that are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and some components that are not. In such a case, multiple equipment leak surveys would be conducted for the components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements, to fulfill the requirements of the NSPS subpart OOOOa for those components, that would be consistent with subpart W monitoring methods under these final revisions.

However, under the current interpretation of a ''complete'' survey, it would appear that these reporters would either: (1) Be unable to use the NSPS subpart OOOOa fugitive emissions monitoring results as directed, because they did not survey all components at the facility; or (2) be forced to monitor all components at the facility on the same frequency as the components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements to meet the subpart W requirement to use all additional leak surveys conducted in accordance with NSPS OOOOa. The first interpretation would render these final amendments useless, and the second interpretation would increase the burden beyond the EPA's intentions, and could also have unintended consequences for the components subject to the NSPS subpart OOOOa (*e.g.*, a subpart W facility with some components subject to the NSPS subpart OOOOa well site fugitive emissions requirements and others subject to the NSPS subpart OOOOa compressor station fugitive emissions requirements could end up being required to monitor the fugitive emissions components at a well site four times a year instead of twice). Therefore, the EPA is clarifying in 40 CFR 98.233(q)(2)(i) that any monitoring conducted pursuant to and in compliance with the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements constitutes a ''complete'' survey for purposes of subpart W and must be used for subpart W reporting. The EPA is further clarifying that, to meet the requirements of 40 CFR 98.233(q), at least one equipment leak survey must be conducted in a calendar year.

2. Summary of Comments and Responses

Comment: Several commenters addressed the EPA's proposed leaker emission factors. Some of the commenters indicated that the EPA/Gas Research Institute (GRI) data set upon which the proposed factors are based is an older data set and asserted that it may not be representative of operating practices and procedures that have changed significantly over the past 20 years. In addition, the commenters stated that the EPA/GRI data set includes a limited population of measurements, so the proposed leaker emission factors may not account for operational variability on a regional or national level. Some commenters requested that the EPA consider newer studies, including those cited in

[22] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emissions Estimates.* EPA–453/R–95–017. November 1995. Docket Item No. EPA–HQ–OAR–2009–0927–0043.

[23] U.S. Environmental Protection Agency. *Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments.* November 2010. Docket Item No. EPA–HQ–OAR–2009–0923–3608. Response to Comment Number EPA–HQ–OAR–2009–0923–1014–9, pp. 1281–1282.

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''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (Docket Item No. EPA–HQ–OAR–2015–0764–0028) either instead of or in combination with the EPA/GRI data set.

Several commenters urged the EPA to work with the regulated community to improve the default leaker emission factors in subpart W. One commenter noted that the proposed leaker emission factors may be a viable interim solution but recommended that the EPA analyze more robust data sets consisting of the combined results of all studies for each industry segment and evaluate whether the subpart W leaker emission factors should be revised.

Response: As described in the preamble to the proposed rule and the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' (Docket ID No. EPA–HQ–OAR–2015–0764), the EPA has determined that the EPA/GRI data set is appropriate to base leaker emission factors in these subpart W amendments. We note that the EPA/GRI data set provides sufficient data to develop leaker emission factors and that using this data set for the leaker emission factors provides consistency with the population emission factors used by reporters that do not conduct equipment leak surveys.

The EPA agrees that there are numerous recent studies that could be used to either replace or supplement the EPA/GRI study data, and many of these are described in the technical support document. The EPA evaluated these other studies and found that the leaker emission factors determined from these data sets agreed reasonably well with the leaker emission factors developed from the EPA/GRI data set, suggesting that the EPA/GRI leaker emission factors are still valid. Commenters that supported a different basis for the leaker emission factors than the EPA/GRI data set did not provide specific information explaining why another study would be a better basis or address any of the specific considerations listed above, although the comments received suggest that stakeholders are interested in further involvement in the assessment of the available data. Therefore, for the reasons stated in the preamble to the proposed rule and the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' in Docket ID No. EPA–HQ–OAR–2015–0764, the EPA is finalizing the leaker emission factors as proposed.

The EPA appreciates the commenters' interest in providing a thorough review of the available study data to develop an accurate set of leaker emission factors. The EPA is committed to working with stakeholders to ensure that GHGRP requirements and calculation methods are based upon the most robust data available. If the EPA determines that revisions to the subpart W leaker emission factors are appropriate in the future based on additional information, we anticipate that we will propose to amend the rule accordingly.

Comment: Numerous commenters stated that reporters should be allowed to use site-specific leak quantification data if available, either directly for each individual leak (*i.e.,* direct measurement data) or to develop their own leaker emission factors on a facility-specific, company-specific, or product-specific basis. Most of these commenters supported the EPA's proposal to include default leaker emission factors, but stated that reporters should not be limited to using them if the facility has more accurate, site-specific information. Some commenters further noted that the site-specific data reported to the GHGRP could be used to improve the default leaker emission factors in the future. One commenter also requested that the EPA require quantification of any leak that a reporter elects not to repair.

Response: The EPA did not propose and, after review and consideration of comments, is not finalizing provisions allowing reporters to use site-specific information to calculate equipment leak emissions for subpart W. While we agree that direct measurement has the potential to provide more accurate emissions data than using emission factors, we would need to develop criteria and guidelines for using direct measurement data consistently across subpart W reporters for calculating equipment leak emissions. Similarly, we agree that using site-specific emission factors can provide more accurate emissions data than using default emission factors, but a robust set of requirements would be needed for reporters to use when developing their own emission factors to ensure that those factors are as unbiased and representative as possible. In addition, if reporters are using direct measurement or their own emission factors, we would most likely need to amend the reporting requirements (*e.g.*, to require reporters to provide site-specific emission factors), and we would need to consider whether any other amendments would be needed to enable us to review and verify reported data. In either of these cases, we would provide the opportunity for the public to comment on those amended requirements before finalizing them within subpart W.

F. Summary of Final Amendments to Reporting Requirements

1. Summary of Final Amendments

The EPA is finalizing largely as proposed the new reporting requirements for facilities conducting equipment leak surveys under subpart W. Reporters in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, reporters with storage wellheads in the Underground Natural Gas Storage industry segment, and reporters with components in gas service in the LNG Storage and LNG Import and Export Equipment industry segments that begin using the calculation methodology based on equipment leak surveys must report the information currently listed in 40 CFR 98.236(q)(1) and (2), which includes the number of equipment leak surveys, component types, number of leaking components, average time the components were assumed to be leaking, and annual CO_2 and CH_4 emissions. Facilities that conduct surveys using the new monitoring methods in 40 CFR 98.234(a)(6) or (7) must also report the data elements in 40 CFR 98.236(q)(2) for additional component types specified in 40 CFR 98.232. Reporters may elect to report the data elements in 40 CFR 98.236(q)(2) for the additional component types if they conduct surveys using a monitoring method in 40 CFR 98.234(a)(1) through (5).

The data elements in 40 CFR 98.236(q)(1) and (2) are already required to be reported by facilities conducting equipment leak surveys in the Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage (storage stations), and LNG Storage and LNG Import and Export Equipment (components in LNG service) industry segments. However, facilities in those segments conducting equipment leak surveys using the new OGI method or Method 21, as specified in the NSPS subpart OOOOa (finalized in subpart W as 40 CFR 98.234(a)(6) or (7)), must begin reporting the data elements in 40 CFR 98.236(q)(2) for component types with the new leaker emission factors, including component types that are not currently subject to reporting. Facilities conducting equipment leak surveys using a monitoring method in 40 CFR

98.234(a)(1) through (5) may elect to begin reporting the data elements in 40 CFR 98.236(q)(2) for other components that are not currently subject to reporting.

In addition, the EPA is finalizing as proposed three new reporting requirements for facilities conducting equipment leak surveys in all of the above segments as well as the Onshore Natural Gas Processing and Natural Gas Distribution segments. First, facilities in those segments will be required to report the monitoring method(s) in 40 CFR 98.234(a) used to conduct the survey(s). Second, facilities in the above segments except for Onshore Natural Gas Processing and Natural Gas Distribution will be required to indicate whether any of their component types are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements. Finally, facilities with components for which the calculation methodology based on equipment leak surveys is optional (*e.g.,* facilities in the Onshore Petroleum and Natural Gas Production segment) will be required to indicate whether they elected to use the calculation methodology based on equipment leak surveys for any of their component types at the facility.

Additionally, in reviewing specific reporting requirements while responding to public comments, we recognized that the reporting requirements at 40 CFR 98.236(r)(3)(ii) were unclear, and could be misinterpreted with respect to how this reporting element relates to the calculated emissions. Therefore, we are revising 40 CFR 98.236(r)(3)(ii) by adding the phrase ''. . . for which equipment leak emissions are calculated using the methodology in § 98.233(r)'' to clarify our original intent that the major equipment counts reported under this requirement are specific to equipment for which emissions are calculated using the population count methodology.

2. Summary of Comments and Responses

Comment: Two commenters addressed the proposed requirement in 40 CFR 98.236(q)(1)(iii) to indicate whether any component types at a facility are subject to the NSPS subpart OOOOa. One commenter opposed the addition, stating that it is overly burdensome to require reporters to delineate reporting of emission sources subject to the NSPS subpart OOOOa, especially if this is intended to be a numeric response regarding the number of individual components subject to the NSPS subpart OOOOa. Another commenter asserted that it is not clear if the response to proposed 40 CFR 98.236(q)(1)(iii) is a single yes or no for each facility or if the EPA will be expecting a yes or no response for each component type.

Response: In the final rule, the EPA has revised the proposed requirement in 40 CFR 98.236(q)(1)(iii) (indicate whether any component types are subject to the NSPS subpart OOOOa) to be clear that the EPA expects only one yes or no response for an entire facility. While the EPA understands that the number of leaking components and equipment leak emissions may increase as the number of components subject to the NSPS subpart OOOOa increases, this response will allow the EPA to provide transparent data related to changes in emissions for facilities with components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements over time. This data element will also support verification that the appropriate GHGRP monitoring method was used by the facility.

III. Confidentiality Determinations

A. Summary of Final Confidentiality Determinations for New Subpart W Data Elements

As noted in the proposed rule, we are applying the same approach as previously used for making confidentiality determinations for data elements reported under the GHGRP. In the ''Confidentiality Determinations for Data Required Under the Mandatory Greenhouse Gas Reporting Rule and Amendments to Special Rules Governing Certain Information Obtained Under the Clean Air Act'' (hereafter referred to as ''2011 Final CBI Rulemaking'') (76 FR 30782, May 26, 2011), the EPA grouped part 98 data elements for which EPA was determining confidentiality status through that rulemaking into 22 data categories (11 direct emitter data categories and 11 supplier data categories) with each of the 22 data categories containing data elements that are similar in type or characteristics. The EPA then made categorical confidentiality determinations for eight direct emitter data categories and eight supplier data categories and applied the categorical confidentiality determination to all data elements assigned to the category. Of these data categories with categorical determinations, the EPA determined that four direct emitter data categories are comprised of those data elements that meet the definition of ''emission data,'' as defined at 40 CFR 2.301(a), and are, therefore, not entitled to confidential treatment under section 114(c) of the CAA.[24] The EPA determined that the other four direct emitter data categories and the eight supplier data categories do not meet the definition of ''emission data.'' For these data categories that are determined not to be emission data, the EPA determined categorically that data in three direct emitter data categories and five supplier data categories are eligible for confidential treatment as CBI, and that the data in one direct emitter data category and three supplier data categories are ineligible for confidential treatment as CBI. For two direct emitter data categories, ''Unit/Process 'Static' Characteristics that Are Not Inputs to Emission Equations'' and ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' and three supplier data categories, ''GHGs Reported,'' ''Production/Throughput Quantities and Composition,'' and ''Unit/Process Operating Characteristics,'' the EPA determined in the 2011 Final CBI Rulemaking that the data elements assigned to those categories are not emission data, but the EPA did not make categorical CBI determinations for them. Rather, the EPA made CBI determinations for each individual data element included in those categories on a case-by-case basis taking into consideration the criteria in 40 CFR 2.208. The EPA did not make a final confidentiality determination for data elements assigned to the inputs to emission equation data category (a direct emitter data category) in the 2011 Final CBI Rulemaking. However, the EPA has since proposed and finalized an approach for addressing disclosure concerns associated with inputs to emissions equations.[25]

In the proposed rule, we assigned the nine proposed new or substantially revised data elements to the appropriate direct emitter data categories created in the 2011 Final CBI Rulemaking based on the type and characteristics of each data element. For the seven data elements the EPA assigned to a direct emitter category with a categorical determination, the EPA proposed that the categorical determination for the category be applied to the proposed new or substantially revised data elements,

[24] Direct emitter data categories that meet the definition of ''emission data'' in 40 CFR 2.301(a) are ''Facility and Unit Identifier Information,'' ''Emissions,'' ''Calculation Methodology and Methodological Tier,'' and ''Data Elements Reported for Periods of Missing Data that are not Inputs to Emission Equations.''

[25] Revisions to Reporting and Recordkeeping Requirements, and Confidentiality Determinations Under the Greenhouse Gas Reporting Program; Final Rule. (79 FR 63750, October 24, 2014).

as shown in Table 4 of this preamble. For the two data elements assigned to the ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' we proposed confidentiality determinations on a case-by-case basis taking into consideration the criteria in 40 CFR 2.208, consistent with the approach used for data elements previously assigned to these two data categories, as shown in Table 5 of this preamble. Refer to the preamble to the proposed rule (81 FR 4987; January 29, 2016) for additional information regarding the proposed confidentiality determinations.

With consideration of the information provided by commenters, the EPA is finalizing the confidentiality determinations as proposed. Specifically, the EPA is finalizing the proposed determination for each of the nine new or substantially revised data elements to be designated as ''emission data'' or ''not CBI.''

TABLE 4—FINAL DATA CATEGORY ASSIGNMENTS AND CONFIDENTIALITY DETERMINATIONS FOR NEW DATA ELEMENTS ASSIGNED TO CATEGORIES WITH CATEGORICAL DETERMINATIONS

Citation	Data element	Final category assignment	Categorical determination (as established in 2011)[26]
§ 98.236(q)(1)(i)	The number of complete equipment leak surveys performed during the calendar year.	Test and Calibration Methods.	Not Emission Data and Not CBI.
§ 98.236(q)(1)(iii)	Whether any component types were subject to 40 CFR part 60, subpart OOOOa.	Facility and Unit Identifier Information.	Emission Data.
§ 98.236(q)(1)(iv)	Whether you elected to comply with § 98.233(q) per § 98.233(q)(1)(iii).	Facility and Unit Identifier Information.	Emission Data.
§ 98.236(q)(1)(v)	Each type of method described in § 98.234(a) that was used to conduct leak surveys.	Test and Calibration Methods.	Not Emission Data and Not CBI.
§ 98.236(q)(2)(i)	For each component type that is located at your facility, component type.	Facility and Unit Identifier Information.	Emission Data.
§ 98.236(q)(2)(iv)	For each component type that is located at your facility, annual CO_2 emissions, in metric tons CO_2.	Emissions	Emission Data.
§ 98.236(q)(2)(v)	For each component type that is located at your facility, annual CH_4 emissions, in metric tons CH_4.	Emissions	Emission Data.

TABLE 5—FINAL CONFIDENTIALITY FOR DATA ELEMENTS ASSIGNED TO THE ''UNIT/PROCESS OPERATING CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS'' DATA CATEGORY

Citation	Data element	Final confidentiality determination and rationale
§ 98.236(q)(2)(ii)	For each component type that is located at your facility, total number of the surveyed component type that were identified as leaking in the calendar year (''x_p'' in Equation W–30).	Not Emission Data (Categorical Determination as Established in 2011). Not CBI. The term ''equipment leaks'' refers to those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening. Leaking components at a facility may have a correlation to the level of maintenance at a facility. However, there is no direct correlation between the level of maintenance and process efficiency, *i.e.,* a higher number of leaks in one facility do not indicate that the processes have been running longer or more frequently than those processes at another facility that has a lower number of leaks. Furthermore, Department of Transportation (DOT) regulations require natural gas distribution companies and transmission pipeline companies to conduct periodic leak detection and fix any leaking equipment. The number of leaks detected and fixed is reported to the DOT and is publicly available. Finally, 40 CFR part 60, subpart OOOOa requires reporting for each component with visible emissions at affected well sites and compressor station sites. The EPA is finalizing that this data element is not confidential; and that it will be considered ''not CBI.''
§ 98.236(q)(2)(iii)	For each component type that is located at your facility, average time the surveyed components are assumed to be leaking and operational, in hours (average of ''T_p,z'' from Equation W–30).	Not Emission Data (Categorical Determination as Established in 2011). Not CBI. This data element will provide information on the amount of time operational components were found to be leaking. This information provides little insight into maintenance practices at a facility because it does not identify the cause of the leaks or the nature and cost of repairs. Therefore, this information would not be likely to cause substantial competitive harm to reporters. For this reason, we are finalizing the average time operational components were found leaking be designated as ''not CBI.''

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed categorical assignments and confidentiality determinations. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–

[26] The categorical confidentiality determinations for the data categories listed in this table were finalized on May 26, 2011 (see 76 FR 30782).

0764 for a complete listing of all comments and responses. See the memorandum ''Final Data Category Assignments and Confidentiality Determinations for Data Elements in the 'Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket ID No. EPA–HQ–OAR–2015–0764 for a complete listing of final data category assignments and confidentiality determinations.

Comment: One commenter stated that the EPA should reconsider the proposed determination of ''not CBI'' for the number of components identified as leaking in a calendar year and the average time the surveyed components are assumed to be leaking. The commenter asserted that designating this information as CBI would encourage more reporters to voluntarily conduct leak surveys. The commenter also noted that this information is publically available for some sources and suggested that the rule provide an exception from classification as CBI for components subject to State programs or NSPS that already require public disclosure. Another commenter requested that the EPA protect the community's right to know and not allow companies to keep the public from finding out about leaks from hydrocarbon facilities.

Response: While it is possible that the requirement to report the number of leaking components and the average time those components were leaking could discourage some reporters from conducting voluntary equipment leak surveys, this is not a valid reason to allow reporters to claim these data elements as confidential. As noted in section III.C of the preamble to the proposed rule, the EPA proposed that disclosure of these data elements is unlikely to cause substantial harm to a business's competitive position, and the commenter did not indicate that the EPA's determination was incorrect. Therefore, the EPA is finalizing the confidentiality determinations for these data elements as ''not CBI.''

IV. Impacts of the Final Amendments to Subpart W

A. Impacts of the Final Amendments

The final amendments to subpart W revise costs associated with the use of the monitoring methods and the calculation methodology based on equipment leak surveys for reporters in the following industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment. Reporters in these industry segments are required to use the results of fugitive emissions component monitoring required for well sites and compressor stations under the NSPS subpart OOOOa. Reporters in these segments with components not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and for which they are currently required to use the calculation methodology based on population counts under subpart W may voluntarily use the calculation methodology based on equipment leak surveys for those components if the equipment leak survey is conducted following a monitoring method listed in subpart W.

The EPA received comments from one commenter regarding the specific impacts of the proposed amendments. After evaluating these comments and reviewing other changes from proposal, the EPA revised the impacts assessment from proposal. The EPA estimates that the costs of the final amendments to subpart W are slightly more burdensome than we estimated at proposal, but they do not significantly change the overall burden to subpart W reporters. The EPA estimated that the additional costs to subpart W reporters in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to transition their existing equipment leak recordkeeping, calculating, and reporting systems to use the calculation methodology based on equipment leak surveys and to determine which components are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and which are not, will be approximately $110,000 per year, or about $410 per reporter. The EPA estimated that the additional costs for subpart W reporters in the other industry segments (*i.e.,* Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, Liquefied Natural Gas (LNG) Storage, and LNG Import and Export Equipment) to add a few new emission factors to their existing systems (rather than transitioning their recordkeeping, calculating, and reporting systems) and to determine which components are covered by the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and which are not, will be approximately $20,000 per year or about $110 per reporter. The total costs are approximately $128,400 per year for all reporters, or about $286 per reporter. See the memorandum, ''Assessment of Impacts of the Final Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for additional information.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the impacts of the proposed amendments to subpart W of part 98. We note that while several commenters asserted that the proposed rule would be burdensome for many operators and suggested revisions to the rule requirements that would reduce the burden, only one commenter provided comments on the EPA's impacts estimate and supporting statement, and that commenter's major comments are summarized in this section. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for a complete listing of all comments and responses.

Comment: One commenter stated that the EPA's estimate of two hours of labor and $198 per reporter significantly underestimates and misrepresents the amount of time and effort that goes into implementing a new rule. The commenter provided a cost estimate that assumes more labor hours than in the EPA's memorandum ''Assessment of Impacts of the Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (Docket Item No. EPA–HQ–OAR–2015–0764–0025). The commenter noted that as more sites become subject to the NSPS subpart OOOOa at a facility, the costs of managing the data and processing it into a usable format for the GHGRP will increase each year for that reporter. The commenter also noted that the EPA was incorrect in assuming that there would be no costs for facilities in the Onshore Natural Gas Processing segment.

Response: The EPA has evaluated the comments and has made changes to the estimate of burden in the supporting statement. The following paragraphs address each of the points in the commenter's detailed cost estimate included with the comment letter and explain how the points are being addressed in the final burden and cost estimate.

The commenter suggested adding burden of two hours in the first year related to the initial monitoring plan development and burden of 0.5 hours in subsequent years related to yearly monitoring plan revisions. The EPA did not include costs at proposal related to the monitoring plan because the subpart W amendments do not require the development of a separate monitoring plan. Instead, the subpart W amendments cross reference the monitoring plan that is already being developed according to the NSPS subpart OOOOa. The EPA recognizes that reporters that are not subject to the NSPS subpart OOOOa would not already be required to develop a monitoring plan under the NSPS subpart OOOOa; however, reporters that elect to use one of the new leak detection methods are also electing to incur the burden of developing a monitoring plan. Therefore, there is no monitoring plan burden associated with the subpart W amendments and the final burden and cost estimate has not changed from proposal as a result of this comment.

The commenter suggested changing the number of hours to revise the reporting system to five hours and to allow one hour for maintenance in each subsequent year. At proposal, the EPA estimated that revising the reporting system to use the calculation methodology based on equipment leak surveys would require two hours. The commenter did not provide the basis for their estimate of five hours to update the data management system. The overall reporting costs for compliance already include a burden of ten hours per year and the EPA disagrees that updating the data management system would encompass half of that allotment because EPA anticipates that reporters would only need to add a few emission factors for leaking components to their existing system, rather than something more time-intensive such as creating a new data management system. We reviewed the revisions expected to be needed in the data management system. While we maintain that two hours are sufficient to implement the calculation methodology based on equipment leak surveys into a reporter's existing system, we recognize that this process will also require quality assurance reviews and testing to ensure the data are stored properly and the calculations are performed correctly. Therefore, we increased the number of hours estimated to revise the reporting system from two hours to 3.5 hours to account for these additional quality reviews of the data management system. However, the EPA has made no changes to burden associated with maintenance of the revised reporting system because the EPA asserts that any reporting system maintenance related to subpart W is already reflected in the twenty hours per year allotted to each subpart W reporter for recordkeeping and reporting activities.

The commenter suggested that the EPA adjust the proposed burden and cost estimate by adding the following activities and burden estimates: (1) Time for staff to process the survey data resulting from the calculation methodology based on equipment leak surveys and to enter it into the GHGRP system at a burden of three hours per year; (2) time for staff training at a burden of two hours for initial training and one hour per year in subsequent years; and (3) time for staff to review the data for quality assurance, follow missing data requirements, report data to the EPA, and retain all records at a burden of four total hours per year.

At proposal, the EPA did not include burden related to these activities because they are covered by the twenty hours per year already accounted for in the overall subpart W reporter burden for recordkeeping and reporting activities. Therefore, the final burden and cost estimate has not changed from proposal as a result of these comments.

However, at proposal, the EPA did not account for the time associated with determining which components in the reporting system are covered by the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and which are not. As a result, the EPA has added 0.5 hours per reporter in the first year that the reporter has an affected collection of fugitive emissions components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and 0.1 hours per reporter in subsequent years.

Finally, for the reasons described in section II.B.2 of this preamble, the final rule language specifies that the requirement to use the NSPS subpart OOOOa results as part of the calculation methodology based on equipment leak surveys only applies to components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements. The subpart W equipment leak survey requirements for facilities in the Onshore Natural Gas Processing segment do not change as a result of these amendments. Therefore, the EPA is not including any burden estimate for Onshore Natural Gas Processing reporters (i.e., the revisions to the burden estimate described in this response do not apply to the Onshore Natural Gas Processing segment).

Overall, the burden and cost estimate has been revised as discussed above from 502 hours and $50,000 per year at proposal to approximately 1,295 hours and $128,400 per year for all reporters.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-and-executive orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2300.19. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This action increases burden for industry segments that conduct equipment leak surveys. These revisions are expected to increase respondent burden for subpart W reporters that become subject to the NSPS subpart OOOOa well site or compressor station fugitive requirements. To accommodate the new methods and emission factors added by these final amendments, the EPA expects that each affected subpart W reporter will either revise their reporter-specific calculation mechanism (i.e., calculation spreadsheet, recordkeeping database, etc.) or add a few new emission factors to the reporter-specific calculation mechanism, when and if the reporter becomes subject to the NSPS subpart OOOOa well site or compressor station fugitive requirements. The recordkeeping and reporting requirements are being finalized as proposed. Impacts associated with the final revisions to the recordkeeping and reporting requirements are detailed in the memorandum ''Assessment of Impacts of the Final Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems''

(see Docket ID No. EPA–HQ–OAR–2015–0764).

Data collection provides a critical tool for communities to identify nearby sources of GHGs and provides information to state and local governments. The data can be used to complement atmospheric GHG studies and inform updates to emission inventories such as the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory). Various activity data are collected that can be used to improve understanding of the occurrence of emissions from a variety of sources.

Data collected must be made available to the public unless the data qualify for CBI treatment under the CAA and EPA regulations. All data determined by the EPA to be CBI are safeguarded in accordance with regulations in 40 CFR chapter 1, part 2, subpart B.

Respondents/affected entities: The respondents in this information collection include owners and operators of petroleum and natural gas systems facilities that report their GHG emissions from equipment leaks to the EPA to comply with subpart W.

Respondent's obligation to respond: The respondent's obligation to respond is mandatory under the authority provided in CAA section 114.

Estimated number of respondents: Approximately 899 respondents per year.

Frequency of response: Annual.

Total estimated burden: 1,295 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $128,400 (per year), includes $0 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the EPA will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities directly regulated by this final rule include small businesses in the petroleum and natural gas industry. The EPA has determined that some small businesses will be affected because their production processes emit GHGs exceeding the reporting threshold. This action includes amendments that may result in a small burden increase on some subpart W reporters, but the EPA has determined that the increased cost of less than $286 per reporter is not a significant impact. Details of this analysis are presented in ''Assessment of Impacts of the Final Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. As shown in sections IV.A and V.B of this preamble, the annual cost of this action is $128,400, which is well under $100 million per year.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This regulation will apply directly to petroleum and natural gas facilities that emit GHGs. Although few facilities that will be subject to the rule are likely to be owned by tribal governments, the EPA sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final subpart W that was promulgated on November 30, 2010 (75 FR 74458).

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in section IV.F of the preamble to the re-proposal of subpart W published on April 12, 2010 (75 FR 18608), and section IV.F of the preamble to the subpart W 2010 final rule published on November 30, 2010 (75 FR 74458).

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action is not subject to Executive Order 12898 (59 FR 7629, February 16, 1994) because it does not establish an environmental health or safety standard. Instead, this rule addresses information collection and reporting and verification procedures.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Reporting and recordkeeping requirements.

Dated: November 10, 2016.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 1. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart W—Petroleum and Natural Gas Systems

■ 2. Section 98.232 is amended by:
■ a. Revising paragraph (c)(21);
■ b. Adding paragraph (e)(8);
■ c. Revising paragraph (f)(5);
■ d. Adding paragraphs (f)(6) through (8);
■ e. Revising paragraphs (g)(3) and (4);
■ f. Adding paragraphs (g)(5) through (7);
■ g. Revising paragraphs (h)(4) and (5);
■ h. Adding paragraphs (h)(6) through (8); and
■ i. Revising paragraph (j)(10).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

* * * * *

(c) * * *

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

* * * * *

(e) * * *

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel. If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(f) * * *

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters associated with storage stations.

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(7) Equipment leaks from valves, connectors, open-ended lines, and pressure relief valves associated with storage wellheads.

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a, of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(g) * * *

(3) Flare stack emissions.

(4) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(5) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (g)(6) of this section.

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(h) * * *

(4) Flare stack emissions.

(5) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(6) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (h)(7) of this section.

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

* * * * *

(j) * * *

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

* * * * *

■ 3. Section 98.233 is amended by:
■ a. Revising the parameter EF_t of Equation W–1 in paragraph (a) introductory text, and paragraph (q);

■ b. Removing the first two sentences of paragraph (r) introductory text and adding four sentences in their place; and

■ c. Revising the parameters $Count_e$ and $EF_{s,e}$ of Equation W–32A in paragraph (r) introductory text, and paragraphs (r)(3) through (5).

The revisions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) * * *

* * * * *

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' listed in Tables W–1A, W–3B, and W–4B to this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W–1A to this subpart.

* * * * *

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported.

(1) *Survey requirements.* (i) For the components listed in § 98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you must conduct surveys using any of the leak detection methods listed in § 98.234(a) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(ii) For the components listed in § 98.232(d)(7) and (i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a)(1) through (5) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iii) For the components listed in § 98.232(c)(21), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), and (j)(10) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you must conduct surveys using any of the leak detection methods in § 98.234(a)(6) or (7) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iv) For the components listed in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), or (j)(10), that are not subject to fugitive emissions standards in § 60.5397a of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in § 98.234(a).

(A) If you elect to use a leak detection method in § 98.234(a)(1) through (5) for the surveyed component types in § 98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in § 98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) using the procedures in paragraph (q)(2) of this section.

(B) If you elect to use a leak detection method in § 98.234(a)(1) through (5) for the surveyed component types in § 98.232(e)(8), (f)(6), (f)(8), (g)(7), and (h)(8), then you must use the procedures in paragraph (q)(2) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in § 98.234(a)(6) or (7) for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) that are not subject to fugitive emissions standards in § 60.5397a of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) using the emission calculation requirements in paragraph (q)(2) of this section.

(2) *Emission calculation methodology.* For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (iv) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W–30 of this section and the requirements specified in paragraphs (q)(2)(i) through (xi) of this section. For the industry segment listed in § 98.230(a)(8), the results from Equation W–30 are used to calculate population emission factors on a meter/regulator run basis using Equation W–31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(2)(x)(A) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

$$E_{s,p,i} = GHG_i * EF_{s,p} * \sum_{z=1}^{x_p} T_{p,z} \qquad \text{(Eq. W-30)}$$

Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHGi from specific component type ''p'' (in accordance with paragraphs (q)(1)(i) through (iv) of this section) in standard (''s'') cubic feet, as specified in paragraphs (q)(2)(ii) through (x) of this section.

x_p = Total number of specific component type ''p'' detected as leaking in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$EF_{s,p}$ = Leaker emission factor for specific component types listed in Tables W–1E, W–2, W–3A, W–4A, W–5A, W–6A, and W–7 to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural

gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

$T_{p,z}$ = The total time the surveyed component ''z,'' component type ''p,'' was assumed to be leaking and operational, in hours. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.,* not operating under pressure) using an engineering estimate based on best available data.

(i) You must conduct at least one leak detection survey in a calendar year. The leak detection surveys selected must be conducted during the calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using Equation W–30. For components subject to the well site and compressor station fugitive emissions standards in § 60.5397a of this chapter, each survey conducted in accordance with § 60.5397a of this chapter will be considered a complete leak detection survey for purposes of this section.

(ii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(iii) Onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors for components in gas service, light crude service, and heavy crude service listed in Table W–1E to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas leaker factors for components in gas service listed in Table W–1E to this subpart.

(v) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–2 to this subpart.

(vi) Onshore natural gas transmission compression facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–3A to this subpart.

(vii) Underground natural gas storage facilities must use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in Table W–4A to this subpart.

(viii) LNG storage facilities must use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in Table W–5A to this subpart.

(ix) LNG import and export facilities must use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in Table W–6A to this subpart.

(x) Natural gas distribution facilities must use Equation W–30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W–7 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations. Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section.

(A) Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years ''n,'' not exceeding a five year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(B) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHG_i. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHG_i annually according to paragraph (q)(2)(x)(C) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \qquad \text{(Eq. W-31)}$$

Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type ''p'' during year ''y'' in standard (''s'') cubic feet, as calculated using Equation W–30 of this section.

p = Seven component types listed in Table W–7 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run ''w'' was operational, in hours during survey year ''y'' using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year ''y''.

y = Year of data included in emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(C) of this section.

n = Number of years of data, according to paragraph (q)(2)(x)(A) of this section, whose results are used to calculate emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(C) of this section.

(C) The emission factor ''$EFs_{,MR,i,}$'' based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated

annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(2)(x)(A) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 of this section. After the first survey cycle of ''n'' years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year ''y'' and survey results from all previous $(n-1)$ calendar years, such that each annual calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 is based on survey results from ''n'' years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, ''n_{new},'' in the new cycle is smaller than the number of years in the previous cycle, ''n,'' calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous $(n_{new}-1)$ calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(2)(x)(A) of this section, you must use the meter/regulator run population emission factors calculated using Equation W–31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(r) * * * This paragraph (r) applies to emissions sources listed in § 98.232(c)(21), (f)(7), (g)(5), (h)(6), and (j)(10) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in § 98.232(i)(2), (i)(3), (i)(4), (i)(5), (i)(6), and (j)(11). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. * * *

* * * * *

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C to this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W–4B to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W–7 to this subpart.

* * * * *

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W–1A, W–4B, W–5B, W–6B, and W–7 to this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D to this subpart.

* * * * *

(3) Underground natural gas storage facilities must use the appropriate default total hydrocarbon population emission factors for storage wellheads in gas service listed in Table W–4B to this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factor for LNG storage compressors in gas service listed in Table W–5B to this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factor for LNG terminal compressors in gas service listed in Table W–6B to this subpart.

* * * * *

■ 4. Section 98.234 is amended by:

■ a. Revising paragraph (a) introductory text, the paragraph (a)(1) heading, and the fourth sentence in paragraph (a)(2); and

■ b. Adding paragraphs (a)(6) and (7).

The revisions and additions read as follows:

* * * * *

§ 98.234 Monitoring and QA/QC requirements.

(a) You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of through-valve leakage from all source types listed in § 98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(i) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(ii) that occur during a calendar year. You must use one of the methods described in paragraph (a)(6) or (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(iii). If electing to comply with § 98.233(q) as specified in § 98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from component types as specified in § 98.233(q)(1)(iv) that occur during a calendar year.

(1) Optical gas imaging instrument as specified in § 60.18 of this chapter. * * *

* * * * *

(2) * * * If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

* * * * *

(6) Optical gas imaging instrument as specified in § 60.5397a of this chapter. Use an optical gas imaging instrument for equipment leak detection in accordance with § 60.5397a(b), (c)(3), (c)(7), and (e) of this chapter and paragraphs (a)(6)(i) through (iii) of this section. Unless using methods in paragraph (a)(7) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring

personnel more than 2 meters above a support surface.

(i) For the purposes of this subpart, any visible emissions from a component listed in § 98.232 observed by the optical gas imaging instrument is a leak.

(ii) For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(iii) For the purpose of complying with § 98.233(q)(1)(iv), the phrase ''the collection of fugitive emissions components at well sites and compressor stations'' in § 60.5397a(b) of this chapter means ''the collection of components for which you elect to comply with § 98.233(q)(1)(iv).''

(7) Method 21 as specified in § 60.5397a of this chapter. Use the equipment leak detection methods in appendix A–7 to part 60 of this chapter, Method 21, in accordance with § 60.5397a(b), (c)(8), and (e) of this chapter and paragraphs (a)(7)(i) through (iii) of this section. Inaccessible emissions sources, as defined in part 60 of this chapter, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(6) of this section to monitor inaccessible equipment leaks.

(i) For the purposes of this subpart, any instrument reading from a component listed in § 98.232 of this chapter of 500 ppm or greater using Method 21 is a leak.

(ii) For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(iii) For the purpose of complying with § 98.233(q)(1)(iv), the phrase ''the collection of fugitive emissions components at well sites and compressor stations'' in § 60.5397a(b) of this chapter means ''the collection of components for which you elect to comply with § 98.233(q)(1)(iv).''

* * * * *

■ 5. Section 98.236 is amended by:
■ a. Redesignating paragraphs (a)(1)(xiv) through (xvii) as paragraphs (a)(1)(xv) through (xviii), respectively;
■ b. Adding new paragraph (a)(1)(xiv);
■ c. Redesignating paragraphs (a)(9)(x) and (xi) as paragraphs (a)(9)(xi) and (xii), respectively;
■ d. Adding new paragraph (a)(9)(x);
■ e. Revising paragraph (q) introductory text, paragraph (q)(1), paragraph (q)(2) introductory text, paragraph (r)(3)(ii) introductory text, and the second sentence of paragraph (z) introductory text.

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

* * * * *

(a) * * *

(1) * * *

(xiv) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

* * * * *

(9) * * *

(x) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

* * * * *

(q) Equipment leak surveys. For any components subject to or complying with the requirements of § 98.233(q), you must report the information specified in paragraphs (q)(1) and (2) of this section. Natural gas distribution facilities with emission sources listed in § 98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) through (v) of this section.

(i) Except as specified in paragraph (q)(1)(ii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(ii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(iii) Except for onshore natural gas processing facilities and natural gas distribution facilities, indicate whether any equipment components at your facility are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter. Report the indication per facility, not per component type.

(iv) For facilities in onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment, indicate whether you elected to comply with § 98.233(q) according to § 98.233(q)(1)(iv) for any equipment components at your facility.

(v) Report each type of method described in § 98.234(a) that was used to conduct leak surveys.

(2) You must indicate whether your facility contains any of the component types subject to or complying with § 98.233(q) that are listed in § 98.232(c)(21), (d)(7), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), (i)(1), or (j)(10) for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero (''0'') for the information required according to paragraphs (q)(2)(ii) through (v) of this section.

* * * * *

(r) * * *

(3) * * *

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W–1B and W–1C to this subpart for which equipment leak emissions are calculated using the methodology in § 98.233(r).

* * * * *

(z) * * * If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xviii), (a)(8)(i), or (a)(9)(xii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

* * * * *

■ 6. Add Table W–1E to subpart W of part 98 in numerical order to read as follows:

TABLE W–1E TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING

Equipment components	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—All Components, Gas Service [1]		
Valve	4.9	3.5
Flange	4.1	2.2
Connector (other)	1.3	0.8
Open-Ended Line [2]	2.8	1.9
Pressure Relief Valve	4.5	2.8
Pump Seal	3.7	1.4
Other [3]	4.5	2.8
Leaker Emission Factors—All Components, Light Crude Service [4]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other [3]	3.1	2.0
Leaker Emission Factors—All Components, Heavy Crude Service [5]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other [3]	3.1	2.0

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.
[3] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).
[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."
[5] Hydrocarbon liquids less than 20°API are considered "heavy crude."

■ 7. Remove Table W–3 to subpart W of part 98 and add Table W–3A and Table W–3B to subpart W of part 98 in numerical order to read as follows:

TABLE W–3A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—Compressor Components, Gas Service		
Valve [1]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter or Instrument	19.33	12.39
Other [2]	4.1	2.63
Leaker Emission Factors—Non-Compressor Components, Gas Service		
Valve [1]	6.42	4.12
Connector	5.71	3.66
Open-Ended Line	11.27	7.22

TABLE W–3A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION—Continued

Onshore natural gas transmission compression	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Pressure Relief Valve	2.01	1.29
Meter or Instrument	2.93	1.88
Other [2]	4.1	2.63

[1] Valves include control valves, block valves and regulator valves.
[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(e)(8).

TABLE W–3B TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Population emission factors—gas service onshore natural gas transmission compression	Emission factor (scf/hour/component)
Low Continuous Bleed Pneumatic Device Vents [1]	1.37
High Continuous Bleed Pneumatic Device Vents [1]	18.20
Intermittent Bleed Pneumatic Device Vents [1]	2.35

[1] Emission Factor is in units of "scf/hour/device."

■ 8. Remove Table W–4 to subpart W of part 98 and add Table W–4A and Table W–4B to subpart W of part 98 in numerical order to read as follows:

TABLE W–4A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—Storage Station, Gas Service		
Valve [1]	14.84	9.51
Connector (other)	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other [2]	4.1	2.63
Leaker Emission Factors—Storage Wellheads, Gas Service		
Valve [1]	4.5	3.2
Connector (other than flanges)	1.2	0.7
Flange	3.8	2.0
Open-Ended Line	2.5	1.7
Pressure Relief Valve	4.1	2.5
Other [2]	4.1	2.5

[1] Valves include control valves, block valves and regulator valves.
[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(f)(6) and (8).

TABLE W–4B TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01

TABLE W–4B TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE—Continued

Underground natural gas storage	Emission factor (scf/hour/component)
Valve	0.1
Pressure Relief Valve	0.17
Open-Ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents [1]	1.37
High Continuous Bleed Pneumatic Device Vents [1]	18.20
Intermittent Bleed Pneumatic Device Vents [1]	2.35

[1] Emission Factor is in units of "scf/hour/device."

■ 9. Remove Table W–5 to subpart W of part 98 and add Table W–5A and Table W–5B to subpart W of part 98 in numerical order to read as follows:

TABLE W–5A TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—LNG Storage Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other [1]	1.77	0.99
Leaker Emission Factors—LNG Storage Components, Gas Service		
Valve [2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other [3]	4.1	2.63

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[2] Valves include control valves, block valves and regulator valves.
[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(g)(6) and (7).

TABLE W–5B TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG storage	Emission factor (scf/hour/component)
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor [1]	4.17

[1] Emission Factor is in units of "scf/hour/device."

■ 10. Remove Table W–6 to subpart W of part 98 and add Table W–6A and Table W–6B to subpart W of part 98 in numerical order to read as follows:

TABLE W–6A TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in sect; 98.234(a)(7)
Leaker Emission Factors—LNG Terminals Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other [1]	1.77	0.99
Leaker Emission Factors—LNG Terminals Components, Gas Service		
Valve [2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other [3]	4.1	2.63

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[2] Valves include control valves, block valves and regulator valves.
[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(h)(7) and (8).

TABLE W–6B TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission factor (scf/hour/component)
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor [1]	4.17

[1] Emission Factor is in units of "scf/hour/compressor."

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Convert Gas Pneumatic Controls To Instrument Air



Executive Summary

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector, and <1 Bcf from processing.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power, either from a utility or self-generated.

Natural Gas STAR Partners have reported savings of up to 70,000 thousand cubic feet (Mcf) per year per facility by replacing natural gas-powered pneumatic systems with instrument air systems, representing annual savings of up to $490,000 per facility. Partners have found that most investments to convert pneumatic systems pay for themselves in just over one year. Individual savings will vary depending on the design, condition and specific operating conditions of the controllers.

Technology Background

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. In the vast majority of applications, the natural gas industry uses pneumatic devices, which make use of readily available high-pressure natural gas to provide the required energy and control signals. Pneumatic instrument systems powered by high-pressure natural gas are used throughout the natural gas industry. In the production sector, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. Most processing plants already use instrument air, but some use gas pneumatics, and including the gathering/booster stations that feed these processing plants, there are about 13,000 gas pneumatic devices in this sector. In the transmission sector, an estimated 85,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at distribution company gate stations and distribution grids where they regulate flow and pressure.

Exhibit 1 depicts a pneumatic control system powered by natural gas. The pneumatic control system consists of the process control instruments and valves that are operated by natural gas regulated at approximately 20-30 pounds

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/year)	Value of Natural Gas Savings ($/year)			Implementation Cost ($)[a]	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Replace Gas with Air in Pneumatic Systems (per facility)	20,000	$60,000	$100,000	$140,000	$60,000	12	8	6

General Assumptions:
[a] Cost of installing compressor, dryer and other accessories, and annual electricity requirements.

NMED Exhibit 99 - 0001

Exhibit 1: Natural Gas Pneumatic Control System

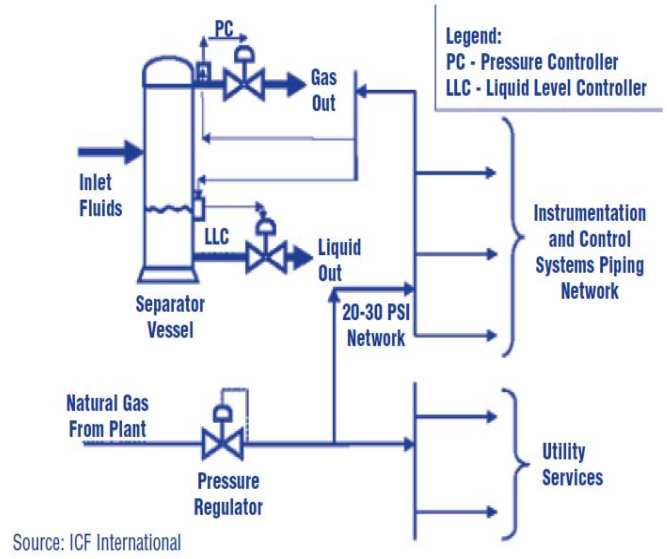
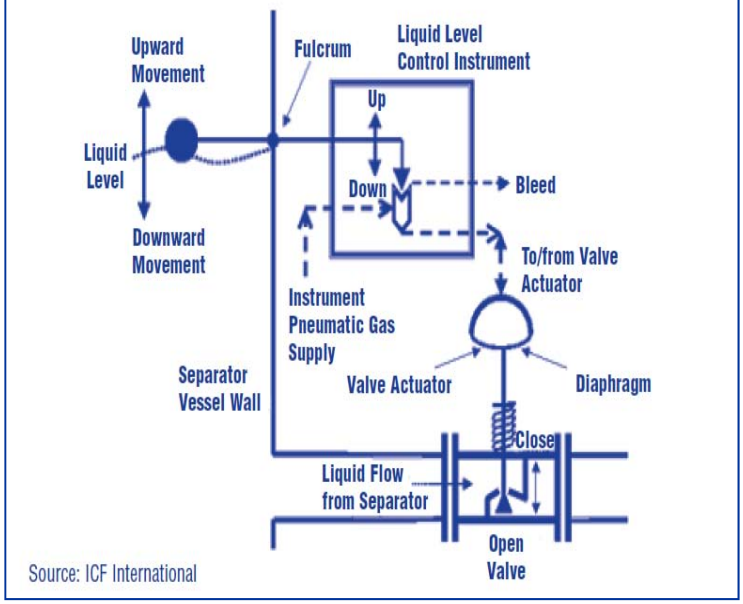


Exhibit 2: Signal and Actuation Schematics



per square inch (psi), and a network of distribution tubing to supply all of the control instruments. Natural gas is also used for a few "utility services," such as small pneumatic pumps, compressor motor starters, and isolation shutoff valves. Exhibit 2 shows a simplified diagram of a pneumatic control loop. A process condition, such as liquid level in a separator vessel, is monitored by a float that is mechanically linked to the liquid level controller outside the vessel. A rise or fall in liquid level moves the float upward or downward, which is translated to small needle valves inside the controller. Pneumatic supply gas is either directed to the valve actuator by the needle valve pinching off an orifice, or gas pressure is bled off the valve actuator. Increasing gas pressure on the valve actuator pushes down a diaphragm connected by a rod to the valve plug, causing the plug to open and increasing the flow of liquid draining out of the separator vessel. Gas pressure relieved from the valve actuator allows a spring to push the valve plug closed.

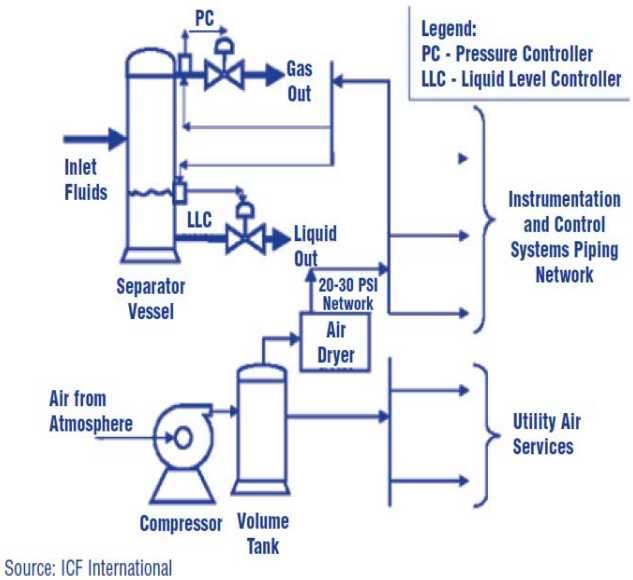
As part of normal operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network. The actual bleed rate or emissions level largely depends on the design of the device. In general, controllers of similar design have similar steady-state bleed rates regardless of brand name. The methane emission rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment.

Many Partners have found that it is economic to substitute compressed air for natural gas in pneumatic systems. The use of instrument air eliminates methane emissions and leads to increased gas sales. In addition, by eliminating the use of a flammable substance, operational safety is significantly increased. The primary costs associated with conversion to instrument air systems are initial capital expenditures for installing compressors and related equipment and operating costs for electrical energy to power the compressor motor. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.

A compressed instrument air system is shown in Exhibit 3. In these systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. Air used for utility services (e.g. small pneumatic pumps, gas compressor motor starters, pneumatic tools, sand blasting) does not need to be dried. All other parts of a gas pneumatic system will work the same way with air as they do with gas.

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following are descriptions of each of

Exhibit 3: Compressed Instrument Air System



Source: ICF International

these components along with important installation considerations.

- **Compressor.** Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.

- **Power Source.** A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduces both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- **Dehydrators.** Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices. For smaller systems, membrane dryers have become economic. These are molecular filters that allow oxygen and nitrogen molecules to pass through the membrane, and hold back water molecules. They are very reliable, with no moving parts, and the filter element can be easily replaced. For larger applications, desiccant (alumina) dryers are more cost effective.

- **Volume Tank.** The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Economic and Environmental Benefits

Reducing methane emissions from pneumatic devices by converting to instrument air control and instrumentation systems can yield significant economic and environmental benefits for natural gas companies including:

- **Financial Return From Reducing Gas Emission Losses.** Assuming a natural gas price of $7.00 per Mcf, savings from reduced emissions can be estimated at $840 per year per device or $490,000 or more per year per facility. In many cases, the cost of converting to instrument air can be recovered in less than a year.

- **Increased Life of Control Devices and Improved Operational Efficiency.** Natural gas used in pneumatic control devices and instruments often contains corrosive gases (such as carbon dioxide and hydrogen sulfide) that can reduce the effective operating life of these devices. In addition, natural

gas often produces by-products of iron oxidation, which can plug small orifices in the equipment resulting in operational inefficiencies or hazards. When instrument air is used, and properly filtered and dried, system degradation is reduced and operating life is extended.

★ **Avoided Use Of Flammable Natural Gas.** Using compressed air as an alternative to natural gas eliminates the use of a flammable substance, significantly increasing the safety of natural gas processing plants and transmission and distribution systems. This can be particularly important at offshore installations, where risks associated with hazardous and flammable materials are greater.

★ **Lower Methane Emissions.** Reductions in methane emissions have been reported as high as 70,000 Mcf per facility annually, depending on the device(s) and the type of control application.

Decision Process

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants. To determine the most cost-effective applications, however, requires a technical and economic feasibility study. The six steps outlined below, and the practical example with cost tables, equations, and factors, can help companies to evaluate their opportunities.

Step 1: Identify Possible Locations For Instrument Air System Installations.

Most natural gas-operated pneumatic control systems can be replaced with instrument air. Instrument air systems will require new investments for the compressor, dehydrator, and other related equipment, as well as a supply of electricity. As a result, a first step in a successful instrument air conversion project is screening existing facilities to identify locations that are most suitable for cost effective projects. In general, three main factors should be considered during this process.

Decision Process for Converting Gas Pneumatic Devices to Instrument Air:

1. Identify possible locations for system installations.
2. Determine optimal system capacity.
3. Estimate the project costs.
4. Estimate gas savings.
5. Evaluate the economics.
6. Develop an implementation plan.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

★ **Facility Layout.** The layout of a natural gas facility can significantly affect equipment and installation costs for an instrument air system. For example, conversion to instrument air might not be cost effective at decentralized facilities where tank batteries are remote or widely scattered. Instrument air is most appropriate when used at offshore platforms and onshore facilities where pneumatics are consolidated within a relatively small area.

★ **Number Of Pneumatics.** The more pneumatic controllers converted to instrument air, the greater the potential for reduced emissions and increased company savings. Conversion to instrument air is most profitable when a company is planning a facility -wide change.

★ **Available Power Supply.** Since most instrument air systems rely on electric power for operating the compressor, a cost-effective, uninterrupted electrical energy source is essential. While major facilities often have an existing power supply or their own power generation system, many smaller and remote facilities do not. For these facilities, the cost of power generation generally makes the use of instrument air unprofitable. In addition, facilities with dedicated generators need to assess whether the generators have enough available capacity to support an air compression system, as the cost of a generator upgrade can be prohibitive. Remote facilities should examine alternatives for power generation, which range from microturbines to solar power.

Step 2: Determine Optimal System Capacity.

Once project sites have been identified, it is important to determine the appropriate capacity of the new instrument air system. The capacity needed is a direct function of the amount of compressed air needed to both operate the pneumatic instrumentation and meet any utility air requirements.

★ **Instrument Air Requirements.** The compressed air needs for the pneumatic system are equivalent to the volume of gas being used to run the existing instrumentation—adjusted for air losses during the drying process. The current volume of gas usage can be determined by a direct meter reading (if a meter has been installed). In nonmetered systems, a conservative rule-of-thumb for sizing air systems is one cubic foot per minute (cfm) of instrument air for each control loop (consisting of a pneumatic controller and a control valve).

Rule-of-Thumb

1 cfm air/control loop

The initial estimate of instrument air needs should then be adjusted to account for air losses during the drying process. Typically, the membrane filters in the air dryer consume about 17 percent of the air input. As a result, the estimated volume of instrument air usage is 83 percent of the total compressed air supply: i.e., divide estimated air usage by 83 percent. Desiccant dryers do not consume air and therefore require no adjustment.

Rule-of-Thumb

17 percent of air input is consumed by the membrane dryer

★ **Utility Air Requirements.** It is common to use compressed air for utility purposes, such as engine starters, pneumatic driven pumps, pneumatic tools (e.g., impact wrenches), and sand blasting. Unlike instrument air, utility air does not have to be dried. The frequency and volumes of such utility air uses are additive. Companies will need to evaluate these other compressed air services on a site-specific basis, allowing for the possibility of expansion at the site. A general rule-of-thumb is to assume that the maximum rate of compressed air needed periodically for utility purposes will be double the steady rate used for instrument air.

Rule-of-Thumb

Pneumatic air uses: 1/3 for instrument air; 2/3 for utility air

Exhibit 4 illustrates how the instrument air compressor size can be estimated. Using the rule-of-thumb of 1 cfm/ control loop, the current gas usage would translate to approximately 35 cfm of dry instrument air. Adjusting for the dryer's air consumption (17 percent of air input), the total instrument air supply requirement will be 42 cfm. Factoring in utility air needs of about 70 cfm, the project would require a total of 112 cfm of compressed air.

Exhibit 4: Calculate Compressor Size for Converting Gas Pneumatics to Instrument Air

Given:	For an average size production site with pneumatics, glycol dehydration, compression, 35 control loops, and an average of 10 cfm utility gas usage for pneumatic pumps and compressor engine starting.
A IAu IAs UAs L	= Total Compressed Air = Instrument air use = Instrument air supply = Utility air supply = Control loops
	Rule-of-thumb: 1 cfm per control loop for estimating instrument air systems. Rule-of-thumb: 17% of air is bypassed in membrane dryers. Rule-of-thumb: 1/3 of total air used for instruments, 2/3 of total air used for utility services.
	Calculate: A = Air compressor capacity required.
A IAu IAs UAs A	= IAs + UAs = L * (1 cfm/loop) = IAu/(100% - % air bypassed in dryer) = IAu * (fraction of utility air use) / (fraction of instrument air use) = (35*1) / (100% - 17%) + (35*1) * (2/3) / (1/3) = 112 cfm

Step 3: Estimate the Project Costs.

The major costs associated with installing and operating an instrument air system are the installation costs for compressors, dryers, and volume tanks, and energy costs. The actual installation costs will be a function of the size, location, and other location specific factors. A typical conversion of a natural gas pneumatic control system to compressed instrument air costs approximately $45,000 to $75,000.

To estimate the cost for a given project, all expenses associated with the compressor, dryer, volume tank, and power supply must be calculated. Most vendors are willing to provide estimates of the equipment costs and installation requirements (including compressor size, motor horsepower, electrical power requirements, and storage capacity). Alternatively, operators can use the following information on the major system components to estimate the total installed cost of the instrument air system.

★ **Compressor Costs.** It is common to install two compressors at a facility (one operating and one stand-by spare) to ensure reliability and allow for maintenance and overhauls without service interruptions. The capacity for each of the compressors must be sufficient to handle the total expected compressed air volume for the project (i.e., both instrument and utility air). Exhibit 5 presents

cost estimates for purchasing and servicing small, medium, and large compressors. For screw-type compressors, operators should expect to overhaul the unit every 5 to 6 years. This normally involves exchanging the compressor core for a rebuilt compressor at a cost of approximately $3,929, with an additional $720 in labor expense and a $650 core exchange credit.

Exhibit 5: Air Compressor Costs

Service Size	Air Volume (cfm)	Compressor Type	Horsepower	Equipment Costs ($)	Annual Service ($/yr)	Service Life (yrs)
Small	30	Reciprocating	10	3,275[a]	434	1
Medium	125	Screw	30	16,371	868	5-6[b]
Large	350	Screw	75	28,812	868	5-6[b]

[a] Cost included package compressor with a volume tank.
[b] Rebuilt compressor costs $3,929 plus $500 labor minus $500 core exchange credit.

★ **Volume Tank.** Compressed air supply systems include a volume tank, which maintains a steady pressure with the on-off operation of the air compressor. The rule-of-thumb in determining the size of the volume tank is 1-gallon capacity for each cfm of compressed air. Exhibit 6 presents equipment costs for small, medium, and large volume tanks. Volume tanks have essentially no operating and maintenance costs.

Rule-of-Thumb

1 gallon tank capacity/1 cfm air

★ **Air Dryer Costs.** Because instrument air must be very dry to avoid plugging and corrosion, the compressed air is commonly put through a dryer. The most common dryer used in small to medium applications is a permeable membrane dryer. Larger air systems can use multiple membrane dryers, or, more cost effectively, alumina bed desiccant dryers. Membrane dryers filter out oil mist and particulate solids and have no moving parts. As a result, annual operating costs are kept low. Exhibit 7 presents equipment and service cost data for different size dryers. The appropriate sized dryer would need to accommodate the expected volume of gas needed for the instrument air system.

Exhibit 6: Volume Tank Costs

Service Size	Air Volume (gallons)	Equipment Cost ($)
Small[a]	80	655
Medium	400	1,964
Large	1,000	3,929

[a] Small reciprocating air compressors, 10 horsepower and less, are commonly supplied with a surge tank.

Exhibit 7: Air Dryer Costs

Service Size	Air Volume (cfm)	Dryer Type	Equipment Cost ($)	Annual Service ($/yr)
Small	30	membrane	1,964	724
Medium	60[a]	membrane	5,893	2,894
Large	350	alumina	13,096	4,341

[a] Largest membrane size; use multiple units, larger volumes.

Using the equipment information described above, the total installed cost for a project can be calculated. Exhibit 8 illustrates this using the earlier example of a medium-sized production facility with an instrument air requirement of 42 cfm and a maximum utility air requirement of 70 cfm (for a total of 112 cfm of compressed air). To estimate the installed cost of equipment, it is a common practice in industry to assume that installation labor is equivalent to equipment purchase cost (i.e. double equipment purchase cost to estimate the installed cost). This would be suitable for large, desiccant dried instrument air systems, but for small, skid-mounted instrument air systems a factor of 1.5 is used to estimate the total installed cost (installation labor is half the cost of equipment).

In addition to the facility costs, it is also necessary to estimate the energy costs associated with operating the system. The most significant operating cost of an air compressor is electricity, unless the site has excess self-generation capacity. To continue the example from above, assuming that electricity is purchased at 7.5 cents per kilowatt-hour (kWh) and that one compressor is in standby while the other compressor runs at full capacity half the time (a 50 percent operating factor), the electrical power

Exhibit 8: Calculate Total Installation Costs	
Given:	
Compressors (2) Volume Tanks (2-small) Membrane Dryer Installed Cost Factor	= $32,742 (Exhibit 5) = $1,310 (Exhibit 6) = $5,893 (Exhibit 7) = 1.5
Calculate Total Installed Cost:	
Equipment Cost	= Compressor Cost + Tank Cost + Dryer Cost = $32,742 + $1,310 + $5,893 = $39,945
Total Cost	= Equipment Cost * Installation Cost Factor = $39,945 * 1.5 = $59,917

cost amounts to $13,140 per year. This calculation is shown in Exhibit 9.

Step 4: Estimate Gas Savings.

To estimate the gas savings that result from the installation of an instrument air system, it is important to determine the normal bleed rates (continuous leak from piping networks, control devices, etc.), as well as the peak bleed rates (associated with movements in the control devices). One approach is to list all the control devices,

Exhibit 9: Calculate Electricity Cost	
Given:	
Engine Power Operating Factor (OF) Electricity Cost	= 30 HP = 50 percent = $0.075/kwh
Calculate Required Power:	
Electrical Power	= Engine Power * OF * Electricity Cost = [30 HP * 8,760 hrs/yr * 0.5 * $0.075/kwh] / 0.75 HP/kw = $13,140/yr

assess their normal and peak bleed rates, frequency of actuation, and estimates of leakage from the piping networks. Manufacturers of the control devices usually publish the emission rates for each type of device, and for each type of operation. Rates should be increased by 25 percent for devices that have been in service without overhaul for five to 10 years, and by about 50 percent for devices that have not been overhauled for more than 10 years to account for increased leakage associated with wear and tear. Alternatively, installing a meter can be more accurate, provided monitoring occurs over a long enough period of time to take account of all the utility uses of gas (i.e., pumps, motor starters, activation of isolation valves).

EPA's *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, provides brand name, model, and gas consumption information for a wide variety of currently used pneumatic devices. Manufacturer information and actual field measurement data, wherever available, are provided as well (see Appendix of that report). To simplify the calculation of gas savings for the purpose of this lesson learned analysis, we can use the earlier rules-of-thumb to estimate the gas savings. The gas savings for the medium-sized production facility example in Exhibit 4 include the conservatively estimated 35 cfm used in the 35 gas pneumatic controllers plus the gas used occasionally for compressor motor starters and small pneumatic chemical and transfer pumps. (Note that replacing these gas usages will result in direct savings of gas emissions.) Natural gas is not used for pneumatic tools or sand blasting, so additional compressed air provided for these services does not reduce methane emissions. Assuming an annual average of 10 cfm gas use for natural gas powered non-instrument services, the gas savings would be 45 cfm. As shown in Exhibit 10, this is equivalent to 23,652 Mcf per year and annual savings of $165,600.

Step 5: Evaluate the Economics.

The cost effectiveness of replacing the natural gas pneumatic control systems with instrument air systems

Exhibit 10: Calculate Gas Savings	
Given:	
Pneumatic instrument gas usage Other non-instrument gas usage	= 35 cfm = 10 cfm
Calculate Value of Gas Saved:	
Volume of Natural Gas Saved	= Instrument Usage + Other Usage = 35 cfm + 10 cfm = 45 cfm
Annual Volume of Gas Saved	= 45 cfm * 525,600 min/yr / 1000 = 23,652 Mcf/yr
Annual Value of Gas Saved	= volume * $7.00/Mcf = 23,652 Mcf/yr * $7.00/Mcf = $165,600/year

can be evaluated using straightforward cost-benefit economic analyses.

Exhibit 11 illustrates a cost-benefit analysis for the medium-sized production facility example. The cash flow over a five-year period is analyzed by showing the magnitude and timing of costs from Exhibits 8 and 9 (shown in parentheses) and benefits from Exhibit 10. The annual maintenance costs associated with the compressors and air dryer, from Exhibits 5 and 7, are accounted for, as well as a five-year major overhaul of a compressor per Exhibit 5. The net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. The Internal Rate of Return (IRR) reflects the discount rate at which the NPV generated by the investment equals zero.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Step 6: Develop an Implementation Plan.

After determining the feasibility and economics of converting to an instrument air system, develop a systematic plan for implementing the required changes. This can include installing a gas measuring meter in the gas supply line, making an estimate of the number of control loops, ensuring an uninterrupted supply of electric energy for operating the compressors, and replacing old, obsolete and high-bleed controllers. It is recommended that all necessary changes be made at one time to minimize labor costs and disruption of operations. This might include a parallel strategy to install low-bleed devices in conjunction with the switch to instrument air systems. There are similar economic savings for conserving instrument air use as for conserving methane emissions with low bleed pneumatic devices. Whenever specific pneumatic devices are being replaced, such as in the case of alternative mechanical and/or electronic

Exhibit 11: Economic Analysis of Instrument Air System Conversion

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Implementation Cost ($)	(59,917)					
O&M Cost ($)		(13,140)[a] (4,630)[b]	(13,140) (4,630)	(13,140) (4,630)	(13,140) (4,630)	(13,140) (4,630)
Overhaul Cost ($)	0	0	0	0	0	(6,286)[c]
Total Cost ($)	(59,917)	(17,770)	(17,770)	(17,770)	(17,770)	(24,057)
Gas Savings ($)	0	165,600[d]	165,600	165,600	165,600	165,600
Annual Cash Flow ($)	(59,917)	147,830	147,830	147,830	147,830	141,543
Cumulative Cash Flow ($)	(59,917)	87,912	235,742	383,571	531,401	672,944
					Payback Period (months)	5
					IRR	246%
					NPV[e]	$496,570

[a] Electrical power at 7.5 cents per kilowatt-hour.
[b] Maintenance costs include $1,736 compressor service and $2,894 air dryer membrane replacement.
[c] Compressor overhaul cost of $3,929, inflated at 10% per year.
[d] Value of gas = $7.00/Mcf.
[e] Net Present Value (NPV) based on 10% discount rate for 5 years.

systems, the existing pneumatic devices should be replaced on a similar economic basis as discussed in the companion document *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*.

When assessing options for converting gas pneumatic controls to instrument air, natural gas price may influence the decision making process. Exhibit 12 shows an economic analysis installing two 30 hp compressors, two medium sized volume tanks, and a medium sized membrane dryer at different natural gas prices.

Partner Experiences

Several EPA Natural Gas Star Partners have reported the conversion of natural gas pneumatic control systems to compressed instrument air systems as the single most significant source of methane emission reduction and a source of substantial cost savings. Exhibit 13 below highlights the accomplishments that several Natural Gas STAR Partners have reported.

Exhibit 12: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$70,971	$118,286	$165,600	$189,257	$236,571
Payback Period (months)	14	8	5	5	4
Internal Rate of Return (IRR)	84%	166%	246%	286%	365%
Net Present Value (*i*=10%)	$137,853	$317,211	$496,570	$586,249	$765,607

Other Technologies

The majority of Partners' experiences in substituting natural gas-powered pneumatic devices and control instrumentation with alternative controllers have involved

Exhibit 13: Partner Reported Experience

Gas STAR Partner	Description of Project	Project Cost ($)	Annual Emissions Reductions (Mcf/yr)	Annual Savings ($/yr)[a]	Payback (months)[b]
Unocal[c] (now Chevron)	Installed an air compression system in its Fresh Water Bayou facility in southern Vermillion Parish, Louisiana	$79,000	69,350	$485,450	2
Texaco[c] (now Chevron)	Installed compressed air system to drive pneumatic devices in 10 South Louisiana facilities	$52,000	23,000	$161,000	4
Chevron[c]	Converted pneumatic controllers to compressed air, including new installations	$227,000 over 2 years	31,700	$221,900	7
ExxonMobil[d]	Installed instrument air systems at 3 production satellites and 1 central tank battery at Postle CO_2 unit	$72,000	19,163	$134,141	7
Shell	Used instrument air operated devices on over 4,300 valves at off-shore platforms	Not available	532,800	$3,729,600	Not available
Marathon	Installed 15 instrument air systems in New Mexico facilities	Not available	120 - 38,000 per facility	$840 - 226,000	Not available

[a] Value of gas = $7.00/Mcf.
[b] Calculated based on Partner-reported costs and gas savings updated to 2006 costs.
[c] Data for this report were collected prior to the Chevron-Texaco and Chevron-Unocal mergers.
[d] Data for this report were collected prior to the Exxon/Mobil merger in 1999.

the installation of compressed instrument air systems. Some additional alternatives to gas pneumatics implemented by Partners are described below:

- ★ **Liquid Nitrogen.** In a system using liquid nitrogen, the volume tank, air compressor, and dryer are replaced with a cylinder containing cryogenic liquid nitrogen. A pressure regulator allows expansion of the nitrogen gas into the instrument and control-piping network at the desired pressure. Liquid nitrogen bottles are replaced periodically. Liquid nitrogen-operated devices require handling of cryogenic liquids, which can be expensive as well as a potential safety hazard. Large volume demands on a liquid nitrogen system require a vaporizer.

- ★ **Mechanical Controls and Instrumentation System.** Mechanical instrument and control devices have a long history of use in the natural gas and petroleum industry. They are usually distinguished by the absence of pneumatic and electric components, are simple in design, and require no power source. Such equipment operates using springs, levers, baffles, flow channels, and hand wheels. They have several disadvantages, such as limited application, the need for continuous calibration, lack of sensitivity, inability to handle large variations, and potential for sticking parts.

- ★ **Electric and Electro-Pneumatic Devices.** As a result of advanced technology and increasing sophistication, the use of electronic instrument and control devices is increasing. The advantage of these devices is that they require no compression devices to supply energy to operate the equipment; a simple 120 -volt electric supply is used for power. Another advantage is that the use of electronic instrument and control devices is far less dangerous than using combustible natural gas or cryogenic liquid nitrogen cylinders. The disadvantage of these devices is their reliance on an uninterrupted source of electric supply, and significantly higher costs.

Although these options have advantages, systems using air instead of natural gas are the most widely employed alternative in replacing natural gas-operated pneumatic control devices. It is important to note that maintaining a constant, reliable supply of dry, compressed air in a plant environment is a significant cost, albeit more economic than natural gas. Therefore, a parallel strategy to install low-bleed devices in conjunction with the switch to instrument air systems (refer to *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*), and to design a maintenance schedule to keep the instruments and control devices in tune, is often economic. Such actions can significantly reduce the consumption of instrument air in the overall system and, therefore, minimize both the size of the compression system and the electricity consumption over the life of the plant.

Lessons Learned

The lessons learned from Natural Gas STAR Partners are:

- ★ Installing instrument air systems has the potential to increase revenues and substantially reduce methane emissions.

- ★ Instrument air systems can extend the life cycle of system equipment, which can accumulate trace amounts of sulfur and various acid gases when controlled by natural gas, thus adding to the potential savings and increasing operational efficiencies.

- ★ Remote locations and facilities without a reliable source of electric supply often need to evaluate alternate power generation sources. When feasible, solar-powered air compressors provide an economical and ecologically beneficial alternative to expensive electricity in remote production areas. On site generation using microturbines running on natural gas is another alternative.

- ★ A parallel strategy of installing low-bleed devices in conjunction with the switch to instrument air systems is often economic.

- ★ Existing infrastructure can be used; therefore, no pipe replacement is needed. However, existing piping and tubing should be flushed clear of accumulated debris.

- ★ Rotary air compressors are normally lubricated with oil, which must be filtered to maintain the life and proper performance of membrane dryers.

- ★ Use of instrument air will eliminate safety hazards associated with flammable natural gas usage in pneumatic devices.

- ★ Nitrogen-drive systems may be an alternative to instrument air in special cases, but tends to be

NMED Exhibit 99 - 0010

expensive and handling of cryogenic gas is a safety concern.

★ Report reductions in methane emissions from converting gas pneumatic controls to instrument air in your Natural Gas STAR Annual Report.

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NMED Exhibit 99 - 0011

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

October 2006

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, 60 and 61

[FRL–5691–2]

RIN 2020–AA27

Credible Evidence Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In an October 22, 1993 Federal Register, EPA solicited public comment on a proposal to amend 40 CFR Parts 51, 52, 60 and 61 to eliminate language that has been read to provide for exclusive reliance on reference test methods as the means of demonstrating compliance with various emission limits under the Clean Air Act (''CAA'' or ''Act''). These revisions—generally referred to as the ''credible evidence'' revisions—were designed to clarify that non-reference test data can be used in enforcement actions, and to remove any potential ambiguity regarding this data's use for compliance certifications under Section 114 and Title V of the Act. In the same document, EPA proposed an ''enhanced monitoring'' rule under Section 114 and Title V. EPA subsequently decided to suspend development of the original enhanced monitoring rule and develop a compliance assurance monitoring (''CAM'') approach to serve the same statutory goals as the original enhanced monitoring proposal. Today's rulemaking finalizes the previously proposed credible evidence revisions to Parts 51, 52, 60 and 61. EPA will take final action regarding enhanced monitoring and CAM in a separate rulemaking.

DATES: *Effective Date:* April 25, 1997. *Judicial Review:* Under CAA section 307(b)(1), judicial review of this nationally applicable final action is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under CAA section 307(b)(2), the regulations that are the subject of today's rule may not be challenged later in civil or criminal proceedings brought by EPA in reliance on them.

ADDRESSES: *Docket.* Supporting information used in developing this rulemaking is contained in Public Docket No. A–91–52. This docket is available for public inspection and copying between 8:00 a.m. and 5:30 p.m. on weekdays, excluding federal holidays, at the EPA Air and Radiation Docket and Information Center, Room M–1500, Waterside Mall, 401 M Street SW., Washington, DC 20460; telephone (202) 260–7548. A reasonable fee may be charged for photocopying docket materials.

FOR FURTHER INFORMATION CONTACT: Gregory Jaffe, Air Enforcement Division (Mailcode 2242–A), Office of Regulatory Enforcement, U.S. Environmental Protection Agency, 401 M Street, SW, Washington, D.C. 20460; telephone (202) 564–2260.

SUPPLEMENTARY INFORMATION: The contents of the preamble are listed in the following outline:

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I. Background

A. Statutory and Regulatory Authority

The credible evidence revisions are based on EPA's long-standing authority under the Act, and on amplified authority provided by the 1990 CAA Amendments. Section 113(a) of the Act authorizes EPA to bring an administrative, civil or criminal enforcement action ''on the basis of any information available to the Administrator.'' In this provision, which predates the 1990 CAA Amendments, Congress gave EPA clear statutory authority to use any available information—not just data from reference tests or other federally promulgated or approved compliance methods—to prove CAA violations. (The preamble will generally use the phrase ''reference tests'' to include all these compliance methods. Where appropriate, the phrase ''reference tests'' will also include test conditions specified in individual regulations.)

In the 1990 CAA Amendments, Congress included an enforcement title (Title VII) to enhance EPA's compliance and enforcement authorities. Among other things, Congress revised Section 113(e)(1) of the Act to overrule a federal court decision (*Kaiser Steel*, discussed below) that had held that only specified reference test data could prove violations. Thus, although the pre-existing authority of Section 113(a) forms the principal basis for today's action, the credible evidence revisions are also supported by the language, history and intent of the 1990 CAA Amendments. *See also* Section III.C. below.

In addition to clarifying EPA's, states' and citizens' enforcement authorities under the Act, the credible evidence revisions eliminate any potential ambiguity regarding the use of non-reference test data as a basis for Title V compliance certifications. Such potential ambiguity could arise from comparing the draft compliance assurance monitoring (CAM) approach and associated Part 70 changes, which would allow sources to include CAM data as a basis for certifying compliance, with various EPA regulations that could be read on their face to specify reference test methods as the sole means of determining compliance.

B. Benefits of the Credible Evidence Revisions

As a preliminary matter, EPA wishes to clearly state that this rulemaking merely addresses an evidentiary issue. The credible evidence revisions are not

intended to and will not serve to affect the stringency of underlying emission standards by amending the nature of the compliance obligation. This rulemaking does not amend existing emission standards nor does it modify generic regulations affecting the compliance obligation such as exceptions for startup, shutdown, and malfunctions. See, e.g., 40 CFR 60.8(c). This regulation also does not designate any particular data as probative of a violation of an emission standard. Rather, this regulation merely removes what some have construed to be a regulatory bar to the admission of non-reference test data to prove a violation of an emission standard, no matter how credible and probative those data are that a violation has occurred. The credible evidence revisions do not affect the compliance obligation and thus do not affect the stringency of existing emission standards. What compliance obligation is imposed by any given emission standard remains an issue ultimately to be determined based on that emission standard and not this rulemaking.

For these reasons, we do not believe that this rulemaking affects whether emission standards require intermittent or continuous compliance. However, as made clear below, and in the detailed response to comments document, EPA's position continues to be that an emission standard requires continuous compliance unless the emission standard specifically provides otherwise.

Today's credible evidence revisions will benefit sources, state environmental agencies, EPA and the public. EPA, states and citizens will be able to use credible evidence to assess a source's compliance status and respond to noncompliance. This will help ensure that the government and citizens alike can respond to sources that are not complying with air pollutant emission standards on an ongoing basis, thus furthering the protection of public health and the environment. At the same time, sources will be able to use credible evidence for contesting allegations of noncompliance in enforcement actions. Accordingly, today's rulemaking exemplifies EPA's ''common sense'' approach to environmental protection, which encourages smarter, cheaper and more flexible means of achieving environmental goals without compromising the fundamental health and environmental protections provided by federal environmental laws.

In the past, state regulatory authorities and EPA have relied primarily on infrequent on-site inspections and even more infrequent reference tests in order to check compliance with emission limits at major stationary sources. According to a September, 1990, General Accounting Office (GAO) report, these on-site inspections were performed approximately once a year; the reference tests, typically once every five years. ''Air Pollution: Improvements Needed in Detecting and Preventing Violations,'' GAO, No. GAO/RCED–90–155, September 1990, at 12, 19. These methods are inadequate to ensure that sources continuously stay within their emission limits: for example, Pennsylvania officials have estimated that, in comparison with continuous emissions monitoring, on-site inspections may be 50 times less likely to detect non-compliance. *Id.* at 18. Reference tests may not yield a representative emissions picture because the sources typically schedule, set up and run the tests themselves. This allows sources to ''fine tune'' their operations and emissions control processes prior to the tests, and generate results that may not be typical of day-to-day source operations. *Id.* at 19–20. Reference tests can also be expensive and burdensome: They can cost up to $100,000, and take a week or more to complete. *See, e.g.*, 43 FR 7568, 7571 (1978).

In contrast to the above approach, today's rule will make it clear that various kinds of information other than reference test data, much of which is already available and utilized for other purposes, may be used to demonstrate compliance or noncompliance with emission standards. (The preamble generally refers to this other information as ''non-reference test data''). EPA, state agencies and industry routinely rely on many types of information, including engineering calculations, indirect estimates of emissions, and direct measurement of emissions by a variety of means, in order to assess compliance with CAA requirements. Where available, continuous emission monitoring (CEM) data and well-chosen parametric monitoring data, such as the operating temperature and air flow rate of a regenerative thermal oxidizer, generally provide accurate data regarding a source's compliance with emission limits and standards. These data also generally cover a greater percentage of a source's time in operation and are more representative of a source's ongoing compliance status than sporadic performance testing.

Under today's rule both sources and potential enforcers will be put on the same evidentiary footing in an enforcement action. Further, since 1992, EPA's Part 70 operating permit regulations have allowed the use of this data in compliance certifications. Today's action reaffirms this approach, and removes any potential ambiguity regarding the use of such data for this purpose.

Today's action reflects EPA's efforts to make existing regulatory programs work better rather than creating additional requirements. By ensuring greater compliance with existing emissions limits, the credible evidence revisions will help minimize the need for further requirements to achieve air quality goals. *See* the October, 1993, proposal, 58 FR 54654.

C. Public Participation

The final credible evidence revisions were developed with the benefit of insight from many parties that will be affected by the regulations, including State and local air pollution control agencies, large and small industries, trade associations and environmental organizations. Many comments regarding credible evidence issues were received during the development and after the proposal of the original enhanced monitoring rule, in 1991 through 1995. Many additional comments were received after the Agency announced that it was continuing to go forward with the credible evidence revisions in 1996.

To obtain the views of all interested parties at the early stages of developing the enhanced monitoring rulemaking, EPA published a notice in the Federal Register on August 8, 1991, to make available a Public Information Document on enhanced monitoring and to provide notice of a public meeting to be held on August 22, 1991, on the subject (56 FR 37700–37701, August 8, 1991). In response to the public meeting, EPA received many comments which were included in the docket for the proposed regulations.

Over the next four years, EPA held over one hundred informal informational and discussion sessions with representatives of interested organizations to receive their views on enhanced monitoring, as well as a second informational meeting with approximately fifty attendees held on August 12, 1993. Following publication of the proposed enhanced monitoring regulations on October 22, 1993 at 58 FR 54648, EPA conducted a public hearing in Washington, D.C., on November 19, 1993. Testimony was given by twelve individuals, representing industry and environmental organizations.

In addition, during the public comment period, which was first scheduled to close on December 30, 1993, and was extended until January 31, 1994, in response to requests for

extension, EPA received comments from a wide variety of interested parties concerning the enhanced monitoring proposal, including numerous comments on credible evidence issues. In the fall of 1994, EPA held a series of informational meetings with interested parties affected by the rule. The Agency then reopened the public comment period on specific issues to solicit additional comments, and held an additional stakeholder meeting. In response to the reopened public comment period, EPA received over 200 additional comment letters.

In April, 1995, EPA announced that it was suspending development of the enhanced monitoring rule while it developed the CAM approach to serve the same statutory goals. In a September, 1995, public draft of the CAM approach, EPA stated that it would hold further discussions with stakeholders before it proceeded to finalize the credible evidence revisions. On March 8, 1996, EPA announced that a public meeting on credible evidence issues would be held on April 2, 1996. To focus the meeting's discussion, EPA released a paper on March 21, 1996, entitled ''The Use of Information Other Than Reference Test Results for Determining Compliance With the Clean Air Act'' (sometimes referred to as the ''Credible Evidence White Paper''). EPA distributed this paper by electronic bulletin board to the same stakeholders who were involved in the enhanced monitoring and CAM rulemakings, further distributed it to various other interested parties, and made it generally available to the public.

The public meeting was held on April 2, 1996, where twenty-three organizations and individuals presented oral statements and written comments. At the meeting, EPA announced that, although the rulemaking docket would not formally be re-opened, additional written comments would be accepted for at least another 30 days. Moreover, EPA stated that it would meet with any interested parties to discuss the credible evidence rules. As a result, many additional written comments have been received, and numerous additional EPA/stakeholder meetings have been held.

Section III of this preamble contains a description of the most significant public comments and EPA's responses to them. Summaries of other public comments on the credible evidence revisions received over the past five years, together with the Agency's responses, are available in the docket in a document entitled ''Credible Evidence Revisions: Detailed Response to Comments Document'' (referred to in this preamble as the ''Detailed Response Document'').

II. Summary of Final Rule

The credible evidence revisions consist of various changes to 40 CFR 51.212, 52.12, 52.30, 60.11 and 61.12. These revisions provide minor modifications to existing regulatory provisions to clearly allow for the use of any credible evidence—that is, both reference test and comparable non-reference test data—to prove or disprove violations of the Act in enforcement actions. These revisions make clear that enforcement authorities can prosecute actions based exclusively on any credible evidence, without the need to rely on any data from a particular reference test. The revisions also have the effect of eliminating any potential ambiguity regarding the use of non-reference test data as a basis for Title V compliance certifications. The credible evidence revisions do not call for the creation or submission of any new emissions or parametric data, but rather address the role of existing data in enforcement actions and compliance certifications. As such, today's final action is distinct and separable from the bulk of the proposed enhanced monitoring rule, which addressed new monitoring requirements.

By clearly providing that federally approved SIP test methods or Agency reference test methods are not the exclusive means of establishing noncompliance or compliance, EPA in no way intends to alter the underlying emission standards. The Agency will still use the reference methods for exactly what they are: test methods of reference against which to compare information generated by means other than the reference tests. The National Bureau of Standards maintains a number of standards against which other measuring devices, used in scientific or commercial applications, are calibrated. Similarly, where a SIP, New Source Performance Standard or permit specifies EPA Method 25A, for example, for determining the amount of volatile organic compounds (''VOCs'') that are emitted, the ''other evidence'' that could establish compliance would have to relate to the likely measurement of VOCs that would be obtained by a Method 25A measurement. This could include, for example, consideration of key operating parameters for the facility as correlated with emissions during a Method 25A test.

A. 40 CFR Part 51, § 51.212

Section 51.212(c) is revised to clarify that the inclusion in a state implementation plan (SIP) of enforceable test methods for SIP emissions limits does not preclude enforcement based on other credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed. This revision does not affect the existing requirements in §§ 51.212(a) and (b) for periodic testing and inspections, and establishment of a system of violation detection and investigation.

The proposed revisions to § 51.212 contained detailed lists of ''presumptively credible evidence'' and ''presumptively credible monitoring methods.'' After consideration of public comments, EPA has decided to delete these lists because they are potentially confusing and unnecessary. While EPA continues to believe that the listed evidence and monitoring methods are indeed credible, the Agency recognizes that both judicial and administrative tribunals routinely make determinations concerning the admissibility and weight of evidence on a case-by-case basis.

B. 40 CFR Part 52, § 52.12

Section 52.12(c) is revised to clarify that, for purposes of federal enforcement, any credible evidence relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed may be used to establish whether or not SIP violations have occurred. As with § 51.212 above, EPA has deleted the proposed lists of presumptively credible evidence and monitoring methods for the same reasons stated above. Under today's final action, where an emission limitation specifies a particular monitoring or testing method approved by EPA for use in the SIP to determine compliance, data from such method will continue to be the benchmark against which other emissions or parametric data, or engineering analyses, will be measured. Similarly, where there are no approved SIP methods, the test methods specified in part 60 of this chapter will remain the standard against which other such information will be evaluated.

C. 40 CFR Part 52, § 52.30

Proposed § 52.30(a), which concerned compliance certifications, has been revised in accordance with § 51.212 above, and the same comments apply. The enforcement-related § 52.30(b) is rendered unnecessary by today's final § 52.12(c), which effectively

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encompasses it. Finally, the entire section has been renumbered as § 52.33.

D. 40 CFR Part 60, § 60.11

Similar to the existing regulation, § 60.11(a) states that compliance with Part 60 standards shall be determined in accordance with the applicable performance tests and performance testing provisions in this part. A new § 60.11(g) clarifies that nothing in § 60.11 precludes the use, including exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed, for purposes of submitting compliance certifications or establishing whether or not a source has violated or is in violation of any Part 60 standard, including opacity standards.

The first sentence in today's final § 60.11(a) has been modified from the proposal. EPA has decided to use mandatory phrasing in the first sentence (''Compliance with standards * * * shall be determined in accordance with the applicable performance tests * * *'') as is included in the existing regulation, rather than adopt the permissive language proposed in 1993 (''Compliance with standards * * * may be determined by performance tests * * *). The rationale for retaining this mandatory language is to make clear that, although the regulation is being modified to clarify that it does not establish an exclusive method of determining compliance, the reference tests remain the benchmark against which other emissions or parametric data, engineering analyses, or other information will be evaluated. For similar reasons, EPA included in § 60.11(g) the requirement that evidence or information gathered by other means than the reference tests be ''relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed''. This phrase means that the evidence or information must bear on whether a facility would have been found to be in compliance, during the time period in question, if the appropriate performance test had been conducted. It does not mean that, to prove a violation occurred, ideal testing conditions, for example the sun light at a certain angle to the tester for an opacity reading, must exist if other credible evidence, such as continuous opacity monitor data, can establish that a violation occurred. These changes have been made in response to comments that EPA's proposal did not give full recognition to the role of reference tests in determining compliance with emission standards. Section 60.11(g) combines the requirements of the proposed subsections (g) and (h) with the exception of presumptions included in those sections which have been deleted. The clarifying language in § 60.11(g) renders unnecessary the previously proposed language in § 60.11(b). Accordingly, the proposed language for that subsection is deleted from today's rule. The proposed changes to subsection (e) have been deleted as unnecessary due to changes to subsections (a) and (g). Finally, § 60.11(f) is revised so as to clarify that it does not countermand subsection (g).

Under today's revisions, information generated from an appropriate and properly conducted test method established under the general provisions of Part 60 or in the applicable subpart will still generally be the best method for determining a source's compliance during the test period. Other emissions or parametric data, or engineering analyses, may be considered if relevant to the results that would have been obtained by the appropriate, properly conducted reference test methods.

E. 40 CFR Part 61, § 61.12

Today's revisions to § 61.12 generally mirror the revisions to § 60.11, largely for the same reasons. Section 61.12(b) remains unchanged from its current promulgated version because credible evidence has always been used to establish violations of these standards.

III. Major Issues

Throughout the development of this rulemaking, various commenters have expressed concerns regarding the proposed rule's potential effects on CAA enforcement, compliance certifications and emissions standards. The most significant of these comments, together with EPA's responses, are discussed below.

A. Use of Credible Evidence in Enforcement Actions

Commenters raised various concerns regarding the potential use of credible evidence in enforcement actions. Some commenters argued that the use of such evidence would be unconstitutional, unprecedented and unfair. Others expressed concern that EPA, states or citizen groups would use credible evidence to bring enforcement actions for insignificant violations. These comments are addressed below.

Industry commenters have argued that the use of credible evidence in enforcement actions would violate sources' constitutional right to due process. Specifically, the commenters argue that EPA must comprehensively identify the precise types of information that can be used as credible evidence, or else sources will not have sufficient ''fair warning'' regarding potential enforcement. EPA rejects this view. ''Fair warning'' jurisprudence holds that regulated sources must have adequate notice identifying ''the standards with which the agency expects parties to conform.'' *General Electric Co.* v. *U.S. EPA,* 53 F.3d 1324, 1329 (D.C. Cir. 1995). Today's rule does not establish or alter standards with which sources regulated under the CAA must comply. Rather, today's rule only concerns the evidence that can be used to prove violations of a standard, giving full recognition to the role of reference test methods under the standards. The Federal Rules of Evidence govern the admission of evidence in all federal district court litigation, including CAA enforcement actions, without any discernible constitutional infirmity. Similar evidentiary rules govern federal administrative and state environmental actions. Our legal system provides that a federal or administrative law judge will be the ultimate, independent arbitrator of the evidence's admissibility and credibility.

Credible evidence is far from a new concept in judicial and administrative actions. In private lawsuits such as contract disputes, and in governmental and citizen enforcement actions brought under environmental laws other than the CAA, litigants can and do use a wide variety of information to prove their claims, or to refute the claims of opposing parties. In all these lawsuits, the judge acts as the final, independent arbitrator of what constitutes credible and admissible evidence. Today's final rule addresses problems arising from certain CAA regulations, which predate the 1990 Amendments to the CAA, containing language that has been read to allow only a very limited amount of information, i.e., data from reference test methods, to be used as evidence of violations. As such, the rule merely corrects an anomaly that has been read into these regulations, and brings their potential enforcement into line with that of other CAA requirements such as the ''general duty obligations'' in 40 CFR 60.11(d) (for NSPS standards) and 40 CFR 61.22(c) (for National Emission Standards for Hazardous Air Pollutants (NESHAPs)), and with other environmental statutes. It should be emphasized that the determination that evidence or information is credible is merely a threshold determination that

the evidence or information in question is technically relevant, and therefore, legally admissible in an enforcement action. In light of section 113(a) providing that the Administrator may bring an enforcement action based on ''any information'', EPA believes that Congress intended this threshold to be a low one.

Industry commenters have also argued that using credible evidence in enforcement actions is unfair because sources will not know what credible evidence may be used against them. EPA believes that this claim lacks merit. This issue is no different in CAA enforcement than in any civil or criminal matter resolved by our nation's courts. Further, EPA disagrees with the notion that sources will likely be faced with an unknown and unlimited array of evidence. To the contrary, with regard to sources subject to Title V permits, EPA generally expects that most if not all of the data that EPA would consider as potentially credible evidence of an emission violation at a unit subject to monitoring under the agency's proposed CAM rule would be generated through means of appropriate, well-designed parametric or emission monitoring submitted by the source itself and approved by the permitting authority, or through other requirements in the source's permit. Sources not subject to CAM should still be readily able to discern the information, for example information about the operation of pollution control devices, that is relevant to their compliance with applicable regulation.

Some industry representatives have expressed concern that the use of credible evidence in compliance determinations will reveal multiple minor violations for which EPA, the states or citizens will bring lawsuits. It is not EPA's intent to foster frivolous lawsuits, and EPA does not expect that such lawsuits will occur as the result of today's action. As EPA explained in the Credible Evidence March 1996 memorandum, EPA generally focuses its judicial enforcement resources on violations that (1) may threaten or result in harm to public health or the environment, (2) are of significant duration or magnitude, (3) represent a pattern of noncompliance, (4) involve a refusal to provide specifically requested compliance information, (5) involve criminal conduct, or (6) allow a source to reap an economic windfall. *See* March 1996 Memorandum, p. 5.

An examination of EPA's judicial enforcement cases over the past few years reveals that EPA has focused its judicial enforcement resources on large, significant cases rather than a large number of relatively minor matters. The Credible Evidence March 1996 memorandum contains several examples that illustrate this point. In contrast, EPA's approach to minor unexcused violations generally has been to exercise prosecutorial discretion and use tools such as notices of violation and administrative compliance and penalty orders. In every case, EPA considers the nature and extent of the violation and all other circumstances surrounding the violation in determining whether and what kind of enforcement response is appropriate. Further, for any type of noncompliance, EPA generally will not bring a federal enforcement action where a state or local permitting authority has taken timely and appropriate action under existing policies to resolve the violations. Finally, for all violations, EPA will apply all other existing specific enforcement policies, such as the May, 1996, *Policy on Compliance Incentives for Small Businesses*, in accordance with their terms. EPA does not intend to use credible evidence to change any of these policies.

EPA has a balanced enforcement program that seeks to assure compliance using the mix of the compliance and enforcement tools available to it. Deterrence is also an overall goal of the program. Judicial enforcement against minor CAA violations generally is a lower enforcement priority, because EPA believes its other enforcement and compliance assistance tools allow it to respond to such violations without the need to file an action in federal court. Accordingly, in considering whether to bring a judicial action, or whether to use some other enforcement or compliance tool, EPA generally takes into consideration such factors as number and duration of the exceedances, harm or risk posed by the exceedance, potential for recurrence, the source's compliance history, and other circumstances surrounding the violation. For example, if a source were installing a new unit subject to an NSPS standard and had some difficulty getting the control equipment to operate properly after the ''shakedown'' period permitted before the initial performance test (*see* 40 CFR 60.8(a)) but solved the problem promptly after the test, this generally would be a low enforcement priority, absent other circumstances indicating a need for judicial action.

These same general policies regarding EPA's use of judicial and administrative enforcement actions were discussed in Section I.D. of the August 2, 1996, CAM draft approach. Therein, EPA provided various specific examples of circumstances where the Agency was or was not likely to take compliance or enforcement action based on the examination of CAM data.

Finally, the NSPS general provisions and many SIPs generally excuse sources from compliance with emissions limits during periods of startup, shutdown or malfunction. *See* 40 CFR 60.11(c). Some specific NSPS standards additionally excuse sources from compliance during certain operating periods. Exceedances monitored during any of these specifically excused periods are not violations of the emission limit. Moreover, some NSPS standards specify averaging periods for determining compliance and noncompliance. As a result, many short term emissions values when averaged with other values in the relevant averaging period, will not constitute violations. The credible evidence proposal does not change any of these general or specific periods of excused noncompliance, or any averaging periods, or any of their effects on compliance.

Regarding citizen suits, in February, 1996, EPA performed a review of citizen enforcement actions under the Clean Water Act (CWA), and found that citizen enforcers generally do not focus on sporadic, inconsequential violations. This analysis was summarized in the Credible Evidence White Paper, and is included in the Air Docket. Although to date there have been far fewer CAA citizen suits than CWA citizen suits, there have been at least two notable CAA citizen cases involving serious violations: *National Wildlife Federation* v. *Copper Range Co.*, Civil Action No. 2:92–CV–186 (W.D. Michigan), involving one of the largest sources of particulate matter in Michigan's Upper Peninsula, which was emitting particulates at 230 lbs/hour (over five times its permitted limit) and toxic air pollutants including mercury, arsenic, cadmium and lead; and *Sierra Club* v. *Public Service Company*, 894 F. Supp. 1455 (D.C. Col. 1995), involving a power plant that had committed over 19,000 opacity emission violations, which had allegedly affected a nearby wilderness area. Both of these suits were ultimately settled (with the United States an intervenor) for multi-million dollar penalties and significant injunctive relief, including the installation of appropriate pollution controls.

EPA notes that today's rule creates no new rights or powers for citizen enforcers; instead, the rule clarifies existing EPA regulations. Citizens have been free to use credible evidence in Clean Air Act enforcement, and have won at least two court cases using it. *See Sierra Club* v. *PSC*, cited above, and *Unitek Environmental Services* v.

Hawaiian Cement, Civ. No. 95–00723 (D. Hawaii 1996). Also, EPA is aware of no increase in citizen suits in any of the five states—Kansas, Iowa, Nebraska, North Dakota and Georgia—whose SIPs, based on EPA's SIP Call, have specifically clarified that credible evidence can be used for enforcement, or in those states that have credible evidence provisions in other parts of their state law.

Finally, EPA takes this opportunity to further elaborate on certain credible evidence and enforcement issues that were discussed in the August, 1996, draft CAM approach preamble. Therein, EPA explained that ''the CAM rule cannot and does not replace a source's obligation to comply with otherwise applicable emission limits.'' Nonetheless, as a practical matter, ''EPA expects that a unit that is operating within appropriately established indicator ranges as part of an approved CAM plan will, in fact, be in compliance with its applicable limits.'' (*See* draft CAM rule § 64.6(c), which requires that ''the ranges shall be established so as to provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at a pollutant-specific emissions unit.'') Such a unit generally will not be an enforcement target. However, if the Agency obtains information that the unit is in fact exceeding its applicable emission limit even though it is operating within its approved indicator ranges, the Agency will consider whether or not to take compliance or enforcement action in accordance with its general enforcement policies. Further, under the CAM approach, the source has such information, it would have to promptly remedy the exceedance and notify the permitting authority and submit a proposed permit modification to correct its CAM monitoring as required under draft CAM rule § 64.3(b)(5).

Under today's rule, the legal burdens regarding the establishment of violations or compliance in an enforcement action are not changed. The means of meeting these burdens will vary in different circumstances. Today's rule provides that where information (such as non-reference emissions data, parametric data or engineering analyses) is equivalent to information generated by reference test methods, the former may be used to establish compliance or noncompliance in an enforcement action. There is no need to establish that every test condition specified in a reference test method has been matched by a surrogate condition in the method used to generate the comparable information. Typically, reference test methods (and any additional test conditions specified in individual regulations) quantify the presence of particular physical attributes—for example, mass or concentration of a chemical or group of chemicals—over a specified period of time. As long as these two elements—quantification and specified time period—are retained and the data from the alternate method is related to the reference test, information generated by alternate methods yield data bearing on what the results of a reference test would have been, and the use of such information to establish compliance or noncompliance in an enforcement action will not affect the stringency of the underlying standard. Of course, non-reference data that is already quantified in the same units as the underlying standard, e.g., emissions data generated by properly operating and calibrated non-reference CEMs, should generally be comparable to reference test data, with all specified averaging periods still applying.

For example, Method 9, the NSPS reference method for opacity, requires that a trained visible emissions observer (VEO) view a smoke plume with the sun at a certain angle to the plume in order to properly illuminate it. In contrast, a continuous opacity monitor (COM) contains a calibrated light source that provides for accurate and precise measurement of opacity at all times. Notably, EPA uses COM data to certify and re-certify the credentials of VEOs under Method 9. Accordingly, since a comparable light source is provided by a COM, if COM data were offered in an enforcement action to prove or disprove opacity violations, there would be no need to establish that the sun was shining during the period the COM data was collected. Where a reference test method or test requirements in an individual regulation include plant operating conditions, e.g., a requirement that testing be conducted at a specified percentage of maximum plant capacity, this does not mean that the underlying standard applies only when the plant is operating at that capacity or that the ''other information'' would have to show that the plant was operating at the specified capacity during the period that the other ''credible evidence'' was obtained.

Where a party seeks to introduce other sorts of information in an enforcement action, for example, expert testimony as to whether a unit was able to meet its emission limit based on the operation or nonoperation of its control equipment during the period of alleged violation, the information would still need to be relevant to reference test data in the sense that it must be related to reference test data in some fashion. In the expert testimony example, this might be accomplished by a qualified expert opinion that a reference test would have demonstrated noncompliance in these same circumstances. Finally, where general burdens of proof for the proponent of this information are reduced through statutory provisions or other means, the same reduced burdens will apply in circumstances where EPA uses non-reference test data to assert noncompliance. *See, e.g.*, CAA section 113(e)(2).

B. Use of Credible Evidence in Compliance Certifications

Some commenters argued that today's final action will create new uncertainties and burdens for sources, because sources will not know what information they must consider before certifying compliance with Title V permit requirements. Previously, these commenters argue, sources would have needed to consider only the results of any specified reference tests, whereas under the credible evidence revisions almost any information could be potentially relevant to determining compliance. Thus, as a practical matter sources would need to ''go through every file drawer'' and examine a great deal of additional information before certifying compliance. Even then, sources would not know whether they had reviewed all compliance information that was potentially credible. According to some commenters, even if the source determined its compliance using a reference method, the source would still be uncertain as to whether it could certify compliance during that period, because other contemporaneous information might still indicate noncompliance. Still other commenters argue that allowing a broad array of information to be considered in compliance certifications would render the certification requirement void for vagueness.

At the outset, EPA notes that today's action merely eliminates any potential ambiguity or conflict between Parts 51, 52, 60, and 61 and Part 70 regarding the ability of sources to use non-reference test data in compliance certifications. Consistent with the congressional intent reflected in Title V and section 114(a)(3), Part 70 already contemplates use of non-reference test data in compliance certifications. There are other pending rulemakings—specifically, pending actions involving the CAM approach and Part 70—that are

proposing to modify existing Part 70 requirements to provide additional detail as to what information sources must consider when certifying compliance. Nothing in these rule revisions is meant to specify what degree of correlation there must be between CAM monitoring data and emissions violations or compliance certifications; rather this issue will be discussed in the CAM rulemaking.

In addition, EPA believes that the commenters have greatly exaggerated the purported uncertainties and burdens in certifying compliance under Part 70 and notes that facilities routinely determine their compliance with numerous statutory or regulatory obligations without government imposed ''checklists.'' Under Title V, the source's substantive CAA obligations (i.e., the source's applicable requirements) are clearly set forth in the source's CAA operating permit.

Contrary to the commenters' claims, sources that are certifying compliance using properly conducted continuous reference methods may generally certify compliance based solely on the continuous reference method data, although naturally such sole reliance would be inappropriate in the face of obvious contrary information or fraud as discussed below.

Of course, if a source becomes aware of other material information that indicates that an emission unit has experienced deviations (as that term is defined in the draft CAM approach) or may otherwise be out of compliance with an applicable requirement even though the unit's permit-identified data indicates compliance, the source must consider this information, identify and address it in the compliance certification, and certify accordingly. This ensures, among other things, that sources will not certify compliance in circumstances where doing so would constitute a violation of CAA section 113(c) and 18 U.S.C. Section 1001, which prohibits sources from knowingly making a false certification or omitting material information, or a violation of other prohibitions on fraud. EPA emphasizes, however, that its purpose here is to make clear that sources may not ignore obvious relevant information. EPA does not view compliance certification requirements as imposing a duty on the source to search out and review every possible document to determine its relevance on the issue of the source's compliance.

Following on the above discussion, the Agency takes this opportunity to restate that while a Title V permit can include a ''permit shield'' protecting it from allegations that it has failed to satisfy CAA *monitoring* requirements, such shield does not relieve the source of its obligation to comply with the underlying emission limits or other applicable requirements being monitored. In other words, even where a source receives a ''shield'' providing that the monitoring provisions set forth in its Title V permit constitute compliance with all monitoring requirements of the CAA, the source would not be shielded from allegations of noncompliance with the underlying substantive requirements (e.g., emission limits) being monitored even if the source's required monitoring failed to detect the violation. *See also* the October, 1993, proposal, 58 FR 54678.

Industry commenters argued that allowing credible evidence in Title V compliance certifications would render the certification requirement constitutionally void for vagueness. According to these commenters, reference test methods are necessary to define, in a consistent and reproducible manner, the level of performance that constitutes compliance; without a reference method, an emission limit would be incomplete. As discussed above, EPA in no way intends to eliminate reference tests or to alter their methodology. Instead, these tests, performed as specified under EPA and state regulations, will remain the benchmark against which to compare other emissions or parametric data, or engineering analyses, regarding source compliance.

Finally, numerous commenters argued that allowing credible evidence in compliance certifications and enforcement actions would disrupt the Title V permit process and cause substantial delays in the issuance of these permits because local permitting authorities would have to adjust many of the sources' emission limits, which the commenters contend were not intended to be complied with continuously. Such Title V gridlock could occur only if today's action in fact changed the stringency of emission standards.

C. EPA's Authority To Promulgate the Credible Evidence Revisions

1. Statutory Authority

Today's rulemaking and related SIP call are based primarily on EPA's existing authority prior to the 1990 CAA Amendments. Section 113(a) of the Act authorizes EPA to bring an administrative, civil or criminal enforcement action ''on the basis of any information available to the Administrator.'' This provision provides the Agency with clear statutory authority to use any available information to prove violations of requirements under the Act, and demonstrates that Congress did not intend to limit EPA to using reference test method results in bringing enforcement actions. The language of Section 113(a), together with the fact that the Act nowhere prohibits the use of information other than reference test results to prove violations, indicates that the Act does not limit the use of any information to prove a violation. Therefore, by law the Agency is limited only by general evidentiary rules in what it can use to prove a violation alleged in an enforcement action.

2. The Kaiser Steel Decision Does Not Constrain EPA's Authority To Amend Its Regulations

Although the Act sets no inherent limits on EPA's authority to use any type of information to prove a violation, some EPA regulations provide for specific test methods for determining compliance and have been read by some to constrain EPA's enforcement authority. In *United States* v. *Kaiser Steel Corp.,* No. CV–82–2623 IH (C.D. Cal. Jan. 17, 1984), the district court construed the language of EPA's regulations at 40 CFR 60.11 as limiting the admissible evidence of violations of opacity standards to observations utilizing Method 9, the opacity reference test method. Thus, when the Agency attempted to use expert testimony pertaining to opacity to prove the existence of violations without Method 9 test data, the court rejected the evidence and held that EPA could prove violations only on those days where the Method 9 test was conducted. This decision—which interpreted only EPA's existing regulations, not the Act—was specifically overruled by Congress in the 1990 CAA Amendments. Today's rulemaking is intended to clarify that EPA's regulations do not constrain EPA to using reference tests to prove a violation of an emission standard. Rather, EPA retains its full authority under Section 113(a) to use ''any information'' as the basis for an enforcement action.

3. Despite Commenters' Claims, Clean Air Act Case Law Does Not Mandate Exclusive Reference Tests

At least one commenter has asserted that the decision in *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 399 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974), stands for the proposition that CAA emission standards may be enforced only through an exclusive reference test method. First, the commenter relies on the court's ruling

that a reference test method must make measurements with ''reasonable accuracy'' and be ''objective.'' 486 F.2d at 401 & n. 103. Second, the commenter cited the court's concern with deviations between sampling methods used in gathering data to set an emission standard and sampling methods used in reference methods. The court stated that ''a significant difference between techniques used by the agency in arriving at standards, and requirements presently prescribed for determining compliance with standards [i.e., the reference method], raises serious questions about the validity of the standards.'' 486 F.2d at 396. EPA disagrees with this reading of *Portland Cement.*

These holdings, individually or together, do not support the conclusion that violations of an emission standard may only be demonstrated by an exclusive reference method. The court's statements regarding the reliability of reference methods were made in context of a challenge to an opacity standard. The industry petitioner argued that testing compliance with that standard, inspector observations, is inaccurate and therefore arbitrary. The court agreed that the evidence called the reliability of inspector observations into question and remanded to EPA for it to determine if there was a way to measure compliance with the standard with ''reasonable accuracy.'' In no way did the court imply that the opacity standard had to have an exclusive reference test but simply rejected the test EPA proposed to use as insufficiently supported.

The *Portland Cement* court's discussion of a compliance method that differed from the test method used to develop the standard also lends no support to the conclusion that an exclusive test method is required. It is true that the court mentioned reference methods ''outlined by regulation.'' However, the mere description of an agency practice (here, the inclusion of a reference test in a regulation setting an emission standard) does not transform that practice into a statutory requirement. Moreover, the thrust of the court's remarks was to caution EPA that, where EPA has established by regulation a reference method for sources to demonstrate compliance, the best data EPA can put forth to show that a standard is in fact achievable is data generated by the reference method. The D.C. Circuit, however, has specifically rejected the assertion that standards can only be supported by reference test data. *See National Lime Ass'n* v. *EPA,* 627 F.2d 416, 446, fn.103 (D.C. Cir. 1980). None of this, thus, supports the commenter's claim that a standard's supporting data must be generated using the reference method, and its supposed corollary that only reference method data can be used to enforce the standard, especially where, as here, that other information must be related back to a reference test method. At best, the commenter's arguments would apply only in the context of an original standard-setting, where an emission limitation or other standard newly promulgated by EPA was being challenged on the basis that the standard's supporting data was inadequate. Today's rule sets no new emission or work-practice standards, and amends no existing ones.

Thus, the commenter is mistaken. Neither of the two passages in *Portland Cement* cited by the commenter address whether exclusive reference tests are necessary, much less mandate establishment of such tests. Further, EPA regulations are inconsistent with the exclusivity argument of the commenter. For example, section 60.8(a) of Title 40 of the CFR provides a whole string of circumstances under which a source can alter or completely replace the reference test required by the regulation. Finally, today's final action regarding the use of non-reference test data in enforcement is fully consistent with the court's requirement that reference testing be conducted in a nonarbitrary manner.

4. The 1990 CAA Amendments Further Support EPA's Authority

Various provisions of the 1990 CAA Amendments provide additional support for EPA's position that reference tests are not the exclusive means of proving violations. As noted above, Congress specifically reversed the *Kaiser Steel* decision in Section 113(e) of the Amendments by providing that the duration of a violation may be established ''by any credible evidence (including evidence other than the applicable test method).'' The legislative history for this provision shows that Congress meant to clarify that in an enforcement action courts are not restricted to reference test method data, but may consider any evidence of violation or compliance admissible under relevant evidentiary rules. *See* S. Rep. No. 228, 101st Cong., 1st Sess. 1, 358 (1989) (''Senate Report''), *reprinted in* 1990 U.S. Code Cong. & Admin. News 3385, 3741 (''Reprint'').

Other provisions of the 1990 CAA Amendments also evidence Congressional intent that reference test methods should not be used as the exclusive means for assessing compliance with CAA emission limits. Most pointedly, the requirements in Section 114(a)(3) for enhanced monitoring and for compliance certifications based on a determination of whether compliance was continuous or intermittent presumes that data other than reference tests would be used for these purposes. As explained in the October, 1993, proposal, the use of non-reference test data is also consistent with the monitoring, compliance assurance, and compliance certification requirements in Sections 504(a), 504(c), and 503(b)(2) of the Act. *See* 58 FR 54649–50. In addition, Section 504(b) of the Act grants discretionary authority to the Administrator to prescribe procedures and methods for monitoring, and provides that continuous emission monitoring systems need not be required ''if alternative methods are available that provide sufficiently reliable and timely information for determining compliance.'' In sum, Congress' repeated emphasis on providing reliable and timely compliance information is inconsistent with the notion that only data from infrequently performed reference tests is relevant to compliance certifications and enforcement actions.

5. Commenters' Attempts To Narrow the Scope of Sections 113(e) and 113(a) Are Unpersuasive

Several industry commenters have claimed that the legislative history of the 1990 CAA Amendments shows that section 113(e)(1) does not provide authority for today's final action. Additionally, these commenters have asserted that the section's legislative history upon which EPA has relied is ambiguous.

In the October, 1993, proposal, EPA cited to the Senate Report's discussion of Section 113(e)(1). The Senate Report stated:

> This title of the bill enhances the ability of the Environmental Protection Agency * * * by making clear that the Agency may rely upon any credible evidence of violations in pursuing alleged violations.

Senate Report at 358, Reprint at 3741. The Report further explained:

> [T]he amendment clarifies that courts may consider any evidence of violation or compliance admissible under the Federal Rules of Evidence, and that they are not limited to consideration of evidence that is based solely on the applicable test method in the State implementation [plan] or regulation. For example, courts may consider evidence from continuous emission monitoring systems, expert testimony, and bypassing and control equipment malfunctions, even if these are not the applicable test methods. Thus, this amendment overrules the ruling in *United States v. Kaiser Steel Corp.,* No. 82–2623 (C.D. Cal. January 17, 1984) to the extent that

the court in that case excluded the consideration of such evidence.

Senate Report at 366, Reprint at 3749. Finally, the Report notes that data from enhanced monitoring and compliance certifications ''will facilitate enforcement, due in part to the fact that such data and certifications can be used as evidence.'' Senate Report at 368, Reprint at 3751.

The commenters, in turn, rely on the views of Senator Chafee regarding S. 1630, inserted into the Congressional Record at the time the legislation was introduced. Senator Chafee stated with regard to Section 113(e)(1):

> Subsection 113(e) also clarifies and confirms that once EPA establishes evidence of a violation using a formal test method, EPA can use other credible evidence to prove additional violations, or that violation has continued.

135 Cong. Rec. S 9650, 9655 (August 3, 1989).

EPA believes that the best reading of the legislative history still supports its interpretation of Section 113(e)(1). First, there is no ambiguity in the Senate Report, the language of which unreservedly supports enforcement actions brought on the basis of non-reference test data. Second, EPA does not believe that Senator Chafee's floor statement outweighs the clear statement in the Senate Report. The Senate Report is a more authoritative reflection of congressional intent than a floor statement produced at the beginning of the legislative process.

Various commenters also objected to EPA's reliance on Section 113(a) as a basis for today's action. One commenter argued that Section 113(a) does not preempt regulatorily specified reference test methods. Several commenters asserted that EPA's construction of Section 113(a) would render superfluous the new language in Section 113(e)(1) concerning credible evidence. These commenters claim that, under EPA's interpretation of Section 113(a), Congress could have ''fixed'' the *Kaiser Steel* decision simply by clarifying the scope of EPA's authority under Section 113(a).

These various commenters have misunderstood EPA's interpretation of Section 113(a). EPA has not asserted that Section 113(a) preempts reference test methods. Rather, EPA believes that Section 113(a) provides authority to amend current regulations to make clear that data from reference test methods are not the exclusive means of establishing noncompliance or compliance in enforcement actions. Given this interpretation of Section 113(a), Congress's passage of Section 113(e)(1) cannot be described as superfluous—particularly in light of the decision in *Kaiser Steel.*

6. EPA Can Promulgate the Credible Evidence Revisions Without Reproposal

Several commenters have argued that finalization of the proposed changes in Parts 51, 52, 60 and 61 without first reproposing those changes violates the Administrative Procedure Act (APA), the CAA, and due process. The commenters' main argument is based on EPA's presumed change in course on implementing the requirement in Section 114(a)(3) concerning enhanced monitoring and compliance certification. As noted above, the changes to Parts 51, 52, 60 and 61 were proposed in the same rulemaking that proposed an enhanced monitoring and compliance certification program. Since that proposal, EPA has re-evaluated its approach to enhanced monitoring and has made publicly available and has sought comment on a revised approach—the CAM approach—for satisfying the same statutory goals as the original enhanced monitoring proposal. Some commenters contend that switching to CAM will fundamentally change their view of the proposed changes to Parts 51, 52, 60 and 61 because those proposed changes were evaluated only in terms of how they would be implemented under the October, 1993, proposal on enhanced monitoring. Until CAM is formally proposed, these commenters assert, they cannot give meaningful comments on the credible evidence revisions. Further, the commenters argue that the proposed revisions provided insufficient notice and opportunity to comment because EPA has not adequately defined the term ''credible evidence.''

EPA believes today's rule has no procedural infirmities. EPA is today finalizing the enforcement-related portions of the proposal it made in 1993 with only minor changes.

The commenters' claim that they cannot meaningfully comment on credible evidence revisions prior to proposal of the CAM approach is not well-taken for two reasons. First, EPA does not believe that any knowledge of the draft CAM approach is necessary to comment on today's rulemaking. In today's final rule, EPA has removed any presumptions regarding the credibility of any specific data. If and when the draft CAM approach is finally adopted, CAM data will be treated under today's rule like any other potential source of compliance information. Thus, knowledge of the draft CAM approach is not critical to commenting on this rulemaking. In any event, the nature of the draft CAM approach has been generally available in some detail since September, 1995—well before EPA renewed its request for comment on today's rulemaking. Further, EPA has sought and received additional comment on the enforcement consequences of the draft CAM approach by distribution of a revision of the CAM approach in August, 1996. The revised approach specifically discussed the relationship of the draft CAM approach and today's action.

Second, the October, 1993, proposed rulemaking gave interested parties sufficient notice of the issues raised by the proposed changes to Parts 51, 52, 60 and 61. The Agency made clear that these revisions were designed to remove any potential ambiguity regarding the use of enhanced monitoring data in compliance certifications, and to clarify that any credible evidence of a violation of an emission standard was admissible to prove (or disprove) such a violation. *See* 58 FR 54677. To clarify that these credible evidence revisions extended beyond the data gathered under an enhanced monitoring program, EPA gave two specific examples of evidence collected outside the enhanced monitoring program that under the revised regulations could be used to prove a violation. *See* 58 FR 54676–54677. Thus, the October, 1993, proposal clearly put interested parties on notice that the credible evidence revisions were not merely an adjunct to the enhanced monitoring program. In fact, industry commenters on the October, 1993, proposal clearly understood the central issue posed by the proposed credible evidence changes, and they commented on it extensively. Today's final action promulgates revisions to *existing* regulations, and are not contingent upon *future* promulgation of the CAM approach or any other form of enhanced monitoring requirement.

Neither is this rulemaking procedurally deficient for not providing an express regulatory definition of the term ''credible evidence''—a term which Congress itself inserted, without definition, into the Act. The issues of credibility, admissibility and weight of evidence have been exhaustively addressed by federal and state court evidentiary rules regarding evidence, and the thousands of cases decided under them. Today's final action defers to those regulations and makes clear that there are no bars in regulations under the CAA which prevent the use of evidence or information other than reference test methods in compliance certifications and enforcement actions. Of course, in judicial enforcement

proceedings, what evidence is credible and admissible will be determined by the court taking into account how the evidence was gathered and the specifics of the emission standard and any associated reference method.

Finally, EPA believes that it has taken extensive steps, detailed in Section I.C. above, to ensure that the concerns of affected parties were fully aired. None of the additional public outreach actions that EPA undertook in 1996 were required by the APA or the CAA; instead, EPA undertook them voluntarily to ensure full input by interested parties regarding the credible evidence rules.

D. Stringency

Industry commenters have presented several arguments in support of their position that this rulemaking requires sources to be in continuous compliance and thus would effectively increase the stringency of underlying requirements, including SIP limits and standards established by EPA under the NSPS and NESHAP programs.

EPA believes that industry's arguments on this point are fundamentally wrong. It is not EPA's intent that these rules should increase the stringency of any applicable requirement. These rules do not do so because they maintain the focus of the compliance determination on whether or not the appropriate reference test would have shown a violation.

The commenters' arguments regarding increased stringency are as follows: applicable requirements are accompanied by specified reference tests. Any departure from past practice regarding the use of these tests, including the use of other credible information to directly assess compliance, particularly on a more frequent basis, will inevitably change the results of an inquiry into the compliance status of any source compared to exclusive reliance on the infrequent performance of the reference tests. Therefore, industry argues, using credible evidence would change the underlying applicable requirements—usually in a manner that makes them more stringent—without going through the necessary rulemaking procedures.

Industry's argument hinges on the premise that adoption of an emission standard that includes a particular form of reference test—one that is not required to be performed continuously as a matter of course—limits the compliance obligation. The scope of the compliance obligation is not at issue in this rulemaking. The scope of the compliance obligation prescribed by any particular standard shall be based on the emission standard and not this rulemaking. However, to fully respond to industry comments, and to give notice of the position EPA will take in future enforcement proceedings, EPA believes it is necessary to address in some detail the nature of the compliance obligation under emission standards with particular emphasis on the compliance obligation as it pertains to emission standards which have a reference test method that is not required to be performed continuously.

While the bulk of the commenters' concerns were expressed with respect to NSPS, the same concerns also apply in most cases to NESHAPs and SIPs. Likewise, EPA's responses focus on NSPS, but are generally applicable to other emissions limits as well.

1. Emissions Limits Require Continuous Compliance (Consistent With Any Averaging Times) Except During Periods Where Compliance Is Specifically Excused

To resolve commenters' claims of increased stringency, the nature of the compliance obligation facing owners and operators of sources of air pollution under the Act must be addressed. Under the CAA, its regulations, and the case law, a source's compliance with emission limitations must be continuous (consistent with any averaging times) except where a particular emission standard specifically provides for periods of noncompliance.

The Statute. The Clean Air Act defines the terms ''emission limitation'' and ''emission standard'' as meaning ''a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a *continuous* basis * * *.'' CAA section 302(k) (emphasis added). In accordance with this clear statutory statement, the Act authorizes penalties for multiple days of violation should a source fail to meet its continuing obligation. *See also* CAA sections 113(e)(2) (providing that ''a penalty may be assessed for each day of violation,'' and establishing a presumption of continuing violation if certain conditions are met) and 113(e)(1).

CAA Regulations. The Act's general requirement of continuous compliance is mirrored in the NSPS regulations, which generally require that sources comply with established emission limits except during certain defined time periods. NSPS provisions typically specify that compliance with stated limits is required ''on and after the date'' of an initial performance test conducted in accordance with 40 CFR 60.8. *See, e.g.,* 40 CFR 60.502. The need for continuous compliance is also discussed in the preambles to numerous NSPS, including many older ones. For example, in proposing standards for glass manufacturing plants (Subpart CC), EPA stressed the need for effective monitoring to assure that affected facilities are ''continuing to maintain the emission reduction observed during the performance test.'' 48 FR 50670, 50675 (1983). EPA has also made this point clear in publicly-available guidance memoranda. *See* Detailed Response Document at Section 4.

In addition to requirements for continuous compliance, NSPS regulations also typically contain specifically excused periods of noncompliance. These periods confirm that compliance is required at other times. They also confirm the basic reasonableness of this compliance scheme—that is, sources must generally comply continuously with their numerical emission limits, but not during periods of specifically excused noncompliance, and only in accordance with any specified averaging periods. For example, for many standards, compliance is not required during periods of startup, shutdown or malfunction. This exception is contained in the NSPS general provisions and in individual standards. *See* 40 CFR 60.8(c); *see also, e.g.,* 40 CFR 60.46a.

Case Law. In various judicial decisions, courts have approved of the basic NSPS regulatory scheme of continuous compliance accompanied by limited, specified exceptions for noncompliance. The courts have stated that the specified exceptions are needed because sources must comply at all other times. *See, e.g., Portland Cement,* 486 F.2d at 399 (court noted EPA's then-proposed ''startup, shutdown and malfunction'' compliance exclusion regulation with approval, suggested that it was a ''limited safety valve'' and stated that it imparts a construction of ''reasonableness'' to the standards as a whole and adopts a more flexible system of regulation that can be had by a system devoid of ''give''; (*Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d. 427, 433 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974) (in a challenge to sulfuric acid plant and coal-fired steam generator NSPS standards, the court again noted with approval the proposed start-up, shutdown and malfunction exception and remanded the rule stating that ''such variant provisions appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the ''never to be

exceeded'' standard currently in force'') (emphasis added); and *Bunker Hill Co.* v. *EPA,* 572 F.2d 1286, 1301–02 (9th Cir. 1977) (in challenge to SIP sulfur dioxide standard, court observed that EPA regulations required that the standard be met ''all of the time,'' and thus EPA must typically promulgate upset provisions to excuse noncompliance beyond the source's control). Similarly, the proposition that compliance must be continuous is reflected in numerous judicial decisions involving challenges to various NSPS rulemakings. In these cases, both the D.C. Circuit Court and industry petitioners have emphasized that for an emission standard to be achievable it must be able to be continuously complied with over wide operating ranges at varied facilities. *See, e.g., Portland Cement, Essex Chemical, National Lime,* and *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981). In *National Lime,* for example, the lime industry's trade association itself complained that the data underlying the promulgated numerical emission standards were insufficient to show that the standards were ''in fact achievable on a continuous basis.'' 627 F.2d at 430. In holding that EPA had not adequately demonstrated the achievability of the standards for the industry as a whole, the court explained that ''to be achievable, we think a uniform standard must be capable of being met under most adverse conditions that can reasonably be expected to recur . . . .'' *Id.* at 431. In *Sierra Club* v. *Costle,* various electric utility companies challenged a particulate standard on the basis that ''the data reflect only short term performance while the standard requires long term continuous compliance.'' 657 F.2d at 377 (emphasis added). This challenge was rejected by the court based on data showing that certain sources had ''consistently complied with the standard.'' *Id.* at 382.

2. Commenters' Advocacy of Noncontinuous Compliance Would Lead to Numerous Anomalies

Some industry commenters have argued that numerous emissions limitations do not require continuous compliance or, alternatively, that ''continuous'' does not have the straightforward meaning suggested above. The commenters' argument centers on NSPS standards issued under CAA section 111. In the commenters' view, many such standards do not contemplate that facilities will operate in compliance on a continuous basis with stated emissions limits, but rather require only an initial demonstration of compliance with stated limits upon start-up or shortly thereafter. After an initial performance test, continuous compliance is required only with respect to operation and maintenance ''in a manner consistent with good air pollution control practice'' as specified in 40 CFR 60.11(d). As to numerical emissions limits, commenters suggest that these must be met only on those infrequent occasions that a subsequent performance test is conducted. So long as any such performance test is passed, the source is in ''continuous'' compliance with numerical emissions limits without regard to whether its emissions in fact exceeded the numerical limit during the time between the tests, no matter how long that may be.

EPA rejects this view of the nature of the obligation to comply with NSPS and other emission limits under the CAA. *See* Detailed Response Document. EPA and the courts have long held that emission limits must be complied with continuously, consistent with any associated averaging periods, except where a particular limit provides otherwise. Adopting the commenters' view of compliance would lead to numerous anomalies.

In the April 2, 1996, public meeting and in follow-up written comments, several commenters argued that many reference test methods were selected specifically because they would only be performed infrequently—for example, on a yearly basis. These once a year tests would be proper for their associated emission standards, which in the commenters' view were intended to be complied with only 95% of the time. Specifically, performing a reference test once a year would yield ''acceptable'' compliance results, because on average a source would be found out of compliance only 5% of the time—that is, in one in twenty tests, or once every twenty years. According to these commenters, testing for compliance more frequently would be unfair, because it would increase the likelihood that the source would be found out of compliance during periods where the standard itself contemplated noncompliance. In order to avoid being found in noncompliance, sources would have to continuously stay below their emission limits—which in these commenters' view would effectively increase the stringency of the emission standard.

EPA disagrees with the commenters' notion that sources must meet their legal numerical air emission limits only seldomly. Further, EPA rejects as inconsistent with the Act and its underlying purposes the notion that sources can somehow be in routine ''compliance'' without staying within these limits on an ongoing basis. The fundamental goal of the CAA and the emission standards established under it, is to achieve clean air. Moreover, many emission standards, such as hazardous air pollutant standards under Section 112 and emission standards in State Implementation Plans designed to implement national ambient air quality standards, have a direct relationship to the protection of human health. Routine compliance with numerical emission standards is critical to achieving this goal. The commenters' view that such compliance is somehow not required would completely undercut these public health and safety goals.

If the commenters' view was correct, any EPA or state targeting of a specific source by requiring the source to perform more frequent reference tests would be unfair and presumably illegal, because any such increased frequency in reference testing would destroy the delicate balance of frequent noncompliance and infrequent testing that the commenters claim is contemplated by the rules. Under this view, EPA and states might not be able to require an apparently violating source to conduct a previously unscheduled reference test, because it would improperly raise the source's chances of being found in noncompliance and thereby ''increase the stringency of the underlying standards.''

The commenters'' argument is also inconsistent with the language, structure, and purpose of the CAA. For example, if the frequency of testing must be limited to meet the intent of the emission limits, to be fair to all sources EPA's regulations should have required that the tests be performed only at infrequent intervals. EPA's rules contain no such restrictions; rather, CAA section 114(a)(1)(D) grants EPA broad discretion to order reference tests whenever the Administrator deems it appropriate. Moreover, commenters'' argument is inconsistent with CAA section 113(e)(1), which even on its narrowest reading (note that EPA's reading is considerably broader) specifically provides for use of non-reference test data to prove continuing additional days of violation after an initial violation is established by reference test data, and by CAA section 113(e)(2), which establishes a presumption of continuing violation after notice of the violation has been given to the source, provided that EPA can make a prima facie showing that ''the conduct or events giving rise to the violation are likely to have continued or recurred past the date of notice.'' This presumption continues until the violator ''establishes that continuous compliance has been achieved.''

Likewise, sections 114(a)(3) and 504(a)-(c) regarding enhanced monitoring and certification as to whether compliance is continuous or intermittent, and prompt reporting of deviations, are simply inconsistent with a regulatory regime that would require only occasional demonstrations of compliance with emission limits. Taken together, these provisions, represent a fundamental statutory rejection of the commenters' argument. *See* Detailed Response Document, Section 4, which discusses other reasons why these comments are without merit.

3. Comments Regarding Continuous Compliance Are Not Directed at Today's Action, but Rather at Underlying Emission Standards

Industry commenters have argued that the quality and quantity of the data used in establishing emissions limitations, such as those under the NSPS and NESHAP programs, reflect a conscious decision by EPA that compliance with such standards would need to be demonstrated only periodically. It follows that requiring continuous compliance with stated limits at this juncture would effectively increase the stringency of the standards. As discussed above, EPA believes that the commenters' general arguments strain common sense. Commenters have pointed to various NSPS standards to support their views, but EPA finds these examples unpersuasive.

In particular, commenters have pointed to the NSPS for kraft pulp mills, 40 CFR Part 60, Subpart BB, and for steam electric generators constructed between 1971 and 1978, Subpart D, as reflecting a general acknowledgment by EPA that national standards need not be complied with at all times. EPA believes that, to the contrary, Subparts BB and D and other cases demonstrate that where EPA intended to allow affected sources to exceed stated emissions limits, the standards in question expressly so provide. It is true that in the development of some NSPS and NESHAP standards, EPA was concerned with the limited number and distribution of test runs and the inherent variability in levels of emissions from even well-controlled facilities. Where appropriate, EPA addressed those concerns by adjusting the numerical value of the standard, providing excess emissions allowances and provisions for noncompliance during certain upset conditions, or through changes in averaging times. With other standards, EPA did not provide for any departure from the general requirement that compliance must be continuous. Examples of all these approaches, and specific responses to comments regarding Subparts D and BB, are provided in the Detailed Response Document.

The commenters' assertions that sources cannot comply on a continuous basis are really directed not to the propriety of today's rules, but rather to the adequacy of the underlying NSPS and other emission standards that are not at issue in this rulemaking. To the extent there is any documentation that a well-run facility cannot comply consistently with underlying national emission standards, or applicable SIP requirements, such documentation would be relevant only to those existing standards, not to today's rule. EPA notes that despite several requests to commenters to identify any standards that cannot be complied with on a regular basis, no specific information has been provided to this rulemaking docket that demonstrates that well operated and maintained facilities employing pollution control technologies of the types upon which the underlying emission standards were based cannot comply with those standards on a continuing basis. The most that was submitted was a statistical re-analysis of the data relied upon by EPA in promulgating several emission standards and a one page graph purporting to show that an industrial boiler could not comply with the NO_X emission limit at low levels.

The agency has considered this comment concerning the Subpart D NO_X standard carefully, as it does not intend to impose requirements that are impossible for well-designed sources to meet, but believes that this concern is largely theoretical. The information provided by the commenter to EPA was vague and did not prove that the undisclosed source could not comply with the emission standard. Further, if a standard was impossible to achieve under some circumstance, EPA and citizens are not likely to bring enforcement cases in such instances. In reviewing CAA enforcement actions the agency has been unable to identify any case where either the agency or a citizen sought to enforce a standard that was impossible to achieve. The agency was also unable to identify any case in which a defendant established that compliance was not possible at the time of the alleged violation. This appears to be the case even in those states and localities that have had ''credible evidence'' rules for years.

Additionally, should it be determined that a standard could not be met during some relatively infrequent or inconsequential period of source activity, the potential for significant adverse impact on that source is remote. The agency has previously expressed its policy that, generally, judicial enforcement is not the appropriate vehicle to redress sporadic, infrequent violations with no environmental consequence. Further, it is unlikely that a citizen could prevail in enforcing a theoretically impossible standard since Courts will not issue an injunction where there is nothing to be done. Similarly, where one cannot establish that a source failed to act in a manner required by law a significant penalty will not be imposed by the courts. The agency is not aware of any situation in which it has filed, and one should not anticipate large numbers of citizen suits being filed, where there is nothing the source could have done or could do to achieve a greater degree of compliance. Moreover, the courts today have additional tools, including fee awards and sanctions available under the Federal Rules of Civil Procedure and other statutes to address meritless suits.

In further response to these industry comments, EPA has included in the record a 1993 study conducted by EPA Region V that shows that almost all (95%) of sources with sulfur dioxide CEMs were meeting their federal and state sulfur dioxide emission limits approximately 97% of the time, with excess emission periods totaling only 3%. *See* Region V Study, Figure 2. Because this 3% figure included excess emissions recorded during periods in which compliance is specifically not required, such as startup and shutdown, the percentage of operating time in noncompliance with the standard is even smaller and may mean that most sources are in compliance all the time. EPA Region V sources with continuous opacity monitors showed similar results: the average source's percentage of opacity exceedances was less than 2%, with 95% of sources at or below approximately 4%. *See* Study, Figure 1. As with the sulfur dioxide data, opacity exceedances during periods of startup, shutdown and other excused periods were not excluded. Accordingly, the percentage of actual noncompliance with opacity limits was even smaller. Note that these figures are for the average (50th percentile) and worst (95th percentile) facilities. The best run facilities have fewer excess emissions reports.

Additional CEM data from EPA Region V that focused specifically on exceedances from NSPS Subpart D SO_2 emission standards shows similar results. This data shows that Subpart D sources report few or no excess SO_2 emissions. Approximately two-thirds of the sources report no excess emissions

at all, during any three month reporting period. Further, since 1990, the vast majority of sources (95%) have reported total excess emissions averaging less than 2.5% of operating time; since 1993, less than 1.7%. Since these figures include all excess emission periods, including periods that are probably excused, the actual SO_2 exceedance rates were even lower.

These data show that there are not ''fundamental flaws'' in the subject standards such that the standard cannot be met. *Indeed,* the data demonstrate that most sources do comply all or nearly all of the time.

If the regulated community believes that a standard cannot be met across some meaningful range of normal operating conditions, or if specific exemptions beyond those currently provided are proper, we believe the appropriate action is for the affected industry to file a petition for amendment of the standard at issue or propose more specific permit conditions so that the matter can be fully assessed and addressed through the regulatory process. However, the information submitted by the commenters does not show that there currently exists a significant ''impossibility'' issue that is so widespread as to outweigh the benefits of the proposed rule.

4. Enforcement Using Continuous Monitoring Data Does Not Increase the Stringency of Applicable Requirements

Industry commenters have argued that the stringency of emission standards will be increased if enforceable data is obtained more frequently than has been ordinarily obtained in the past through reference testing. Further, the commenters argue that direct enforceability of this data would contradict EPA's stated positions in adopting standards under the NSPS and NESHAP programs because EPA intended that continuous monitoring would only show compliance with good operation and maintenance procedures, i.e., general duty requirements, and would not be otherwise used in enforcement. (*See, e.g.,* 38 FR 10820 (1973) (preamble to proposed startup, shutdown and malfunction regulation); 43 FR 7571 (1978) (preamble to final kraft pulp mill standards).

Because the NSPS and NESHAP emission standards must be met continuously, consistent with any averaging times and except during periods where compliance is specifically excused, any more frequent or continuous monitoring of the standards and any enforcement based on violations uncovered thereby have no effect on the stringency of the standards. To take a simple analogy, allowing the use of radar guns or increasing the number of police checking for speeding may raise the chance that a speeder will be detected, but this does not alter the legal stringency of a posted speed limit.

In some early NSPS, the agency required the installation of what were styled ''indicator monitors'' and provided policy guidance that such monitoring data would not be used as the sole basis of enforcement actions absent further rulemaking. 38 FR 10820. To the extent that the CAA Amendments of 1990 did not supersede this policy statement, today's action is that future rulemaking. These policy statements, like today's rulemaking, pertain only to the kinds of evidence EPA uses to prove violations. The policy change that was contemplated in our 1993 proposal and 1996 memorandum are supported by technological advances in the accuracy and reliability of continuous emission monitors, deficiencies in EPA's previous practices identified by GAO and others, and the language and intent of the Act and the 1990 CAA Amendments.

EPA's past statements regarding limitations on the use of data derived from continuous monitoring methods for purposes of enforcing standards were motivated in part by concerns over the cost and availability of such methods and their ability to accurately determine compliance. *See, e.g., National Lime,* 627 F.2d at 450 (responding to petitioners' argument that there was no adequately demonstrated technology for monitoring opacity, EPA stated that the continuous monitoring data would not be used to determine compliance with the opacity standard but ''to keep a check on the operation and maintenance of the control equipment,'' and that the monitors were reliable enough to perform this limited function). For example, in the 1973 startup, shutdown and malfunction regulation proposal, EPA noted that while continuous monitoring data would not, at that time, be used to determine compliance as a general matter, such data could be used if ''approved as [an] equivalent or alternative method for performance testing.'' 38 FR 10820. Indeed, the NSPS general provisions have long provided that in lieu of performance tests using reference methods, a source could demonstrate compliance using an approved equivalent or alternative method, and that EPA can waive reference tests where the source has otherwise satisfactorily demonstrated compliance. *See* 40 CFR 60.8(b).

Since the 1970s, the availability, cost and accuracy of methods that enable determinations of compliance on a continuous basis has improved markedly. *See, e.g.,* 1990 GAO report at 19, 22–23 (1986 and 1988 EPA studies showed CEM data highly reliable); *Continuous Emission Monitoring,* 1993, Jahake, Thomas Publishing Co. For these reasons, EPA believes it is appropriate as a technical matter to allow information derived from these methods to be used in compliance certifications and enforcement actions. In fact, more recent national standards issued by EPA provide for determining and enforcing compliance directly by use of continuous monitoring data.

5. Sources Must Comply Both With Good Operation and Maintenance Requirements and With Emission Limits

Industry commenters have claimed that as to the NSPS program, the only goal of the program was to insure that best demonstrated technology was employed, such that once an initial reference test demonstrated that compliance with the standards could be achieved, it need not be demonstrated thereafter, and that an affected source's only ongoing obligation was its ''general duty'' to employ good operation and maintenance practices to minimize emissions in accordance with 40 CFR 60.11(d).

EPA agrees that proper operation and maintenance of an emissions unit and any associated pollution controls in accordance with 40 CFR 60.11(d) is vital to complying with emission standards. However, while it is true that sources have a continuing duty to employ good operations and maintenance practices, this duty does not substitute for the sources' obligation to comply with its emission limits. The two obligations, while related, are separate requirements in the NSPS regulations and in legal effect.

EPA has made these points plain as far back as 1973 in the proposed NSPS startup, shutdown and malfunction rulemaking:

> It is anticipated that the initial performance test and subsequent performance tests will ensure that equipment is installed which will permit the standards to be attained and that such equipment is not allowed to deteriorate to the point where the standards are no longer maintained. In addition, the proposed regulation requires that the plant operator use maintenance and operating procedures designed to minimize emissions in excess of the standard.

38 FR 10820 (1973) (emphasis added). This preamble text clearly states both that proper equipment maintenance is vital to remaining within an emission

standard (otherwise equipment would deteriorate to the point where standards were not met) and that the general operation and maintenance obligation is a separate regulatory requirement. Additional discussion of the distinction between the emission limits and good operating practice requirements can be in the Detailed Response Document. These statements make it clear that good operating practices requirements are separate and distinct from the need to continuously comply with emissions limits.

E. SIP Call

In the October, 1993, proposal, EPA announced that it planned to call for States to amend their applicable implementation plans to ensure that owners or operators may use enhanced monitoring (or other monitoring approved for the source pursuant to part 70) for compliance certification purposes, and that data from this monitoring, along with any other credible evidence, may be used as evidence of a violation of an applicable plan. 58 FR 54660. In December, 1993, and February, 1994, the Office of Air and Radiation's Stationary Source Compliance Division, the division then responsible for writing and implementing the enhanced monitoring rules, issued memoranda to EPA's Regional offices instructing them to conduct the SIP call. As of September, 1996, fifteen states and local air pollution control districts, together with the Commonwealth of Puerto Rico, had responded to the call and submitted SIP amendments for EPA approval. Kansas, Iowa, Nebraska, North Dakota, Georgia and Puerto Rico had received approval; the other states and districts' revisions were pending.

For substantially the same reasons that allow EPA to go forward with today's final rule, EPA has the authority to initiate and continue this SIP call. EPA's decision to forego the enhanced monitoring approach in favor of the CAM proposal has no effect on the basic goals of the SIP call, which are to clarify that non-reference test data can be used in enforcement actions, and to remove any potential ambiguity regarding this data's use for Title V compliance certifications.

Today's action ensures that the evidentiary rules for CAA violations are consistent in all fifty states. EPA has surveyed those states that have responded to the SIP call and has determined that the credible evidence changes have not created the difficulties forecast by the commenters.

IV. Administrative Requirements

A. Docket

Today's final rulemaking action is subject to Section 307(d) of the Act. Accordingly, EPA has established a docket (No. A–91–52), which consists of an organized and complete file of all information submitted to, or otherwise considered by, EPA in the development of today's action and the CAM approach. The docket includes all memoranda and studies cited by EPA in this preamble. The principal purposes of the docket are: (1) to allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review. The docket is available for public inspection at EPA's Air Docket, which is listed under the **ADDRESSES** section of this document.

B. Office of Management and Budget (OMB) Review

Today's rulemaking is not a ''significant regulatory action'' because the revisions make only evidentiary changes and do not impose any additional implementation costs on regulated sources. Nevertheless, EPA submitted this final rule to OMB for review. Changes made in response to OMB suggestions and recommendations will be documented in the public record.

C. Unfunded Mandates Reform Act

Under section 202 of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, EPA generally must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in expenditure by State, local, or tribal governments in the aggregate, or by the private sector, of $100 million or more. Before promulgating a rule for which such a statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Section 203 requires the Agency to establish a plan for obtaining input from and informing, educating, and advising any small governments that may be significantly or uniquely affected by the rule.

EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Today's rulemaking makes only evidentiary changes and does not impose any additional costs on regulated sources or State, local, or tribal governments. For the same reason, these evidentiary changes will not significantly or uniquely affect small governments. Accordingly, this rulemaking is not subject to the requirements of sections 202, 203, and 205 of the UMRA.

D. Regulatory Flexibility Act

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has also determined that this rule will not have a significant economic impact on a substantial number of small entities. As explained above, this rulemaking does not impose any additional implementation costs on small or large entities.

E. Paperwork Reduction Act

The information collection requirements for the proposed enhanced monitoring rule were previously submitted for approval to OMB under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.* In contrast, today's rule does not contain any information collection requirements subject to OMB review under the PRA.

F. Submission to Congress and the General Accounting Office

Under 5 U.S.C. 801(a)(1)(A) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121, 110 Stat. 847), EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Controller General of the General Accounting Office prior to publication of this rule in today's Federal Register. For the same reasons that this rulemaking is not a ''significant regulatory action'' under Executive Order 12866, this rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects

40 CFR Part 51

Environmental protection, Air pollution control.

40 CFR Part 52

Air pollution control.

40 CFR Part 60

Air pollution control.

40 CFR Part 61

Air pollution control.

Dated: February 13, 1997.

Carol M. Browner,

Administrator, U.S. Environmental Protection Agency.

For the reasons set out in the preamble, 40 CFR Chapter I is amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7411, 7412, 7413, 7414, 7470–7479, 7501–7508, 7601, and 7602.

2. Section 51.212 is amended by revising paragraph (c) to read as follows:

§ 51.212 Testing, inspection, enforcement, and complaints.

* * * * *

(c) Enforceable test methods for each emission limit specified in the plan. For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, the plan must not preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. As an enforceable method, States may use:

(1) Any of the appropriate methods in appendix M to this part, Recommended Test Methods for State Implementation Plans; or

(2) An alternative method following review and approval of that method by the Administrator; or

(3) Any appropriate method in appendix A to 40 CFR part 60.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 is revised to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

2. Section 52.12 is amended by revising paragraph (c) to read as follows:

§ 52.12 Source surveillance.

* * * * *

(c) For purposes of Federal enforcement, the following test procedures and methods shall be used, provided that for the purpose of establishing whether or not a person has violated or is in violation of any provision of the plan, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed:

(1) Sources subject to plan provisions which do not specify a test procedure and sources subject to provisions promulgated by the Administrator will be tested by means of the appropriate procedures and methods prescribed in part 60 of this chapter unless otherwise specified in this part.

(2) Sources subject to approved provisions of a plan wherein a test procedure is specified will be tested by the specified procedure.

3. Subpart A is amended by adding a new § 52.33 to read as follows:

§ 52.33 Compliance certifications.

(a) For the purpose of submitting compliance certifications, nothing in this part or in a plan promulgated by the Administrator shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

(b) For all federal implementation plans, paragraph (a) of this section is incorporated into the plan.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7411, 7413, 7414, 7416, 7601 and 7602.

2. Section 60.11 is amended by revising paragraphs (a) and (f) and by adding paragraph (g) to read as follows:

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by § 60.8, unless otherwise specified in the applicable standard.

* * * * *

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

1. The authority citation for part 61 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7412, 7413, 7414, 7416, 7601 and 7602.

2. Section 61.12 is amended by revising paragraph (a) and adding paragraph (e) to read as follows:

§ 61.12 Compliance with standards and maintenance requirements.

(a) Compliance with numerical emission limits shall be determined in accordance with emission tests established in § 61.13 or as otherwise specified in an individual subpart.

* * * * *

(e) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

[FR Doc. 97–4196 Filed 2–21– 97; 8:45 am]

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NMED Exhibit 101 - 0015

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF SUSAN DAY AND ELIZABETH BISBEY-KUEHN

Susan Day

My name is Susan Day, and I am the Senior Economist with ERG, Inc. I have been asked to provide testimony in support of the New Mexico Environment Department's ("Department" or "NMED") proposed new air quality regulations at 20.2.50 NMAC ("Part 50"). My testimony is set forth in Sections I.A and III below, and addresses the compilation of the data used to develop the proposed definition of "small business facility" in 20.2.50.7.OO.

Elizabeth Bisbey-Kuehn

My name is Elizabeth Bisbey-Kuehn. I am the Bureau Chief of the Department's Air Quality Bureau ("Bureau"). My testimony is set forth in Sections I.B, II, and IV below, and addresses the basis for the proposed definition of "small business facility" in 20.2.50.7.OO, and the regulatory requirements for such facilities in Section 20.2.50.125.

I. QUALIFICATIONS

A. Susan Day

I hold a BA in Economics from Colby College and an MS in Resource Economics from the University of Rhode Island. I am an economist and project manager with 34 years of experience conducting and managing economic, regulatory, and data analyses that support environmental regulations under the Toxic Substances Control Act, Emergency Planning and Community Right-to-Know Act, Pollution Prevention Act, Clean Water Act, and the Safe Drinking Water Act. I have

also conducted benefit cost analyses in support of worker health and safety regulations for the U.S. Occupational Safety and Health Administration. My work includes preparing pre-rulemaking options analyses; estimating regulatory compliance costs; characterizing potential benefits associated with regulatory and nonregulatory options; evaluating small business impacts in accordance with Small Business Regulatory Enforcement Fairness Act requirements; tracking, organizing, and summarizing public comments; and preparing information collection requests.

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 103.

B. Elizabeth Bisbey-Kuehn

A summary of my background and qualifications is provided in my other pre-filed testimony at NMED Exhibit 5. My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 6.

II. SMALL BUSINESS FACILITY DEFINITION (Kuehn)

Under the proposed rule, a small business facility is defined as a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited-service workers.

III. DATA ANALYSIS FOR SMALL BUSINESS FACILITY DEFINITION (Day)

The small business definition proposed in 20.2.50.7.OO includes, among other factors, an indication of the position of the facility (highest level) in the overall corporate hierarchy. For the purposes of the analysis conducted by ERG, the term “global ultimate parent company” is used to define the highest level in the corporate family tree. As discussed below, in conducting this

analysis ERG identified the global ultimate parent associated with a list of New Mexico Oil and Gas well owners/operators potentially subject to the proposed rulemaking. Additionally, ERG obtained information on the revenues and employment associated with these global ultimate parent companies.

A. Master List of Well Owners/Operators, and Other Affected Facilities

NMED provided ERG with the names and addresses for well owners/operators and other affected facilities compiled from the NMED Equipment Data and NM Oil Conservation Division data.[1] Using this data, ERG created a master list of 535 well owners/operators and owners/operators of other affected facilities (hereafter collectively referred to as "owners/operators") by combining the two lists and eliminating duplicate entries. *See* NMED Exhibit. 104 – Owner Address List Final Spreadsheet.

Global Ultimate Parent Data

As input to the determination of whether facilities can be classified as "small business facilities" under Part 50, information on ownership by a global ultimate parent company and the revenue and employment data linked to each global ultimate parent company is required. Using information on industry classification signified by North American Industry Classification System ("NAICS") code, as well as name and address, facilities can be identified and linked to global ultimate parent companies in commercially available business databases such as Dun and Bradstreet ("D&B"). Information on revenues and employment for global ultimate parent companies can also be obtained from D&B. D&B is a fee for service operation, typically dealing in transactions for large scale queries (e.g., an entire industry sector). Due to the limited size of the universe of facilities covered by Part 50, it was cost effective for ERG to purchase the needed

[1] http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx

D&B data from another vendor called NAICS Association, LLC ("NAICS Association"). This process involved the following steps:

Step 1 – Submit the master list of New Mexico owners/operators to NAICS Association.

Step 2 – NAICS Association links the master list of owners/operators to D&B data and develops a dataset of facility records.

Step 3 – Review the dataset returned by NAICS Association, which includes the following categories of data:

- Name and address of the owner/operator identified as matching each facility on the master list of New Mexico owners/operators.
- Match fields including match method, match grade and confidence code.
- Facility identification including D&B number, facility sales (which is used as a proxy for revenues) and employment, industry sector designation (NAICS and SIC codes), and organization type (e.g., subsidiary).
- Global ultimate parent company identification including name, location, D&B number, sales (which is used as a proxy for revenues) and employment, and industry sector designation (NAICS and SIC codes) for the global ultimate parent.

NAICS Association used a matching algorithm to identify each New Mexico owner/operator or other affected facility in their data. Standard Matches are based on company name, address, and phone number, while Company Name Only matching is based on company name and country (no address). Where a match was made, NAICS Association appended D&B numbers and confidence codes for each matched record showing the degree of confidence they have in that particular match. The confidence codes range from 10, which is a perfect match, down to 4, which is a loose match. Following NAICS Association recommendations, only

matches above 7 were retained for ERG's analysis. Of matches with a confidence code of 8, 9, and 10, the matches were further categorized by match method (standard, name only) and match grade (in the form of letter grades A, B, F, and Z). For both standard and name-only matches, match grade can be interpreted in the following manner:

A - Same: ABC WIDGET MFG vs. ABC Widgeting MFG

B - Similar: ABC Widget MFG vs. ABC MFG

F - Different: ABC Widget MFG vs. XYZ MFG

Z - Null: One or Both are Null (Blank)

Match grade is shown in the NAICS Association dataset as a sequence in which the match grade string reflects the following data elements:

1. Business Name
2. Street Address Number
3. Street Name
4. City
5. State
6. PO
7. Phone

For example, a match grade sequence could be AAAAAZA, with each letter representing the match grade for each data element.

Of the 535 owners/operators ERG submitted to NAICS Association, 404 were identified using a standard match with a confidence code of 8 or above; 80 were identified using a name-only match (i.e., only the "business name" data element is the same between the NM facility and the facility identified by NAICS Association), and 51 could not be matched at all. ERG reviewed

all 80 name-only matched facilities and accepted 56 matches where enough information could be located through google searches on either the original name from NMED or the matched name suggested by NAICS Association to confidently conclude that they were the same facility. The remaining 24 matches were rejected where sufficient information could not be located.

For the 460 matched New Mexico facilities (404 standard matches plus 56 name-only matches confirmed by further research), NAICS Association attempted to identify a global ultimate parent company associated with the facility. Where a separate global ultimate parent was not identified, the owner/operator or other affected facility was not a subsidiary of a company and was considered to be the global ultimate parent for the purpose of this analysis (e.g., the facility itself could own other locations but was not itself owned by another entity). Of the 460 "matched" owners/operators, global ultimate parent companies were identified for 154 facilities. The remaining 306 facilities were considered to be their own global ultimate parent.

B. U.S. Small Business Administration Definition of "Small Business"

The U.S. Small Business Administration ("SBA") is a federal government agency that was created by federal legislation to support small businesses. SBA is responsible for defining industry size standards that identify threshold values below which firms in individual industries are classified as small businesses. These size standards are the basis for qualifying firms for preference in government contracting, and define eligibility criteria for loans at attractive rates under government lending programs.

SBA's small business size standards vary by industry sector and are set by NAICS code. In establishing size standards, SBA considers a number of economic and market characteristics that may allow a business of concern to exercise dominance in an industry sector. Size standards are based on criteria – such as annual receipts or number of employees – that represent a measure

of these characteristics. The standards define the largest size a for-profit enterprise (together with its affiliates) can be and still qualify as a "small business." As such, the size standard is established at the parent company level, encompassing all identified sites under a common ownership structure.

For context in this rulemaking, ERG included the SBA size standards for potentially affected owners/operators and other facilities and, using global ultimate parent company information identified for each facility, identified how that global ultimate parent would be classified based on the SBA size definition. *See* NMED Exhibit 105 – Preliminary Results NAICS.COM Updated Spreadsheet. Note that this analysis required NAICS code, revenue, and employment data. Accounting for the 22 facilities that were linked to the same global ultimate parent as at least one other affected facility, ERG counted 406 unique ultimate parents with revenue and employment data, and 24 ultimate parents that did not have revenue or employment data. The 406 unique global ultimate parent companies are associated with 436 owners/operators.

A comparison of these data to the SBA size definition (revenue or employment, depending on the NAICS code) resulted in 355 (87%) global ultimate parent companies that meet the SBA definition of "small business", and 51 (13%) global ultimate parent companies that do not meet that definition (i.e., "not small"), associated with 436 owners/operators and other facilities with usable data (revenue and employment). The 355 small global ultimate parent companies are associated with 359 small owners/operators, and the 51 not small global ultimate parent companies are associated with 77 not small owners/operators.

C. Estimation of Revenue Per Well and Total Gas/Oil Value Per Well

ERG obtained oil and gas well production data for New Mexico owner/operators and other affected facilities from the Go-Tech website.[2] The Go-Tech website presents historical oil and gas production data, updated monthly for the state of New Mexico. The production data on the website is obtained primarily from the New Mexico Oil Conservation Division, and the website is sponsored by the State of New Mexico; the U.S. Department of Energy's Office of Fossil Energy and the National Energy Technology Laboratory; and the New Mexico Petroleum Recovery Research Center, a division of the New Mexico Institute of Mining and Technology. These data include information on the number of stripper and non-stripper wells[3] per owner/operator, as well as the total MSCF of gas and BBLS of oil produced by the owner/operator in the 18-month time period between January 2019 and June 2020. Production data were available for 399 (75%) of the 535 owner/operators. ERG used these data to calculate an estimate of "value" per well using two methods, as described below.

Method 1: ERG estimated average revenue per well for each owner/operator by dividing the global ultimate parent revenues associated with the owner/operator by the total number of wells reported in the GO-TECH data for that owner/operator. The distribution of average global

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[2] Available at: http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx

[3] Stripper wells are defined in the New Mexico Natural Gas and Crude Oil Incentive Act at NMSA 1978, § 7-29B-2(L), as follows:

> "stripper well property" means a crude oil or natural gas producing property that is assigned a single production unit number by the department and:
>
> (1) if a crude oil producing property, produced an average daily production of less than ten barrels of oil per eligible well per day for the preceding calendar year;
>
> (2) if a natural gas producing property, produced an average daily production of less than sixty thousand cubic feet of natural gas per eligible well per day during the preceding calendar year; or
>
> (3) if a property with wells that produce both crude oil and natural gas, produced an average daily production of less than ten barrels of oil per eligible well per day for the preceding calendar year, as determined by converting the volume of natural gas produced by the well to barrels of oil by using a ratio of six thousand cubic feet to one barrel of oil.

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ultimate parent revenue per well ranges from a low of $38 per well to a high of $3,314,250,000 per well. It should be noted that the global ultimate parent revenue for many ultimate parent companies can come from other sources besides oil and gas well production, including sources entirely outside the oil and gas production industry. Therefore, the global ultimate parent revenue per well can be highly variable.

Note also that 22 global ultimate parent companies are associated with more than one well owner/operator. As such, the estimate of average revenue per well associated with the individual owner/operator is overstated in these 22 instances because the number of wells only includes those wells associated with the individual owner/operator, while the revenue is for the global ultimate parent, which is associated with multiple owner/operators.

Method 2: ERG estimated the average value of the oil and gas production per well for each owner/operator. Production data were available for an 18-month period including all of 2019 and the first 6 months of 2020. Using dollars per barrel (BBLS) for oil, and dollars per million BTU (MMBTU) for gas, ERG calculated the average value of the production from wells of each type per owner/operator. Production volumes were multiplied by 12/18ths to convert from 18 months to annual estimates. Price information was taken from the following:

- New Mexico Crude Oil First Purchase Price (Dollars per BBLS) – US Energy Information Administration[4] 24-Month average (February 2019 - January 2021) = **$45/BBLS**
- Henry Hub Natural Gas Spot Price (Dollars per MMBTU) - US Energy Information Administration[5] 24-Month average (March 2019 - February 2021) = **$2.39/MMBTU**

[4]Available at: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F003035__3&f=M
[5] http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

See NMED Exhibit 105 – Preliminary Results NAICS.COM Updated Spreadsheet.

To estimate the average oil and gas value per well, ERG calculated the total production value (oil and gas) for all wells owned by each owner/operator then divided that value by the total number of wells per owner/operator as reported in the GO-TECH data. The distribution of average oil and gas value per well ranges from a low of $30 per well to a high of $5,306,080 per well.

IV. BASIS FOR SMALL BUSINESS FACILITY DEFINITION AND REQUIREMENTS OF SUBPART 125 (Kuehn)

The Department structured the overall requirements of Part 50 such that there is a baseline set of requirements applicable to all owners and operators, and a tiered set of requirements that apply based upon the equipment or source type, the PTE of the equipment or source, and whether a facility meets the definition of a small business facility as defined in this rule. All owners and operators are required to calculate the PTE of equipment and have that calculation certified by a professional engineer and conduct equipment leak monitoring and find and repair leaking components by specified deadlines. The monitoring frequency is determined by the facility PTE. An owner or operator of a facility that meets the definition of a small business facility must comply with the requirements of Sections 20.2.50.111 and 125. If a facility does not meet the definition of a small business facility, the owner or operator must comply with the other sections of Part 50 applicable to the particular sources at the facility.

The Department developed the definition of a small business facility to recognize the unique challenges smaller independent operators may face in determining applicability of complex regulations and financing the initial and ongoing costs of compliance with Part 50. Both the federal Clean Air Act and the Board's air quality construction permit fee regulations at 20.2.75 NMAC contain provisions to assist to small businesses by providing compliance

assistance and a tiered fee schedule that gives a 50% reduction in initial and annual permit fees. These programs were developed because small businesses frequently lack the technical expertise and financial resources necessary to evaluate complex regulations, to finance the initial and ongoing compliance requirements, and to pay the full cost of recurring permitting fees.

A. Use of Data Complied by ERG

In developing the definition of small business facility in Part 50, the Department evaluated the report prepared by ERG and sorted the companies by the annual Global Ultimate (GULT) Parent revenue and staffing levels. The thresholds established in the rule were chosen because the data compiled by ERG indicated that those thresholds balanced the costs of compliance with Part 50 against a company's ability to finance the costs of compliance, and would not put the majority of companies at risk of becoming insolvent and therefore cause wells to be abandoned without remediation.

The Department estimated the annual average cost of compliance for a representative well site facility to determine the number of companies that could finance those compliance costs. The representative facility was assumed to have facility-wide emissions greater than 5 TPY VOC, requiring quarterly LDAR monitoring under Section 20.2.50.116; a storage vessel emitting greater than 2 TPY, requiring a control device, and an annual inspection of the storage vessel under Section 20.2.50.123. The annual average cost of compliance for the representative facility was estimated at $37,945 (based on an average cost of $32,400 to control a storage vessel, $4,385 for quarterly LDAR monitoring, and $1,160 for an annual inspection). Because the cost estimates are based on the average cost of compliance for companies operating throughout the sector, the cost estimates are conservative and may overestimate the true cost of compliance for an individual facility. The Department then ranked the companies by GULT

revenue from highest to lowest revenue and screened the companies that reported $1,000,000 or less and $250,000 or less to determine how many of those companies had per well site revenue less than the cost of compliance for the representative facility. Based on this review, the Department determined that 96 companies reporting a GULT revenue of $1,000,000 and less had a calculated revenue per well less than $37,945. These companies operate approximately 9,277 wells or 18% of the total wells (9,277/50,866). The Department determined that 54 companies reporting a GULT revenue of $250,000 and less had a calculated revenue per well less than $37,945. These companies operate approximately 4,638 wells or 9% of the total wells (4,638/50,866).

The Department then determined the average annual cost of compliance for a facility meeting the small business definition at $4,385 (based on a conservative quarterly LDAR monitoring requirement). According to the report, few companies have a revenue of less than $4,385 per well.

Based on the above, the Department established $250,000 as the revenue threshold to meet the small business definition. This is based on the need to require robust emission reduction requirements for a majority of wells and facilities; to tailor the requirements for companies with low annual revenue; and to reduce the potential early abandonment of wells that will result in increased uncontrolled air emissions and significant public cost to remediate those wells.

Based on the ERG report and the proposed definition, a total of 82 companies that operate 4,638 wells would qualify as small business facilities under the thresholds established in the rule. Therefore, under the proposed definition, 15% of the total number of companies (82/535) subject to Part 50 would be considered owners/operators of small business facilities,

and 9% of the total number of wells (4,638/50,866) would be considered small business facilities.

The Department also estimated the revenue from a well producing 7.5 bbl of oil per day, (7.5 bbl oil/day * 365 days/year * $60.00/bbl of crude oil) as $164,250 per year (or $450 per day). Comparing this estimated revenue with the estimated cost of complying with the small business provisions of Part 50 (estimated at $4,385), it would cost companies approximately 2.6% of total revenue to comply. The estimated cost of compliance for the representative facility (estimated at $37,945) as a percentage of the total estimated revenue is approximately 23% of total revenue.

B. Rationale for Proposed Small Business Facility Provisions

As detailed above, Part 50 establishes a baseline set of requirements for all owners and operators and then a tiered set of requirements depending on the PTE, type of equipment, and if a facility meets the definition of a small business facility. The rationale for the definition of a small business is provided below.

The proposed definition is based upon three principal criteria that help delineate between small, independent businesses and large, vertically integrated companies. The first criterion is ownership structure, which was used to distinguish companies that are independently owned and operated and are not a subsidiary or division of another company from larger corporations. The differences between small and large companies include the size of the business, number of employees, revenue, legal structures, and financing and tax requirements. Small and large companies may both operate within the same industrial sector, however, the differences in how these companies operate, their ability to access and finance capital, and their overall size affect their operations.

The second criterion is the total number of staff employed by the company, which is an indication of the company's personnel and staff resource capacity to interpret and implement the requirements of the rule. Larger companies have the financing capacity to employ dedicated environmental, health, and safety specialists; these staff typically monitor the company's compliance with numerous state and federal environmental regulations. Small companies employing fewer numbers of employees typically do not have the staffing or funding capacity to finance dedicated environmental compliance specialists.

The third criterion is annual revenue. The Department recognizes that the cost of complying with the requirements of Part 50 may disproportionately impact the smallest companies and may result in early abandonment of small business-owned wells, which, in turn, may result in increased uncontrolled air emissions from abandoned wells. Thus, by establishing a definition for small business facility, the Department is rightsizing the rule to require robust equipment and emission monitoring for smaller, independent operations, while simultaneously balancing those requirements against the unintended negative environmental consequences resulting from early abandonment.

C. Proposed Requirements for Small Business Facilities

The definition of small business facility in Part 50 distinguishes those companies that are independently owned, have low annual revenues (less than $250,000), and a small number of employees (10 or fewer), from those companies with larger annual revenues ($250,000 or greater) and a greater number of employees (more than 10 employees). As discussed previously in the testimony of Susan Day, the Department established the definition of small business facility based on ownership, revenue, and staffing information obtained from NAICS Association, LLC.

Sections 20.2.50.111 and 125 require the owner or operator of a small business facility to comply with emission reduction, monitoring, and operational requirements. The requirements of Section 20.2.50.111 include estimating the facility's PTE and having those emissions calculations certified by a professional engineer.

The requirements of Section 20.2.50.125 include operating equipment in accordance with manufacturer specifications and keeping those specifications on file; calculating the annual VOC and NOx emissions from each facility using the actual production and processing rates; maintaining a company-wide database of emission calculations for all subject facilities; complying with third party verification requirements if requested by the Department; conducting fugitive leak monitoring requirements as required in Subsections C and D of Section 20.2.50.116; repairing equipment leaks as required under Subsection E of Section 20.2.50.116; submitting an initial certification certifying that the small business facility meets the definition of small business facility in Part 50, and annual certifications thereafter.

Subsection G of Section 20.2.50.125 contains an important provision that triggers the applicability of the remaining sections and requirements of Part 50 if the Secretary finds, based on credible evidence, that the facility presents an imminent threat to public health or welfare or to the environment; is not being operated in a manner that minimizes emissions of air contaminants; or has violated another requirement of Section 20.2.50.125 NMAC. This provision incentivizes owners and operators of small business facilities to fully comply with Section 20.2.50.125 providing for an applicability onramp for the other sections of Part 50 if they fail to do so. The annual emissions data collected and reported to the Department will be used in air quality planning projects, air dispersion modeling analyses, air emissions databases and emissions inventories, and in other air quality related projects.

Susan Day
Economist



A seasoned economist and program manager with extensive experience in data collection and analysis supporting development of federal regulations

- Has extensive experience with all aspects of the regulatory development process and has estimated compliance costs/savings, characterized benefits, and evaluated the potential for small business impacts for more than 30 rulemakings related to worker safety, toxic chemicals, water quality standards, and government mandated electronic reporting.
- Has more than two decades of experience managing contracts and large and small projects, as well as coordinating the work of multiple subcontractors and consultants.
- Currently leading ERG's team providing a range of economic, engineering, and data analyses in support of the proposed Toxic Substances Control Act (TSCA) Chemical Data Reporting (CDR) Revisions Rule.

EMPLOYMENT

2017–present
Senior Economist, ERG, Lexington, MA

2014–2017
Principal Associate, Abt Associates Inc.

1987–2014
Various Positions, Abt Associates Inc.

1985–1987
Graduate Research Assistant, Department of Resource Economics, University of Rhode Island

1985–1986
Research Assistant, Economic Analysis Inc.

1985
Research Assistant, Coastal Resources Center

EDUCATION

M.S., Resource Economics, University of Rhode Island, 1987

B.A., Economics, Colby College, 1983

RELEVANT PROJECTS

Economic Support for TSCA CDR Revisions Rule

Client: U.S. EPA OCSPP. Currently leading ERG's team providing a range of economic, engineering, and data analyses in support of the proposed TSCA CDR Revisions Rule. Developed a model to estimate reporting burden and cost for multiple future CDR reporting scenarios and changes to reporting requirements. Prepared regulatory options for potential changes to small business definitions under section 8(a) of TSCA. Responsible for developing reporting burden estimates, modeling total burden, and preparing the full suite of regulatory documents for the proposed rule.

Economic and Regulatory Analyses of Toxics Release Inventory (TRI) Reporting Requirements

Client: U.S. EPA OPPT. For the TRI program, from 1990 to 2017, prepared more than 50 economic and regulatory analyses supporting options selection and rulemaking packages for several industry and chemicals expansion regulations. Prepared industry profiles, estimates of potentially affected universe, compliance cost estimates, characterization of small entities affected by rulemakings, benefits, sensitivity analyses, SBREFA analyses (using cost impact ratios compared to thresholds), and analyses of other statutory and EO requirements. Incorporated results from models such as RSEI to assess potential distributional impacts. Oversaw literature reviews related to topics

such as industry trends, specific industrial processes, and the value of information. Also developed a rapid, low-cost screening analysis approach that is appropriate for use when compliance costs are minor. For several rulemakings, also organized and tracked public comments, summarizing key themes and assisting in the preparation of responses to comments.

Regulatory Support for CAA Section 112(r) (RMP), CERCLA and EPCRA Regulations, Lists of Chemicals and Guidance Documents

Client: U.S. EPA OEM. Leading ERG's team to provide support for the development and modification of regulations, as well as the revision of lists of chemicals and reporting thresholds under CAA Section 112(r) ("RMP"), CERCLA, and EPCRA. Oversaw the update of existing EPA guidance on CERCLA Section 103 continuous release reporting. Prepared a regulatory impact analysis (RIA) in support of adjustments to reportable quantities (RQ) for ammonia and hydrogen sulfide continuous releases from animal farms under CERCLA and EPCRA. This task was a quick-turnaround engagement (two weeks) to prepare and deliver all analyses (and final RIA document), including estimation of the number of farms that would no longer report under the higher RQs, estimation of reporting burden and cost averted, agency burden and costs averted, benefits, and small entity impacts.

As part of the development of the economic analysis supporting this rulemaking, evaluated whether other statutory and executive order (EO) requirements needed to be addressed, including EO 12866, Regulatory Planning and Review; EO 13563, Improving Regulation and Regulatory Review; EO 13771, Reducing Regulations and Controlling Regulatory Costs, Paperwork Reduction Act (PRA), Regulatory Flexibility Act (RFA), Unfunded Mandates Reform Act (UMRA); EO 13132: Federalism; EO 13175, Consultation and Coordination with Indian Tribal Governments; EO 13045, Protection of Children from Environmental Health Risks and Safety Risks; EO 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use, National Technology Transfer and Advancement Act (NTTAA); and EO 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations. Developed language demonstrating how the rulemaking addressed each, using the economic analysis where appropriate.

Other tasks include 1) preparing an ICR Renewal for the Episodic Releases of Oil and Hazardous Substances data collection. Conducted informal interview of reporters to estimate their reporting burden; 2) responding to multiple quick turnaround requests for data mining (ERNS data) and economic analysis, 3) In support of the Amendment to Emergency Release Notification Regulations on Reporting Exemption for Air Emissions from Animal Waste at Farms; Emergency Planning and Community Right-to-Know Act, organized, tracked, and summarized 87,000 comments received on the proposed rule.

Telecommunications Structures Small Entity Representative (SER) Background Document

Client: OSHA. Led the development of SER background document for the Telecommunications Structures Standard covering both maintenance and construction activities. Estimated the number of antenna-supporting structures in the United States as well as the number of structures constructed and dismantled. Further, estimated the number of establishments and climbing employees potentially affected by the proposed standard. Estimated the number of entities and employees by NAICS code and size category for use in the estimation of small business impacts. Estimated unit compliance costs for components of the standard including rule familiarization, training, recordkeeping, job hazard analysis, rigging plans, weather monitoring, structural modifications, communication, fall protection and 100% tie-off, and inspections. Prepared unit labor costs (wage rates) for relevant labor categories (e.g., authorized climber, competent rigger) using BLSOES occupational costs and wage categories.

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF RALPH MORRIS

My name is Ralph E. Morris, and I am the Managing Principal of Ramboll's Environment and Health ("REH") Central West Business Unit ("CWBU") with offices in Northern California, Utah, and Colorado. I have been asked to provide testimony on the air quality impacts of the New Mexico Environmental Department's ("Department" or "NMED") proposed new air quality regulations at 20.2.50 NMAC ("Part 50") to control ozone precursor emissions from oil and gas ("O&G") sources in New Mexico. My testimony will address the potential future year ozone air quality impacts from the implementation of the emissions controls for ozone precursor emissions on oil and gas sources due to NMED's proposed new air quality regulations.

I. Qualifications

As Managing Principal of the REH CWBU, I am responsible for the business operations for approximately 140 Ramboll employees in the San Francisco Bay Area, Salt Lake City, and Denver offices. REH is a 2,600 person environmental and health consulting group that is part of Ramboll Group A/S that consists of ~16,000 employees in ~250 offices in ~30 countries with headquarters in Copenhagen, Denmark.

I am part of REH's Air Sciences Group where I direct a variety of air quality studies including air quality model development and application, emissions inventory development and control strategy evaluation, meteorological modeling, and analysis and regulatory air issues

studies. With over 40 years of air quality consulting experience, I am one of the original developers of many of the photochemical air quality models that are or have been used for regulatory decision making in the United States and around the world, including one of the leaders in the development of Ramboll's Comprehensive Air-quality Model with extensions ("CAMx")[1] that was used to evaluate the ozone impacts of Part 50.

In the 1980s I led, or was a key person in, the development of the ozone models Reactive Plume Model ("RPM"), Regional Transport Model ("RTM") and Urban Airshed Model ("UAM"), and I was ultimately responsible for the delivery of the UAM photochemical grid model ("PGM") to the U.S. Environmental Protection Agency ("EPA") in 1990. EPA subsequently designated the UAM as the EPA-recommended model for ozone air quality planning in their air quality modeling guidelines at 40 CFR Part 51, Appendix W. During the early 1990s I directed the development of the variable grid version of UAM ("UAM-V") that was used in the Ozone Transport Assessment Group ("OTAG") and subsequent EPA NOx State Implementation Plan ("SIP") Call, the first regional NOx control strategy for the eastern United States. And in the mid-1990s I was one of the leaders in the development of the CAMx PGM that has been used in numerous ozone and $PM_{2.5}$ SIPs, as well as by EPA for national rules such as the Cross State Air Pollution Rule ("CSAPR")[2].

I directed the application of regional particulate matter ("PM"), ozone, and visibility modeling using EPA's Community Multiscale Air Quality ("CMAQ") modeling system and CAMx PGMs for the southeastern ("VISTA/ASIP"), western ("WRAP") and central ("CENRAP") US Regional Planning Organizations ("RPOs") for the development of the first round of regional haze SIPs that were due to EPA in 2007. I directed the development of an

[1] https://www.camx.com/
[2] https://www.epa.gov/csapr

updated Pollutants in the ATmosphere for Hong Kong ("PATH") air quality modeling system (the air quality component of PATH used the CMAQ and CAMx models) for the Hong Kong Environmental Protection Department, and applied it to Southeast Asia to assess regional transport and urban ozone and particulate matter formation. I was an original member of EPA's ozone and particulate matter modeling guidance workgroups, the Community Modeling and Analysis System,[3]Models-3/CMAQ External Advisory Committee, and I am currently a member of the Scientific Technical Modeling Peer Review Advisory Group for the South Coast Air Quality Management District ("SCAQMD"), offering advice on South Coast (Los Angeles) Air Basin ozone and PM air quality issues for over 15 years. I was formerly a member of the Air Quality Modeling Subcommittee of the Science Advisory Board that advised EPA on their air modeling studies.

I have been assisting EPA in developing air quality modeling techniques for over 30 years, which included addressing near-source, far-field and photochemical modeling issues. Currently, I am leading the air quality modeling efforts of the western states to develop their Regional Haze SIPs due in July of 2021, and have just finished leading the air quality modeling efforts for the Denver Serious ozone SIP and starting the Denver Severe/Moderate ozone SIP modeling efforts under the 2008 and 2015 ozone national ambient air quality standards ("NAAQS"). Because of my expertise in air quality modeling, over the last 15 years I have served as an expert witness in numerous litigation cases, many related to violations of the Clean Air Act, with the last time I testified at a trial being in St. Louis in April of 2019 in the Ameren Rush Island coal-fired power plant case.

[3] https://www.cmascenter.org/

My full background and qualifications are set forth in my resume, which is marked as NMED Exhibit 107.

II. Fundamentals of Ozone Air Pollution

Ozone is a molecule composed of three oxygen atoms (O_3) and is the main component of smog. Ozone occurs in both the Earth's upper atmosphere (stratospheric ozone) and at ground-level (tropospheric ozone). Stratospheric ozone in the upper atmosphere is good ozone because it shields us from harmful ultraviolet rays from the sun. However, ozone at ground-level is harmful to human health and the environment. Elevated levels of ground-level ozone can cause breathing difficulties, coughing and scratchy throat, aggravate lung disease such as asthma, emphysema and chronic bronchitis and make the lungs more susceptible to infection. Ozone can also harm plants, especially during the growing season, and cause material damage. Ozone is one of six criteria pollutants for which EPA sets NAAQS, with the primary NAAQS set to protect public health with a margin of safety, and the secondary NAAQS set to protect public welfare, which includes decreased visibility and damage to animals, crops, vegetation, and buildings. Currently, the primary and secondary ozone NAAQS are set to the same value. In 2008 and 2015 EPA promulgated ozone NAAQS with thresholds of, respectively, 75 and 70 parts per billion (ppb). The relevant ozone NAAQS metric is the ozone design value ("DV"), which is defined as the three-year average of the fourth highest maximum daily average 8-hour ozone concentration.

Ozone is not directly emitted but instead is formed in the atmosphere through a set of complex photochemical reactions involving volatile organic compounds ("VOC") and oxides of nitrogen ("NO_X") in the presence of sunlight. Elevated ozone concentrations typically occur on hot summer days under low wind speed and/or ground-level trapping inversions that allow the VOC and NO_X concentrations to build up. There have, however, been occurrences of winter high

ozone concentrations in Wyoming and Utah oil and gas fields in locations with strong trapping inversions that produce very high VOC and NO_X concentrations and white snow on the ground with high albedo that reflects the sunlight resulting in near-ground ultraviolet light comparable to the summer. NO_X emissions are produced by combustion where the heat converts the naturally occurring nitrogen and oxygen in the air[4] to NO_X emissions. NO_X is primarily produced by anthropogenic (man-made) sources through fuel combustion of coal, gasoline, diesel, oil, natural gas, and biomass burning. Natural sources of NO_X include wildfires, lightning, and soils. Anthropogenic sources of VOCs include mobile sources, chemical plants and refineries, oil and gas production, consumer products and other sources. On a region-wide basis, biogenic VOCs from plants are the largest VOC contributor, but in locations of large amounts of anthropogenic VOC emission sources, such as urban areas, oil and gas production fields or industrial complexes, biogenic VOC may not be the largest source sector but is usually still a large component of the total VOC emissions.

Emission control plans designed to mitigate high ozone concentrations reduce anthropogenic VOC and/or NO_X emissions. Ozone formation can be more sensitive to NO_X or VOC emissions, but usually has some sensitivity to both ozone precursors. Reducing VOC emissions almost always reduces ozone concentrations or has no effect. Reducing NO_X emissions can reduce ozone concentrations, but can also have localized ozone increases, a case known as "NO_X disbenefits." There are two causes of NO_X disbenefits. Most NO_X is emitted as nitric oxide (NO), some of which is quickly converted to nitrogen dioxide (NO_2) in the ozone titration reaction ($NO + O_3 \rightarrow NO_2 + O_2$). When NO_X emissions are reduced there is less ozone titrated by NO, resulting in a localized increase in ozone concentrations. The second way NO_X disbenefits occur

[4] Air in the earth's atmosphere is made up of approximately 78% nitrogen and 21% oxygen.

is due to the NO_X inhibition effect on ozone formation, where high NO_X concentrations can terminate the radical cycle that drives photochemical reactions. The reduction in NO_X emissions can result in an increase in the hydroxyl radical OH due to less of them being reacted away by the lower NO_2 concentrations ($NO_2 + OH + M \rightarrow HNO_3 + M$). NO_X disbenefits occur in areas with high NO_X concentrations where ozone formation is more VOC sensitive, such as urban areas and NO_X point source plumes. NO_X disbenefits were the cause of the "weekend effect" where, in urban areas like Los Angles, higher ozone concentrations were more likely to occur on weekend days than weekdays due to the lower morning NO_X emissions since there is no morning commute on weekend days.

With climate change, there are more hot days with higher temperatures that promote ozone formation resulting in higher ozone levels, as well as a lengthening of the ozone season resulting in more ozone exceedance days in the spring and fall than there have been in the past. Ozone attainment VOC/NO_X emission control plans designed to achieve the ozone NAAQS for a region under current climate conditions may be insufficient in the future under climate change, a phenomenon known as the "climate penalty."

III. Fundamentals of Ozone Modeling

Ozone modeling is usually conducted using a photochemical grid model ("PGM"). A PGM divides the region to be modeled into three-dimensional ("3-D") arrays of boxes (grid cells) that is shown schematically in Figure 1. There are three main inputs for a PGM: (1) 3-D meteorological fields that are usually produced by a prognostic meteorological model such as the Weather Research Forecast ("WRF")[5] model; (2) hourly speciated emission inputs that consist of gridded surface layer emissions that are emitted into layer 1 of the PGM (e.g., mobile sources and biogenic

[5] https://www.mmm.ucar.edu/weather-research-and-forecasting-model

emissions) and point source emissions that are emitted in an appropriate upper layer grid cell of the PGM based on its plume rise[6] (e.g., power plants and industrial point sources); and (3) Boundary Condition ("BC") species concentrations that are defined around the boundaries of the modeling domain (i.e., transport from outside of the PGM modeling domain). PGM emission inputs are prepared by processing county-level and point source emissions using an emissions model, such as the Sparse Matrix Operator Kernel Emissions ("SMOKE")[7] modeling system. PGM BC inputs are usually defined using output from a global chemistry model, such as GEOS-Chem.[8] Unlike air quality dispersion models (e.g., AERMOD) that are applied for a single source or small group of sources, PGMs must include all sources of air pollution, and so are more intensive and costly to apply.

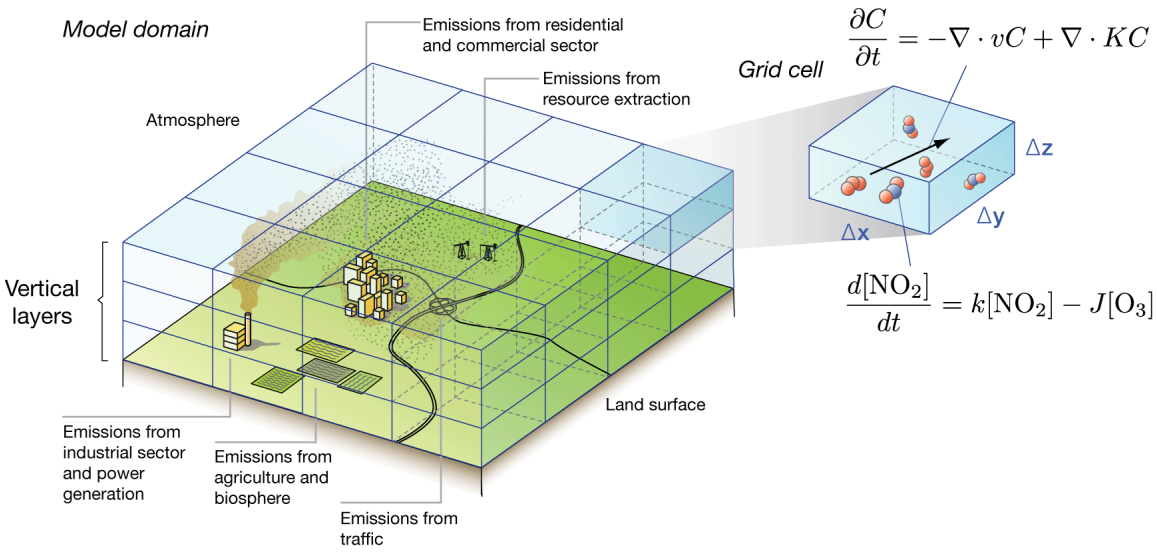


Figure 1. Schematic illustration of a PGM modeling domain that is divided up into a three-dimensional array of grid cells (Source: AWMA Environmental Manager magazine, July 2012 issue on AQMEII, D. Steyn, P. Builtjes, M. Schaap and G. Yarwood).

[6] Point source emissions usually have buoyancy through an exit velocity out of the stack and/or higher temperatures of the emitted effluent than the ambient air that causes the emissions to rise in the atmosphere after their release.
[7] https://www.cmascenter.org/smoke/
[8] http://acmg.seas.harvard.edu/geos/

A PGM will first be set-up for a historical base year (e.g., 2014), or in the case of an ozone modeling PGM application, an ozone season period of a past year. A PGM base year base case simulation is conducted that is subjected to a model performance evaluation ("MPE") that compares the modeled concentrations with concurrent observations. Graphical and statistical techniques are used in the MPE, the results of which are also compared to model performance goals and criteria based on past well-performing PGM applications to help put the PGM MPE in context. Diagnostic sensitivity tests may also be conducted to improve the PGM model performance through alternative model inputs or model options.

A typical PGM application will then project the anthropogenic emissions to a future year with all other inputs typically held constant the same as used in the base year.[9] Anthropogenic emissions are then controlled and future year PGM simulations made to determine the types and levels of emissions controls required to meet the air quality objectives under study (e.g., attainment of the ozone NAAQS).

IV. Overview of PGM Modeling to Support the NMED's Ozone Attainment Initiative

The Department contracted with a team consisting of the Western States Air Resource Council ("WESTAR") and Ramboll US Consulting, Inc. ("Ramboll") to conduct PGM modeling in support of the Department's Ozone Attainment Initiative ("OAI"). The OAI PGM study was conducted from April 2020 to May 2021, with results and progress of the study continuously documented on a website[10] as the study evolved. Although the OAI PGM study was not part of the development of an ozone SIP, it was conducted following EPA's 2018 photochemical modeling guidance for ozone SIPs ("EPA 2018 PCM Guidance"). *See* NMED Exhibit 108 – *Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze*,

[9] In some application, future year BC inputs may be used based on future year global chemistry model simulations.
[10] https://www.wrapair2.org/NMOAI.aspx

EPA 454/R-18-009 (November 2018). This included preparing a Modeling Protocol (Ramboll and WESTAR, 2020a)[11] at the outset of the study (May 2020) that provided a roadmap for how the study would be conducted, and allow NMED and other interested parties to comment on the study approach prior to conducting the OAI PGM study.

The OAI PGM study used the Comprehensive Air-quality Model with extensions (CAMx[12]) PGM on a 36/12/4-km grid resolution nested modeling domains shown in Figure 2 with the 4-km domain covering New Mexico and nearby regions (e.g., the San Juan and Permian O&G development regions). The CAMx 2014 36/12/4-km modeling platform was developed for the May-August 2014 base year period. The CAMx 2014 36/12/4-km modeling platform was based on the Western Regional Air Partnership ("WRAP") and Western Air Quality Study ("WAQS") CAMx 2014 36/12-km annual modeling platform.[13] Boundary Conditions for the OAI PGM study CAMx 36/12/4-km simulation were based on output from the WRAP-WAQS 2014 GEOS-Chem global chemistry model simulation. The OAI study conducted two Weather Research Forecast ("WRF") 2014 36/12/4-km meteorological model simulations that differed in the analysis fields used to initialize, provide BCs, and used in the four dimensional data assimilation ("FDDA") that nudges the WRF meteorological model predictions to the observations. Details on the OAI PGM study 2014 WRF meteorological modeling are contained in Chapter 2 of the 2014v2 base case modeling report[14] and the Air Quality Technical Support Document ("AQ Technical Support Document").[15]

[11] http://wrapair2.org/pdf/NM_OAI_Modeling_Protocol_v5.pdf
[12] https://www.camx.com/
[13] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx
[14] https://www.wrapair2.org/pdf/NM_OAI_2014_BaseCase_MPE_v3.pdf
[15] https://www.wrapair2.org/pdf/NM_OAI_2028_AQTSD_v8.pdf

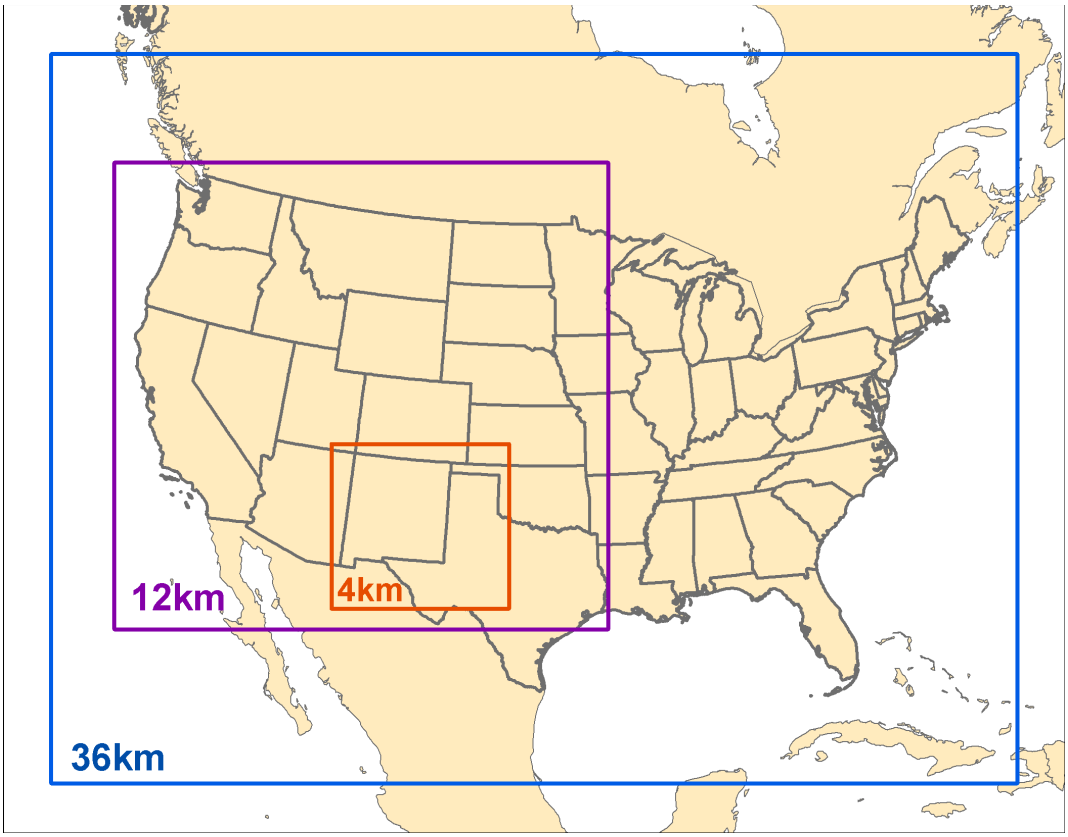


Figure 2. CAMx 36/12/4-km modeling domains used in the OAI PGM study.

A CAMx 2014v2 base case simulation and model performance evaluation was conducted and documented in an addendum[16] to the 2014 base case modeling report and the OAI PGM study AQ Technical Support Document, cited above. A 2028 base case emissions scenario was developed that was based on the WRAP-WAQS 2028 on-the-books (2028OTBa2) scenario with updated 2028 New Mexico base case O&G emissions. A 2028 O&G control strategy scenario was developed that reduced the New Mexico 2028 base case O&G emissions accounting for the estimated effects of Part 50, as determined by Eastern Research Group ("ERG") under separate contract with NMED. CAMx 2028 base case and 2028 O&G control strategy simulations were conducted, and the resultant ozone estimates were analyzed to determine the effect that the

[16] http://wrapair2.org/pdf/NM_OAI_Addendum_2014v2_MPE_v2.pdf

requirements in Part 50 would have on ozone concentrations if implemented. Ozone source apportionment modeling for the 2028 O&G control strategy was also conducted.

V. Summary of Modeled Ozone Impacts from Implementation of Part 50

Section IX below and Chapter 8 of the OAI PGM study AQ Technical Support Document present details on the ozone impacts of the NMED proposed O&G ozone precursor regulations. In this section I briefly summarize the key results of the estimated effects of Part 50 on ozone concentrations in New Mexico, with the remainder of my testimony going into details on how the OAI PGM study was carried out and its results.

The requirements of Part 50 are estimated to reduce projected 2028 future year ozone design values ("DVF") at New Mexico monitoring sites by between -0.2 to -1.5 ppb (see Table 5 in Section IX). The largest reductions in 2028 ozone DVFs occurs at the Navajo Lake (-1.5 ppb) and Substation (-1.2 ppb) monitoring sites in San Juan County in the San Juan Basin. The largest reductions in 2028 ozone DVFs in the Permian Basin occur at the Hobbs monitor (-0.7 ppb) in Lea County and the Carlsbad monitor (-0.3 ppb) in Eddy County.

The requirements of Part 50 are estimated to reduce daily MDA8 ozone concentrations across wide areas in New Mexico. On some days there are also isolated areas of increases in MDA8 ozone concentrations due to VOC and NO_X emissions reductions from Part 50 that are due to NO_X disbenefits. Figures 8-3 through 8-8 of the OAI PGM study AQ Technical Support Document display the ozone impacts of the 2028 O&G control strategy across the 4-km New Mexico domain for 6 example higher ozone days, which show that the extent of the ozone reductions due to the O&G controls are much greater than the extent of ozone increases due to the controls. In Figure 15 in Section IX below I present results for two example days. On June 5th the CAMx 2028 base case simulation estimates there are MDA8 ozone concentrations in excess of the 70 ppb 2015 ozone NAAQS in the San Juan Basin with a MDA8 ozone peak of 74.0 ppb that are reduced to

below the 70 ppb 2015 ozone NAAQS in the 2028 O&G control strategy simulation. And on July 24 there is a 2028 base case estimated MDA8 ozone peak of 71.3 ppb on the Colorado side of the San Juan Basin that is brought to below the 70 ppb 2015 ozone NAAQS in the 2028 O&G control strategy. However, on July 24th the 2028 O&G control strategy is also estimated to cause increases MDA8 ozone concentrations in portions of San Juan County with a maximum ozone increase of 6.4 ppb that was sufficient to increase the MDA8 ozone in a single grid cell to 71.0 ppb in the 2028 O&G control strategy scenario that exceeds the 70 ppb 2015 ozone NAAQS.

In summary, proposed Part 50 is estimated to reduce 2028 ozone DVFs and MDA8 ozone concentrations across New Mexico, with the largest ozone reductions occurring within the San Juan and Permian Basins. On some days there are also areas of ozone increases due to the O&G controls, although the area of ozone increases are much less than the areas of ozone decreases, and the magnitudes of the ozone increases are also usually less than the magnitudes of the ozone decreases. The area of reductions in projected 2028 ozone DVFs due to the O&G emission reductions are also much greater in extent and magnitudes than the areas of ozone DVF increases that appear to occur in 7 isolated grid cells whose ozone increases are presumed to be due to localized NO_X disbenefits due to the NO_X controls on O&G sources.

Ozone source apportionment modeling was also conducted for the 2028 O&G control strategy emissions scenario to examine source sector ozone contributions. This modeling found, among other things, that even with implementation of Part 50, New Mexico O&G emissions still had substantial contributions to ozone concentrations. For example, O&G emissions in the New Mexico portions of the San Juan and Permian Basins contributed as much as 3.0 and 2.0 ppb to the projected 2028 ozone DVF in the 2028 O&G control strategy (Table 8 in Section XI). And the

highest contribution of New Mexico O&G emissions to MDA8 ozone concentrations in the 2028 O&G control strategy emissions scenario exceeded 10 ppb (Figure 19 in Section XI).

A second CAMx ozone source apportionment simulation was conducted to examine whether ozone formation under the 2028 O&G control strategy emissions scenario was more sensitive to VOC or NO_X. Although ozone formation in New Mexico was mostly highly NO_X sensitive across most of New Mexico, frequently the highest MDA8 ozone concentrations in New Mexico were more evenly divided between VOC and NO_X sensitive ozone formation conditions. This was especially true in the San Juan Basin (e.g., see Figure 20 in Section XII).

VI. Development of the 2014 and 2028 Base Case Emission Scenarios

The emissions inventories for the OAI PGM study CAMx 2014v2 base case modeling were based on the WRAP-WAQS 2014v2 emissions inventory[17] that in turn was based on EPA's 2014 National Emissions Inventory ("2014NEI")[18] with updates made by the western states. Within the 36-km North American and 12-km western U.S. domains (Figure 1), the WRAP-WAQS CAMx 2014v2 base case emission inputs were used as is without any changes. For the 4-km New Mexico domain, the WRAP-WAQS 2014v2 emissions were reviewed and updated as needed by NMED and processed by the SMOKE emissions model to generate gridded hourly speciated emission inputs for the 4-km New Mexico domain. Biogenic VOC and NO_X emissions were initially based on the MEGAN v3.1 biogenic emissions model but were ultimately replaced by biogenic emissions from the BEIS biogenic emissions model because MEGAN v3.1 required data filling for the Leaf Area Index ("LAI") input for the urban land use type that was beyond the scope of the OAI PGM study. The final CAMx 2014v2 base case, 2028 base case and 2028 O&G control strategy CAMx simulations used the BEIS biogenic emission inputs.

[17] https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx
[18] https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data

The OAI PGM study future year 2028 base case emissions were based on the WRAP 2028OTBa2[19] emissions inventory with updated New Mexico O&G emissions and use of 2014 actual fires instead of the Representative Baseline fires used in 2028OTBa2. The 2028OTBa2 CAMx-ready anthropogenic emission inputs for the 36/12-km domains were used as is. For the 4-km NM domain, the 2028OTBa2 emissions were processed using the SMOKE emissions model substituting the new 2028 New Mexico oil and gas O&G emissions developed in the OAI PGM study for the New Mexico O&G emissions used in the 2028OTBa2 emissions scenario.

A circa 2028 New Mexico O&G emission inventory was developed in the OAI PGM study for the 2028 base case emission scenario. The basis of the forecast 2028 New Mexico O&G emission inventory is circa 2028 O&G activity estimates provided by the Bureau of Land Management ("BLM")[20] that was used to project the O&G activity from the 2023 future year New Mexico O&G activity data developed by the WRAP Oil and Gas Working Group ("OGWG")[21] for the 2028OTBa2 emission inventory.[22] The 2028 New Mexico O&G emission base case inventory includes wellsite, gathering, and processing subsectors. The BLM New Mexico O&G future year forecast factors were used to project New Mexico O&G emissions to 2028. Table 1 compares the New Mexico O&G activity data for the WRAP 2014 and 2023 emission scenarios with the OAI PGM study 2028 O&G activity data that was based on BLM forecasts. Except for spud count, the 2028 New Mexico O&G activity is greater than 2014.

A comparison of the WRAP OGWG 2014 and 2023 New Mexico O&G emissions with the 2028 base case New Mexico O&G emissions from the OAI PGM study is shown in Table 2.

[19]https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/EmissionsSpecifications_WRAP_RepBase2_and_2028OTBa2_RegionalHazeModelingScenarios_Sept30_2020.pdf
[20] Email communication from BLM Staff (Forrest Cook) to Ramboll (John Grant). September 15, 2020.
[21] http://wrapair2.org/OGWG.aspx
[22] http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf

Across New Mexico, 2028 base case O&G NO_x and VOC emissions are, respectively, 29% and 15% higher than in 2014. In the Permian Basin, New Mexico 2028 base case O&G NO_x emissions are 64% higher than 2014, with VOC emissions 19% higher. The 2028 and 2014 New Mexico O&G emissions in the San Juan Basin are more comparable, with 2028 base case NO_x and VOC emissions, respectively, 1% and 10% higher than 2014.

Table 1. Comparison of WRAP OGWG 2014 and 2023 New Mexico O&G activity data used in the WRAP 2014v2 and 2028OTBa2 emission scenarios with the OAI PGM study 2028 base case New Mexico O&G activity data based on BLM forecast.

Activity Metric	WRAP OGWG		BLM Forecast
	2014	2023	Circa- 2028
Permian Basin (NM)			
Oil Production (million bbl)	119	276	166
Gas Production (BCF)	508	1,190	790
Well Count	28,615	27,335	40,478
Spud Count	1,178	651	794
San Juan Basin (NM)			
Oil Production (million bbl)	6	7	7
Gas Production (BCF)	713	440	1,138
Well Count	21,687	19,604	23,073
Spud Count	146	64	94
Las Vegas-Raton Basin (NM)			
Oil Production (million bbl)	0	0	0
Gas Production (BCF)	24	24	20
Well Count	835	835	835
Spud Count	0	0	0
Sierra Grande Uplift (NM)			
Oil Production (million bbl)	0	0	0
Gas Production (BCF)	0.02	0.02	0.27
Well Count	1	1	8
Spud Count	34	34	0.4

Table 2. Comparison of WRAP OGWG 2014 and 2023 New Mexico NO_x and VOC O&G emissions with the OAI PGM study 2028 base case New Mexico O&G emissions.

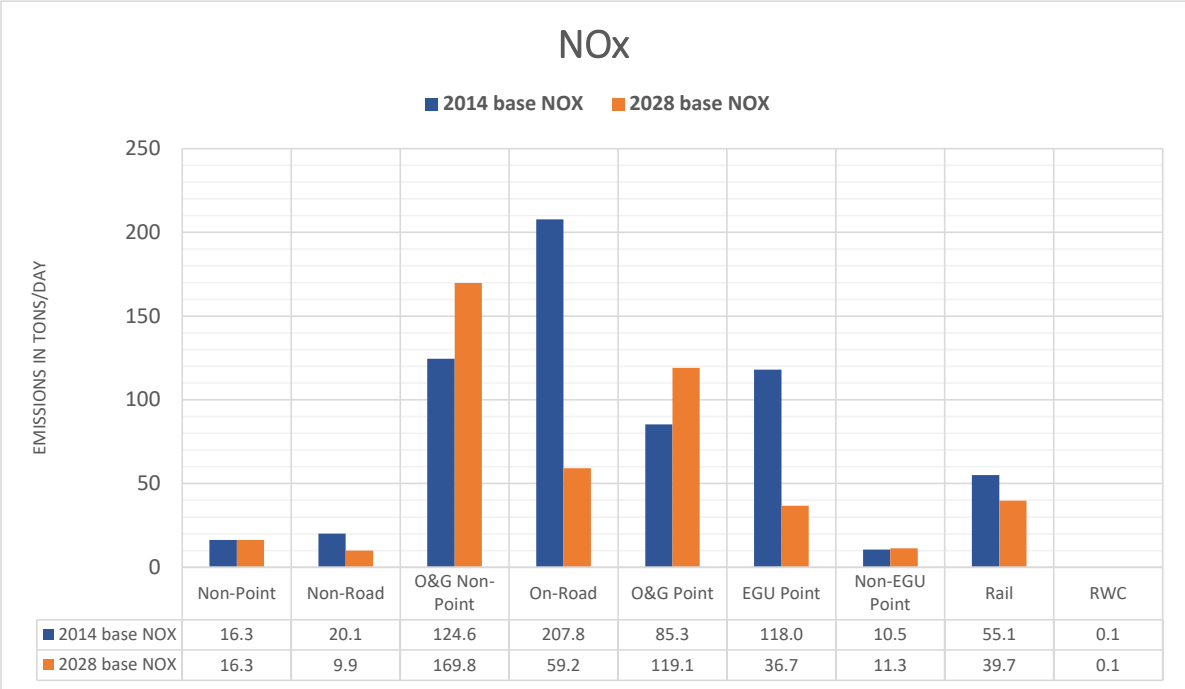
Pollutant	WRAP OGWG		NMED OAI EI
	2014	2023	2028
New Mexico State Total			
NOx	81,188	93,719	104,955
VOC	185,269	226,032	213,073
Permian , NM			
NOx	35,251	52,074	57,922
VOC	97,977	149,609	116,896
San Juan , NM			
NOx	44,730	39,789	45,200
VOC	86,567	75,670	95,500
Estancia Basin , NM			
NOx	113	645	645
VOC	5	26	26
Orogrande Basin , NM			
NOx	541	548	548
VOC	28	30	29
Raton , NM			
NOx	8	8	6
VOC	646	646	600
Pedregosa Basin , NM			
NOx	262	373	373
VOC	6	9	9
Basin-And-Range Province , NM			
NOx	261	261	261
VOC	10	11	11
Sierra Grande Uplift , NM			
NOx	23	23	0
VOC	31	31	2

Figures 3 and 4 compare anthropogenic emissions in New Mexico by source sector for the 2014 and 2028 base case emission scenarios. Total anthropogenic NO_x emissions in New Mexico are estimated to be reduced by -28% between 2014 and 2028, with the largest reductions coming from on-road mobile (-72%), EGU point (-69%), and non-road mobile (-51%) source sectors (Figure 3). These NO_x emission reductions were offset somewhat by increases in NO_X emissions between the 2014 and 2028 base cases from the O&G point (+40%) and non-point (+36%) source sectors.

Oil and gas emission sources are typically divided into "non-point" and "point" sources. Non-point oil and gas emission sources generally consist of emissions from upstream well-sites during both exploration and production phases. Typical non-point oil and gas emission sources include drilling rigs, hydraulic fracturing engines, and completion venting during the exploration phase, and sources such as wellhead engines, oil tanks, condensate tanks, produced water tanks, fugitive components, pneumatic controllers, pneumatic pumps, dehydrators, heaters, liquid unloading, and workover engines during the production phase. Representative, process-specific inputs specific to each non-point emission source category are used to estimate emissions from numerous sources in a given county or oil and gas basin. Point oil and gas emission sources generally include midstream gathering and treating facilities, such as compressor stations and gas plants, because midstream facilities typically have larger per facility emissions than well-sites and are more likely to be compelled to report their criteria and/or hazardous air pollutant emissions to state and/or federal agencies under regulatory requirements such as Title V. Emission processes at oil and gas point sources may include such categories as large spark-ignition engines, turbines, fugitive components, amine units, heaters, dehydrators, and tanks.

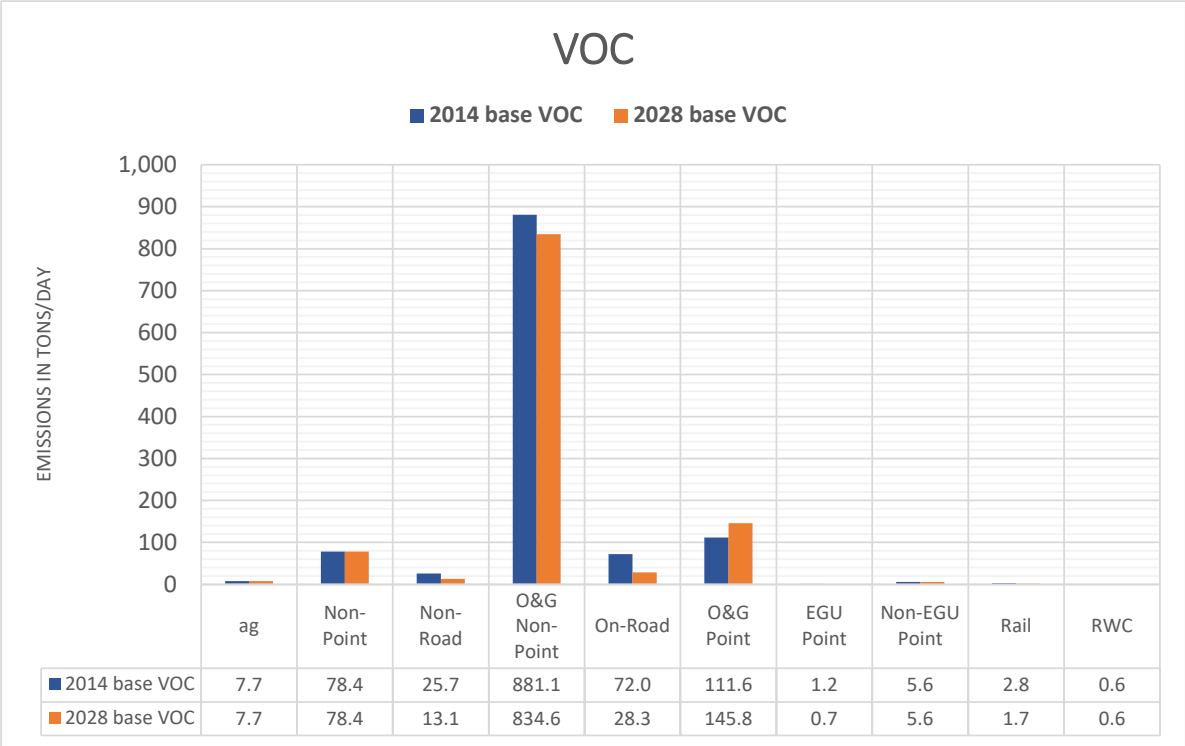
Facility owner/operator engineering estimates of process -level emissions are typically submitted to the permitting authority and included directly in the emissions inventory.

Although there are large reductions in on-road (-61%) and non-road (-49%) mobile source VOC emissions between the 2014 and 2028 base cases, the total reduction in New Mexico VOC emissions between 2014 and 2028 is only -6% because non-point O&G dominates (~75%) anthropogenic VOC emissions in New Mexico and they are only reduced by -5% between 2014 and 2028.



	Non-Point	Non-Road	O&G Non-Point	On-Road	O&G Point	EGU Point	Non-EGU Point	Rail	RWC
2014 base NOX	16.3	20.1	124.6	207.8	85.3	118.0	10.5	55.1	0.1
2028 base NOX	16.3	9.9	169.8	59.2	119.1	36.7	11.3	39.7	0.1

Figure 3. Comparison of 2014 and 2028 base cases New Mexico anthropogenic NOx emissions by source sector.



	ag	Non-Point	Non-Road	O&G Non-Point	On-Road	O&G Point	EGU Point	Non-EGU Point	Rail	RWC
2014 base VOC	7.7	78.4	25.7	881.1	72.0	111.6	1.2	5.6	2.8	0.6
2028 base VOC	7.7	78.4	13.1	834.6	28.3	145.8	0.7	5.6	1.7	0.6

Figure 4. Comparison of 2014 and 2028 base cases New Mexico anthropogenic VOC emissions by source sector.

Figure 5 displays the spatial distribution of differences in NO_X emissions between the 2014 and 2028 base case emission scenarios (2028 – 2014) across the 4-km New Mexico domain for four source sectors: (a) on-road mobile; (b) non-road mobile; (c) non-point O&G; and (d) point O&G. Except for Mexico (e.g. Juarez), mobile source NO_X emissions are reduced (Figures 5a and 5b), with the largest reductions occurring in the major urban areas (e.g., Albuquerque, Las Cruces, El Paso) and, for on-road mobile, along the major highways. Within New Mexico, 2028 non-point O&G NO_X emissions are greater than in 2014 in both the San Juan and Permian Basins, although on the Texas side of the Permian Basin the future year O&G non-point NO_X emissions are mainly lower than in 2014 (Figure 5c). 2028 point source O&G emissions are greater than 2014 in the Permian Basin, but mostly less in the San Juan Basin (Figure 5d). Figure 6 is like Figure 5 only for VOC emissions. Except for Mexico, mobile source VOC emissions are reduced across the 4-km New Mexico domain between 2014 and 2028 (Figures 6a and 6b). Non-

point O&G emissions are increased in northeast San Juan and northwest Rio Arriba Counties in the San Juan Basin, with a mixture of increases and decreases in the New Mexico portion of the Permian Basin and mainly increases in the Texas portion of the Permian Basin.

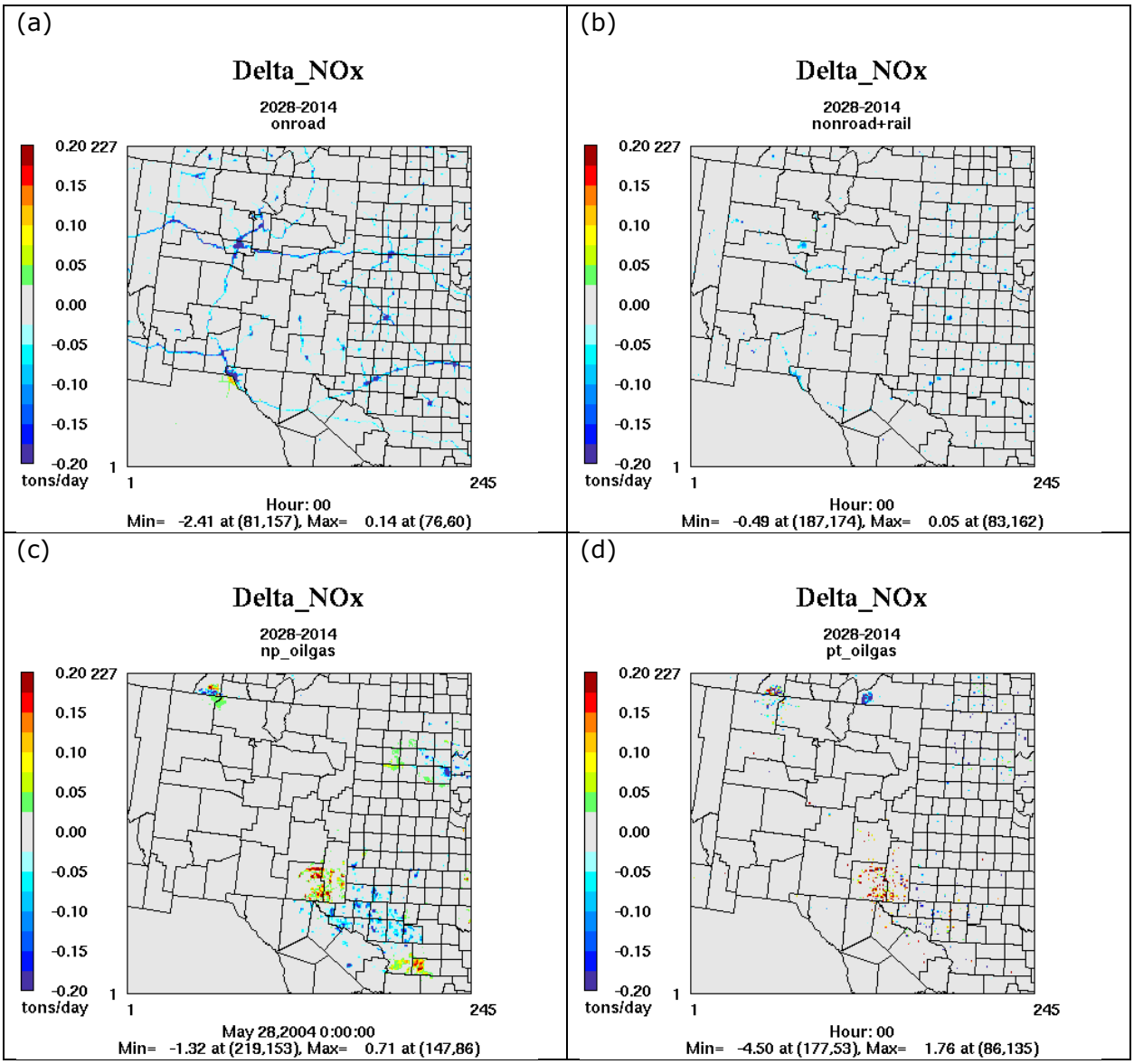


Figure 5. Differences in 2028 and 2014 base case NOx emissions (2028-2014) within the 4-km New Mexico domain for: (a) on-road mobile; (b) non-road mobile; (c) non-point oil and gas; and (d) point oil and gas source sectors.

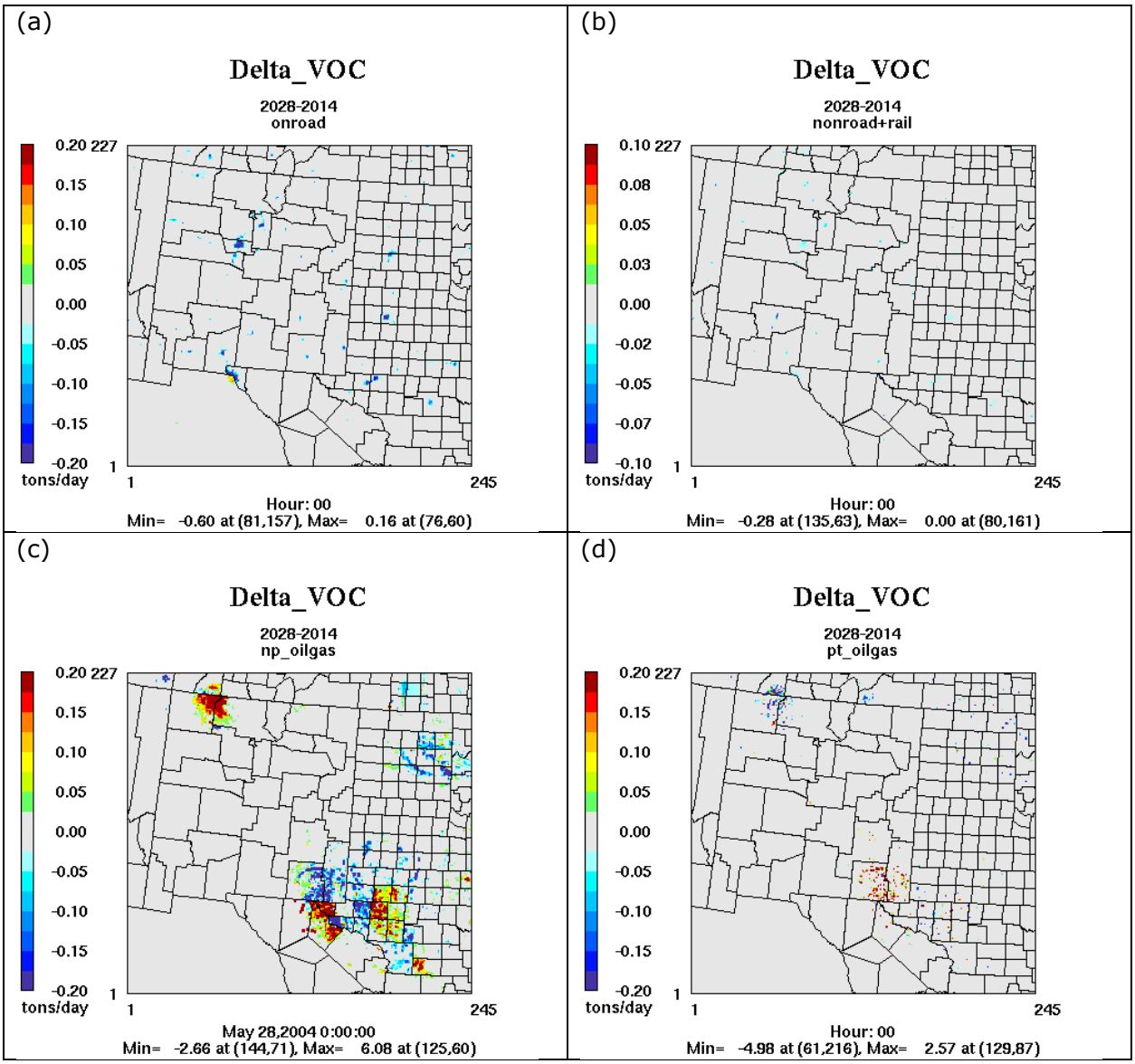


Figure 6. Differences in 2028 and 2014 base case VOC emissions (2028-2014) within the 4-km New Mexico domain for: (a) on-road mobile; (b) non-road mobile; (c) non-point oil and gas; and (d) point oil and gas source sectors.

VII. Development of 2028 New Mexico Oil and Gas Control Strategy Emissions

The WESTAR/Ramboll Team provided the New Mexico 2028 base case O&G emissions to the Department. ERG, under separate contract with NMED, estimated the reductions in the 2028 New Mexico O&G emissions from implementation of emission controls based on their

interpretation of the proposed requirements in Part 50.[23] The 2028 O&G Control Strategy reduced O&G emissions in seven New Mexico counties.

The 2028 NM O&G controlled emissions were processed by SMOKE and substituted for the 2028 NM O&G base case emissions to create the 2028 O&G control strategy emissions scenario. The only difference between the OAI PGM study 2028 base case and 2028 O&G control strategy emission scenarios were the controls on O&G emissions in New Mexico as implemented by ERG to reflect the proposed O&G ozone precursor regulations.

Table 3 displays the New Mexico state-wide O&G emissions for the 2028 base case and 2028 O&G control strategy. State-wide O&G NO_x emissions are reduced by approximately -45% with similar percent reductions from both the point and non-point O&G source sectors. State-wide O&G VOC emission are reduced by approximately -50% with more reductions coming from the non-point (-53%) than point (-35%) source sectors.

Table 3. New Mexico NO_x and VOC O&G emissions (tons per year, TPY) for the 2028 Base Case and 2028 NM O&G control strategy.

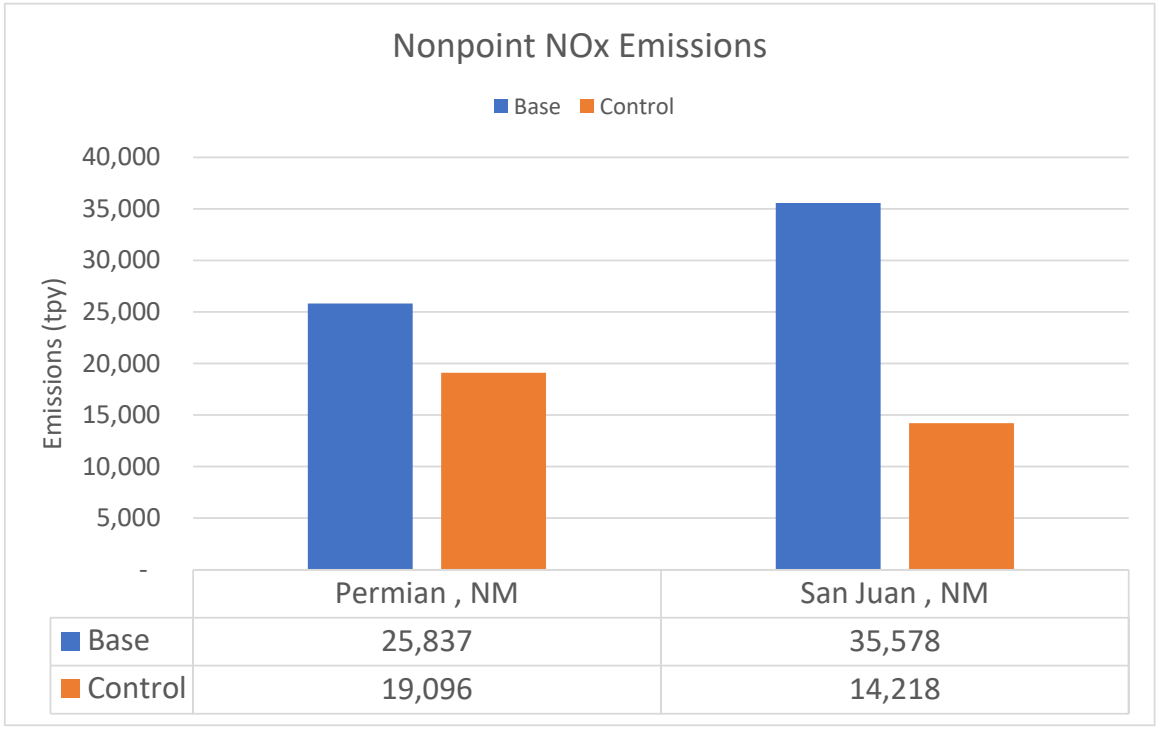
Source Sector	NO_x Emissions (TPY)			VOC Emissions (TPY)		
	Base	Control	Diff	Base	Control	Diff
Non-Point	61,245	33,144	-46%	181,252	85,564	-53%
Point	41,066	22,872	-44%	30,340	19,608	-35%
Total	102,311	56,016	-45%	211,592	105,172	-50%

Figures 7 and 8 display the changes in, respectively, NO_x and VOC O&G emissions in the Permian and San Juan Basins between the 2028 base and 2028 control strategy cases by point and non-point source sectors. In the Permian Basin, O&G NO_x emissions are estimated to be reduced by approximately 21,000 tons per year ("TPY") (-64%). In the San Juan Basin, O&G NO_x emissions are estimated to be reduced by approximately 25,000 TPY (-44%). 2028 VOC

[23] https://www.env.nm.gov/new-mexico-methane-strategy/wp-content/uploads/sites/15/2020/07/Draft-Ozone-Precursor-Rule-for-Oil-and-Natural-Gas-Sector-Version-Date-7.20.20.pdf

O&G emissions in the Permian and San Juan Basins are estimated to be reduced by approximately 53,000 TPY each (-46% and -55% reduction, respectively).

Figure 9 shows the spatial distribution of the differences in non-point and point O&G NO_x and VOC emissions between the 2028 base case and 2028 O&G control strategy scenario. The O&G emission reductions are restricted to the New Mexico portions of the San Juan and Permian Basins.



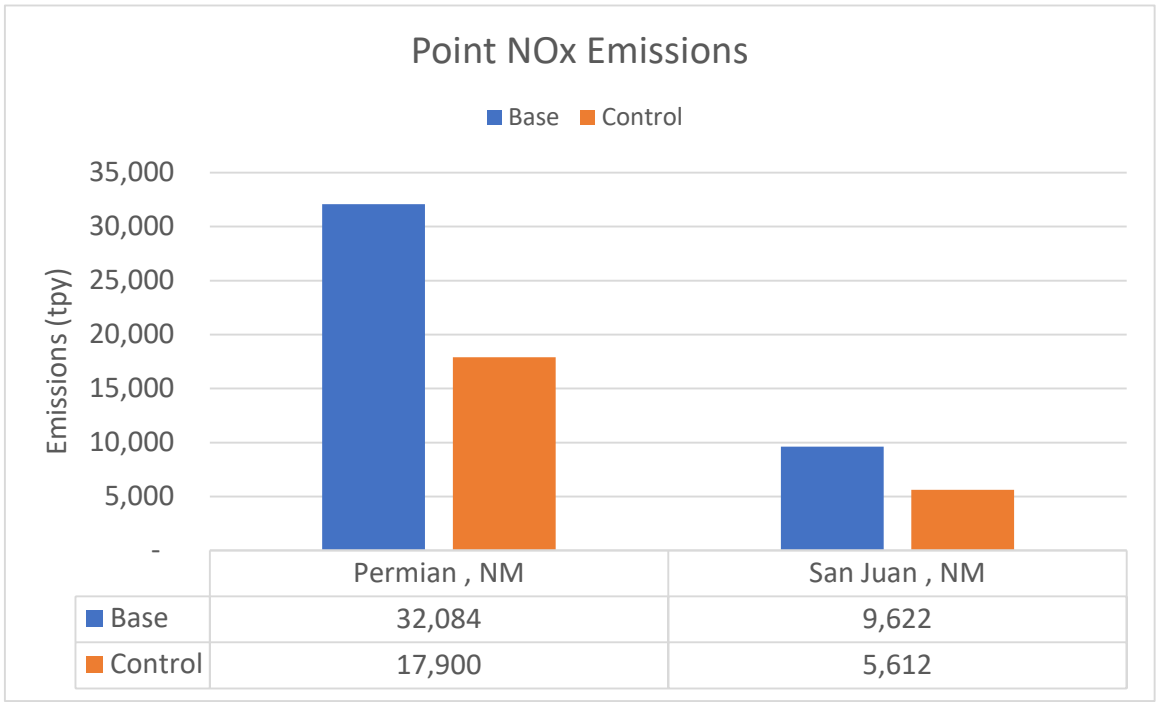
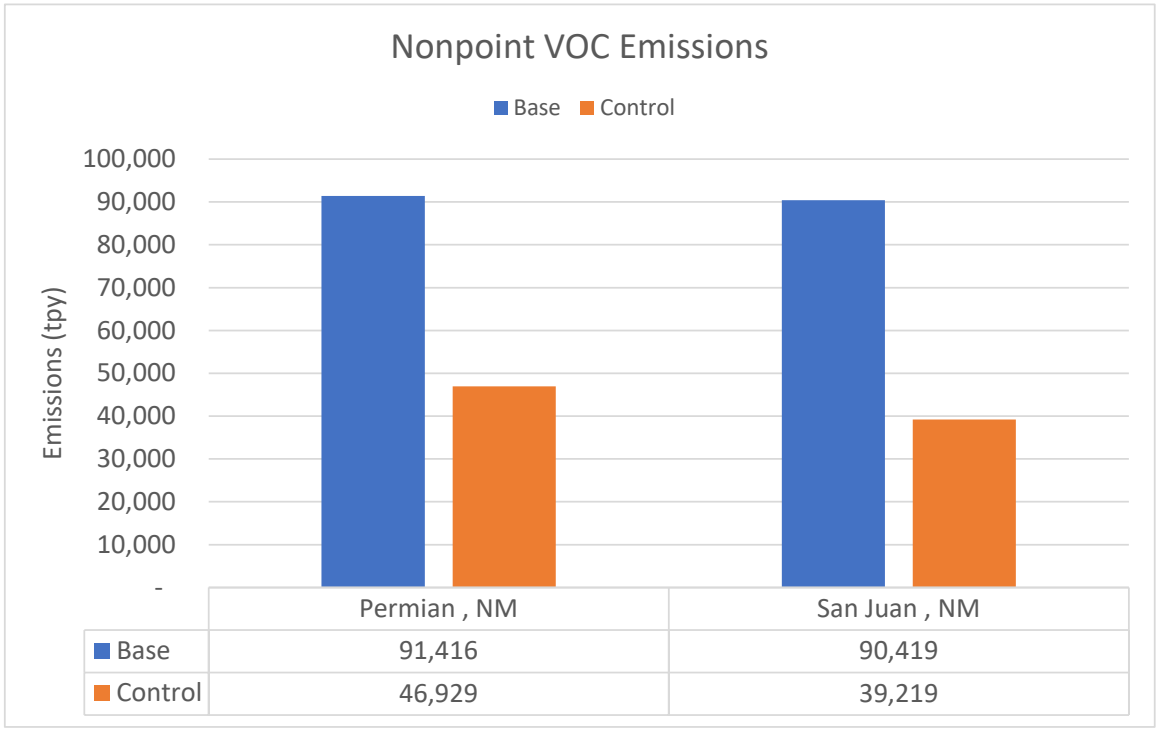


Figure 7. Comparison of 2028 Base Case and 2028 NM O&G control strategy NO_x emissions for the non-point (top) and point (bottom) source sectors and the Permian (left) and San Juan (right) basins.



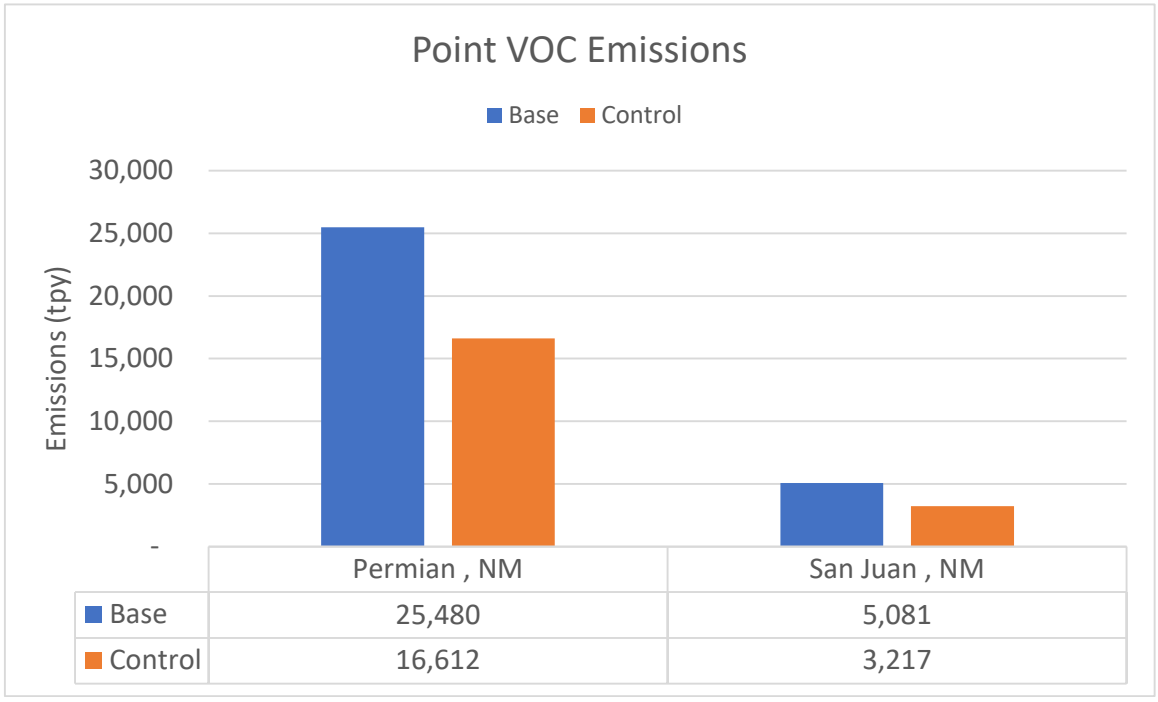


Figure 8. Comparison of 2028 Base Case and 2028 NM O&G control strategy VOC emissions for the non-point (top) and point (bottom) source sectors and the Permian (left) and San Juan (right) basins.

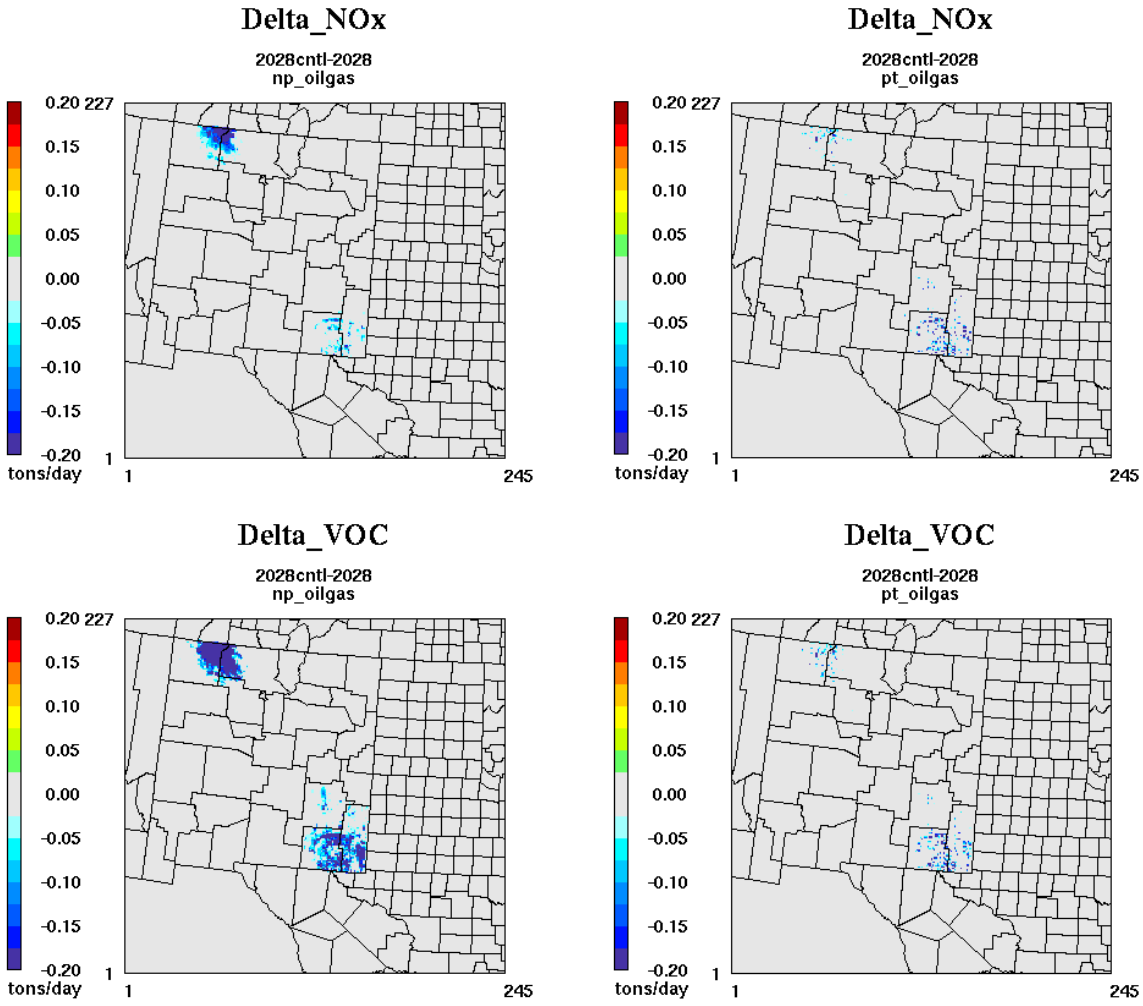


Figure 9. Differences between 2028 O&G Control Strategy and 2028 Base Case O&G NO_x (top) and VOC (bottom) emissions for the non-point (left) and point (right) source sectors.

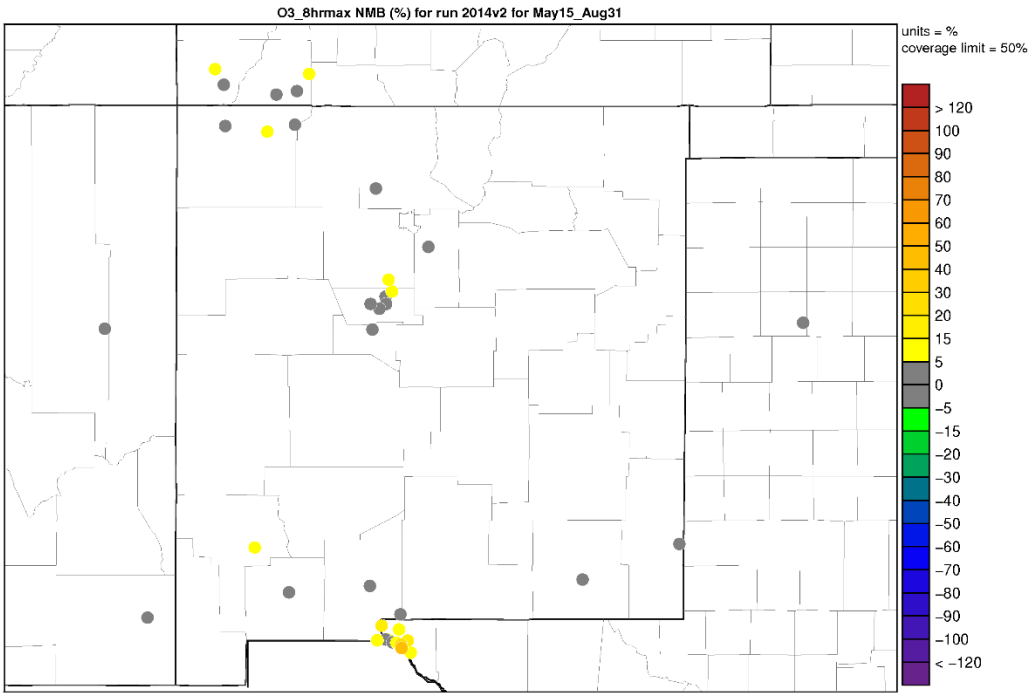
VIII. CAMx 2014v2 Base Case Modeling and Model Performance Evaluation

Four CAMx 2014 diagnostic sensitivity tests were conducted using different sets of meteorological inputs based on the OAI PGM study 2014 WRF meteorological model output. The CAMx ozone model performance for the four sensitivity tests was evaluated and the meteorological inputs from the best performing sensitivity test were selected for use in the final CAMx 2014v2 base case and 2028 future year modeling.

The CAMx final 2014v2 36/12/4-km base case simulation ozone estimates were evaluated by comparing them against concurrent observed ozone concentrations matched by time and

location. Both graphical and statistical measures of ozone model performance were used in the CAMx 2014v2 base case model performance evaluation ("MPE"), with the statistical performance metrics compared against ozone model performance goals and criteria developed from the peer reviewed literature[24] that were based on good ozone performing PGMs. Ozone model performance goals and criteria are not pass/fail tests; rather, they are used to help put the model performance in context. Model performance statistics for bias, error, and correlation were calculated across the domain and at each monitoring site using all predicted and observed maximum daily average 8-hour ("MDA8") ozone pairs and using just predicted and observed MDA8 ozone pairs when the observed MDA8 ozone concentration is above a 60 ppb cutoff value in order to evaluate how well the model is predicting observed higher MDA8 ozone concentrations. Figure 10 displays the spatial distribution of the Normalized Mean Bias ("NMB") performance statistic for MDA8 ozone concentrations at monitoring sites in the 4-km New Mexico domain with and without using the 60 ppb observed ozone cutoff. The NMB are colored grey when they achieve the NMB performance goal (≤±5%), and bright yellow or bright green when they fall between the performance goal and performance criteria (i.e., between ±5% and ±15%). Without using the 60 ppb ozone cutoff, NMB at all sites in New Mexico achieve the performance criteria with most sites also achieving the NMB performance goal (Figure 10, top). When a 60 ppb ozone cutoff is used, almost all sites in New Mexico achieve the ozone bias performance criteria, with approximately half the sites also achieving the ozone bias performance goal.

[24] https://www.tandfonline.com/doi/full/10.1080/10962247.2016.1265027



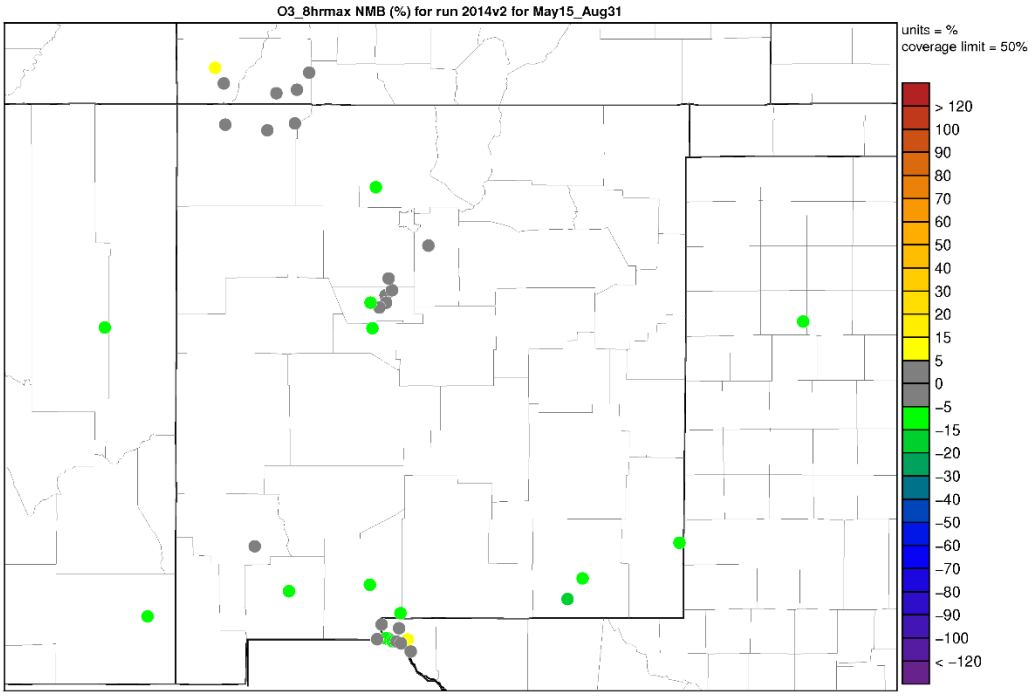


Figure 10. Normalized Mean Bias (NMB) for MDA8 ozone concentrations at monitoring sites in the 4-km New Mexico domain without (top) and with using a 60 ppb observed ozone cutoff.

Figure 11 displays scatter plots of predicted and observed MDA8 ozone concentrations for monitoring sites in the 4-km New Mexico domain from EPA's Air Quality System ("AQS") and the more rural CASTNet networks. The NMB across both the AQS (4.4%) and CASTNet (-1.4%) achieves the ozone bias performance goal (≤±5%) with the Normalized Mean Error ("NME") across both networks (10.9% and 7.9%) achieving the ozone error performance goal (≤15%). The ozone model performance of the final CAMx 2014v2 base case simulation was quite good; more details on the OAI PGM study CAMx 2014v2 base case MPE are provided in the addendum[25] to the 2014 base case modeling report and Chapter 6 of the AQ Technical Support Document.[26]

[25] http://wrapair2.org/pdf/NM_OAI_Addendum_2014v2_MPE_v2.pdf
[26] http://wrapair2.org/pdf/NM_OAI_2028_AQTSD_v8.pdf

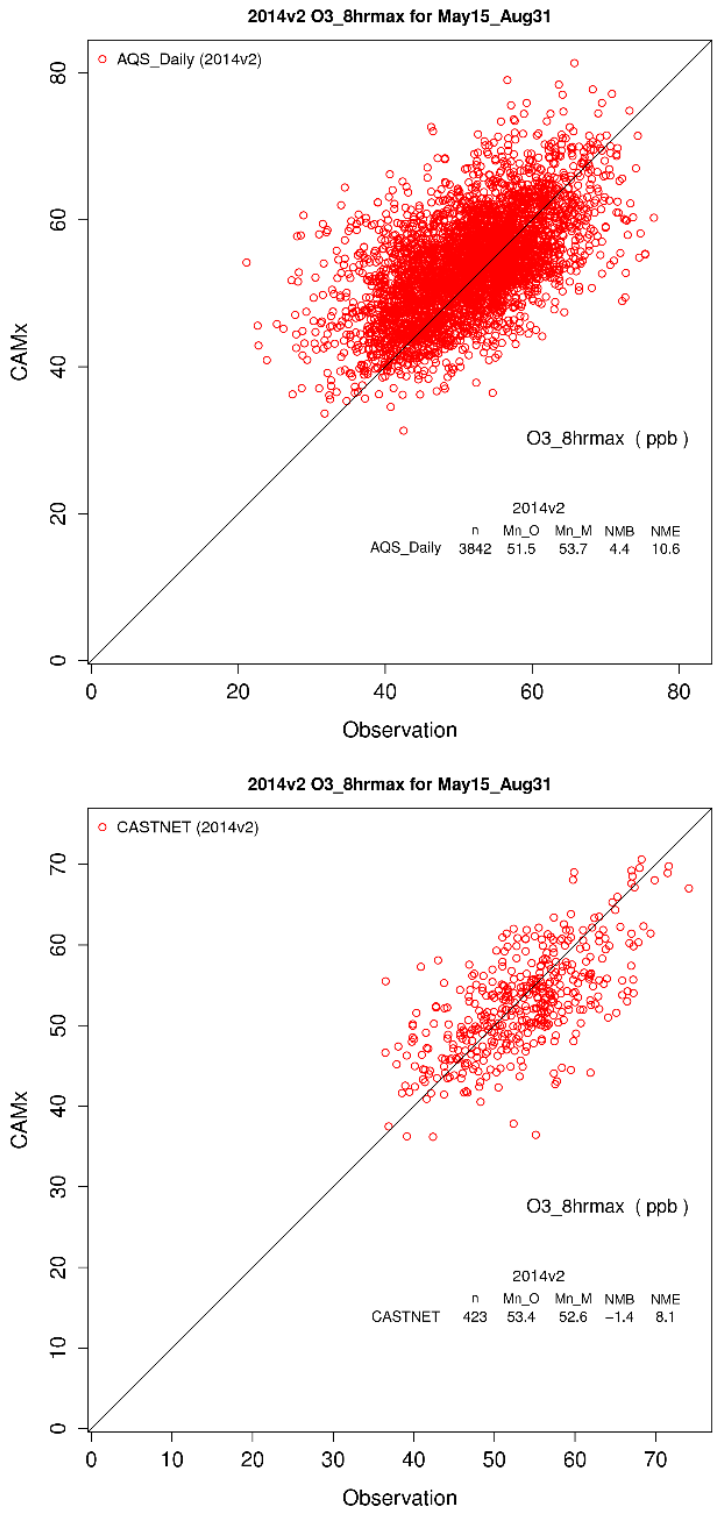


Figure 11. Scatter plots of predicted and observed MDA8 ozone concentrations for AQS (top) and CASTNet (bottom) monitoring sites within the 4-km New Mexico domain and the final 2014v2 CAMx base case simulation.

VIII. CAMx 2028 Base Case Modeling Results

A CAMx 2028 36/12/4-km base case simulation was conducted whose emissions were based on the WRAP-WAQS 2028OTBa2 emissions scenario only using updated 2028 O&G emissions for New Mexico and 2014 actual fires. 2028 future year ozone design values ("DVF") were estimated by projecting observed current year ozone design values ("DVC") using the CAMx 2014v2 and 2028 base cases modeling results following the EPA 2018 PCM Guidance (NMED Exhibit 108) for making future year ozone DVF projections.

EPA recommends using PGM modeling results in a relative fashion to scale the observed current year ozone DVC to estimate the future year ozone DVF. The model derived scaling factors are called Relative Response Factors ("RRF") and are the ratio of future (2028) to base (2014v2) year ozone modeling results averaged over the 10 days with the highest base year base case modeled MDA8 ozone concentrations:

$$RRF = \sum \text{Model MDA8 Ozone}_{2028} / \sum \text{Model MDA8 Ozone}_{2014}$$

$$DVF = DVC \times RRF$$

The EPA 2018 PCM Guidance recommends that the DVC be calculated as the average of three-years of observed ozone design values (DV)[27] centered on the base modeling year, which is 2014 in this case:

$$DVC_{2012\text{-}2016} = (DV_{2012\text{-}2014} + DV_{2013\text{-}2015} + DV_{2014\text{-}2016}) / 3$$

The EPA 2018 PCM Guidance recommends for the RRFs that the highest modeled base year MDA8 ozone be selected within a 3x3 array of grid cells centred on the monitor. For the future year, the MDA8 ozone is selected from the same grid cell in the 3x3 array centered on the monitor as used in the base year.

[27] An ozone DV is defined as the three-year average of the fourth highest observed MDA8 ozone concentrations at a monitoring site.

The EPA 2018 PCM Guidance recommends using the 10 highest modeled base year MDA8 ozone concentrations days with MDA8 ozone greater than 60 ppb in the RRFs. If there are less than 10 modeled days with base year MDA8 ozone greater than 60 ppb, the EPA 2018 PCM Guidance states that RRFs can still be calculated if there are at least 5 days with MDA8 ozone greater than 60 ppb. EPA has codified their recommended ozone DVF projection approach in the Software for the Modeled Attainment Test ("SMAT")[28]. The SMAT tool was used to make 2028 ozone DVF projections in the OAI PGM study. The default SMAT parameters that follow the EPA 2018 PCM Guidance were used, except that the minimum number of days needed to calculated an RRF was lowered from 5 to 4 in order to obtain 2028 ozone DV projections at all sites in New Mexico as one site only had 4 days with 2014v2 MDA8 ozone greater than 60 ppb (Hobbs in Lea County).

Table 4 displays the current year ozone $DVC_{2012\text{-}2016}$ and projected 2028 ozone DVFs at monitoring sites in New Mexico for the 2028 base case simulation and their differences. There are two sites in Doña Ana County with current year ozone $DVC_{2012\text{-}2016}$ above the 70 ppb 2015 ozone NAAQS: Desert View (72.0 ppb) and Santa Teresa (71.3 ppb). The 2028 base case ozone DVFs at monitoring sites in New Mexico are projected to be -2.0 ppb to -5.7 ppb lower than the observed $DVC_{2012\text{-}2016}$. Following the EPA 2018 PCM Guidance, the 2028 ozone DVF at all monitoring sites in New Mexico are projected to be below the 70 ppb 2015 ozone NAAQS with the two highest values being 67.0 ppb at Desert View in Doña Ana County and 66.7 ppb at Carlsbad in Eddy County, both in southern New Mexico.

[28] https://www.epa.gov/scram/photochemical-modeling-tools

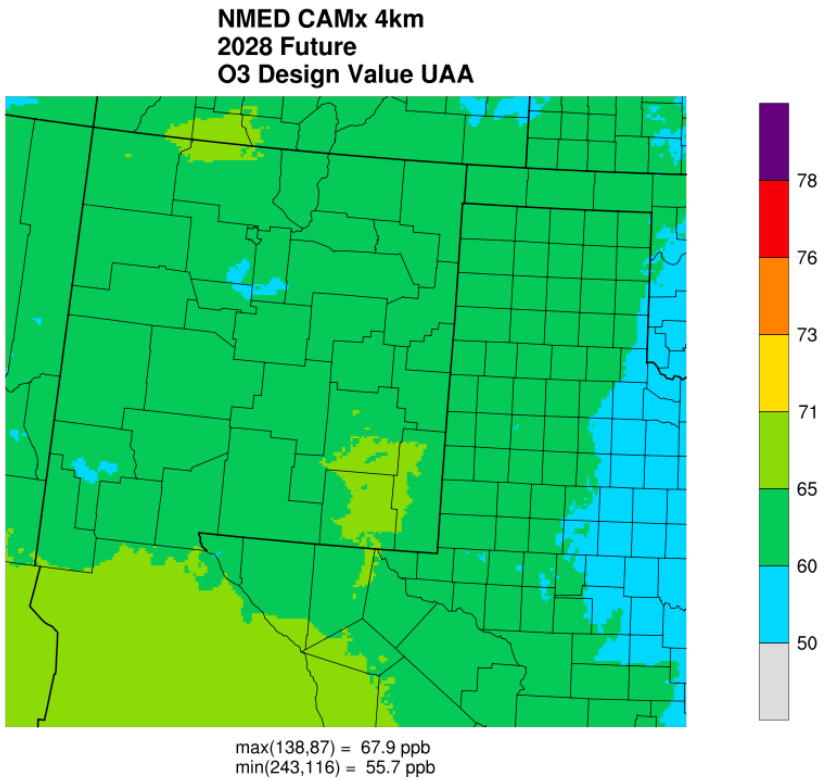
Table 4. Current year ozone $DVC_{2012-2016}$ and projected 2028 Base Case ozone DVFs at New Mexico monitoring sites.

AQS_ID	2012-2016 DVC (ppb)	2028 Base DVF Base (ppb)	Difference 2028 DVF minus $DVC_{2012-16}$ (ppb)	Site Name	State	County
Northern New Mexico						
350390026	64.0	60.8	-3.2	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	-5.6	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	-3.3	Bloomfield	NM	San Juan
350450018	67.0	64.8	-2.2	Navajo Lake	NM	San Juan
350451005	63.7	60.8	-2.9	Substation	NM	San Juan
350490021	64.3	60.6	-3.7	Santa Fe Airport	NM	Santa Fe
Bernalillo County						
350010023	66.3	60.9	-5.4	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	-5.7	South East Heights	NM	Bernalillo
350010029	66.0	61.0	-5.0	South Valley	NM	Bernalillo
350010032	67.0	62.6	-4.4	Westside	NM	Bernalillo
350011012	65.0	59.1	-5.9	Foothills	NM	Bernalillo
Southern New Mexico						
350130008	66.3	60.0	-6.3	La Union	NM	Doña Ana
350130017	67.0	61.9	-5.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	-4.7	Chaparral	NM	Doña Ana
350130021	72.0	67.0	-5.0	Desert View	NM	Doña Ana
350130022	71.3	66.1	-5.2	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	-4.7	Solano	NM	Doña Ana
350151005	69.0	66.7	-2.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	-3.0	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	-2.0	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	-3.3	Deming Airport	NM	Luna
350610008	66.3	62.2	-4.1	Los Lunas (Los Lentes)	NM	Valencia

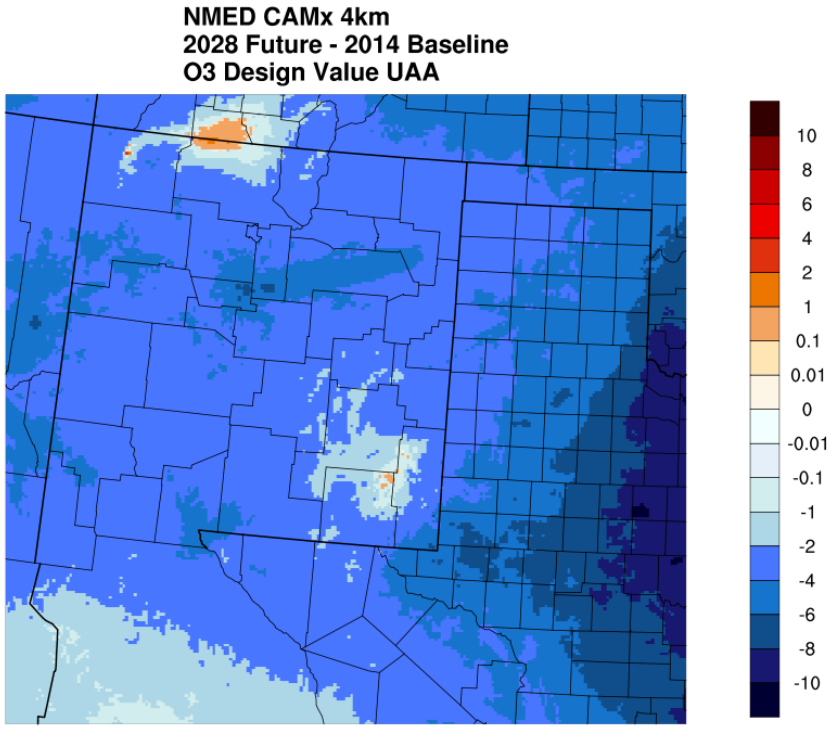
EPA's SMAT tool has an ozone DVF Unmonitored Area Analysis ("UAA") feature that was used to make 2028 ozone DVF projections across the 4-km New Mexico domain. The SMAT UAA tool first spatially interpolates the observed ozone $DVC_{2012-2016}$ at the monitoring sites to each 4-km grid cell in the New Mexico modeling domain, where an option exists in SMAT to use the modeled ozone concentration gradients in the interpolation procedure. I do not present the SMAT UAA results using the option to use the modeled concentrations gradients in the spatial

interpolation procedure in this testimony, as it produced spurious results due to high modeled ozone concentrations caused by wildfires, although those results are available in the OAI PGM study AQ Technical Support Document. The SMAT UAA procedure then makes the 2028 ozone DVF projections in each 4-km grid cell using the CAMx 2014v2 and 2028 base case modeling results in the same relative fashion as used to project 2028 ozone DVF at the monitoring sites described above, only instead of using the modeling results from a 3x3 array of grid cells centered on the monitor it uses the modeling results in the 4-km grid cell in question.

Figure 12 displays the SMAT UAA projected 2028 ozone DVFs and the differences between in the projected 2028 ozone DVF and the observed current year $DVC_{2012\text{-}2016}$ across the 4-km New Mexico modeling domain. The highest SMAT UAA 2028 ozone DVF in the 2028 base case is 67.9 ppb, which occurs within the Permian Basin, with 2028 ozone DVF exceeding 65 ppb in the San Juan Basin (Figure 12, top). The differences between the SMAT UAA 2028 ozone DVF and current year ozone $DVC_{2012\text{-}2016}$ show ozone reductions across most of New Mexico except for small area of ozone increases in the Permian Basin and larger area of ozone increases in the San Juan Basin (Figure 12, bottom). These are areas where there were increases in O&G emissions between 2014 and 2028 (see Figures 5 and 6).



1



2

3 **Figure 12. Projected 2028 ozone DVF for the 2028 base case (top) and differences between**
4 **the projected 2028 ozone DVFs and the observed current year ozone DVC$_{2012\text{-}2016}$ (bottom)**
5 **across the 4-km New Mexico modeling domain.**

Figure 13 displays spatial maps of daily MDA8 ozone concentrations for the 2014v2 base case, 2028 base case and their differences for two example days during the May-August 2014 modeling period. The OAI PGM study AQ Technical Support Document contains MDA8 ozone results for additional example days. For the 2014v2 base case, the highest CAMx estimated MDA8 ozone concentration on June 5, 2014 (Figure 13, top left panel) is 72.9 ppb which occurs in El Paso, and there is a small area in northeastern San Juan County that exceeds the 70 ppb 2015 ozone NAAQS that is indicated by the yellow shading (i.e., MDA8 ozone between 71 and 73 ppb). The highest estimated MDA8 ozone on June 5th for the 2028 base case is 74.0 ppb and occurs in the San Juan Basin just over the border of New Mexico in southern Colorado, with MDA8 ozone above the 2015 ozone NAAQS in northeast San Juan and northwest Rio Arriba counties (Figure 13, middle left). The difference plot in MDA8 ozone between 2028 and 2014 base cases on June 5th, shown in the bottom right panel of Figure 13, show that the 2028 base case has higher MDA8 ozone than the 2014 base case within the Permian and San Juan Basins due to higher O&G emissions in the 2028 base case emissions scenario than in the 2014v2 base case (see Figures 5 and 6). However, outside the San Juan and Permian Basins, the 2028 base case has lower MDA8 ozone concentrations on June 5th due to lower mobile source and other non-O&G source sector emissions.

The 2028 and 2014 base case daily MDA8 ozone concentrations and their differences on July 24, 2014 are shown in the right panels in Figure 13. On July 24th the 2014v2 base case has a peak MDA8 ozone value of 74.7 ppb in the San Juan Basin just across the border in Colorado, with areas in San Juan County, New Mexico above the 2015 ozone NAAQS (Figure 13, top right). In 2028 the MDA8 ozone peak across the border from New Mexico in Colorado on July 24th is reduced to 71.3 and the area above the 2015 ozone NAAQS in the 2014v2 scenario (indicated by

yellow in Figure 13, top right) is reduced to below the NAAQS in the 2028 base case scenario (indicated by green in Figure 13, middle left). The 2028 minus 2014v2 MDA8 ozone difference plot on July 24th show more wide-spread and higher magnitudes of ozone decreases in the future year that appear to be due in part to lower ozone concentrations in the 2028 than 2014 base case emission scenarios being transported into New Mexico from Texas.

The differences between the MDA8 ozone concentrations in the 2014v2 and 2028 base case simulations vary day-to-day, as illustrated in the two example days shown in Figure 13. In general, there is higher ozone in the San Juan and Permian Basins due to increases in O&G emission between 2014v2 and 2028, but lower ozone everywhere else due to lower emissions in the other source sectors (e.g., mobile). Whether there is a net increase in MDA8 ozone concentrations in the two O&G basins depends on whether the ozone reductions due to emission reductions in the non-O&G source sectors is sufficient to offset the ozone increases due to increases in O&G emissions between 2014v2 and 2028.

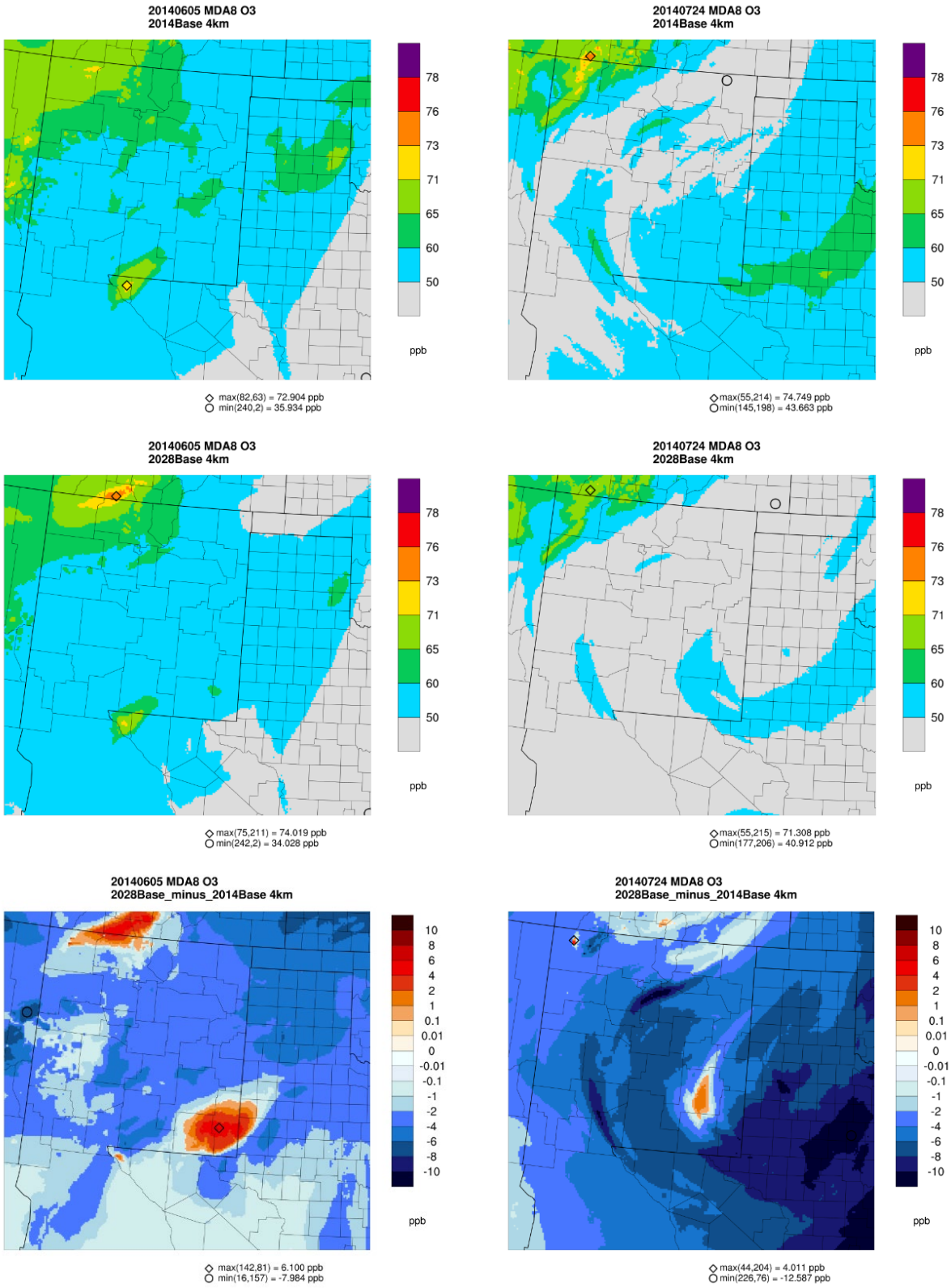


Figure 13. MDA8 ozone concentrations (ppb) on June 5, 2014 (left) and July 24, 2014 (right) for the 2014v2 base case (top), 2028 base case (middle) and their differences (bottom).

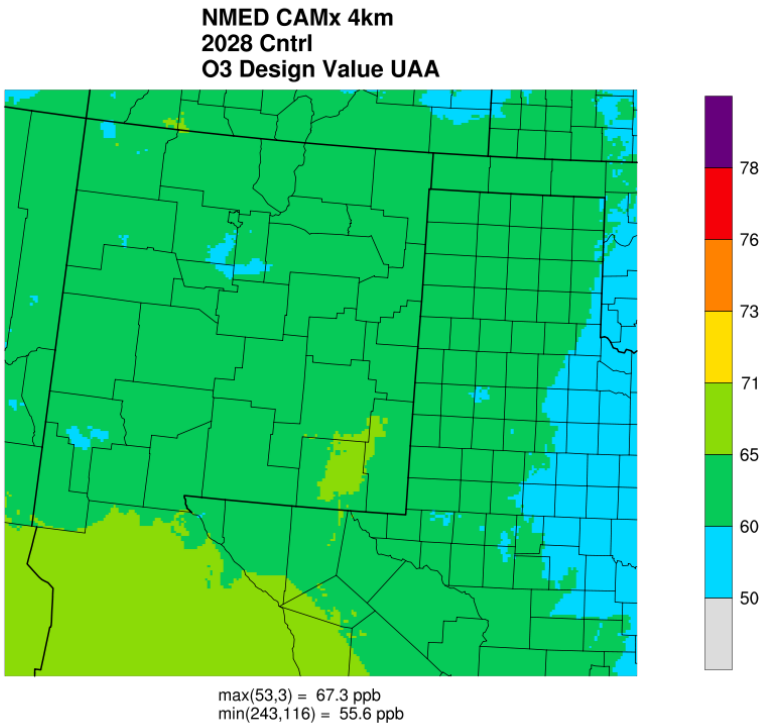
IX. 2028 New Mexico Oil and Gas Control Strategy Ozone Results

Future year 2028 ozone DVF projections were made using the 2014v2 and 2028 O&G control strategy CAMx modeling results (DVF_{Cntl}) following the same EPA-recommended procedures as used to make projections for the 2028 base case (DVF_{Base}), described above only substituting the CAMx 2028 O&G control strategy results for the 2028 base case results. Table 5 compares the projected 2028 ozone DVFs for the 2028 base case and 2028 O&G control strategy and their differences at monitoring sites in New Mexico. The O&G control strategy reduces the 2028 base case ozone DVF_{Base} at the monitoring sites from -0.1 ppb to -1.5 ppb. The largest reductions in 2028 ozone DVF_{Base} due to the O&G control strategy occur at Navajo Lake (-1.5 ppb) and Substation (-1.2) monitoring sites in San Juan County in northwestern New Mexico. The largest reductions in 2028 ozone DVF_{Base} due to the O&G control strategy in southern New Mexico occurs at the Hobbs (-0.7 ppb) and Carlsbad (-0.3 ppb) monitoring sites in the Permian Basin.

Figure 14 displays the spatial distribution of the SMAT UAA ozone DVFs for the 2028 O&G Control Strategy where the SMAT UAA was applied without using concentration gradients in the spatial interpolation of the $DVC_{2012\text{-}2016}$. As shown in Figure 12 (top), within New Mexico, the projected 2028 DVF_{Base} tends to be mostly in the 60-71 ppb range, with the highest ozone concentrations (65-71 ppb) occurring in the San Juan and Permian Basins as indicated by the lighter green shading. When the O&G control strategy is applied, the 2028 ozone DVF_{Cntl} in the San Juan Basin is lower (i.e., in the 60-65 ppb range with the light green shading completely gone in Figure 14, top) and the area of ozone DVF_{Base} in the 65-71 ppb range is greatly reduced for the ozone DVF_{Cntl} case.

Table 5. Observed ozone $DVC_{2012-2016}$ and projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control strategy and differences in the 2028 ozone DVFs ($DVF_{Cntl} - DVF_{Base}$).

AQS_ID	2012-16	Projected 2028 DVF			Site Name	State	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base			
Northern New Mexico							
350390026	64.0	60.8	60.0	-0.8	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	58.1	-0.3	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	60.2	-0.8	Bloomfield	NM	San Juan
350450018	67.0	64.8	63.3	-1.5	Navajo Lake	NM	San Juan
350451005	63.7	60.8	59.6	-1.2	Substation	NM	San Juan
350490021	64.3	60.6	60.4	-0.2	Santa Fe Airport	NM	Santa Fe
Bernalillo County							
350010023	66.3	60.9	60.7	-0.2	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	62.0	-0.3	South East Heights	NM	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	NM	Bernalillo
350010032	67.0	62.6	62.1	-0.5	Westside	NM	Bernalillo
350011012	65.0	59.1	58.8	-0.3	Foothills	NM	Bernalillo
Southern New Mexico							
350130008	66.3	60.0	59.8	-0.2	La Union	NM	Doña Ana
350130017	67.0	61.9	61.8	-0.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	62.2	-0.1	Chaparral	NM	Doña Ana
350130021	72.0	67.0	66.8	-0.2	Desert View	NM	Doña Ana
350130022	71.3	66.1	66.0	-0.1	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	60.2	-0.1	Solano	NM	Doña Ana
350151005	69.0	66.7	66.4	-0.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	58.9	-0.1	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	63.3	-0.7	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	62.5	-0.2	Deming Airport	NM	Luna
350610008	66.3	62.2	62.0	-0.2	Los Lunas (Los Lentes)	NM	Valencia



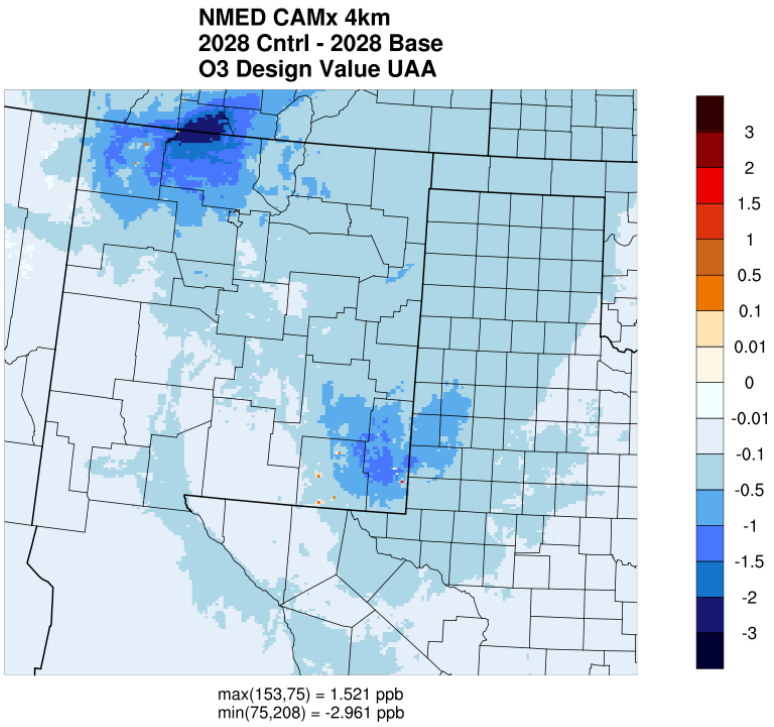


Figure 14. Projected 2028 ozone DVF_{Cntl} for the 2028 O&G control strategy (top) and differences between the projected 2028 ozone DVFs for the 2028 base case and 2028 O&G control strategy ($DVF_{Cntl} - DVF_{Base}$) (bottom) across the 4-km New Mexico modeling domain.

The spatial map of the differences in SMAT UAA projected 2028 ozone DVFs are shown in the bottom panel of Figure 14 (i.e., $DVF_{Cntl} - DVF_{Base}$). Within the Permian Basin, the 2028 O&G control strategy reduces the ozone DVF_{Base} by -0.5 to -1.5 ppb with the largest reductions (-1.0 to -1.5 ppb) mostly occurring in Lea County. The 2028 O&G control strategy has a bigger reduction effect on the 2028 ozone DVF in the San Jun Basin with reductions of -1.0 to -3.0 ppb, with the largest reductions (-2.0 to -3.0 ppb) straddling the New Mexico/Colorado state line, and includes the northern portions of Rio Arriba County. There are also isolated grid cells of SMAT UAA ozone DVF increases in the Permian and San Juan Basins due to the 2028 O&G Control Strategy (i.e., red dots in Figure 14, bottom). These ozone DVF increases appear to be several isolated 4-km grid cells and are likely due to NO_X disbenefits that occur at the locations of O&G NO_x emission reductions due to the 2028 O&G control strategy.

Figure 15 displays the spatial distribution of daily MDA8 ozone concentrations for the 2028 base case, the 2028 O&G control strategy case, and their differences for two days with additional days presented in the AQ Technical Support Document. On June 5, 2014, the 2028 base case has CAMx-estimated MDA8 ozone concentrations in excess of the 70 ppb 2015 ozone NAAQS in northeast San Juan and northwest Rio Arriba Counties, with a peak MDA8 ozone of 74 ppb on the border with and just inside of Colorado (Figure 15, top left). The 2028 O&G control strategy is very effectively reducing these high MDA8 ozone exceedances in the San Juan Basin, with ozone reductions of up to -4.6 ppb that reduce the MDA8 ozone concentrations that were above the 2015 ozone NAAQS in San Juan and Rio Arriba Counties in the 2028 base case to below the 2015 ozone NAAQS in the 2028 O&G control strategy case. MDA8 ozone is also reduced in the Permian Basin, although not to the extent as in the San Juan Basin on this

day. There are also very small areas of ozone increases due to the 2028 O&G control strategy on June 5th that are as high as 0.4 ppb in New Mexico.

On July 24th the 2028 base case has elevated MDA8 ozone concentrations approaching, but below, the 2015 ozone NAAQS in San Juan County, but right across the border in Colorado there is an MDA8 ozone peak of 71.3 ppb that is above the NAAQS (Figure 15, top right). Although the 2028 O&G control strategy reduces the MDA8 ozone across wide areas of New Mexico on this day, with ozone reductions as high as -2.8 ppb in the Permian Basin, there are areas of estimated increases in MDA8 ozone in San Juan County due to the O&G control strategy. These MDA8 ozone increases on July 24th in San Juan County due to the 2028 O&G control strategy are as high as +6.4 ppb. The ozone increases in San Juan County due to the 2028 O&G control strategy are sufficient to increase the MDA8 ozone concentration in one grid cell to 71.0 ppb that exceeds the 2015 ozone NAAQS.

In conclusion, the O&G control strategy results in wide areas of reductions in daily MDA8 ozone concentrations and projected 2028 ozone DVFs across large portions of New Mexico, with the largest ozone reductions occurring in the San Juan and Permian Basins. There are also areas of ozone increases (NO_X disbenefits) in MDA8 ozone and projected 2028 ozone DVFs due to the O&G Control Strategy that usually occur in isolated locations within and near the San Juan and Permian Basins. The size of the areas and magnitudes of the ozone reductions due to the 2028 O&G Control Strategy scenario are much greater than the ozone increases. Using the EPA 2018 PCM Guidance, the projected 2028 ozone DVF were below the 2008 and 2015 ozone NAAQS for both the 2028 base case and 2028 O&G control strategy scenarios.

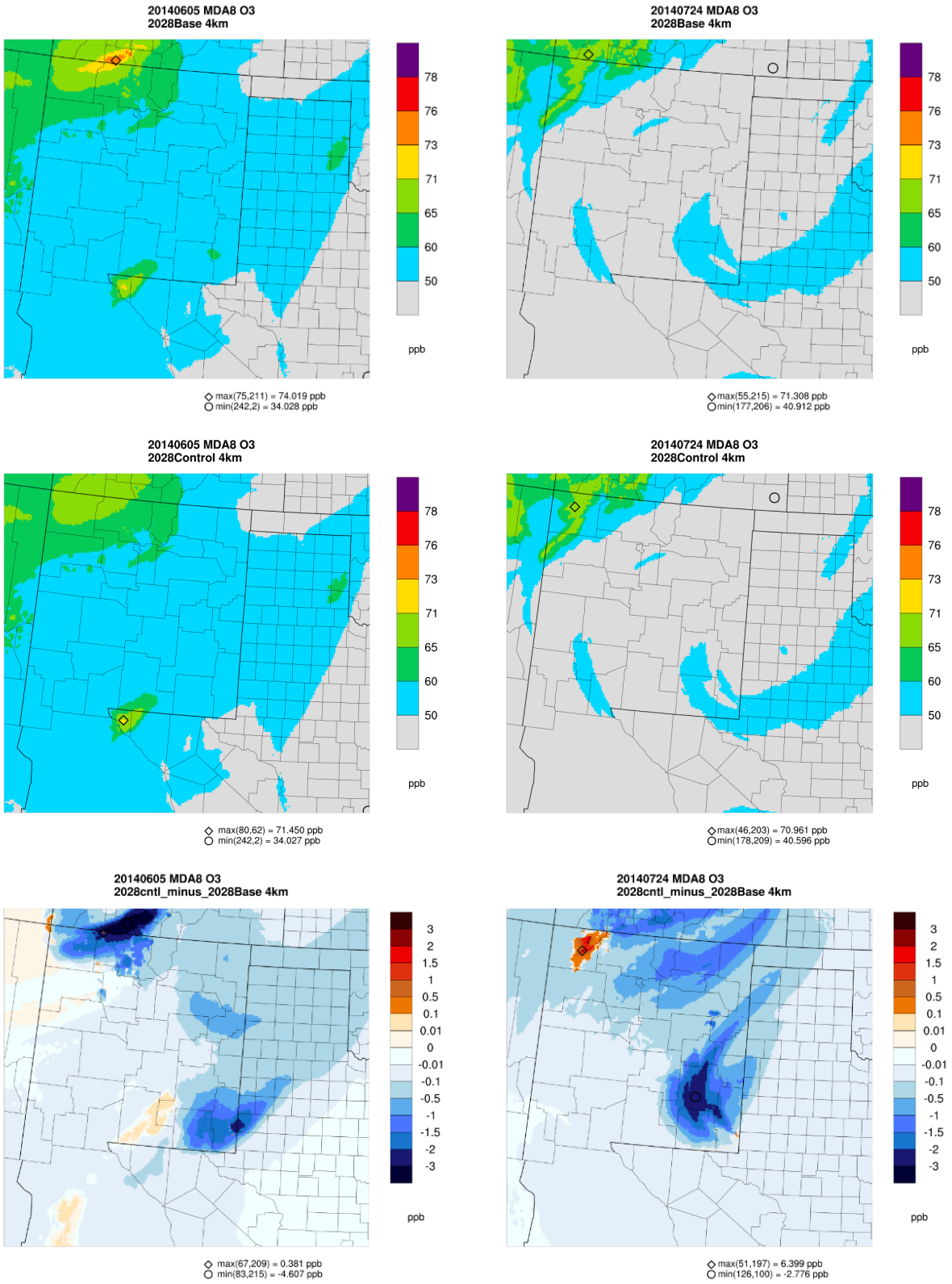


Figure 15. Daily MDA8 ozone concentrations (ppb) on June 5, 2014 (left) and July 24, 2014 (right) for the 2028 base case (top), 2028 O&G control strategy (middle) and their differences (bottom).

X. Sensitivity of the 2028 Ozone DVF Projections to Current Year Ozone DVC

Although the projected 2028 ozone DVF for the 2028 base and 2028 O&G control strategy cases are below the 70 ppb 2015 ozone NAAQS at all monitoring sites in New Mexico when using the current year DVC from 2012-2016 ($DVC_{2012\text{-}2016}$) following EPA's 2018 modeling guidance, in more recent years there has been an increase in observed ozone DVs at some monitoring sites in southern New Mexico. For example, at the Desert View site in Doña Ana County the most recent $DV_{2017\text{-}2019}$ is 77 ppb, which is 5 ppb higher than the $DVC_{2012\text{-}2016}$ (72.0 ppb) used in the 2028 ozone DVF projections when following the EPA 2018 PCM Guidance. And the most recent $DV_{2017\text{-}2019}$ at the Carlsbad site in Eddy County (79 ppb) is 7.7 ppb higher than the $DVC_{2012\text{-}2016}$ (71.3 ppb). Thus, I examined the sensitivity of the 2028 ozone DVF projections to the observed current year DVC. Instead of using the $DVC_{2012\text{-}2016}$ as the starting point for the 2028 ozone DVF projections, I used an average of three ozone design values from 2015-2019 5-year period (i.e., $DVC_{2015\text{-}2019}$) as well as the DV from 2017-2019 (i.e., $DVC_{2017\text{-}2019}$). Note that the CAMx 2014v2 Base Case modeling results used in the denominator of the RRFs to make the 2028 ozone DVF projections does not account for the changes in emissions between 2014 and the more recent years (i.e., 2015-2019 and 2017-2019) that affect the magnitude of the ozone $DVC_{2015\text{-}2019}$ and $DVC_{2017\text{-}2019}$. This includes emission reductions from mobile sources, as well as emission increases from O&G sources. Thus, because the 2014 emission conditions used in the CAMx 2014v2 base case do not represent the emissions conditions that produced the observed current year $DVC_{2015\text{-}2019}$ and $DVC_{2017\text{-}2019}$, the DVC sensitivity analysis of projected 2028 ozone DVFs has additional uncertainties and will likely overstate 2028 ozone DVFs in and near the Permian Basin where the more current year O&G emissions are higher than they were in 2014, and understate the DVFs in areas not affected by

O&G emissions away from the Permian Basin that are more affected by reductions in mobile source emissions in the more recent years.

The 2028 projected ozone DVFs for the 2028 base case using the $DVC_{2015\text{-}2019}$ have one monitoring site that exceeds the 2015 ozone NAAQS, 71.2 ppb at Carlsbad (Table 6). The next highest 2028 ozone DVFs for the 2028 Base Case are 69.3 ppb at Carlsbad Caverns NP and 69.1 ppb at Desert View. The emissions controls in the 2028 O&G control strategy are sufficient to reduce the 2028 Base Case ozone DVF at Carlsbad (71.2 ppb) to below the ozone NAAQS (70.9 ppb) using the $DVC_{2015\text{-}2019}$ current year design value in the 2028 ozone DVF projections.

Table 6. Projected 2028 ozone DVFs for the 2015-2019 current year design value $DVC_{2015\text{-}2019}$ sensitivity analysis.

AQS_ID	2015-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	69.0	63.4	63.1	-0.3	Del Norte HS	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	Bernalillo
350011012	69.0	62.7	62.4	-0.3	Foothills	Bernalillo
350130008	68.7	62.1	62.0	-0.1	La Union	Doña Ana
350130020	70.7	65.7	65.7	0.0	Chaparral	Doña Ana
350130021	74.3	69.1	68.9	-0.2	Desert View	Doña Ana
350130022	74.0	68.6	68.5	-0.1	Santa Teresa	Doña Ana
350130023	67.7	62.9	62.7	-0.2	Solano	Doña Ana
350151005	73.7	71.2	70.9	-0.3	Carlsbad	Eddy
350153001	71.0	69.3	69.3	0.0	Carlsbad Caverns NP	Eddy
350250008	69.3	67.2	66.5	-0.7	Hobbs Jefferson	Lea
350390026	66.3	63.0	62.2	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	67.0	61.2	60.9	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	67.0	63.6	62.8	-0.8	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	67.3	64.2	62.9	-1.3	Substation	San Juan
350490021	65.0	61.2	61.0	-0.2	Santa Fe Airport	Santa Fe
350610008	66.7	62.6	62.3	-0.3	Los Lunas (Los Lentes)	Valencia

Table 7 shows the results of the 2028 ozone DVF projection current year ozone design value sensitivity analysis using the latest 2017-2019 ozone design value ($DVC_{2017\text{-}2019}$) as the starting point for the 2028 ozone DVF projections. There are three monitors in New Mexico with

$DVC_{2017\text{-}2019}$ above the 75 ppb 2008 ozone NAAQS: Desert View (77.0 ppb), Santa Teresa (76.0 ppb) and Carlsbad (79 ppb). These $DV_{2017\text{-}2019}$ values are, respectively, 5.0, 4.7 and 10.0 ppb higher than the $DVC_{2012\text{-}2016}$ used as the ozone projection starting point in the 2028 ozone DVF projections presented previously following the EPA 2018 PCM Guidance. There are an additional three sites with $DVC_{2017\text{-}2019}$ above the 70 ppb 2015 ozone NAAQS but below the 75 ppb 2008 ozone NAAQS.

For the 2028 base case, there are two sites with projected 2028 ozone DVFs with values above the 70 ppb 2015 ozone NAAQS in the $DVC_{2017\text{-}2019}$ current year design value sensitivity test: 71.6 ppb at Desert View and 76.4 ppb at Carlsbad. The 76.0 ppb $DV_{2017\text{-}2019}$ at Santa Teresa is reduced to 70.5 ppb under the 2028 Base Case, so attains the 2015 ozone NAAQS.

The projected 2028 ozone DVF using the $DVC_{2017\text{-}2019}$ as the current year DVC under the 2028 O&G control strategy are 71.4 ppb at Desert View and 76.0 at Carlsbad, so still exceed the 2015 ozone NAAQS. In fact, the Carlsbad 76.0 ppb ozone DVF even exceeds the 2008 ozone NAAQS.

In addition to the uncertainties and bias in the 2028 ozone DVF projections introduced by using the ozone $DVC_{2015\text{-}2019}$ and $DVC_{2017\text{-}2019}$ that do not overlap with the 2014 base modeling year, the $DVC_{2017\text{-}2019}$ 2028 ozone DVF projection sensitivity analysis has additional uncertainties as it is only based on 3-years of ozone monitoring data and EPA recommends using 5-years of observed ozone concentrations in the DVC to help mitigate the effects of year-to-year variability in the observed ozone concentrations.

Table 7. Projected 2028 ozone DVFs for the 2017-2019 current year design value $DVC_{2017-2019}$ sensitivity analysis.

AQS_ID	2017-19	Projected 2028 DVF			Site Name	County
	DVC (ppb)	Base (ppb)	Cntl (ppb)	Cntl - Base		
350010023	70.0	64.3	64.0	-0.3	Del Norte HS	Bernalillo
350010029	67.0	61.9	61.4	-0.5	South Valley	Bernalillo
350011012	71.0	64.5	64.2	-0.3	Foothills	Bernalillo
350130008	70.0	63.3	63.2	-0.1	La Union	Doña Ana
350130020	73.0	67.8	67.8	0.0	Chaparral	Doña Ana
350130021	77.0	71.6	71.4	-0.2	Desert View	Doña Ana
350130022	76.0	70.5	70.3	-0.2	Santa Teresa	Doña Ana
350130023	70.0	65.0	64.8	-0.2	Solano	Doña Ana
350151005	79.0	76.4	76.0	-0.4	Carlsbad	Eddy
350250008	71.0	68.9	68.1	-0.8	Hobbs Jefferson	Lea
350390026	67.0	63.6	62.8	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	68.0	62.1	61.8	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	68.0	64.6	63.7	-0.9	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	69.0	65.8	64.5	-1.3	Substation	San Juan
350490021	66.0	62.2	62.0	-0.2	Santa Fe Airport	Santa Fe
350610008	68.0	63.8	63.5	-0.3	Los Lunas (Los Lentes)	Valencia

XI. CAMx 2023 Source Sector APCA Ozone Source Apportionment Modeling

The CAMx 2023 Source Sector APCA ozone source apportionment obtained separate ozone contributions due to emissions from several source regions (e.g., New Mexico) and source sectors (e.g., O&G point sources) using the Anthropogenic Precursor Culpability Assessment ("APCA") version of the CAMx ozone source apportionment tool and the 2028 O&G control strategy emissions scenario. Separate ozone contributions were obtained for the following 9 source categories:

1. NAT: Natural (biogenic, lightning NO_x, windblown dust and oceanic [sea salt and dimethyl sulfide]).
2. FIR: Fires (U.S. wildfires, wildland prescribed burns and agricultural burning and other [Mexico/Canada] fires).

3. O&GPT: Oil and gas point sources (surrogate for midstream O&G).
4. O&GNP: Oil and gas non-point sources (surrogate for upstream O&G).
5. EGU: Electrical Generating Unit point sources.
6. NonEGU: Non-EGU point sources.
7. OnRoad: On-road mobile.
8. NonRoad: Non-road mobile.
9. OAnth: Remainder anthropogenic.

The ozone contributions due to New Mexico anthropogenic emissions for each source sector were removed from the CAMx 2028 O&G control strategy ozone results and SMAT was used to estimate the New Mexico source sector contributions to the projected 2028 ozone DVFs that are shown in Table 8. Sites in northern New Mexico have the highest contributions from O&G sources and EGU point sources due to being in or near the San Juan Basin and in close proximity to the Four Corners Power Plant that is assumed to still be operating in 2028. Sites in central New Mexico (e.g., Bernalillo County) tend to have higher ozone contributions associated with sources related to population (e.g., mobile sources and other anthropogenic) due to being in or within proximity of Albuquerque, New Mexico's largest city. Sites in southern New Mexico include those in southern Doña Ana County on the border with Texas that tend to have mostly small contributions from New Mexico source sectors with the exception of EGU (0.7 to 0.9 ppb), due to the proximity of the Rio Grande Power Plant to some of the sites, and on-road mobile (0.4-0.5 ppb) due to population centers along I-25, with the Solano monitor having higher ozone contributions from mobile sources due to being close to emissions from the City of Las Cruces, the second largest city in New Mexico. Finally, the Carlsbad and Hobbs monitors are within the Permian Basin so have relatively high contributions from New Mexico O&G sources.

Table 8. Reduction in 2028 O&G control strategy ozone DVFs due to the elimination of ozone contributions due to New Mexico emissions from 7 anthropogenic emissions source sectors.

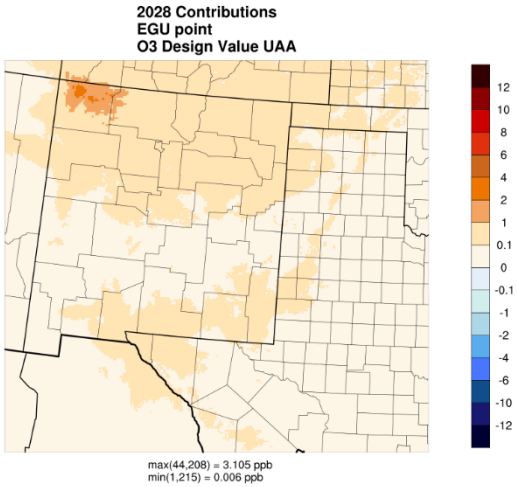
AQS_ID	Site_ID	DVC	DVF	O&GPT	O&GNP	EGU	NonEGU	OnRoad	NonRoad	OAnth
Northern New Mexico										
350390026	COYOT	64.0	60.0	-0.2	-0.5	-0.5	0.0	-0.2	-0.1	0.0
350450009	BLOOM	64.3	60.2	-0.7	-1.4	-1.9	0.0	-0.4	-0.1	-0.1
350450018	NAVAJ	67.0	63.3	-0.9	-2.1	-1.7	-0.1	-0.4	-0.2	-0.1
350451005	SUBST	63.7	59.6	-0.6	-1.5	-3.1	-0.1	-0.5	-0.2	-0.2
Central New Mexico										
350010023	NORTE	66.3	60.7	-0.2	-0.3	-0.5	-1.0	-2.7	-2.0	-3.6
350010024	SEHGS	68.0	62.0	-0.2	-0.3	-0.5	-1.1	-2.5	-1.9	-3.2
350010029	STHVA	66.0	60.5	-0.3	-0.5	-0.5	-1.0	-2.2	-1.7	-2.4
350010032	WSTSD	67.0	62.1	-0.2	-0.4	-0.4	-0.4	-1.6	-1.2	-1.8
350011012	FTHIL	65.0	58.8	-0.2	-0.3	-0.5	-0.7	-2.5	-2.0	-3.0
350431001	BERNA	64.0	58.1	-0.1	-0.2	-0.4	-0.4	-2.1	-1.5	-1.9
350490021	SNTFE	64.3	60.4	-0.2	-0.3	-0.2	-0.3	-1.2	-0.7	-0.8
Southern New Mexico										
350130008	UNION	66.3	59.8	-0.2	-0.2	-0.7	0.0	-0.5	-0.3	-0.1
350130017	SPARK	67.0	61.8	-0.2	-0.2	-0.9	0.0	-0.4	-0.2	-0.2
350130020	CHAPA	67.0	62.2	-0.1	-0.1	-0.3	0.0	-0.2	-0.1	-0.1
350130021	DSVIE	72.0	66.8	-0.2	-0.3	-0.9	-0.1	-0.5	-0.3	-0.2
350130022	TERES	71.3	66.0	-0.3	-0.3	-0.7	-0.1	-0.5	-0.3	-0.2
350130023	SOLAN	65.0	60.2	-0.2	-0.2	-0.2	-0.2	-1.2	-0.7	-0.3
350151005	CARLS	69.0	66.4	-0.5	-0.5	-0.2	-0.1	-0.3	-0.2	-0.1
350171003	GRANT	62.0	58.9	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0
350250008	HOBBS	66.0	63.3	-0.9	-1.1	-0.2	0.0	-0.3	-0.2	-0.1
350290003	DEAIR	66.0	62.5	-0.2	-0.1	-0.2	0.0	-0.6	-0.4	0.0

The SMAT UAA feature was used to estimate the spatial distribution 2028 ozone DVFs across the 4-km New Mexico domain for the 2028 O&G control scenario without New Mexico emissions from each of the 7 anthropogenic emission source sectors as shown in Figures 17 and 18. Removing New Mexico EGU emissions results in a reduction in the 2028 ozone DVF by as much as 3.1 ppb in San Juan County with ozone reductions of 0.1 to 1.0 ppb in the upper half of New Mexico and from Doña Ana to Lea Counties in southern New Mexico (Figure 17a). The removal of New Mexico Non-EGU Point emissions results in a reduction of 1.3 ppb in eastern

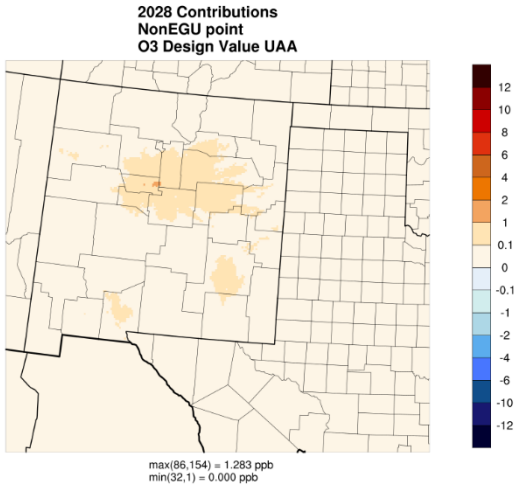
Bernalillo County and reductions of 0.1 to 1.0 in adjacent counties, with little effect over the rest of New Mexico away from Bernalillo County (Figure 17b). New Mexico on-road mobile contributes as much as 2.6 ppb to the 2028 ozone DVF, with reductions of 1-2 ppb stretching from Albuquerque to Santa Fe and in Las Cruces (Figure 17c). New Mexico non-road mobile contributes as much as 2.1 ppb in Bernalillo County (Figure 17d). New Mexico Non-Point O&G has large (> 2 ppb) contributions to the 2028 ozone DVF in the San Juan and Permian Basins (Figure 18a). Whereas, New Mexico Point O&G contributes as much as 1-2 ppb in the Permian Basin but less than 1 ppb in the San Juan Basin (Figure 18b). The Other Anthropogenic Source Sector contributions has a similar distribution to the two mobile Source Sectors with the highest ozone contributions centered on Bernalillo County (Figure 18c).

1

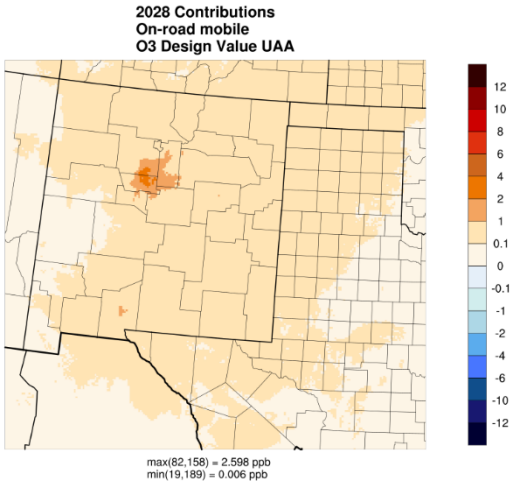
(a)



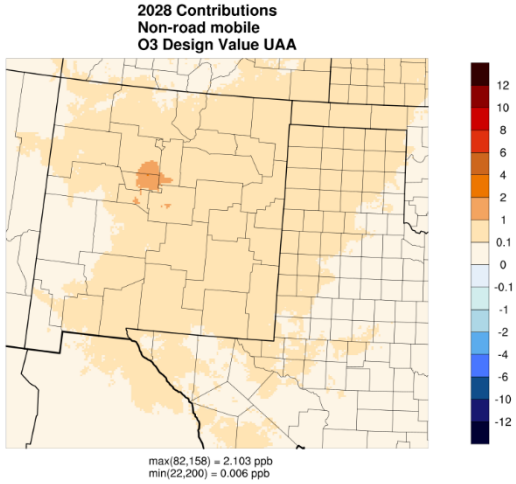
(b)



(c)

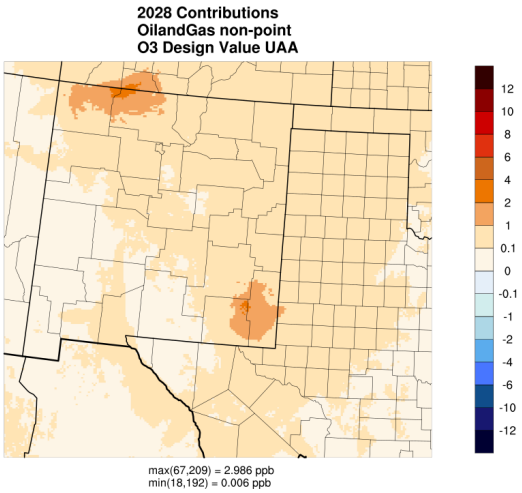


(d)

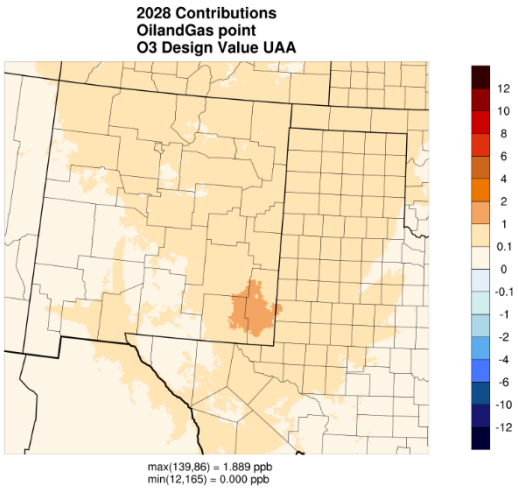


2 **Figure 17. Reduction in 2028 O&G control strategy ozone DVF due to removal of New**
3 **Mexico Source Sector emissions for: (a) EGU Point; (b) Non-EGU Point; (c) On-Road**
4 **Mobile; and (d) Non-Road Mobile.**
5

a)



(b)



(c)

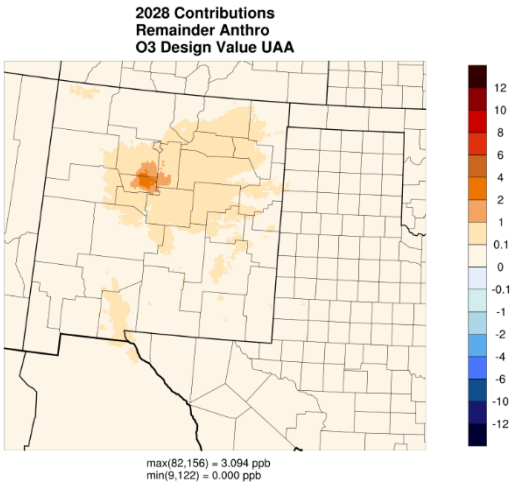
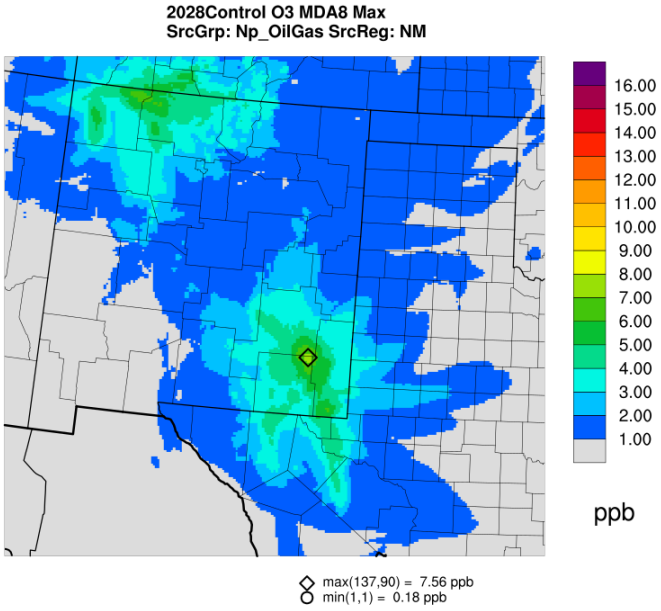


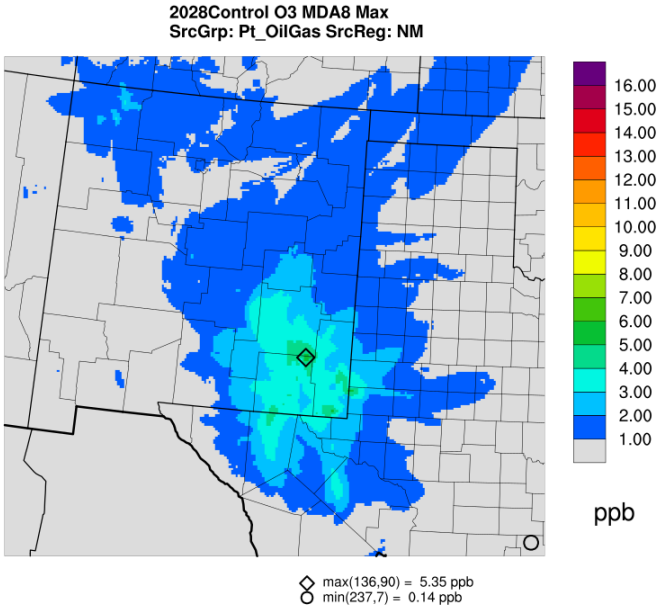
Figure 18. Reduction in 2028 O&G control strategy ozone DVF due to removal of New Mexico Source Sector emissions for: (a) Non-Point O&G; (b) Point O&G; and (c) Other Anthropogenic.

Figure 19 displays the episode maximum MDA8 ozone contributions due to emissions in New Mexico from the non-point and point O&G source sectors. There are substantial ozone contributions (e.g., > 5 ppb) to MDA8 ozone due to non-point O&G in both the Permian and San Juan Basins, with a maximum value of 7.6 ppb in the northeast corner of Eddy County in the Permian Basin. The New Mexico point O&G source sector has lower contributions than non-point O&G, especially in the San Juan Basin, with a peak MDA8 ozone contribution of 5.4 ppb

at the same location in the northeast corner of Eddy County that the non-point O&G peak occurred (i.e., total episode maximum O&G contribution of 13 ppb). Thus, even with implementation of the proposed requirements in Part 50, New Mexico O&G emissions in 2028 are still estimated to have substantial contributions to MDA8 ozone concentrations in New Mexico.



1



2

3 **Figure 19. Episode maximum MDA8 ozone contribution due to emissions from the New**
4 **Mexico non-point (top) and point (bottom) O&G emissions source sector from the CAMx**
5 **2028 O&G control strategy source sector APCA ozone source apportionment simulation.**

XII. CAMx 2028 VOC/NO_X Sensitivity OSAT Ozone Source Apportionment Modeling

A second CAMx 2028 O&G control strategy ozone source apportionment simulation was conducted to examine whether ozone formation resulting in high ozone concentrations in New Mexico is more sensitive to VOC or NO_X emissions. The VOC/NOx sensitivity ozone source apportionment simulation used the Ozone Source Apportionment Technology ("OSAT") version of the CAMx ozone source apportionment tool. When ozone is formed in CAMx, OSAT determines whether ozone formation is more VOC or NOx sensitive, and assigns a fraction of the ozone formed to either the OSAT source group's O3V (VOC sensitive) or O3N (NO_X sensitive) ozone tracers based on the relative contribution of the source group's limiting precursor contribution (i.e., VOC or NO_X). Thus, comparing the OSAT O3V and O3N tracers provides an indication of whether ozone formation is more sensitive to VOC or NO_X precursors. I developed the percent contribution of NO_x sensitive ozone formation metric (%NOxSens) to display the degree that ozone formation is more sensitive to VOC or NO_X as follows:

$$\text{Percent } NO_x \text{ Sensitive Ozone (\%NOxSens)} = 100 \times \sum O3N_i / \sum (O3V_i + O3N_i)$$

where the sum is performed over the source groups (i) being analyzed. In the displays below I present spatial maps of the %NOxSens metric for the following summed source groups:

- All emission source groups in the 36/12/4-km modeling domains (anthropogenic and natural);
- Anthropogenic emission source groups in the 36/12/4-km modeling domains (U.S. and international); and
- New Mexico anthropogenic emission source groups.

To interpret the %NOxSens for the above three summed source groups, I also present the MDA8 ozone contribution of the summed source groups to understand whether the level VOC

and NO_X ozone formation sensitivity occurs under elevated MDA8 ozone conditions or not. Example %NOxSens results are presented below for the three source groups listed above and two example days in detail and then 15 days for the total anthropogenic emissions source group.

On June 5, 2014 CAMx estimates high MDA8 ozone concentrations in excess of the 70 ppb ozone NAAQS in the San Juan Basin and El Paso under the 2028 O&G control strategy scenario (Figure 20a). In these high ozone locations, ozone formation is split approximately equally between VOC and NO_x sensitive ozone formation conditions (Figure 20b). When looking at just anthropogenic emissions, ozone formation tends to be more NO_x sensitive with %NOxSens ranging from 60-85% in El Paso and 70-85% in San Juan Basin (Figure 20d). Ozone from New Mexico anthropogenic emissions is mainly NO_x sensitive in El Paso on June 5th, but in the San Juan Basin there is more VOC sensitive ozone formation, with New Mexico anthropogenic emissions ozone contribution ranging from 1 to 4 ppb (Figure 20e and 20f). In particular, there are large areas of blue shaded %NOxSens ozone in San Juan County due to New Mexico anthropogenic emissions indicating that New Mexico VOC and NO_x anthropogenic emissions are approximately equally important to ozone formation in San Juan County on this day (Figure 20f). On the other hand, ozone formation within the Permian Basin appears to be more NO_x sensitive on June 5th.

On July 24th, the peak MDA8 ozone in the 4-km domain is above the NAAQS (71.1 ppb) and occurs in San Juan County (Figure 21a). Although ozone formation is primarily NO_x sensitive across the 4-km NM domain, the largest VOC sensitive ozone (23%) due to all emissions (%NOxSens = 77%) occurs at the location of the peak ozone in San Juan County (Figure 21b).

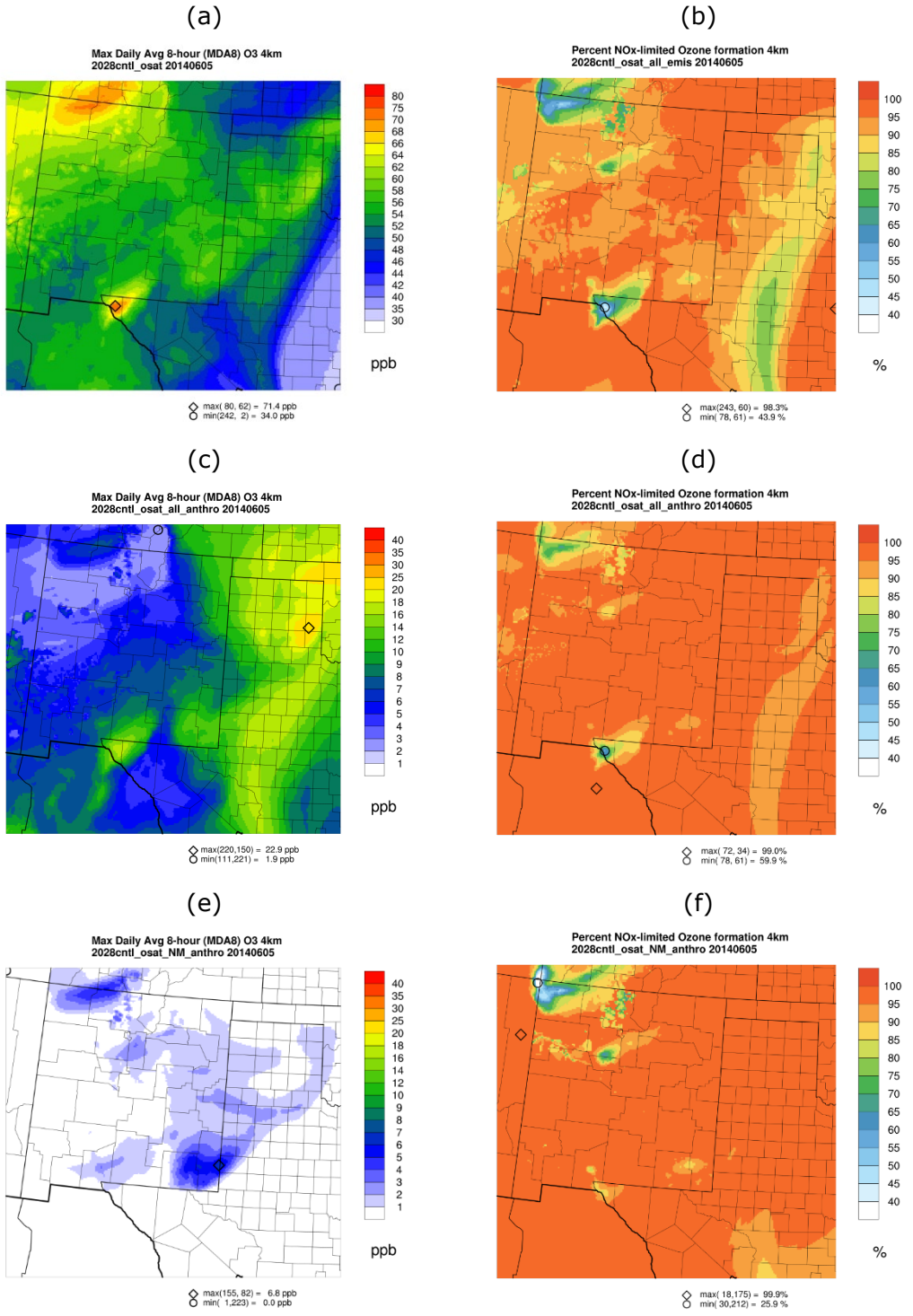


Figure 20. 2028 O&G control strategy MDA8 ozone (left) and Percent NOx Sensitive Ozone (right) on June 5, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

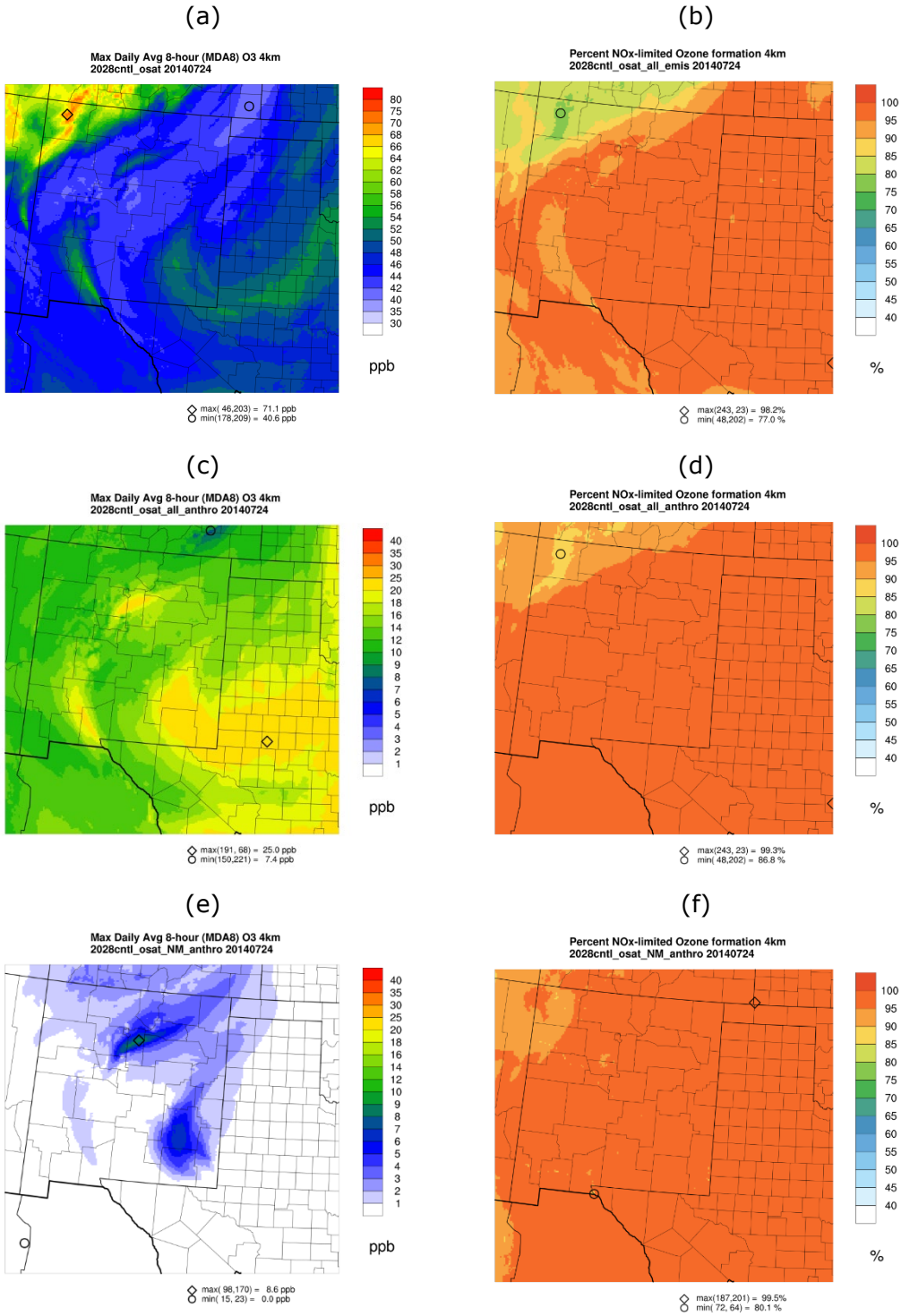


Figure 21. 2028 O&G control strategy MDA8 ozone (left) and Percent NOx Sensitive Ozone (right) on July 24, 2014 for: (a) total MDA8 ozone; (c) ozone due to anthropogenic emissions; (e) ozone due to New Mexico anthropogenic emissions; (b) %NOxSens for all emissions; (d) %NOxSens for all anthropogenic emissions; and (f) %NOxSens for New Mexico anthropogenic emissions.

Figure 22 displays the spatial distribution of the %NOxSens metric due to 2028 O&G control strategy New Mexico anthropogenic emissions for 15 example days from the May-August 2014 modeling episode. As expected, given its mostly rural nature, the CAMx OSAT simulation estimates that ozone formation due to New Mexico anthropogenic emissions is primarily NO_x sensitive across most of New Mexico. However, there are several locations where ozone formation is estimated to have relatively higher VOC sensitive ozone formation conditions. The San Juan Basin consistently has higher VOC sensitive ozone formation conditions due to New Mexico anthropogenic emissions. Albuquerque also has higher VOC sensitive ozone formation conditions due to New Mexico anthropogenic emissions, and occasionally, ozone formation in the Permian Basin also has relatively higher VOC sensitive ozone formation. The highest MDA8 ozone concentrations also tend to have relatively higher VOC sensitive ozone formation conditions. For example, at the location of the relatively high (58 ppb) MDA8 ozone in San Juan County on May 26th the fraction of VOC sensitive ozone is 32% for all emissions, 31% for all anthropogenic emissions and 55% for New Mexico anthropogenic emissions (Figure 22, top middle). On May 28th an ozone peak in the Permian Basin is split 75%/25% NO_X/VOC sensitive ozone (Figure 22, top right). June 5th is a day where there is high MDA8 ozone in San Juan and Rio Arriba Counties that is approaching the NAAQS that is split approximately equally between VOC and NO_X sensitive ozone (Figure 20 and Figure 22, second row right). On August 14th the modeled ozone peak exceeds the ozone NAAQS in El Paso and ~70% of the ozone was formed under NOx sensitive conditions (Figure 22, bottom middle).

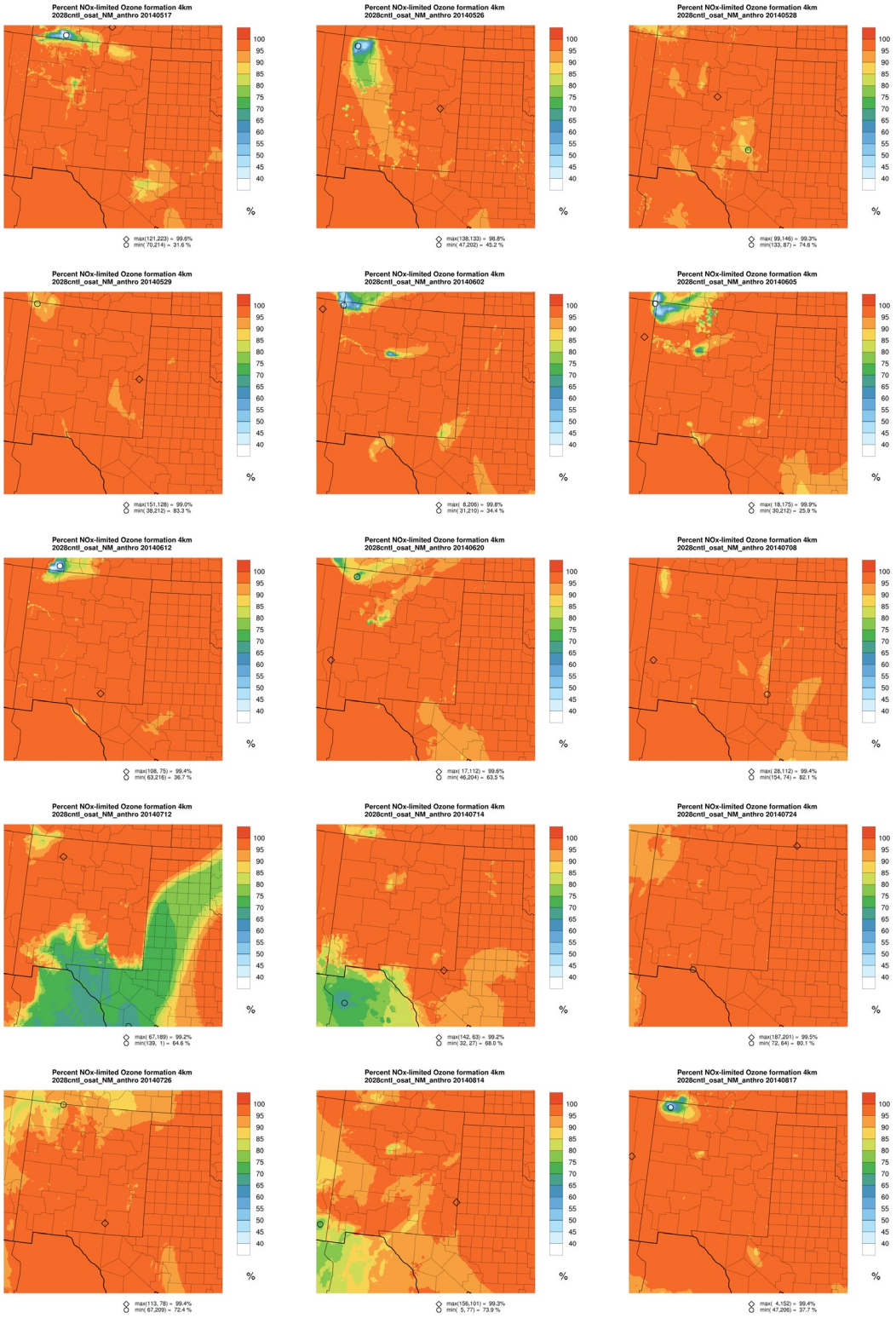
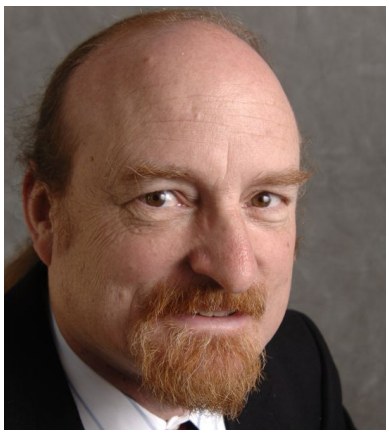


Figure 22. Spatial distribution of Percent NO_x Sensitive Ozone due to New Mexico anthropogenic emissions across the 4-km New Mexico domain for 15 days of relatively higher MDA8 ozone concentrations.

RALPH E MORRIS

Managing Principal



Ralph Morris is the Managing Principal at Ramboll's North California, Utah and Colorado Offices, where he directs air quality modeling and analysis, emission inventory development, control strategy evaluation, and regulatory air issues projects. With over 40 years of air quality consulting experience, Ralph is one of the original developers of many of the photochemical air quality models that are being or have been used for regulatory decision making in the United States and around the world, including co-developer of Ramboll's Comprehensive Air Quality Model with extensions (CAMx) as well as the UAM and UAM-V models.

In the late 1970s and 1980s, Ralph was one of the pioneers in modeling air pollution in Los Angeles using one of the first ever photochemical grid models (PGM), the Urban Airshed Model (UAM). In the late 1980s, Ralph performed the EPA Five Cities UAM Study for the United States Environmental Protection Agency (USEPA) that demonstrated the use the UAM PGM for ozone air quality planning culminating in the delivery of the UAM to USEPA in 1990 as the USEPA-recommended (Appendix W) ozone model. In the late 1980s and early 1990s, Ralph developed the next generation variable grid PGM (UAM-V) that treats urban and regional transport issues within the same nested grid model that was used by the Ozone Transport Assessment Group (OTAG) to define the first regional control strategies designed to reduce the contributions of ozone transport in the eastern U.S. (i.e., NO_X SIP Call). Ralph also led the development of ozone and $PM_{2.5}$ State Implemental Plans (SIPs) for numerous cities to allow them to achieve clean air. After joining Ramboll in 1994 (then called ENVIRON), Ralph was one of the leaders in the development of the Comprehensive Air-quality Model with extensions (CAMx) PGM that is still being used today around the world for air quality planning, including for USEPA's transport rules. During the 1990s Ralph was involved in numerous ozone and $PM_{2.5}$ SIP modeling studies and analyzed long-range transport of air pollutants.

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In the 2000s, Ralph directed the development of an updated Pollutants in the ATmosphere for Hong Kong (PATH) air quality modeling system for the Hong Kong Environmental Protection Department (HKEPD) and applied it to southeast Asia to assess regional transport and urban ozone and particulate matter formation. During this time he also directed the application of regional particulate matter (PM), ozone and visibility modeling using CMAQ and CAMx photochemical grid models for the southeastern (VISTA/ASIP), western (WRAP) and central (CENRAP) U.S. Regional Planning Organizations (RPOs) for the development of the first round of regional haze State Implementation Plans (SIPs) due in 2007.

For almost two decades, Ralph led regional air quality modeling for Alberta Environment for a variety of issues including to assess the air and ecological impacts of oil sands, development of modeling databases for various regions in Alberta and most recently to model the high winter $PM_{2.5}$ occurrences in Edmonton and Red Deer. He led or is leading the application of the CMAQ and CAMx models to address

numerous ozone and $PM_{2.5}$ State implementation Plans (SIPs), as well as to address other air quality and air quality-related value (AQRV) issues associated with oil and gas development projects. Ralph has also addressed NO_2 and SO_2 issues including SIPs. Ralph was an original member of USEPA's ozone and fine particulate guidance workgroup and the CMAS Models-3/CMAQ External Advisory Committee (EAC).

Ralph is currently leading the WRF meteorological, SMOKE emissions and CAMx and CMAQ photochemical modeling effort for the Western Regional Air Partnership (WRAP) to develop the western states Regional Haze SIPs. He is also currently leading the WRF/SMOKE/CAMx modeling efforts for the Denver ozone SIPs to address both the 2008 and 2015 ozone NAAQS as well as the Fairbanks Alaska $PM_{2.5}$ SIP efforts.

CAREER

1994-Present
Managing Principal
Ramboll (formerly Ramboll Environ and ENVIRON), Northern California, United States

1979-1994
Manager Advanced Modeling Group and Director of Model Development Program
ICF/Systems Applications International, San Rafael, California, United States

1978-1979
Associate Professor
University of California, Davis, California, United States

EDUCATION

1977-1979
MA, Mathematics
University of California, Davis, California, United States

1974-1976
BA, Mathematics
University of California, Berkeley, California, United States

1972-1974
University of California, San Diego, California, United States

EXPERIENCE

Over the last 40+ years, Ralph has been involved in thousands of air quality studies. These studies include the development of clean air plans for cities and states so that they attain the health-based air quality standards and the evaluation of the air quality impacts of numerous types of sources. any of the studies involved photochemical modeling, usually using CMAQ and/or CAMx, that required WRF meteorological and SMOKE emissions modeling as well. A few examples for some of Ralph's projects are provided below.

- **WRAP Regional Haze Photochemical Modeling**. Ralph led the development of photochemical modeling databases for western states used in the second round of regional haze SIPs due July 2021. For the Western Regional Air Partnership (WRAP), Ralph has set up the CMAQ and CAMx models for the 2014 calendar year and conducted model performance evaluation and 2028 future year modeling.
- **Denver 2020 and 2023 SIPs Ozone Attainment Demonstration Modeling.** Ralph just finished the 2020 Denver Serious ozone SIP modeling and is just starting the 2023 Denver ozone SIP ozone attainment demonstration modeling for the 2023 and 2026 future years. The CAMx PGM

was set-up for the 2016 summer ozone season using WRF meteorology and will be used for the 2023 and 2026 future year attainment demonstration modeling to address attainment of the 2015 and 2008 ozone NAAQS, respectively.

- **Allegheny County Annual $PM_{2.5}$ State Implementation Plan.** Project Director for performing the air quality modeling to define emissions control strategy to demonstrate that Allegheny County (Pittsburgh), Pennsylvania will attain the annual $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). Performed 36/12/4/1.30.444 km WRF meteorological modeling for the 2011 year. SMOKE emissions modeling for 2011 and 2021. CAMx regional 36/12 km modeling to provided boundary conditions for mesoscale 4/1.33 km PM source apportionment modeling for 2011 base and 2021 future years. 2021 PM control strategy evaluation.
- **Evaluation of USEPA's 2011 National Air Toxics Assessment (NATA**). Evaluated and assessed USEA's 2011 NATA modeling approach and results for modeling hundreds of air toxics compounds on a national scale. The 2011 NATA combined CMAQ national modeling results for reactive and non-reactive pollutants at 12 km grid cell resolution with AERMOD local-scale non-reactive modeling results by using the AERMOD results for receptors in the 12 km grid cell in a relative fashion to scale the CMAQ 12 km average concentrations. This unique method of model fusion of the CMAQ and AERMOD modeling results overcomes some of the issues associated with other techniques (e.g., CMAQ zero-out runs) when combining modeling results with disparate formulations.
- **Dynamic Evaluation of Ozone Models for the South Coast (Los Angeles) Air Basin (SoCAB).** Project Manager for conducting a dynamic evaluation of the CMAQ photochemical grid model in the SoCAB (Los Angeles, California region) using a 2008 and 2012 CMAQ modeling database. The dynamic evaluation compared the CMAQ modeled ozone trends over a long period (1990-2015) with the observed ozone trends and found the CMAQ model underestuimat6ed the observed rate of ozone reductions over time. Potential reasons for this included the likely underestimation of VOC or overestimation of NOx emissions in the region.
- **Denver 2017 Ozone SIP Modeling.** For almost two decades, Ralph has led the Denver ozone SIP modeling for the 2003, 2008 and 2017 Denver ozone SIPs. For the Denver 2017 ozone SIP modeling we developed 2011 CAMx PGM modeling database using WRF meteorological and SMOKE emissions modeling. This included high-resolution mobile source emissions for the Denver region using link-based activity data from a Transportation Demand Model (TDM) and mobile source emission factors from MOVES2014. Conducted CAMx 2011 base case modeling and model performance evaluation. Projected emission to 2017 and 2023 and conducted emission reduction control strategy modeling to demonstrate attainment of the ozone standard.
- **Allegheny County 1-Hour SO_2 State Implementation Plan.** Project Manager for performing the air quality modeling to define emissions control strategy to demonstrate that Allegheny County (Pittsburgh), Pennsylvania will attain the 1-hour SO_2 National Ambient Air Quality Standard (NAAQS). Perform 36/12/4/1.3 km WRF meteorological modeling for multiple years. Conduct model shoot-out using multiple models (e.g., AERMOD, CALPUFF and SCICHEM) and model configurations to determine best performing model for simulating SO_2 and use model to demonstrate attainment of the SO2 NAAQS.
- **BLM Environmental Impact Statement and Resource Management Plan for Oklahoma, Texas and Kansas.** Project Manager for preparing the air quality and climate change sections of the Environmental Impact Statement (EIS)/ Resource Management Plan (RMP) for the U.S. Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA) to guide the management of BLM- and BIA-administered lands in the states of Oklahoma, Texas and Kansas
- **Navajo Generating Station Environmental Impact Statement.** Project Manager for coordinating the Environmental Impact Statement (EIS) required under the National Environmental Policy Act (NEPA) for the Navajo Generating Station coal-fired power plant and Kayenta Coal Mine Complex in Arizona. Technical services include air quality modeling and analysis of air monitoring data for criteria and hazardous air pollutants, assessments of human health risk and ecological risk due to atmospheric deposition from the emission sources, and preparation of Technical Support Documents for the EIS.
- **Western Air Quality Study (WAQS).** Project Manager for WRF meteorological, SMOKE emissions and CMAQ/CAMx air quality modeling of the western U.S. to develop the next generation air quality

modeling databases to address ozone, $PM_{2.5}$, visibility and deposition issues in the western U.S.. Develop new 2008, 2011 and 2014 regional modeling platforms and distribute using the Intermountain West Data Warehouse (IWDW). Assess the role of regional transport on ozone, PM, and visibility issues in western U.S. states.

- **Air Quality Impacts of Off-Shore Oil and Gas Production.** Ralph led the photochemical modeling for two studies for BOEM to estimate the on-shore air quality impacts due to off-shore oil and gas development in the Arctic Sea north of Alaska and the Gulf of Mexico. This multi-year multi-million dollar study projected future year emissions and air quality impacts and developed emission exception screening thresholds.
- **Air Quality Impacts of Fires**. Project Manager of studies to assess the contributions of wildfires, prescribed burns and agricultural burning to ozone and PM air quality throughout the USA. Developed fire emission inventories and use the CAMx photochemical grid model source apportionment tool to calculate the contributions of fires to ozone and PM air quality. Results are used to identify exceptional events and assist planners in fire management practices.
- **BLM Montana/Dakotas Photochemical Grid Model Modeling Study.** Project Manager for the BLM Montana/Dakotas PGM modeling study to assess the air quality and AQRV impacts due to oil and gas development. The Bakken Shale formation in the Montana/Dakotas region is one of the most rapidly growing oil and gas development area in the U.S. Under this study, Ramboll is developing a comprehensive oil and gas emissions inventory and performing base year 2012/2013 and future year 2032 modeling using the CAMx photochemical grid model.
- **Allegheny County 24-Hour $PM_{2.5}$ SIP Modeling.** The $PM_{2.5}$ problem in Allegheny County (Pittsburgh), Pennsylvania is due to a combination of regional transport from upwind states and local sources within a river valley complex terrain environment. Ralph Morris led the Allegheny County $PM_{2.5}$ SIP modeling effort that used the CAMx photochemical grid model with a 36 km CONUS, 12 km Midwest, 4 km southeastern Pennsylvania and 0.8 km Allegheny County grid nests to demonstrate the area would achieve the 24-hour $PM_{2.5}$ standard by 2010. CAMx was run on the 36/12/4/0.8 km grids using two-way grid nesting. Local sources were treated using the CAMx subgrid-scale Plume-in-Grid treatment.
- **Development of Air Quality Modeling System for Hong Kong**. Ralph was Project Manager and led the development of a new air quality modeling system for Hong Kong. The WRF/MM5 meteorological, SMOKE/CONCEPT emissions and CMAQ/CAMx air quality models were set up for a 27/9/3/1 km modeling domain with the 36 km domain covering Asia and the 1 km domain focused on Hong Kong. The modeling system was delivered to the HKEPD as a turn-key system.
- **St. Louis Ozone and $PM_{2.5}$ SIP.** Ralph led the air quality modeling efforts for the development of clean air plans for St. Louis, Missouri that were included in the St. Louis ozone and $PM_{2.5}$ State Implementation Plans (SIPs). He worked with the states of Missouri and Illinois to identify the optimal control plan for the region and performed air quality modeling to demonstrate that St. Louis would achieve the ozone and $PM_{2.5}$ standards.
- **Air Quality Assessments in Alberta, Canada**. For over a decade, Ralph Morris has been leading air quality studies for Alberta Environment to address Canada wide standards and Province air quality goals and objectives. These activities have included developing emission inventories for the Alberta oil sands region and urban areas, conducting meteorological modeling and performing air quality modeling using the CMAQ model to address ozone, $PM_{2.5}$, SO_2, NO_2, exposure and deposition issues in the Province.
- **Expert Testimony for Air Quality Related Issues**. Because of Ralph's vast expertise in air quality issues and in particular air quality modeling, for over two decades he has served as an expert witness in numerous litigation cases.
  - Ameren Rush Island: Ralph was an expert witness and testified at trial in St. Louis April 2019 in a case where the Rush Island coal-fired power plant was accused of causing health effect impacts due to alleged illegal emissions since it failed to obtain a PSD permit and install BACT.
  - LG&E Cane Run Class Action Suit: Starting in 2015, Mr. Morris served as an expert witness led by Hunton and Williams in a Class Action case involving nuisance dust deposition from the Louisville Gas and Electric Cane Run coal-fired EGU. He discovered a fatal flaw in the opposing experts AERMOD modeling analysis that undermined the class action arguments.

- Minnesota Power Plant Damage Assessment: During 2015, Ralph performed air quality modeling of the potential damages and costs associated with fossil-fueled power generation in Minnesota and prepared testimony.
- Mead Westvaco Luke Mill: Expert witness and testified at trial in a case where a Maryland paper mill was accused of violating the Clean Air Act (CAA) and emitting illegal emissions (2012-2016).
- DTE Energy Monroe: In 2010-2011 Ralph was retained as an expert witness by Hunton and Williams and prepared expert report and attended trial in Detroit for the USDOJ CAA NOV case against the Monroe coal-fired power plant in the Detroit, Michigan region.
- AEP NOV: Ralph was an expert witness for American Electric Power (AEP) from 2003-2006 through Sidley Austin in the US DOJ CAA NOV charges against 9 coal-fired power plants in the Midwestern US.
- Illinois Power/Dynegy Baldwin NOV: Ralph was an expert witness for Illinois Power through Akin Gump in the US DOJ CAA NOV case against the Baldwin Power Plant in Illinois. Ralph prepared expert reports and was deposed on the ozone and PM impacts of the alleged excess emissions including a review and critique of the plaintiffs CALPUFF modeling that found errors and omissions.
- First Energy Sammis: Expert witness for the Sammis coal fired power plant in Ohio NOV case.
- Louisiana Generating Big Cajun 2: Ralph was an expert witness for a USDOJ CAA NOV case against the Big Cajun 2 coal-fired power plant in Baton Rouge, Louisiana during 2012.
- WE Energies Power the Future: In 2004, Ralph performed air quality modeling using CAMx and testified in front of a judge in Madison, WI on the Wisconsin Electric's plans to retire an old and build a new coal fired power plant at the Oak Creek facility. Testimony also included a critical review of CALPUFF modeling performed by the opponents.
- Minnesota Acid Rain Legislation: In the early 1980s Ralph performed modeling and testified in Minneapolis, MN in front of a judge for Northern States Power regarding the impacts of local sources in Minnesota on acid deposition in Minnesota.

CALPUFF Modeling Experience. Ralph has been directing and using the CALPUFF model, and its predecessor MESOPUFF, for over 35 years. In fact, the Diagnostic Wind Model (DWM), which is the wind model component of CALMET that is part of the CALPUFF modeling system, was developed under Ralph's direction as part of the UAM modeling system and implemented in CALMET as part of its original development for the California Air Resources Board. Ralph's Experience with CALPUFF includes the following:

Mount Zirkel Visibility Study (MZVS): In the 1995-1997 period, Ralph led the CALPUFF modeling component of the MZVS that was assessing the visibility impacts of the Hayden and Craig coal-fired power plants in northern Colorado on visibility impairment at the Mount Zirkel Class I Area.

PSD Permitting Of New Sources: Ralph has directed and conducted CALPUFF model applications for numerous proposed new sources as part permitting under the U.S. Prevention of Significant Deterioration (PSD) program. CALPUFF was used to model the long-range transport of pollutants and assess their impacts at Class I and sensitive Class II areas for comparison against Significant Impact Levels (SILs) and PSD Increments as well as the Assessment of Air Quality Related Values (AQRVs, e.g., visibility and acid deposition). Example CALPUFF permitting for PSD applications include applications for

LSPower (e.g., Doswell Energy, Hanover, Virginia; White Pine Energy Development near Ely, Nevada; High Plains Energy Project northeast of Denver, Colorado; Sunrise River, Minnesota; Plum Point Unit II in Arkansas; West Deptford Energy Station in New Jersey

Holcim (now LaFarge) Ste. Genevieve Cement Plant: Holcim proposed to build the largest cement plan in the U.S. south of St. Louis and Ralph led the CALPUFF modeling component of the PSD permit.

NEPA Air Quality Modeling: In the U.S., proposed development on Federal land must disclose their environmental impacts under the National Environmental Policy Act (NEPA).

Ralph has led numerous NEPA air quality assessment that have included CALPUFF modeling for a variety types of sources, including oil and gas and energy development.
EPA Modeling Techniques: Ralph has assisted USEPA in developing and evaluating numerous air quality modeling techniques for 35 years. In 2012 Ralph published the results of several the definitive long-range transport model evaluation studies[1] that included the evaluation of CALPUFF and 5 other models against regional tracer test field experiments[2] that helped formulate EPA's latest January 2017 air quality modeling guidelines[3]. Ralph was also Principal-in-Charge in the development of the Mesoscale Model Interface (MMIF[4]) program the generates CALPUFF meteorological inputs directly from WRF model output without the need of CALMET.
Litigation Support: Ralph has used and critiqued the CALPUFF modeling system in several litigation cases, including the Illinois Power Baldwin coal-fired power plant case where Ralph's identification of errors introduced in the model by the Plaintiff's expert modifications resulted in them pulling their expert report.

- **Oil and Gas Environmental Impact Statements.** Ralph has led the air quality modeling component of several oil and gas Environmental Impact Statements to assess the air quality, visibility and deposition impact of oil and gas development in Colorado, Utah, Wyoming and New Mexico. These activities includes near-source AERMOD modeling and frequently regional PGM modeling.
- **Air Quality Permitting Studies.** As part of the permitting process, Ralph has conducted numerous air quality modeling studies to demonstrate that new sources would be compliant with air quality standard and thresholds of concern. Sources evaluated include coal and natural gas powered electricity generation; cement plans and oil and gas production, distribution and refining.
- **Air Quality Impacts of Mobile Sources**. Ralph has performed numerous studies to assess the air quality impacts of alternative engine technologies and fuels. In the 1980s he modeled the air quality impacts of alternative fuels in five cities for the USEPA. In the 1990s he led the air quality modeling component of the $20M Auto/Oil Program for the automobile manufacturers and oil companies. He also led the assessment of the air quality impacts of hybrid vehicles for a joint study by General Motors and Toyota. More recently he evaluated air quality impacts of passenger vehicles for Toyota and the air quality impacts in California due to the use of biodiesel in on-road and non-road diesel engines.
- **Technical Assistance to USEPA.** For over three decades, Ralph has provided technical assistance to the USEPA to assist them in implementing their air program and developing the USEPA air quality modeling techniques and guidelines. This assistance included developing guidance for plume modeling, demonstrating how photochemical grid models (PGMs) can be used in ozone air quality planning and delivering the UAM PGM to USEPA in 1990 as a turn-key PGM ozone modeling system. In 2012 Ralph evaluated six long range transport (LRT) models using atmospheric field study tracer tests, evaluated chemical dispersion models using aircraft data and demonstrated how a PGM can be used for single-source modeling that helped EPA formulate their latest January 2017 air quality modeling guidelines. More recently he is assisting USEPA to update the chemical mechanisms in the CAMx and CMAQ models and implement improved aqueous-chemistry and secondary organic aerosol modules.
- **Various Clients.** Prior to joining Ramboll, Ralph worked for over 15 years at Systems Applications International (SAI) in San Rafael (now part of ICF Consulting), California, where he was Director of the Advanced Modeling Program, managed model development activities and air quality modeling and analysis studies. His work at SAI included the development and application of the RPM, UAM, UAM-V and REMSAD modeling systems.

[1] https://www3.epa.gov/ttn/scram/reports/Single_Source_Compare_Final_Sep_2012v4.pdf
[2] https://www3.epa.gov/ttn/scram/reports/EPA-454_R-12-003.pdf
[3] https://www3.epa.gov/ttn/scram/appendix_w-2016.htm
[4] https://www.epa.gov/scram/air-quality-dispersion-modeling-related-model-support-programs

PEER-REVIEWED PUBLICATIONS

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Karamchandani, P., P. Vennam, T. Shah, D. Henn, A. Alvarez, G. Yarwood, R. Morris, B. Brashers, E,. Knipping and N. Kumar. Single Source Impacts on Secondary Pollutants using a LaGrange Reactive Puff Model: Comparison with Photochemical Grid Models. *Atmos. Env.* 237, 15 September 2020.

Posner, L.N., G. Theodoritsi, A. Robinson, G. Yarwood, B. Koo, R. Morris, M. Mavko, T. Moore and S. Pandis. 2019. Simulation of Fresh and Chemically-Aged Biomass Burning Organic Aerosol. *Atmos. Env.* 196 (2019) 27-37.

Brewer, P., G. Tonnesen, R. Morris, T. Moore, U. Nopmongcol and D. Miller. 2019. Air Pollutant Source Characterization using the Revised Regional Haze Tracking Metric and a Photochemical Grid Model and Implications for Regional Haze Planning". *J. Air & Waste Man. Assoc.*, Vol. 69, s019, Issue 3. (https://www.tandfonline.com/doi/full/10.1080/10962247.2018.1537985).

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PRESENTATIONS

Morris, R. Panel on $PM_{2.5}$ Implementation Issues – Treatment of Secondary $PM_{2.5}$. Presented at Air and Waste Management Association 114th Conference and Exhibition, June 14-17.

Morris, R. 2021. Assessment of the Ability of Photochemical Models to Reproduce Changes in Ozone in Response to Emission Changes due to COVID-19 Pandemic. Presented at 30th CRC Real World Emissions Workshop (Virtual), March 8-11.

Morris, R. 2020. Photochemical Modeling to Address Regional Haze State Implementation Plans for the Western States. Presented at A&WMA 113th Annual Conference and Exhibition, Virtual Conference. June 29 – July 2, 2020.

Morris, R. 2020. Visibility Panel – Issues Related to Western States Regional Haze State Implementation Plans. Presented at A&WMA 113th Annual Conference and Exhibition, Virtual Conference. July 1, 2020.

Morris, R. and D. McNally. 2020. Denver RAQC Modeling Forum – Denver Serious Ozone SIP 2016 Base Year and 2020 Future Year Modeling and Attainment Demonstration. Denver Regional Air Quality Council,. June 4, 2020.

Morris, R. and A. Brimmer. 2020. Serious Ozone Update. Live Video Webinar Series. Davis Graham and Stubbs, Denver, Colorado. May 27.

Morris, R. 2019. Single-Source Visibility Ranking and Modeling Techniques for Regional Haze SIPs. Presented at A&WMA 112th Annual Conference and Exhibition, Quebec City, Canada. June 25-28, 2019.

Morris, R., M. Zatko, B. Brashers and J. Maranche. 2019. PM2.5 Precursor Insignificance Demonstration for Allegheny County, Pennsylvania. Presented at A&WMA Guideline on Air Quality Models: Planning Ahead. Durham, North Carolina. March 19-21, 2019.

Morris, R., 2019. Air Quality Modeling of the Gulf of Mexico Region. Presented at A&WMA Guideline on Air Quality Models: Planning Ahead. Durham, North Carolina. March 19-21, 2019.

Morris, R. and B. Brashers. 2019. Introduction to CAMx. Half Day Course Presented at A&WMA Guideline on Air Quality Models: Planning Ahead. Durham, North Carolina. March 19-21, 2019.

Morris, R., L. Parker and T. Stoeckenius. 2019. Analysis of Recent Observed Ozone Increases in the South Coast Air Basin in 2016-2018 While Emissions Are Reduced. Presented at Coordinating Research Council (CRC) 29th Real World Emissions Conference, Long Beach, California. March 11-13, 2019.

Morris, R. Denver Ozone Modeling Update. 2018. Presented at David Graham and Stubbs Air Quality Summit, Denver, Colorado. September 13, 2018.

Morris, R., L. Parker and T. Stoeckenius. 2018. Effects of Meteorology and Other Processes on Observed and Modeling Ozone in the SoCAB. Presented at Southern California Ozone Research Symposium (SCORES), UC Riverside, California. June 6-7, 2018.

Morris, R. 2018. Contributions of International Emissions to Ozone Attainment in the United States. Presented at 111th A&WMA Conference and Exhibition, Hartford, Connecticut. June 25-28, 2018.

Morris, R. 2018. Assessment of the Air Quality Impacts due to Oil and Gas Development in the Gulf of Mexico Region. Presented at 111th A&WMA Conference and Exhibition, Hartford, Connecticut. June 25-28, 2018.

Morris, R. and U. Nopmongcol. 2018. Source Contribution to Secondary PM2.5 in Central Alberta. Presented at 2018 A&MA CPANS Conference -- Western Canada: Environment State of the Union. Calgary, Alberta. May 9, 2018.

Morris, R., L. Parker and T. Stoeckenius. 2018. Analysis of Recent Ozone Increases in the South Coast Air Basin. Presented at CRC 28th Real World Emissions Conference, Garden Grove, California. March 18-21, 2018.

Morris. 2017. Fires and International Uncontrollable Emissions. Presented at Regional Haze Planning Workshop, Denver, CO. December 5-7, 2017.

Morris, R. and D. McNally. 2017. Preliminary Future Ozone Projections and Source Contributions. Regional Air Quality Council Board Meeting. Denver, CO. November 3, 2017.

Morris, R. and D. McNally. 2017. Modeling Sensitivities Overview. Denver Ozone Modeling Forum. Denver, CO. November 2, 2017.

Morris, R. and D. McNally. 2017. Local Source 2017 Ozone Source Apportionment Modeling. Denver Ozone Modeling Forum. Denver, CO. November 2, 2017.

Morris, R. and D. McNally. 2017. Ozone Contributions of International Emissions using 2011 Modeling Platform. Denver Ozone Modeling Forum. Denver, CO. November 2, 2017.

Morris, R. and D. McNally. 2017. 2023 Preliminary Modeling: 2023 Ozone Projections and VOC/NOx Sensitivity. Denver Ozone Modeling Forum. Denver, CO. November 2, 2017.

Morris, R. BOEM Photochemical Modeling of Offshore Oil and Gas Development in the Arctic. Presented at U.S. Canada Northern Oil and Gas Research Forum, Anchorage, Alaska. October 11-13, 2017.

Morris, R. 2017. Evaluation of Visibility Metrics for Demonstrating Reasonable Progress Goals under the Regional Haze Rule. Presented at 4th Biannual Western Modeling Workshop, Boulder, Colorado. September 6, 2017.

Morris, R., Z. Adelman, T. Moore and R. Bates. 2017. Southern New Mexico Ozone Modeling Study and the Section 179B Option. Presented at 4th Biannual Western Modeling Workshop, Boulder, Colorado. September 6, 2017.

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Morris, R. 2017. Windows Version of CAMx. Presented at A&WMA Guideline on Air Quality Models: A New Path, Chapel Hill, North Carolina. November 14-16, 2017.

Morris, R. and B. Brashers. Introduction to CAMx with Single-Source Discussion. Half Day Course Presented at A&WMA Guideline on Air Quality Models: A New Path, Chapel Hill, North Carolina. November 13, 2017.

Morris, R., P. Karamchandani, A. Wentland, T. Shah and J. Lester. 2017. Measured versus Modeled Ozone Trends in California's South Coast Air Basin and Effects on Mobile Source Controls. Presented at CRC 27th Real World Emissions Conference, Long Beach, California. March 26-29, 2019.

Morris, R., J. Jung, B. Brashers and J. Maranche and A. Sadar. 2017. Hybrid Grid/Plume Modeling for the Allegheny County 24-Hour PM2.5 Attainment Demonstration. Presented at 110th Annual Conference and Exhibition, Pittsburgh, Pennsylvania. June 5-8, 2017.

Morris, R. 2017. Measurements, Emissions and Modeling. Presented at the Critical Review in the 110th Annual Conference and Exhibition, Pittsburgh, Pennsylvania. June 5-8, 2017.

Morris, R., Z. Adelman, and T. Moore. Development and Application of Photochemical Modeling Systems to Address Ozone, Particulate Matter, Visibility and Deposition Issues in the Rocky Mountain Region. Presented at the 2-17 Air Quality Conference of the Rocky Mountain States Section of the A&MA, Denver, Colorado. April 13, 2017.

Kemball-Cook, S., R. Morris and G. Yarwood. 2016. Identifying the Influence of Exceptional Events and International Transport – An Overview of When and How to Apply Clean Air Act Provisions for Background Ozone. Presented at the American Fuel and Petrochemical Manufactures 2016 Annual Conference, San Francisco, California. March 13-15, 2017.

Vijayaraghavan, K., Beardsley, R., Jung, J., Yarwood G. & Morris, R. 2016. "The Contribution of Emissions Sources and Atmospheric Deposition to Mercury in South Florida and the Everglades." Society of Environmental Toxicology and Chemistry. Orlando, FL. November.

Morris, R.. 2016. SMOKE-MOVES Processing – Incorporate Travel Demand Model Data in Denver Ozone Modeling. Presented at 15th Annual CMAS Conference, Chapel Hill, NC, October 24-36.

Morris, R. 2016. "Modeling of Single-Source Secondary Impacts using the Higher Order Direct Decoupled Method Sensitivity." Presented at 15th Annual CMAS Conference, Chapel Hill, NC, October 24-36.

Nopmongcol. U., R. Morris, C. Archuleta, J. Adlhoch. 2016. "A Conceptual Approach to Address Anthropogenic / Non-Anthropogenic Emission Sources to Help Develop a More Accurate Regional Haze Program Glidepath." Presented at the A&WMA Visibility Conference, Jackson Hole, WY, September 27-30.

Morris R. and U. Nopmongcol. 2016. "Assessment of the Contributions to Visibility Impairment in the Western US and Effect of New Guidance for Tracking Progress." Presented at the A&WMA Visibility Conference, Jackson Hole, WY, September 27-30.

Morris. 2016. "Evaluation of Revised Uniform Rate of Progress Goals for Western United States." Presented at the A&WMA Visibility Conference, Jackson Hole, WY, September 27-30.

Morris. 2016. "BOEM Air Quality Studies." Presented at A&WMA 109th Annual Conference, New Orleans, LA. June.

Nopmongcol, U., Z. Liu, J. Johnson, T. Shah., R. Morris. 2016. "Formation of Secondary Particulate Matter in Capital Region." Presented at AWMA Annual Conference, Alberta, Canada. May.

Morris. 2016. "Single-Source Ozone Modeling Studies." Presented at A&WMA Guidelines on Air Quality Models Conference, Chapel Hill, NC. April.

Karamchandani, P., B. Chowdhury, B. Brashers, L. Parker, G. Yarwood, R. Morris, A. Kaulfus, E. Knipping. 2015. "SCICHEM 3.0: Improvements, Testing and Evaluation." Poster presentation at the 14th Annual CMAS Conference, Chapel Hill, NC., October.

Parker, L.K., R.E. Morris, J. Zapert, F. Cook, C. Meister, B. Koo, D.J. Rasmussen, J. Jung, J. Grant, J. Johnson, T. Shah and T. Pavlovic. 2015. "Photochemical Grid Modeling Study to Assess Potential Air Quality Impacts Associated with Energy Development in Colorado and Northern New Mexico." Presented at the Fall 2015 AGU Conference.

Morris, R.E. 2014. Ozone and PM Source Apportionment Modeling for Reducing Regional Transport. Presented at 4th International Workshop on Regional Air Quality Management in Rapidly Developing Economic Regions (4RAQM), January 14-17, 2014, Hong Kong, China.

Koo, B., R. Morris and G. Yarwood. 2013. "Transformation Rate of SO2 to Sulfate for the Houston Ship Channel based on TexAQS 2006 Data." Presented at the Texas AQRP Workshop, Austin, TX. November.

Karamchandani, P., R. Morris, B. Brashers, G. Yarwood, L. Parker, E. Knipping, N. Kumar, B. Chowdhury, and I. Sykes. 2013. "Application of SCICHEM for Near-Field and Far-Field Single Source Impacts". Presented at the AWMA Guideline on Air Quality Models: The Path Forward Conference, Raleigh, NC, March.

Karamchandani, P., R. Morris, G. Yarwood, B. Brashers, E. Knipping, B. Chowdhury, and Ian Sykes. 2012. "Application of the Reactive Plume Model, SCICHEM-2012, to Simulate Near-Source 1-hour NO2 Concentrations". Presented at the 11th Annual CMAS Conference, Chapel Hill, NC, October.

Emery, C., J. Jung, G. Yarwood, R. Morris. 2011. "Regional/Global Modeling of PRB Ozone Over the US." Presented at the 10th Annual CMAS Conference, Chapel Hill, NC, October.

Bar-Ilan,A., J. Grant, R. Parikh, A. Pollack, R. Morris, D. Henderer, K. Sgamma. 2010. "A Comprehensive Emissions Inventory of Upstream Oil and Gas Activities in the Rocky Mountain States." Presented at the 19th International Emission Inventory Conference, "Emission Inventories - Informing Emerging Issues." San Antonio, TX, September.

Kemball-Cook, S. T. Shah and R. Morris. 2010. "Challenges for Making Ozone, PM2.5 and Visibility Projections in Remote Regions with Sparse Measurement Databases." Presented at AWMA 103rd Annual Conference, Alberta, Canada. June.

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Morris, R., U. Nopmongcol, G. Mansell, C. Mooney, S. Cho. 2010. "Assessment of the Air Quality Impacts of Alberta Oil Sands Development on Tropospheric Ozone and Particulate Matter." Presented at AWMA 103rd Annual Conference, Alberta, Canada. June.

Emery, C.A., E. Tai, R.E. Morris and G. Yarwood. 2010. "A New Algorithm in CAMx to Reduce Excessive Vertical Transport over Complex Terrain." Presented at AWMA 103rd Annual Conference. Alberta, Canada. June.

Kemball-Cook, S., T. Shah and R. Morris. 2010. "Challenges for Making Ozone, PM2.5 and Visibility Projections in Remote Regions with Sparse Measurement Databases." Presented at AWMA 103rd Annual Conference, Alberta, Canada. June.

Morris, R.E., G.E. Mansell, A.K. Pollack, D. Yeung, B. Ho, C. Fung, K. Leung. 2009. "Development of a New Air Quality Modeling System for the Hong Kong and Vicinity Regions." Presented at The 2nd International Workshop on Regional Air Quality Management in Rapidly Developing Economic Regions; International Conference Centre, South China University of Technology, University City, Guangzhou, China. November.

Morris, R.E., S. Kemball-Cook, U. Nopmongcol, L. Parker. 2009. "Fine-Scale Modeling with CMAQ and CAMx for Air Toxics, PM and Ozone in Detroit." Presented at AWMA Guideline on Air Quality Models: Next Generation of Models Conference, Research Triangle Park, NC. October.

Morris, R.E., S. R. Kemball-Cook, U. Nopmongcol and L. K. Parker. 2009. "Use of Photochemical Grid Models to Address Far-Field Air Quality and Air Quality Related Value Impacts of Proposed New Sources." Presented at AWMA Guideline on Air Quality Models: Next Generation of Models Conference, Research Triangle Park, NC. October.

Emery, C.E., E. Tai, R.E. Morris, G. Yarwood. 2009. "Reducing Vertical Transport Over Complex Terrain in Photochemical Grid Models." Presented at the CMAS 8th Annual Conference, Chapel Hill, NC. October.

Morris, R.E., S. Kemball-Cook, B. Koo, T. Stoeckenius, G. Yarwood. 2009. "Simulation of Wintertime High Ozone Concentrations in Southwestern Wyoming." Presented at CMAS 8th Annual Conference, Chapel Hill, NC. October.

Koo, B., G.M. Wilson, R.E. Morris, G. Yarwood. 2009. "Comparison of PM Source Apportionment and Sensitivity Analysis in CAMx." Presented at CMAS 8th Annual Conference, Chapel Hill, NC. October.

Morris, R.E., J. Jung, E. Fujita, P. Brewer. 2009. "Assessment of the Sources of Organic Carbon at Monitoring Sites in the Southeastern US Using Receptor and Deterministic Models." Presented at CMAS 8th Annual Conference, Chapel Hill, NC. October.

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Koo, B., G. Yarwood, and R. Morris. 2008. "Evaluation of Secondary Organic Aerosol Formation in CAMx for Urban and Rural Area." Presented at the AAAR 27th Annual Conference, Orlando, FL, October.

Wilson, G., B. Wang, C. Emery, R. Morris and G. Yarwood. 2008. "Applying a 3-D Photochemical Model (CAMx) in Multi-Processor Cluster (MPI) and Shared-Memory (Open-MP) Computing Environments." Presented at the 7th Annual CMAS Conference, University of North Carolina, October 6-8.

Morris, R., B. Koo and T. Sakulyanontvittaya. 2008. "Use of Hybrid Grid/Plume Modeling to Address PM2.5 Attainment in the St. Louis Nonattainment Area." Presented at the 7th Annual CMAS Conference, University of North Carolina, October 6-8.

Morris, R., T. Sakulyanontvittaya, J. Johnson, D. McNally, C. Loomis, and P. Brewer. 2008. "Use of PM Source Apportionment to Assess the Contributions of Individual Point Sources to PM2.5 Concentrations in the Eastern U.S." Presented at the 7th Annual CMAS Conference, University of North Carolina, October 6-8.

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Pollack, A., R. Morris, D. Yeung, P. Sham, C. Fung, and K. Leung. 2008. "Emission Inventory Development for the Hong Kong Special Administrative Region." Presented at the Air & Waste Management 101st Annual Conference, Portland, OR. June.

Pollack, A., R. Morris, D. Yeung, P. Sham, C. Fung, and K. Leung. 2008. "Application of Emission Processing Tools in Air Quality Modeling for Hong Kong Special Administrative Region." Presented at the Air & Waste Management 101st Annual Conference, Portland, OR. June.

Emery, C.A., R. Morris and E. Tai, J. Wilkinson. 2008. "Columbia River Gorge Air Quality Study (CRGAQS): Photochemical Grid Modeling Results." Presented at the Air & Waste Management 101st Annual Conference, Portland, OR. June.

Morris, R., S. Kemball-Cook, D. Strohm, J. Johnson, and E. Tai. 2008. "Use of Photochemical Grid Models to Assess PSD Pollutant, Ozone, Visibility and Deposition Impacts Due to Proposed New Sources." Presented at the Air & Waste Management 101st Annual Conference, Portland, OR. June.

Yeung D., P. Sham, R. Morris, A. Pollack, C. Fung, and K. Leung. 2008. "Development of a New Air Quality Modeling System for the Hong Kong Special Administrative Region." Presented at the Air & Waste Management 101st Annual Conference, Portland, OR. June.

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Koo, B., G. Yarwood, R. Morris, T. Gaydos, and S. Pandis. 2007. "Equilibrium, Dynamic, and Hybrid Approaches for Atmospheric Aerosol Modeling." Presented at International Aerosol Modeling Algorithms Conference, UC Davis, CA. December.

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EPA Fine Particulate Modeling Guidance Workgroup
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NOV 2 9 2018

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze

FROM: Richard A. Wayland, Division Director
Air Quality Assessment Division

TO: Regional Air Division Directors, Regions 1 – 10

The Environmental Protection Agency (EPA) is issuing the attached *Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze*. This document reflects the EPA's recommendations for how air agencies should conduct air quality modeling and related technical analyses to satisfy model attainment demonstration requirements for the 2015 ozone and 2012 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS), as well as for regional haze reasonable progress analyses. This document updates the previous draft version of the modeling guidance, which was released in December 2014.

This document does not substitute for provisions or regulations of the Clean Air Act (CAA), nor is it a regulation itself. As the term "guidance" suggests, it provides recommendations on how to implement the modeling requirements. Thus, it does not impose binding, enforceable requirements on any party, nor does it assure that the EPA will approve all instances of its application, as the guidance may not apply to a particular situation based upon the circumstances. Final decisions by the EPA regarding a particular State Implementation Plan (SIP) demonstration will only be made based on the statute and applicable regulations and will only be made following a final submission by air agencies and after notice and opportunity for public review and comment.

In December 2014, the EPA released a draft version of this guidance for public review and comment. A total of 13 substantive comments were received. After considering the comments, the EPA made changes which are reflected in this updated version of the guidance. Major guidance updates include responding to the public comments as well as updates to reflect requirements in the most recent NAAQS implementation rules and regional haze rule.

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Similar to the draft guidance, the updated guidance is divided into two main sections. The first part describes how to setup and apply a photochemical modeling platform (including meteorological, emissions, and air quality modeling), and the second part describes how to use the air quality modeling results to show whether future attainment of the ozone and/or $PM_{2.5}$ NAAQS is likely. The guidance also describes how to use photochemical grid modeling to evaluate reasonable progress goals for regional haze.

Many of guidance updates are in the form of revised and reorganized text. In addition, numerous references have been added and/or updated. The updated guidance reflects the requirements contained in the 2015 ozone NAAQS SIP requirements rule (November 2018)[1], the 2012 $PM_{2.5}$ NAAQS SIP requirements rule (August 2016)[2], and the regional haze rule (January 2017)[3].

Specific updates to the draft guidance include:

- Reorganization of the document including removal of outdated language and references.
- The 2014 draft guidance updates to the recommended 8-hour ozone attainment test (relative response factors using the top ten modeled days) were finalized, and now also apply to the 2015 ozone NAAQS.
- Consistent with the 2017 regional haze rule revisions, the reasonable progress goals methodology has been updated to reference the 20 percent "most anthropogenically impaired" days and 20 percent "clearest" days.
- The emissions modeling section has been extensively updated to account for new and improved emissions models, techniques, and input data, and has been closely coordinated with the SIP emissions inventory guidance, "*Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations*," available at: https://www.epa.gov/air-emissions-inventories/air-emissions-inventory-guidance-implementation-ozone-and-particulate.

Please share this guidance with air agencies in your Region. If you have any questions concerning this document, please contact Brian Timin at (919) 541-1850 or *timin.brian@epa.gov*. The guidance document is available electronically on the EPA's website: https://www.epa.gov/scram/state-implementation-plan-sip-attainment-demonstration-guidance.

Attachment

[1] *See* https://www.epa.gov/ground-level-ozone-pollution/implementation-2015-national-ambient-air-quality-standards-ozone
[2] *See* 81 FR 58101
[3] *See* 82 FR 3078



Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze

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EPA 454/R-18-009
November 2018

Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Assessment Division
Research Triangle Park, NC

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1.0 Introduction

This document describes how to estimate the impacts of an emissions control strategy on air quality for purposes of demonstrating attainment of the annual average and 24-hour average national ambient air quality standards (NAAQS) for particles smaller than 2.5 µm in diameter ($PM_{2.5}$) and the 8-hour NAAQS for ozone. We also describe how to use modeled and monitored air quality data to estimate future visibility conditions in *Class I areas* (e.g., national parks, wilderness areas) as part of the development of reasonable progress goals (RPGs) that reflect the long-term strategy in a regional haze state implementation plan (SIP).[1]

This document describes how to apply air quality models to generate the predictions used to evaluate attainment and/or to set RPGs for regional haze. Modeling to show attainment of the NAAQS primarily applies to nonattainment areas[2] for which modeling is required, or desired. Modeling to assess reasonable progress for regional haze applies to all states, the District of Columbia, and the U.S. Virgin Islands.[3]

This guidance is designed to implement national policy on air quality modeling requirements as embodied in the Clean Air Act (CAA), the Ozone SIP Requirements Rule[4], the $PM_{2.5}$ SIP Requirements Rule[5], and the Regional Haze Rule[6]. In addition, the United States Environmental Protection Agency (EPA) revised 40 CFR part 51, Appendix W (Guideline on Air Quality Models) (U.S. EPA, 2017a), hereafter referred to as "Appendix W," in 2017 to provide general information about the types of model approaches that may be appropriate for the purposes of demonstrating attainment with the ozone and $PM_{2.5}$ NAAQS (section 5) and projecting visibility impacts at Class I areas (section 6). Appendix W is a regulation and, as such, contains binding requirements. However, the Appendix W photochemical modeling requirements related to SIP

[1] Modeling to determine RPGs as described in this document is part of the development of a regional haze SIP. However, unlike the NAAQS, the Regional Haze program does not involve fixed air quality standards that must be achieved. The ways that RPGs are used in the development of a regional haze SIP are described in more detail in section 5.

[2] While this guidance document is primarily directed at modeling applications in nonattainment areas, it may also be useful as a guide for modeling to support NEPA analyses, maintenance plans or to support other rules or provisions of the Clean Air Act.

[3] *See* 40 CFR 51.300(b).

[4] *See* Implementation of the 2015 National Ambient Air Quality Standards for Ozone: Nonattainment Area State Implementation Plan Requirements; [Final rule signed November 7, 2018]

[5] *See* Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements ($PM_{2.5}$ SIP Requirements Rule), 81 FR 58101 (Aug. 24, 2016).

[6] The Regional Haze Rule was revised by a final rule published on January 10, 2017 (82 FR 3078). This version of the modeling guidance reflects that revision of the rule. Additional revisions may be made to this guidance to be consistent with any future regional haze rule and/or guidance issued by EPA.

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attainment demonstration modeling and regional haze modeling do not proscribe any particular models or modeling techniques. As such, this modeling guidance provides additional details about how to set up and run photochemical models that may be useful to air agencies that are required to submit SIP attainment demonstrations and/or regional haze modeling.

This guidance is intended for use by the EPA headquarters and Regional offices; federal land managers of mandatory Class I federal areas; state, local and tribal air quality management authorities, and the general public. This document does not substitute for provisions or regulations of the CAA enumerated above, nor is it a regulation itself. As the term "guidance" suggests, it provides recommendations on how to implement the modeling requirements. Thus, it does not impose binding, enforceable requirements on any party, nor does it assure that the EPA will approve all instances of its application, as the guidance may not apply to a particular situation based upon the circumstances.

The EPA and state, local, and tribal air agencies (hereinafter referred simply as "air agency" or "air agencies") retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Final decisions by the EPA regarding a particular SIP submission that includes a modeling demonstration will ultimately be made based on the statute and applicable regulations and will only be made following a final submission by air agencies and after notice and opportunity for public review and comment. Interested parties are free to raise questions and objections about the appropriateness of the application of this guidance to a particular situation; the EPA and air agencies should consider whether or not the recommendations in this guidance are appropriate in that situation.

1.1 What Is the Purpose of This Document?

This document has two purposes. The first purpose is to describe how to apply an air quality model to produce results needed to support an attainment demonstration or to calculate RPGs for a regional haze reasonable progress analysis in a scientifically appropriate manner. The second is to explain how to interpret whether results of modeling and other analyses support a conclusion that attainment of the ozone and/or $PM_{2.5}$ NAAQS will occur by the appropriate date for an area, and/or to assess progress towards the national visibility goal of the regional haze program.

1.2 Does the Guidance in This Document Apply to Me?

This guidance applies to all air agencies that are required to submit a State Implementation Plan (SIP), or Tribal Implementation Plan (TIP) submission with an attainment plan designed to

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achieve attainment of the ozone and/or $PM_{2.5}$ NAAQS. The guidance also applies to air agency SIP submissions developed to address Regional Haze Rule requirements. Air agencies required to submit an attainment demonstration and/or a reasonable progress analysis for regional haze are encouraged to follow the procedures described in this document. Details on when a state is required to submit a modeled attainment demonstration can be found in the Ozone SIP Requirements Rule[7] and the $PM_{2.5}$ SIP Requirements Rule[8]. Details on when a state is required to submit a regional haze SIP that includes RPGs can be found in the Regional Haze Rule[9].

1.3 Outline

Part 1 of this guidance provides an overview of the modeling and attainment demonstration process. Part 2 describes how to build a "modeling platform" and apply air quality models. A "modeling platform" consists of the building blocks of an air quality modeling demonstration. This includes emissions modeling[10], meteorological modeling, and the development of all other inputs needed to run an air quality model. The model platform development process consists of the following steps as outlined in section 2:

Section 2.1	Development of a conceptual description of the problem to be addressed
Section 2.2	Develop a modeling protocol
Section 2.3	Select appropriate meteorological time periods to model
Section 2.4	Choose an appropriate area to model with appropriate horizontal/vertical resolution
Section 2.5	Select an appropriate model to support the demonstration
Section 2.6	Generate meteorological inputs to the air quality model
Section 2.7	Generate emissions inputs to the air quality model
Section 2.8	Develop initial and lateral boundary conditions that are suitable for the application

Typically, the air quality modeling process starts with the development of base year emissions and meteorology for input to an air quality model to evaluate model performance. Section 3

[7] *See* 40 CFR 51.1308.
[8] *See* 40 CFR 51.1011.
[9] *See* 40 CFR 51.308. Sections 308(d) and (e) apply for SIPs for the first implementation period only. States that followed section 51.309 (which is also part of the Regional Haze Rule) in the first implementation period were not required to develop RPGs. Section 51.308(f) applies to all Regional Haze SIPs due in 2021 and later.
[10] Additional emissions inventory requirements and details on emissions modeling are contained in "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations."

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describes the process for evaluating model performance and performing diagnostic analyses. After evaluating the model and making any necessary input changes or adjustments, the model is run for a future year, which corresponds to the appropriate attainment year for the area or to the future year modeled for regional haze planning purposes. Sections 2 and 3 apply to both ozone and $PM_{2.5}$ modeling and modeling to set RPGs for regional haze SIPs.

Section 4 describes how the air quality model outputs are then used to apply the modeled attainment test to support an attainment demonstration for ozone or $PM_{2.5}$. We explain what is meant by a *modeled attainment demonstration*, a *modeled attainment test*, and a *weight of evidence demonstration*. Modeled attainment tests are described for the 8-hr ozone NAAQS and the annual and 24-hour $PM_{2.5}$ NAAQS. Section 5 addresses aspects of modeling specific to regional haze SIPs.

Model applications require a substantial effort. Air agencies are encouraged to work closely with the appropriate EPA Regional office(s) in executing each step of the modeling and attainment demonstration or regional haze planning process. This will increase the likelihood of approval of the demonstration at the end of the process.

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2.0 Building a Model Platform

2.1 Conceptual Description

The first step in developing an attainment demonstration is to construct a conceptual description of the problem that is being addressed. Conceptual descriptions, which are also referred to as conceptual models, are comprehensive summaries of the "state of the knowledge" regarding the influence of emissions, meteorology, transport, and other relevant atmospheric processes on air quality in the area (Vickery, 2004). For a conceptual description to be informative, it should identify what processes and sources, in the generic sense, are most responsible for the air quality issue being simulated. Well-constructed conceptual models can substantially inform the design of the attainment demonstration modeling (e.g., episode selection, choice of domain, emissions priorities, evaluation focus) and should be conducted in advance of the development of a modeling protocol. It is worth noting that conceptual descriptions can be valuable in other air quality planning efforts besides attainment demonstrations, such as determining nonattainment area boundaries, investigating emissions control program impacts, interstate transport analyses, and monitoring network design, among others.

The following bullets describe some of the key building blocks in developing a conceptual model. The process steps discussed below are meant to illustrate one possible template for building a conceptual model to inform an air quality modeling demonstration; there may be alternate approaches that better suit individual study areas or issues, which air agencies should discuss with the appropriate EPA Regional office.

- Introduce the general nature of the air quality problem addressed by the conceptual model:
    - What are the pollutants of concern in the area?
    - What are the current air quality levels in the area?
    - What is the attainment/nonattainment status of the area?
    - What is the geographical scope of poor air quality?
    - What is the temporal scope of poor air quality?
    - What are the air quality trends in the area? Is the problem getting better or worse?
    - What are the suspected mechanisms for formation of poor air quality levels?
    - What are the sources of emissions that may contribute to poor air quality?
    - Are there unique meteorological influences on local air quality levels?

- Describe the ambient monitoring network used for the conceptual model:
    - Develop a map of monitor sites and types (e.g., FRM, FEM, CSN, IMPROVE, CASTNET, etc.).

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- Describe characteristics of individual monitoring sites (scale, frequency, etc.).

- Describe the status and trends of air quality in the area:
  - Summarize the relevant monitoring data for the air quality problem being studied.
  - Identify locations that are in violation of the NAAQS.
  - Describe the spatial pattern in pollutant and precursor pollutant levels.
  - Describe the temporal pattern in pollutant and precursor pollutant levels.
  - Describe the annual trends in concentrations over the period of interest.
  - If appropriate, develop fused ambient/model surfaces to fill any gaps within the monitoring network.

- Investigate possible relationships between emissions and air quality:
  - Examine emissions estimates for the main sector/source categories.
  - Compare emission trends for annual and or seasonal/episodic periods to corresponding air quality trends.
  - Identify key emission sources or source categories.
  - Assess the historical effectiveness of control programs.
  - Consider how future emissions growth or reductions may affect air quality.
  - List control programs that are in place, or will soon be implemented, that may impact emissions sources in the area.

- Investigate possible relationships between meteorology and air quality (AQ):
  - Describe meteorological characteristics on poor air quality days (e.g., wind speed/direction, temperatures, relative humidity levels, inversion indicators, etc.).
  - Identify any distinct meteorological phenomena that coincide with poor air quality days.
  - Prepare pollution roses, HYSPLIT back-trajectories (Draxler, 1998), or any other relevant analysis needed to link poor air quality days to specific meteorological patterns and sources of transported pollutants.
  - Assess the impact from pollutant transport into area based on meteorological data and ambient air quality data.

- Synthesize all the relevant information into a detailed conceptual model:
  - Aggregate all elements of the conceptual model and provide the key findings resulting from the analyses completed.
  - Characterize the potential factors that influence air quality in the area and where possible rank the importance of those influences.

- Identify issues that require further investigation, either in terms of data collection or chemical transport modeling.
- Discuss how the subsequent SIP modeling and associated protocol is impacted by this conceptual description.

2.1.1 Example Applications of Conceptual Models

The idea of developing a modeling protocol based upon a conceptual description of the sources and processes that lead to poor air quality is well-established (U.S. EPA, 2007a). Numerous excellent conceptual models of local and regional air quality issues have been developed over the past decade. Table 2-1 provides a non-comprehensive list of example conceptual models that have been developed since the last release of the guidance that may be useful in orienting future SIP modeling applications.

Table 2.1 Examples of recently developed conceptual models

Air quality issue	**Reference**
$PM_{2.5}$ / Regional Haze (Northeast U.S.)	MANE-VU (2013)
$PM_{2.5}$ (Midwest U.S.)	Lake Michigan Air Directors Consortium (LADCO) (2009)
Ozone (Austin TX)	McGaughey *et al.* (2010)
Ozone (Wyoming)	Stoeckenius (2010)
$PM_{2.5}$ (Southeast Michigan)	Turner (2008)

2.2 Modeling Protocol and Supporting Documentation

As with any technical support document designed to inform air quality planning, an attainment demonstration or regional haze analysis should be supported by documentation that sufficiently describes the procedures used in the analysis. In order to facilitate the process of EPA Regional office review and approval, we recommend the preparation of two separate supporting documents for ozone and $PM_{2.5}$ SIPs: one before the modeling analyses are initiated (modeling protocol) and one after the analyses have been completed (attainment demonstration package). We recommend a similar approach during the development of regional haze SIPs.

2.2.1 Modeling Protocol

Developing and implementing a modeling protocol is an important part of a modeling demonstration. The protocol should detail and formalize the procedures for conducting all

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phases of the modeling study, such as describing the background and objectives for the study, creating a schedule and organizational structure for the study, selection of appropriate period(s) for modeling, developing the input data, conducting model performance evaluations, interpreting modeling results, describing procedures for using the model to demonstrate whether proposed strategies are sufficient to attain the NAAQS and/or regional haze goals, and producing documentation to be submitted for EPA Regional office review and approval. The most important function of the modeling protocol is to serve as a blueprint for planning how the modeled demonstration will be performed. The protocol should be a valuable communication device by which air agencies, EPA, and other stakeholders can assess the applicability of default recommendations and develop area-specific alternatives, where needed, prior to conducting the work to build the modeling system. A suitable protocol should lead to extensive participation by stakeholders in developing the demonstration. It should also reduce the risk of spending time and resources on efforts that are unproductive or inconsistent with EPA rules, policy, and guidance. While the modeling protocol is initially developed at the beginning of a modeling exercise to foster communication, it is advisable to modify the document as needed throughout the modeling process when alterations from the original modeling plan are necessary. Again, any changes to the protocol should be fully communicated between affected air agencies, stakeholders, and the EPA.

Meaningful protocols should fully communicate the expected scope of the analysis and provide a blueprint for carrying out the needed analyses. There is no “one-size-fits-all” format for a sufficient modeling protocol, as different individual areas may require specific points of emphasis. However, past attainment demonstrations have yielded several excellent protocol examples that could serve as templates for any groups developing new modeling protocols. While not exhaustive, potentially valuable protocol references include attainment demonstration modeling efforts completed in the Dallas/Fort Worth area (Environ, 2003), the Denver region (Morris, 2011), and the San Joaquin Valley (CARB, 2012). Based on past experience, the EPA recommends that the following topics be core elements of any modeling protocol:

- Overview of the air quality issue being considered including historical background
- List of the planned participants in the analysis and their expected roles
- Schedule for completion of key steps in the analysis and final documentation
- Description of the conceptual model for the area
- Description of periods to be modeled, how they comport with the conceptual model, and why they are sufficient
- Models to be used in the demonstration and why they are appropriate
- Description of model inputs and their expected sources (e.g., emissions, meteorology, etc.)

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- Description and justification of the domain to be modeled (expanse and resolution)
- Process for evaluating base year model performance (meteorology, emissions, and air quality) and demonstrating that the model is an appropriate tool for the intended use
- Description of the future years to be modeled and how projection inputs will be prepared
- Description of the NAAQS attainment test procedures and (if known) planned weight of evidence, and/or description of the procedures for calculating RPGs from the modeling outputs, as applicable.
- Expected diagnostic or supplemental analyses needed to develop weight of evidence analyses
- Commitment to specific deliverables fully documenting the completed analysis

2.2.2 Attainment Demonstration and/or Reasonable Progress Goals Modeling Documentation Package

Whereas the modeling protocol describes the planned scope of the analysis, the final modeling documentation package summarizes the actual analysis conducted (including procedures used) to show that an area will likely meet the NAAQS and/or RPGs under a specific set of future conditions. This document can follow the same basic outline as the modeling protocol, highlighting those aspects of the modeling that may have changed from the original plans. Additionally, the modeling documentation package should have detailed information on any emission reduction strategies that will be implemented as part of an attainment or regional haze SIP. Ultimately, the modeling documentation package should provide a narrative that fully describes the technical rationale behind the projection of a specific air quality goal in an area. Based on past experience, the EPA recommends that the following topics be core elements of any modeling documentation package:

- Executive summary that provides an overview of the analysis and the key conclusions
- Reference to the modeling protocol noting any major deviations from the original plans
- List of the institutional participants in the attainment demonstration and their roles
- Description of air quality in the area and describe how that shaped the analysis
- Justification for the model, episodes, domain, and grid(s) used in the analysis
- Description of the development of the emissions inputs used in the base year modeling, including, at a minimum, tabular summaries by state/county, as appropriate

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- Description of the development of meteorological inputs used in the base year modeling
- Description of all other base year modeling inputs
- Evaluation of base year model performance (meteorology, emissions, and air quality), including a description of the observational database used in the evaluation and any diagnostic or sensitivity tests used to improve the model
- Description of the strategy used to demonstrate attainment and/or RPGs, including speciated emissions summaries for the future year and identification of authority for implementing these strategies
- Description of the attainment test inputs and results
- Description of any supplemental analyses designed to bolster the original attainment test results
- Detailed summary of the entire analysis that leads to the conclusion that the selected attainment demonstration strategy is likely to produce attainment of the NAAQS by the required date and/or leads to the calculation of the RPGs
- Appendices that contain more detailed information on the model inputs and outputs (emissions, meteorology, etc.), model performance, and attainment demonstration, including charts, tables, and descriptive text

All model input and output files (in electronic format) should be made available upon request by the EPA and/or stakeholders.

2.3 Episode Selection

The modeled attainment test and the recommended procedure for setting RPGs for regional haze both adjust observed ambient concentrations during a base case period (e.g., 2012-2016) to a future period (e.g., 2023) using model-derived "relative response factors" (RRFs). It is important that emissions used in the attainment modeling correspond with the period reflected by the chosen baseline design value period (e.g., 2012-2016).[11] Deviations from this constraint will diminish the credibility of the RRFs. The base year modeling inventory typically corresponds to the middle year of the baseline average design value period (e.g. 2014 for a 2012-2016 average design value period). Alternatively, the base year emissions can reflect multi-year average emissions from the base year period (e.g. average emissions for the 2013-2015 period). But in

[11] The regional haze program does not use design values. However, in an analogous approach, this guidance recommends the use of 5 years of historical visibility data (non-weighted) in a manner similar to the approach in the modeled attainment test for ozone and $PM_{2.5}$. For this reason and for brevity, sections 2 and 3 use the "design value" terminology in some explanations that apply to both ozone and $PM_{2.5}$ attainment modeling and to the setting of regional haze RPGs. That is, for regional haze purposes, "design values" can be understood to mean "visibility data."

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either case, the emissions year or years should be representative of the 5-year design value window.

There is no recommended default base year for modeling. However, it is recommended to use a relatively recent base period so that the emissions projection period is as short as possible and the base year ambient data is as current as possible. For example, projecting emissions from 2014 to 2023 (using a 2012-2016 base year average design value) should be less uncertain than projecting emissions from 2005 to 2023 (using a 2003-2007 base year average design value). The most recent ambient design values reflect actual emissions changes that have occurred over time. It is, therefore, better to use recent design values, which are actual measurements, combined with modeled emissions changes to project future concentrations, then to use older ambient data to estimate the change in design values. When selecting a base modeling year, air agencies should review recent ambient data and consider the factors in the following section.

2.3.1 Choosing Time Periods to Model

In the past, the choice of modeled episode days has been limited by the speed of computers and the ability to store model output files. With the advancement in computer technology over the past two decades, computer speed and storage issues are no longer an impediment to modeling long time periods. In fact, the majority of recent regulatory assessment modeling platforms have been inclusive of entire summers and/or full years (as appropriate) for ozone, $PM_{2.5}$, and regional haze (Boylan and Russell, 2006; Morris et al., 2006; Rodriguez et al., 2009; Simon et al., 2012; Tesche et al., 2006; U.S. EPA, 2011a, 2011b, 2016a).

Ozone-based research has shown that model performance evaluations and the response to emissions controls need to consider modeling results from relatively long time periods, in particular, full synoptic cycles or even full ozone seasons (Hogrefe et al., 2000; Vizuete et al., 2011). In order to examine the response to ozone control strategies, it may not be necessary to model a full ozone season (or seasons), but, at a minimum, modeling "longer" episodes that encompass full synoptic cycles is advisable. Time periods which include a ramp-up to a high ozone period and a ramp-down to cleaner conditions allow for a more complete evaluation of model performance under a variety of meteorological conditions.

Most model applications for the annual $PM_{2.5}$ NAAQS have modeled a full year (Morris et al., 2006; Tesche et al., 2006; U.S. EPA, 2011a, 2011b, 2017b). This is a logical goal since every monitored day of the year is included in the calculation of the annual NAAQS. The annual $PM_{2.5}$ NAAQS is unique because each and every ambient observation is included in the average. It is,

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therefore, likely that a full year of modeled data is needed to adequately represent the annual average $PM_{2.5}$ NAAQS.

Eight-hour ozone and 24-hour $PM_{2.5}$ episode selection criteria are similar because both standards are based on short-term peak concentration periods. Regional haze calculations are based on an average of 20 or more days per year (20% clearest and 20% most impaired days). Therefore, regional haze episode selection will likely include more days throughout the year.

At a minimum, several criteria should be used to select time periods that are appropriate to model:

- Model time periods that are close to the most recently compiled and quality assured National Emission Inventory (NEI). These comprehensive inventories are typically generated every 3 years (e.g. 2011, 2014, 2017, etc.), but often contain year-specific data for the intermediate years. Since NEI years will have a nationwide complete and comprehensive inventory, selecting a base modeling year that is also an NEI year may save resources. However, other factors should be considered when selecting a base modeling year, such as the availability and magnitude of observed ambient data, meteorology, and availability of special study data. After consideration of all factors, the most appropriate base year may or may not be an NEI year. See section 2.7 for more information on base year inventory selection issues.

- Model time periods in which observed concentrations are close to the appropriate base year design value or level of visibility impairment and ensure there are a sufficient number of days so that the modeled test applied at each monitor is based on multiple days.

- Model time periods both before and following elevated pollution concentration (poor air quality) episodes to ensure the modeling system appropriately characterizes low pollution periods, development of elevated periods, and transition back to low pollution periods through synoptic cycles.

- Simulate a variety of meteorological conditions conducive to elevated/poor air quality.

Primary Ozone (8-Hour Ozone) - Choose time periods which reflect a variety of meteorological conditions that frequently correspond with observed 8-hour daily maxima concentrations greater than the level of the NAAQS at monitoring sites in the nonattainment area.

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24-Hour $PM_{2.5}$ - Choose time periods that reflect a variety of meteorological conditions that frequently correspond with observed 24-hour average concentrations greater than the level of the NAAQS at monitoring sites in the nonattainment area.
Annual $PM_{2.5}$ - The best way to represent the meteorological variability within a season and over an entire year is to model an entire year that has meteorology generally conducive to elevated $PM_{2.5}$ concentrations.
Regional Haze - Choose time periods that reflect the variety of meteorological conditions that represent visibility impairment on the 20% clearest and 20% most impaired days in the Class I areas being modeled (high and low concentrations necessary). This is best accomplished by modeling a full year.
Long-term or seasonal ozone – Since long-term (seasonal) ozone assessments are based on accumulated ozone over multiple months during the ozone season, the most appropriate way to represent the variability in high and low ozone is to model an entire ozone season that is representative of long-term values. [**Note:** This analysis is only applicable if seasonal ozone assessments are necessary (e.g. to support ozone benefits calculations). Currently, there are no long-term or seasonal ozone NAAQS (primary or secondary).]

2.3.2 Future Year Selection

For ozone and $PM_{2.5}$, future emissions should be projected to the attainment year or appropriate time period based on the area's classification. The Ozone SIP Requirements Rule provides a schedule for implementing emission reductions needed to ensure attainment by the area's attainment date. Specifically, it states that emission reductions needed for attainment must be implemented no later than the beginning of the attainment year ozone season.[12] The $PM_{2.5}$ Implementation Rule contains similar provisions. It states that emissions reductions should be in place no later than the beginning of the year containing the applicable attainment date.[13]

As part of demonstrating attainment of the ozone and $PM_{2.5}$ NAAQS, air agencies are required to conduct a Reasonably Available Control Measures (RACM) analysis to determine if the attainment date can be advanced by at least a year. Since areas are required to attain as expeditiously as practicable, results of the RACM analysis may indicate attainment can be achieved earlier.

[12] *See* 40 CFR 51.1308(d).
[13] *See* 40 CFR 51.1011(a)(5) and 40 CFR 51.1011(b)(5).

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There are varying requirements related to attainment year and RACM analyses for ozone and $PM_{2.5}$ nonattainment areas, depending on classifications and other factors. Please see the appropriate ozone and/or $PM_{2.5}$ implementation rule for more details and information.[14]

For regional haze SIPs, RPGs must reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period.[15] Therefore, the modeling should be based on emissions forecasted for the end year of the implementation period addressed by the SIP. These end years are 2018, 2028, etc.

2.4 Modeling Domain Selection

A modeling domain identifies the geographical bounds of the area to be modeled. Horizontal resolution is the geographic size of individual grid cells within the modeling domain. Vertical resolution is specified in terms of multiple layers of the atmosphere between the surface and top of the model (usually near the tropopause).

2.4.1 Domain Size

The principal determinants of model domain size are the nature of the ozone, $PM_{2.5}$ and/or regional haze problem being modeled, and the spatial scale of the emissions that impact the nonattainment or Class I area. Establishment of a sufficiently large model domain that utilizes the output from a larger regional or global modeling simulation to feed hourly lateral boundary conditions is a preferred approach (see section 2.8 for more information on boundary conditions). However, regardless of the size of the modeling domain, sources outside the modeling domain may have an important influence on concentrations within nonattainment areas or Class I areas. Therefore, boundary conditions need to be well characterized. The grid containing the key emissions sources and receptors needs to have sufficiently fine-scale to resolve local gradients and have a large enough spatial extent to capture recirculation due to shifting wind directions. An alternative to a single large domain to capture recirculation is to apply a chemical transport model with a large coarse domain with a smaller-domain, nested fine grid with feedback between the grids (i.e., 2-way nesting). This option allows pollutants from the fine grid to move into the coarser domain and back into the fine grid depending on wind patterns.

Global models are routinely used to supply regional chemical transport models with temporally and spatially variant lateral boundary conditions. Since regional and urban model applications

[14] *See* 40 CFR 51.1009 (moderate $PM_{2.5}$), 40 CFR 51.1010 (serious $PM_{2.5}$) and 40 CFR 51.1312 (ozone).
[15] See 40 CFR 51.308(f)(3)(i).

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for attainment demonstration purposes are typically less than or equal to 12 km sized grid cells, it may be worthwhile to apply the regional scale model at a coarser grid resolution (e.g. 36 km) to downscale global model estimates to the regional model. The coarser simulation results provide a better transition from the global simulation to the nested urban or urban/regional area of interest both at the boundaries near the surface and in the free troposphere. See section 2.8 for more information on using global and/or regional models to derive initial and lateral boundary conditions.

Isolated nonattainment areas that have limited impacts from regional transport of ozone and/or $PM_{2.5}$ and its precursors may be able to use a relatively small domain. The modeling domain should be designed so that all major upwind source areas that influence the downwind nonattainment area are included in the modeling domain. It is also important to be able to directly capture the impact of future year emissions increases or decreases from upwind areas. In addition, all monitors that are currently or recently (within any of the years included in the base year period) violating the NAAQS or close to violating[16] the NAAQS in the nonattainment area should be contained in the modeling domain far enough from the edge to minimize complications associated with air mass recirculation and to minimize lateral boundary influence. Similarly, all Class I areas to be evaluated in a regional haze modeling application should be sufficiently distant from the edge of the modeling domain.

2.4.2 Vertical Layer Configuration

There is no correct maximum or minimum number of vertical layers needed in attainment demonstration modeling. However, the specification of the air quality model vertical layer structure should closely match the vertical layer structure of the meteorological model used to generate inputs for the air quality model. It is best to have an air quality model's vertical layers align with the layers in the meteorological model matching one-to-one. However, resource constraints sometimes preclude direct vertical layer mapping. When vertical layer collapsing is necessary, use the highest resolution where the conceptual model suggests it is most needed.

The top of the modeling domain should typically be set above the tropopause at the 50 or 100 millibar level. The lowest layer (surface layer) in the air quality model should be no more than ~40 meters thick. The vertical resolution between the surface layer and model top will vary

[16] A monitor that is "close to violating" the NAAQS in a base year may be modeled to violate in the future due to projected emissions increases or modeled "dis-benefits" due to non-linear chemistry. Air agencies should consult with the appropriate EPA Regional office if there are questions regarding the interpretation of "close to violating" and which monitors should be included in the modeling analysis.

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depending on the application. Layer thickness should monotonically increase or be the same size as altitude increases.

In view of the importance of carefully specifying the temporal variation in mixing height, high precision below and near the anticipated maximum afternoon mixing height is ideal. In addition, near-surface vertical resolution is important to capture overnight stable conditions. Layers above the boundary layer are important for characterizing clouds and precipitation and layers near the tropopause are important to create a realistic stratification of strongly variant pollutant concentrations in the stratosphere and free troposphere (Emery et al., 2011).

There are some model applications that may not need to consider the full extent of the troposphere. These applications typically use vertical domains, which extend up to 4 or 5 km. These types of applications may cover episodes of elevated pollutant concentrations associated with strong surface-based inversions that occur in isolated areas. However, in almost all cases, the EPA encourages the use of full-scale one-atmosphere models that account for all atmospheric processes throughout the extent of the troposphere.

2.4.3 Horizontal Grid Cell Size

Recent chemical transport modeling applications for ozone, $PM_{2.5}$, and regional haze have commonly used grid cell sizes ranging from 4 km to 12 km resolution (Morris et al., 2006; Rodriguez et al., 2009; Simon et al., 2012; U.S. EPA, 2011b, 2016a; Vizuete et al., 2010). Urban scale assessments have used chemical transport grid models at 1 to 2 km resolution (Vizuete et al., 2011). Intuitively, one would expect to get more accurate results in urban applications with smaller grid cells (e.g., ~1 or 4 km) provided the spatial details in the emissions and meteorological inputs support making such predictions. However, model performance at 4 km resolution is not always better than 12 km resolution (Simon et al., 2012).

For coarse portions of the regional grids, a grid cell size of 12 km is generally recommended. For urban areas, it may be desirable to use grid cells sized ~1 to 4 km, but not larger than 12 km. The relative importance of using a domain with grid cells as small as ~1 km should be weighed on a case-by-case basis. If the conceptual model indicates that there are atmospheric, physical, or chemical processes related to the air quality issue that require a specific minimum resolution to simulate (e.g., localized emissions, complex terrain, land-water interfaces, etc.), then that resolution should be utilized in the model. For example, it is likely that spatial gradients in concentrations are higher for primary pollutants (e.g., primary particulate matter, or PM) than for secondary pollutants because physical processes dominate concentration rather than chemical processes. Although it is clear that spatial resolution of primary pollutants will impact

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the predicted concentrations, it is not clear how it will impact the relative change in concentrations due to emissions changes. Areas that have large gradients in primary $PM_{2.5}$ may need to use finer resolution (approximately ~1 to 4 km) or may need to supplement the grid modeling with dispersion modeling. This is particularly true if violating monitors are strongly impacted by local sources of primary $PM_{2.5}$ emissions.

The most important factor to consider when establishing grid cell size is model response to emissions controls. Analysis of ambient data, sensitivity modeling, and past modeling results can be used to evaluate the expected response to emissions controls at various horizontal resolutions for ozone, $PM_{2.5}$, and regional haze. If model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary. The use of grid resolution finer than 12 km would generally be more appropriate for areas with a combination of complex meteorology, strong gradients in emissions sources, and/or land-water interfaces in or near the nonattainment area(s).

Sensitivity tests comparing relative response factors in predicted 8-hour daily maximum ozone at sites in the eastern United States indicate relatively small unbiased differences (< 4%, in RRF difference in 95% of the comparisons) using a grid with 12 km versus 4 km sized grid cells (Arunachalam, 2006). The largest difference in the relative response of secondary pollutants at varying resolution is likely to occur in oxidant limited areas (areas that are more sensitive to VOC reductions than NOx reductions). In such areas, horizontal resolution may have a large impact on the spatial distribution and magnitude of modeled NOx "disbenefits" (i.e., ozone increases in oxidant limited areas when NOx emissions are reduced).

2.5 Air Quality Model Selection

Chemical transport models address the physical processes and chemistry that form ozone and PM. Air quality models continue to evolve and each has its own strengths and weakness (Galmarini et al., 2012; Pirovano et al., 2012; Russell, 2008; Simon et al., 2012). The most commonly used chemical transport models for attainment demonstrations are the Community Multiscale Air Quality Model (CMAQ) (Byun and Schere, 2006; Foley et al., 2010) and the Comprehensive Air Quality Model with Extensions (CAMx) (Baker and Scheff, 2007; Vizuete et al., 2011). The mention of CMAQ and CAMx is not intended to be a comprehensive list of available chemical transport models and omittance from this discussion does not imply that a different model cannot be used to support a modeled attainment demonstration or reasonable

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progress assessment. In the same way, inclusion in this discussion does not imply that a model is "preferred" for a particular type of application.

A modeling-based demonstration of the impacts of an emissions control scenario for attainment of the ozone or $PM_{2.5}$ NAAQS, or as part of a regional haze assessment, usually necessitates the application of a chemical transport grid model. However, it is not necessary to use a model that considers atmospheric chemistry in addressing changes in primary $PM_{2.5}$ components. Either a numerical grid or a Lagrangian (such as a Gaussian dispersion) model or other empirical techniques could potentially be used for this purpose. In general, modeling primary $PM_{2.5}$ components with a grid model is acceptable, but dispersion modeling may be necessary in areas with large spatial gradients of primary $PM_{2.5}$. Depending on the nature of the problem, an air agency may choose to use a regional chemical transport grid model to address both primary and secondary components of PM or they may need to use a chemical transport model to address secondary $PM_{2.5}$ and regional primary PM and an inert model applied over a more limited domain to address fine scale primary components of PM. In addition, the EPA recognizes that in some cases, more simplistic modeling techniques (such as dispersion, receptor, rollback, and/or box models) may suffice to demonstrate that an area will attain the $PM_{2.5}$ NAAQS, especially in areas that are dominated by primary $PM_{2.5}$ emissions (e.g., residential wood smoke).

A model should meet several general criteria in order to be considered for use in an attainment demonstration or reasonable progress assessment. These general criteria are consistent with requirements in Appendix W (U.S. EPA, 2017a). Appendix W does not identify a "preferred model" for use in attainment demonstrations of the NAAQS for ozone or $PM_{2.5}$ or reasonable progress assessments for regional haze. Therefore, at this time, the EPA is not recommending a specific model for use in ozone or $PM_{2.5}$ attainment demonstrations or regional haze uniform rate of progress assessments. Instead, models used for these purposes should meet requirements for "alternative models" in Appendix W, section 3.2. Air agencies should use a non-proprietary model, which is a model whose source code is available for free (or for a reasonable cost). Furthermore, the user should be able to revise the source code to perform diagnostic analyses and/or to improve the model's ability to describe observations in a credible manner. Several additional prerequisites should be met for a model to be used to support an attainment demonstration or reasonable progress assessment (see Appendix W, section 3.2.2(e), as well as sections 5 and 6 for more general secondary pollutant modeling requirements):

1) The model or technique has received a scientific peer review.

   An air quality model may be considered to have undergone "scientific peer review" if each of the major components of the modeling system has been

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described and tested, and the results have been documented and reviewed by one or more disinterested third parties, and the model has been revised in response to the review. This review is not the responsibility of the EPA. Air agencies should reference available documentation to gain acceptance of an air quality model for use in a modeled attainment demonstration.

2) The model or technique can be demonstrated to be applicable to the problem on a theoretical basis.
    - The model should be scientifically appropriate and applicable for the intended purpose.

3) Databases, which are necessary to perform the analysis, are available and adequate.

4) Appropriate performance evaluations of the model or technique have shown that the model or technique is not inappropriately biased for regulatory application.
    - Prior to use of a selected model's results in an attainment demonstration or regional haze analysis, the model should be shown to perform adequately for the specific application.
    - If the application is the first for a particular model, then the air agency should demonstrate that the new model is expected to perform sufficiently. For a model to be used in an attainment demonstration, evidence should be presented that it has been found acceptable for estimating hourly and 8-hourly ozone concentrations and/or hourly and 24-hour average $PM_{2.5}$ and $PM_{2.5}$ component concentrations. In addition to ozone and/or $PM_{2.5}$, the model should be acceptable for estimating precursor species, important chemical intermediates, and in the case of $PM_{2.5,}$ the main chemical constituents. Preference should be given to models exhibiting satisfactory past performance under a variety of conditions.

5) A protocol on methods and procedures to be followed has been established (such as described in section 2.2.1).

In addition to the criteria in Appendix W, the EPA also recommends the following criteria and considerations:

1) A user's guide (including a benchmark example and outputs) and technical description of the model should be available.

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2) The advanced technical features available in a model could be a consideration when other criteria are satisfied. Models are often differentiated by their available advanced science features and tools. For example, some models include advanced probing tools that allow tracking of downwind impacts from upwind emissions sources. Availability of probing tools and/or science algorithms is a legitimate reason to choose one equally capable model over another.

3) When other criteria are satisfied, resource considerations may be important. This is a legitimate criterion provided the other listed criteria are met.

The EPA has prepared an "alternative model" demonstration for both CMAQ and CAMx for the purposes of supporting ozone or $PM_{2.5}$ attainment demonstrations and regional haze assessments (Fox, 2017). This document is also a useful template for others seeking to provide a similar type of demonstration for another photochemical modeling system.

2.6 Meteorological Inputs

In order to solve for the pollutant concentrations over time and space, air quality models require accurate meteorological inputs to properly simulate the formation, transport, and removal of pollutant material. The required meteorological inputs can vary by air quality model, but all models require parameters such as wind, vertical mixing, temperature, humidity, and solar radiation. While model inputs can be created strictly from ambient measurements, a more credible technical approach is to use off-line, dynamic, meteorological grid models to provide the necessary inputs. When these models are applied retrospectively (i.e., for historical time periods), they are able to blend ambient data with model predictions via four-dimensional data assimilation (FDDA), thereby providing temporally and spatially complete data sets that are grounded by actual observations.

This section provides recommendations for generating the meteorological data sets needed for regional air quality modeling purposes. In many ways, the development of meteorological inputs parallels the steps needed to conduct the air quality modeling. A meteorological model platform (episodes, domain, model selection, model configuration, input data, etc.) must be established and then evaluated. Because of the strong sensitivity of the eventual air quality results to the input meteorology (Appel, 2007; Appel, 2010), it is recommended that air agencies spend extensive effort in developing and evaluating the meteorological inputs.

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2.6.1 Developing Base Year Meteorological Fields

The recommended approach for generating the base year meteorological data needed to conduct the attainment or regional haze demonstration is to apply off-line, dynamic meteorological models with FDDA. These models use the fundamental equations of momentum, thermodynamics, and moisture to determine the evolution of specific meteorological variables from a given initial state. When modeling historic episodes, the use of data assimilation helps to "nudge" solutions so that they do not diverge greatly from the actual observed meteorological fields. A major benefit of using dynamic meteorological models is that they provide a way of consistently characterizing conditions at times and locations where observations do not exist.

The Weather Research and Forecasting (WRF) (Skamarock, 2008) model is a community supported mesoscale numerical prediction model that replaced the previous community supported mesoscale meteorological model v5 (MM5) model. The MM5 model is no longer being updated or supported. Meteorological models other than the WRF can be used as long as they are appropriate for the situation being modeled and are properly evaluated. A number of recent studies (Appel et al., 2010; de Meij et al., 2009; Gilliam et al., 2010; Matichuk et al., 2017; Pleim et al., 2016) have compared the ability of the WRF and MM5 models to reproduce past meteorological conditions and their suitability for use in air quality modeling. Generally speaking, comparative evaluation efforts have shown that the WRF model outputs represent equivalent or better statistical skill over a variety of meteorological conditions. An additional advantage of the WRF model is that there is a large community of WRF users and developers. As a result, the code is both maintained and frequently updated as new science emerges. The EPA recommends the use of a well-supported gridded mesoscale meteorological model for generating meteorological inputs to regional air quality model attainment demonstrations.

In some cases, however, there may be legitimate reasons for using an approach other than well-supported gridded mesoscale meteorological models to provide the requisite meteorological data. For instance, there may be long-standing local experience for a given domain and/or episode with a different meteorological model. In other cases, dynamic meteorological models may not adequately capture key meteorological elements of an airshed's conceptual model (e.g., source-receptor transport vectors to key monitoring locations). In rare cases such as these, it may be appropriate to blend the dynamic model data with wind data from an objective analysis of observed wind fields. The guiding factor in determining which meteorological model or approach to use should be an assessment of which set of inputs will best capture the key meteorological conditions that led to poor air quality. It is recommended that a description of the methods used to generate the meteorological fields be

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included in the modeling protocol. For those cases in which an off-line prognostic meteorological model is not used, it is recommended that a detailed description of the alternate technique that will be used to generate the three-dimensional meteorological fields be shared with the appropriate EPA Regional office(s) prior to conducting the meteorological analysis and air quality modeling analysis.

As with other parts of the air quality modeling system, choices made regarding how to configure the meteorological modeling can affect the quality and suitability of the air quality model predictions. Decisions regarding the configuration of complex dynamic meteorological models can be particularly challenging because of the amount of flexibility available to the user. The goal in establishing the proper configuration for meteorological modeling should be to obtain the best possible meteorological model performance, especially for those parameters identified as most important in the conceptual description. As part of the overall chemical transport modeling system evaluation process, performance issues in the chemical transport model can sometimes be explained by options chosen in the meteorological simulation. Therefore, a feedback between the meteorological model evaluation and the air quality model evaluation can be highly beneficial.

2.6.1.1 Selecting a Model Domain

The selection of the meteorological modeling domain should closely match the air quality domain. The outermost grid should capture all upwind areas that can reasonably be expected to influence local concentrations of ozone and/or $PM_{2.5}$. In terms of selecting an appropriate meteorological modeling domain, one should extend the grid at least 3 to 6 cells beyond the domains of each air quality modeling grid to avoid boundary effects. It is recommended that the vertical and horizontal grid structures, including geographic datum and projected coordinate definitions, be generally consistent within the meteorological and air quality models to minimize interpolation and aggregation issues associated with the post-processing of meteorological model outputs into air quality model inputs.

2.6.1.2 Selecting Physics Options

Meteorological models have a suite of physics options that allow users to configure how a given meteorological effect will be simulated. For example, there may be several options for specifying the planetary boundary layer scheme or how sub-grid cumulus clouds will be handled. In many situations, the "optimal" configuration cannot be determined without performing an initial series of sensitivity tests, which consider various combinations of physics options over specific time periods and regions. While these tests may not ultimately conclude that any one configuration is clearly superior at all times and in all areas, it is recommended

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that these sensitivity tests be completed, as they should lead to a modeling analysis that is best suited for the domain and period being simulated. An optimal starting point of physics options may be selected from another modeling application that has a similar set of meteorological conditions that lead to elevated pollutant levels. Typically, the model configuration that yields predictions that provide the best statistical match with observed data over the most cases (episodes, regions, etc.) is the one that should be chosen, although other more qualitative information can also be considered. Additionally, model configurations should be designed to account for the pollutants and time periods that are of most interest, per the conceptual description.

2.6.1.3 Use of Data Assimilation

As noted above, the use of FDDA helps to keep the model predictions from widely diverging from what was actually observed to occur at a particular point in time/space. Studies have shown that the incorporation of FDDA into atmospheric models improves meteorological simulations (Otte, 2008a and b; Pleim and Gilliam, 2009; Gilliam and Pleim, 2010). In particular, these studies have shown that better representation of the atmospheric fields aloft through assimilation of data from nationwide atmospheric profiler networks can aid in reproducing certain meteorological features (e.g., low-level jets) (Godowitch et al., 2011; Gilliam et al., 2012). However, if used improperly, FDDA can significantly degrade overall model performance and introduce computational artifacts (Tesche and McNally, 2001). Inappropriately strong nudging coefficients can distort the magnitude of the physical terms in the underlying atmospheric thermodynamic equations and result in "patchwork" meteorological fields with strong gradients between near-site grid cells and the remainder of the grid. Additionally, if specific meteorological features are expected to be important for predicting the location and amount of pollution formed, based on an area's conceptual model, then the meteorological modeling should be set up to ensure that FDDA does not prevent the model from forming these features (e.g., lake/sea breeze circulations).

In general, analysis nudging strengths should be no greater than 3.0×10^{-4} for winds and temperatures and 1.0×10^{-5} for water vapor mixing ratio. In the case of observation nudging (i.e., FDDA based on individual observations as opposed to analysis fields), it is recommended that the resultant meteorological fields be examined to ensure that the results over the entire domain are still consistent. Further, based on past experience, we recommend against using FDDA within the boundary layer for thermodynamic variables like temperature and water vapor mixing ratio because of the potential for spurious convection. If the dynamic model is applied without FDDA, it is suggested that the simulation durations be no longer than 24 hours. As with selecting physics options, it is often valuable to conduct sensitivity testing of various FDDA approaches to help determine the optimal nudging configuration for any specific case.

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Along with application of the meteorological modeling, users should be careful when translating the meteorological model outputs into air quality modeling inputs. A number of air quality model pre-processors (which are meteorological model post-processors) exist to conduct this off-line coupling, including the Meteorology-Chemistry Interface Processor (MCIP) (Otte and Pleim, 2010) and wrfcamx (Ramboll-Environ, 2017). These meteorological post-processors generate the complete set of meteorological data needed for the air quality simulation by accounting for issues related to:

1) Data format translation;
2) Conversion of parameter units;
3) Extraction of data for appropriate window domains;
4) Reconstruction of the meteorological data on different grid and layer structures; and
5) Calculation of additional variables.

As noted above, most meteorological modeling applications should be set up to minimize the influence of the pre-processing software. For instance, it is recommended that the horizontal grid structures be consistent within the meteorological and air quality models to minimize issues associated with interpolation and aggregation. While it is often not feasible to run the air quality model with the same vertical layer structure as the meteorological model, it is recommended that vertical layer collapsing between the models be minimized (preferably with no layer collapsing), to the extent possible.

While the traditional approach for attainment and regional haze demonstration modeling is to convert "off-line" meteorological model outputs into air quality model inputs via specific pre-processing tools, there have been recent efforts to couple "on-line" meteorological models within air quality model applications, such as WRF-Chem (Grell et al., 2005; Wilczak et al., 2009), NOAA-EPA CMAQ (Davidson et al., 2007), and WRF-CMAQ (Wong et al., 2012). The advantage of an on-line meteorological model is that one can simulate impacts that air quality changes might have on meteorological conditions (and vice versa) through direct and indirect feedback mechanisms. In most cases, the EPA does not expect emissions reductions from local SIP reductions to appreciably affect future meteorological conditions. Therefore, off-line meteorological approaches, where the same meteorological fields are used for multiple emissions scenarios, are expected to be sufficient for the majority of SIP modeling exercises.

2.6.2 Assessing Impacts of Future Year Meteorology

Traditionally, SIP meteorology simulations have not accounted for the impact of global emissions of carbon dioxide and other climate forcers on future meteorological conditions. However, ozone concentrations have a high correlation with daily maximum temperatures over many areas in the U.S. (Camalier et al., 2007), suggestive of a potential climate connection.

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Recent research, taking into account temperature and other meteorological variables, indicates that in certain populated regions of the country, climate change could lead to higher future ozone concentrations (often called a "climate penalty") (Jacob and Winner, 2009; Bloomer et al., 2009; U.S. EPA, 2009; CARB 2010; Fiore, 2012; Fann, 2016). Assuming climate change does lead to higher ozone concentrations, there could potentially be a need for more stringent emissions reductions to counteract the higher ozone potential from warmer conditions. However, there are significant uncertainties regarding the precise location and timing of climate change impacts on air quality. Generally, climate projections are more robust for periods at least several decades in the future because the forcing mechanisms that drive near-term natural variability in climate patterns (e.g., El Nino, North American Oscillation) have substantially larger signals over short time spans than the driving forces related to long-term climate change. In contrast, projections for SIP purposes are generally for time spans of less than 20 years. Given the relatively short time span between base and future year meteorology in most SIP demonstrations, the EPA does not recommend that air agencies explicitly account for long-term climate change in attainment demonstrations. However, air agencies are welcome to consider potential climate impacts in their specific areas, especially where and when there is evidence of significant potential impacts.

2.6.3 Evaluation of Base Year Meteorological Fields

While the air quality models used in attainment and regional haze demonstrations have consistently been subjected to a rigorous performance assessment, in many cases the meteorological inputs to these models have received less rigorous evaluation, even though this component of the modeling is quite complex and has the potential to substantially affect air quality predictions (Tesche, 2002). The EPA recommends that air agencies devote appropriate effort to the process of evaluating the meteorological inputs to the air quality model as we believe good meteorological model performance will yield more confidence in predictions from the air quality model. One of the objectives of this evaluation should be to determine if the meteorological model output fields represent a reasonable approximation of the actual meteorology that occurred during the modeling period. Further, because it will never be possible to exactly simulate the actual meteorological fields at all points in space/time, a second objective of the evaluation should be to identify and quantify the existing biases and errors in the meteorological predictions in order to allow for a downstream assessment of how the air quality modeling results are affected by issues associated with the meteorological data. To address both objectives, it will be necessary to complete both an operational evaluation (i.e., quantitative, statistical, and graphical comparisons) as well as a more phenomenological assessment (i.e., generally qualitative comparisons of observed features versus their depiction in the model data).

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2.6.3.1 Operational Evaluation

The operational evaluation results should focus on the values and distributions of specific meteorological parameters as paired with and compared to observed data. It is recommended that the observation-model matching be paired as closely as possible in space and time. Typical statistical comparisons of the key meteorological parameters will include: comparisons of the means, mean bias, normalized mean bias, mean absolute error, normalized mean error, and root mean square error. For modeling exercises over large domains and entire ozone seasons or years, it is recommended that the operational evaluation be broken into individual segments such as geographic subregions and/or months/seasons to allow for a more comprehensive assessment of the meteorological strengths and weaknesses. It may also be useful to break out model performance aloft, at the surface, during individual episodes (e.g., high ozone/$PM_{2.5}$ days), over the diurnal cycle, and as a function of synoptic regime. Modelers are also encouraged to set aside a portion of the ambient data strictly for evaluation purposes (i.e., data not used in the FDDA). Examples of observed meteorological data sets available for operational evaluations include (some of these data sets are not typically used in FDDA and, therefore, may be serve as an "independent" source of evaluation data):

1. TDL U.S and Canada Surface Hourly Observations (http://rda.ucar.edu/datasets/ds472.0);
2. Cooperative Agency Profilers (https://madis-data.noaa.gov/cap/);
3. NOAA Profiler Network (http://profiler.noaa.gov/npn/);
4. Individual State Climate Office Observation Networks; and
5. PRISM Climate Group Precipitation Analysis (http://www.prism.oregonstate.edu/).

While these data are readily available, it is up to the air agency to determine if the data have undergone appropriate quality assurance/quality control (QA/QC) procedures through the provider.

It may be helpful when calculating domainwide and/or regional summary statistics to compare the results against previously generated meteorological model performance "benchmarks" (Emery et al., 2001). However, because of concerns about potentially misleading comparisons of model performance findings across different analyses with differing model configurations and FDDA strengths, the EPA does not recommend using these benchmarks as a "pass/fail" indicator of the acceptability of a model simulation. The benchmarks should only be used as a means of assessing general confidence in the meteorological model data. Statistical results that are outside the range of the compiled benchmarks may indicate a performance issue that should be given further examination. In some cases, adjustment of input data and/or model settings may be needed in order to improve model performance. The Atmospheric Model

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Evaluation Tool (AMET) was designed for use in the assessment of meteorological and chemical transport models. AMET provides a method of pairing observed and simulated values and performing common analysis techniques to evaluate the performance and suitability of atmospheric models.

2.6.3.2 Phenomenological Evaluation

As discussed in section 2.1, it is recommended that a conceptual description of the area's air quality problem be developed prior to the initiation of any air modeling study. Within the conceptual description, it is recommended that the specific meteorological parameters that influence air quality be identified and qualitatively ranked in importance. When evaluating meteorological models or any other source of meteorological data, the focus of the phenomenological evaluation should be on those specific meteorological phenomena that are thought to strongly affect air pollution formation and transport within the geographic area of interest. This event-oriented evaluation should summarize model performance in terms of statistical metrics such as probability of detection and false alarm rate. As an example of a potential phenomenological analysis, many regional air quality modeling exercises attempt to assess the effects of transport of pollutants from one area to a downwind area with the intent of establishing source-receptor relationships. For these types of analyses, accurate transport wind trajectories are needed to properly establish these source-receptor linkages. A useful event-based meteorological evaluation would be to compare model-derived trajectories versus those based on ambient data to determine what error distance can be associated with the model fields. Other examples of phenomenological evaluations would be the replication by the model of low level nocturnal jets, cold pool conditions, fog events, or land/sea breezes.

2.7 How Are the Emission Inputs Developed?

Air quality modeling for 8-hour ozone, $PM_{2.5}$, and regional haze requires emissions data for a base year and future modeling years. While not explicitly a requirement of the implementation rules, the emissions data for modeling are a necessary input to the modeling that is required by the implementation rules as part of the modeled attainment demonstration and for regional haze analyses.

A separate EPA guidance document describes the planning inventories that are specifically required for SIPs and provides an overview of all emission inventory requirements, resources, and techniques. That guidance is the "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations" (U.S. EPA, 2017b), and is used as a key reference throughout this section.

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Many of the issues associated with the planning inventories are also relevant for modeling inventories. We will refer to that guidance here as the "EI SIP Guidance."

Table 1 of the EI SIP Guidance provides a list of emissions estimation resources for emissions inventories. In addition to the resources listed there, the EPA also provides emissions data used in modeling analyses in support of rulemakings. The current available "emissions platforms" are based on 2005, 2007, 2008, 2011, and 2014 base years. These platforms are available publicly on the Emissions Modeling Clearinghouse website. The emissions modeling data and other data included in these platforms can be a starting point for air agencies in developing their own capabilities for preparing emissions for use in air quality models.

2.7.1 What Emissions Inventory Years Should I use for Base and Future Modeling?

For the base year, the EPA does not require a particular modeling year for $PM_{2.5}$ and ozone SIP attainment plans, and regional haze plans. However, for several reasons, it is technically appropriate to use a recent year as the base year. In addition, there are certain regulatory requirements for selecting an appropriate base year for planning inventories. See ozone NAAQS inventory requirements at 40 CFR 51.1315 and $PM_{2.5}$ NAAQS inventory requirements at 40 CFR 51.1008.[17] Currently, the most recent base National Emissions Inventory (NEI) is 2014 (U.S. EPA 2016c), and NEI data are developed every 3 years (the next NEI year will be 2017). In most cases, the most recent NEI year will be the most appropriate year to use for base case modeling. In some cases, other years (either before or after the most recent NEI year) may be more appropriate for modeling in view of unusual meteorology, transport patterns, exceptional events (i.e. large wildfires), lack of air pollution events, or other factors that may vary from year to year. See section 2.3.1 for more information on episode selection. The choice of the base year should be discussed with the appropriate EPA Regional office as part of the SIP planning process for the attainment demonstration.

For attainment planning in particular, the choice of a future year for an inventory depends on the nonattainment classification of the nonattainment area, as described in section 2.3.2. For ozone and $PM_{2.5}$, in most cases the future modeling year will be the expected attainment year. Requirements for selecting appropriate future years for modeling are provided in the ozone and $PM_{2.5}$ NAAQS implementation rules. For regional haze, the future year will depend on the end-date of the planning period being examined.

[17] There are additional regulations related to reasonable further progress (RFP) requirements for both the ozone and $PM_{2.5}$ NAAQS.

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2.7.2 What Base Year Emission Inventory Data Are Needed to Support Air Quality Models?

Air quality models require hourly emissions of modeled species for each grid cell and model layer in the modeling domain. For the base year, the inventories are called the *base year inventory for modeling.* To meet the input requirements of models, the inventory must have pollutants that are the scientific precursors (pollutants that impact the relevant chemistry) to the ozone, $PM_{2.5}$, and/or regional haze being addressed in the modeling demonstration. The time frame of the emissions inventory should be consistent with the period being modeled. The inventory should include states, counties, and tribes that are covered by the spatial extent of the modeling domain. Additionally, the emissions sources included should be comprehensive, including emissions from all source categories. As explained with additional detail below, this includes point sources, non-point stationary sources, on-road and nonroad mobile sources, fires, and biogenic sources.

2.7.3 What Pollutants Should Be Included in Base Year Inventories?

Because many sources emit more than one of the precursor pollutants, and because the precursor pollutants have the potential to be transported across state boundaries, the EPA encourages air agencies to develop comprehensive inventories to support integrated, regional-scale modeling, and control strategy development for ozone, $PM_{2.5}$, and regional haze. However, there are some considerations for which pollutants to include in inventories for the purpose of supporting air quality modeling.

For 8-hour ozone NAAQS modeling, the pollutants to be inventoried for modeling are VOC, NO_X, and CO. For $PM_{2.5}$ NAAQS modeling, the pollutants to be inventoried are primary emissions of $PM_{2.5}$ and PM_{10} (including both the filterable and condensable portions) and emissions of SO_2, NH_3, VOC, NO_X, and CO. While certain $PM_{2.5}$ precursors may not be considered precursors for planning purposes in some nonattainment areas[18], inclusion of all precursors is a prerequisite for appropriate application of air quality models for modeled attainment demonstrations. For regional haze, the pollutants to be inventoried include all of the pollutants and precursor pollutants identified for ozone and $PM_{2.5}$. While CO does not need to be included in the *planning inventories* associated with ozone and/or $PM_{2.5}$ SIP submissions (as described in the EI SIP Guidance), it should be included for modeling purposes because CO plays an important role in atmospheric chemistry.

[18] See the $PM_{2.5}$ SIP requirements rule for detailed information on the definition of "planning" precursors for $PM_{2.5}$ nonattainment areas.

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For modeling purposes, emissions inventories of these pollutants undergo many transformations to prepare the inventories for use in air quality models. These transformations include chemical speciation, which is described below in section 2.7.8.2. As part of the chemical transformations of VOC, in particular, total organic gases (TOG) are calculated to include lower reactivity compounds that are not included in the regulatory definition of VOC, but nonetheless have some role in ozone and/or $PM_{2.5}$ formation.

2.7.4 What Temporal Resolution Should Be Used for Base Year Inventories?

The emissions inventories should cover the time periods associated with the modeled time period. Different approaches to accomplishing this goal arise because of the nature of ozone, $PM_{2.5}$, and regional haze problems.

For ozone, the episodic nature of 8-hour ozone exceedances leads to inventories that may reflect a specific period being modeled. For this reason, the *planning* inventories should be provided as an ozone season day inventory[19] (as described in the EI SIP Guidance). For the nonattainment area, the planning ozone season day inventories are also often used for modeling inventories.

For $PM_{2.5}$, both annual and daily NAAQS result in different inventory temporal possibilities for the modeling episode, depending on which NAAQS a particular nonattainment area must address in the SIP. As a result, the *planning* inventories may be annual, seasonal, or both. Like ozone, the planning inventories may also be used as the starting point for the modeling inventories. For example, an annual planning inventory will need to be temporally allocated to the days and hours of the time period used for $PM_{2.5}$ modeled attainment demonstrations. This is the case for both annual modeling and when the air agency has chosen to use a seasonal demonstration as part of a 24-hour demonstration.

Modeling inventories also include areas outside the nonattainment area, for which ozone season day or average season day (for $PM_{2.5}$) emissions may not be readily available. In these instances, air agencies may elect to start with an annual inventory and use an emissions model to adjust the annual emissions to reflect the modeling period. This may not be advisable in every case; in particular, mobile source emissions are highly variable with meteorology and day of the week, and are often available on a monthly or even daily basis that reflects variability in temperature, traffic patterns, and other factors. In addition, more detailed temporal data from electric generating units (EGUs), biogenic sources, windblown dust, sea salt, lighting, wildfires,

[19] The definition of "ozone season day" emissions specifies weekday emissions and is intended to reflect the periods of emissions associated with monitored ambient ozone exceedances.

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prescribed fires, agricultural burning, or other sources should be used when available to enhance the technical quality of the modeled attainment demonstration.

For regional haze, the use of annual emissions inventories is appropriate given the nature of the regional haze problem. However, the same considerations apply for the inventory's temporal aspects as they do in the cases above; more detailed temporal data should be used as the inventory starting point when it is available for important sources of the pollutants included in the inventory.

2.7.5 What Spatial Coverage Is Needed for Base Year Inventories?

Modeling inventories must cover all areas of the modeling domain, which will include areas outside of a nonattainment area and Class I areas and most often includes areas in neighboring states or tribes. This subsection addresses areas within and outside the nonattainment area separately.

2.7.5.1 Areas Within the Nonattainment Area

As mentioned above, planning inventories (which are a CAA and regulatory requirement for ozone and $PM_{2.5}$ SIPs) include emissions within the nonattainment area. The EPA expects that modeling inventories will be consistent with those planning inventories; however, some exceptions may exist. Where possible, the planning inventories (which are typically annual or seasonal) can be a sum (for annual data) or average (for ozone or $PM_{2.5}$ season day data) of day-specific or hour-specific data used for modeling. In some cases, however, this approach may not be sufficient for modeling purposes. For example, greater spatial and temporal detail are needed for on-road mobile modeling inventories as compared to the base year (planning) inventory for the nonattainment area. For the planning inventory, one goal is to allow for the repeatability of the approach in order to create average, seasonal, or annual inventories for use in rule requirements, such as reasonable further progress or conformity demonstrations. That goal is not necessarily compatible with the modeling need for spatial and temporal detail. In cases where some differences between planning and modeling inventories are unavoidable, air agencies should attempt to promote consistency where feasible. More information on the temporal basis of inventories is provided in section 4.5 of the EI SIP Guidance.

2.7.5.2 Areas Outside of the Nonattainment Area

For air quality modeling, emissions inventories are often needed for areas outside the nonattainment area. Developing modeling inventories for these areas should be relatively straightforward and can be included as part of the SIP planning inventories. For areas outside of

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the air agency's jurisdiction, however, it can be more difficult for air agencies to develop the inventories themselves. In these cases, the EPA encourages participation in regional modeling efforts, which are designed to allow sharing of data and help promote consistent approaches across state boundaries. When those organizations lack the needed inventories, the EPA recommends using the EPA's publicly available emissions, as described in the next section.

2.7.5.3 Areas Outside of the United States

In some cases, the modeling domain may need to extend into areas of Canada and/or Mexico. In this case, emissions modelers will need to include emissions from these countries in their modeling domain. Both Canada and Mexico have emission inventory programs that provide inventories that can be used in modeling, and the EPA includes the latest available inventories from these countries in its national emissions modeling platform. States are encouraged to use the latest available data for these countries. While the EPA is one source for that data, states may work directly with other countries or work with their EPA Regional office to try to get inventories that are more current or otherwise improved over what is available directly from the EPA.

2.7.6 How Can the National Emission Inventory Be Used by Air Agencies?

The EPA recommends that state, local, and tribal agencies start with available inventories suitable for air quality modeling of the selected time period(s). If no such inventories are available from a prior state or tribal effort, from regional modeling groups, or from some other source, air agencies may choose to derive an inventory suitable for use with models from EPA-provided information. Two sources of information are available, as described below. In both cases, the EPA expects that air agencies will only use such data after additional review to ensure the appropriate quality of the data for SIP planning purposes.

First, the National Emission Inventory (NEI) provides criteria air pollutant and hazardous air pollutant emissions as annual emissions totals for most (if not all) sources of emissions relevant for ozone, $PM_{2.5}$, and regional haze implementation purposes. Air agencies may use the most recent public release of the NEI as a starting point for inventory development. The data and documentation are available from the NEI Website.

Additionally, the EPA provides emissions modeling "platforms" that are based on the NEI and can be a starting point for air agencies. The modeling platform data provide additional information not available from the NEI, such as daily EGU and fire emissions, monthly nonroad emissions, biogenic emissions and/or input to biogenic emissions models, and inputs to mobile source models. Furthermore, these modeling platforms usually include future-year emissions

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projections. Both base and future-year data are provided in a format used by emissions models and can, therefore, be more readily adopted by air agencies that need to process emissions for use in air quality models. The data and documentation are available from the latest platform release at the Air Emissions Modeling Website.

The detail and accuracy of the EPA emissions inventories and platforms may or may not be sufficient for use in any particular SIP. Air agencies should review the emissions and associated documentation and make improvements where deficiencies exist. Such improvements will often be necessary to demonstrate appropriate model performance, as described in section 3. Additional degrees of review are needed for areas closer to the nonattainment area. For example, EPA data may be sufficient for estimating emissions in states that are hundreds of kilometers upwind or downwind of the nonattainment area, but may not be sufficient for estimating emissions closer to the nonattainment area because those emissions can have a greater impact on the final results of the attainment demonstration.

2.7.7 How Should Base Year Emissions Be Created?

Emission inventory data from at least five general categories are needed to support air quality modeling: stationary point-source emissions, stationary area-source emissions (also called non-point), emissions for on-road mobile sources, emissions for nonroad mobile sources (including railroad and marine vessels), and biogenic/geogenic emissions. A sixth category of wildland fires also exists and includes day-specific emissions from wildfires and prescribed burns. These fire emissions are included as an "event" source in the NEI. Emissions inventories are expected to include "all" sources of emissions; if an air agency wishes to exclude a particular source (e.g., because it is a very small contributor), then the air agency should document the reasons such omissions are acceptable. In addition, some "traditional" nonroad mobile sources (e.g., airports and rail yards) can also be included in inventories as a point source. For example, in the NEI, airports and rail yards are included as point sources and railroad and marine vessel emissions as part of the nonpoint data category.

The EI SIP Guidance (U.S. EPA, 2017b) addresses numerous details about emissions inventory development. Readers are encouraged to refer to information in that document as a resource for building base year emissions inventories. That guidance contains additional information on the definitions of the data categories (point sources, nonpoint sources, etc.), provides more information about emissions estimation for each data category, includes a process for prioritization of inventory development, and includes quality assurance recommendations. All of this information is highly relevant to inventories developed for air quality modeling. In the remainder of this section, we provide a basic description of the data categories and their base

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year emissions and additional information needed for their use in modeling applications where appropriate.

2.7.7.1 Point Sources

Point sources are emissions sources that are attributed to specific facilities and emissions release points within those facilities. The Air Emissions Reporting Rule (AERR) provides information on how to define which sources to include as specific point sources in the inventory. This definition is the same as the New Source Review program major source definition, with a lower potential-to-emit threshold for nonattainment areas. More information on the relationship between SIP inventories and the AERR and how that affects SIP inventories is available in the EI SIP Guidance. For modeling inventories, data developers may include sources with emissions smaller than the required reporting threshold, and should be careful to prevent double counting with nonpoint source categories that may overlap with some of these smaller sources. This is especially a concern when compiling point and nonpoint inventories from different sources, because a nonpoint inventory is compiled using certain assumptions about what an associated point source inventory includes. This issue is described as "nonpoint reconciliation" and is discussed further in the EI SIP Guidance.

Point source inventories for modeling should be compiled at a minimum by country, state/tribe, county, facility, unit, process or source category code (SCC) and by "release point" or stack (see references below to point-source inventory development). The point source data should include information on the location of the sources (e.g., latitude/longitude coordinates); their stack parameters (e.g., stack diameter and height, exit gas temperature and velocity); and operating schedules (e.g., monthly, day-of-week, and diurnal). Information on existing control device types, measures and associated emissions reductions are also useful to identify sources that might be further controlled and to prepare future year inventories.

For air quality modeling purposes, the precision of the latitude/longitude values can be very important, as it will determine the modeled grid cell of the source. It is recommended to use coordinates reported to one-ten-thousandth of a degree (four digits after the decimal point) to give a precision of approximately 30 feet. In addition, metadata about the latitude/longitude should ideally be collected, such as the horizontal reference datum code used (e.g., WGS84). The EPA provides a data standard for latitude/longitude which can be considered when collecting, storing, and reporting latitude and longitude data values (see here). When working with other states to share point source data, it may be useful to use the same horizontal reference datum across states, such as the World Geodetic System of 1984 (WGS84). Other datum codes listed on the EPA Data Element Registry Services include the North American Datum of 1927 (NAD27) and the North American Datum of 1983 (NAD83).

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For modeling needs, many point sources will also be post-processed for the estimation of plume rise of the emissions vertically through layers of the atmosphere as modeled by the air quality model. This plume rise depends on the stack parameters (listed above) and on meteorological conditions. Plume rise can be calculated by emissions models or as part of air quality models (either approach is acceptable and the results can be equivalent). In this latter case, inventory developers are responsible only for identifying for which sources' plume rise will be computed using tools available in emissions models.

Also, for modeling needs, hourly emissions data are usually a starting point for inventories of EGUs. In most cases, such data are readily available from Continuous Emissions Monitoring Systems (CEMS) installed as part of EPA trading programs[20] and include hourly emissions of NO_X, SO_2, CO_2, and heat input. The heat input data can be used to estimate hourly emissions of other pollutants (such of primary $PM_{2.5}$ emissions) using facility-specific emission factors or other emission factors. The EPA's modeling platforms also include these hourly data.

2.7.7.2 Nonpoint Sources

Nonpoint sources are also called "area sources." These sources collectively represent sources of emissions that have not been inventoried as specific point sources. The individual sources within the nonpoint emissions county totals are typically too small, numerous, or difficult to inventory using the methods for point sources. The nonpoint emissions data should be compiled by country, state/tribe, county, and SCC, and sometimes by emission type (e.g., hoteling and cruising for commercial marine emissions in the NEI) and Geographic Information Systems (GIS) shape (for locomotive and commercial marine emissions in the NEI). The specification of nonpoint emissions at a more detailed resolution than county is typically not necessary for modeling inventories, but can provide a more detailed spatial representation for areas where such an approach is needed. Spatial allocation of emissions with spatial surrogates (see section 2.7.8.3) can be equally effective.

2.7.7.3 On-Road Mobile

Emissions from on-road vehicles are the result of several emission processes, including the combustion of fuel while vehicles are starting, idling, and moving, evaporation of fuel from the fuel system and during refueling, and from brake wear and tire wear.

[20] CEM data are provided by the EPA's Clean Air Markets Division in a format suitable for use in emissions processing at the Air Markets Program Data Website. From this page, click the "Prepackaged data" tab and scroll to the bottom to download the data in a form that can be input into SMOKE.

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Mobile source inventory modelers should use the latest version of the Motor Vehicle Emission Simulator (MOVES) for on-road mobile source emissions. They should also subscribe to the MOVES email list to be notified of any bug fixes or updates to the MOVES model. For on-road emissions in California, the most recent EPA-approved version of the EMission FACtors model (EMFAC) should be used. In addition, the Sparse Matrix Operator Kernel Emissions (SMOKE) emissions modeling system includes tools that support the use of MOVES emission factors with SMOKE, and thereby allows modelers to account for the sensitivity of on-road emissions to temperature. SMOKE uses county-specific inputs and gridded hourly temperature and other meteorological information, which is typically based on the same meteorological data used for air quality modeling.

Emissions modelers have a choice in MOVES between "inventory" mode and "emission factors" mode (which creates emission factors that can be further processed using SMOKE-MOVES). Both approaches are valid for supporting air quality modeling for SIPs. More information on the different ways of running MOVES is provided in the MOVES documentation and guidance.

Modelers should consider using a refined approach (such as the SMOKE-MOVES system, day-specific MOVES runs, or some other approach) for use in emissions modeling needed for modeled attainment demonstrations. The SMOKE-MOVES approach first generates emissions rates from MOVES by process (running, start, vapor venting, refueling, etc.), vehicle type, road type, temperature, speed, and hour of day, according to specified fuel parameters and other inputs. Then, subsequent steps apply the appropriate MOVES emissions rates along with vehicle miles traveled (VMT) and vehicle population data for the counties and grid cells in the modeling domain for each hour of the modeling episode.

The MOVES model allows modelers to override default database settings to obtain a locality-specific on-road inventory, and EPA strongly encourages data developers to develop and use MOVES input databases that are specific to the states and counties within the modeling domain. The MOVES Technical Guidance[21] discusses when local data should be used in place of model default data, as well as potential sources of local data.

For some input parameters, there is overlap with the inputs needed for other models, such as the nonroad mobile models. For example, meteorology and fuels information is needed to drive both the mobile and non-road emissions models. Efforts should be made to use the same source of data across multiple categories when the inputs are shared by multiple models. Not doing so calls into question the validity of one or both approaches. Air agencies should explain

[21] The most current version of this document is available on the MOVES website.

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the use of shared inputs, or reasons for not using them, as part of the documentation prepared with their modeled attainment demonstration.

On-road emissions and VMT should be compiled at least at the country, state/tribe, county, and SCC level. Vehicle population data by county and vehicle type should also be compiled as well as idling hours, if available. For some inputs such as VMT, modelers may optionally compile and use data for individual road segments (called "links"). Link approaches require starting and ending coordinates for each road link. Link-based modeling is typically performed for fine scale (i.e., 4-km or finer) modeling studies. Travel Demand Models (TDMs) can be a source of data needed to develop link-based approaches. In regional scale modeling, county-level on-road emissions can be allocated onto road links using spatial surrogates that are generated based on link data and mapped into the modeling grid cells using appropriate weights.

2.7.7.4 Nonroad Mobile Equipment

Nonroad mobile equipment emissions result from the use of fuel in a diverse collection of vehicles and equipment, and the EPA's NONROAD emissions model estimates these emissions. The NONROAD model was originally a separate model, but has now been incorporated into the MOVES model (starting with MOVES2014a). Nonroad emissions should be compiled as country, state/tribe, county and SCC totals.

For the MOVES2014a version of MOVES and later versions, the MOVES model should be used to calculate nonroad source emissions. MOVES2014a (and newer versions) includes features not previously available in MOVES that simplify processing of emissions output and includes updated fuel input files that result in small changes in emission results. In addition, the prior tools available for nonroad emissions estimations (NONROAD2008 and NMIM2008) may no longer work with current operating systems, and the EPA cannot continue to provide technical support for these models. Therefore, the EPA recommends that for modeling nonroad emissions, MOVES2014a or newer versions be used for all new SIP development, although state and local agencies that have already completed significant work with MOVES2014, NONROAD2008, or NMIM2008 can continue to do so to allow for timely submission of the SIP. As a general matter, air agencies should review and possibly update and customize the MOVES model inputs to give better emissions estimates for their state.

Unlike models for onroad emissions, the EPA does not specifically "approve" nonroad models. However, use of alternative models can be justified as part of a SIP submission. For example, California has previously developed and used a state-specific approach for estimating its nonroad source emissions for SIP purposes, called OFFROAD2007. Although this model has now been replaced by category-specific methods for many categories, it is still the default approach for categories not listed with newer methods, as described on the OFFROAD website. Any use

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of such an alternative approach is subject to review by the EPA as part of the review of the SIP, and thus states are encouraged to coordinate with Regional offices on any use of alternative models. The MOVES nonroad capabilities include more than 80 basic and 260 specific types of nonroad equipment and further stratifies equipment types by horsepower rating. Fuel types include gasoline, diesel, compressed natural gas (CNG), and liquified petroleum gas (LPG). The nonroad capabilities of the MOVES model estimates emissions for all criteria pollutant and precursors from both exhaust and non-exhaust processes (diurnal, refueling spillage, vapor displacement, hot soak, running loss, take permeation, hose permeation, and crankcase emissions). MOVES supports many SIP-related inventory development needs, including support for partial counties and seasonal emissions.

Air agencies are encouraged to replace default model inputs with more representative data. Common input adjustments include equipment population, geographic allocations, and local growth rates. If agencies make changes to default model values, the agency should submit the input files to the EPA as well as a description of why the defaults were changed. As mentioned in the previous discussion of on-road mobile emissions, for some input parameters, there is overlap with the inputs needed for other models, such as the on-road mobile models (e.g., meteorology and fuels). Efforts should be made to use the same source of data across multiple categories when the inputs are shared. Not doing so calls into question the validity of one or both approaches. Air agencies should explain the use of shared inputs, or reasons for not using them, as part of the documentation provided with their inventories.

2.7.7.5 Nonroad Mobile: Commercial Marine Vessels, Locomotives, and Aircraft

Emissions from commercial marine vessels, locomotives, and aircraft are estimated in other ways as described in detail in the EI SIP Guidance. These sources can be particularly important for urban areas and in some Class I areas (especially in coastal areas). The EI SIP Guidance contains information about methods available to estimate emissions from these sources.

Commercial marine vessel emissions can be a particular challenge for nonattainment areas that include ports or are adjacent to major shipping lanes. While the level of emissions from these vessels can be outside of the control of state air agencies (coming under national rather than state jurisdiction), it is still important to accurately represent these emissions when they are significant contributors in the vicinity of a nonattainment area or Class I area. Vessels are divided into the largest ocean-going “category 3” (C3) vessels and the smaller “category 1” (C1) and “category 2” (C2) vessels such as tug boats, ferries, support vessels, fishing vessels, and others. Commercial marine emissions include both in-port emissions and underway emissions, with most (~90% of nationwide emissions) emissions associated with underway activity. For the planning inventories covered by the EI SIP Guidance, air agencies need to include only those

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emissions within state waters. For the modeling inventories, however, air agencies may also need to include emissions in Federal waters when the modeling domains extend more than a few miles offshore. This is especially important for coastal areas where offshore commercial marine emissions may be an important contributor to ozone and/or PM in the nonattainment area and/or visibility impairment in Class I areas.

The current EPA methods for estimating commercial marine emissions use a bottom-up approaches for C1, C2, and C3 vessels. The method uses activity data from Entrance and Clearance Waterbourne Commerce (both from the Army Corps of Engineers) and from a 2007 EPA census of C1 and C2 vessel activities. The most recent documentation for EPA methods is provided in the 2014 NEI v2 Technical Support Document, section 4.19.

Uncertainties in estimating commercial marine emissions with EPA's current methods remain. Thus, the EPA strongly encourages air agencies preparing modeling inventories to seek out, develop, and use local-specific information about their ports and waterway vessels to better compute emissions whenever possible, and particularly when the commercial marine sector is a major factor in emissions conditions that lead to nonattainment and/or visibility impairment in Class I areas.

2.7.7.5 Biogenic Emissions

Biogenic sources are a subset of natural emissions sources that may be an important component of the emissions inventory. Vegetation (i.e., forests and crops) is the predominant biogenic source of VOC and is typically the only source that is included in a biogenic VOC emissions inventory. Additionally, microbial activity in the soil contributes to biogenic NO emissions.

Biogenic emissions from vegetation and soils are computed using a model that utilizes spatial information on vegetation and land use and environmental conditions of temperature and solar radiation. The model inputs are typically horizontally allocated (gridded) data, and the outputs are gridded biogenic emissions which can then be speciated and utilized as input to chemical transport grid models. Several models exist, and are described more fully in section 2.7.9.2 and the EI SIP Guidance.

Modeled biogenic vegetation emissions are significant for understanding ozone formation, particularly in the Eastern U.S., and the dependence on meteorology makes using case-specific meteorology very important. In addition, the impact and model characterization of biogenic monoterpene and sequiterpene emissions on secondary aerosol formation is important in many areas of the U.S., most notably the Southeast. Therefore, biogenic emissions should be

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generated using hourly meteorology reflective of the time period being modeled to best capture important relationships between temperature, solar radiation, and biogenic emissions.

2.7.7.6 Geogenic and Other Natural Sources

Geogenic emissions are primarily the result of oil or natural gas seeps, soil wind erosion, and sea salt spray. In addition, lightning may also be an important contributor to natural NO emissions in an inventory area. Volcanoes and fumaroles (i.e., vapor or gas vents in a volcanic region) can be additional sources of geogenic emissions. SIP developers should consider these sources as part of their conceptual description. If geogenic sources are identified as potentially contributing to air quality, such emissions should be included in the modeling.

Oil or Natural Gas Seeps

The U.S. Geological Survey Bureau of Ocean Energy Management (BOEM) has documented emissions from oil and gas seeps in the Gulf of Mexico. The University of California Santa Barbara also provides inventory information about California- area seeps. This is an area of ongoing research.

Windblown Dust

Wind erosion may contribute substantially to PM emissions in an area. Emissions from wind erosion is an area of active research and development, and multiple approaches for estimating wind-blown dust emissions are available. For example, the EPA's CMAQ model includes a module that dynamically estimates hourly natural emissions of fine and coarse dust particles due to wind action over arid and agricultural land. The windblown dust approach is based on the work of J.S. Fu et al. (2016). Other examples of windblown dust approaches include Draxler, Ginoux and Stein (2010), Mansell et al. (2006), and Sundram et al. (2004).

Air agencies using any "in-line" approach for windblown dust emissions should evaluate the results of the approach to determine if it provides a reasonable representation of dust emissions in their modeling domains. Air quality models can have an option to output in-line emissions for evaluation, so that modelers can assess and quality assure the emission estimates directly.

Sea Salt and Other Ocean Emissions

The interaction of sea-salt particles in coastal environments with air chemistry can impact concentrations of $PM_{2.5}$ and gas-phase species in the atmosphere. Various emissions estimation methods are available to account for sea salt emissions. For example, the CMAQ model has been updated to account for these emissions, so that emission inventory developers are able to

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rely primarily on the air quality model to internally calculate sea-salt emissions. Additional information for CMAQ is available in Kelly et al., (2010) and Gantt et al., (2015). For CAMx, additional information on sea salt simulations is available in Athanasopoulou et al. (2008). When an in-line approach is used, emissions should be output from the model so that modelers can assess and quality assure the emission estimates directly. When an in-line approach is not used, modelers should consider the possible need for including sea salt emissions data as an input to the air quality model.

In addition to particulate impacts, ozone in coastal areas can be affected by ocean emissions of halogen compounds including chlorine, bromine, and iodine. Many approaches could be taken to represent those emissions. For example, Yarwood et al. (2014) describes an updated chemical mechanism to include halogen chemistry and a CAMx preprocessor that was used to estimate emissions of halogen precursors in coastal areas, and Sarwar (2015) describes a similar halogen chemistry implementation that has been used in CMAQ. Numerous other references are available in the peer reviewed literature that describe halogen chemistry impacts on ozone formation and modeling of that process.

Lightning

Another natural source of emissions is lightning, which produces NO that forms NO_2 in the presence of ozone or in a photochemically reactive atmosphere. The NO and NO_2 are formed in the mid-upper troposphere and can impact the vertical distribution of reactive nitrogen as well as ozone. Because lightning is not a direct source of NO_2, accounting for this source category is more important for air quality modeling purposes than for SIP planning inventory purposes.

Various methods for estimating lightning emissions could be used. For example, the EPA's CMAQ model includes a parameterized approach to estimate NO_X emissions and the vertical distribution that is generated from lightning. The peer reviewed literature contains both a description of the approach (Allen, 2012) and a model evaluation (Appel, 2010). In addition, Koo et al. (2010) describe estimating annual total lightning NO emissions for North America and then spatially and temporally allocating those emissions to model grid cells using convective precipitation activity as a surrogate.

Volcanoes and Fumaroles

Basic information on volcanic gas is available from the USGS. The USGS also has a monitoring program focused on predicting eruptions. Although this program does not include information on pollutant concentrations, the monitoring program website provides potentially useful maps of volcanos using the "Find a U.S. Volcano" pull-down menu near the top of the site. Finally, the publications related to volcanoes search allows for searching publications for pollutant

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keywords such as CO_2, SO_2, gas, hydrogen sulfide, and volcanic gas. Most of these emissions-related articles focus on information in California, Washington, Hawaii, and the Yellowstone area.

2.7.7.7 Wildland and Cropland Fires

Wildland fires are generally defined as any non-structure fire that occurs in wildland (an area in which human activity and development are essentially non-existent, except for roads, railroads, power lines, and similar transportation facilities and structures, if any, are widely scattered). Cropland fires are any non-structure fire that occurs on croplands. The Exceptional Events Rule[22] (which applies to NAAQS implementation) and the Regional Haze Rule define two types of fire that can occur on wildland:

- *Prescribed fire* means any fire intentionally ignited by management actions in accordance with applicable laws, policies, and regulations to meet specific land or resource management objectives.
- *Wildfire* means any fire started by an unplanned ignition caused by lightning; volcanoes; other acts of nature; unauthorized activity; or accidental, human-caused actions, or a prescribed fire that has developed into a wildfire. A wildfire that predominantly occurs on wildland is a natural event.

Inventories used for ozone, $PM_{2.5}$, and regional haze modeling purposes should include wildland (wild and prescribed) and cropland fire emissions. Wildland and cropland fires can emit large amounts of primary $PM_{2.5}$ as well as precursors that can react in the atmosphere to form ozone and secondary $PM_{2.5}$ downwind potentially impacting both urban and Class I areas. Thus, wildfire and prescribed fire emissions should be included in the nonattainment area inventories when and where these emissions occur within the modeling domain during time periods being modeled. Cropland fires can also be inventoried when and where these emissions occurred or as a nonpoint source.

Detailed information about how the EPA develops wildland and cropland (Pouliot et al, 2016) fire inventories can be found in the latest version of an NEI Technical Support Document, such as that provided with the 2014 NEI. The EPA's approach for wildland fires relies on a combination of satellite detection of fires merged with on-the-ground observational data where available. The EPA encourages the use of ground-based observations and local fuel information whenever possible, as these factors can have a large impact on the emissions. One option for obtaining fire date and location information includes the latest version of the

[22] *See* 81 FR 68216, October 3, 2016.

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Satellite Mapping Automated Reanalysis Tool for Fire Incident Reconciliation (SMARTFIRE) system (Du et al., 2013; Sullivan, et al., 2008). Detailed information on the SMARTFIRE system is available in Raffuse et al., 2007. Additional references and information are available as part of the 2014 NEI Technical Support Document. Other sources of fire location, size, duration, and emissions may be available and could be used instead of the SMARTFIRE approach. Examples of other approaches include the WRAP FETS (JFSP, 2013) and the Fire Inventory from NCAR (FINN).

Important aspects of wildland fire that impact resulting emissions estimates include the location of the fire, timing of the fire (start and end date/time), fire type (wild, prescribed, or cropland), fuel type, fuel loading, area burned, and fuel moisture. Daily emissions are allocated to hour of the day using profiles based on fire type. VOC and primary $PM_{2.5}$ emissions are speciated to specific compounds based on profiles generated from laboratory and field testing. The activity information noted is not just critically important for estimating emissions, it is also important toward estimating the heat flux of the fire and subsequent plume rise in the photochemical model. The estimated plume rise can have a large impact on how far downwind smoke can be transported (to a nonattainment area and/or Class I area). Combustion phase can also be an important consideration when modeling wildland fires in terms of emissions, plume rise, and vertical allocation of emissions. Fires that are largely smoldering (such as peat fires) can have different emission factors and have a different profile of VOC and primarily emitted $PM_{2.5}$ emissions.

Since fire emissions can be a large source of emissions, the treatment of fires should be discussed with the relevant EPA Regional office(s) as part of the modeling protocol development process.

2.7.8 What Other Data Are Needed to Support Emissions Modeling?

For modeling purposes, emission inventories need to be converted through emissions modeling from their original resolution (e.g., annual emissions by point source or count) to air quality model input files. Air quality models generally require emissions inputs to be specified by model grid cell, hour, and model chemical species. Modeling inventories also identify which point sources should have their plume rise computed. This section describes the ancillary data that modelers should collect and prepare to allow emissions models to convert the emission inventory data into air quality model inputs.

2.7.8.1 Temporal Allocation

Ancillary data for temporal allocation are necessary for stationary point, stationary area, and all mobile sources. To facilitate temporal allocation of the emissions, factors called “temporal

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profiles" should be created to convert annual emissions to specific months (i.e., monthly profiles), average-day emissions to a specific day of the week (i.e., weekly profiles), and daily emissions to hours of the day (i.e., hourly profiles). Additionally, a cross-reference file is needed to assign the temporal profiles to the inventory records by SCC, facility, geographic area such as state or county, or some other inventory characteristics. Where available, the operating information that may be available from the point-source inventory should be used to create inventory-specific temporal factors. The EPA provides a starting point for the temporal profiles and cross-reference files as part of the latest modeling platforms (previously described), available at the Air Emissions Modeling website.

The EPA has developed a SMOKE utility program (Gentpro) that estimates temporal profiles for residential wood combustion (RWC), agricultural NH_3 from animals, and other generic (user-defined) area sources by relating meteorology to air emission fluxes. Gentpro reads in hourly gridded meteorological data (temperature and wind) from the Meteorology-Chemistry Interface Processor (MCIP)[23] and a gridded spatial surrogate to produce temporal profiles and cross-reference data. Annual MCIP input data are required to calculate temporal profiles with Gentpro and the spatial surrogates are needed to identify the grid cells for computing county-averaged meteorology variables. The Gentpro program is described in the latest SMOKE User's Manual.

For RWC, Gentpro allocates emissions to specific days from annual totals based on a regression equation that was developed by relating daily minimum temperatures and chemical tracers of RWC. This approach results in more RWC emissions assigned to periods of colder temperatures using a user-defined temperature threshold that restricts RWC emissions to days with morning lows below a specific value. Air agencies that use EPA's emissions data for this category should note that this approach has been used to temporally allocate the RWC emissions.

For agricultural NH_3 from animals (i.e., from concentrated animal feeding operations, or CAFOs), Gentpro allocates annual, monthly or daily emissions to hourly emissions based on empirical equations derived from investigations of emissions from animal waste decomposition as a function of temperature and wind speed. The resolution of emissions input to Gentpro for this sector depends on the available data. Air agencies that use EPA's emissions data for this category should note that this approach has been used to temporally allocate agricultural NH_3 emissions from CAFOs.

[23] MCIP is a meteorology postprocessing program. It is typically used to convert WRF meteorological model output data to CMAQ input format. The latest version of MCIP can be found here.

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For point sources, hourly CEMS data are recommended for use in base year emissions modeling rather than temporal profiles, where such CEMS data are available, and with the following caveats. CEMS data are collected as part of emissions compliance and/or trading programs. Because these programs require complete hourly data, alternative emissions values are assigned to hours when CEMS devices are not functioning. These alternative values can be extremely high values (compared to actual emissions rates), in order to motivate CEMS operators to provide a complete data record to the extent possible. As a result, CEMS data may have some anomalies and should be reviewed prior to use in a modeling study. The CEMS data fields include an emissions method code, which identifies the hours with alternative values. Furthermore, CEMS data may be available for only part of a year; therefore, for annual modeling, users should be careful to ensure CEMS data are used for the appropriate periods and total annual emissions are temporally allocated to fill in the other hours of the year.

For wildland fire emissions, the EPA recommends using daily, location-specific fire data such as the NEI "events" sources. These sources can have a large impact on ambient levels of ozone and $PM_{2.5}$, and on regional haze. Although emissions from these sources are largely uncontrollable, the inclusion of all emissions sources (including biogenic and uncontrollable sources) is needed to accurately predict pollutant concentrations and derive relative response factors for both PM and ozone.

As a general matter, the temporal allocation approach should remain consistent between the base year modeling and the future year modeling. Consistency is important when using the RRF approach to make future year projections of ozone, $PM_{2.5}$ and/or visibility, because the results of that approach can be affected by changes in when emissions are modeled to occur. In general, this means that the temporal allocation will be the same between base and future years, except when an intentional change is made to reflect a real expected change in the temporal distribution. An example of such a change includes intentionally reducing emission peaks from units during incidents of poor air quality. In addition, modeling can be specially done for the current year with an emissions case which uses "typical" emissions temporal allocations for major sources, and this case may be different from the current year case, where actual source schedules are used to evaluate model performance.

For future-year modeling there are two choices for representing EGU emissions derived from CEMs data and wildfire emissions. Modelers can use day-specific emissions for both the base and future years, or a "typical year" temporal allocation (averaging) approach can be used to create representative emissions. If a typical year approach is used, it should include similar daily temporal variability as could be expected for any given year (in most cases, the daily temporal variability also needs to be consistent with the base year meteorology). Air agencies should

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discuss the temporal approach to fires (see also section 2.7.11) and point sources with the appropriate EPA Regional office as part of the modeling protocol development process.

2.7.8.2 Chemical Speciation

The emissions models also need information about the chemical species of the VOC, NOx, and $PM_{2.5}$ emissions for all emissions sources. These data are used to disaggregate the total VOC, NOx, and $PM_{2.5}$ emissions to the chemical species expected by the air quality model and are called speciation "factors" or "profiles."

The EPA provides a starting point for the VOC, NOx, and $PM_{2.5}$ speciation data, which are available with the EPA modeling platforms (previously described). The VOC and $PM_{2.5}$ speciation profiles are based on the SPECIATE database, which is available on the SPECIATE website. In addition to the speciation profiles, a speciation cross-reference file assigns speciation profiles. The default EPA speciation cross-reference assigns profiles to sources using SCCs. These speciation profiles in many cases are highly uncertain and should be assessed and improved where possible for emissions source categories that are critical to model performance.

For large or critical VOC and $PM_{2.5}$ sources in the modeling domain, air agencies should consider determining the individual chemical compounds contributing to the total VOC and $PM_{2.5}$. If collected, this information should then be used to compile speciation profiles for the critical facilities or source categories. These speciation profiles should be assigned to the facilities by updating the speciation cross-reference file to support a facility-specific or facility-SCC-specific assignment.

For VOC, low reactivity chemical components including methane have traditionally been calculated by applying a factor to the VOC emissions to calculate total organic gases (TOG). These TOG emissions are then split during emissions processing into the VOC model species that include methane. In limited situations, air agencies may want to investigate the extent that methane emissions and low volatility compounds play a role in ozone episodes and/or secondary $PM_{2.5}$ formation. Additional efforts going beyond the use of the default VOC-to-TOG profiles from the speciation profiles may develop over time.

In some limited cases, it may be of interest to include methane emissions inputs to air quality models to achieve sufficient model performance for a modeled attainment demonstration. Approaches can include incorporating methane emissions from other sources into emissions inventories used for modeled air quality. For example, the MOVES model estimates methane emissions directly, so there would be no need to use VOC speciation to estimate those emissions. Air agencies considering methane as a contributing factor should consult with their

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EPA Regional office to discuss the best sources for such data as this inventory development area is undergoing many changes at this time. Furthermore, more specific VOC-to-TOG factors and speciation profiles may be useful, particularly for analysis related to areas of very high methane emissions. Additionally, the EPA encourages the use of HAP emissions data when available to augment VOC speciation; therefore, we suggest using the inventory HAPs where criteria air pollutants (CAPs) and HAPs were provided by the same data source. When possible, the EPA's modeling platforms generally process the following HAPs rather than relying on VOC speciation: benzene, acetaldehyde, formaldehyde and methanol. These 4 HAPs are collectively known as "BAFM" and are removed from VOC speciation calculations for the remaining VOC HAPs needed for the air quality models. Ethanol can also be added to this "VOC integration" process where ethanol emissions are available. It is entirely up to the user to determine the "integration" status of specific sources in each inventory. A simple test for possible integration of VOC HAPs is the following. For each inventory unique source (i.e., a stack or nonpoint/mobile FIPS+SCC): 1) confirm that VOC HAPs and VOC were reported by the same data provider, and 2) compute VOC HAPs to ensure they are non-zero and less than inventory VOC. A detailed methodology is provided in section 3.2.1 of the 2011 emissions modeling platform technical support document.

County-specific speciation profile combinations are also available for cases where user-defined mixtures of two or more speciation profiles are needed. The "GSPRO_COMBO" feature in SMOKE can be applied by state and county and time period (e.g., month) and is currently used for on-road and nonroad mobile and gasoline-related stationary sources where the emissions sources use fuels with varying ethanol content (e.g., E0 and E10 profiles). Ethanol content varies spatially by state and county via nonattainment areas or local programs, temporally (e.g., during ozone season months), and by modeling year because future years have more ethanol. Certain source categories will require more careful review of speciation assignments. For example, the oil and gas sector (point, area and nonroad) inventories are generally constructed for specific drilling areas (i.e., drilling basins) which may include multiple counties with unique production gas characteristics. Knowledge of the type of gas (e.g., dry, wet, coal bed methane) or oil produced, flared and vented in these basin inventories is helpful for developing basin specific speciation assignments.

NO_x emission factors and, therefore, NO_x inventories are developed on a NO_2 weight basis. For air quality modeling, emissions processors must split NO_x to NO and NO_2 and in some cases HONO. Although emissions models allow using multiple speciation profiles for NO_x, historically only one split factor has been used of 90% NO and 10% NO_2. For mobile sources, the MOVES model calculates NO and NO_2 internally based on a more nuanced selection of factors and uses an NO_2 factor of 0.008 for onroad sources based on Sarwar (2008).

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One additional NO_x speciation data resource is stack test data of NO/NO_2 ratios for use in AERMOD modeling for the 1-hr NO_2 standard. These data are available here.

2.7.8.3 Spatial Allocation

For all source sectors that are compiled at a county resolution, the emissions models also need information about allocating the countywide emissions to individual grid cells that intersect the county boundaries. Such sectors include stationary area, nonroad mobile, and (non-link) on-road mobile sources. The spatial allocation process assigns fractions of county-total emissions to the model grid cells intersecting the county based on a "surrogate" data type (e.g., population, housing data). The appropriate types of surrogate data to use for each SCC in the inventories should be identified for this processing step. Spatial surrogates can be created using GIS to calculate the fraction of countywide emissions to allocate to each grid cell based on the surrogate type. These calculations can also be made using the EPA's Surrogate Tool, which is based on the Multimedia Integrated Modeling System (MIMS) Spatial Allocator. In addition, all SCCs needing spatial surrogates should be assigned a surrogate in a cross-reference file. Point sources do not need spatial surrogates, since the emissions models assign the grid location based on the latitude and longitude of the point sources. The EPA provides spatial surrogates and cross-references as part of its latest modeling platform. The same spatial surrogate data are normally used in both the base and future year modeling. However, emissions developers can choose to alter the spatial surrogate data based on predicted changes in land use patterns, population growth, and demographics, although the impacts and utility of such approaches are not well characterized,[24] so their use needs to be well documented and explained.

2.7.8.4 Other Ancillary Inputs

On-road emissions for fine-scale model grids (e.g., 4-km grid cells or smaller) may be based on a link-based approach as mentioned in section 2.7.7.3. The VMT and speed data needed for a link-based approach can be provided using a Travel Demand Model (TDM). These models require their own sets of inputs, which depend on the specific TDM used. The MOVES Technical Guidance provides general guidance on the development of MOVES inputs. Details on using TDMs for link-based on-road mobile emissions are available from the EIIP document "Use of Locality-Specific Transportation Data for the Development of Source Emission Inventories." An example of the use of TDMs can be found in "Use of Travel Demand Model Data to Improve Inventories in Philadelphia."

[24] At the time this document was written, tools to readily predict future-year land use patterns are not readily available in a form for use in emissions modeling.

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Emissions models have other input files that must be created. Previously, we noted that for point sources, emissions developers will have to identify which sources should be treated as elevated sources by an air quality model. To do this, data developers will select criteria such as stack height or a screening plume height value to allow an emissions model to flag point sources as elevated sources. In the SMOKE modeling system for example, the Elevpoint program can be used for this purpose.

The emissions models have a large number of files and settings which work together in fairly complex ways; therefore, users should be careful to select the appropriate files needed for the emissions model, and to prepare all input files in a way that will support using the emissions model for the specific air quality model application. A possible shortcut can be starting with the emissions modeling scripts included with the EPA's modeling platforms.

2.7.9 How Are Inventory Data Converted into Air Quality Model Input?

Emissions models are used to convert inventory data to inputs for air quality modeling. As described in section 2.7.8, as part of the emissions modeling process, additional ancillary data are needed to augment the raw emissions inventories. The emissions data for each of the six emissions sectors (point, area, on-road mobile, nonroad mobile, biogenics, and wildland fires) are temporally allocated, chemically speciated, and spatially allocated by the emissions model. The resulting hourly, gridded, and speciated emissions from all sectors are then combined before being used by an air quality model. In this section, we will provide information on several emissions models and summarize some key issues with the application of emissions models.

2.7.9.1 Emissions Models

Several emissions models are available for use in developing SIPs. While no single model has been specifically created for all situations, each model is generally capable of performing the necessary emissions processing steps including temporal, chemical, and spatial allocation. Users of such models are responsible for ensuring that the emissions processing steps transform the emission inventories as intended and are not changing the emissions in any unexpected way. Each model has different capabilities, limitations, and nuances. Therefore, when choosing an emissions model, it is worthwhile to discuss the choice with the developers of these systems and/or with EPA to determine which model is best suited for a particular application. Note that there are a number of programs that process emissions for individual source sectors. These are discussed below in the sector-specific subsections. Currently, SMOKE is the primary emissions

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model used to develop emissions data for input into chemical transport grid models. Other emissions models can also be used, such as the Emissions Preprocessing System (EPS).

SMOKE supports processing of criteria, mercury, and toxics inventories for stationary point, stationary area, mobile, and biogenic emissions. This emissions model can create input files for the CMAQ and CAM_X air quality models. Applications of SMOKE have been presented at several of the International Emissions Inventory Workshops (Houyoux, 2000; Strum, 2003, Zubrow, 2012, Baek, 2010, Adelman, 2008, Baek, 2007a, Baek, 2007b, Baek, 2006, Eyth, 2006, Pouliot, 2005). SMOKE is available for UNIX and Linux operating systems, but is not recommended for use on PCs running Windows. It does not require third party software. The SMOKE software and User's Guide are available on the SMOKE website.

Utilities for creating speciation profiles, biogenic land use, or spatial surrogates are not included within SMOKE. However, the Speciation Tool can create speciation profile inputs for SMOKE (Eyth, 2006), and biogenic land use and spatial surrogates can be built using the MIMS Spatial Allocator Tool along with the related Surrogate Tools.

2.7.9.2 Biogenic Emissions Models

There are several available biogenic emissions models that can be used to develop biogenic emissions for modeled attainment demonstrations and regional haze modeling. One such model is the Biogenic Emissions Inventory System, version 3.6 (BEIS3.6) (Bash et al, 2016). This model can be run both as part of a CMAQ model run and alternatively as a module of the SMOKE system. The CMAQ approach is described here. The latest documentation on the SMOKE approach to run BEIS is available here.

Another biogenic model commonly used to support air quality model applications is the Model of Emissions of Gases and Aerosols from Nature (MEGAN). The MEGAN model also uses meteorological data including temperature and solar radiation as input to generate biogenic emissions. MEGAN is distributed with vegetation/land-use data that includes all of North America. Other biogenic emissions models have been used to support air quality modeling, such as BEIGIS, which is a GIS-based biogenic emission model developed by the California Air Resources Board.

The BEIS modeling system uses land-use data from the Biogenic Emissions Land Use Database, version 4.1 (BELD4). BELD4 data provides data on the 230 vegetation classes at 1-km resolution over most of North America. These land use data can be created with the MIMS Spatial Allocator. Based on inputs from the emissions developer, the Spatial Allocator will select the 1-km grid cells from the BELD data that intersect the modeling domain and (if necessary)

aggregate to the grid resolution of the modeling domain. Air agencies can alternatively rely on the EPA's 12-km gridded data for modeling domains that overlap with the EPA national domain, provided with the EPA's latest modeling platform on the Emissions Modeling Clearinghouse.

In situations where air agencies consider biogenic emissions important for ozone, PM, or regional haze, the data used in these biogenic emission models could be updated to provide a better representation of vegetation and vegetation specific emission factors. For future-year modeling, land use data is typically held constant (same as the base case). Emissions developers can choose to change their land cover data based on predicted changes in land use patterns, however, the impact and utility of such approaches is not well characterized, so their use needs to be well documented and explained. Where fundamental changes are made to landuse/vegetation data or emission factors, those changes should be noted in the modeling protocol and/or final documentation package along with references to the source of updated/alternative data.

The meteorological data used as input to any biogenic emission model should be consistent with the data used for the air quality model. Biogenic emissions models are generally set up to use gridded hourly meteorological data, so inventory developers should be able to convert their meteorological inputs from air quality modeling inputs for use in their selected biogenics emissions model. Surface (or canopy level) temperature and solar radiation data can be obtained from modeled meteorological data, such as the WRF Model. Alternatively, solar radiation data could be obtained from satellite products.

Biogenic emission models evolve over time, so agencies using these models should evaluate the suitability of one model over the other as part of a modeling analysis. Once a choice has been made for modeling purposes, emissions should also be summed across the NAA for inclusion in the base year inventory for the NAA and/or the attainment projected inventory for the NAA.

2.7.10 Other Emissions Modeling Issues

In addition to the emissions modeling process and tools described above, there are several other important issues to consider. In the remainder of this section, we briefly address each of these issues.

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2.7.10.1 Elevated Point Sources

Point sources need to be assigned to an appropriate model layer[25] (the vertical modeling dimension). Depending on the air quality model that is being used, different emissions modeling steps can be taken. Models such as CMAQ and CAM_X expect input emissions files separately for surface level emissions versus the elevated point-source emissions.

2.7.10.2 Treatment of 'Atypical' Sources of Emissions

In the NEI, there are several sources of emissions that are reported by only one state or a small number of states. These sources typically have very low emissions, so whether they are included in the modeling inventory typically has little impact on air quality modeling. Examples of these sources include domestic and wild animal waste emissions (primarily NH_3), human perspiration and cigarette smoke, and swimming pools. In some inventories, large catastrophic/accidental releases are reported (e.g., car accidents, tire fires). It is generally considered inappropriate to include these sources in emissions processing for air quality models. However, some source categories may be important or unique to a particular area. Before removing seemingly unimportant source categories, the relative importance (e.g., as a percentage of emissions in the area) of each category should be evaluated.

Air agencies should also review and consider the draft EI SIP Guidance and the Ozone Implementation Rule regarding EGU emissions during High Electric Demand Day (HEDD) periods. Such emissions can be crucial for having a complete understanding of relevant emissions sources within a modeling domain. Where these emissions are important for assessing a nonattainment problem, air agencies should consider the potential impact of HEDD emissions when selecting time periods (e.g., episodes, season, year) to model.

2.7.10.3 Transport and Meteorology-based Reductions in Fugitive Dust Emissions

Fugitive dust emissions are another large source of primary $PM_{2.5}$ emissions. However, past modeling experience has shown modeled $PM_{2.5}$ concentration over-predictions from these emissions (Pouliot et al, 2010). Therefore, the EPA recommends reducing area-source fugitive dust emissions prior to air quality modeling to account for "capture" by the terrain (such as deposition on vegetation and buildings), changes in the emissions potential (such as frozen ground), and removal by meteorology (such as precipitation). These two components should be accounted for when adjusting the inventory PM emissions from PM sources such as paved and unpaved roads, construction, mining, agricultural activities, and industrial dust and other low-

[25] Point sources generally comprise most of the elevated emissions (above layer 1), although other sources, such as fires, ships, and aircraft may also have emissions assigned to elevated layers.

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level fugitive dust source categories. The "captured" portion of the reduction can be based on gridded land use data such as vegetation and building characteristics. The EPA has developed a methodology within SMOKE to adjust the fugitive dust emissions. The "meteorological" component of the reduction requires intermediate SMOKE processing scripts to merge hourly, gridded precipitation data and snow cover values to zero-out all fugitive dust emissions where appropriate. To avoid double-counting the precipitation-based reduction, the user should make sure that the inventory fugitive dust inventory does not already include a "MET-adjusted" reduction prior to these manipulations. This combined transport and met-based reduction approach is documented in Pouliot et al., 2010.

2.7.10.4 Quality Assurance

Quality assurance (QA) is a key component of any successful emissions modeling effort. A brief synopsis of appropriate QA approaches for emissions modeling is available in section 2.20 of the SMOKE manual. The purpose of QA for emissions modeling is to ensure that the inventories are correctly processed using the information the modeler intended. (It is assumed here that the inventory itself has already been QA'd and erroneous values and/or outliers removed through inventory QA procedures, as described in the EI SIP Guidance.)

Emissions modeling QA includes such activities as:

- Reviewing log files for errors and warnings and addressing problems;
- Comparing emissions between each of the processing stages (e.g., data import, speciation, temporal allocation) to ensure mass is conserved;
- Checking that the correct speciation, temporal allocation, and spatial allocation factors were applied; and
- Reviewing the modeling-specific parameters such as stack parameters.

It is also useful to compare air quality modeling-ready emissions summaries to previous emissions modeling efforts to verify expected emissions changes by source category(s) and geographic area(s) of interest. In addition, the process of running emissions inventories through emissions models and air quality models often provides insights into the emission inventories themselves. These insights can lead to inventory changes that improve the quality of inventories for additional modeling iterations.

In general, this guidance also encourages the use of graphical analysis and GIS for improved QA of emissions data and processing. A commonly used analysis tool for model-ready emissions data is the EPA-sponsored Visualization Environment for Rich Data Interpretation (VERDI) tool. The VERDI software package provides for efficient, flexible and modular capabilities of

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overlaying meteorology, emissions and air quality modeling data with GIS shapefiles. More information on VERDI is available on the VERDI website.

2.7.11 How Are Emissions Estimated for Future Years?

Emissions estimates for future years are called "emissions projections." The inventory developed for modeled attainment demonstrations is called the *attainment projected inventory for modeling.*[26] These emissions projections include emissions changes (due to increased or decreased activities), facility and/or unit-level shutdowns, and emissions controls (which can be due to, among other things, regulations, settlements or fuel-switching that reduce emissions in specific ways in the future). The goal in making projections is to obtain a reasonable estimate of future-year emissions that accounts for the key variables that will affect future emissions. Each air agency is encouraged to incorporate in its analysis the variables that have historically been shown to drive the economy and emissions within the modeling domain, as well as the changes in growth patterns and regulations that are expected to take place between the time of the base year and future years.

Complete guidance on emissions projections is provided in the EI SIP Guidance, with subsections on EGUs, non-EGU stationary sources, on-road mobile sources, nonroad mobile equipment, other nonroad mobile sources, and a list of other projection resources. The EI SIP Guidance includes a lengthy discussion about considerations that should be made for models or other tools that forecast EGU emissions. As noted in that guidance, "the states are advised to make sure that the tools meet the criteria laid out in this document because EPA will use these criteria to assess any EGU projection information submitted as part of SIPs." In addition, several additional issues are listed here for consideration for modeling inventories.

Emissions models (e.g., SMOKE, EPS) provide the capability to create future-year inventories using base year inventories and projection information. Emissions modelers will need to convert the projection data into specific formats for input to these models. Inventory developers should determine which emissions model will be used to perform the calculations and make sure that the type(s) of information needed by the model is being collected.

In the context of modeling for ozone and $PM_{2.5}$ purposes, for fires, it is recommended that the base year fires be held constant for use in the future year modeling. This approach allows for

[26] The name applies even if it turns out that the modeling shows that the area is not able to attain the standard by the latest applicable attainment date. Note that projected inventories are also used for regional haze modeling, however, the name "attainment projected inventory for modeling" applies specifically to attainment demonstrations.

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the impact of these fires to be minimized using the RRF approach, while still including realistic fire patterns that are relevant to ozone and $PM_{2.5}$ formation necessary for modeled attainment demonstrations. States have flexibility in how they estimate base year fires, but it is recommended that states should hold these constant in the future modeling case. Additional specific discussion of future-year fires as they relate to $PM_{2.5}$ SIPs is available in section IV.D.3.b of the preamble to the $PM_{2.5}$ SIP Requirements Rule. For regional haze purposes, air agencies should consult sections IV.E and IV.G of the 2017 Regional Haze Rule, 82 FR 3078 (Jan. 10, 2017), as well as their Regional EPA office as appropriate, to develop an approach for the treatment of emissions from fires.

Ancillary input files for inputs to emissions models, such as spatial surrogates, temporal allocation factors and especially speciation profiles may also need to be adjusted to reflect conditions expected in the future. The EPA modeling platforms, for example, consider the impact on speciation of fuels used in the future, which are expected to change over time due to regulations.

Once a future-year inventory and other data have been created, it should undergo the same steps as for the base-year modeling, including temporal allocation, speciation, spatial allocation, elevated source selection, special on-road mobile processing, any other custom processing steps (e.g. applying meteorology-based information to fugitive dust, agricultural NH_3 and residential wood combustion), and QA**.** Except where intentional, every attempt should be made to use consistent approaches between the future year and the base year for all of these modeling steps. Inconsistencies in approaches between the future-year modeling and the base-year modeling can lead to artificial differences in air quality modeling results that can affect conclusions.[27] Therefore, it is critical to avoid such differences whenever possible. If inconsistent base and future year approaches are necessary, they should be well documented and explained.

2.8 Initial and Lateral Boundary Conditions

Air quality models require chemical time and space boundary conditions in order to solve for concentrations within the modeled domain and time period. The time boundary or *initial condition* (IC) is provided at the beginning of the first simulated time step and the space boundary or *lateral boundary condition* (LBC) is provided at the outer edge of the modeling domain. As with other model inputs, the establishment of the IC and LBC data should be guided

[27] This is especially important due to the use of the "relative" change in modeled concentrations as part of the modeled attainment test. An inconsistency in base and future year emissions may lead to a very large modeled percent change in ozone and/or $PM_{2.5}$ concentrations.

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by the conceptual model of the air quality issue being simulated. For instance, more attention will be needed in developing accurate LBC for cases in which ambient data analyses (or previous modeling scenarios) have indicated the potential for long-range transport of pollutant material, compared to cases in which the air quality problem has been identified as largely local in nature. Numerous studies have highlighted the importance of accurately representing LBC in optimizing model performance and identifying the most effective path to attaining the NAAQS (Jacob *et al.*, 1999; Tang *et al.*, 2009; Hogrefe *et al.*, 2011).

Given limitations in available ambient data, it is impossible to exactly specify the complex three-dimensional chemical characteristics of the IC or LBC. As a result, two basic approaches to establishing these fields have been used within the modeling community. The first and preferred approach is to characterize the IC/LBC data as accurately as possible given the existing state of knowledge about ambient conditions at those times and in those locations. The second approach is to attempt to minimize the impacts of the IC and LBC by configuring the domain and modeling period such that the air quality concentrations in the locations and times of interest are largely unaffected by the IC/LBC inputs.

The impacts of the IC are most easily minimized when they are reasonably accurate. In most cases, it will be possible to minimize the impacts of the IC data via the use of a model "spin up" period. A spin up period is defined as some number of modeling days that precede the time period of actual interest. The model outputs for this spin up period are discarded from any analytical post-processing and evaluation, as they are potentially affected by the uncertain initial conditions. The length of the needed model spin-up period will vary as a function of: the domain size, prevailing meteorological conditions, and the chemical lifetimes of the pollutants being simulated. It is a simple modeling exercise to test the sensitivity of the key time periods to the initial conditions. Previous sensitivity modeling has determined that the IC are typically "washed out" of the system in as few as 3-5 days for a local-scale modeling analysis; approximately 10-20 days for a regional-scale analysis; and on the order of 6 months or more for a hemispheric-scale analysis (Berge *et al.*, 2001; U.S. EPA 2010; Anenberg et al., 2011). More recent work shows that 2 weeks is generally sufficient to reduce IC influence to under 1%, with more realistic IC decreasing the spin-up time (Hogrefe et al., 2017). Upper air (elevated layers in the model) takes longer to minimize the influence of IC, and as a result, some locations may require longer spin-up). If there is any question as to the appropriate length of the spin-up period, then sensitivity modeling tests should be conducted. Otherwise, the above guidelines should be sufficient for most ozone and $PM_{2.5}$ attainment demonstrations and regional haze assessments.

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In many cases, it will not be feasible to build a large enough domain to minimize the impacts from emissions outside the domain. For these cases, it will be necessary to downscale the requisite species concentration data from well-performing, coarser-grid, larger domain modeling runs. (In rare cases, it may be possible to assign LBC from detailed field study species data, but most domains will not have complete chemical profiles in space and time along the domain edges.). These larger "parent" grids may be generated by the same regional scale model at coarser resolution; or they can be generated via global or hemispheric models. In the last decade, several global/hemispheric air quality models have been used to generate regional LBC inputs. A sample of models used for LBC include: GEOS-Chem (Bey et al., 2001), the AM3 atmospheric component of the GFDL global coupled model (Donner, et al., 2011), the Model for Ozone And Related Tracers (MOZART, Emmons et al, 2010), the WRF-Chem model (Zhang, et al., 2012a), and the hemispheric CMAQ model (Byun and Schere, 2006; Fu et al., 2012). The EPA does not recommend any one particular global/hemispheric model. Each regional modeling exercise should individually assess whether the chosen global/hemispheric or coarse regional model accurately captures lateral boundary conditions.

For cases in which the LBC will be extracted from larger-scale regional/hemispheric modeling, the EPA recommends two efforts to optimize the LBC characterizations. First, modelers should try to minimize any disconnects in the downscaling process. Wherever possible, one should attempt to utilize the same species, chemical mechanism, layer depths, and meteorological inputs in the regional/hemispheric model as are being used in the finer-scale attainment demonstration modeling (Lam and Fu, 2009). This will minimize the number of uncertain translations needed to convert coarse-scale outputs to finer-scale LBC inputs. In particular, careful consideration of the stratosphere in the two modeling systems will be needed to ensure that regional/hemispheric ozone that is stratospheric in origin is not excessively mixed down to the surface in the finer-scale modeling due to disconnects between the two systems.[28] Second, there should be a comprehensive evaluation of the regional/hemispheric model performance (Bey *et al*., 2001). While there may not be a detailed data set available for model evaluation along the domain lateral boundaries in most cases, consideration of model performance across the domain will provide a first-order indication of the ability of the coarser-scale model to characterize air quality at the boundaries. Additionally, it may also be possible to infer

[28] In establishing the layer structure for both global and regional models, it is advisable to avoid selecting upper model layers that span both the upper troposphere and lower stratosphere. It has been seen that "hybrid" layers can allow for inappropriate diffusive mixing between those two generally decoupled sections of the atmosphere. In cases where stratospheric intrusions are not expected to influence ozone in the area, it may be appropriate to artificially cap stratospheric ozone concentrations to avoid ozone performance issues. This should be a "last resort" fix, only applied after detailed assessments of the vertical diffusion and vertical advection schemes within the model.

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information about the quality of the coarse-model estimates via comparisons with satellite data (Liu *et al.*, 2006, Henderson *et al.*, 2013).

In some situations, it may be possible to construct a modeling platform in which the LBC will not substantially influence the air quality issue under consideration. For instance, areas for which there is no evidence of pollutant transport from the far edges of the model domain to the local area may be able to demonstrate that the determination of LBC data will not impact the eventual modeling demonstration. As with the IC data, this conclusion can be proven via simple sensitivity tests in which the LBC are modified from a base state and the results between the two runs are compared (e.g., Appel *et al*, 2007). For situations in which alterations to the LBC data will not impact key findings, it is acceptable to use time-invariant profiles for LBC. Because there are many publicly available sources of modeled boundary conditions, this approach should only be used only when there is good reason.

Due to the potential impact of LBCs on model response to emissions controls, it is important to accurately characterize the relative influence of LBC versus local emissions. For example, if the impacts of LBC on local air quality are overestimated, it will be more difficult than it otherwise should be to show reductions in future design values from local controls. Conversely, if the modeling system underestimates the role of inflow air quality, local emissions reductions may appear more effective in the model than they will be in reality.

The selection of future year LBCs also has potentially important ramifications on the relative response factors derived from the modeling for the various control scenarios. If LBC are known to impact local air quality, then modelers may need to consider how these contributions will change between the base year and the attainment year (Adelman *et al.*, 2011). Ambient trends analyses for 1990-2010 have indicated that free tropospheric ozone levels above the western U.S. have increased by approximately 0.5 ppb/year over those two decades with increases seen at rural surface monitors in the west (Cooper et al., 2012; Cooper et al., 2010; Lin et al., 2017). More recent analysis focusing on 2000-2016 shows mixed trends in the free troposphere with only one high altitude surface monitor with a significant increase in its median or 95th percentile concentration. The most recent trends may suggest decreasing future ozone contributions from LBC due to international controls (e.g., van der A et al., 2017). It is left to the discretion of the air agency to determine whether varying future LBC are needed as part of an attainment demonstration. Updated future boundary conditions may be needed when emissions changes are expected outside the domain that will meaningfully change the LBC and impact the area(s) of interest within the domain. This decision should consider both the length of the projection period and the potential for significant air quality changes outside the modeling domain. Additionally, careful consideration of upstream emissions will be needed as

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part of any additional future-year regional/hemispheric modeling conducted to develop future LBC. If updated future year LBC are used, those data should be fully described and justified in the modeling protocol.

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3.0 Evaluating Model Performance

3.1 Overview of Model Performance Evaluation

The results of a model performance evaluation (MPE) should be considered prior to using modeling to support an attainment demonstration or regional haze assessment. The objective of the MPE is to demonstrate that the base case model can simulate observed pollution concentrations during historical pollution episodes, and to develop confidence that the model can reliably predict how future pollution levels will change in response to changes in emissions. A particular concern in photochemical models is that compensating errors in the model can cause the model to reproduce observed pollution concentrations in the base case while incorrectly representing the emissions, dispersion and chemistry processes that control pollution formation. Models that achieve good performance through compensating errors may not be reliable for predicting how pollution levels will respond to future emissions reductions. However, if an operational evaluation is conducted over a large enough spatial and temporal scale to incorporate a variety of meteorology and emissions conditions, good model performance is less likely the result of compensating error. Thus, a key goal of the MPE is to demonstrate that the model is getting good results for the right reason (Russell and Dennis, 2000) and to show that the model is able to capture pollution concentrations over the range of conditions that are relevant for the regulatory application being undertaken. In addition, the MPE can provide air agencies with tools to identify and fix causes of poor model performance such as problems in the meteorological, emissions, or boundary condition input files.

Dennis et al. (2010) describe an MPE framework that includes four different approaches that can be used to evaluate air quality models:

1. Operational evaluation techniques include statistical and graphical analyses aimed at determining whether the modeled simulated variables are comparable to measurements.
2. Diagnostic evaluation focuses on process-oriented analyses that determine whether the individual processes and components of the model system are working correctly, both independently and in combination.
3. Dynamic evaluation assesses the ability of the air quality model to predict changes in air quality given changes in source emissions or meteorology, the principal forces that drive the air quality model.
4. Probabilistic evaluation attempts to assess the level of confidence in the model predictions through techniques such as ensemble model simulations.

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The goal of the operational evaluation is to determine how well the model replicates observed concentrations of $PM_{2.5}$ components, ozone and their precursors. Diagnostic and dynamic evaluations are used to determine whether the model accurately represents the processes that determine pollutant concentrations, including emissions, dispersion, chemical reactions, and deposition (i.e., to determine if the model is getting good results for the right reason). For cases in which the model performs poorly in the operational evaluation, the diagnostic and dynamic evaluation can provide insights into the causes of the poor performance and to improve model performance. Ultimately, the goal of these evaluation methods is to assess the degree of confidence in the use of the model as a tool to inform the planning process, and more specifically, to determine how reliably the model predicts the response of ozone and/or $PM_{2.5}$ to changes in emissions. The modeled attainment and regional haze tests use models to predict the response of ozone and/or $PM_{2.5}$ to changes in emissions and then applies the resulting relative response factors (RRFs) to observed (rather than modeled) ambient data. Thus, while historically, most of the effort has focused on the operational evaluation, the relative test makes the diagnostic and dynamic evaluation also important.

At a minimum, a model used for air quality planning purposes should include a complete operational MPE using all available ambient monitoring data for the base case model simulation period. Section 3.2 describes the types of metrics and plots that are typically developed as part of an operational MPE, and section 3.3 describes ambient data that is available through continuously operating monitoring networks. If available, monitoring data from special field studies and other research data may also be used in the operational MPE.

Where practical, the MPE should also include some level of diagnostic evaluation. The use of sensitivity studies, process analysis, indicator ratios and source apportionment approaches for diagnostic evaluation, including dynamic and probabilistic evaluations are described in section 3.4. Given that air agencies might have limited resources and time to perform diagnostic and dynamic evaluation, the use of these methods may be limited in scope in a typical regulatory modeling application. However, more comprehensive diagnostic testing of the model can be a valuable component of the weight of evidence analysis used to support a SIP model attainment demonstration.

From an operational standpoint, the EPA recommends that air agencies compare their evaluation results against similar modeling exercises to ensure that the model performance approximates the quality of other applications. Recent literature reviews (Simon et al, 2012; Emery et al., 2017) summarize photochemical model performance for applications published in the peer-reviewed literature between 2006 and 2012. These reviews may serve as a resource for identifying typical model performance for state of the science modeling applications. It is clear that there is no single definitive test for evaluating model performance. All of the tests

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mentioned here have strengths and weaknesses. Further, even with a single performance test, it is not appropriate to assign "bright line" criteria that distinguish between adequate and inadequate model performance. In this regard, the EPA recommends that a "weight of evidence" approach be used to determine whether a particular modeling application is valid for assessing the future attainment status of an area. The EPA recommends that air agencies conduct a variety of performance tests and weigh them qualitatively to assess model performance. Provided suitable databases are available, greater weight should be given to those tests which assess the model capabilities most closely related to how the model is used (i.e., tests that provide insight into the accuracy of the model's relative response to emissions reductions should be given more weight). Generally, additional confidence should be attributed to model applications in which a variety of the tests described here are applied and the results indicate that the model is performing well.

3.2 Operational Evaluation

An operational evaluation is used to assess how accurately the model predicts observed concentrations. The underlying rationale is that if we are able to correctly characterize historical concentrations of ozone, PM and their precursors for a variety of meteorological conditions, this gives us some confidence that we can correctly characterize future concentrations under alternative emissions levels. Typically, this type of evaluation is comprised of statistical assessments of modeled versus observed data. Operational evaluations are generally accompanied by graphical and other qualitative descriptions of the model's ability to replicate historical air quality patterns. An operational evaluation provides a benchmark for model performance and can therefore identify model limitations and uncertainties that may require further model development/improvement and/or diagnostic evaluation

The robustness of an operational evaluation is directly related to the amount and quality of the ambient data available for comparison. An operational evaluation for ozone would ideally include co-located measurements of ozone precursors NOx and VOC and vertical profile measurements that can be used to determine the extent of vertical mixing of pollutants and the concentration of ozone and precursors above the boundary layer.

An operational evaluation for $PM_{2.5}$ and regional haze is similar to that for ozone; however, an important difference is that $PM_{2.5}$ consists of many component species and is typically measured with a 24-hour averaging time. The chemical components of $PM_{2.5}$ should be evaluated individually. In fact, in undertaking an operational assessment, it is more important to evaluate the components of $PM_{2.5}$ than to evaluate total $PM_{2.5}$. Apparent "good performance" for total $PM_{2.5}$ does not indicate whether the model is predicting the proper mix of components, which is important for the modeled attainment test or regional haze

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assessment. If performance of the major components is good, then it follows that performance for total $PM_{2.5}$ will also be good. In addition to measurements of VOC and NOx, which are precursors for organic aerosols and nitrate, a $PM_{2.5}$ model evaluation should also include measurements of gaseous precursors SO_2 and (where available) NH_3. Due to the influence of initial conditions, model predictions from the spin-up days should be excluded from the analysis of model performance.

3.2.1 Metrics

Operational evaluations quantify model performance through a variety of statistical metrics. Recommended metrics are described below and shown in Table 3.1. It is important to include multiple statistical measures in any operational evaluation to fully characterize model performance. At a minimum, we recommend evaluating: Mean Observed, Mean Model, Mean Bias, Mean Error and/or Root Mean Square Error, Normalized Mean Bias and/or Fractional Bias, Normalized Mean Error and/or Fractional Error, and the correlation coefficient. The equations for calculating each of these metrics are given in Table 3.1.

Mean Observed: The time-averaged mean observed value (in ppb or $\mu g/m^3$).

Mean Model: The time-averaged mean predicted value (in ppb or $\mu g/m^3$) paired in time and space with the observations.

Mean Bias (MB): This performance statistic averages the model/observation residual paired in time and space. A value of zero would indicate that the model over-predictions and model under predictions exactly cancel each other out. This metric is reported in the unit of measure (ppb or $\mu g/m^3$).

Mean (Gross) Error (ME/MGE): This performance statistic averages the absolute value of the model/observation residual paired in time and space. A value of zero would indicate that the model exactly matches the observed values at all points in space/time. This metric is reported in the unit of measure (ppb or $\mu g/m^3$).

Root Mean Square Error (RMSE): This performance statistic (in units of ppb or ug/m^3) is a measure of the average distance between predicted and observed values. It is calculated as the standard deviation of the difference between modeled and observed values.

Normalized Mean Bias (NMB): This statistic (given in units of percent) is used to normalize MB to the average observed value. NMB values range from -100% to +infinity. Consequently, negative and positive bias values using this metric are not symmetrical around 0.

Normalized Mean Error (NME): This performance statistic (given in units of percent) is used to normalize the mean error relative to the average observation. This statistic averages the

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absolute value of the difference (model - observed) over the sum of observed values. NME values range from 0 to +infinity.

(Mean) Fractional Bias (MFB/FB): Fractional bias is determined by normalizing the MB by the average of observed and modeled concentrations. The range of FB is -200% to +200%. The fractional bias for cases with factors of 2 under- and over-prediction are -67 and + 67 percent, respectively (as opposed to -50 and +100 percent, when using normalized bias). Fractional bias equally weights positive and negative bias estimates (underestimates and overestimates are symmetrical around 0).

(Mean) Fractional Error (MFE/FE): Fractional error is determined by normalizing the ME by the average of observed and modeled concentrations. The range of values for FE is 0 to 200%. It is similar to the fractional bias except the absolute value of the difference is used so that the error is always positive.

Correlation Coefficient (r) and Coefficient of Determination (R^2): These performance statistic measures the degree to which two variables are linearly related. A correlation coefficient of 1 indicates a perfect linear relationship; whereas a correlation coefficient of 0 means that there is no linear relationship between the variables. A correlation coefficient of less than 0 indicate anti-correlation. The Coefficient of Determination is always positive.

Table 3.1: Definitions of recommended statistical metrics

Abbreviation	Term	Definition
MB	mean bias	$\frac{1}{N}\sum(M_i - O_i)$
ME	mean error	$\frac{1}{N}\sum\lvert M_i - O_i\rvert$
RMSE	root mean squared error	$\sqrt{\frac{\sum(M_i - O_i)^2}{N}}$
FB	fractional bias	$100\% \times \frac{2}{N}\sum\frac{(M_i - O_i)}{(M_i + O_i)}$
FE	fractional error	$100\% \times \frac{2}{N}\sum\frac{\lvert M_i - O_i\rvert}{(M_i + O_i)}$
NMB	normalized mean bias	$100\% \times \frac{\sum(M_i - O_i)}{\sum O_i}$

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NME	normalized mean error	$100\% \times \frac{\sum \lvert M_i - O_i \rvert}{\sum O_i}$
r	Correlation coefficient	$\left(\frac{\sum_1^N \left((M_i - \bar{M}) \times (O_i - \bar{O}) \right)}{\sqrt{\sum_1^N (M_i - \bar{M})^2 \sum_1^N (O_i - \bar{O})^2}} \right)$
r^2	coefficient of determination	$\left(\frac{\sum_1^N \left((M_i - \bar{M}) \times (O_i - \bar{O}) \right)}{\sqrt{\sum_1^N (M_i - \bar{M})^2 \sum_1^N (O_i - \bar{O})^2}} \right)^2$

M_i = modeled concentration i. O_i = observed concentration i. N = number of paired obs/model concentrations. $\bar{M}$= mean modeled concentration. $\bar{O}$= mean observed concentration.

Observations and model predictions should initially be paired in time and space, matching the temporal resolution of the raw observation data. When matching in time, modelers should pay special attention to making sure that monitor and model data are both in local standard time. The units of time associated with model and observed concentrations can be 24-hour (usually for PM and its species), hourly (usually for species with continuous measurements, like ozone), or sometimes weekly (such as for CASTNet filter pack measurements). Temporal averaging is appropriate when used to match a relevant regulatory metric such as maximum 8-hr daily average ozone. As appropriate, air agencies should then aggregate the raw statistical results into meaningful groups of sub-regions or sub-periods. For example, examining model performance within and near the non-attainment area(s) of interest may be more important than performance in other parts of the modeling domain. For larger areas with more spatial variation, it may also be informative to evaluate sub-regions within the non-attainment area. In addition to any spatially aggregated statistics, model performance should also be evaluated at individual monitors within the nonattainment area. Similarly, priority may be placed on examination of the days that are potentially used in the attainment test (i.e., base period days with 8-hour ozone > 60 ppb). That is not to say that model performance evaluations should ignore performance on lower ozone days or in areas outside of the nonattainment areas. Model performance on lower concentration days and in areas outside of the nonattainment area are still important, but it is appropriate to give more attention to the model outputs that most directly impact the outcome of the attainment test. Unlike attainment demonstrations, model performance on days with low concentrations may be especially important for regional haze analyses. Some IMPROVE sites routinely measure extremely low PM species concentrations (even on the most impaired days).

In terms of pairing model predictions with monitored observations, the EPA recommends that the grid cell value in which the monitor resides be used for the calculations. It would also be acceptable to consider bi-linear interpolation of model predictions to specific monitoring

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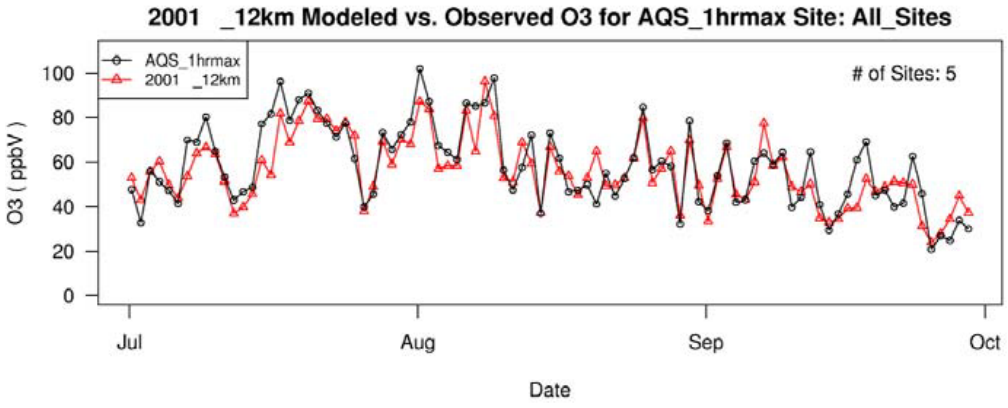
locations.[29] Air agencies should recognize that, even in the case of perfect model performance, model-observed residuals are unlikely to result in exact matches due to measurement uncertainty and differences in the spatial extent represented by model predictions, which are volume averages, and the observations, which are point values.

3.2.2 Plots

In addition to statistical summaries, graphical displays of data allow for a fuller characterization of model performance. Therefore, plots play a key role in any model performance evaluation. Below are examples of some types of plots which have been useful in past evaluations.

Time series plots of model and predicted hourly and/or daily concentrations (e.g., maximum 1-hour average, maximum 8-hour average, or 24-hour average) for each monitoring location in the nonattainment area, as well as key sites outside of the nonattainment area. These plots are especially important for examining performance at individual monitors and show how well the model captures temporal variations in pollutant concentrations at individual locations. Time series plots can indicate if there are particular times of day or days/episodes when the model performs especially poorly.

Figure 3.2.1 Example time series plot of daily 1-hour maximum ozone concentrations



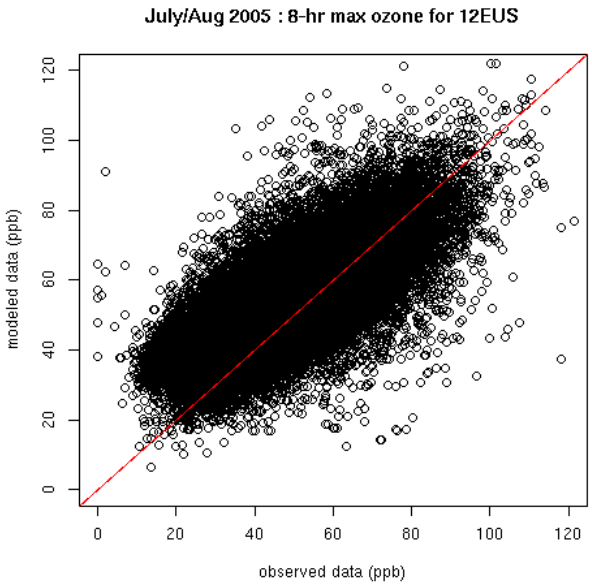
Scatter plots of predicted and observed concentrations at each site. These plots are useful for indicating if there is a particular part of the distribution of observations that is poorly

[29]In certain instances, air agencies may also want to conduct performance evaluations using a "near the monitor" grid cell array (i.e., the best match within a 3X3 grid cell array centered on the monitor). A "near the monitor" analysis may be useful when strong ozone gradients are observed, such as in the presence of a sea breeze or in strongly oxidant limited conditions.

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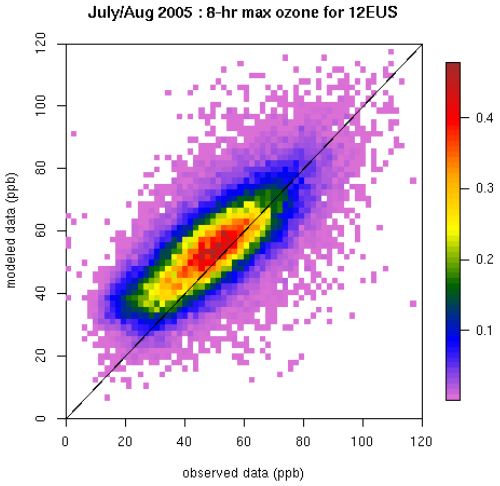
represented by the model. It may also be useful to develop separate plots for individual time periods or key sub-regions.

Figure 3.2.2 Example scatter plot of 8-hour daily maximum ozone concentrations



Density plots are a variation on scatter plots which are especially useful with large amounts of data when individual points overlap on a scatter plot. Density plots color code each point on the scatter plot based on the number of points falling in that location.

Figure 3.2.3 Example density plot of 8-hour daily maximum ozone concentrations

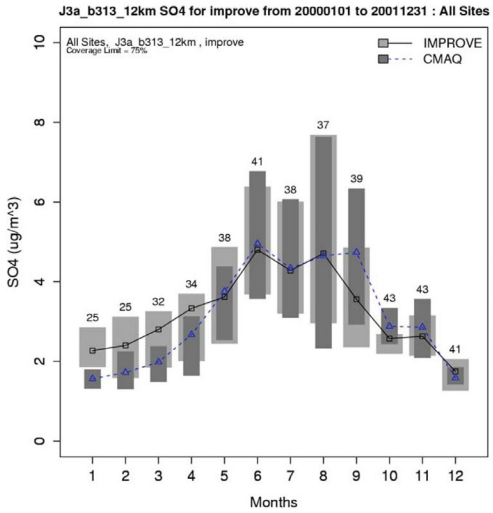


Box plots can be developed for model performance evaluation. These types of plots show the distribution of observations, model estimates, or performance metrics, which can be grouped

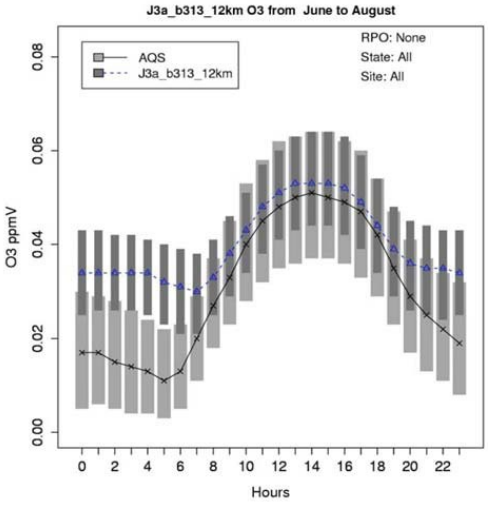
in a variety of ways, most commonly by observed ozone concentration, month, or hour of the day. Box plots can show several quantities: the 25% to 75% percentiles, the median values, and outliers. The monthly box plot can be used to quickly visualize model performance across the entire year, highlighting the seasonal change in model performance. The hourly or "diurnal" box plot is constructed using hourly data, and shows how the model predictions compare against observations throughout an entire day.

Figure 3.2.4 Example box plots of (a) monthly average sulfate concentrations, (b) daily diurnal average ozone concentrations, and (c) seasonal ozone bias binned by concentration range

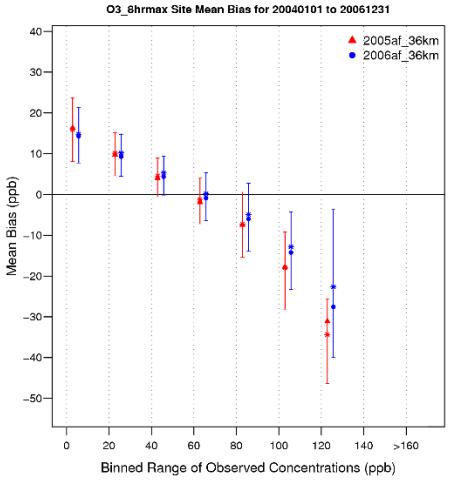
(a)



(b)



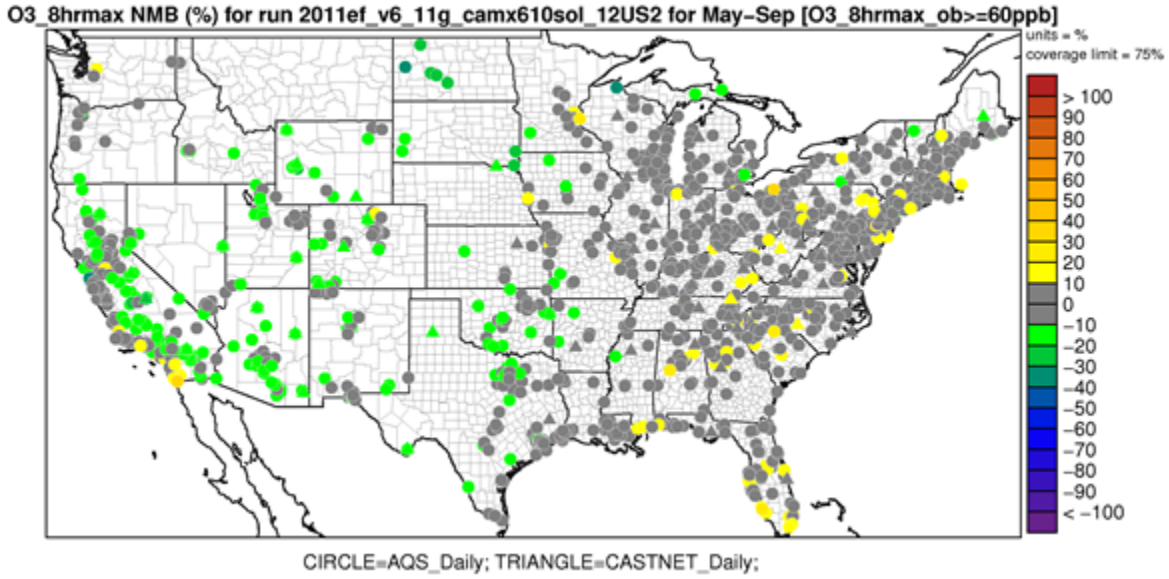
(c)



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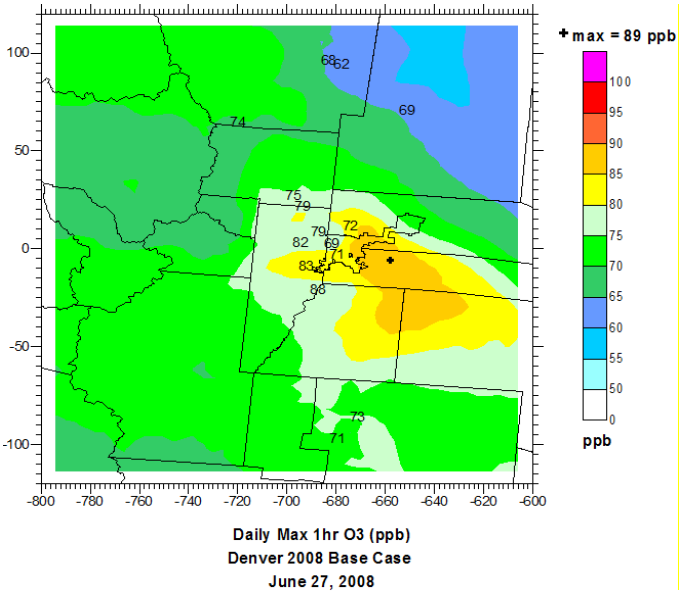
Spatial plots of model performance at monitor locations provide an overall picture of the geographic patterns in model performance. Any performance metric can be plotted in this manner, but it is most common to include spatial plots of MB, ME, NMB, and NME. Spatial plots of correlation may also be useful. These plots are most useful when constructed on a monthly or seasonal basis. For ozone these plots may be constructed to include all days or only "high ozone days." For regional haze, these plots may be constructed to include only the 20% most impaired days or 20% clearest days.

Figure 3.2.5 Example of spatial plot of NMB at monitor locations for days with O_3 above 60 ppb during the 2011 ozone summer season (May-September).



Daily gridded tile plots of predicted concentrations across the modeling domain with the actual observations as an overlay. Plots should be prepared for relevant averaging time (i.e., 1-hour maxima, daily 8-hour maxima, 24-hour average, etc.). These plots can reveal locations where the model performs poorly. Superimposing observed concentrations on the predicted isopleths reveals useful information on the spatial alignment of predicted and observed plumes.

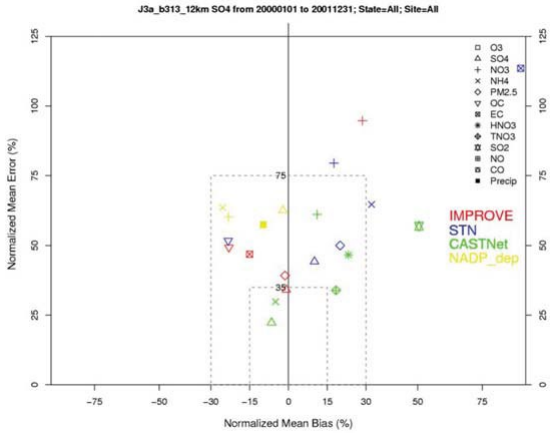
Figure 3.2.6 Example gridded tile plot of daily maximum 1-hour ozone concentrations (with overlaid observations)



Animations of predicted hourly concentrations for all episode days or for certain periods of interest. Animations are useful for examining the timing and location of pollutant formation. Animations may also reveal transport patterns (especially when looking at aloft layers). Animations can also be used to qualitatively compare model outputs with the conceptual model of particular pollution episodes. These plots may also reveal whether an important feature was simulated but was spatially or temporally displaced.

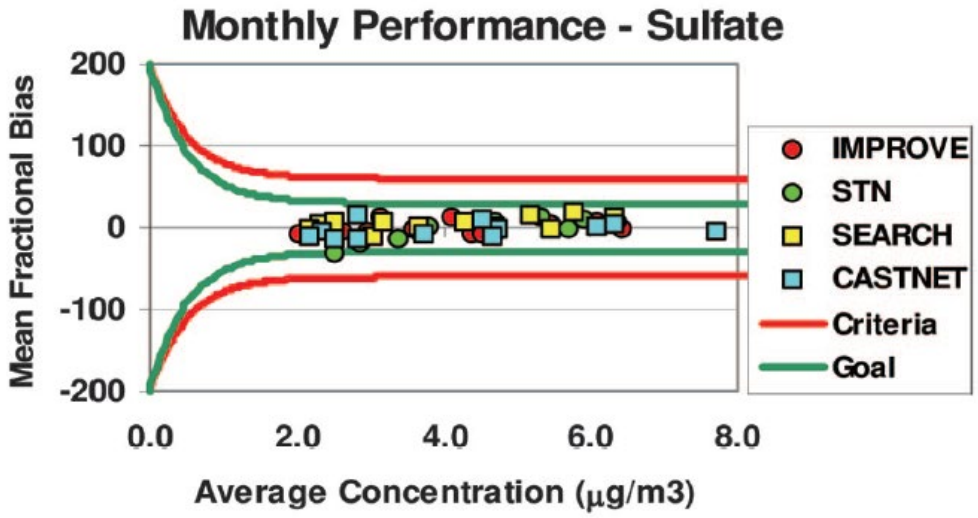
The soccer plot (Tesche et al, 2006) is so named because the dotted lines illustrating performance goals resemble a soccer goal. The plot is a convenient way to visualize model performance of both bias and error on a single plot. As bias and error approach zero, the points are plotted closer to or within the "goal," represented by the dashed boxes.

Figure 3.2.7 Example soccer plot of sulfate normalized mean bias and error.



The bugle plot (Boylan and Russell, 2006; Tesche et al., 2006), named for the shape formed by the criteria and goal lines, is another plot available for model performance evaluation. The bugle plots are shaped as such because the goal and criteria lines are adjusted based on the average concentration of the observed species. As the average concentration becomes smaller, the criteria and goal lines become larger to adjust for the model's ability to predict at low concentrations.

Figure 3.2.8 Example bugle plot of sulfate mean fractional bias as a function of modeled concentration.



Source: Morris et al, 2005

3.2.3 Ozone Model Performance

It is recommended that, at a minimum, statistical performance metrics be calculated for hourly ozone and 8-hour ozone maxima for each day of the model simulation used to support the attainment demonstration. The EPA recommends that the metrics be calculated both for all pairs of modeled and observed data and for pairs in which the hourly or 8-hour daily max values are above 60 ppb. Another acceptable approach would be to estimate metrics binned by observed ozone concentration. This would allow for a thorough evaluation of the model tendencies to estimate ambient concentrations in different observed ranges of interest. Wherever possible, these types of performance measures should also be calculated for ozone precursors and related gas phase oxidants.

Ozone precursors and related gas-phase oxidants (partial list) are listed below.

- Total Volatile Organic Compounds (VOCs)
- Speciated VOC

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- Nitric acid (HNO_3)
- Nitric oxide (NO)
- Nitrogen dioxide (NO_2)
- Peroxyacetyl nitrate (PAN)
- NOy (NOx=NO+NO_2 and other oxidized nitrogen compounds)
- Carbon monoxide (CO)

3.2.4 $PM_{2.5}$ Model Performance

Performance metrics for PM and regional haze are similar to those calculated for ozone. Metrics should be estimated for components of $PM_{2.5}$ and PM precursors. Since modeling for $PM_{2.5}$ and regional haze will likely require modeling different times of year, season-specific statistics and graphical displays are helpful for evaluating and diagnosing model performance. Statistics and graphics can be averaged for various time scales depending on the model application. For example, statistical metrics and scatterplots can show daily averaged ambient-modeled pairs or annual average pairs for attainment demonstration of the daily and annual $PM_{2.5}$ standards respectively. In addition, the EPA recommends that daily pairs be grouped by season or month and statistics be given for different times of the year since different processes dominated $PM_{2.5}$ formation and fate in different seasons. Note that in this case, pairings should be performed on 24-hour average concentrations and statistics may then be reported for subgroups (seasons, regions etc.) of this data. This is different than pairing monthly or seasonally averaged data since statistics and plots tend to look "better" as the averaging time increases from daily to monthly to quarterly to annual. As such, daily pairs should always be examined to ensure a detailed look at model performance on the time scale of the measurements (24-hour average). Finally, air agencies may also want to subset the 20% clearest and most impaired visibility days at IMPROVE sites or the "high" modeled $PM_{2.5}$ days (e.g. the 10% highest modeled days in each quarter) to examine model performance on the days which will potentially be used to evaluate air quality goals.

Because $PM_{2.5}$ is a mixture, a meaningful performance evaluation should include an assessment of how well the model is able to predict individual chemical components that constitute $PM_{2.5}$. Components of $PM_{2.5}$ of interest include:

- Sulfate ion (SO_4)
- Nitrate ion (NO_3)
- Ammonium ion (NH_4)
- Elemental Carbon (EC)

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- Organic Carbon (OC) and/or Organic Carbon Mass[30]
- Crustal (weighted average of the most abundant trace elements in ambient air)
- Sea salt constituents (Na and Cl)[31]
- Other mass including Non-Carbon Organic Matter (NCOM) and metal oxides not captured by the crustal component

There are a number of gas-phase species that can be used to evaluate $PM_{2.5}$. Their presence may affect the formation of secondary PM and the response of secondary PM components to emissions strategies. Also, the model's performance in predicting certain gaseous species may provide diagnostic clues which help explain poor performance. Gas phase species of most interest for performance evaluation due to being a direct precursor to secondarily formed $PM_{2.5}$ are listed below:

- Nitric acid (HNO_3)
- Ammonia (NH_3)
- Sulfur dioxide (SO_2)
- Volatile Organic Compounds (VOCs)

Other related gas-phase oxidants (partial list) that indirectly influence $PM_{2.5}$ formation and destruction are listed below.

- Ozone (O_3)
- Nitric oxide (NO)
- Nitrogen dioxide (NO_2)
- Peroxyacetyl nitrate (PAN)
- NOy (sum of NOx and other oxidized compounds)
- Carbon monoxide (CO)
- Hydrogen peroxide (H_2O_2)

Some of the species listed above are currently available from either existing monitoring network systems and/or special studies. However, it is important to note that many of the species listed above are not routinely measured (e.g., H_2O_2, HNO_3, and NH_3) or measurements are not co-located with speciated PM measurements. Model performance can best be assessed using extensive databases, such as those obtained in major field studies. Where possible, model

[30] For predicted/observed comparisons, organic carbon is preferred over organic carbon mass to allow for transparency between model predictions and observed measurements. Ambient measurements will generally only account for the carbon portion of organic carbon. Organic carbon mass may include hydrogen, oxygen, and other components.

[31] White (2008) recommends the use of $1.8xCl^-$ to characterize ambient sea salt concentrations at coastal IMPROVE sites due to uncertainty in the XRF Na measurements.

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time periods can be prioritized to correspond to periods when field study or special study data was collected. However, it is recognized that many of the precursor species will not be available for every model application.

3.3 Ambient Measurement Networks

Provided below is an overview of some of the various ambient air monitoring networks currently available. Network methods and procedures are subject to change annually due to systematic review and/or updates to the existing monitoring network/program. Please note, there are other available monitoring networks which are not mentioned here and more details on these networks and measurements can be obtained from other sources, if necessary.

3.3.1 AQS

The Air Quality System (AQS) is a repository of ambient air pollution data and related meteorological data collected by EPA, state, local and tribal air pollution control agencies from tens of thousands of monitors (it is not an actual monitoring network). The monitoring data in AQS are the result of the various CAA requirements to provide a national database of ambient air pollution data. This information management system contains data on over 1,000 pollutants from 1957 through the present day. AQS contains all the routine hourly gaseous pollutant data collected from State and Local Air Monitoring Stations (SLAMS) sites. SLAMS is a dynamic network of monitors for state and local directed monitoring objectives (e.g., control strategy development) which consists of thousands of monitoring stations. The SLAMS network includes stations classified as NCore, PAMS, and Speciation, and stations formerly categorized as NAMS, but does not include Special Purpose Monitors (SPM) and other monitors used for non-regulatory or industrial monitoring purposes. AQS also contains data from the IMPROVE monitoring network, described separately in section 3.3.3 of this document.

The AQS database includes criteria pollutant data (SO_2, NO_2, O_3, CO, PM_{10}, $PM_{2.5}$, and Pb) and speciation data of particulate matter (SO_4, NO_3, NH_4, EC, OC, and crustal material), air toxic data, photochemical assessment data, and meteorological data. The data are measured and reported on an hourly or daily average basis. The AQS system continues to expand to include more ambient air pollutants. An overview of the AQS can be found here. For querying the database or viewing the data one can use the EPA's AirData website, which is a collection of user-friendly visualization tools for air quality analysts. The tools generate maps, graphs, and data tables dynamically. An AQS User's Guide is also available.

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3.3.2 NCore

The term "NCore monitoring network" (for national core) refers to a set of monitoring sites in major urban areas that generally started operating in 2011. These sites combine several advanced measurement systems for particles, pollutant gases and meteorology. Specifically, chemical measurements at these sites includes $PM_{2.5}$ speciation, continuous mass, 24-hr filter-based mass, ozone, CO, SO_2, NO, NOy. More information about this network is available here.

3.3.3 IMPROVE

The Interagency Monitoring of PROtected Visual Environments (IMPROVE) network began in 1985 as a cooperative visibility monitoring effort between EPA, federal land management agencies, and state air agencies (IMPROVE, 2011). Data are collected at Class I areas across the U.S., mostly at national parks, national wilderness areas, and national wildlife refuges. As of 2018, there were approximately 160 IMPROVE sites that have complete annual $PM_{2.5}$ mass and/or $PM_{2.5}$ species data. There are 110 IMPROVE monitoring sites which represent air quality at the 156 designated Class I areas. The additional IMPROVE sites are "IMPROVE protocol" sites, which are generally located in rural areas throughout the U.S., although there are also a handful of urban sites in the U.S. These protocol sites provide additional spatial information across the country, being generally located in areas where there are few Class I areas. The protocol sites use the IMPROVE monitoring samplers and collection routines. In addition to IMPROVE data that is available in AQS, the IMPROVE program provides summary datasets that contains information and pre-calculated data needed for Regional Haze Rule analyses. This includes daily average and annual data for the 20% most impaired and 20% clearest visibility days. The IMPROVE documentation and data can be found here. IMPROVE data advisories are posted here.

3.3.4 CASTNet

Established in 1987, the Clean Air Status and Trends Network (CASTNet) is a dry deposition monitoring network where PM data are collected and reported as weekly average data (U.S. EPA, 2012a). In addition, this network measures and reports hourly ozone concentrations. CASTNet provides atmospheric data on the dry deposition component of total acid deposition, ground-level ozone and other forms of atmospheric pollution. The data (except for ozone) are collected in filter packs that sample the ambient air continuously during the week. As of 2018, CASTNet is comprised of 95 monitoring stations across the U.S. The longest data records are primarily at eastern U.S. sites. More information can be obtained through the CASTNet website.

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3.3.5 CSN

The Chemical Speciation Network (formerly known as STN: The Speciation Trends Network) began operation in 1999 to provide nationally consistent speciated $PM_{2.5}$ data for the assessment of trends at representative sites in urban areas in the U.S. The CSN was established by regulation and is a companion network to the mass-based Federal Reference Method (FRM) network implemented in support of the $PM_{2.5}$ NAAQS. As part of a routine monitoring program, the CSN quantifies mass concentrations and $PM_{2.5}$ constituents, including numerous trace elements, ions (sulfate, nitrate, sodium, potassium, and ammonium), elemental carbon, and organic carbon. As of 2018, there were 52 trends sites in the CSN nationally. CSN trends sites are largely static urban monitoring stations with protocols for sampling methods that are dedicated to characterizing aerosol mass components in urban areas of the U.S. to discern long-term trends and provide an accountability mechanism to assess the effectiveness of control programs. In addition, in 2018, there were approximately 100 supplemental speciation sites that are also part of the CSN. The CSN data at trends sites are collected 1 in every 3 days, whereas supplemental sites collect data either 1 in every 3 days or 1 in every 6 days. Comprehensive information on the CSN and related speciation monitoring can be found here.

3.3.6 NADP

Initiated in the late 1970s, the National Acid Deposition Program (NADP) monitoring network began as a cooperative program between federal and state agencies, universities, electric utilities, and other industries to determine geographical patterns and trends in precipitation chemistry in the U.S. NADP collects and reports wet deposition measurements as weekly average data (NADP, 2013). The network is now known as NADP/NTN (National Trends Network), with nearly 200 sites in operation. The NADP analyzes the constituents important in precipitation chemistry, including those affecting rainfall acidity and those that may have ecological effects. The NTN measures sulfate, nitrate, hydrogen ion (measure of acidity), ammonia, chloride, and base cations (calcium, magnesium, potassium). Detailed information regarding the NADP/NTN monitoring network can be found here.

The Ammonia Monitoring Network (AMoN) is a NADP network that provides additional ambient and deposition ammonia data. The network began as part of a special study in 2007, was approved as an NADP network in 2010, and as of 2016 included approximately 50 monitoring sites across the U.S. AMoN monitors collect 2-week average data. More information can be found here.

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3.3.7 SEARCH

The South Eastern Aerosol Research and Characterization (SEARCH) monitoring network was established in 1998 and is a coordinated effort between the public and private sector to characterize the chemical and physical composition as well as the geographical distribution and long-term trends of $PM_{2.5}$ in the Southeastern U.S. (Edgerton, 2005; Hansen, 2003) The SEARCH network officially shut down in December 2016. However, SEARCH data are still useful for evaluating model performance for any simulations that included the Southeastern U.S. between 1998 and 2016. SEARCH data were collected and reported on an hourly/daily basis. A total of eight sites were operated at one time by SEARCH, although only six operated during SEARCH's final years: Birmingham, Alabama (urban), Centreville, Alabama (rural), Gulfport, Mississippi (urban), Jefferson Street, Atlanta, Georgia (urban), Oak Grove, Mississippi (rural) (not operational as of 2010), Yorkville, Georgia (rural) (not operational as of 2009), suburban Pensacola, Florida (suburban), and downtown Pensacola, Florida (urban). Historical SEARCH data from 1992-2016 can be accessed here.

3.3.8 Speciated $PM_{2.5}$ Data Summary

Speciated $PM_{2.5}$ data play an especially important role in performance evaluation, as the deterministic models predict exact chemical components which can be compared to some of the corresponding measured analytes. There are known positive and negative sampling artifacts as well as analysis artifacts associated with FRM and speciation monitors (Frank, 2006). Due to the complex nature of the measurements, a basic understanding of the various $PM_{2.5}$ and speciation monitoring technology and measurements are needed before undertaking a model evaluation.

Table 3.2: Known measurement artifacts for $PM_{2.5}$ and speciated PM for different monitoring networks.

Network	Measurement	Notes	Sampling Time
FRM	$PM_{2.5}$	- Negative artifacts: ammonium nitrate, organic carbon - Positive artifacts: organic carbon, water	24-hour average 1/3 days or 1/6 days (some daily sites)
	$PM_{2.5}$	- Negative artifacts: ammonium nitrate, organic carbon	

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Network	Measurement	Notes	Sampling Time
CSN (formally STN)		- Positive artifacts: organic carbon, water -Note that positive and negative artifacts for $PM_{2.5}$ may be different from artifacts for individual PM components because the speciated $PM_{2.5}$ samples are collected on different types of filters than are used for total $PM_{2.5}$ gravimetric measurements -CSN $PM_{2.5}$ mass may be different from FRM measurements due to differences in handling procedures	24-hour average 1/3 days or 1/6 days
	SO_4		
	NO_3		
	NH_4		
	OC	- Blank correction is needed to account for positive artifact[32] - Before 2007, OC/EC split was operationally defined using Thermal Optical Transmittance (TOT) method (NIOSH). CSN monitors switched to using the Thermal Optical Reflectance (TOR) method (consistent with	

[32] CSN OC measurements reported in AQS currently have artifact correction applied, although ambient data provided in SMAT-CE does already include a blank correction. The same artifact correction techniques are applied to measurements from CSN and IMPROVE networks. The CSN began implementing IMPROVE-like samplers and the IMPROVE analysis method in 2007. The implementation was fully completed in late 2009. Work by Malm et al (2011) suggests that CSN OC from 2005 and 2006 (before the switch in samplers) likely had a positive multiplicative bias of ~1.2 and a positive additive bias between 1.0 and 1.9 $\mu g/m^3$ depending on the time of year. We recommend using artifact corrected measurements where available and adjusting any uncorrected AQS CSN OC data by subtracting 1.4 $\mu g/m^3$ for measurement before the switch to IMPROVE-like measurements and by subtracting 0.12 $\mu g/m^3$ from measurements after the switch based on Frank (2012).

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Network	Measurement	Notes	Sampling Time
CSN (formerly STN) (con't.)		IMPROVE monitors) between 2007and 2009. [33]	
	EC	- Before 2007, OC/EC split was operationally defined using TOT method (NIOSH). CSN monitors switched to using the TOR method (consistent with IMPROVE monitors) between 2007 and 2009(see footnote 23)	
CASTNet	SO_4		weekly average
	NO_3	Split between NO_3 and HNO_3 may not be reliable in warm weather due to conversion from NO_3 to HNO_3. Recommend comparing total nitrate (NO_3 + HNO_3) between model and observations.	
	NH_4		
	SO_2		
	HNO_3	Split between NO_3 and HNO_3 may not be reliable in warm weather due to conversion from NO_3 to HNO_3. Recommend comparing total nitrate (NO_3 + HNO_3) between model and observations.	
	$PM_{2.5}$	- Negative artifacts: ammonium nitrate, organic carbon - Positive artifacts: organic carbon, water	

[33] The transition from TOT to TOR for CSN monitors occurred in shifts: 56 sites switched in May 2007, 63 sites switched in April 2009, and 78 sites switched in October 2009.

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Network	Measurement	Notes	Sampling Time
IMPROVE		-Note that positive and negative artifacts for $PM_{2.5}$ may be different from artifacts for individual PM components because the speciated $PM_{2.5}$ samples are collected on different types of filters than are used for total $PM_{2.5}$ gravimetric measurements	24-hour average 1/3 days
	SO_4 and S	-IMPROVE monitors measure both elemental S (by XRF) and ionic SO_4^- by ion chromatography. Generally, either measurement is reliable and may be used for model evaluation purposes although some caveats should be noted.[34]	
	NO_3		
	NH_4	-Only available at a limited number of sites for a limited number of years	
IMPROVE (con't.)	Organic Carbon	- OC/EC split is operationally defined using Thermal Optical Reflectance (TOR) analysis. - Blank corrections based on a median measured positive OC artifact from back-up filters at six sites are applied on a month-specific basis to all data before they are reported (Chow et al, 2010; Watson et al., 2009). Frank (2012) recommended changing blank	

[34] Hyslop et al (2012) report that XRF elemental sulfur measurements are somewhat affected by changes in XRF methodologies over time. Also, prior to 2000, filters used to collect sulfate for ion chromatography became clogged during high sulfate episodes. Changes in filter collection techniques eliminated this problem after 2000. In addition, recent literature by Tolocka and Turpin (2012) suggests that differences between XRF sulfur and ion chromatography sulfate are due to the presence of organic sulfur in aerosol (which would be measured by XRF but not IC). If this is the case, then the IC sulfate measurement is more appropriate for comparison with modeled sulfate which generally does not include formation of organic sulfur compounds.

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Network	Measurement	Notes	Sampling Time
		correction procedures for both IMPROVE and STN OC measurements. These recommendations have not yet been implemented.	
	Elemental Carbon	- OC/EC split is operationally defined using Thermal Optical Reflectance (TOR) analysis.	
	Sodium	XRF analysis is not as sensitive to sodium as other methods and generally under-reports sodium concentrations.	
	Silicon	XRF silicon measurements are unreliable at high sulfur conditions (when S/Si > about 7)	
	Aluminum	Elemental concentrations above the MDL can go undetected. IMPROVE has published an alternate soil calculation which estimates Al based on Si concentrations.[35]	

In general, the speciated $PM_{2.5}$ data can be directly compared to the model outputs. Of note, care should be taken in examining issues with blank corrections for organic carbon (especially when measured OC is low) as well as the EC/OC split. Prior to 2006, the CSN and IMPROVE networks used different analysis techniques when estimating EC and OC (CSN monitor locations switched to a similar method to IMPROVE between 2007 and 2009, depending on the monitor). The EC/OC analysis method will generally have a larger impact on EC concentrations than OC concentrations. The difference in OC/EC splits between the two techniques has been investigated in depth in the literature and by IMPROVE staff (Chow, 2001, Chow, 2010, White, 2007). It may not be appropriate to compare EC concentrations between networks for years prior to 2009 (although the data can still be used to evaluate model performance).

Total $PM_{2.5}$ mass measured gravimetrically at CSN and IMPROVE monitors is known to have several measurement artifacts (both positive and negative) (Frank, 2006, Simon et al., 2011,

[35] Due to difficulties in detecting Al, IMPROVE sometimes uses an alternative SOIL calculation which does not include Al: SOIL = 3.48*Si + 1.63*Ca + 2.42*Fe + 1.94*Ti (http://vista.cira.colostate.edu/improve/publications/SOPs/ucdavis_sops/sop351_V2.pdf).

Malm et al., 2011). Consequently, summing the mass of all $PM_{2.5}$ species components is not likely to give the same answer as the total measured $PM_{2.5}$ mass from a Teflon filter. Therefore, model evaluations should concentrate on comparisons with speciated $PM_{2.5}$ components at these sites, rather than total $PM_{2.5}$ mass.

FRM monitors do not measure all of the $PM_{2.5}$ in the air, and the speciation samplers don't measure $PM_{2.5}$ in the same way as the FRM monitors (Frank, 2006). Due to these positive and negative artifacts, the FRM data may not be directly comparable with model outputs without adjustment. The models predict PM species as they might be measured in the ambient air, but the FRM measurements may not always measure what is in the air (due to known positive and negative artifacts). As part of the $PM_{2.5}$ attainment test, we recommend default methodologies to adjust speciation (CSN and IMPROVE) data to better approximate the FRM data (see sections 4.4 and 4.5). A similar adjustment could be made to the model output data to allow the direct comparison to FRM measurements. However, as noted earlier, there may be limited value of information gained by evaluating daily average total measured $PM_{2.5}$ mass (as compared to $PM_{2.5}$ components). More meaningful information may be gleaned from continuous $PM_{2.5}$ ambient data.

Another issue to consider when comparing modeled and observed PM concentrations is the size definitions for PM. IMPROVE and CSN ambient monitors measure $PM_{2.5}$ using inlets which screen out any particles with aerodynamic diameters greater than 2.5 µm. Air quality models use varying schemes to characterize particulate matter size distributions. The two most common modeling schemes are the sectional treatment and the modal treatment. The default configuration for CAMx includes a sectional aerosol treatment while the default configuration for CMAQ includes a modal aerosol treatment, although other versions of these models exist with alternate aerosol treatments. Sectional aerosol modules split particles into bins defined using discrete size cut-points based on aerodynamic diameter (e.g., particles with aerodynamic diameters between 1 µm and 2.5 µm). One common sectional set-up includes 2 bins, one containing particles with aerodynamic diameters < 2.5 µm (fine PM) and one containing particles with aerodynamic diameters > 2.5 µm (coarse particles). Other models have split the fine PM into more than two bins (Nolte et al., 2008; Pandis et al., 1993). With sectional models, the comparison to measured $PM_{2.5}$ is straightforward so long as one of the PM bins has a cutoff at an aerodynamic diameter of 2.5 µm (i.e., add up PM mass in all bins less than 2.5 µm). The modal approach treats PM as occurring in distinct “modes,” each one having a lognormal distribution. Each PM mode is characterized by the geometric mean diameter and the geometric standard deviation of the diameter (the geometric mean and standard deviation can be tracked for particle number, surface area, mass or all three). With modal aerosol treatment, $PM_{2.5}$ can be estimated in several ways. One method is to simply sum the mass in the modes that generally contain fine PM. Another method would be to use the geometric mean and

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standard deviation to calculate the fraction of PM mass in each mode which is associated with particles less than 2.5 µm. However, there are several complicating factors with taking the second approach. First, the EPA's NEIy and many other inventories define $PM_{2.5}$ as being entirely less than 2.5 µm in diameter. If these primary emissions are injected into a modal model (generally into a fine PM mode), they are instantaneously mixed with existing aerosol mass in that mode. The tail of the fine PM mode will include particles greater than 2.5 µm. Therefore, a fraction of the PM that was operationally defined as primarily emitted $PM_{2.5}$ (diameter < 2.5 µm) would be incorrectly distributed into the > 2.5 µm size range based on the mode distribution. If primary emissions were quantified based on modes versus a discrete cut-point, then this would not be a problem. Secondly, some modal models have been shown to over-predict the peak-concentration diameter and distribution width of the fine PM mode (Kelly et al., 2011; Kelly et al., 2010). This would lead to under-predictions of the $PM_{2.5}$ fraction by increasing the mass fraction in the > 2.5 micron diameter range. Air agencies should consider these complications when deciding whether to calculate the fraction of PM mass in each mode below the 2.5 µm cut-point or to simply sum mass over the fine PM mode(s).

Finally, although we recommend weighing performance of speciated PM components more heavily than total PM, some additional insight can be gained by looking at Federal Equivalent Method (FEM) continuous $PM_{2.5}$ measurements[36]. Since speciated measurements are generally derived from filters, these measurements are usually taken as 24-hour averages. The FEM continuous measurements provide a diurnal profile of $PM_{2.5}$ concentrations that can be compared against hourly model outputs to determine whether the model is replicating the measured temporal pattern.

3.4 Diagnostic Evaluation

The goal of a diagnostic model evaluation is to determine whether the model correctly represents the physical and chemical processes that control the ambient concentrations of precursors and secondary pollutants. It is possible that a model can incorrectly represent the relative amount of primary emissions versus secondary production or that a model can incorrectly represent the importance of dispersion, deposition or chemical reaction as a sink. Thus, the ability of a model to accurately reproduce the observed concentration of a particular pollutant does not guarantee that the model correctly simulated the processes that determine the concentration of the pollutant. The goal of a diagnostic evaluation is to investigate the processes that determine the ambient concentrations of ozone, $PM_{2.5}$ and their precursors, and to develop confidence that the model can accurately predict how these concentrations will

[36] Monitoring of atmospheric air quality for purposes of determining compliance with the NAAQS generally requires the use of either Federal reference methods (FRM) or equivalent methods (FEM), as specified in Section 2.1 of Appendix C to 40 CFR part 58.

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change in the future (e.g., Arnold et al., 2006). It is likely that research grade measurements needed to perform a diagnostic evaluation will not be available in many SIP modeling studies, however, it can still be valuable to perform diagnostic analyses and compare the results with previous modeling research studies.

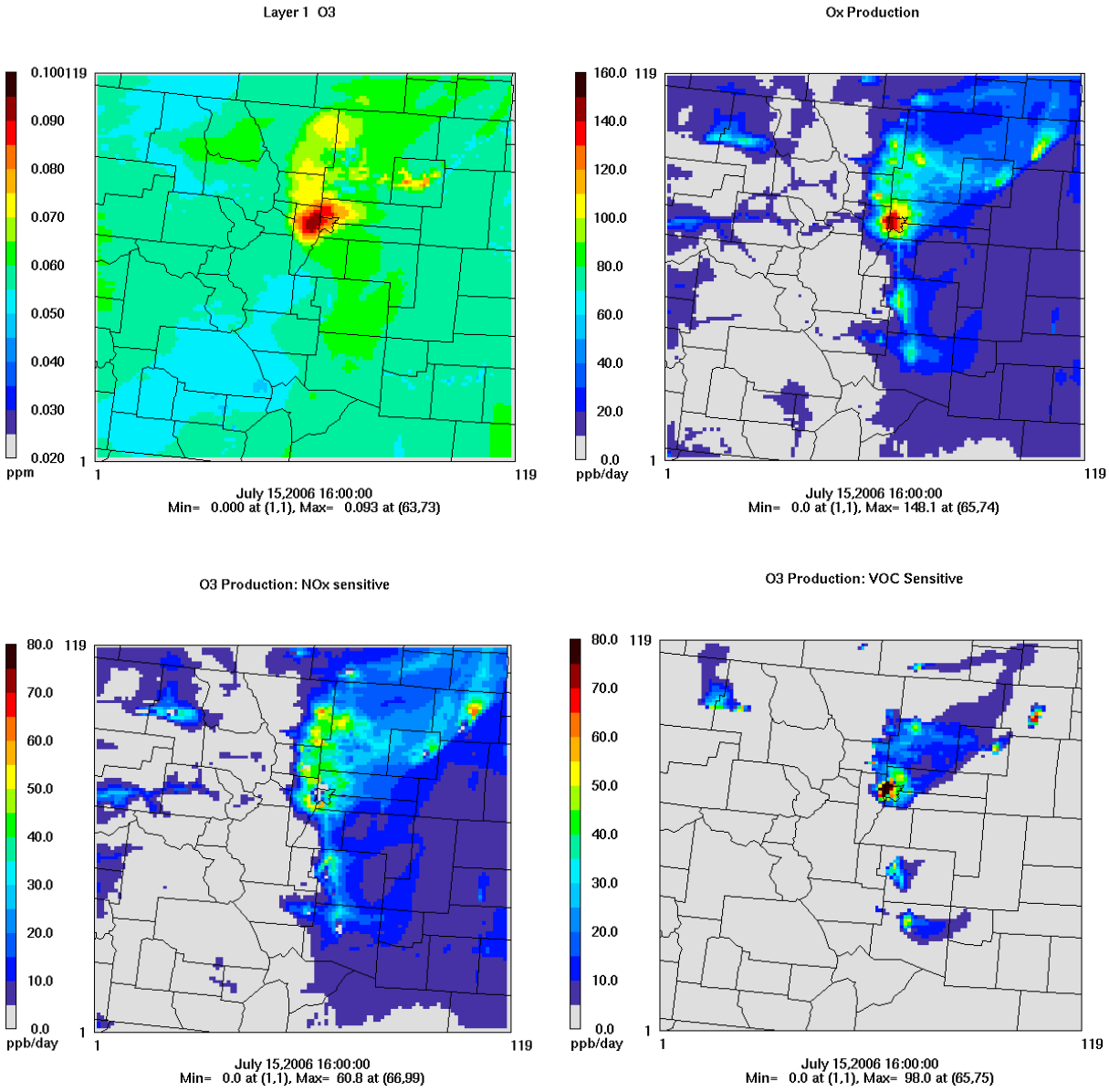
Several different tools and analysis methods are available for use in diagnostic model evaluation including process analysis, indicator ratios, source apportionment methods, model sensitivity studies, and retrospective studies.

3.4.1 Process Analysis

Both the CMAQ and CAMx models include a process analysis tool (Jeffries and Tonnesen, 1994) that provides additional diagnostic information on the chemical reactions and physical processes (e.g., emissions, deposition, advection, vertical mixing, and net change from chemistry) that determine species concentrations. Chemical reaction data can be output either as the hourly integrated reaction rate (IRR) for each reaction or as a summary of key reactions in the chemical process analysis (CPA). Physical processes can be output as hourly concentration changes in the integrated process rate (IPR) file. Detailed analysis off IRR and IPR outputs have been demonstrated in research studies (Jang et al., 1995; Vizuete et al., 2008; Henderson et al., 2011), but significant time and effort are required to complete these analyses. The CPA output provides a more limited set of chemical process information that is more accessible and that can be visualized using the same tools used to analyze model concentration output files. Minimal computational cost is required to produce the CPA files, and they are in the same format as the model concentration files and can be viewed using the same visualization tools. Below are examples of these plots comparing modeled ozone concentration, daily total Ox (Ox = O3 + O3P + O1D + NO2 +2*NO3 + PNA + PAN + 3*N2O5) production, and net ozone production in NOx limited and oxidant limited chemical regimes. The CPA tool can also provide information on the chemical reactions of VOC, NOy and radical species. The need for a process analysis evaluation and the specific processes investigated should be determined on a case-by-case basis.

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Figure 3.4.1 Chemical process analysis plots showing modeled ozone concentration, daily total Ox production, and net ozone production under VOC sensitive and NOx sensitive conditions.



3.4.2 Indicator Ratios

One way to evaluate the response of the model is to examine predicted and observed ratios of indicator species. Indicator species techniques have been developed for both ozone and secondary PM species (in particular nitrate) (Sillman, 1995, 1998; Ansari and Pandis, 1998;

Blanchard et al., 2000; Tonnesen and Dennis, 2000a and 2000b). If ratios of observed indicator species are very high or very low, they provide a sense of whether further ozone or secondary $PM_{2.5}$ production at the monitored location is likely to be limited by availability of NOx or VOC (or NH_3 in the case of particulate nitrate). Agreement between paired observed and predicted ratios suggests a model may correctly predict the sensitivity of ozone or secondary $PM_{2.5}$ at the monitored locations to emission control strategies. Thus, the use of indicator species aims to validate the modeled chemical regime and may help to build confidence in the RRFs predicted from the specific model application.

For ozone, measurements of certain "indicator species ratios" (e.g., comparisons between modeled and observed ratios: O_3/NO_y, O_3/HNO_3) are a potentially useful way to assess whether local ozone formation is VOC or NO_x limited at any particular point in space and time, as well as help reveal whether the model is correctly predicting the sensitivity of ozone to VOC and/or NO_x controls (Millford et al., 1994; Sillman, 1995, 1997, 1998, 2002; Lu and Chang, 1998). Tonnesen and Dennis (2000a and 2000b) distinguished between short lived indicators of instantaneous rates of production of ozone (PO_3) or odd oxygen (PO_x) versus long lived indicators of peak ozone concentration and found that the ratio of production of H_2O_2 to production of HNO_3 ($PH_2O_2/PHNO_3$) is strongly associated with PO_x sensitivity to VOC and NO_x. Tonnesen and Dennis also found that the ratio of formaldehyde to NO_2 was useful as an indicator of ozone sensitivity, and this ratio can be evaluated using satellite data (Martin et al., 2004; Duncan et al., 2010). For PM, such a comparison may reveal whether the model is predicting sensitivity of secondary components of $PM_{2.5}$ to changes in SO_2, NH_3, VOC and/or NO_x controls correctly (Ansari and Pandis, 1998; Blanchard et al., 2000; Pun and Seigneur, 1999, 2001). If a model accurately predicts observed indicator species relationships, then one can conclude with additional confidence that the predicted change in future year ozone or PM may be accurate.

Although ratios of indicator species have the potential to be quite useful, they should be used with caution since different studies have identified different ranges of values to characterize VOC and NOx limited regimes in different locations. Table 3.3 summarizes the range of values determined for 10 indicator species or ratios in various studies. In cases where the NOx and VOC limited ranges are broad or overlap, air agencies should attempt to use values from studies in the local area. Air agencies should be cautious with respect to the use of indicator species when the range of observed values does not provide a clear direction of control. When this occurs, agreement between predictions and observations does not necessarily imply that the response to controls as predicted by the model is correct (especially for secondary particulate matter to changes in precursors). If a model predicts observed values of indicator species relationships such that observed and predicted value fall within the same range, this provides

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some confidence that the predicted change in ozone or secondary particulate matter may be accurate.

A second precaution is that this method often requires more types of measurements than are commonly available. In some cases, it may be difficult to calculate meaningful indicator ratios from relatively imprecise measurements from routine monitoring networks.

Table 3.3: Ranges of indicator species/ratios that have been reported for VOC and NOx limited regimes.

indicator	median VOC-sensitive	transition	median NO_x-sensitive
O_3/NO_y	1.6 - 8.8[a,b,d,f-m]	6 – 15[c,d,m,n,q]	8.8 – 26[a,b,d,f-m]
O_3/NO_z	5.8 – 16[a,d,f,j-m]	7 – 100[c-f,n,q]	10.1 – 35[a,d,f,j-m]
O_3/NO_x	< 15	15 – 60[n,o,q,t]	> 40
O_3/HNO_3	7 - 33.9[a,d,j,k,m]	12 – 25[c,d]	17.2 - 62.9[a,d,j,k,m]
H_2O_2/HNO_3	0.3 - 1.5[d,j-m]	0.2 - 2.4[c,e,h,n-q]	0.4 - 3.6[d,j-m]
H_2O_2/NO_z	0.2 - 1.1[a,j]	0.2 - 0.25[c]	0.6 - 1.3[a,j]
H_2O_2/NO_y	0.2 - 0.4[a,j]	0.12 - 0.17[c]	0.6 - 1.0[a,j]
$HCHO/NO_2$	< 1	1-2[n,o,u]	> 2
NO_z/NO_y	< .5	0.5-0.6[f]	> 0.6
NOy	7.7 - 12.2[j]	5 -2 0[c,e,f,n,r,s]	3.2 - 5.7[j]

[a]Castell et al., 2009; [b]Xie et al., 2011; [c]Torres-Jardon and Keener, 2006; [d]Sillman and He, 2002; [e]Sillman, 1995; [f] Lu and Chang, 1998; [g]Stein et al, 2005; [h]Sillman et al., 1997; [i]Martilli et al., 2002; [j]Jimenez and Baldasano, 2004; [k]Torres-Jardon et al, 2009; [l]Chock et al, 1999; [m]Sillman et al., 2003; [n]Zhang et al, 2009; [o]Tonnesen and Dennis, 2000a; [p]Hammer et al., 2002; [q]Liang et al., 2006; [r]Milford et al, 1994; [s]Vogel et al, 1995; [t]Tonnesen and Dennis, 2000b; [u]Martin et al., 2004

Much of the work done to date with indicator species has focused on peak concentrations of ozone. Limited research has been conducted on development of indicator ratios for secondary PM. This includes work by Blanchard et al., (2000) who examined how indicator species might be used to assess whether particulate nitrate concentrations are limited by NOx or by ammonia

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emissions using mechanisms which incorporate reactions dealing with secondary PM. These authors identify several indicators which appear potentially useful for determining limiting precursors for secondary nitrate PM. The indicators include:

(1) excess NH_3 defined in Equation 3-1 (values greater than zero indicate NOx limited regimes and values less than 0 indicate ammonia limited regimes);

$$excess\ NH_3 = [\mathrm{NH3(g)}] + [\mathrm{NH4+(a)}] - 2 * [\mathrm{SO42-(a)}] - [\mathrm{NO3-(a)}] - [\mathrm{HNO3(g)}] - [\mathrm{HCl(g)}] + 2 * [\mathrm{Ca2+}] + 2 * [\mathrm{Mg2+}] + [\mathrm{Na+}] + [\mathrm{K+}] + [\mathrm{Cl-}] \quad [3\text{-}1]^{37}$$

(2) The ratio of particulate to total nitrate. Values above 0.9 at high temperatures indicate NOx limited regimes (values below 0.3 to 0.5 were indicative of ammonia limited regimes).

Ansari and Pandis (1998) also have suggested the use of the gas ratio (GS), defined in equation 3-2, as an indicator of PM formation regimes.

$$GS = \frac{NH_3^F}{HNO_3^T} \quad [3\text{-}2]^{38}$$

In summary, major challenges in evaluating indicator species include variability in the characteristic ratios for VOC and NOx limited regimes in different locations and the availability of ambient data. Despite these caveats, comparing predicted and observed relationships of indicator species provides a means of assessing a model's ability to accurately characterize the sensitivity of predicted ozone and predicted secondary components of $PM_{2.5}$ to changes in precursors.

3.4.3 Source Apportionment

Source apportionment methods and model sensitivity studies are two complementary approaches that can be used to identify emissions sources that contribute to high pollutant concentrations. While these tools do not directly diagnose the model's ability to replicate the real world, they are useful in their ability to further characterize the sources that are most important to high pollutant concentrations within the model. The CMAQ and CAMx models both include options to use source apportionment tools to identify sources that contribute to

[37] Concentrations are in µmol/m^3, (g) represent gas-phase and (a) represents aerosol phase.
[38] NH_3^F is free ammonia (total ammonia – 2*sulfate). HNO_3^T is total nitrate (gas + PM).

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the production of ozone (Ramboll, 2018; Kwok et al, 2014) and some components of $PM_{2.5}$, including sulfate, nitrate, ammonium and primary emissions of $PM_{2.5}$ (Ramboll, 2018; Kwok et al., 2013). Source apportionment tools employ a set of model tracers to attribute pollutant concentrations to user selected emissions source sectors and geographic areas. This approach can be useful both as a diagnostic tool to identify sources that contribute to ozone and $PM_{2.5}$ and also as an aid in regulatory analysis to identify emissions control measures that will be effective for attaining air quality standards. An advantage of source apportionment approaches is that tracers attribute the mass contribution from a source to a receptor and, therefore, this approach is less susceptible to the effects of non-linear chemistry, which can complicate the interpretation of model sensitivity simulations.

3.4.4 Sensitivity Studies

Model sensitivity simulations can be used to identify model inputs (IC/LBC, meteorological data, chemical reactions, and emissions) that have the greatest impact on model-predicted concentrations. The objective of sensitivity tests is to identify whether the inputs have a large enough influence that errors in these inputs could be a driving influence on the model predictions. In "brute-force" sensitivity simulations, the model input data is modified directly (e.g., increasing or decreasing emissions in the model input file). Brute-force simulations are relatively easy to implement but are resource intensive when many different inputs must be evaluated. The Direct Decoupled Method (DDM) is an approach that can be used to evaluate the first order sensitivity to multiple model inputs in a single model simulation (e.g., Cohan et al., 2005; Napelenok et al., 2006). Because of non-linearity in chemical reactions, first-order sensitivity is not always sufficient, and high-order DDM (HDDM) can be used to evaluate second order sensitivities to inputs that are subject to non-linear chemistry (Zhang et al., 2012b).

In cases where the model performs poorly in the base case, sensitivity simulation may be useful to identify potential causes for poor model performance. However, caution should be used in modifying inputs to achieve good model performance because arbitrarily "tuning" of model input data to fit the observations can introduce compensating errors. For example, if a model underestimates observed ozone because the meteorological data is overly dispersive, the model performance could be improved by increasing emissions or LBC concentrations, but this model would not be reliable for predicting future concentrations because its good performance in the base case was achieved through compensating errors in the input. An appropriate use of sensitivity approaches is to identify each of the processes or inputs that has a large effect on model predictions, and then perform additional analysis of those inputs to determine if they are accurately represented in the base case model.

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3.4.5 Dynamic Model Evaluation

A second method for assessing a model's performance in predicting the sensitivity of ozone or $PM_{2.5}$ species to changes in emissions is to perform a retrospective dynamic analysis. This involves comparing model predicted historical trends with observed trends. Retrospective analyses provide potentially useful means for diagnosing why a strategy did or did not work as expected. They also provide an important opportunity to evaluate model performance in a way that is closely related to how models are used to support an attainment demonstration.

A dynamic evaluation uses various analyses to assess the accuracy of the model in characterizing the sensitivity of ozone and/or $PM_{2.5}$ to changes in emissions. Although dynamic evaluation is always recommended, the measurements and resources needed for a dynamic evaluation may not be readily available to air agencies performing SIP modeling. Additional challenges for retrospective analyses include identifying appropriate case studies for which responses to emissions changes are large enough to be distinguished in ambient data, developing or obtaining equivalent and appropriate emissions for multiple historical years, and disentangling the confounding influences of year to year changes in meteorology and emissions.

A retrospective analysis is intended to examine the ability of the model to respond to emissions changes by comparing recent trends in observed ozone or $PM_{2.5}$ concentrations to the model-predicted trend over the same time period. The approach is a direct assessment of what is most important in an attainment demonstration: does the model accurately predict changes in air quality as a result of changes in emissions? As part of a retrospective analysis, the model is run for (a) current episodes or time periods and (b) episodes in one or more historical time periods using the emissions and meteorological inputs appropriate for each time period modeled.

While retrospective analyses may be useful, it may be difficult to obtain meteorological and emissions inputs for the historical time period(s) that are calculated using techniques and assumptions that are consistent with the calculation of these same inputs for the current time period. Using inconsistent inputs will confound the interpretation of the predicted trend. One method for ensuring consistent methodology for emissions estimates is to backcast emissions from the most recent year to the earliest year. The model should respond in a predictable way if the emissions changes are large enough. Hence, modeling an emissions change of only a few percent would not be viable. However, if NOx or SO_2 emissions have been reduced by a large percentage (e.g., 30% or more) over a relatively short time period, then that may be a good time period to test the response of the model.

Because differences in meteorology between years can confound the apparent change in pollutants, a complete retrospective analysis could include multiple sensitivity runs using both

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year-specific meteorology and constant meteorology. The year-specific meteorology would allow the modeler to compare modeled and observed trends most accurately, and the constant meteorology would help inform the analysis on what portion of the change in pollutant concentrations were due to emissions versus meteorological differences.

Retrospective analyses are one of the few tools that can be used to determine if the model is responding "adequately" or "correctly" to control measures. Recent efforts to perform this type of analysis have been undertaken by Zhou et al (2013), Gilliland et al. (2008), Godowitch et al. (2010), Pierce et al. (2010) and Foley et al. (2014). These published analyses may be used to better understand the ability of certain models to properly capture relationships between ambient pollution levels and emissions.

Another dynamic evaluation approach is to look at operational performance under varying conditions (e.g., by day of the week, by season, and by region) (Marr and Harley, 2002; Murphy et al, 2007; Harley et al, 2005). The mix of pollutants vary by day of the week and from area to area; when a model shows good operational performance across these different chemical environments, it supports the assertion that it will respond appropriately to changes in emissions. Two studies have performed model evaluations that focused on the model's ability to capture weekend/weekday changes (CRC, 2011; Pierce et al, 2010).

3.5 Evaluation Tools

There is available software and tools that can be used to process ambient and model data to create statistical output and plots for model performance evaluations. One example is the Atmospheric Model Evaluation Tool (AMET) (Appel, 2011). AMET is built on several open-source software packages and uses the MySQL database software to store paired observation and model output data. There are modules in AMET for evaluating both meteorological and air quality model output. AMET provides a useful set of scripts for creating various types of plots and statistics.

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4.0 Assessing Modeled Attainment for Ozone and $PM_{2.5}$

A *model attainment demonstration* usually consists of two key components: a) analyses which estimate whether a set of simulated emissions reductions corresponding to a control program scenario will result in ambient concentrations that meet the NAAQS and b) an identified set of control measures which will result in the required emissions reductions. This guidance focuses on the first component of a model attainment demonstration; that is, the completion and interpretation of analyses to estimate the amount of emission reduction needed to attain the NAAQS.

Air agencies should determine whether a control program scenario will provide sufficient emission reductions to demonstrate attainment of the NAAQS using the *modeled attainment test*. The modeled attainment test is a technical procedure in which an air quality model is used to simulate base year and future air pollutant concentrations for the purpose of demonstrating attainment of the relevant NAAQS. The recommended test uses model estimates in a "relative" rather than "absolute" sense to estimate future year design values. As explained in more detail in subsequent sections, the fractional changes in air pollutant concentrations between the model future year and model base year are calculated for all valid monitors. These ratios are called *relative response factors* (RRF). Future ozone and/or $PM_{2.5}$ design values are estimated at existing monitoring sites by multiplying the modeled relative response factor for each monitor by the monitor-specific base year design value. The resulting estimates of future concentrations are then compared to the NAAQS. If the future estimates of ozone and/or $PM_{2.5}$ design values do not exceed the NAAQS, then this provides evidence that attainment will be reached.

In addition to the modeled attainment test, air agencies should also consider performing a set of corroboratory analyses to further assess whether a proposed set of emission reductions is likely to lead to attainment of the NAAQS. As discussed later in this section (see section 6), the modeled attainment test and these supplemental analyses should be aggregated into a *weight of evidence determination* to evaluate whether the selected emissions reductions will yield attainment. The concept of relative response factors also applies to modeling for the purpose of setting RPGs for regional haze, the subject of section 5.

4.1 Overview of Modeled Attainment Test

There are four reasons why the recommended modeled attainment test is based on application of the model in a relative sense. First and foremost, this approach has the effect of anchoring the future concentrations to a "real" measured ambient value, which is important given model bias and error in the base year simulation(s). It is reasoned that factors causing bias (either under or over-predictions) in the base case will also affect the future case. While good model

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performance remains a prerequisite for use of a model for regulatory analyses, problems posed by imperfect model performance on individual days are expected to be reduced when using the relative approach. An internal EPA analysis (U.S. EPA, 2014a) considered whether daily ratios of model future/current maximum daily 8-hour ozone averages (MDA8) varied strongly as a function of site-specific base case model performance. This analysis was completed using a national model simulation that projected 2020 ozone concentrations from a 2007 base case. The analysis determined that when modeled, MDA8 ozone bias was relatively small (e.g., less than +/- 20 ppb), the average response ratios were not a strong function of the model MDA8 bias. This provides confidence that the model can detect the air quality response in the midst of reasonable levels of absolute bias and error. Second, the relative modeled attainment test allows for a future projection of 3-year average ozone and $PM_{2.5}$ design values or 5-year average visibility values without explicitly having to model a 3-year or 5-year period. Third, because $PM_{2.5}$ concentrations typically consist of a diverse mix of primary and secondary components, the modeled attainment test based on RRFs decreases the possibility of choosing ineffective control strategies based on inaccurate model estimations of $PM_{2.5}$ composition, by assessing component specific RRFs. Fourth, and finally, there is evidence, based on a retrospective modeling analysis of ozone changes between 2002 and 2005 (Foley et al, 2014) and 2002 and 2010 (Hogrefe et al, 2014), that using the model in a relative sense provides better estimates of future ozone design values than using the absolute future year simulation. The correlation between model-projected and actual design values, as well as the accuracy of model projections of attaining a 75 ppb NAAQS, appear to be slightly improved when a relative modeled attainment test is utilized.

Equation (4.1) describes the recommended modeled attainment test in its simplest form, which directly applies for ozone, as applied for monitoring site *i*:

$$(\mathrm{DVF})_{\mathrm{i}} = (RRF)_i * (DVB)_i \qquad [4.1]$$

where $\mathrm{DVF_i}$ is the estimated design value for the future year in which attainment is required at monitoring site *i*; $\mathrm{RRF_i}$ is the relative response factor at monitoring site *i*; and $\mathrm{DVB_i}$ is the *base design value* monitored at site *i*. Each of these terms is discussed in more detail below. For $PM_{2.5}$ and visibility, the modeled attainment test is more complicated in that each PM component (defined in a certain way) has its own RRF.

The EPA has developed the Software for Modeled Attainment Test-Community Edition (SMAT-CE) tool to enable completion of the modeled attainment tests for $PM_{2.5}$ and ozone, as well as for calculating changes in visibility in Class I areas. SMAT replaced the previous EPA attainment test software called MATS (Abt, 2014). SMAT can be found on the EPA's Support Center for Regulatory Atmospheric Modeling (SCRAM) website.

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4.1.1 Establishing the Base Design Value

The base design value for each monitoring site (DVB_i) is the anchor point for estimating future year projected concentrations. Because the modeling is being used in a relative sense to determine how the modeled emissions changes will affect air quality design values in an area, it is important to match the base design value as closely as possible to the base year for which future/base ratios will be assessed. That is, if one is estimating the expected air quality change from emissions reductions between 2016 and 2030, it is important to establish an air quality anchor that represents 2016 emissions levels as closely as possible. However, it is well-established that inter-annual variability in meteorological conditions often leads to year to year differences in design values, even with static emissions levels (U.S. EPA, 2012). In addition, there is also year to year variability in emissions due to economic factors (such as recessions) and compliance with regulations. We, therefore, recommend using the base design value approach described below.

For the modeled attainment tests for ozone and $PM_{2.5}$, we recommend using the average of the three design value periods, which include the base emissions inventory year. This average is expected to best represent the air quality resulting from base year emissions with consideration of meteorological and emissions variability. For example, if the modeled attainment test uses base year emissions from 2014, then the base design value (DVB) would be calculated as shown in equation 4.2 for each site *i*:

$$(DVB)i = \frac{((DV\ 2014)_i + (DV\ 2015)_i + (DV\ 2016)_i)}{3} \qquad [4.2]^{39}$$

This has the desired effect of weighting the projected ozone or $PM_{2.5}$ base design values towards the middle year of a five-year period (2012-2016); in this example, for a 2014 base emissions inventory year. Additionally, an average of three design values will be more stable (less year to year variability) than any single design value period. An EPA analysis of design values data at 761 ozone monitors over the period between 2002 and 2011 concluded that the median standard deviation of individual 3-year ozone design values was 5.3 ppb, whereas the standard deviation of the average of multiple 3-year ozone design values was only 4.0 ppb.

In cases in which there are less than 5 years of valid monitoring data at a site, we recommend that base design values be calculated only when there are at least 3 years of consecutive valid data (i.e., at least one complete design value). If a location has less than 3 consecutive years of

[39] For nomenclature purposes, the 3-year design value is referred to by the last year of the averaging period. That is, DV 2014 represents air quality data averaged over 2012, 2013, and 2014 for ozone and $PM_{2.5}$.

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valid data, then that site should not ordinarily be used in the modeled attainment test.[40] An example calculation for DVB is shown in Table 4.1 and includes the number of significant digits to include for ozone and each form of the $PM_{2.5}$ standard.

Table 4.1: Example illustrating the calculation of base design values.

	2014 DV	2015 DV	2016 DV	DVB
O3 NAAQS (ppb)[41]	76	76	78	76.7
Annual $PM_{2.5}$ NAAQS ($\mu g/m^3$)	12.9	13.1	12.6	12.87
24-hour $PM_{2.5}$ NAAQS ($\mu g/m^3$)	32	33	32	32.3

The measured 3-year average design values use the rounding/truncation rules established in 40 CFR part 50 Appendix U (8-hour ozone) and Appendix N ($PM_{2.5}$). The resultant 5-year weighted average DVB should carry one digit to the right of the decimal point for ozone and 24-hour $PM_{2.5}$ and two digits to the right of the decimal for annual $PM_{2.5}$.

The EPA also recognizes that the ambient data record may be modified under certain circumstances. For example, air agencies can request that the EPA agree to exclude event-influenced data by demonstrating that these data have been influenced by "exceptional" events and otherwise meet the criteria in the Exceptional Events Rule (81 FR 68216, October 3, 2016). Once an air agency submits an exceptional events demonstration and the EPA concurs with an air agency's request, the event-influenced data are officially noted and removed from AQS user reports (unless the AQS user specifically indicates that they should be included) and not used to calculate design values. In other cases, data may not qualify for exclusion under the Exceptional Events Rule but Appendix W to Part 51 may provide guidance on considering data which may be influenced by events that are not typical or expected to recur in the future (e.g., wildfires, construction, roadway repairs, or unusual agricultural activities) for certain modeling analyses. Potential event-influenced data may affect future year projections that are part of the modeled attainment demonstration. If potential event-influenced data from the historical

[40] Monitoring sites with less than 3 years of valid data cannot ordinarily be used to determine attainment status. Therefore, in most cases, those sites should not be used in the attainment demonstration or for regulatory analyses. However, there may be cases where a monitoring site with incomplete data indicates an area of high ozone or PM concentration. Further examination of the monitoring data and modeled response (RRF) in the area is recommended as part of either the monitor-based attainment test or an unmonitored area analysis, as appropriate.

[41] The current ozone NAAQS is defined in units of ppm. However, for ease of use, this document will use ppb units.

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record may affect regulatory outcomes, we encourage air agencies to consult with their EPA Regional office to determine how best to handle this situation.

In practice, the choice of the base design value can be critical to the determination of the estimated future year design values (Cohan, 2006) and careful consideration should be given to the selection of the years used in the calculation of base design values. There is no single methodology that can derive a "correct" base design value, but the 5-year weighted average value establishes a relatively stable value that is weighted towards the emissions and meteorological modeling year. In most cases, this provides an appropriate anchor point on which to base the future year design value calculations. Alternate, equally plausible, calculations of base design values may be considered with appropriate justification. Alternate base design values may also be considered as part of the corroborating analyses that comprise the aggregate weight of evidence determination. For instance, one may want to consider establishing the base design value on the highest of the relevant design values to ensure that the emissions measures will yield attainment even in periods with meteorological conditions especially conducive to poor air quality. In addition, in some cases, large year to year emissions changes or highly unusual meteorological conditions may make certain periods/years unsuitable for consideration in the base year period. Consideration of adjustments to the base design value(s) can be made, with appropriate justification, on a case-by-case basis and in consultation with the relevant EPA Regional office.

4.1.2 Calculation of Relative Response Factors

The relative response factor for each monitoring site $(RRF)_i$ is the fractional change in air quality concentrations that is simulated due to emissions changes between a base and a future year emissions scenario. The specific RRF calculation techniques vary by pollutant and are described in more detail in the remainder of section 4 below. The most important consideration associated with the RRF calculation is determining which model values are most representative of the expected air quality change for a given location. This requires consideration of all of the varying changes in hourly pollutant concentrations between the base and future cases and a determination of the most appropriate summary (average) value to apply to the base design value. As with the selection of a base design value, there may be plausible alternative means of calculating the RRFs that can differ from the approaches recommended below (e.g., Kulkarni et al., 2014, Porter et al., 2014). Where justified, alternate RRF calculation techniques can be included as corroborative analyses as part of a weight of evidence determination.

4.2 Modeled Attainment Test for the Primary Ozone Standard

The 8-hour ozone design value is currently calculated as the 3-year average of the annual fourth highest daily maximum 8-hour average concentration for a specific monitor. The standard is

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considered to be attained if the observed design value does not exceed the level of the ozone NAAQS[42]. Similarly, the modeled attainment test is considered satisfied when the $(\mathrm{DVF})_i$ is less than or equal to the current NAAQS level. The recommended test is described below.

4.2.1 Model Values to Use in the RRF Calculation

Given the formulation of the modeled attainment test, it is important to identify which model days are best suited for determining the expected air quality response resulting from a set of emissions changes. On any given modeled day, meteorological conditions may or may not be conducive to high concentrations at a monitor. If ozone predicted near a monitor on any particular day is much less than the design value, the model predictions for that day could be unresponsive to controls (e.g., the location could be upwind from most of the emissions in the nonattainment area on that day). If these days are included in the RRF calculation, they will likely lead to a higher RRF (closer to one) and a potential overestimation of the future design value.

Internal EPA analyses (U.S. EPA, 2014a) have shown that model response to decreasing emissions is generally most stable when the base ozone predictions are highest. The greater model response at higher concentrations is likely due to more "controllable" ozone at higher concentrations. In addition, the high model days are selected individually for each monitor. Meteorological conditions that lead to high ozone may differ between monitors in an area. For example, monitors that are typically "upwind" or "downwind" of an area may experience high ozone on different days, depending on the prevailing wind direction. In most urban areas, on days with high ozone concentrations, there is a relatively high percentage of locally generated ozone compared to days with low base case concentrations (U.S. EPA 2014b). Days with low ozone concentrations are more likely to have a high percentage of ozone due to background and boundary conditions. Since the form of the standard is also focused on the highest days of an ozone season (i.e., the fourth highest MDA8), the RRF calculation should also focus on days when the model predicts the highest ozone concentrations.

As the ozone NAAQS has been lowered, a key question is whether the attainment test should use an average RRF based on all modeled days that are greater than the NAAQS, as in the previous guidance approach. In some areas of the country, this could lead to RRF calculations that might include upwards of 100 days per ozone season. In these cases, including too many

[42] At the time of publication of this guidance, the ozone NAAQS is 0.070 ppm per 40 CFR 50.19. Design values for the 0.070 ppm NAAQS are truncated to the 3rd decimal digit. Therefore, 0.0709 ppm (70.9 ppb) is considered attainment and 0.0710 (71.0 ppb) is considered nonattainment. The same rounding/truncation procedures should be applied in the modeled attainment test. A detailed description of the methodology to calculate ambient ozone design values is provided in Appendix U to Part 50.

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days in the RRF calculation may lead to higher (closer to 1) RRFs. Using a reasonable number of the highest modeled days at each monitor is most likely to represent the response of the observed design value at a monitor. Since the design value is based on the seasonal 4th high observed values, we recommend selecting a set of modeled days that are likely to encompass a range of values that are somewhat higher than and somewhat lower than the 4th high value. We, therefore, recommend calculating the RRF based on the highest 10 modeled days in the simulated period (at each monitoring site). We believe this balances the desire to have enough days in the RRF to generate a robust calculation, but not so many days that the RRF does not represent days with concentrations near the observed design values. In addition, use of the highest 10 days (without an initial threshold) allows the attainment test to be easily adapted to any level of the NAAQS with little or no change in the methodology. In support of the revised recommendation, a recent assessment of modeled ozone changes between two ozone seasons (Foley et al., 2014) suggests that the use of the highest 10 days in the mean RRF calculation yields a slightly better estimate of the actual observed ozone change than the previous guidance approach.

The EPA recommends that the ozone RRF calculations be based on the 10 highest days in the base year modeling at the monitor location, as long as the base MDA8 value is greater than or equal to 60 ppb for that day. In cases for which the base model simulation does not have 10 days with MDA8 values greater than or equal to 60 ppb at a site, then EPA recommends using all days where MDA8 >= 60 ppb, as long as there are at least 5 days that meet the minimum threshold criteria. If there are less than 5 days with MDA8 >= 60 ppb, EPA recommends that air agencies do not calculate a DVF for the site.[43] If the modeled attainment test is based on less than 10 days, then other assessments in the aggregate weight of evidence demonstration will need to be more rigorous to counter the reduced robustness of the modeled attainment test.

In addition, as discussed by Vizuete et al. (2011), there can be days in which the modeled source-receptor relationships may not yield a representative response for a particular cell or array of grid cells. This can result from small inconsistencies between the model representation of transport patterns (or chemical formation) and what actually occurred on that day. In other situations, perhaps the high modeled ozone results from an atypical condition (e.g., in conjunction with a wildfire smoke plume) that is not representative of conditions that led to the area's design value. If there is compelling evidence to determine that a particular day, while being among the 10 highest MDA8 values at a location, is not representative of the expected source-receptor relationship at that location; then that day can be considered for removal from

[43] A scenario in which the 5th highest base model MDA8 values is less than 60 ppb either indicates an extremely low ozone site or a site with poor model performance. In either case, projections of DVF values are likely not reliable.

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the RRF calculation.[44] If a day or days are removed, we recommended adding the next-highest modeled day or days from outside the top 10 to maintain the use of 10 days in the RRF calculation. Air agencies should document the evidence that argues for the exclusion of any otherwise-eligible days. As noted earlier, poor model performance on individual days can lead to ratios of future to base ozone that may be biased on those days. For example, underprediction of ozone concentrations may lead to ratios that are unresponsive to emissions controls. Air agencies may want to examine the day- and site-specific model performance for days that are part of the RRF calculation to make sure that they can be appropriately used in calculating the expected response.

4.2.2 Grid Cells to Use in the RRF Calculation

It is recommended that ozone RRF calculations consider model response in grid cells immediately surrounding the monitoring site along with the grid cell in which the monitor is located. There are two primary reasons why we believe it is appropriate to include predictions from grid cells near a monitor rather than just the cell containing the monitor. First, limitations in the inputs and model physics can affect model precision at the grid cell level. Allowing some leeway in the precision of the predicted location of daily maximum ozone concentrations can help assure that possibly artificial, fine scale variations do not inadvertently impact an assessment of modeled ozone response. Second, some ozone monitors and important emission sources may be located very close to the border of a grid cell. Considering multiple cells near a monitor, rather than the single cell containing the monitor, diminishes the likelihood of inappropriate results which may occur from the artificial geometry of the superimposed grid system.

Based on the above considerations, it is recommended that the RRF be based on a 3 x 3 array of cells centered on the location of the grid cell containing the monitor. This is a change from the 2007 guidance (U.S. EPA, 2007), which pre-identified 15 km as an appropriate distance for grid cell proximity to a monitor and, therefore, recommended the selection of RRF grid cells to be contingent upon the chosen model grid resolution (i.e., a finer grid resolution considered a larger array of grid cells to maintain the pre-identified 15 km distance). The revised approach allows for small spatial differences in the response to be considered in the RRF calculation and presumes that the chosen model grid resolution is able to appropriately capture model response at the location of the monitoring site. Additionally, as described in section 4.2.3, the guidance now recommends that the grid cell with the highest base year MDA8 ozone value in the 3 x 3 array be used for both the base and future components of the RRF calculation, as opposed to the 2007 guidance approach, which recommended selecting the peak value in the

[44] Days that have been removed from the official record as exceptional events should be considered for removal from the RRF calculations.

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base and future cases even if they were in different grid cells. The rationale behind this change is that the goal of the modeling is to assess the ozone change at a specific location (i.e., a grid cell representative of a monitor location), independent of how the ozone peak may shift across an area. As the monitor location does not change between the base and future, it stands to reason that the future-year value should come from the same grid cell as the base case.

The selection of grid cells to use in the RRF calculation is especially important in "oxidant limited" areas (i.e., areas where incremental NOx decreases may lead to ozone increases) because these areas are likely to have grid cells that respond to VOC controls, with NOx sensitive grid cells nearby (perhaps even in the same 3 x 3 array). The 3 x 3 array methodology could lead to unrealistically small or large RRFs in these locations, depending on the specific case. Internal EPA analyses with a 12 km grid resolution have shown that on average, model-estimated future design values vary by less than 1 ppb when a 1x1 approach is used as opposed to the recommended array, although higher variability can occur (U.S. EPA, 2014a).

While the use of a 3 x 3 array of cells is the recommended approach for the modeled attainment test, air agencies are encouraged to consider the actual spatial scales of the monitors at which the modeled attainment test is being applied. Most ozone monitors are generally sited to be representative of an urban or neighborhood scale. In cases in which the spatial representativeness of a monitoring location is much smaller or larger than the area covered by the 3 x 3 array of cells, air agencies may consider assessing site-specific model response over an alternative grid cell array as part of corroborative analyses that inform the aggregate weight of evidence determination. Additionally, there may be cases where certain cells along the periphery of the 3 x 3 array have different modeled responses than what would be expected at the monitor location at the center of array due to a specific local topographic or geographical feature (e.g., a large water body or a significant elevation change). A potential example of this situation would be an array where several cells are over water and where the meteorological conditions and relevant emissions sources differ substantially from the land-based monitor location. Again, in these types of cases and with appropriate justification, air agencies could consider removing the unrepresentative cells from the calculation.

4.2.3 Sample Modeled Attainment Test Calculation

Once the appropriate RRF days are determined at each site, the calculation is straightforward. RRFs are not calculated on a daily basis, but instead are based on the mean 8-hour daily maximum values on all eligible calculation days. At the last step in the process, the final DVF should be calculated in accordance with the data handling conventions associated with the NAAQS (e.g., truncated to the third decimal in ppm units as per current Appendix U). An example is provided below for a 2016 base year and 2030 future year simulation based on an

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annual model simulation. This hypothetical modeled attainment test considers an area with three ozone monitors.

Step 1: Compute site-specific base year design values (DVBs) from observed data at all eligible sites in the area by calculating the average of the design value periods which include the base year inventory year. All averaged values should be rounded to the tenth of a ppb. See Table 4.2 for the calculation in this sample case. The base design value is the average of the 3-year design values for 2016, 2017, and 2018.

Table 4.2: Ambient ozone base design values in example calculation.

Monitoring site	2014 DV (ppb)	2015 DV (ppb)	2016 DV (ppb)	Base design value (ppb)
A	84	79	73	78.7
B	N/A	67	83	75.0
C	86	76	80	80.7

Step 2: Compute site-specific relative response factors (RRFs) from modeled data at all eligible sites (i.e., A, B, and C). This is done by first identifying the 10 days with the highest daily 8-hour maximum ozone concentrations greater than 60 ppb (or subset of days if there are 5-9 days greater than 60 ppb) in the base year. For each of these days, identify the grid cell with the highest base year MDA8 ozone in the 3 x 3 cell array surrounding the monitor cell location and use that value in the calculation of a multi-day average. 10-day averages (where possible) should be calculated for both the base and future simulations. The future case average should be based on MDA8 values paired to the same cell as used in the base average. Figure 4.1 below shows an abbreviated subset of the RRF calculation for 3 days at a single sample site. Model estimates of MDA8 (in ppb) should be calculated to at least four places to the right of the decimal, with the last digit truncated.

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Figure 4.1. Example demonstration of daily selections of 8-hour maxima to be used in RRF calculation.[45]

Base

6/21/2014		
60.24	68.15	66.20
73.41	**76.26**	71.27
67.62	74.02	73.24

6/26/2014		
76.20	75.35	77.41
78.51	76.79	75.92
76.66	75.95	77.21

7/17/2014		
50.22	58.55	56.22
53.47	56.22	51.28
57.76	**59.10**	53.29

Future

6/21/2014		
56.89	59.22	58.05
63.69	**68.46**	63.39
61.86	67.16	66.80

6/26/2014		
<u>69.84</u>	67.71	68.14
68.30	66.27	67.95
64.28	65.15	66.58

7/17/2014		
46.80	49.27	48.55
51.91	50.41	50.34
53.62	**54.10**	50.62

Day 1 (6/21) is straightforward. The daily maximum 8-hour average is > 60 ppb and is in the same cell in both the base and future case.

For day 2 (6/26), the peak location shifts from the base to another cell in the array in the future (underlined cell). However, the center left cell is used for base and future values (paired in space).

Day 3 (7/17) would not be eligible for the RRF calculation because there are no base values > 60 ppb.

Step 3: Once the MDA8 values are selected for each appropriate day for each monitoring site, they should be averaged together over the days while maintaining at least four places to the right of the decimal. The RRF is the ratio of the average future MDA8 values to the average base MDA8 values. Table 4.3 shows an example RRF calculation, using the results from days 1 and 2 from Figure 4.1, plus the other eight (top 10) days in which the daily model predictions were deemed appropriate for RRF calculation. RRF values should be estimated to four decimal places (rounded to the 4th decimal digit).

[45] Figure 4.1 depicts the modeled ozone in each cell with only two digits to the right of the decimal to make the formatting simpler. The actual cell values used in the calculation should carry at least 4 digits to the right of the decimal.

Table 4.3. Relative response factor (RRF) calculation in example calculation.

Date	Base (ppb)	Future (ppb)
6/21/2014	76.2632	68.4626
6/26/2014	78.5156	68.3089
6/27/2014	75.2235	65.4333
6/28/2014	70.0509	62.7618
7/11/2014	76.3311	68.1865
7/12/2014	81.6739	72.6237
7/13/2014	78.3132	64.5255
8/02/2014	73.6956	69.9670
8/03/2014	75.8379	65.0507
8/21/2014	71.4430	59.3647
Average	75.7348	66.4685
RRF_i	**0.8776**	

The last step of the process is to multiply all of the site-specific RRFs by the corresponding site-specific DVBs and compare the results against the current level of the ozone NAAQS. In the final step, as noted in footnote 34, the design values are truncated to the integer ppb unit. Table 4.4 shows those results, assuming that the sample RRF shown above is for site C in the example. The final DVF for this sample site would be 70 ppb or 0.070 ppm. This would be considered a passing modeled attainment test for an ozone NAAQS of 0.070 ppm.

Table 4.4. Calculation of DVF_i for the three sites in the sample exercise.

Monitoring site	Base design value (ppb)	RRF	Future design value, pre-truncation (ppb)	Final Future design value (ppb)
A	78.7	0.8933	70.3	70
B	75.0	0.9138	68.5	68
C	80.7	0.8776	70.8	70

Note: The "final" future year design value represents the truncated value to compare to the NAAQS. However, it is recommended to retain the tenths (of a ppb) digit in all documentation, so that small ozone changes can be gleaned from control strategy and sensitivity analyses.

4.3 Modeled Attainment Test for the Secondary Ozone Standard

At the time this guidance document was written, the secondary ozone NAAQS is the same as the primary NAAQS. However, in the past, EPA has considered setting a secondary ozone NAAQS that is based on a cumulative measure of ozone concentrations, as opposed to the 3-year average of the annual fourth-highest daily maxima. If EPA were to establish a distinct secondary standard, it is possible that air agencies would need to separately show that the planned emissions reductions would be sufficient to meet both the primary and secondary

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NAAQS. If a new secondary standard is subsequently developed, EPA will provide supplemental guidance on how to assess attainment of that new standard at the time of its promulgation.

4.4 What is the Modeled Attainment Tests for the Annual Average $PM_{2.5}$ NAAQS?

Because ambient $PM_{2.5}$ often consists of multiple PM species, the modeled attainment test for $PM_{2.5}$ utilizes both $PM_{2.5}$ and individual $PM_{2.5}$ component species. A separate RRF and a separate concentration representing the base period is calculated for each $PM_{2.5}$ species. In order to perform the recommended modeled attainment test, air agencies should divide observed mass concentrations of $PM_{2.5}$ into 8 components (plus passive mass):

- Sulfates
- Nitrates
- Ammonium
- Organic carbon
- Elemental carbon
- Particle bound water
- Salt
- "Other" primary inorganic particulate matter
- Passively collected mass (blank mass)

To apply the attainment test, air agencies must first have outputs from air quality model simulations for a base year and a future year emissions scenario. We recommend a modeled attainment test which has four basic steps, as described in this section.

Step 1. Compute *observed* quarterly mean $PM_{2.5}$ and quarterly mean composition for each monitor.

Derive base year period quarterly mean concentrations[46] for each of the major components of

[46]Concentrations should be calculated based on calendar quarters for two reasons. First, the NAAQS is calculated as an annual average of 3 calendar years, so it would be inconsistent to average the data by season (where the winter season would span two calendar years). Second, the monitored data used to calculate design values is averaged on a calendar quarter basis before calculating annual averages.

$PM_{2.5}$.[47] This is done by multiplying the monitored quarterly mean concentration of FRM derived $PM_{2.5}$ (40 CFR part 53) by the monitored fractional composition of $PM_{2.5}$ species for each calendar quarter (e.g., 20% sulfate x 15.0 µg/m^3 $PM_{2.5}$ = 3.0 µg/m^3 sulfate).

Step 2. Using air quality model results, derive component-specific relative response factors (RRF) at each monitor for each calendar quarter.

Use the air quality model predictions to calculate the quarterly mean concentration for each $PM_{2.5}$ component for the base year and future year scenario.[48] Take the ratio of future to base year predictions for each component. The result is a component-specific relative response factor (RRF).

The RRF for component j at a site i is given by the following expression:

$$(RRF)_{ij} = [C_{ij,\ projected}]/[C_{ij,\ base\ year}] \qquad [4.3]$$

where $C_{ij,\ base\ year}$ is the quarterly mean concentration predicted at or near the monitoring site[49] with emissions characteristic of the period used to calculate the base design value for annual $PM_{2.5.}$

$C_{ij,\ projected}$ is the future year quarterly mean concentration predicted at or near the monitoring site.

(e.g., given model predicted mean third quarter base year period sulfate of 10.12 µg/m^3 and future year mean third quarter concentration of 8.23 µg/$m^{3,}$ then the third quarter RRF for sulfate is 0.8132).

[47] The mean species concentrations should be representative of the base period. The default approach to calculate mean species concentrations in SMAT is to use the 3-year average, centered about the base modeling year. These values are used to calculate species fractions by quarter. This differs from the 5-year weighted average design values recommended for base year $PM_{2.5}$ values. However, it is expected that there will be less variation in the species fractions compared to the absolute measured $PM_{2.5}$ concentrations. Alternative species fractions calculations can be considered, as long as they are representative of the expected species fractions during base year period.

[48] The calculations assume that there is one full year of model outputs.

[49] For greater (coarser) than 12km grid resolution, use the single grid cell. For 12km or less grid resolution, use the mean of the 3 x 3 array of the grid cells surrounding the monitor.

Step 3. Apply the component specific RRFs to observed air quality to obtain projected quarterly species estimates.

For each quarter, multiply the base year period quarterly mean component concentration (step 1) times the component-specific RRF obtained in step 2. This leads to an estimated future quarterly mean concentration for each component (e.g., 3.0 µg/m^3 sulfate x 0.8132 = future sulfate of 2.44 µg/m^3).

Step 4. Calculate a future year annual average $PM_{2.5}$ estimate.

Sum the quarterly mean $PM_{2.5}$ components to get quarterly mean $PM_{2.5}$ values. Then average the quarterly mean $PM_{2.5}$ concentrations to get a future year annual average $PM_{2.5}$ estimate for each FRM site.

Compare the projected average annual arithmetic mean $PM_{2.5}$ concentration obtained in Step 4 with 12.0 µg/m^3. If the values at all FRM sites are $\leq$ 12.0 µg/m^3, the test is passed.

4.4.1 Ambient $PM_{2.5}$ Data Used in the Annual $PM_{2.5}$ Attainment Test

$PM_{2.5}$ data collected at FRM and FEM sites are used for nonattainment designations. Therefore, we recommend using FRM and FEM data as the base data for projecting future $PM_{2.5}$ concentrations. As can be seen from the list of steps, the modeled attainment test is critically dependent on the availability of species component mass at FRM sites. This raises several issues. First, the majority of FRM sites do not have co-located chemical speciation network (CSN[50]) samplers.[51] And second, the FRM filter measurements and $PM_{2.5}$ speciation measurements do not always measure the same mass (Frank, 2006). There are numerous known issues with positive and negative sampling artifacts. These issues are addressed below.

4.4.2 FRM Monitors that Do Not Have Speciation Data

Species concentration data and/or species fractions are needed in order to apply the $PM_{2.5}$ attainment test. There are approximately 1200 FRM and FEM $PM_{2.5}$ monitoring sites, but only ~200 urban speciation monitoring sites. This makes it difficult to apply the attainment test at

[50] References to CSN monitors in this document refers to the overall speciation network which includes both trends sites and SLAMS sites.
[51] There are ~1200 FRM measurement sites and ~200-250 urban speciation sites (trends and SLAMS).

the majority of FRM/FEM sites. There are several possible ways to estimate species concentrations at FRM monitors that lack speciation data. Among them are:

1) Use concurrent data from a nearby speciation monitor to estimate species concentrations and/or fractions at one or more FRM sites.
2) Use representative speciation data (from a different time period) collected in an area to estimates species data at FRM sites.
3) Use interpolation techniques to create spatial fields using ambient speciation data.
4) Use interpolation techniques to create spatial fields using ambient speciation data **and** gridded model outputs to adjust the species concentrations based on the modeled spatial gradients.

In general, we recommend using spatial interpolation techniques to estimate species concentrations at FRM sites that do not have speciation data (numbers 3 and 4 above). But in some cases, interpolating data from nearby sites may not be appropriate, may not be feasible, or simply may not be necessary. In the EPA's SMAT, a relatively simple interpolation technique is used to estimate species concentrations at all FRM sites in the country. The analysis uses a Voronoi Neighbor Averaging (VNA) technique (consistent with approach number 3 above). Other interpolations have been done using Kriging and other more complicated methodologies such as "Downscaler" (Berrocal, 2010a and 2010b). Air agencies are encouraged to explore techniques that are most appropriate for their area and situation. EPA's SMAT software is available for air agencies to use as a default technique.

For areas that contain one or more speciation sites, and where FRM sites exhibit very little spatial gradients, it may be appropriate to assume that the speciation site(s) is/are representative of the entire area. For areas that exhibit strong spatial gradients in $PM_{2.5}$ concentrations, air agencies should strongly consider using more sophisticated techniques to estimate species concentrations. Combining ambient data with model output concentrations (number 4 above) may help adjust concentrations in areas with strong gradients, but limited speciation data. This technique has been used extensively to create spatial fields of $PM_{2.5}$ concentrations for the purpose of generating health benefits calculations and other examinations of unmonitored areas (also see section 4.6), but it has generally not been used to generate species fractions at FRM sites. The technique is further limited by uncertainties in the representativeness of the model outputs and emissions inventories.

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4.4.3 $PM_{2.5}$ Species Calculations and Definitions

Data analyses (Frank, 2006) have noted that the FRM monitors do not measure the same components and do not retain all of the $PM_{2.5}$ that is measured by routine speciation samplers and, therefore, cannot be directly compared to speciation measurements from the Chemical Speciation Network (CSN).[52] The FRM mass measurement does not retain all ammonium nitrate and other semi-volatile materials (negative sampling artifacts) and includes particle bound water associated with sulfates, nitrates and other hygroscopic species (positive sampling artifacts). This results in FRM measured concentrations (and percent contributions to $PM_{2.5}$ mass), which may be different than the ambient levels of some measured $PM_{2.5}$ chemical constituents.

Because the FRM data are used to determine compliance with the NAAQS, it is critical to estimate the species composition as measured on the FRM filters. In addition, for the purposes of predicting changes in $PM_{2.5}$ components, constructed $PM_{2.5}$ mass should match the composition of mass retained by the FRM.

The goal is to reconstruct the measured species components so that they add up to the measured FRM mass. This concept can generally be represented by equation 4.4:

$RCFM_{FRM}$ = [Ammoniated Sulfate Mass] + [Retained Ammoniated Nitrate Mass] + [Retained Carbonaceous Mass] + [Other Primary $PM_{2.5}$] + [Other Components] [4.4]

In the above characterization, $RCFM_{FRM}$, or reconstructed fine mass, and all of the listed chemical components reflect those retained during sampling and equilibration on the FRM's Teflon filter. Sulfate and nitrate mass include associated ammonium, which may be different than assumed ammonium sulfate and ammonium nitrate compounds. Carbonaceous mass includes elemental carbon (EC), organic carbon (OC), and hundreds of different carbon compounds, which are not directly measured, and which may not match the carbon mass in speciated measurement data. Also, sulfates and nitrates include particle bound water associated with these hygroscopic aerosols. In this characterization, other primary $PM_{2.5}$ mass is intended to be a more general term that includes fine soil, and oxides that result from other PM emissions.

[52] The information in this section applies to the most common samplers in the CSN. The characteristics of the sampler and the analytical procedures used to produce chemical speciation data should be considered in determining which, if any, adjustments are appropriate to make the data useful for comparison to FRM and FEM data.

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4.4.4 Recommended Treatment of Species Data

We recommend an adjustment technique based on an FRM mass construction methodology, which results in reduced nitrates (relative to the amount measured by routine speciation networks), higher mass associated with sulfates and nitrates (reflecting water included in gravimetric FRM measurements), and a measure of organic carbonaceous mass, which is derived from the difference between measured $PM_{2.5}$ and its non-organic carbon components (Frank, 2006). This characterization of $PM_{2.5}$ mass also reflects "other" primary inorganic $PM_{2.5}$ and other minor constituents. Frank (2006) terms this approach "sulfate, adjusted nitrate, derived water, inferred carbonaceous material balance approach (SANDWICH)." The resulting characterization provides a complete mass balance. It does not have any unknown mass, which is sometimes presented as the difference between measured $PM_{2.5}$ mass and the characterized chemical components derived from routine speciation measurements. The recommended SANDWICH-based characterizations should yield more accurate assessments of future $PM_{2.5}$ concentrations as measured by FRM monitors, compared to using unadjusted CSN data.

4.4.4.1 Retained Nitrate Mass

The first step in the procedure for identifying FRM mass components is to estimate the retained nitrate mass on the FRM filters. The FRM does not capture all of the semi-volatile components of the ambient air, such as ammonium nitrate. The retained amount of nitrate ion, however, can be estimated by a simple thermodynamic model that involves 24-hr ambient nitrate speciation concentrations (as measured by a standard speciation sampler using a nylon filter preceded by a HNO_3 denuder) together with hourly ambient temperature and humidity. Atmospheric nitrates are highest during the cooler months. Retention on the FRM is also higher during the cooler months and essentially all the nitrates are lost during the summer. The retention does not appear to depend on ambient NH_3 or HNO_3 concentrations. More NO_3 is retained at low temperatures and high humidity, which varies by sampling location and time of year.

Because nitrate retention varies by site and season, a simple ammonium nitrate equilibrium model can be used to predict the amount of nitrates retained on the FRM Teflon filter. As used by Hering (Hering, 1999; Zhang, 1992),

$$\text{delta } NO_3\ (\mu g/m3) = 745.7/T_R * 1/24 * \sum_{i=1}^{24} (\mathbf{K}_i^{\frac{1}{2}}) \qquad [4.5]$$

where delta NO_3 is the amount of volatilized nitrate mass, T_R is the reference temperature for the sampled air volume in degrees Kelvin, and $\mathbf{K_i}$ is the dissociation constant for ammonium nitrate evaluated at the ambient temperature and relative humidity for hour i. The nitrate loss can be predicted for each day, based on hourly temperature and relative humidity data. It must be subtracted from the NO_3 measured at speciation sites to estimate the FRM retained nitrate. The SMAT software is populated with a speciation ambient data file with daily average retained nitrate pre-calculated for all CSN and IMPROVE sites. The analysis uses National Weather Service temperature and relative humidity data from the closest station. Other sources of meteorological data may also be appropriate. Further details on the nitrate loss calculations can be found in Frank (2006).

4.4.4.2 Ammonium Associated with Sulfates and Retained Nitrates

There are several ways to estimate ammonium mass for use in attainment test. The most direct way is to use measured ammonium concentrations from the CSN network (IMPROVE does not measure ammonium ion). A second, more indirect method is to estimate the ammonium associated with nitrate, and to calculate the ammonium associated with sulfate and the degree of neutralization of sulfate (DON), and then use the resulting information to calculate ammonium mass. Due to uncertainties associated with the ammonium measurements and the lack of ammonium measurements in rural areas, this indirect method is recommended as the default attainment test methodology.

To determine the mass associated with nitrates, we assume retained nitrate is all ammonium nitrate. Thus, using the ratio of the molecular weight of ammonium to that of nitrate, the ammonium associated with nitrates ($NH4_{NO3}$) can be derived directly from the estimated retained nitrate ($NO3_{FRM}$) as:

$$NH4_{NO3} = 0.29 * NO3_{FRM} \qquad [4.6]$$

The difference between total FRM NH_4 (amount associated with nitrates and sulfates), termed $NH4_{FRM}$, and the measured NH_4, termed NH_{4CSN}, is needed to determine the ammoniated form of sulfates as described by equation 4.4. A measurement study by Collett (Collett, 2004) shows that NH_4 may not be completely retained during collection on nylon filters preceded by a nitric acid denuder, such as are used at CSN sites. At several FRM study sites, the CSN NH_4 which is adjusted for evaporated NH_4NO_3 tends to more closely correspond to the measured NH_4 from the FRM Teflon filter. However, for other sites, the measured CSN NH_4 appears to agree with FRM NH_4.

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The available information suggests that using measured ammonium (assuming none is volatilized) may be the best assumption. We, therefore, recommend using unadjusted ammonium, but further analysis of this issue is warranted.

To calculate the ammonium associated with sulfate, we recommend using the degree of neutralization of sulfate (DON). This is defined as the ammonium associated with sulfate (i.e., total ammonium less the ammonium associated with nitrate), divided by sulfate. This reflects the degree to which sulfate has been neutralized by ammonium. The ambient data is such that nearly all of the ammonium data is from urban sites (CSN), but the sulfate and nitrate data is from both urban (CSN) and rural (IMPROVE) sites. This may lead to an overestimation of ammonium concentration in rural areas when ammonium is directly interpolated. Therefore, we recommend using calculated DON with SO_4 and $NO3_{FRM,}$ and interpolating to each FRM site to get quarterly average concentrations. The interpolated DON and species concentrations are used to calculate $NH4_{FRM}$ using the following equation:

$$NH4_{FRM} = DON * SO4 + 0.29*NO3_{FRM} \quad [4.7]$$

The indirect calculation of ammonium mass from interpolated fields tends to smooth out the gradients in mass. This is deemed to be beneficial, due to the uncertainty in the measurements.

4.4.4.3 Particle Bound Water

Because ammoniated sulfate and ammonium nitrate are hygroscopic, the retained sulfate and nitrate mass will include water. Particle bound water (PBW) can be estimated using an equilibrium model. The EPA developed an approach using the Aerosol Inorganic Model (AIM) (Clegg, 1998). PBW is derived from quarterly average FRM concentrations of sulfate, ammonium, and nitrate (as described above). Estimated hydronium ion, H+, needed to achieve ionic balance is derived from the latter values. The model enables the distribution of water and ions to be calculated between liquid, solid and vapor phases for specific temperature and relative humidity conditions. Typical FRM filter equilibration conditions of 35% RH and 22 deg C (295 deg K) temperature are used to estimate water concentrations at those conditions.

Application of AIM at the specified FRM filter equilibration conditions show that PBW is much more dependent on sulfate concentration compared to nitrate and that the relationship varies somewhat by season. There is proportionally less estimated PBW water for wintertime aerosol which has higher NO_3 and lower SO_4. The PBW concentrations are also sensitive to the degree

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of neutralization of the sulfate particles (determined by the relative concentration of $NH4_{FRM}$).

We recommend calculating PBW as a component of $PM_{2.5}$ mass. The AIM model (or other equilibrium models) can be used, or a regression equation can be developed to simplify the process. For computational convenience, EPA derived a polynomial regression equation fit to the calculated water mass from AIM and the three input values to AIM (sulfate, nitrate and ammonium). The polynomial equation is used in the SMAT software to calculate PBW. See the SMAT User's Guide for more details on the default PBW equation.

4.4.4.4 Salt

In the $PM_{2.5}$ attainment test methodology, salt is represented as a species which accounts primarily for sea salt at sites near the oceans. The salt species is estimated using the CSN measured Cl^+ ion concentration multiplied by 1.8. The multiplier accounts for the sodium contribution to the species. In areas distant from oceans, measured Cl^+ may represent PM mass that is not associated with salt water. For instance, there may be chloride emissions resulting from various industrial processes. Therefore, the use of measured salt in the attainment test calculations should be evaluated on an individual area/monitor basis.

Measured salt is included by default in the SMAT species ambient data file. The inclusion of modeled salt (and hence an RRF for salt) is optional and can be included if there are accurate modeled salt concentrations. If modeled salt is not included in the SMAT input files, an RRF of 1.0 used in the SMAT calculations.

4.4.4.5 Other Primary PM2.5

The terms "crustal," "fine soil," "major metal oxides," "inorganic particulates," and "other PM," are sometimes used interchangeably. For $PM_{2.5}$ design value calculations we will refer to this material as "other primary $PM_{2.5}$" (OPP). For regional haze calculations, we will continue to refer to this material as "fine soil."

For the purposes of estimating OPP for the $PM_{2.5}$ attainment test, all measured non-carbon mass that is not organic in nature (not associated with sulfate and/or nitrate) should be counted. As with the other $PM_{2.5}$ components measured on the FRM filter, there is uncertainty associated with this estimate. The "crustal" or "fine soil" definition from IMPROVE can be used

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to estimate OPP[53] or an alternative formula can be defined which better estimates the urban nature of the FRM measurements. The IMPROVE definition of "fine soil" accounts for the typical crustal components (and attached mass) that would be expected in remote Class I areas. Fine soil is represented as five elements (Al, Si, Fe, Ti, and Ca) with coefficients to represent various oxides and material, which may be attached to or associated with the major elements. In urban areas, inorganic PM, which is not elemental carbon or associated with sulfate or nitrate, may come from many sources such as re-suspended dust or industrial sources (stack or fugitives). It is generally "crustal" in nature (dominated by silicon), but urban PM is more likely to contain heavy metals and industrial components.

Although the composition of inorganic PM may differ between urban and rural (remote) areas, an alternative equation, similar to the IMPROVE fine soil equation, can be used to estimate OPP for the $PM_{2.5}$ attainment test. The alternative equation is suggested by (Frank, 2006) and uses only four elements. The equation removes aluminum (and accounts for associated mass by increasing the coefficient for Si), due to the fact that aluminum is often missing from the speciation measurements. This allows for more complete data.

The alternative "fine soil" equation is as follows:

$$\text{Other primary } PM_{2.5} \text{ mass} = 3.73 \times [Si] + 1.63 \times [Ca] + 2.42 \times [Fe] + 1.94 \times [Ti] \qquad [4.8]$$

4.4.4.6 Blank mass

The other quantifiable components of $PM_{2.5}$ mass include passively collected mass, represented by a field blank concentration (U.S. EPA, 2002). This appears to constitute a contamination of the filter resulting from handling or contact with the FRM cassette. This value is deemed to be an important constituent of $PM_{2.5}$ mass (it is assumed to not be dependent on pollutant emissions). Based on recently collected ambient QA data, we recommend using a default nominal blank mass value of 0.2 $\mu g/m^3$ (see the EPA QA website for more details). This value represents an approximate nationwide network median value. This value can be modified based on local FRM blank mass measurements. The blank mass is assumed to remain constant through time (RRF=1.0).

[53] IMPROVE estimates fine soil as: $2.2 \times [Al] + 2.49 \times [Si] + 1.63 \times [Ca] + 2.42 \times [Fe] + 1.94 \times [Ti]$

4.4.4.7 Calculation of Carbonaceous Mass

Organic carbon mass is typically estimated from blank corrected speciation data, where organic carbonaceous mass is first estimated by multiplying the organic carbon concentrations by 1.4 or alternative factors to account for the oxygen, hydrogen and other elements associated with ambient carbon particles.

There are many uncertainties in estimating carbonaceous mass from carbon measurements (Turpin, 2001; Chow, 2004). Uncertainties include differences in carbon measurement protocol between urban and rural monitoring locations; a relatively "bumpy" surface of urban carbon concentrations as derived from urban and rural organic carbon measurements; and lack of carbon measurements at all FRM locations. We, therefore, recommend an alternative approach to estimate the organic carbon contribution to $PM_{2.5}$ mass.

The recommended attainment test approach estimates organic carbon by *mass balance*. Precisely measured FRM $PM_{2.5}$ mass (U.S. EPA, 2003) is compared to the sum of its non-organic carbon components. The latter are sulfates, ammonium, nitrates, estimated particle bound water, elemental carbon, estimated other primary $PM_{2.5}$ material, salt, plus 0.2 µg/m3 blank mass as discussed earlier.

This approach estimates retained organic carbon FRM mass and explicitly accounts for the following important and difficult to estimate carbon mass properties: 1) regional and urban-rural differences in the mix of carbonaceous aerosols (i.e., the amount of oxygen, hydrogen, etc); 2) retained water associated with hygroscopic carbon compounds (Saxena, 1996; Yua, 2004*)*; 3) volatile carbonaceous material measured by speciation samplers, but not retained in FRM mass; and 4) uncertainties associated with blank corrections of measured organic carbon.

Organic Carbon Mass by mass balance **(OCM_{mb})** is defined as,

$$\mathbf{OCM_{mb}} = PM_{2.5} - \{ [SO4] + [NO3_{FRM}] + [NH4_{FRM}] + [water] + [EC] + [OPP] + [salt] + [0.2] \} \quad [4.9]$$

In this expression, all of the above components represent the mass retained on FRM Teflon filters.

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This approach completely accounts for FRM mass[54] and OCMmb is often greater than the amount that would be derived directly from speciation measurements. Because of uncertainties in speciation measurements and their estimates from interpolated surfaces, setting a lower limit (floor) may be necessary so that the OCMmb is not unreasonably low. In some cases, the OCMmb could be lower than the measured OC or OCM. Since measured OC (without accounting for mass associated with OC) is a conservative minimum estimate of OC mass, we recommend setting the OCMmb "floor" to be equal to measured OC.

There may also be situations where an OCMmb "ceiling" is needed. In remote urban areas with relatively high FRM concentrations that may be surrounded by rural background concentrations, the OC by mass balance technique may apportion 95%+ of the $PM_{2.5}$ mass to OCM. If this is not a reasonable assumption, then a ceiling may be needed to cap the OCM as a percentage of $PM_{2.5}$ mass. Based on measured data (FRM sites with co-located speciation data), it appears that on a quarterly average basis, OCM is rarely more than 80% of total $PM_{2.5}$ mass. This may be a reasonable default ceiling, but a lower value (or in rare circumstances, a higher value) may be more appropriate in some regions of the country.

4.4.4.8 Summary of $PM_{2.5}$ Composition Calculations

The terms of equation 4.10 reflect the final estimated composition of the particles measured by the FRM (for each quarter). Quarterly average FRM mass is equal to the sum of the eight species plus blank mass.

$$PM_{2.5FRM} = \{ [OCMmb] + [EC] + [SO4] + [NO3_{FRM}] + [NH4_{FRM}] + [water] + [OPP] + [salt] + [0.2] \} \quad [4.10]$$

The recommended order to generate the data is as follows:

1) Calculate adjusted nitrate using hourly meteorology and 24-hour average nitrate measurements.

[54] The OC by mass balance technique assumes that all other mass is accounted for and, therefore, all remaining mass is OCM. This may not always be a good assumption. The results of the technique should be carefully evaluated to ensure that OC mass is not overestimated (and, therefore, other mass components are underestimated). This may be an issue in areas that do not have nearby speciation data and have relatively large concentrations of primary $PM_{2.5}$. The OC by mass balance technique may inadvertently apportion mass to organic carbon, which may actually be EC or "other" primary $PM_{2.5}$ mass components (such as heavy metals). All available ambient data and modeling data should be used to evaluate the species apportionment results.

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2) Calculate quarterly averages for adjusted nitrate, sulfate, elemental carbon, ammonium (or degree of sulfate neutralization (DON)), OPP, salt, and measured OCM[55].

3) Quarterly average ammonium is calculated from the adjusted nitrate, sulfate, and DON values (if measured ammonium is not used directly).

4) Ammonium, sulfate, and nitrate concentrations are input into the polynomial water equation to derive particle bound water concentrations.

5) Carbon mass by difference (OMCmb) is calculated from the $PM_{2.5}$ mass, adjusted nitrate, ammonium, sulfate, water, elemental carbon, salt, other primary $PM_{2.5}$, and blank mass values. The sum of the eight species plus blank mass is equal to the FRM mass.

We illustrate application of the recommended test in example 4.4.1.

Example 4.4.1

Given: (1) Area "C" has 2 monitoring sites.

(2) Monitored FRM air quality data show the following average quarterly mean $PM_{2.5}$ concentrations based on a 5-year weighted average of observations from 2012-2016 at each site (values are in $\mu g/m^3$).

Table 4.4.1 Quarterly average $PM_{2.5}$ FRM mass concentration ($\mu g/m^3$) at 2 example sites

Site	Quarter 1	Quarter 2	Quarter 3	Quarter 4
1	17.21	16.34	20.00	14.76
2	15.39	17.98	18.23	13.76

(3) The area has 1 urban speciation site, which is co-located with FRM site 2. The speciation data is available for the entire time period, but the species concentrations for the 2013-2015 time period have been deemed to be most representative of the 2012-2016 5- year weighted average. Therefore, the species data for the average 3-year period (2013-2015) has been

[55]The measured OCM is only used to calculate the "floor" for OCMmb.

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interpolated to derive estimated species concentrations at each site. The species concentrations are matched up with FRM data for the same 2013-2015 period to derive representative species fractions. The average monitored air quality for the 3rd quarter of 2013-2015 at site 1 is as follows[56]:

Table 4.4.2 Average monitored 3rd quarter ambient data at site 1

FRM Mass (µg/m3)	Blank Mass (µg/m3)	Non-blank Mass (µg/m3)	Sulfate (µg/m3)	Nitrate (µg/m3)	Organic Carbon Mass (µg/m3)	Elemental Carbon (µg/m3)	Water (µg/m3)	Ammonium (µg/m3)	Salt (µg/m3)	OPP (µg/m3)
22.62	0 .2	22.42	8.51	1.11	5.21	0.91	2.31	3.31	0.35	0.71

The blank mass is subtracted before species fractions are calculated because the blank mass is held constant at 0.2 µg/m3 throughout the analysis. In the example, the measured FRM mass for quarter 3 is 22.62 µg/m3. The non-blank FRM mass is 22.42 µg/m3. The mass of the eight species add up to the non-blank mass.

(4) Species fractions are calculated for each quarter for each species. In the example below, a fraction of non-blank mass is calculated for each of the eight species. Blank mass remains fixed at 0.2 µg/m3.

Table 4.4.3 3rd quarter average species fractions for 2013-2015 at site 1

FRM Mass (µg/m3)	Blank Mass (µg/m3)	Non-blank Mass (µg/m3)	% Sulfate	% Nitrate	% Organic aerosol	% Elemental Carbon	% Water	% Ammonium	% Salt	% OPP
22.62	0 .2	22.42	37.96	4.95	23.24	4.06	10.30	14.76	1.56	3.17

The percentages in table 4.4.3 above are the relative composition for the 3rd quarter of 2013-2015. It is assumed that these species fractions are representative of the 2012-2016 time-period.[57]

[56] The species concentrations can be derived from co-located speciation data, nearby speciation data or from interpolated spatial fields. FRM mass is not interpolated.

[57] The default assumption is that the average of the middle 3 years of speciation data is representative of the 5-year weighted average FRM data. However, other assumptions (number of years of speciation

(5) The weighted quarterly average FRM design values are used as the base year FRM value for each monitoring site (2012-2016). The species fractions from the 2013-2015 speciation data were used to estimate the species concentrations for the base year FRM $PM_{2.5}$ data. The percentage compositions for 2013-2015 are applied to the quarterly weighted average design values as shown in table 4.4.4. In the example below, the weighted average design value for the 3rd quarter for the site from table 4.4.1 is 20.00 µg/m3. This leads to the following concentrations of $PM_{2.5}$ species:

Table 4.4.4 Calculation of the "base case" species concentrations at site 1

Weighted Avg. FRM Mass (µg/m3)	Blank Mass (µg/m3)	Non-blank Mass (µg/m3)	Sulfate (µg/m3)	Nitrate (µg/m3)	Organic aerosol (µg/m3)	Elemental Carbon (µg/m3)	Water (µg/m3)	Ammonium (µg/m3)	Salt	OPP (µg/m3)
20.00	0.2	19.80	7.52	0.98	4.60	0.80	2.04	2.92	0.31	0.63

This procedure is repeated for each $PM_{2.5}$ site and quarter to complete the calculation of base year ambient concentrations used as the basis for future estimates of $PM_{2.5}$ mass and its components.

data) can be used. It is generally assumed that the inter-annual variability of the species fractions is small compared to the variability of species concentrations.

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(6) Modeled results show the following relative response factors (RRF) for predicted mass of 5 components of $PM_{2.5}$ for the 3rd quarter[58]:

Table 4.4.5 3rd quarter modeled RRFs for site 1

RRF Sulfate	RRF Nitrate	RRF Organic aerosol	RRF Elemental Carbon	RRF Salt	RRF OPP
0.8761	0.9432	0.9713	0.9324	1.0	1.0423

(7) The quarterly mean RRFs from table 4.4.5 are multiplied by the weighted quarterly average species concentrations from table 4.4.4 to derive future year concentrations.

From the example above, the future year 3rd quarter concentrations are:

$Sulfate_{Future}$ = 7.52 * 0.8761 = 6.58 µg/m3
$Nitrate_{Future}$= 0.98 * 0.9432 = 0.92 µg/m3
Organic carbon $mass_{Future}$= 4.60 * 0.9713 = 4.47 µg/m3
Elemental $Carbon_{Future}$= 0.80 * 0.9324 = 0.75 µg/m3
$Salt_{Future}$=0.31*1.0 = 0.31 µg/m3
OPP_{Future}= 0.63 * 1.0423 = 0.65 µg/m3

(8) The future year concentrations derived above are used to calculate the future year concentration of ammonium (if the direct ammonium RRF is not used) and particle bound water.

The future year ammonium concentrations are calculated from the sulfate, nitrate, and (base year) DON values. Assuming that the DON is unchanged from the base year[59], the ammonium is

[58] The default assumption for the annual average $PM_{2.5}$ NAAQS test is to calculate RRFs from the mean of the 3 X 3 matrix of grid cells surrounding each FRM monitoring site.
[59] Due to the uncertainty in the ammonium measurements, by default, the DON is assumed to stay constant through time. The water calculation is sensitive to the ammonium (and, therefore, the DON value) concentrations. Holding the DON constant allows for the future year ammonium and water values to be solely a function of the change in sulfate and nitrate concentrations. Otherwise, the water concentration can go up when the sulfate and nitrate concentrations go down (and vice versa). This may occur if sulfate becomes more neutralized in the future. It is a somewhat illogical outcome (although scientifically possible) and is highly dependent on an uncertain measurement (ammonium). Therefore,

calculated using the following formula:

$NH4_{future}$ = DON * $SO4_{future}$ + 0.29*$NO3_{future}$, [4.7]

In the example above, assuming the base year DON is 0.336,

$Ammonium_{Future}$= 0.336 * 6.58 + 0.29 * 0.92 = 2.48 µg/m3

The $NH4_{future}$, $SO4_{future,}$ and $NO3_{future}$ concentrations can then be input into an equilibrium model (AIM or another alternative model) or through a polynomial regression equation to predict future year particle bound water concentration (based on the default equation, the future year water concentration in this case is 1.73 µg/m3).

(9) The future species concentrations at each FRM site are then summed over the eight species plus blank mass to estimate the future quarterly average $PM_{2.5}$ concentration.

In the example above, the total $PM_{2.5Future}$=
6.58 + 0.92 + 4.47 + 0.75 + 0.65 + 2.48 + 1.73 + 0.2 = 17.78 µg/m3

(10) The same calculations are completed for the other 3 quarters to get a future year $PM_{2.5}$ concentration for each quarter. The 4 quarters are then averaged to get a final future year annual average $PM_{2.5}$ concentration for each FRM site.

(11) The future year annual average concentration is compared to 12.0 µg/m^3.[60]

4.5 What Is the Recommended Modeled Attainment Test for the 24-Hour NAAQS?

Our recommended modeled attainment test for the 24-hour NAAQS for $PM_{2.5}$ is similar to the previously described test for the annual NAAQS in that it uses model predictions in a relative

use of a constant DON creates a more stable set of calculations. If the measured and modeled ammonium concentrations are believed to be accurate and respond in a reasonable way to emissions controls, then it would be more scientifically credible to use the model predicted change in ammonium. Otherwise, it is a reasonable assumption to keep the DON constant over time.

[60] In the final step, the future year concentration should be rounded to the tenths digit. A (rounded) value of 12.0 µg/m3 meets the NAAQS. A value of 12.1 µg/m3 or greater violates the NAAQS.

sense to reduce site-specific *observations* (averaged over 5 years). In the test, we are interested in reducing the base year design values at each site to $\leq$ 35 µg/m^3 (the 2006 24-hour $PM_{2.5}$ NAAQS). [61]

Ideally, the modeled attainment test should reflect model results obtained for days in each season having observed $PM_{2.5}$ concentrations above the design value. Even though the 24-hour NAAQS is based on the single 98th percentile value of all days in the year, it is important to perform the test on a seasonal basis, since $PM_{2.5}$ consists of a mixture of pollutants whose composition can vary substantially from season to season. There could be a substantial amount of uncertainty associated with predictions on any single day. Thus, our test is most likely to be reliable when relative response factors (RRFs) reflect composite responses from multiple days. Therefore, we recommend modeling as many days as feasible where observed $PM_{2.5}$ is greater than 35 µg/m^3. Alternatively, the test can focus on the high end of the distribution of days in each quarter[62] (e.g., the top 10% of $PM_{2.5}$ days[63]) assuming that the high days are representative of days that violate the NAAQS. As with the annual NAAQS (and for the same reasons), the preferred approach is to develop RRFs, which are quarter specific[64].

The 24-hour $PM_{2.5}$ attainment test should be based on the same 5-year weighted average methodology that was used for the annual standard, with some slight modifications. The 24-hour design values are calculated from the 98th percentile value for each year. In the 24-hour $PM_{2.5}$ calculations, the 98th percentile value from each year is used in the final calculations. Since the 98th percentile value can come from any day in the year, all quarters and years should be carried through to near the end of the calculations. To calculate final future year design

[61] *See* 71 FR 61224 and 40 CFR 50.13.

[62] Similar to the annual $PM_{2.5}$ NAAQS, the default recommended procedures for the 24-hr NAAQS assume handling of the ambient data and model data on a calendar quarter basis. However, in some nonattainment areas, 24-hr $PM_{2.5}$ NAAQS exceedances may occur during a very limited time of the year or season. Processing the data (both ambient and model) on a sub-quarterly basis may be appropriate in certain circumstances.

[63] For most sites, the top 10% of monitored days per quarter will represent between 3 and 8 ambient measurement days.

[64] In some areas it may not be necessary to model and evaluate the 24-hour NAAQS for all quarters. For example, if observed $PM_{2.5}$ concentrations only exceed the NAAQS in the 1st and 4th quarters, and concentrations in the 2nd and 3rd quarters are very low, then it may not be necessary to model the full year. But for areas that have monitored violations (or high values that are close to the NAAQS) in all four seasons, the entire year should be evaluated.

values, the 98th percentile day for each year is identified and then a 5-year weighted average of the 98th percentile values for each site is calculated to derive the future year design value.[65] In nonattainment areas that measure violations of the daily $PM_{2.5}$ NAAQS in multiple seasons (most often summer and winter), the highest PM days can sometimes shift between seasons when days are projected to the future. A consequence of this shift is that a base year 98th percentile winter day may have a higher future year concentration than a summer day that started with a higher concentration in the base year. Therefore, the recommended attainment test methodology has been designed so that the temporal distribution of high days in the base and future periods can shift between quarters.

In the 24-hour attainment test methodology (described below), the eight highest ambient $PM_{2.5}$ days in each quarter at each site are projected to the future (32 days per year) using species specific quarterly RRFs. After all 32 days are projected to the future, the days are re-ranked to determine the future year 98th percentile day.[66] The rank of the future year 98th percentile day is selected based on the rank of the observed 98th percentile day in the base year ambient data (which depends on the number of valid daily samples). For example, at monitoring site A, if there are 120 observations in year 1 then the 98th percentile day is the 3rd high observation day for the year. In that case, the future year 98th percentile day is selected as the 3rd high future day for the year (out of the 32 highest days).

Similar to the annual $PM_{2.5}$ attainment test, we recommend interpolation techniques for FRM monitors that do not have co-located speciation data. Because the 24-hour standard is a 98th percentile-based value, the species composition on high concentration days may be highly variable from day to day and from site to site. Therefore, while interpolation techniques may be needed, we strongly recommend collecting speciation data at all FRM sites that violate the 24-hour NAAQS. A precise estimate of the $PM_{2.5}$ components at violating sites will help reduce uncertainty in projecting the future year concentration estimates.

[65] Similar to the annual average $PM_{2.5}$ attainment test, design values are calculated for consecutive 3-year periods. From the 5-year base period, three design values are calculated and then averaged together to create a 5-year weighted average.

[66] The observed 98th percentile day is always between the 1st and 8th high for the year, depending on the sampling schedule. Therefore, projecting the 8 highest days in each quarter ensures that the observed 98th percentile day is always captured. Additional days could be projected, but a maximum of 32 days per year is needed to guarantee that the 98th percentile observation day at each site is projected to the future.

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We recommend a modeled attainment test for the 24-hour $PM_{2.5}$ NAAQS with the following steps.

Step 1. Identify the high observed $PM_{2.5}$ days at each FRM monitoring site for each year.

The first step in projecting the daily design value is to identify at each FRM site, the eight highest observed 24-hour $PM_{2.5}$ concentration days in each quarter for each year of the base period (up to 5 years), and identify the day rank of the observed 98th percentile value for each year based on the number of collected ambient samples (i.e., 3rd highest day of the year). This results in a data set containing 32 days of data for each year (for up to 5 years) for each site.[67]

The test should be performed for each monitoring site that meets the data completeness criteria for calculating a design value for the 24-hour NAAQS. There may not always be data available for all four quarters and all 5 years. We recommend using 8 days per quarter because the 98th percentile day for a year is always one of the 8 highest days of the year.[68] If all of the high days occur in a single quarter, then using the 8 highest days from each quarter will ensure that the actual 98th percentile day is always captured. This may result in processing more days than necessary, but effectively limits the future year design value calculations to a reasonably small number of days.

Step 2. Calculate "high days" species fractions for each quarter for each FRM monitor.

In this step, quarterly ambient species fractions on "high" days are calculated for each of the major component species of $PM_{2.5}$ (i.e., sulfate, nitrate, ammonium, elemental carbon, organic carbon mass, particle bound water, salt, and blank mass). This calculation is performed by dividing the average monitored concentrations of FRM-derived total $PM_{2.5}$ mass on the high $PM_{2.5}$ days at each site for each quarter, by the average monitored species concentration on the high $PM_{2.5}$ days for each quarter.[69] The default recommendation for identification of "high"

[67] The methodology does not assume that the temporal distribution of high days in the base and future periods will remain the same. We recommend projecting at least 8 ambient days per quarter from the base period to the future and then re-rank the entire set of days to find the new future year 98th percentile value (for each year).

[68] If there are 365 samples in a year, then the 98th percentile is the eighth high day.

[69] Similar to the annual average calculations, for FRM sites that do not have co-located species data, we recommend calculating the quarterly species fractions using interpolated species data. For the 24-hour species interpolations, we recommend interpolating the average of the highest 10% of monitor days in each quarter.

days is the top 10% of days in each quarter. This results in a relatively robust calculation, which typically uses between 3 and 9 days per quarter (depending on the sampling frequency). The end result is a set of quarterly "high days" species fractions for each FRM site.

Step 3. Calculate species concentrations for each of the high ambient days.

Multiply the quarterly "high day" species fractions from step 2 by the $PM_{2.5}$ mass concentration for the 8 high days per quarter identified in step 1. This results in a set of species concentrations for each of the 32 days per year identified in step 1.

Step 4. Calculate component specific RRFs for the high days in each quarter.

For each quarter, calculate the ratio of future year to base year modeled predictions for sulfate, nitrate, elemental carbon, organic carbon, salt, and OPP for the top 10 percent of modeled $PM_{2.5}$ days based on modeled concentrations of 24-hour average $PM_{2.5}$. The result is a set of species-specific "high day" RRFs for each quarter.

The relative response factor for component j at a site i is given by the following expression:

$$(RRF)_{ij} = ([C_{j,\ projected}]/[C_{j,\ base\ year}])_i$$

where $C_{j,\ base\ year}$ is the base year mean species concentration (for the high modeled $PM_{2.5}$ days for each quarter) predicted at the (single) grid cell which contains monitoring $site_i$.

$C_{j,\ projected}$ is the future year mean species concentration (for the high modeled days for each quarter) predicted at the (single) grid cell which contains monitoring $site_i$.

For example, assume that base year predicted sulfate mass on the 10 percent highest $PM_{2.5}$ days for quarter 3 for a particular location is 20.0 $\mu g/m^3$ and the future year modeled sulfate concentration is 16.0 $\mu g/m^3$, then the RRF for sulfate for quarter 3 is 16.0/20.0 or 0.80. Due to potentially large spatial and temporal gradients, we recommend 24-hour $PM_{2.5}$ NAAQS RRFs to be calculated based on the modeled concentrations at the single grid cell where the monitor is located.

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Step 5. Apply the component specific RRFs to observed air quality by quarter.

For each of the 8 days in each quarter, multiply the daily species concentrations from step 3 by the quarterly species-specific RRFs obtained in step 4. If there is 1 modeled base year, then there will be four quarterly RRFs at each monitor. The modeled quarterly RRF for quarter 1 is multiplied by the ambient data for quarter 1 (8 days in each year) for each of the 5 years of ambient data. For example, for day A, 21.0 $\mu g/m^3$ nitrate x 0.75 = future nitrate of 15.75 $\mu g/m^3$. The same procedure is applied for the 8 high days per quarter in the other 3 quarters. This leads to an estimated future concentration for each component for each day.

Step 6. Calculate remaining future year PM2.5 species.

The future year concentrations for the remaining species are then calculated for each of the days.[70] Similar to the annual $PM_{2.5}$ attainment test, we recommend that the future year ammonium is calculated based on the future year sulfate and nitrate concentrations, using a constant value for the degree of neutralization of sulfate (from the ambient data). The future year particle bound water concentration is then calculated from an empirical formula derived from the AIM model. The inputs to the formula are the future year concentrations of sulfate, nitrate, and ammonium calculated in step 5.

Step 7. Sum the species components to get total $PM_{2.5}$ concentrations for each day.

Sum the species concentrations for each day to obtain total $PM_{2.5}$ values for the 32 days per year per site.

Step 8. Determine future year 98th percentile concentrations for each site year.

Sort the 32 days for each site for each year by total $PM_{2.5}$ concentration. For each site year, the monitored 98th percentile rank (for each year) is used to identify the 98th percentile rank for each year.[71] For example, if the base year 98th percentile value for year 1 was the 3rd high concentration, then the future year 98th percentile concentration is identified as the 3rd high future year $PM_{2.5}$ concentration (out of the 32 days).

[70] If salt is not explicitly modeled, then the salt RRF should be held constant. Blank mass is assumed to be constant between the base and future year.

[71] This assumes that the ambient sampling schedule (and number of samples) would remain the same between base and future years.

Step 9. Calculate future 5-year weighted average 24-hour design values and compare to the NAAQS.

The estimated 98th percentile values for each of the 5 years are averaged over 3-year intervals to create 3-year average design values (e.g., the 98th percentile values from year 1, year 2, and year 3 are averaged. Then the 98th percentile values from year 2, year 3, and year 4 are averaged, etc.). These design values (up to 3) are then averaged to create a future year 5-year weighted average design value for each monitoring site.

The preceding steps for determining future year 24-hour $PM_{2.5}$ concentrations are applied for each FRM site. The 24-hour $PM_{2.5}$ design values are truncated after the first decimal place. This approach is consistent with the truncation and rounding procedures for the 24-hour $PM_{2.5}$ NAAQS. Any value that is greater than or equal to 35.5 µg/m^3 is rounded to 36 µg/m^3 and violates the 24-hour NAAQS. Similarly, a value of 35.4 µg/m^3 is rounded down to 34 µg/m^3 and is attaining the 24-hour NAAQS.

4.6 Local Area Analyses - Special Considerations for Primary $PM_{2.5}$

Primary PM does not undergo chemical transformation between being emitted and its arrival at a receptor location. Thus, high concentrations of primary PM can occur without relatively lengthy travel times from source to receptor. Unlike secondary PM or ozone, we would expect concentrations of primary PM to increase the closer one gets to the source(s) of emissions. Therefore, if a designated nonattainment area contains concentrated sources of primary PM, we would expect there to be relatively large spatial gradients near sources of the primary portion of the organic carbon, elemental carbon and other PM components of ambient $PM_{2.5}$ (these localized areas of high concentrations are often called “hotspots”).

Note that the $PM_{2.5}$ NAAQS ambient monitoring rule language[72] indicates that some monitoring locations may not be comparable to the annual $PM_{2.5}$ NAAQS. $PM_{2.5}$ measurement data from monitors that are not representative of “area-wide” air quality, but rather of relatively unique micro-scale, or localized hot spot, or unique middle-scale impact sites, are not eligible for comparison to the annual $PM_{2.5}$ NAAQS. The ambient air quality monitor siting rules define the appropriate scales of influence for the $PM_{2.5}$ monitoring network.[73]

[72] *See* 40 CFR 58.30.
[73] *See* 40 CFR part 58, Appendix E.

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4.6.1 Analysis of Primary $PM_{2.5}$ Impacts at Monitors

The majority of FRM and FEM $PM_{2.5}$ monitors are located at "urban scale" sites. These sites tend to represent relatively large spatial scales and do not have large gradients compared to other monitors in the area. Some sites are classified as "neighborhood" scale and may be influenced by more local sources. There are also near-road sites that have specifically been sited to measure gradients that may exist near heavily travelled roads. For reasons stated above, local influences creating large spatial gradients are likely to consist mostly of primary $PM_{2.5}$ (OC, EC, and OPP). These sources may be point sources, or they may be nearby roads or other mobile or area sources.

As part of the attainment demonstration modeling, it may be necessary to evaluate the local-scale impacts of primary $PM_{2.5}$ sources for contributions to the 24-hour and/or the annual NAAQS. As stated earlier, for the purposes of determining attainment with the NAAQS, it may not always be appropriate to compare ambient data from $PM_{2.5}$ monitoring sites that are dominated by point sources to the annual NAAQS. But there are numerous cases where local source contributions may not be dominant, but are a sizable contributor to total $PM_{2.5}$ (~10-30% of total annual average $PM_{2.5}$). In these cases, a more refined analysis of the contribution of local primary $PM_{2.5}$ sources to $PM_{2.5}$ at the monitor(s) will help explain the causes of nonattainment at and near the monitor and may lead to the more efficient ways to attain the NAAQS by controlling emissions from local sources which may be important contributors to the violating area.

There are several modeling tools that can be used to evaluate contributions of local $PM_{2.5}$ sources. A grid model can be run at very high horizontal resolution (1 or 2 km or finer) or a Gaussian dispersion model can be used. Grid based models simulate chemical transformation and complex meteorological conditions, while dispersion models are generally more simplistic; being limited to a local-scale, using Gaussian approximations with little or no chemistry. Therefore, while dispersion models may not be an appropriate tool for determining secondary $PM_{2.5}$ or ozone concentrations, they work well for use in determining local primary $PM_{2.5}$ impacts. The model(s) and model setup should be evaluated to determine the most appropriate tools for a specific situation. Regardless of which type of models are used to evaluate changes in primary $PM_{2.5}$ at monitoring locations, we recommend that the model results be used in a relative manner. This is consistent with the already described attainment tests. If a grid model is used at very high resolution, the attainment test as described in sections 4.4 and 4.5 should be followed. If a Gaussian dispersion model is used, then the application of the attainment test

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will vary slightly. The test will need to combine results from the chemical transport grid based modeled attainment test and the results from local-scale dispersion modeling. Because each nonattainment area has unique emissions sources and source-receptor relationships, air agencies should work closely with their EPA Regional office in developing local area analysis applications. The nature of the analyses and calculations of $PM_{2.5}$ concentrations (base and future) depend on the type(s) of local sources, measured PM gradients, the NAAQS being examined, and the model(s) used.

4.6.2 Analysis of Primary $PM_{2.5}$ Impacts at Monitors Using a Gaussian Dispersion Model

To apply a dispersion model in an attainment test, it is important to determine the local component of primary $PM_{2.5}$ at the monitor and the sources that are contributing to this component. There is no single, simple method for quantifying this contribution, but detailed analysis of ambient data and advanced data analysis techniques such as receptor modeling may help quantify the contribution. EPA provides software and information on the CMB, UNMIX, and PMF receptor models.

The simplest method for identifying the local component of $PM_{2.5}$ is to examine local ambient $PM_{2.5}$ concentrations. For this type of analysis, it is important to identify the local contributions from as small a source area as possible. This will make it easier to identify contributing sources. One aspect of this analysis is to examine monitored concentration differences between urban monitors (with the highest concentrations) and more suburban measurements. This is likely to provide a representative indication of the excess contribution from a relatively local area. "Urban excess" calculations which pair an urban monitor with an appropriate rural background monitor (U.S. EPA, 2004b) are likely to indicate "local" contributions that may be representative of a metropolitan area. In most cases, the local component will include contributions from more than one source.

Sources identified as contributing to the monitor through emissions analysis or data analysis (such as receptor modeling) can then be modeled with a dispersion model (or alternatively, a very high resolution grid model). It is common practice to run dispersion models for a limited number of major point sources or line sources in relatively small areas (out to a maximum

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distance of ~50 km).[74] Dispersion models can also be run for all sources of primary $PM_{2.5}$ in a limited area (including mobile, non-road, and area sources).

When applying a model to evaluate the impacts from emissions of primary $PM_{2.5}$, one should determine the $PM_{2.5}$ species that make up the local primary PM.[75] We recommend that the individual components of primary $PM_{2.5}$ be tracked separately. This will allow for a more thorough evaluation of the modeling results (comparing model output to speciated ambient data) and may aid in the development of primary $PM_{2.5}$ control strategies.

The majority of the primary $PM_{2.5}$ will consist of the primary portion of the organic carbon component, elemental carbon (EC), and the general category of "other primary particulate matter" (OPP). Speciated $PM_{2.5}$ measurements may be able to identify some of the more important "other" inorganic components such as heavy metals or salt. In some cases, directly emitted sulfate (and in rare cases nitrate) may also be a significant component of the local primary $PM_{2.5}$.

As part of a local-source impact analysis, an estimated concentration or fraction of primary OC may be needed. There are several methods available for estimating the primary versus secondary portion of ambient OC. Among these are the EC tracer method and receptor modeling. The EC tracer method is the most common method used to estimate secondary and primary OC concentrations (Turpin, 1995), (Strader, 1999), (Cabada, 2004), (Chu, 2005), (Saylor, 2006). The method uses measurements of OC and EC and calculated OC to EC ratios to identify periods when OC is likely to be mostly primary. This information is then used to calculate the secondary contribution to OC. Receptor models such as CMB and PMF have also been used to estimate secondary organic concentrations (Na, 2004), (Yuan, 2006).

Because each nonattainment area has unique emissions sources and source-receptor relationships, air agencies should work closely with their EPA Regional office in developing local area analysis applications.

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[74] This guidance document only applies to $PM_{2.5}$ attainment demonstrations to satisfy requirements in CAA Section 189. Other guidance documents and procedures are applicable for SO_2, NO_2, CO, and/or Pb attainment demonstrations and/or $PM_{2.5}$ permitting applications.

[75] The $PM_{2.5}$ emissions should be broken out into individual species using the best information available. Typically, SCC specific speciation profiles are used to "speciate" the PM into individual components. Local, source specific information should be used whenever possible.

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4.6.2.1 Double Counting

Application of a local area analysis may result in double counting of local emissions sources and reductions. This can happen when a change in emissions is examined with both a dispersion model and a chemical transport model.

The potential for double counting can be evaluated by considering the grid resolution of the chemical transport model and the number of sources in the dispersion model. The finer the resolution of the grid model, the more double counting may be a problem (because the local sources will be more finely resolved). Additionally, the more sources that are run with the dispersion model, the more double counting may be a problem. If the grid cell size is relatively large (e.g., 12km) and the primary emissions are relatively small, it may be possible to assume that double counting is small enough to be ignored. But the nature of the issue should be evaluated on a case by case basis.

The simplest way to evaluate the magnitude of the problem is to run the chemical transport model with and without the sources from the dispersion model. This will indicate the maximum impact that the sources can have on the chemical transport modeling results. A very small impact means that double counting is not a problem. A large impact indicates that a more explicit analysis is needed in order to resolve double counting issues.

4.6.2.2 Analysis of Primary $PM_{2.5}$ at Monitors- Quality Assurance

As with any modeling exercise, it is important to quality assure the model inputs and outputs. In particular, we recommend focused quality assurance checks on emissions from sources flagged for a dispersion modeling analysis. Prior to applying a model, air agencies should review available information to ensure that there are no major discrepancies between modeled estimates and nearby monitored data for PM. The emission factors, activity data, and speciation profiles of the $PM_{2.5}$ emissions should also be analyzed for accuracy. If a speciation monitor exists, the speciated data from the monitor can be compared to the speciation profiles of the flagged sources. Receptor models can also be used as a QA tool. Discrepancies between receptor modeling results (which are based on analyzing ambient data) and speciated emissions may indicate a problem with the magnitude and/or the speciation of the emissions sources. If discrepancies are found, those implementing the modeling protocol (see section 2.1) should consult with the appropriate EPA Regional office to reach agreement on what, if any, adjustments should be made to the emissions estimates for the identified sources.

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It is also important to quality assure the model outputs. Modeling each species of primary $PM_{2.5}$ separately within the dispersion model should aid in this analysis, especially if the selected control strategies applied in the future year do not control each primary species to the same degree. If a speciation monitor exists, the speciated data from the monitor may also help quality assure the dispersion model results. However, the application of the dispersion model results in a relative sense will help to reduce the impact of possible over- or under-estimations by the dispersion model due to emissions, meteorology, or general selection of other model input parameters.

4.7 Estimating design values at unmonitored locations

High ozone and/or $PM_{2.5}$ concentrations can occur at (or near) existing ambient monitors or in unmonitored areas. The modeled attainment test is primarily a monitor-based test. As such, the focus of the attainment test is whether attainment can be reached at existing monitors.
An additional "unmonitored area analysis" can also be performed to examine ozone and/or $PM_{2.5}$ concentrations in unmonitored areas. The unmonitored area analysis is intended to be a means for identifying high ozone and/or $PM_{2.5}$ concentrations outside of traditionally monitored locations, particularly in nonattainment areas where modeling or other data analyses have indicated potential high concentration areas of ozone and/or $PM_{2.5}$ outside of the existing monitoring network. An unmonitored area analysis may also be more important in areas where the ozone or $PM_{2.5}$ monitoring networks just meet or minimally exceed the minimum required network in a nonattainment area.

This review can help ensure that a control strategy leads to reductions in ozone or $PM_{2.5}$ at other locations which could have base case (and future) design values exceeding the NAAQS were a monitor deployed there. In addition, analysis of concentrations in unmonitored areas may serve other purposes such as helping to site new (or move existing) monitors, examining health benefits from emissions reductions, and analyzing the impact of potential new or modified emissions sources. This document describes how an unmonitored area analysis can be performed for a particular area. See the respective ozone and $PM_{2.5}$ SIP Requirements Rules (including the preambles and response to comments documents) for more information on when an unmonitored area analysis is recommended or required.

We use the term "unmonitored area analysis" to describe an analysis that uses a combination of model output and ambient data to identify areas that might exceed the NAAQS in areas that are not currently monitored. An unmonitored area analysis for a particular nonattainment area is intended to address the potential for air quality problems within or near that nonattainment

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area. The analysis should include, at a minimum, all nonattainment counties and counties surrounding the nonattainment area, as appropriate. It is possible that unmonitored area violations may appear in counties far upwind or downwind of the local area of interest. In those cases, the distance to the nonattainment area and ability of the modeling to represent far downwind areas should be evaluated on a case-by-case basis.

The spatial resolution of the unmonitored area analysis should be consistent with the appropriate model resolution for the attainment demonstration. For example, if the attainment demonstration for ozone or $PM_{2.5}$ is conducted at 12km grid resolution, then in most cases, the unmonitored area analysis should also be performed at the same horizontal resolution.

4.7.1 Why does the unmonitored area analysis need to use both ambient data and model output?

When performing an unmonitored area analysis, it is recommended to use interpolated spatial fields of ambient data in combination with gridded modeled outputs (i.e., fused surfaces). Ambient data can be interpolated to provide a set of spatial fields. The resultant spatial fields will provide an indication of pollutant concentrations in monitored and unmonitored areas. But interpolated ambient data cannot identify unmonitored areas with higher concentrations than those measured at monitors. The interpolated concentration between monitors will generally be the same or lower than the measured concentration at the monitors (assuming that more sophisticated statistical techniques are not used). Simple interpolation techniques do not account for emissions or chemistry information that may be needed to identify high concentrations in unmonitored areas.

In addition to interpolated surfaces, gridded model output (absolute) concentrations (from a chemical transport model) can be used to examine unmonitored area concentrations. The model provides an hourly concentration output for every grid cell. The concentrations can be analyzed to determine unmonitored areas where the model predicts high values. But the absolute predictions from the model may not be entirely accurate (they may be biased high or low). But unlike the interpolated ambient data, the model explicitly accounts for emissions, chemistry, and meteorological processes over the entire domain.

Interpolated ambient data and absolute model outputs both have strengths and weaknesses. We can take advantage of the strengths of each dataset by combining the two types of data. Interpolated spatial fields of ambient data provide a strong basis for estimating accurate pollutant concentrations at and near monitor locations. And the model outputs can be used to

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adjust the interpolated spatial fields (either up or down) so that more accurate estimates can be derived in unmonitored areas.[76] A recommended way to use the modeling in the creation of fused surfaces is to adjust the ambient spatial fields using the concentration *gradients* derived from the model predictions. It is preferable to assume that the model is accurately predicting areas of generally high or low ozone or PM, rather than to assume that the absolute predictions from the model are correct. For example, in unmonitored locations where the model predicts relatively high ozone or PM concentrations, the spatial fields can be adjusted upward. In unmonitored locations where the model predicts relatively low ozone or PM concentrations, the spatial fields can be adjusted downward. In this way, it may be possible to predict unmonitored locations that may be likely to record high concentrations (were a monitor located there). We refer to this combination of interpolated spatial fields and modeled output as "gradient adjusted spatial fields."

4.7.2 Implementation of Gradient Adjusted Spatial Fields

A recommended methodology for developing gradient adjusted spatial fields is to first create base year fields. Future year estimates can then be created by applying gridded RRFs to the base year gradient adjusted spatial fields. The basic steps are as follows:

1) Interpolate base year ambient data to create a set of spatial fields.
2) Adjust the spatial fields using gridded model-based spatial gradients (base year values).
3) Apply gridded model-based RRFs to the gradient adjusted spatial fields.
4) Determine if any unmonitored areas are predicted to exceed the NAAQS in the future.

EPA's SMAT will spatially interpolate data, adjust spatial fields based on model output gradients, and multiply the fields by model calculated RRFs (steps 1-3 above) (U.S. EPA, 2018), (ABT, 2014). Air agencies can use the EPA-provided software or may wish to develop alternative techniques that may be appropriate for their area, situation, and/or purpose. Air Agencies should consult with the appropriate EPA Regional office to determine if and how an unmonitored area analysis should be conducted.

Step 1

The first step in developing an unmonitored area analysis is to interpolate ambient data. Ideally, design values should be interpolated. Either the 5-year weighted average design values

[76] The accuracy of interpolated fields can be evaluated by removing data from monitors (either in groups or one at a time) to see how well the interpolation scheme estimates known concentrations at ambient monitoring sites. This is known as a cross-validation.

that are used in the monitor based modeled attainment test or a single design value period can be used in the development of ambient spatial fields. Care should be taken so that the interpolated fields are not unduly influenced by monitoring sites that do not have complete valid data. Since the design values can vary significantly from year to year, it is important to use a consistent set of data.

We are not recommending a single interpolation technique. EPA's SMAT uses the Voronoi Neighbor Averaging (VNA) interpolation technique. Past analyses have used a Kriging interpolation technique (U.S.EPA, 2004).

For ozone analyses, a single spatial field of ozone values is needed. But for the $PM_{2.5}$ NAAQS, the EPA recommends creating interpolated spatial fields for $PM_{2.5}$ (FRM) and for each component species of $PM_{2.5}$. For the annual $PM_{2.5}$ NAAQS, a set of quarterly average spatial fields can be created. The four quarters are averaged to get an annual average set of fields.

For the 24-hour $PM_{2.5}$ standard, a spatial field can be created using the high end of the distribution of 24-hour $PM_{2.5}$ concentrations. This is best represented by interpolating the measured high values from each quarter. For the $PM_{2.5}$ component species, we recommend interpolating the high $PM_{2.5}$ days in each quarter. This can be based on the highest monitored days in each quarter.

Step 2

The second step in the process involves the use of gridded model output to adjust the spatial fields derived from ambient data. SMAT uses the eVNA technique, where the VNA interpolation is "enhanced" by adjusting the interpolated values based on the modeled ozone or PM (or PM species) gradient. See the SMAT user's guide for more details (U.S. EPA, 2018), (Abt, 2014). Other "model adjusted" spatial fields techniques include Hierarchical-Bayesian (McMillan, 2010) and "Downscaler" (Berrocal, 2010a and 2010b).

A specific metric is needed to determine the model predicted gradient in concentrations for each of the NAAQS. For ozone, a logical metric is the 4th highest ozone prediction in each grid cell.[77] For the annual $PM_{2.5}$ NAAQS, the model predicted quarterly mean concentrations for $PM_{2.5}$ and $PM_{2.5}$ species can be used to adjust the ambient spatial fields. For the 24-hour $PM_{2.5}$ NAAQS, the gradient adjusted fields can be derived from the high end of the distribution of

[77] The metric should approximate the measured design values at monitoring sites. Depending on the days modeled, other metrics, such as the average of the top 4 modeled days may be a better proxy for the design value.

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daily averages in each quarter. This could be for the top 10% of modeled days in each quarter or for all days with 24-hour average concentration > 35 µg/m3 (or some other relatively high value).

Step 3

The next step is to create future year spatial fields by multiplying the base year gradient adjusted spatial fields by model derived gridded RRFs. The RRFs for the unmonitored area analysis are calculated in the same way as the monitored based attainment test (except that the grid cell array is not typically used in the spatial fields based analysis). The future year concentrations are equal to the base year concentration multiplied by the RRF in each grid cell. For ozone, a single spatial field is multiplied by a single set of model derived RRFs. For $PM_{2.5}$, the RRFs for each of the species, for each quarter, are multiplied by the spatial fields for each species, for each year.

4.7.3 Using the Results of the Unmonitored Area Analysis

For ozone and/or $PM_{2.5}$ attainment demonstrations, the future year gradient adjusted spatial fields can be analyzed to determine if any grid cells are predicted to remain above the NAAQS. States should consult with their EPA Regional office to determine if an unmonitored area analysis should be conducted for a particular nonattainment area and, if so, how the analysis should be conducted and how the results should be used.

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5.0 What Is the Recommended Modeling Method for Developing Air Quality Goals for Regional Haze?

This section focuses on the modeling analysis needed to set RPGs that reflect the enforceable emission limitations, compliance schedules, and other measures included in the long-term strategy of a regional haze SIP.[78] In this section, we describe the recommended modeled analysis to assess visibility conditions at the end of an implementation period (i.e., the future end-point of a multi-year planning period under the regional haze program). The visibility analysis has many similarities to the $PM_{2.5}$ attainment tests described in sections 4.4 and 4.5. The recommended visibility analysis and the attainment tests both use monitored data to define base year air quality. They divide $PM_{2.5}$ into major species, and component-specific relative response factors are multiplied by base year monitored values to estimate future concentrations.

Section 5.1 provides background information on the requirements of the Regional Haze Rule and explains how RPGs are used in the regional haze program once they are set. The rest of the section describes the recommended modeling analysis to evaluate future year changes in visibility impairment. This document does not address how a state should develop its long-term strategy of emissions controls for regional haze or determine the uniform rate of progress for a Class I area.

5.1 Regional Haze Rule Background

The modeling results are used to quantify the amount of progress, expressed in deciviews of visibility improvement, anticipated to be made at individual Class I areas as of the end of an implementation period. Reasonable progress goals are calculated separately for the 20% most impaired days and the 20% clearest days at each Class I area. These values are then compared to visibility conditions in the "baseline period" (2000-2004 for most areas)[79] for the same type of

[78] The main regional haze section of the guidance is related to setting reasonable progress goals. However, the guidance methods may also be applicable to other regional haze related modeling, including, but not limited to, evaluation of visibility impacts from sources and/or source sectors (including international impacts).

[79] In the context of attainment demonstrations for ozone and $PM_{2.5}$, the term "baseline period" is commonly used to refer to the base period used for modeling. Because the Regional Haze Rule defines "baseline period" specifically as 2000-2004, this section uses "baseline" and "baseline period" only when referring to 2000-2004. The term "base period" is used when referring to a more recent 5-year period used in the modeling-based projection of RPGs.

days (i.e., most impaired and clearest) to verify that the SIP provides for an improvement in visibility on poor visibility days and allows no degradation in visibility on good visibility days. The RPGs for the most impaired days are also plotted against the uniform rate of progress that would be needed at individual Class I areas to achieve natural visibility conditions in 2064, starting at baseline visibility conditions for 2000-2004. The results of this comparison inform whether the SIP must contain an additional component demonstrating that no additional control measures are necessary to make reasonable progress.

Reasonable progress goals are a regulatory construction promulgated to implement the statutory requirements for visibility protection. Section 169A(a)(1) of the Clean Air Act states, "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." This section later directs EPA to promulgate regulations to assure reasonable progress towards meeting this goal. Section 169B calls for EPA to "carry out the Administrator's regulatory responsibilities under [Section 169A], including criteria for measuring 'reasonable progress' toward the national goal."

In response to these mandates, EPA promulgated the Regional Haze Rule on July 1, 1999.[80] The rule was revised on January 10, 2017.[81] The regulations promulgated at 40 CFR 51.308(f) contain the relevant requirements for SIPs for the second and subsequent implementation periods, which are the SIPs that this guidance document addresses. Under section 51.308(f)(2), every state must determine the emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress at Class I areas in the state and other Class I areas that may be affected by sources in the state. The collection of these measures is referred to as the long-term strategy. Under section 51.308(f)(3), a state in which a mandatory Class I Federal area is located must establish RPGs, one each for the 20% most impaired days and the 20% clearest days (expressed in deciviews) for each such area. These RPGs reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period as a result of its own and other states' long-term strategies, as well as the implementation of other requirements of the CAA. They are interim goals that represent the incremental visibility improvement achieved in each implementation period toward Congress's goal of eliminating visibility impairment from manmade emissions sources. The long-term strategy and the RPGs are developed in consultation with other affected air agencies and

[80] *See* 64 FR 35714.
[81] *See* 82 FR 3078.

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Federal Land Managers.[82]

The Regional Haze Rule contains the following requirements that involve the RPGs once they have been set.

> The reasonable progress goals (RPGs) must provide for an improvement in visibility for the 20% most anthropogenically impaired days relative to baseline visibility conditions and ensure no degradation in visibility for the 20% clearest days relative to baseline visibility conditions.[83] As explained in the RHR, the baseline for each Class I area is the average visibility (in deciviews) for the years 2000 through 2004.[84] The visibility conditions in these years are the benchmark for both the "provide for an improvement" and "no degradation" requirements.
>
> States are also required to determine the rate of improvement in visibility needed to reach natural conditions by 2064 for the 20% most anthropogenically impaired days, given the starting point of the 2000-2004 baseline.[85] The "glidepath," or uniform rate of progress (URP), is the amount of visibility improvement needed to stay on a linear path from the baseline period to natural conditions. Every state must compare its RPG for the 20% most anthropogenically impaired days to the point on the glidepath corresponding to the end of the implementation period. The results of this comparison determine whether a SIP must contain a demonstration that no additional emission reductions are needed to make reasonable progress towards achieving natural visibility conditions.

This section does not address the process of calculating the glidepath or determining the measures for inclusion in the long-term strategy.[86]

5.2 How is Regional Haze Measured?

Regional haze is measured by an *extinction coefficient* (b_{ext}) that represents light attenuation resulting from scattering and absorption of light from ambient PM plus scattering of light due to gas molecules in the air (i.e., Rayleigh scattering). Although b_{ext} can be estimated by several

[82] *See* 40 CFR 51.308(f)(2)(ii) and 51.308(i).

[83] *See* 40 CFR 51.308(f)(3)(i).

[84] *See* 40 CFR 51.308(f)(1) and definitions in 51.301.

[85] *See* 40 CFR 51.308(f)(1).

[86] For more details on calculating the URP and regional haze policy guidance, see draft guidance for the second implementation period [note that the draft guidance document will be updated in Spring 2019].

different methodologies, the RHR requires that it be estimated using measured ambient PM. This follows since, for a given set of meteorological conditions, visibility can be improved by reducing concentrations of ambient PM. Thus, deriving b_{ext} in this manner provides a direct link between regional haze and related pollutant concentrations.

5.2.1 IMPROVE Algorithm

The IMPROVE equation or algorithm reflects empirical relationships derived between measured mass of PM components and transmissometer measurements of b_{ext} at a subset of monitoring sites in Class I areas within the IMPROVE monitoring network. The IMPROVE program revised the IMPROVE algorithm in 2006 (Hand, 2006); (Pitchford, 2007). The revised algorithm is intended to reduce biases in light extinction estimates. The revised algorithm is as follows:

$$
\begin{aligned}
b_{ext} = {} & 2.2 \times f_s(RH) \times [\text{Small Sulfate}] + 4.8 \times f_L(RH) \times [\text{Large Sulfate}] \\
& + 2.4 \times f_s(RH) \times [\text{Small Nitrate}] + 5.1 \times f_L(RH) \times [\text{Large Nitrate}] \\
& + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
& + 10 \times [\text{Elemental Carbon}] \\
& + 1 \times [\text{Fine Soil}] \\
& + 1.7 \times f_{ss}(RH) \times [\text{Sea Salt}] \\
& + 0.6 \times [\text{Coarse Mass}] \\
& + \text{Rayleigh Scattering (site specific)} \\
& + 0.33 \times [NO_2 \text{ (ppb)}] \qquad \textbf{[5.1]}
\end{aligned}
$$

The numerical coefficients on the right hand side of the equation represent the light scattering or absorption efficiency, m^2/gm of the corresponding component of particulate matter,

$f_s(rh)$, $f_L(rh)$, $f_{ss}(rh)$ are relative humidity adjustment factors applied to the light scattering efficiency (to be described in greater detail shortly), dimensionless;

SO_4 is the mass associated with sulfates, $\mu g/m^3$;

NO_3 is the mass associated with nitrates, $\mu g/m^3$;

OC is the mass associated with organic carbon, $\mu g/m^3$;

EC is the mass associated with elemental carbon, $\mu g/m^3$;

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Fine Soil is inorganic primary particulate matter (excluding primary sulfate and nitrate particles) associated with soil components with aerodynamic diameter $\leq$ 2.5 µm, µg/m^3;

CM is coarse PM with aerodynamic diameter > 2.5 µm, but $\leq$ 10 µm, µg/m^3;

$b_{rayleigh}$ is light-scattering attributable to Rayleigh scattering, Mm^{-1} (i.e., inverse "mega-meters"); and

b_{ext} is the estimated extinction coefficient, Mm^{-1}.

The total sulfate, nitrate and organic mass concentrations are each split into two fractions, representing small and large size distributions of those components. The organic mass concentration is calculated as 1.8 times the measured IMPROVE organic carbon concentration, to adjust for organic mass from elements other than carbon. Terms are included for sea salt (important for coastal locations) and for absorption by NO_2 (only used where NO_2 data are available). Site-specific Rayleigh scattering is calculated based on the elevation and annual average temperature of each IMPROVE monitoring site.

The apportionment of the total concentration of sulfate compounds into the concentrations of the small and large size fractions is accomplished using the following equations:

[Large Sulfate] = [Total Sulfate]/20 µg/m^3 x [Total Sulfate], for [Total Sulfate] < 20 µg/m^3
[Large Sulfate] = [Total Sulfate], for [Total Sulfate] $\geq$ 20 µg/m^3

[Small Sulfate] = [Total Sulfate] - [Large Sulfate]

The same equations are used to apportion total nitrate and total organic mass concentrations into the small and large size fractions.

Sea salt is calculated as 1.8 x [Chloride] or 1.8 x [Chlorine] if the chloride measurement is below detection limits, missing or invalid. The algorithm also uses three water growth adjustment terms. They are for use with the small size distribution and the large size distribution sulfate and nitrate compounds and for sea salt (f_S(RH), f_L(RH) and f_{SS}(RH) respectively).

All or nearly all states used the revised algorithm in their SIPs for the first implementation period and the IMPROVE program has stopped reporting visibility data using the original

IMPROVE equation. Therefore, we now recommend using the revised IMPROVE equation for all reasonable progress related modeling calculations.

5.2.2 Deciview Haze Index

The RHR requires that reasonable progress is to be measured in terms of changes in a *deciview haze index* or simply "deciviews" (dv). Deciviews are defined as the natural logarithm of the ratio of the extinction coefficient to Rayleigh scattering (Pitchford and Malm, 1994).

$$\text{Deciview} = 10 \ln(b_{ext}/10) \qquad \textbf{[5.2]}$$

Where the units of b_{ext} and light scattering due to Rayleigh scattering[87] (i.e., the "10" in the denominator of the logarithmic expression) are both expressed in Mm^{-1}.

A *change* in deciviews, which is how progress is tracked, is given by Equation (5.3). A one deciview change is equivalent to ~10% change in b_{ext}.

$$\Delta dv = dv_{future} - dv_{base} \qquad \textbf{[5.3]}$$

A negative number indicates a reduction in deciviews, which is an improvement in visibility.

5.2.3 Estimating Mass Associated with Components of Particulate Matter

All Class I areas either have on-site speciated $PM_{2.5}$ measurements or have been assigned a representative IMPROVE monitoring site with measurements.[88] Therefore, it is generally not necessary to interpolate measured $PM_{2.5}$ species data to a site. The existing IMPROVE database of $PM_{2.5}$ measurements should be adequate to provide data for all Class I areas.[89]

FRM data is not used in the regional haze analysis and it is not necessary for the sum of species

[87] Even though the "revised" IMPROVE equation uses a site-specific Rayleigh scattering value, the denominator in the deciview equation should always be 10. In this way, the deciview calculation will be consistent across all Class I areas. When the site-specific Rayleigh scattering is less than 10 (at high elevation sites), the deciview value can be negative (on very clean days), but this should not be considered a problem.

[88] See U.S. EPA 2003b, Appendix A, Table A-2.

[89] There are some IMPROVE sites that do not have enough complete data to provide baseline condition information for the 2000-2004 period. Data substitution is addressed in 40 CFR 51.308(f)(1)(i) and also discussed in (U.S. EPA 2003b).

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components to equal gravimetric measurements obtained with a Federal Reference or equivalent method for measuring $PM_{2.5}$. Therefore, for regional haze calculations, it is not necessary to use the speciated data adjustment procedures introduced in section 4.4 (the "SANDWICH" adjustments).

Hand (2006) has developed a set of default assumptions for mass associated with each of the components of PM for Equation (5.1). These are presented in Table 5.1. The components in Table 5.1 are similar to those used in the modeled attainment demonstrations for the $PM_{2.5}$ NAAQS. Notice, however, that sulfate and nitrate mass are assumed to be fully neutralized (therefore, ammonium is not needed as a separate component); organic carbon is assumed to be equal to 1.8 times **measured** OC mass; there is no water component; and there is a term for coarse PM.

Table 5.1. Default Assumptions Used to Derive Aerosol Species Concentrations from IMPROVE Data for Estimating Extinction Coefficients

(1) Species	(2) Formula	(3) Assumptions
Sulfate	**1.375 *measured SO4**	**Sulfate is assumed to be fully neutralized (ammonium sulfate)**
Nitrate	**1.29 * measured nitrate**	**Denuder efficiency is ~100% & all nitrate is from ammonium nitrate**
EC	**high + low temperature EC**	**All high temperature carbon is elemental**
OC	**1.8 * organic carbon**	**Average organic molecule is 56% carbon**
Fine Soil	**2.2*Al + 2.49*Si + 1.63*Ca + 2.42*Fe + 1.94*Ti**	**(Soil K)=0.6(Fe), FeO & Fe_2O_3 are equally abundant, a factor of 1.16 is used for MgO, Na_2O, H_2O & CO_3**
Sea Salt	**1.8*Cl-**	**Sea salt is 55% chloride ion by weight**

$PM_{2.5}$		**-Measured gravimetrically -Represents dry ambient fine aerosol mass**
CM (coarse mass)	**(PM_{10}) - ($PM_{2.5}$)**	**Consists only of insoluble soil particles**

Throughout this section we make every attempt to be consistent (aside from the use of the revised IMPROVE algorithm) with corresponding parts of the "Guidance for Tracking Progress under the Regional Haze Program" (hereafter referred to as the "Tracking Guidance") (U.S. EPA, 2003b). It will be easier to interpret the modeling results and compare them to measured values if the modeled future year data are calculated in a manner similar to the ambient data.

5.2.4 Normalizing Trends in Regional Haze - f(rh) Factors

It is clear from equation 5.1 that relative humidity can have a substantial effect on estimated extinction coefficients, as well as the relative importance of changes in different components of PM on trends in regional haze. Because of the importance of relative humidity as a determinant of regional haze, it is necessary to normalize any apparent trend in the estimated extinction coefficient for differences in relative humidity. This enables an assessment of how much an emissions control strategy will reduce regional haze, without the confounding effects of different relative humidity levels during the base and future periods.

There are two possible approaches to normalize trends in visibility for changes in relative humidity between the past and future. The first is to assume that the same day-specific values for relative humidity which were observed in the base period calculations will occur in future years. Thus, one would use the relative humidity observations made on a specific day together with measured components of particulate matter on that day to compute the day-specific visibility extinction coefficient on that day in the future. However, the approach could lead to misleading conclusions if humidity observations were missing for some days or if the humidity observations are atypical in some way. Further, if an air agency wanted to perform visibility calculations in a number of Class I areas, it would need to obtain hourly relative humidity data for each area.

The second approach is to review relative humidity data over a long period of record to derive climatological estimates for relative humidity adjustment factors. These climatological estimates can then be used in Equation 5.1 to estimate visibility extinction coefficients. These

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estimates are more likely to reflect "typical" relative humidity at different times of year and, thus, expected future visibility extinction.

There are obvious advantages in using climatological f(rh) data for tracking progress of measured data. The measured relative humidity on the 20% most impaired days in a historical period will be different than the measured relative humidity in a future period. Therefore, the only way to normalize for relative humidity between the base and future years in the context of measured data is to use a single climatological value. However, in the context of modeling, there is a choice between climatological data or modeled (or measured) relative humidity data from a meteorological model. Since the modeled meteorological data is held constant when predicting future year air quality, the modeled relative humidity values would also be constant. This would be one way to normalize the data. But since the Tracking Guidance recommends tracking visibility using climatological f(rh) values, it will be easier to interpret the modeling results and compare them to future measured values if the data are calculated in a similar manner. Therefore, we recommend using climatological f(rh) values to calculate base period and future visibility. Appendix A (Table A-1) from the Tracking Guidance displays the relationship between relative humidity and f(rh) values. The f(rh) values were calculated from relative humidity data reported by Tang (1996). The f(rh) values are 1.00 up to 36% relative humidity and grow to a maximum value of 7.40 at a relative humidity of 95%.[90] These values were calculated using 10 years of meteorological data.

For calculations with the revised IMPROVE equation, three separate f(rh) curves are needed (small, large, and sea salt). These can be found in (Hand, 2006). The monthly f(rh) values for both the old and revised IMPROVE equations have been incorporated into pre-calculated daily extinction and deciview data that can be found on the IMPROVE website. The use of pre-calculated f(rh) and visibility data makes it easier for air agencies and regional organizations to calculate visibility changes and will also provide for more consistency.

5.3 How Do I Apply a Model to Calculate Changes in Visibility?

The purpose of a regional haze modeling assessment is to project future visibility conditions representing the RPGs, which are used to satisfy the requirements described in section 5.1. In

[90]For the regional haze calculations, the f(rh) factors have been capped at the f(rh) value associated with 95% relative humidity. Relative humidity value above 95% use the same value.

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the procedures below, the observed base period visibility data should be linked to the base modeling year. Similar to the ozone and $PM_{2.5}$ attainment tests, the 5-year ambient data period should be centered about the base modeling year. For example, for a base modeling year of 2014, the ambient IMPROVE data should be from the 2012-2016 period.[91] However, unlike the ozone and $PM_{2.5}$ attainment tests, the calculation is a 5-year mean where each year counts equally (unlike the 5-year weighted average values for the ozone and $PM_{2.5}$ attainment test). This is consistent with the regional haze rule ambient data calculations for the 20% most impaired days and 20% clearest days. The analysis we recommend has 6 steps.

1) For each Class I area, estimate anthropogenic impairment on each day using observed speciated $PM_{2.5}$ and PM_{10} data plus climatological f(rh) and Rayleigh scattering data for each of the 5 years comprising the base period (this estimation step is not addressed in this document), and rank the days on this indicator. This ranking will determine the 20% most anthropogenically impaired days and the 20% clearest days.
2) For each of the 5 years comprising the base period, calculate the mean deciviews for the 20% most anthropogenically impaired days and 20% clearest days. For each Class I area, calculate the 5-year mean deciviews for most impaired and clearest days from the 5 year-specific values.
3) Use an air quality model to simulate base period emissions and future emissions. Use the resulting information to develop RRFs for each component of PM identified on the right-hand side of Equation (5.1).
4) Multiply the RRFs by the measured species concentration data during the base period (for the measured 20% most impaired days and 20% clearest days). This results in daily future year species concentrations data.
5) Using the results in Step 4 and the IMPROVE algorithm (equation 5.1), calculate the future daily extinction coefficients for the 20% most impaired days and 20% clearest days in each of the 5 base years.
6) Calculate daily deciview values (from total daily extinction) and then compute the future average mean deciviews for the 20% most impaired days and 20% clearest days for each

[91] The *baseline period* for the regional haze program continues to be 2000-2004, and the uniform rate of progress is calculated using that historical data. However, the modeled reasonable progress visibility projections should use ambient data from a 5-year *base period* that corresponds to the modeled base year meteorological and emissions data. In addition, ambient data trends for the 5-year base period should be examined to make sure the base modeling year emissions are representative of the period. In some cases, an alternative base ambient data period may be more representative of a base modeling year.

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year. Average the 5 years together to get the final future year mean deciview values for the 20% most impaired days and 20% clearest days.

We describe each of these steps more fully below. The methodology follows the same basic procedures outlined in the Tracking Guidance, however, based on the revised regional haze rule, a draft methodology (for steps 1 and 2) is available for calculating the most anthropogenically impaired and clearest days (U.S. EPA, 2016d).[92] We conclude this subsection with an example illustrating the recommended modeled uniform rate of progress analysis.

Step 1. Using monitored data, rank base period visibility for each day with PM_{10}, $PM_{2.5}$ and speciated $PM_{2.5}$ measurements within a Class I area.

Ranking should be performed separately for each of the 5 years comprising the base period.[93] The deciview (dv) should serve as the basis for ranking. Day-specific observations for mass associated with SO_4, NO_3, OC, EC, soil, and CM, as defined in Table 5.1, should be used to calculate b_{ext} for each day. The appropriate month- and area-specific climatological relative humidity adjustment factor(s) (*f(rh)*) should be used. Total b_{ext} for all components should be converted to deciviews for each day to get a daily deciview value.

Step 2. Calculate the average base period deciviews for the 20% most anthropogenically impaired days and 20% clearest days.

For each of the 5 years in the base period, order all days considered in Step 1 from worst (highest deciview value) to best (lowest deciview value) visibility. For each year, note the 20% most impaired days and 20% clearest days. Calculate the arithmetic mean deciview value for the identified 20% most impaired days and 20% clearest days in each year. Average the resulting 5 yearly mean deciview values reflecting the most impaired days. This represents the value subject to improvement requirement (i.e., the value must decrease). Average the 5-yearly mean deciview values reflecting mean visibility on the clearest days. This is the value subject to the requirement of no degradation (i.e., the value cannot increase).

[92] A final recommendation is expected in Fall 2018.

[93] Pre-calculated and ranked anthropogenic impairment, extinction, and deciview calculations for all Class I areas is available on the IMPROVE website. This data can be used to satisfy steps 1 and 2. States may also choose to use an alternative methodology to calculate anthropogenic impairment for Class I areas, which may differ from the default EPA recommended methodology. States should consult with their EPA Regional office to discuss appropriate methodologies for alternative impairment calculations.

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Step 3. Estimate RRFs for each component of $PM_{2.5}$ and for CM.

The RRFs should be determined using results from air quality modeling of base year and future year emissions. These model simulations should be performed for a large number of days (presumably at least a full year; see section 2.3.1 for more details). The (temporal) arithmetic mean concentration for each $PM_{2.5}$ component (and coarse mass) computed near the Class I monitoring site from the future year modeling is divided by the corresponding arithmetic mean concentration for each component from the base year modeling. The resulting ratios are the component-specific RRF's. A separate set of RRF values are calculated for the 20% most impaired days and 20% clearest days identified in step 2. The RRFs are calculated using the model outputs corresponding to the *monitored* 20% most impaired days and 20% clearest days at each Class I area. This will likely be a different set of days at each monitor.

Step 4. Using the RRFs and ambient data, calculate future year daily concentration data for the clearest and most impaired days.

Multiply the RRFs derived in Step 3 by measured daily concentration data for each component of $PM_{2.5}$ and CM to get future daily estimates of species concentrations for $PM_{2.5}$ components and CM on the 20% most impaired days and 20% clearest days. These multiplications produce future concentration estimates for SO_4, NO_3, OC, EC, soil, sea salt, and CM for each of the previously selected 20% most impaired days and 20% clearest days. This calculation is performed for the 5-year period using an RRF for each PM component (a separate set of RRFs for the 20% most impaired days and 20% clearest days).

Step 5. Use the information developed in Step 4 to compute future year daily b_{ext} values for the 20% most impaired days and 20% clearest days.

Use the future year concentration data calculated in step 4 to calculate future year daily b_{ext} values for each PM component for each of the 20% most impaired days and 20% clearest days for the 5-year period. This is accomplished by applying the revised IMPROVE visibility algorithm (equation 5.1).

Step 6. Use the daily total b_{ext} values from step 5 to calculate future mean deciview values for the 20% most impaired days and 20% clearest days .

The total daily b_{ext} for each day is converted to deciviews. This gives a future year daily deciview value for each of the 20% most impaired days and 20% clearest days.

Next, compute the arithmetic mean future deciview value for the 20% most anthropogenically

impaired days and 20% clearest days for each year. This leads to five future estimated mean deciview values for the worst and five future estimated mean deciview values for the best visibility days. Compute the arithmetic mean of the five mean values for deciviews on the 20% most anthropogenically impaired days, and the arithmetic mean of the five mean deciview values estimated for the 20% clearest days. The resulting 5-year average mean values for deciviews on 20% most impaired days and 20% clearest days will be compared to the base period mean deciview values calculated in step 2. If the resulting change in deciviews is a negative number (future - base), this represents an improvement in visibility. The future year visibility value for the 20% most impaired days will also be compared to the glidepath to determine if the Class I area is expected to be on, above, or below the glidepath in the future implementation period.

Example 5.1

We use example 5.1 to illustrate the modeled visibility assessment. For ease of presentation, we assume there are only 10 speciated samples for PM in each of the 5 years comprising the base period. Since sampling occurs every third day, a typical sample size is ~120 days per year. We illustrate the calculations for the first base year and then furnish information regarding mean deciviews for the other 4 base years to illustrate subsequent steps in the test.

Given:

Ten days have measured components of PM in a Class I area during the first year of a 5-year base period. Table 5.2 below shows the measurements (in µg/m^3) for each of the 10 days. Table 5.2 also shows the date of each measurement and the corresponding climatological relative humidity adjustment factor (made up for this example) for the appropriate month and area.

Table 5.2 Example observed IMPROVE data at a Class I area

Day	Date	$f_S(RH)$	$f_L(RH)$	$F_{SS}(RH)$	Ammonium Sulfate (µg/m3)	$SO4_L$ (µg/m3)	$SO4_S$ (µg/m3)	Ammonium Nitrate (µg/m3)	$NO3_L$ (µg/m3)	$NO3_S$ (µg/m3)
1	1/7	3.82	2.75	3.91	2.004	0.201	1.804	1.050	0.055	0.995
2	2/24	3.29	2.46	3.49	2.290	0.262	2.028	0.453	0.010	0.442
3	4/15	3.73	2.67	3.68	2.617	0.342	2.274	1.206	0.073	1.134
4	6/20	3.82	2.73	3.82	4.580	1.049	3.531	0.528	0.014	0.514
5	7/14	4.29	3.00	4.20	2.742	0.376	2.366	0.416	0.009	0.407
6	8/10	4.35	3.04	4.27	3.512	0.617	2.896	0.161	0.001	0.160
7	8/28	4.35	3.04	4.27	2.303	0.265	2.038	0.224	0.003	0.221
8	9/18	4.59	3.17	4.44	1.759	0.155	1.604	0.409	0.008	0.400
9	10/21	4.11	2.92	4.13	1.660	0.138	1.522	0.159	0.001	0.158
10	12/14	4.21	2.97	4.20	1.975	0.195	1.780	0.854	0.036	0.818

Day	Date	Organic Mass (µg/m3)	OM_L (µg/m3)	OM_S (µg/m3)	EC (µg/m3)	Soil (µg/m3)	Sea Salt (µg/m3)	CM (µg/m3)	Rayleigh Mm^{-1}
1	1/7	3.024	0.457	2.567	0.345	0.106	0.214	1.334	12
2	2/24	1.073	0.058	1.016	0.150	0.058	0.150	2.004	12
3	4/15	2.409	0.290	2.119	0.241	0.589	0.357	5.928	12
4	6/20	2.482	0.308	2.174	0.282	0.367	0.132	3.549	12
5	7/14	3.608	0.651	2.957	0.297	0.343	0.157	6.252	12
6	8/10	1.768	0.156	1.612	0.268	0.134	0.026	1.989	12
7	8/28	1.772	0.157	1.615	0.162	0.190	0.165	2.521	12
8	9/18	1.049	0.055	0.994	0.123	0.112	0.725	3.880	12
9	10/21	1.267	0.080	1.186	0.094	0.218	0.086	1.996	12
10	12/14	1.454	0.106	1.348	0.248	0.170	0.046	2.081	12

Using the IMPROVE concentration data for the Class I area and modeled RRFs, calculate the future year extinction and deciview values for the 20% most impaired days and the 20% clearest days for the end of the implementation period addressed in the SIP.

Step 1. Using monitored data, rank base period visibility for each day with PM_{10}, $PM_{2.5}$, and speciated $PM_{2.5}$ measurements within a Class I area.

First, estimate the extinction coefficient for each day that has the needed PM measurements. This is done using the information in table 5.2 with Equation (5.1). For day 1 in year 1, the current extinction coefficient is:

b_{ext} = (2.2*3.82*1.804) + (4.8*2.75*0.201) + (2.4*3.82*0.995) + (5.1*2.75*0.055) + (2.8*2.567) + (6.1*0.457) + (10*0.345) + (1*0.106) + (1.7*3.91*0.214) + (0.6*+ 1.334) + 12

b_{ext} = 55.461 Mm^{-1}

Then convert extinction into deciviews:

dv = 10 * ln (55.461/10) = 17.131 dv

Base year extinction coefficients and deciviews for the remaining 9 days with monitored data in year 1 are calculated in a similar manner. The days are then ranked. The day with the highest impairment is given a rank of "1." The results of these calculations are displayed in the table 5.3 below. Based on these rankings, days 4 and 5 comprise the 20% most impaired. Days 2 and 8 comprise the 20% clearest days.[94]

[94] Note that this is an abbreviated example. The actual IMPROVE sampling schedule collects data every third day. Therefore, with a complete set of data, there will be ~121 samples per year at each site. Both the 20% most impaired days and 20% clearest days will be comprised of an average of ~24 sample days.

Table 5.3 Example observed IMPROVE extinction, deciviews, and rank at a Class I area

Day	Date	Rayleigh (Mm^{-1})	SO4 (Mm^{-1})	NO3 (Mm^{-1})	OM (Mm^{-1})	EC (Mm^{-1})	Soil (Mm^{-1})	CM (Mm^{-1})	Sea Salt (Mm^{-1})	B_{ext} [base period] (Mm^{-1})	Deciviews	Rank
1	1/7	12	17.809	9.897	9.975	3.447	0.106	0.801	1.425	55.461	17.131	5
2	2/24	12	17.777	3.621	3.195	1.500	0.058	1.203	0.891	40.244	13.924	9
3	4/15	12	23.049	11.139	7.702	2.411	0.589	3.557	2.231	62.678	18.354	3
4	6/20	12	43.421	4.905	7.967	2.815	0.367	2.129	0.857	74.460	20.077	1
5	7/14	12	27.743	4.327	12.249	2.969	0.343	3.751	1.118	64.499	18.641	2
6	8/10	12	36.711	1.687	5.467	2.680	0.134	1.194	0.187	60.061	17.928	4
7	8/28	12	23.369	2.351	5.481	1.624	0.190	1.512	1.199	47.726	15.629	7
8	9/18	12	18.556	4.546	3.117	1.234	0.112	2.328	5.473	47.366	15.553	8
9	10/21	12	15.695	1.577	3.811	0.943	0.218	1.198	0.607	36.048	12.823	10
10	12/14	12	19.267	8.817	4.418	2.475	0.170	1.248	0.328	48.723	15.836	6

Step 2. Calculate the average base year deciviews for the 20% most impaired days and 20% clearest days.

For year 1, mean deciview value for 20% most impaired days = (20.077 + 18.641) / 2 = 19.359 dv,
and mean deciview value for the 20% clearest days = (12.823 + 13.924) / 2 = 13.374 dv

Mean deciview values for the 20% most impaired and 20% clearest days for years 2-5 are provided in table 5.4.

Table 5.4 Example mean worst days visibility and best days visibility at a Class I area

Year	Mean $dv_{current}$ 20% Most Anthropogenically Impaired Days	Mean $dv_{current}$ 20% Clearest Days
1	19.35	13.37
2	20.32	12.54
3	19.21	11.78
4	18.93	12.32
5	18.34	12.91

The average mean base period visibility for the 20% most impaired and for the 20% clearest days is obtained by taking the arithmetic mean of these days for the 5 years. Thus, the 5-year mean of the average visibility for the 20% most impaired days is given by

$dv_{base\ period}$ = (19.35 + 20.32 + 19.21 + 18.93 + 18.34) / 5 = **19.23 dv**

The 5-year mean of the average visibility for the 20% clearest days is

$dv_{base\ period}$ = (13.37 + 12.54 + 11.78 + 12.32 + 12.91) / 5 = **12.58 dv**

Step 3. Apply a model to develop component specific RRF's for SO4, NO3, OC, EC, Soil and CM.

Tables 5.5 and 5.6 show the procedure for calculating component-specific relative response factors using an air quality model. The example shows the recommended calculation of RRFs for the 20% most impaired days in the year modeled (the abbreviated example assumes that the 20% most impaired days is represented by only 5 modeled days). The same calculation is repeated for the clearest days.

Table 5.5 Base year modeled species concentrations on the 20% most impaired days (in µg/m3)

Modeled Output	SO_4	NO_3	OC	EC	Soil	CM
Day 1	3.13	1.02	3.56	0.87	0.32	5.43
Day 2	5.21	3.11	4.67	1.23	0.34	4.68
Day 3	4.56	0.59	6.32	1.45	0.87	3.58
Day 4	5.51	1.67	4.56	0.54	1.07	4.67
Day 5	3.99	0.57	4.12	0.69	1.01	5.21
Mean Base Concentration	**4.48**	**1.39**	**4.65**	**0.96**	**0.72**	**4.71**

Table 5.6 Future year modeled species concentrations on 20% most anthropogenically impaired days (in µg/m3)

Modeled Output	SO_4	NO_3	OC	EC	Soil	CM
Day 1	2.45	0.91	3.54	0.82	0.36	5.51
Day 2	3.98	2.98	4.62	1.15	0.37	4.81
Day 3	3.56	0.50	6.30	1.32	0.92	3.76
Day 4	4.12	1.42	4.51	0.46	1.10	4.76
Day 5	2.87	0.39	4.07	0.61	1.08	5.34
Mean Future Concentration	**3.40**	**1.24**	**4.61**	**0.87**	**0.77**	**4.84**

Table 5.7 Component specific RRFs for the 20% most impaired days

Most Impaired days RRF	SO_4	NO_3	OC	EC	Soil	CM
RRF (mean future/mean base)	0.758	0.891	0.992	0.912	1.061	1.026

Step 4. Multiply the relative response factors times the measured daily species concentration data during the base period to compute future daily species concentrations.

In year 1, we previously identified days 4 and 5 as those included in the 20% most impaired days (i.e., see Step 1). Similarly, days 2 and 8 are the 20% clearest days (see Table 5.3). In this step, we estimate future concentrations for components of $PM_{2.5}$ and for CM for these two sets of days. This is done using information shown in tables presented in Steps 1 and 3 as well as the best days RRFs given in table 5.8 below:

Table 5.8 Component specific RRFs for the 20% clearest days

Clearest days RRF	SO_4	NO_3	OC	EC	Soil	CM
RRF (mean future/mean base)	0.780	0.752	0.956	0.768	1.022	1.043

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Most Anthropogenically Impaired Days

Day 4: $[SO_4]_{future} = (RRF)_{SO4}\ [SO_4]_{base\ period} = (0.758)\ [4.580] = 3.472\ \mu g/m^3$
$[NO_3]_{future} = (0.891)\ [0.528] = 0.470\ \mu g/m^3$
$[OC]_{future} = (0.992)\ [2.482] = 2.462\ \mu g/m^3$
$[EC]_{future} = (0.912)\ [0.282] = 0.257\ \mu g/m^3$
$[Soil]_{future} = (1.061)\ [0.367] = 0.389\ \mu g/m^3$
$[CM]_{future} = (1.026)\ [3.549] = 3.641\ \mu g/m^3$
$[Salt]_{future} = (1.00)\ [0.132] = 0.132\ \mu g/m^3$

Day 5: $[SO_4]_{future} = (0.758)\ [2.742] = 2.079\ \mu g/m^3$
$[NO_3]_{future} = (0.891)\ [0.416] = 0.371\ \mu g/m^3$
$[OC]_{future} = (0.992)\ [3.608] = 3.578\ \mu g/m^3$
$[EC]_{future} = (0.912)\ [0.297] = 0.271\ \mu g/m^3$
$[Soil]_{future} = (1.061)\ [0.343] = 0.364\ \mu g/m^3$
$[CM]_{future} = (1.026)\ [6.252] = 6.414\ \mu g/m^3$
$[Salt]_{future} = (1.00)\ [0.157] = 0.157\ \mu g/m^3$

Clearest Days

Day 2: $[SO_4]_{future} = (0.780)\ [2.290] = 1.786\ \mu g/m^3$
$[NO_3]_{future} = (0.752)\ [0.453] = 0.341\ \mu g/m^3$
$[OC]_{future} = (0.956)\ [1.073] = 1.026\ \mu g/m^3$
$[EC]_{future} = (0.768)\ [0.150] = 0.115\ \mu g/m^3$
$[Soil]_{future} = (1.022)\ [0.058] = 0.059\ \mu g/m^3$
$[CM]_{future} = (1.043)\ [2.004] = 2.090\ \mu g/m^3$
$[Salt]_{future} = (1.00)\ [0.150] = 0.150\ \mu g/m^3$

Day 8: $[SO_4]_{future} = (0.780)\ [1.759] = 1.372\ \mu g/m^3$
$[NO_3]_{future} = (0.752)\ [0.409] = 0.308\ \mu g/m^3$
$[OC]_{future} = (0.956)\ [1.049] = 1.003\ \mu g/m^3$
$[EC]_{future} = (0.768)\ [0.123] = 0.094\ \mu g/m^3$
$[Soil]_{future} = (1.022)\ [0.112] = 0.114\ \mu g/m^3$
$[CM]_{future} = (1.043)\ [3.880] = 4.047\ \mu g/m^3$
$[Salt]_{future} = (1.00)\ [0.725] = 0.725\ \mu g/m^3$

Similar calculations (using the same model derived component specific RRFs) are performed for each of the most impaired days and clearest days in each of the other 4 years in the base

period.[95]

Step 5. Using the results in Step 4, calculate the future year extinction coefficients for each of the 20% most impaired days and each of the 20% clearest days in each of the 5 base years.

Using future PM components obtained in Step 4, we can estimate future daily total b_{ext}.

For year 1

Most Impaired Days

Day 4: b_{ext} = (2.2*3.82*2.869) + (4.8*2.73*0.603) + (2.4*3.82*0.459) + (5.1*2.73*0.011) + (2.8*2.159) + (6.1*0.303) + (10*0.257) + (1*0.389) + (1.7*3.91*0.132) + (0.6*3.641) + 12 = 62.288 Mm^{-1}

Day 5: b_{ext} =(2.2*4.29*1.863) + (4.8*3.00*0.216) + (2.4*4.29*0.364) + (5.1*3.00*0.007) + (2.8*2.938) + (6.1*0.640) + (10*0.271) + (1*0.364) + (1.7*4.20*0.157) + (0.6*6.414) + 12 = 56.722 Mm^{-1}

Clearest Days

Day 2: b_{ext} = (2.2*3.29*1.627) + (4.8*2.46*0.160) + (2.4*3.29*0.335) + (5.1*2.46*0.006) + (2.8*0.973) + (6.1*0.053) + (10*0.115) + (1*0.059) + (1.7*3.49*0.150) + (0.6*2.090) + 12 = 34.786 Mm^{-1}

Day 8: b_{ext} = (2.2*4.59*1.278) + (4.8*3.17*0.094) + (2.4*4.59*0.303) + (5.1*3.17*0.005) + (2.8*953) + (6.1*0.050) + (10*0.094) + (1*0.114) + (1.7*4.44*0.725) + (0.6*4.047) + 12 = 41.682Mm^{-1}

Step 6. Use the daily total b_{ext} values from step 5 to calculate future mean deciview values for the 20% most impaired days and the 20% clearest days.

Calculate daily deciview values (from total daily extinction) and then compute the future mean

[95] Unless multiple meteorological years are being modeled, the same mean RRFs (for each component) are applied to the concentrations on all of the most impaired days for each of the 5 years of data. The mean RRFs are derived from the modeled days. A separate set of RRFs are derived (in the same manner) for the clearest days.

deciviews for the 20% most impaired days and the 20% clearest days for each year. Then average the 5 years together to get the final future mean deciview value for each set of days.

For Year 1

Most Impaired Days

Day 4: 62.288 Mm^{-1} = 10* ln (62.288/10) = 18.291 dv
Day 5: 56.722 Mm^{-1} = 10* ln (56.722/10) = 17.355 dv

Future mean visibility on most anthropogenically impaired days = (18.291 + 17.355) / 2 = 17.82 dv

Clearest Days

Day 2: 34.786 Mm^{-1} = 10* ln (34.786/10) = 12.466 dv
Day 8: 41.682 Mm^{-1} = 10* ln (41.682/10) = 14.274 dv

Future mean visibility on clearest days = (12.466 + 14.274) / 2 = 13.37 dv

Similar calculations are performed for previously selected 20% most impaired days and the 20% clearest days in each of years 2-5. Assume these other calculations yield the following estimates for future mean dv on these sets of days.

Table 5.9 Future year mean deciviews on the 20% most impaired days and the 20% clearest days for each of the 5 years

Year	Future Mean dv on 20% Most Impaired Days	Future Mean dv on 20% Clearest Days
1	17.82	13.37
2	18.17	12.45
3	16.78	12.91
4	18.65	11.52
5	18.21	12.31

Using results in table 5.9, we see that the estimated future average mean visibility for the most impaired days is

dv_{future} = (17.82 + 18.17 + 16.78 + 18.65 + 18.21) / 5 = **17.92 dv**

The estimated future average mean visibility for the clearest days is

dv_{future} = (13.37 + 12.45 + 12.91 + 11.52 + 12.31) / 5 = **12.51 dv**

The most impaired days result generated in step 6 can then be compared to the point on the Class I area-specific glidepath for the end of the implementation period. The most impaired days result is also compared to the baseline most impaired days to ensure that there has been improvement relative to the baseline period. The future year clearest days result is compared to the baseline (2000-2004) clearest days to ensure that visibility on the best days is not forecast to degrade relative to the same period.

This information is used to determine the predicted improvement in visibility that will result from implementation of an emissions strategy. It cannot itself determine the necessary content of the long-term strategy. See the Regional Haze Rule and related guidance documents for more information on the reasonable progress requirements.

5.4 How Do I Select Appropriate Inputs For Developing RPGs?

In section 5.3, we described the recommended regional modeling analysis to develop RPGs and to use them to evaluate progress relative to the glidepath and the baseline period. An important part of the analysis requires using component-specific RRFs, obtained with models, to estimate future concentrations of these components and, subsequently, future visibility. In this subsection, we address more details concerning the calculation of visibility RRFs. Additionally, there are several assumptions inherent in the recommended RPG analysis; we identify these assumptions and comment on their underlying rationale. More specifically, we address seven issues:

1. How to estimate base period air quality in a Class I area without monitored data;
2. How to handle a base year without data or with a small sample size;
3. Use of the same days to estimate changes in visibility for the most anthropogenically impaired days and a different set of same days to estimate changes in visibility for the clearest days;
4. Which predictions to use to derive RRFs;

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5. How many and what kind of days to use to develop RRF values;
6. RRFs when modeled species concentration are very low; and
7. Alternative RRF calculations.

Estimating baseline and base period visibility in a Class I area without monitors

There are 156 officially designated Class I areas subject to the Regional Haze Rule and 110 IMPROVE sites in or near Class I areas. Therefore, 46 Class I areas do not have co-located IMPROVE monitors. EPA's Tracking Guidance recommends using IMPROVE data from a nearby site to represent the visibility at each Class I area that does not have ambient data. Table A-2 in Appendix A of the Tracking Guidance lists the recommended monthly f(rh) values[96] for each Class I area as well as the representative site for each Class area. The representative IMPROVE site data will be used to track regional haze progress for the Class I areas. Therefore, it follows that visibility improvement for tracking purposes should be predicted at the location of the IMPROVE monitor, not at the actual Class I area. For the purposes of deriving ambient data for modeling, we recommend following the same representative site assignments contained in the Tracking Guidance. In this way, the needed visibility values can be derived for each Class I area from the network of 110 IMPROVE sites.[97] Similarly, the modeling results should be extracted for the location of the representative monitor, not the actual location of the Class I area.[98]

Considering a year in the base period with little or no monitored particulate matter or missing data

The Tracking Guidance recommends calculating base period visibility values for sites with at least 3 out of 5 complete years of data. It further contains recommendations for determining if a year has complete data. In general, a site should have 50% data completeness in all quarters and meet a 75% completeness criteria for the full year. There should be no periods with more than 30 consecutive days without data. The Tracking Guidance assumes that all IMPROVE sites

[96] The f(rh) values in the Tracking Guidance were developed for the "original" IMPROVE algorithm and should not be used to calculate visibility using the "revised" IMPROVE algorithm.

[97] Bering Sea Wilderness (Alaska) is the only Class I area that has no IMPROVE monitor **and** no representative IMPROVE site. On-site IMPROVE or representative IMPROVE data can be found for the other 155 Class I areas.

[98] There may be other reasons to calculate visibility improvement at the actual Class I area. The SMAT provides options for calculating visibility changes at both the Class I area grid cell center and at the representative IMPROVE monitoring site. It may be informative to compare model response at the representative IMPROVE site versus the grid cell center of the Class I area. Large differences in the model response may indicate that the "representative" site may not adequately represent visibility at the Class I area or across the entire Class I area.

will have at least 3 complete years in the base period (which may or may not be true). The Tracking Guidance also contains procedures for filling in missing data.

There are several data completeness issues that may cause problems within the visibility modeling analysis. First, a site may have less than 3 years of complete data. It is possible to calculate visibility improvement based on as little as 1 year of ambient data. Additionally, the IMPROVE program has procedures to utilize substituted and/or patched data to help minimize data incompleteness. States should work with their EPA Regional office and Federal Land Managers to determine how to estimate baseline visibility for these area(s).

Another issue that is a more specific problem for modeling analyses occurs when data is missing during the meteorological time period that was modeled. It is likely that most air agencies will only be modeling a single year of meteorology and it is possible that the ambient data at one or more Class I areas is incomplete during that year. Without ambient data, it is impossible to identify the 20% most anthropogenically impaired days and 20% clearest days, which are used to calculate modeled RRFs.

Again, if this occurs, states should work with their Regional office and Federal Land Managers to determine the best way to calculate visibility on these days. Potential options are to utilize substituted and/or patched data, data from another nearby IMPROVE site, nearby data from a different ambient data network, or interpolate ambient data to the site.

Using a constant sample of days to estimate base period and future visibility

For a typical Class I area, there will be about 120 days per year having measurements needed to estimate $(dv)_{\text{base period}}$ with Equation (5.1). Thus, there should be about 24 most anthropogenically impaired and 24 clearest days for each of the 5 years in the base period. It is conceivable that the identity of these days could change if emissions were altered to reflect net effects of controls and growth. The recommended test described in section 4.8 assumes that the identity of the most impaired and clearest days remains unchanged. This is done primarily to avoid having to perform iterative analyses to identify future most impaired and clearest visibility days and to keep the test relatively simple and more readily understood. This assumption could cause improvement in visibility to be overestimated for the most anthropogenically impaired days and could also cause the test to overestimate the difficulty in preventing deterioration of visibility on the clearest days. However, for the reasons described below, we do not believe the effects of this assumption are substantial.

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It is unlikely that there would be any wholesale change in the identity of most anthropogenically impaired or clearest days with future versus base year emissions. Analyses performed by Meyer, et al. (1997) have shown that the predicted ranked severity of high ozone days is largely unaffected by simulated controls and growth (i.e., highest days tend to remain the highest days after the effects of growth and controls are simulated). There is no reason to expect a different outcome for other secondary pollutants. If there are differences, we would expect these to occur near the borderline between the most impaired days and more moderate days.

Because the visibility analysis relies on *mean* visibility values on 20 or more most impaired visibility days and most of these days are unlikely to change, we would expect little difference in the outcome of the analysis. Further, because of the shape of the distribution of daily extinction coefficients, the mean of the most impaired days is often more heavily influenced by the very most impaired days rather than those on the borderline between 20% most impaired and more moderate light extinction. There could be differences in some of the clearest visibility days corresponding with pre- and post-control emissions. However, because the differences in concentrations of particulate matter on such days are likely to be relatively low, differences in the computed mean visibility for clearest days are likely to be small. It should be noted that any resulting difference in the projection of RPGs for clearest days would likely be in the direction of it being more difficult to pass the no degradation test compared to the baseline 2000-2004 period, in that some of the future days selected may be higher deciview-valued than they ought to be. If our recommended procedure leads to suspected problems in the outcome of a test, an air agency may wish to perform a more rigorous version of the analysis (in which the identity of pre-control and post-control days changes) as part of additional or supplemental analyses to support the RPG.

Selecting predictions to use in deriving RRF

RRFs should be developed for each Class I area. When a Class I area contains a monitoring site, the RRF estimates should be derived using predictions which are made "near" that site. For each day, daily average surface predictions of each component of PM made near a monitor should be estimated. Similar to the annual $PM_{2.5}$ NAAQS attainment test, nearby grid cells should be averaged. These nearby estimates should be spatially averaged to estimate a spatially representative daily concentration. For 12 km or finer resolution, we recommend averaging the modeled concentrations for a 3 x 3 array of grid cells surrounding the monitor. Note that for cells larger than 12 km on a side, no spatial averaging is necessary—states should just use the

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prediction in the cell containing the monitor. Spatially representative daily concentrations obtained for each modeled day with monitored data should then be temporally averaged. This final average should be used to compute the RRF. Thus, component-specific RRF values for a Class I area with a monitor are the ratio of the temporally averaged spatial mean of nearby concentrations predicted with future emissions to that predicted with base year emissions.

Selecting days to derive RRF values

It may often happen that a planning organization or a group of states decides to model the visibility impacts of a strategy for numerous Class I areas simultaneously. As we note in section 2.3.1, this may make it advisable to simulate (at least) a full year so that RRF values for each Class I area are based on a substantial number of observed best and worst days. For the most impaired days in the chosen year, the RRF for a component of PM should be estimated as the ratio of its modeled arithmetic mean predicted value on the 20% most impaired days with future emissions to that with base year emissions. Thus, in most cases, the RRF should reflect values averaged over ~ 24 most impaired days in that year. The same procedure is followed to derive RRFs over the ~24 clearest days in the year.

Since meteorological conditions and/or emissions may be markedly different on best visibility versus worst visibility days, we recommend calculation of a separate set of RRF values for the 20% clearest days. As with most impaired days, the preferred approach is to model an entire year and select an RRF value for concentrations averaged over the 20% clearest days for each Class I area. The RRF values are the ratios of the future to base year modeled averages. The appropriate RRF values should then be used in concert with each observed best day to estimate future concentrations for each component on each identified clearest day.

RRFs when modeled species concentrations are very low

In most cases, the RRFs derived for visibility components are either less than 1.0 or slightly more than 1.0. However, large RRFs (much greater than 1.0) can occur when the mean modeled concentration of a PM component on the 20% most impaired or clearest days is very small and the concentration of that component increases in the future year case. This most often occurs with the nitrate component. On both the 20% most impaired days and 20% clearest days, the modeled nitrate concentrations at Class I areas can be very small (i.e., < 0.01 µg/m3). These low modeled concentrations can sometimes increase in future year scenarios by orders of magnitude. This occurs most often in ammonia limited areas when sulfate concentrations are reduced in the future (due to SO_2 emissions reductions) causing nitrate

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increases due to an increase in available ammonia. Large RRFs should be closely examined to identify the cause of the issue. In many cases, large RRFs are caused by poor model performance (i.e., underpredicted base case nitrate concentrations) or instability in one or more model components (i.e., the nitrate partitioning model). One solution is to cap the RRF at 1.0 or close to 1 in cases where nitrate (or any other $PM_{2.5}$ component) increases in the future by an unrealistic amount due to very low modeled concentrations. Any adjustments to the default calculations should be documented and discussed with the appropriate EPA Regional office and the Federal Land Managers.

Alternative RRF calculations

The default analysis is relatively simple in that a single mean RRF is calculated for each PM component (separate RRFs on most impaired days and clearest days). A series of tests with more complicated methods has shown that: 1) the difference between various versions of the test are usually small and 2) each of the alternative tests has limitations in its applicability (Environ, 2005). Possible variations include the use of day specific RRFs, season (or quarter) specific RRFs, or climatologically based RRFs. In some cases, these more complicated techniques may provide different answers, but sometimes not. There are specific limitations with each of these alternatives noted in the indicated reference. We have chosen to keep the single mean RRF test as the default recommendation. States are encouraged to explore other methods for estimating RRFs if it is thought that the default recommendation is too simplistic to accurately capture the change in future visibility at any particular Class I area. The SIP analysis to develop RPGs should use the most appropriate method of projecting future concentrations for the characteristics of each Class I area.[99] Alternative methods should be discussed in the modeling protocol and discussed with the appropriate EPA Regional office and Federal Land Managers.

[99] In particular, issues may arise when dealing with visibility contributions from fires, coarse mass and fine soil (from wind-blown dust), and international transport (and possibly other issues). Each of these issues should be addressed in the modeling protocol and solutions should be discussed with the appropriate EPA Regional office(s) and Federal Land Managers on a case-by-case basis.

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6.0 How Can Additional Analyses Be Used to Support an Ozone or $PM_{2.5}$ Attainment Demonstration?

By definition, models are simplistic approximations of complex phenomena. The modeling analyses used to assess whether emission reduction measures will bring an individual area into attainment for the NAAQS contain many elements that are uncertain (e.g., emission projections, meteorological inputs, science formulations, etc.). These uncertain aspects of the analyses prevent definitive assessments of future attainment status. The confidence in the representativeness of the quantitative results from a modeled attainment test should be a function of the degree to which the uncertainties in the analysis were minimized. In general, by following the recommendations contained within this guidance document, EPA hopes that the attainment demonstrations will mitigate the uncertainty as much as possible given the current state of modeling inputs, procedures, and science. However, while air quality models represent the best tools for integrating emissions and meteorological information with atmospheric chemistry, and no single additional analysis can match the expected reliability of these models' results, EPA believes that all attainment demonstrations will be strengthened by additional analyses that can supplement the modeling to enhance the assessment of whether the planned emissions reductions are likely to result in attainment.

Supplemental evidence should accompany all model attainment demonstrations. Generally, those modeling analyses that show that attainment will be reached in the future with some margin of safety will need more limited supporting material. For other attainment cases in which the projected future design value is closer to the NAAQS, more rigorous supporting analyses should be completed. There may be some areas for which the supplemental evidence is persuasive enough to support a conclusion that the area can expect to achieve timely attainment despite failing the modeled attainment test, and other areas for which the modeled attainment test demonstrates attainment, but the supplemental evidence casts significant doubt on that result. This section of the guidance will discuss some specific information and additional analyses that can be used to supplement the model projections. Of particular interest are analyses that help determine whether the modeling-based projections are likely to provide a prediction of the *air quality improvement* that is likely to occur by the attainment date. Air agencies should review these supplemental analyses, in combination with the modeling analysis, in a "weight of evidence" assessment of whether each area is likely to achieve timely attainment. Again, it should be noted that no single supplemental analysis can serve as an adequate substitute for the air quality model. However, in aggregate, supplemental

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analyses may provide information which may provide further support for the outcome of the modeled test or may indicate a different outcome than the modeled test.

In considering the use of supplemental analyses, an important factor is the time (number of years) until the attainment date. In general, modeling and related analyses are the most useful corroborative analyses for areas with attainment dates which are more than several years in the future. In contrast, ambient data and emissions trends become more important (and hence model results become less important) the closer in time the area is to its attainment date. For example, if an area is only 1 or 2 years away from its attainment date, ambient data is in most cases the best predictor of likely air quality levels in the near future. However, this may not be true if there are large emissions reductions that are expected to occur in the near-term period. In that case, modeling is needed to estimate additional ozone and/or PM reductions that are likely to occur due to the emissions controls in the short term. Similarly, if the attainment date is 5 or 10 years or more in the future, appropriate modeling will likely be the most reliable indicator of future year ozone or PM levels. Emission changes over a relatively long period are likely to overwhelm the influence of ambient data trends and meteorological variability, making ambient data and emissions trends analyses relatively less important.

6.1 What Types of Additional Analyses Should Be Completed as Part of an Ozone or $PM_{2.5}$ Attainment Demonstration?

There are three basic types of analyses that are recommended to supplement the primary modeling analysis. They are:

1) Additional modeling analyses;

2) Analyses of trends in ambient air quality and emissions;

3) Additional emissions controls/reductions.

Note that air agencies are encouraged to consult with their EPA Regional office (and Federal Land Managers, when appropriate) in advance of initiating supplemental analyses to determine which additional analyses may be most appropriate for their particular area.

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6.1.1 Modeling Analyses

The relative attainment tests described in sections 4.2, 4.4, and 4.5 are the primary modeling tools used in an attainment demonstration. The application of a chemical transport grid model on a regional or local scale is the best tool available to judge the impacts of changes in future year emissions on concentrations. In addition to this "primary" modeling analysis, there are various other models, model applications, and tools that can be used to supplement the results of the modeled attainment test. These include, but are not limited to:

- Available regional or national scale modeling applications that are suitable[100] for the local area, for example, modeling in support of EPA rulemakings or regional, multi-jurisdictional organization modeling that may be available for the appropriate future year of interest. Modeling analyses may be available that used different models and/or inputs.

- Use of other appropriate local modeling that includes the nonattainment area of interest. This may include applications using alternative models and/or inputs or research-oriented analyses.

- Use of photochemical source apportionment, DDM, and/or process analysis modeling tools to help explain why attainment is (or is not) demonstrated.

- Use of multiple air quality models / model input data sets (e.g., multiple meteorological data sets, alternative chemical mechanisms or emissions inventories, etc.). Multiple model configurations can be used to estimate sensitivity and uncertainty of future year design value predictions.
    - For results to be most relevant to the way we recommend models be applied in attainment demonstrations, it is preferable that such procedures focus on the sensitivity of estimated RRFs and resulting projected design values to the variations in inputs and/or model formulations.

- Application of the attainment test with alternative procedures compared to the default recommendations in sections 4.2, 4.4, and 4.5 of this guidance. Any alternate approaches

[100] The resolution, emissions, meteorology, and other model inputs should be evaluated for applicability to the local nonattainment area. Additionally, model performance for the local nonattainment area should be examined before determining whether the regional model results are suitable for use in the local attainment demonstration.

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should be accompanied with a technical justification to explain why the approach is appropriate for the area in question and should be discussed with the appropriate EPA Regional office.

  - Alternative RRF calculations using non-default assumptions or more detailed temporal and spatial analysis of RRFs at one or more monitoring locations. If a sound technical argument can be made for why atypically high RRFs at any particular location are not reasonable, then these types of supplemental analyses would suggest that attainment is more likely to be achieved than the default modeling analysis alone would indicate.
  - Alternate base year design values that may differ from the 5-year weighted average value. Alternative values could include different methodologies for determining base year design values or removal of potential exceptional events data (see section 4.1.1).

- Use of dispersion models to address primary $PM_{2.5}$ contributions to $PM_{2.5}$ concentrations. In areas with large spatial gradients of primary $PM_{2.5}$, dispersion models are best suited to characterizing the change in primary $PM_{2.5}$ in the future. A local area analysis may be useful as a supplemental analysis (in either monitored or unmonitored areas, as appropriate) for areas that at least partially rely on local primary PM controls to reach attainment and did not otherwise perform and submit a local area analysis of part of the attainment demonstration.

The EPA has determined that the best approach to using models to demonstrate attainment of the NAAQS is to use a model in a relative mode. However, some types of "absolute" model results may be used to assess general progress towards attainment from the baseline inventory to the projected future inventory.[101] Example metrics include:

- Percent change in total amount of ozone or $PM_{2.5}$ >= NAAQS[102] within the nonattainment area
- Percent change in number of grid cells >= NAAQS within the nonattainment area
- Percent change in grid cell-hours (days) >= NAAQS within the nonattainment area
- Percent change in maximum modeled 8-hour ozone within the nonattainment area

[101] Care should be taken in interpreting absolute metrics if the model evaluation shows a large underprediction or overprediction of ozone or $PM_{2.5}$ concentrations. An underprediction of observed concentrations will make it artificially easy to show progress towards absolute attainment levels and an overprediction will make it artificially difficult to show progress towards attainment.

[102] For each of these metrics, the appropriate comparison to the level of the NAAQS is 70 ppb for 8-hour ozone; 35 µg/m3 for 24-hour $PM_{2.5}$; and 12 µg/m3 for annual $PM_{2.5}$.

While these metrics can be used to estimate the magnitude, frequency, and relative amount of ozone or $PM_{2.5}$ reductions from any given future emissions scenario, there are no threshold quantities of these metrics that can directly translate to an attainment determination. Generally, a large reduction in the frequency, magnitude, and relative amount of 8-hour ozone nonattainment (i.e., >= 71 ppb) or $PM_{2.5}$ nonattainment (24-hour and/or annual) is consistent with a conclusion that a proposed strategy would meet the NAAQS. In the context of a weight of evidence determination, these metrics could be used to suggest that a particular location may be "stiff" or relatively unresponsive to emissions controls, while the rest of the modeling domain/nonattainment area is projected to experience widespread reductions.

6.1.2 Analyses and Trends in Ambient Air Quality and Emissions

Generally, air quality models are regarded as the most appropriate tools for assessing the expected impacts of a change in emissions. However, it may also be possible to evaluate progress towards attainment of the ozone or $PM_{2.5}$ NAAQS based on measured historical trends of air quality and emissions. It may be possible to develop a relationship between past emissions changes and historical and current air quality. Once the relationship between past/present emissions and air quality is established, a response to the expected emissions reductions from a particular control strategy can be estimated. There are several elements to this analysis that are difficult to quantify. First, in most cases, the ambient data trends are best assessed by normalizing to account for year-to-year meteorological variations. Second, one must have an accurate accounting of the year-to-year changes in actual emissions (NOx, VOC, and/or SO_2 and NH_3) for the given area and any surrounding areas whose emissions may impact local concentrations. Third, one must have a solid conceptual model of how ozone or $PM_{2.5}$ is formed in the local area (e.g., influence of meteorology, NOx-limited, ammonia limited, transport-influenced, etc.).

If available, meteorologically adjusted ozone and $PM_{2.5}$ concentrations can be used to establish air quality trends. There are several techniques that have been used to examine the influence of meteorology on air quality. Among them are (a) statistical modeling (U.S. EPA, 2005b); (b) filtering techniques (Rao, 1995; Flaum, 1996; Milanchus, 1998; and Hogrefe, 2000), (c) using a probability distribution of meteorological severity based on climatological data (Cox and Chu, 1993, 1996), and (d) using CART analysis to identify meteorological classes and selecting days from each year so that the underlying frequency of the identified meteorological classes remains the same (Deuel and Douglas, 1996). Most of this work has examined the relationship between ozone and meteorology. Only recently have analyses examined the relationship between meteorology and $PM_{2.5}$. Additionally, compared to $PM_{2.5}$, the established relationship

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between ozone and meteorological variables is generally stronger (higher r-square values). In the case of $PM_{2.5}$, the relationship between concentration and meteorology is complicated by the fact that $PM_{2.5}$ components experience high concentrations at different times of the year and for different reasons. This makes it more difficult to meteorologically adjust $PM_{2.5}$ concentrations.

If a meteorologically adjusted trend in ozone or $PM_{2.5}$ can be estimated, then the information can be used to establish a link between emissions and air quality trends. This is not always straightforward due to the multitude of emissions precursors that may lead to high ozone and $PM_{2.5}$ concentrations. A careful analysis of (meteorologically adjusted) air quality trends and emissions trends of each of the ozone and PM precursors (as well as primary PM) is needed to fully establish relationships. Detailed emissions information as well as a solid understanding of the conceptual model of ozone or $PM_{2.5}$ formation is needed. If a trend can be established based on past emissions changes and air quality changes, then future year predicted emissions levels can be used to extrapolate future air quality.

Meteorologically adjusted trends in ozone and/or $PM_{2.5}$ attempt to adjust observed concentrations to levels which would have been observed during average meteorological conditions (Camalier, 2007). This makes it easier to observe trends primarily due to emissions changes and also allows identification of years with above average or below average meteorologically conducive conditions. Identification of "extreme" meteorological conditions, which are not likely to re-occur in a particular design value period, can be used as part of a weight of evidence analysis. For example, the presence of one or more "extreme" (high concentration) meteorological years in either the base year period or the most recent design value period may make it appear that an area is farther away from attaining the NAAQS than would otherwise be the case if more typical meteorological conditions had occurred. It is important to note that 1 or more years of meteorological conditions which are not conducive to ozone formation will have the opposite effect. An area may appear to be on track to attain the NAAQS (or close to attaining) but, in reality, may need substantial additional emissions reductions in order to attain under average or above average meteorological conditions. Meteorological adjusted concentration and/or design value calculations can help explain both of these situations. More information on meteorologically adjusted ozone trends can be found here.

A simpler (and more uncertain) way to qualitatively assess progress toward attainment is to examine recently observed air quality and emissions trends. Downward trends in observed concentrations and in emissions (past and projected) are consistent with progress towards

attainment. Strength of the evidence produced by emissions and air quality trends is increased if an extensive monitoring network exists and if there is a strong, positive and demonstrable, correlation between past emissions reductions and current trends in ozone or $PM_{2.5}$. Until recently, EPA prepared annual air quality trends reports for all criteria pollutants. The latest trends report analyzes ambient data through 2017 and can be found here.

The appropriate weight given to trend analyses depends on several factors. Analyses that use more air quality data and apply a greater variety of trend parameters typically provide more credible results. More weight can be placed on the results if the procedure used to normalize the trend for meteorological differences explains much of the variability attributable to these differences. In addition, trend analysis is usually more reliable if the extrapolation (as applicable) does not extend very far into the future. Finally, trend analysis is most credible if the contemplated strategy is similar to a past strategy (e.g., both strategies focus on reducing sulfates for PM or NOx for ozone). For example, if a past strategy focused on reducing sulfates, but a future one envisions controlling OC, there is no guarantee that ambient OC will respond similarly to changes in past emissions.

In addition to ambient data trends, further analysis of ambient data can provide information on ozone production efficiency, evidence of transport and assist in the quality assurance of emissions inputs. In particular, photochemical assessment monitoring station (PAMS) data, special study data, research and non-routine ambient data (i.e., NOy, and VOC data) can provide insights into the ozone and/or $PM_{2.5}$ concentrations observed in the nonattainment area and can help assess the accuracy of the modeling results and control strategies that are being relied upon for attainment.

6.1.3 Additional Emissions Controls/Reductions

Models are used to predict the future expected concentrations of ozone and/or $PM_{2.5}$, based on modeled emissions changes between a base year and future year. It is expected that emission inventories are as accurate as possible and represent emissions changes (including growth and controls) that are expected to occur. However, there may be various emissions sources and/or controls that are difficult to accurately represent in the modeling analysis, and the effects of some emissions controls may be difficult to quantify. Additionally, there may be uncertainty in how emissions controls may be implemented either in a nonattainment area, or in upwind regions which may contribute ozone to the nonattainment area.

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The following are some of the types of control measures that may be appropriate to include in a weight of evidence demonstration:

- Measures that are difficult to quantify or may not be enforceable in the SIP. Examples include:
    - Energy efficiency or renewable energy (EE/RE) programs may be implemented statewide (and in fact may be enforceable). However, emissions reductions from such programs are hard to quantify and it may be difficult to assign reductions to particular utility sources. EPA has provided an "EE/RE Roadmap Manual." The roadmap includes a weight of evidence "pathway" for air agencies that want to acknowledge the emissions benefits and potential reductions from EE/RE measures, but are unable to accurately quantify the emissions reductions in their SIP.
    - Smart growth initiatives such as land use planning and transportation planning.
    - Truck stop electrification.
    - Emissions reductions from idling regulations which may not be quantified in the mobile emissions modeling.
- Voluntary measures
    - Air agencies may have implemented voluntary measures that are not enforceable and therefore are not included in the SIP. These could include measures such as "ozone action days," voluntary no burn days, telework programs, idling reduction initiatives, etc. Even though these programs may be voluntary, they can still lead to positive actions in the nonattainment area that can lead to lower emissions. Voluntary measures should be documented to the fullest extent possible, including estimates of emissions benefits, where possible.

- Regional/super-regional and/or national programs that may not have been accounted for in the attainment demonstration.
    - Federal measures which were not accounted for in the modeling because they were proposed and/or finalized after the state modeling was completed.
    - Upwind regional, state, and/or local measures which were not known or not able to be quantified in the attainment demonstration due to timing or lack of information.

6.2 Weight of Evidence Summary

A weight of evidence (WOE) determination may examine results from a diverse set of analyses, including the outcome of the primary attainment test, and attempts to summarize the results into an aggregate conclusion with respect to whether a chosen set of control measures are

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likely to result in an area attaining the NAAQS by the applicable attainment date, notwithstanding what the air quality modeling may suggest in isolation. The supplemental analyses discussed above can be part of a WOE determination, although the level of detail required in a WOE submittal will vary as a function of many elements of the model application (e.g., model performance, degree of residual nonattainment in the modeled attainment test, amount of uncertainty in the model and its inputs, etc.). Each WOE determination will be subject to area-specific conditions and data availability. Area-specific factors may also affect the types of analyses that are feasible for a specific nonattainment area, as well as the significance of each. Thus, decisions concerning which analyses to perform, and how much credence to give each, need to be made on a case-by-case basis by those implementing the modeling/analysis protocol. Air agencies are encouraged to consult with their EPA Regional office (and Federal Land Managers, when appropriate) in advance of initiating supplemental analyses to determine which additional analyses may be most appropriate for their particular area for potential use as part of a WOE evaluation.

The most useful supplemental analyses are those providing the best evidence as to how much air quality improvement can be expected as compared to the improvement projected by the air quality modeling analysis. Each analysis is weighed qualitatively, depending on: 1) the capacity of the analysis to address the adequacy of a strategy and 2) the technical credibility of the analysis. If the overall WOE produced by the combination of the primary modeling analysis and the various supplemental analyses supports the attainment hypothesis, then the air agency can demonstrate attainment of the NAAQS proposed control strategy. The end product of a WOE determination is a document which describes analyses performed, databases used, key assumptions and outcomes of each analysis, and why an air agency believes that the evidence, viewed as a whole, supports a conclusion that the area will, or will not, attain the NAAQS. In conclusion, the basic criteria required for an attainment demonstration based on weight of evidence are as follows:

1) A fully-evaluated, high-quality modeling analysis that projects future values that are close to the NAAQS.
2) A description and explanation of each of the individual supplemental analyses, preferably from multiple categories. Analyses that utilize well-established analytical procedures and are grounded with sufficient data should be weighted accordingly higher.
3) A written description as to why the full set of evidence leads to a conclusive determination regarding the future attainment status of the area that differs from the results of the modeled attainment test alone.

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7.0 What Role Should Additional and/or Supplemental Analyses Play in Regional Haze Modeling Demonstrations?

We believe additional and/or supplemental analyses can be a useful tool for air agencies when developing RPGs and applying them in the ways described in section 5. In this subsection, we note some potential supplemental analyses that may be used in this context.

7.1 Additional air quality modeling

Sensitivity tests can be performed to see if conclusions about trends in the 20% most anthropogenically impaired days and 20% clearest days are robust. One example of such an analysis is applying a model with and without a more finely resolved nested grid near source areas or near Class I areas. A purpose of this would be to see whether conclusions are affected by the degree of detail in which nearby sources are considered. A second example of an analysis would be to consider alternative future emissions (including lateral boundary conditions) and/or differing growth rate assumptions. This may be a particular concern for regional haze analyses because the emissions projection period is generally longer than for most ozone and $PM_{2.5}$ attainment demonstrations. Uncertainty in emissions and growth rates become more important as the projection period is lengthened.

If the outcomes of the several comparisons described in section 5.1 are similar using sensitivity tests, alternative models and/or alternative modeling approaches, this finding supports conclusions reached in the main analysis.

7.2 Review of trends

A review of trends generally involves a comparison, sometimes qualitative, between past trends in reconstructed visibility and estimated changes in emissions (e.g., mid ‘00’s to mid ‘10's). This information could be used to confirm that additional reductions of previously controlled emissions of a component or its precursors is likely to result in the predicted visibility improvement. It may also be used to see whether certain PM components are becoming increasingly more or less important sources of light extinction.

7.3 Other models and tools

Trajectory models may be useful for identifying the types of meteorological conditions most often corresponding to observed worst and best visibility in various Class I areas. This, in turn,

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may enable air agencies to draw inferences about the areas containing sources most likely to influence visibility in a Class I area on days with “poor” and “good” visibility. Grid model-based techniques such as DDM or source apportionment may also be useful in identifying areas and emissions sources most responsible for visibility impairment on the most anthropogenically impaired days and clearest days.

7.4 Refinements to the recommended visibility analysis

A state may consider refining the recommended modeling analysis in some manner. Refinements are best made if they are based on local observations/analyses which suggest that some of the underlying assumptions in the recommended assessment may not be applicable. We list some potential refinements that could be considered. The list is intended to illustrate types of additional analyses that could be performed.

- Use an alternative light extinction equation or an area-specific version.
- The 20% most anthropogenically impaired days conceptually will not include days with high impacts from fires or dust storms because anthropogenic impairment relative to natural conditions will be low on such days. However, the particular method initially applied to identify the most anthropogenically impaired days may not implement this concept perfectly at a particular Class I area. Available speciated data and other information may be reviewed to see whether the outcome of the visibility analysis is being influenced by including one or more days with extraordinary events (e.g., a major wildfire lasting a number of days or transported dust events). If convincing arguments can be made that the event is a “natural” one, changes in the initial approach to estimate daily anthropogenic versus natural light extinction should be discussed with the appropriate EPA Regional office and Federal Land Managers.
- Daily component specific RRFs can be examined to determine if one or more days are responding in a different way compared to the majority of the clearest or most impaired days. Determining why days may be more or less responsive to emissions controls may lead to conclusions regarding the suitability of particular days to be represented in the mean response. It may be appropriate, in some cases, to re-calculate mean RRFs with suspect days removed.
- Re-rank future estimated light extinction (i.e., b_{ext} values) for all days that have current measurements and re-compute mean future most impaired and clearest days visibility (i.e., do not assume that the identity of clearest days remains the same between the base year and the future year).

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7.5 Concerns about modeling the clearest days

In some parts of the U.S., concentrations of the components of PM used in visibility calculations may be very close to background levels on the clearest days. Measurements and model estimates may be subject to more relative uncertainty (i.e., lower signal to noise ratio) on days where observed concentrations of PM are very low (and light extinction is also low). The utility of a WOE determination is heightened in such cases. An air agency should see whether a model's inability to accurately predict one or more individual components of PM has a substantial effect on the extinction coefficient calculated with Equation (5.1). If it does, and diagnostic tests are unable to resolve a performance problem, an air agency may need to address the "no degradation" requirement for the clearest days in the particular Class I area(s) without using results from a grid model.

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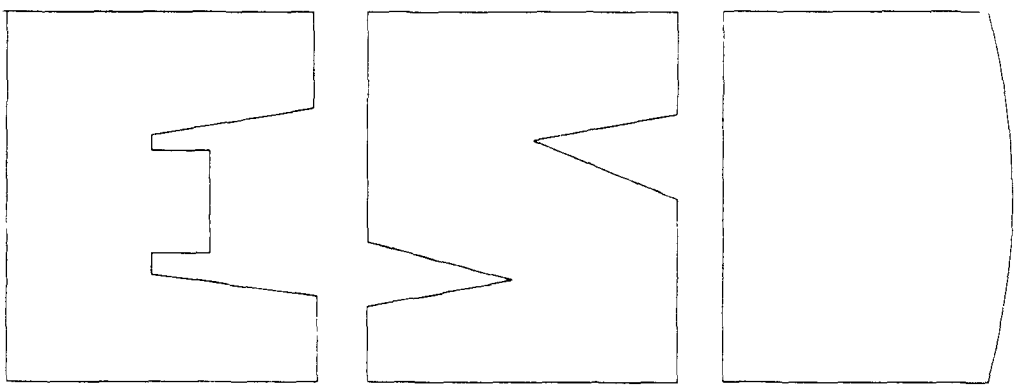
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Alternative Control Techniques Document -- NOx Emissions from Process Heaters (Revised)



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Alternative Control Techniques Document-- NO_x Emissions from Process Heaters
(Revised)

Emission Standards Division

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1.0 INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the [CAAA], the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit, or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Process heaters have been identified as a category with emission sources that emit more than 25 tons of nitrogen oxide (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from process heaters. Additional ACT documents are being developed for other stationary source categories.

The information in this ACT document was generated through literature searches and contacts with process heater control equipment vendors, engineering firms, chemical plants, and petroleum refineries. Chapter 2.0 presents a summary of the findings of this study. Chapter 3.0 presents information on process heater operation and industry applications. Chapter 4.0 contains a discussion of NO_x formation and uncontrolled process heater NO_x emission factors. Alternative control techniques and achievable controlled emission levels are included in

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Chapter 5.0. The cost and cost effectiveness of each control technique are presented in Chapter 6.0 Chapter 7.0 describes environmental and energy impacts associated with implementing the NO_x control techniques.

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2.0 SUMMARY

This chapter presents a summary of the information contained in this document. Section 2.1 presents a summary of NO_x formation and uncontrolled NO_x emissions. Section 2.2 presents a summary of available NO_x emission control techniques and achievable NO_x emission reductions. Section 2.3 presents a summary of the capital costs and cost effectiveness for these NO_x control techniques. Process heaters are direct fired heaters used primarily in the petroleum refining and petrochemical industries. Process fluids are heated to temperatures in excess of 204°C (400°F) in the radiative and convective sections of the heaters. Flue gas entering the convective section is usually in excess of 800°C (1500°F) for most process heaters.

Due to the broad spectrum of process heater designs and capacities, this study uses a limited number of model heaters to evaluate the available NO_x control techniques for process heaters. The model heaters and uncontrolled emission factors are introduced in Chapter 4. The model heaters and uncontrolled emission factors are based on a refinery data base, published literature and data. The performance of the control techniques applied to model heaters is presented in Chapter 5 and is based on published literature and data. Costs and cost effectiveness of the control techniques applied to the model heaters are presented in Chapter 6 and are based on published cost methodologies.

2.1 UNCONTROLLED NO_x EMISSIONS

Nitrogen oxides are produced by three different formation mechanisms: thermal, fuel, and prompt NO_x. Thermal NO_x is primarily temperature-dependent, and fuel NO_x is primarily

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dependent on the presence of fuel-bound nitrogen and the local oxygen concentration. Prompt NO_x is the least understood formation mechanism. Most combustion control techniques are designed to reduce thermal and/or fuel NO_x. Post combustion techniques reduce NO_x in the flue gas regardless of the formation mechanism.

Thermal NO_x formation increases rapidly at temperatures exceeding 1540°C (2800°F) and is the primary source of NO_x in natural gas- and refinery fuel gas-fired heaters. Refinery fuel gas firing generally yields higher thermal NO_x formation than natural gas firing due to the higher flame temperatures caused by the higher hydrogen content of the refinery fuel gas.

Fuel NO_x formation is minimal in heaters that fire natural gas and refinery fuel gas, which contain little or no fuel-bound nitrogen. Fuel NO_x represents a considerable fraction of the total NO_x emissions in heaters burning nitrogen-bearing fuels, such as distillate and residual oils.

Uncontrolled emission factors for the model heaters are presented in Table 2-1. The uncontrolled NO_x emission factors for natural gas-fired, low- and medium-temperature model heaters are 0.098 and 0.197 pounds per million British thermal units (lb/MMBtu) for the natural draft (ND) and mechanical draft (MD) heaters, respectively. The uncontrolled NO_x emission factors for the ND oil-fired model heaters are 0.200 and 0.420 lb/MMBtu for distillate and residual oil-firing, respectively. The distillate and residual oil-fired MD model heaters have uncontrolled NO_x emission factors of 0.320 and 0.540, respectively. The uncontrolled emission factors for the pyrolysis model heaters are 0.135 and 0.162 lb/MMBtu for the natural gas-fired and high-hydrogen fuel gas-fired heaters, respectively.

The uncontrolled emission factors for MD model heaters are greater than for ND model heaters because the MD model heaters have combustion air preheat, which increases thermal NO_x emissions. The oil-fired model heaters have higher thermal NO_x emissions than the natural gas-fired model heaters, primarily due to the higher flame temperature for oil firing. Residual oil

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TABLE 2-1. UNCONTROLLED EMISSION FACTORS FOR MODEL HEATERS

Model heater type	Uncontrolled emission factor, lb/MMBtu		
	Thermal NO_x	Fuel NO_x	Total NO_x[a]
ND, natural gas-fired[b]	0.098	N/A	0.098
MD, natural gas-fired[b]	0.197	N/A	0.197
ND, distillate oil-fired	0.140	0.060	0.200
ND, residual oil-fired	0.140	0.280	0.420
MD, distillate oil-fired	0.260	0.060	0.320
MD, residual oil-fired	0.260	0.280	0.540
ND, pyrolysis, natural gas-fired	0.135	N/A	0.104
ND, pyrolysis, high-hydrogen fuel gas-fired[c]	0.162[d]	N/A	0.140

[a]Total NO_x = Thermal NO_x + Fuel NO_x

[b]Heaters firing refinery fuel gas with up to 50 mole percent hydrogen can have up to 20 percent higher NO_x emissions than similar heaters firing natural gas.

[c]High-hydrogen fuel gas is fuel gas with 50 mole percent or greater hydrogen content.

[d]Calculated assuming approximately 50 mole percent hydrogen.

N/A = Not applicable.

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contains a greater content of fuel-bound nitrogen and therefore has higher fuel NO_x emissions than the distillate oil-fired heaters.

2.2 AVAILABLE NO_x EMISSION CONTROL TECHNIQUES

The following NO_x control techniques are currently used in industry: low-NO_x burners (LNB's), ultra-low NO_x burners (ULNB's), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). Also, LNB's are used in combination with flue gas recirculation (FGR), SNCR, and SCR.

Combustion modifications such as LNB, ULNB and FGR inhibit NO_x formation by controlling the combustion process. Staging techniques are usually used by LNB and ULNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB's create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean primary combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures. The secondary combustion zone is fuel-rich. Ultra-low-NO_x burners use staging techniques similar to staged-fuel LNB in addition to internal flue gas recirculation. Flue gas recirculation returns a portion of the flue gas to the combustion zone through ducting external to the firebox that reduces flame temperature and dilutes the combustion air supply with relatively inert flue gas.

Unlike combustion controls, SNCR and SCR do not reduce NO_x by inhibiting NO_x formation, but reduce NO_x in the flue gas. These techniques control NO_x by using a reactant that reduces NO_x to nitrogen (N_2) and water. The reactant, ammonia (NH_3) or urea for SNCR, and NH_3 for SCR, is injected into the flue gas stream. Temperature and residence time are the primary factors that influence the reduction reaction. Selective catalytic reduction uses a catalyst to facilitate the reaction.

The reduction efficiency of each control technique varies depending on the process heater application and design. The efficiencies for LNB, ULNB, and SCR are considered to be representative averages based on operating experience. Fuel NO_x

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reduction efficiencies and the reduction efficiencies for FGR, and SNCR are based on a Canadian Petroleum Products Institute report. Tables 2-2 and 2-3 present the reduction efficiencies for each NO_x control technique. The total effective reduction efficiencies for natural gas- and refinery fuel gas-fired heaters are shown in Table 2-2 and for low- and medium-temperature process heaters range from 50 percent for LNB to 88 percent for LNB plus SCR. The total effective percent reductions for pyrolysis furnaces are lower for control techniques that use LNB's or ULNB's compared to the low- and medium-temperature heaters, and range from 25 percent for LNB to 81 percent for LNB plus SCR. The total effective reduction efficiencies of the oil-fired heaters are shown in Table 2-3 and range from 27 percent for ND LNB on ND residual oil-fired heaters to 92 percent for MD LNB plus SCR on MD distillate oil-fired heaters. The total effective reduction efficiencies of the gas-fired heaters are the same for ND or MD operation. However, different reduction efficiencies for thermal and fuel NO_x emissions result in varying total effective reduction efficiencies for the oil-fired heaters.

2.3 CAPITAL COSTS AND COST EFFECTIVENESS

The capital costs and cost effectiveness for each of the NO_x control techniques discussed in Section 2.2 are presented in this section for the model heaters. Cost methodologies from reports published by the Canadian Petroleum Products Institute and the South Coast Air Quality Management District are used to estimate the capital and annual costs for the control techniques.

The cost of converting ND heaters to MD heaters is included in the cost analysis in which MD control techniques are used on ND model heaters. Natural draft-to-MD conversion is not considered a NO_x control technique and is usually performed to take advantage of thermal efficiency gains. These efficiency gains are site specific and are not included or quantified in this study. Therefore, the actual cost effectiveness of control

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TABLE 2-2. REDUCTION EFFICIENCIES FOR CONTROL TECHNIQUES APPLIED TO NATURAL GAS- AND REFINERY FUEL GAS-FIRED PROCESS HEATERS AND PYROLYSIS FURNACES

Control technique - low and medium temperature heaters	Total effective NO_x reduction,[a] percent
LNB	50
ULNB	75
SNCR	60
SCR	75
LNB + FGR	55
LNB + SNCR	80
LNB + SCR	88

Control technique - pyrolysis furnaces	Total effective NO_x reduction,[a] percent
LNB	25
ULNB	50
SNCR	60
SCR	75
LNB + FGR	55
LNB + SNCR	70
LNB + SCR	81

[a]Further discussion on the NO_x reduction efficiencies of each control technique is included in Chapter 5.

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TABLE 2-3. REDUCTION EFFICIENCIES FOR CONTROL TECHNIQUES APPLIED TO ND AND MD, DISTILLATE AND RESIDUAL OIL-FIRED PROCESS HEATERS

Draft and fuel type	Control technique	Total effective NO_x reduction,[a] percent
ND, distillate	(ND) LNB	40
	(MD) LNB	43
	(ND) ULNB	76
	(MD) ULNB	74
	SNCR[b]	60
	(MD) SCR	75
	(MD) LNB + FGR	43
	(ND) LNB + SNCR	76
	(MD) LNB + SNCR	77
	(MD) LNB + SCR	86
ND, residual	(ND) LNB	27
	(MD) LNB	33
	(ND) ULNB	77
	(MD) ULNB	73
	SNCR	60
	(MD) SCR	75
	(MD) LNB + FGR	28
	(ND) LNB + SNCR	71
	(MD) LNB + SNCR	73
	(MD) LNB + SCR	83
MD, distillate	(MD) LNB	45
	(MD) ULNB	74
	(MD) SNCR	60
	(MD) SCR	75
	(MD) LNB + FGR	48
	(MD) LNB + SNCR	78
	(MD) LNB + SCR	92
MD, residual	(MD) LNB	37
	(MD) ULNB	73
	(MD) SNCR	60
	(MD) SCR	75
	(MD) LNB + FGR	34
	(MD) LNB + SNCR	75
	(MD) LNB + SCR	91

[a]Further discussion on the NO_x reduction efficiencies of each control technique is included in Chapter 5.
[b]Reduction efficiencies for ND or MD SNCR are equal

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techniques that include ND-to-MD conversion may be lower than shown in this study.

Cost effectiveness of the control techniques, in $/ton of NO_x removed, is calculated as the total annual cost divided by the annual NO_x reduction, in tons, for each control technique applied to each model heater. Tables 2-4 through 2-8 present the cost effectiveness of these control techniques for the ND natural gas-fired, MD natural gas-fired, ND oil-fired, MD oil-fired, and ND pyrolysis model heaters, respectively. Burner control techniques generally have the lowest cost effectiveness, with SCR having the highest. Ultra-low-NO_x burner cost effectiveness is lower than LNB in all cases because the additional reduction efficiency more than offsets the additional cost. The cost effectiveness of SNCR is greater than that of LNB in most cases because of the higher capital and operating costs for SNCR. Low-NO_x burners plus FGR have higher cost effectiveness than SNCR in most cases. The capital cost for SNCR are comparable to LNB plus FGR, but the higher operating costs result in higher cost-effectiveness values for SNCR. The highest reduction efficiencies are achieved by SCR and LNB plus SCR, but these techniques also have the highest cost effectiveness due to the relatively high capital and annual costs for SCR.

The lowest cost effectiveness is achieved with ULNB's and the highest with SCR for each model heater. The range of cost effectiveness for each of the five types of model heaters at a capacity factor of 0.9 are (1) $981/ton to $16,200/ton for the ND natural gas-fired heaters, (2) $813/ton to $10,600/ton for the MD natural gas-fired heaters, (3) $419/ton to $6,490/ton for the ND oil-fired heaters, (4) $245/ton to $4,160/ton for the MD oil-fired heaters, and (5) $1,790/ton to $14,100/ton for the ND pyrolysis heaters. Figures 2-1 through 2-5 graphically present the reduction efficiencies, capital cost, and cost effectiveness for the model heaters.

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TABLE 2-4. MODEL HEATERS: NO_x EMISSION REDUCTIONS, CAPITAL COSTS, AND COST EFFECTIVENESS FOR ND, NATURAL GAS-FIRED LOW- AND MEDIUM-TEMPERATURE HEATERS

Model heater capacity, MMBtu/hr	Uncontrolled NO_x emission factor, lb/MMBtu	NO_x control technique	Total effective NO_x reduction, percent	NO_x reduction, tons/yr[a,b]	Capital cost, $	Cost effectiveness, $/ton @ capacity factors:[c]		
						0.1	0.5	0.9
17	0.098	(ND) LNB	50	3.65	58,200	25,400	5,070	2,820
	0.197	(MD) LNB	50	7.33	191,000	41,400	8,280	4,600
	0.098	(ND) ULNB	75	5.47	62,500	18,200	3,630	2,020
	0.197	(MD) ULNB	75	1.10	249,000	36,000	7,200	4,000
	0.098	(ND) SNCR	60	4.38	155,000	56,700	11,800	6,770
	0.197	(MD) SNCR	60	8.80	258,000	47,100	9,760	5,610
	0.197	(MD) SCR	75	1.10	951,000	141,000	28,700	16,200
	0.197	(MD) LNB + FGR	55	8.07	253,000	50,000	10,100	5,710
	0.098	(ND) LNB + SNCR	80	5.84	213,000	58,400	12,000	6,840
	0.197	(MD) LNB + SNCR	80	1.17	346,000	47,100	9,690	5,530
	0.197	(MD) LNB + SCR	88	12.8	995,000	132,000	26,700	15,100
36	0.098	(ND) LNB	50	7.73	92,600	19,100	3,810	2,120
	0.197	(MD) LNB	50	15.5	302,000	30,900	6,170	3,430
	0.098	(ND) ULNB	75	11.6	96,900	13,300	2,660	1,480
	0.197	(MD) ULNB	75	23.3	308,000	21,000	4,200	2,330
	0.098	(ND) SNCR	60	9.27	243,000	42,100	8,850	5,150
	0.197	(MD) SNCR	60	18.6	405,000	35,000	7,260	4,180
	0.197	(MD) SCR	75	23.3	1,500,000	106,000	21,700	12,300
	0.197	(MD) LNB + FGR	55	17.1	399,000	37,300	7,590	4,290
	0.098	(ND) LNB + SNCR	80	12.4	335,000	43,500	9,020	5,190
	0.197	(MD) LNB + SNCR	80	24.9	544,000	35,100	7,280	4,190
	0.197	(MD) LNB + SCR	88	27.2	1,570,000	99,200	20,200	11,400

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TABLE 2-4. (continued)

Model heater capacity, MMBtu/hr	Uncontrolled NO_x emission factor, lb/MMBtu	NO_x control technique	Total effective NO_x reduction, percent	NO_x reduction, tons/yr[a,b]	Capital cost, $	Cost effectiveness, $/ton @ capacity factors:[c]		
						0.1	0.5	0.9
77	0.098	(ND) LNB	50	16.5	133,000	12,800	2,570	1,430
	0.197	(MD) LNB	50	33.2	457,000	21,900	4,370	2,430
	0.098	(ND) ULNB	75	24.8	138,000	8,830	1,770	981
	0.197	(MD) ULNB	75	49.8	463,000	14,800	2,950	1,640
	0.098	(ND) SNCR	60	19.8	383,000	31,200	6,670	3,940
	0.197	(MD) SNCR	60	39.9	639,000	25,900	5,450	3,170
	0.197	(MD) SCR	75	49.8	2,390,000	80,100	16,400	9,370
	0.197	(MD) LNB + FGR	55	36.5	610,000	26,700	5,480	3,120
	0.098	(ND) LNB + SNCR	80	26.4	516,000	31,400	6,610	3,850
	0.197	(MD) LNB + SNCR	80	53.2	839,000	25,400	5,340	3,119
	0.197	(MD) LNB + SCR	88	58.1	2,480,000	74,100	15,200	8,640
121	0.098	(ND) LNB	50	26.0	232,000	14,200	2,840	1,580
	0.197	(MD) LNB	50	52.2	685,000	20,900	4,170	2,320
	0.098	(ND) ULNB	75	39.0	237,000	9,660	1,930	1,070
	0.197	(MD) ULNB	75	78.3	691,000	14,000	2,810	1,560
	0.098	(ND) SNCR	60	31.2	502,000	26,100	5,660	3,380
	0.197	(MD) SNCR	60	62.6	838,000	21,700	4,610	2,710
	0.197	(MD) SCR	75	78.3	3,160,000	67,900	14,000	8,020
	0.197	(MD) LNB + FGR	55	57.4	887,000	24,700	5,080	2,890
	0.098	(ND) LNB + SNCR	80	41.6	734,000	28,500	6,020	3,520
	0.197	(MD) LNB + SNCR	80	83.5	1,190,000	22,900	4,840	2,830
	0.197	(MD) LNB + SCR	88	91.4	3,370,000	64,300	13,200	7,550

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TABLE 2-4. (continued)

Model heater capacity, MMBtu/hr	Uncontrolled NO_x emission factor, lb/MMBtu	NO_x control technique	Total effective NO_x reduction, percent	NO_x reduction, tons/yr[a,b]	Capital cost, $	Cost effectiveness, $/ton @ capacity factors:[c]		
						0.1	0.5	0.9
186	0.098	(ND) LNB	50	39.9	346,000	13,800	2,760	1,530
	0.197	(MD) LNB	50	80.2	955,000	18,900	3,780	2,100
	0.098	(ND) ULNB	75	59.9	351,000	9,310	1,860	1,030
	0.197	(MD) ULNB	75	12.0	961,000	12,700	2,540	1,410
	0.098	(ND) SNCR	60	47.9	650,000	22,100	4,850	2,930
	0.197	(MD) SNCR	60	96.3	1,090,000	18,300	3,930	2,330
	0.197	(MD) SCR	75	120	4,130,000	58,200	12,100	6,940
	0.197	(MD) LNB + FGR	55	88.3	1,220,000	22,100	4,550	2,600
	0.098	(ND) LNB + SNCR	80	63.9	996,000	25,200	5,360	3,150
	0.197	(MD) LNB + SNCR	80	128	1,600,000	20,200	4,300	2,530
	0.197	(MD) LNB + SCR	88	140	4,460,000	55,700	11,500	6,600

[a] NO_x reductions = Uncontrolled emission factor (lb/MMBtu) * Capacity(MMBtu/hr) * Effective reduction (%) * 1 ton/2,000lb * 8,760 hr/yr * Capacity factor.

[b] NO_x reductions in this column are calculated at a capacity factors of 1.0. To obtain reductions corresponding to particular capacity factors, substitute the desired capacity factor into the above equation.

[c] Cost effectiveness is calculated by dividing the total annual cost (TAC) by the NO_x reductions. Refer to Chapter 6 for the TAC.

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TABLE 2-5. MODEL HEATERS: NO_x EMISSION REDUCTIONS, CAPITAL COSTS, AND COST EFFECTIVENESS FOR MD, NATURAL GAS-FIRED, LOW- AND MEDIUM-TEMPERATURE HEATERS

Model heater capacity, MMBtu/hr	Uncontrolled NO_x emission factor, lb/MMBtu	NO_x control technique	Total effective NO_x reduction, percent	NO_x reduction, tons/yr[a,b]	Capital cost, $	Cost effectiveness, $/ton @ capacity factors:[c]		
						0.1	0.5	0.9
40	0.197	LNB	50	17.3	130,000	12,000	2,390	1,330
		ULNB	75	25.9	136,000	8,380	1,680	931
		SNCR	60	20.7	258,000	20,300	4,400	2,640
		SCR	75	25.9	1,270,000	91,500	18,700	10,600
		LNB + FGR	55	19.0	234,000	19,700	4,080	2,340
		LNB + SNCR	80	27.6	388,000	22,700	4,790	2,810
		LNB + SCR	88	30.2	1,400,000	85,200	17,400	9,880
77	0.197	LNB	50	33.2	282,000	13,500	2,700	1,500
		ULNB	75	49.8	288,000	9,200	1,840	1,020
		SNCR	60	39.9	383,000	15,700	3,480	2,130
		SCR	75	49.8	1,900,000	71,900	14,800	8,460
		LNB + FGR	55	36.5	436,000	19,100	3,960	2,270
		LNB + SNCR	80	53.2	665,000	20,200	4,300	2,530
		LNB + SCR	88	58.1	2,180,000	69,300	14,200	8,110
114	0.197	LNB	50	49.2	507,000	16,400	3,280	1,820
		ULNB	75	73.8	514,000	11,100	2,210	1,230
		SNCR	60	59.0	484,000	13,500	3,040	1,880
		SCR	75	73.8	2,420,000	62,800	12,900	7,410
		LNB + FGR	55	54.1	702,000	20,800	4,290	2,460
		LNB + SNCR	80	78.7	992,000	20,400	4,330	2,550
		LNB + SCR	88	86.1	2,930,000	62,800	12,900	7,390

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TABLE 2-5. (continued)

Model heater capacity, MMBtu/hr	Uncontrolled NO_x emission factor, lb/MMBtu	NO_x control technique	Total effective NO_x reduction, percent	NO_x reduction, tons/yr[a,b]	Capital cost, $	Cost effectiveness, $/ton @ capacity factors:[c]		
						0.1	0.5	0.9
174	0.197	LNB	50	75.1	541,000	11,500	2,290	1,270
		ULNB	75	113	548,000	7,730	1,550	859
		SNCR	60	90.1	624,000	11,400	2,630	1,660
		SCR	75	113	3,150,000	53,700	11,200	6,440
		LNB + FGR	55	82.6	792,000	15,400	3,220	1,860
		LNB + SNCR	80	120	1,170,000	15,700	3,410	2,040
		LNB + SCR	88	131	3,700,000	52,600	10,900	6,250
263	0.197	LNB	50	113	777,000	10,900	2,180	1,210
		ULNB	75	170	783,000	7,310	1,460	813
		SNCR	60	136	800,000	9,770	2,300	1,470
		SCR	75	170	4,090,000	46,500	9,730	5,640
		LNB + FGR	55	125	1,100,000	14,200	2,960	1,720
		LNB + SNCR	80	182	1,580,000	14,100	3,080	1,860
		LNB + SCR	88	199	4,860,000	46,100	9,580	5,530

[a] NO_x reductions = Uncontrolled emission factor (lb/MMBtu) * Capacity(MMBtu/hr) * Effective reduction (%) * 1 ton/2,000lb * 8,760 hr/yr * Capacity factor.
[b] NO_x reductions in this column are calculated at a capacity factors of 1.0. To obtain reductions corresponding to particular capacity factors, substitute the desired capacity factor into the above equation.
[c] Cost effectiveness is calculated by dividing the total annual cost (TAC) by the NO_x reductions. Refer to Chapter 6 for the TAC.

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TABLE 2-6. MODEL HEATERS: NO_x EMISSION REDUCTIONS, CAPITAL COSTS, AND COST EFFECTIVENESS FOR ND, OIL-FIRED, LOW- AND MEDIUM-TEMPERATURE HEATERS

Model heater capacity, MMBtu/hr	Fuel	Uncontrolled NO_x emission factor, lb/MMBtu		NO_x control technique	Total effective NO_x reduction, percent	NO_x reduction, ton/yr[a,b]	Capital cost, $	Cost effectiveness,[c] @ capacity factors:		
		Thermal NO_x	Fuel NO_x					0.1	0.5	0.9
69	Distillate oil	0.14	0.06	(ND) LNB	40	23.9	227,000	15,100	3,030	1,680
		0.26		(MD) LNB	45	43.8	581,000	21,100	4,220	2,340
		0.14		(ND) ULNB	76	45.9	232,000	8,030	1,610	892
		0.26		(MD) ULNB	74	72 0	588,000	13,000	2,600	1,440
		0.14		(ND) SNCR	60	36.3	358,000	16,300	3,750	2,350
		0.26		(MD) SNCR	60	58.0	598,000	16,900	3,780	2,330
		0.26		(MD) SCR	75	72.5	2,240,000	51,800	11,000	6,490
		0.26		(MD) LNB + FGR	48	45.9	558,000	25,200	5,140	2,910
		0.14		(ND) LNB + SNCR	76	45.8	586,000	20,800	4,540	2,740
		0.26		(MD) LNB + SNCR	78	75.6	939,000	20,200	4,340	2,580
		0.26		(MD) LNB + SCR	86	83.5	2,480,000	51,500	10,900	6,360
69	Residual oil	0.14	0 28	(ND) LNB	27	33.8	227,000	10,700	2,140	1,190
		0.26		(MD) LNB	37	60.4	581,000	15,300	3,06	1,700
		0.14		(ND) ULNB	77	97.7	232,000	3,770	753	419
		0.26		(MD) ULNB	73	120	588,000	7,790	1,560	866
		0.14		(ND) SNCR	60	76.2	358,000	7,880	1,900	1,230
		0.26		(MD) SNCR	60	97.9	598,000	10,100	2,280	1,420
		0.26		(MD) SCR	75	122	2,240,000	30,600	6,400	3,710
		0.26		(MD) LNB + FGR	34	55.9	558,000	20,700	4,220	2,390
		0.14		(ND) LNB + SNCR	71	89.7	586,000	10,700	2,360	1,430
		0.26		(MD) LNB + NCR	75	122	939,000	12,500	2,740	1,650
		0.26		(MD) LNB + SCR	84	138	2,480,000	31,200	6,480	3,740

[a] NO_x reductions = Uncontrolled emission factor (lb/MMBtu) * Capacity(MMBtu/hr) * Effective reduction (%) * 1 ton/2,000lb * 8,760 hr/yr * Capacity factor.
[b] NO_x reductions in this column are calculated at a capacity factors of 1.0. To obtain reductions corresponding to particular capacity factors, substitute the desired capacity factor into the above equation.
[c] Cost effectiveness is calculated by dividing the total annual cost (TAC) by the NO_x reductions. Refer to Chapter 6 for the TAC.

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TABLE 2-7. MODEL HEATERS: NO_X EMISSION REDUCTIONS, CAPITAL COSTS, AND COST EFFECTIVENESS FOR MD, OIL-FIRED, LOW- AND MEDIUM-TEMPERATURE HEATERS

Model heater capacity, MMBtu/hr	Fuel	Uncontrolled NO_X emission factor, lb/MMbtu		NO_X control technique	Total effective NO_X reduction, percent	NO_X reduction, ton/yr[a,b]	Capital cost, $	Cost effectiveness, $/ton capacity factors:[c]		
		Thermal NO_X	Fuel NO_X					0.1	0.5	0.9
135	Distillate oil	0.26	0.06	LNB	45	85.7	319,000	5,920	1,180	658
				ULNB	74	141	326,000	3,680	735	408
				SNCR	60	114	536,000	8,010	2,000	1,340
				SCR	75	142	2,780,000	35,300	7,280	4,160
				LNB + FGR	48	89.9	535,000	9,570	2,010	1,170
				LNB + SNCR	78	148	855,000	9,580	2,230	1,410
				LNB + SCR	92	174	3,010,000	30,800	6,340	3,620
135	Residual oil	0.26	0.28	LNB	37	118	319,000	4,290	858	477
				ULNB	73	235	326,000	2,210	442	245
				SNCR	60	192	536,000	4,830	1,280	880
				SCR	75	239	2,780,000	20,900	4,330	2,480
				LNB + FGR	34	109	535,000	7,870	1,650	961
				LNB + SNCR	75	239	855,000	6,000	1,450	942
				LNB + SCR	91	289	3,010,000	18,500	3,820	3,190

[a] NO_X reductions = Uncontrolled emission factor (lb/MMBtu) * Capacity(MMBtu/hr) * Effective reduction (%) * 1 ton/2,000lb * 8,760 hr/yr * capacity factor.

[b] NO_X reductions in this column are calculated at a capacity factors of 1.0. To obtain reductions corresponding to particular capacity factors, substitute the desired capacity factor into the above equation.

[c] Cost effectiveness is calculated by dividing the total annual cost (TAC) by the NO_X reductions. Refer to Chapter 6 for the TAC.

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TABLE 2-8. MODEL HEATERS: NO_x EMISSION REDUCTIONS, CAPITAL COSTS, AND COST EFFECTIVENESS FOR ND OLEFINS PYROLYSIS HEATERS

Model heater capacity, MMBtu/hr	Fuel	Uncontrolled NO_x emission factor, lb/MMBtu	NO_x control technique	Total effective NO_x reduction, percent	Reduction, ton/yr[a,b]	Capital cost, $	Cost effectiveness, $/ton @ capacity factors:[c]		
							0.1	0.5	0.9
84	natural gas	0.135	(ND) LNB	25	37.2	248,000	31,700	6,350	3,530
			(MD) LNB	25	37.2	642,000	82,200	16,400	9,130
			(ND) ULNB	50	24.9	252,000	16,100	3,230	1,790
			(MD) ULNB	50	24.9	648,000	41,500	8,300	4,610
			(ND) SNCR	60	19.9	403,000	22,000	4,780	2,870
			(MD) SNCR	60	19.9	673,000	36,400	7,660	4,470
			SCR	75	12.4	2,520,000	113,000	23,400	13,500
			LNB + FGR	55	22.3	804,000	47,000	9,600	5,440
			(ND) LNB + SNCR	70	14.9	651,000	30,200	6,360	3,720
			(MD) LNB + SNCR	70	14.9	1,050,000	48,200	9,970	5,720
			LNB + SCR	81	9.3	2,900,000	119,000	24,600	14,100
84	high-hydrogen fuel gas	0.162	(ND) LNB	25	44.7	248,000	26,400	5,290	2,940
			(MD) LNB	25	44.7	642,000	68,500	13,700	7,610
			(ND) ULNB	50	29.8	252,000	13,400	2,690	1,490
			(MD) ULNB	50	29.8	648,000	34,600	6,920	3,840
			(ND) SNCR	60	23.9	403,000	18,400	4,040	2,450
			(MD)SCNR	60	23.9	673,000	30,400	6,440	3,780
			SCR	75	14.9	2,520,000	94,300	19,600	11,300
			LNB +FGR	55	26.8	804,000	39,200	8,000	4,530
			(ND) LNB + SNCR	70	17.9	651,000	25,200	5,350	3,140
			(MD) LNB + SNCR	70	17.9	1,050,000	40,200	8,350	4,810
			LNB + SCR	81	11.2	2,900,000	99,500	20,600	11,800

[a] NO_x reductions = Uncontrolled emission factor (lb/MMBtu) * Capacity(MMBtu/hr) * effective reduction (%) * 1 ton/2,000 lb * 8,760 hr/yr * Capacity factor.

[b] NO_x reductions in this column are calculated at a capacity factor of 1.0. To obtain reductions corresponding to other capacity factors, substitute the desired capacity factor into the above equation.

[c] Cost effectiveness is calculated by dividing the total annual cost (TAC) by the NO_x reductions. Refer to Chapter 6 for the TAC.

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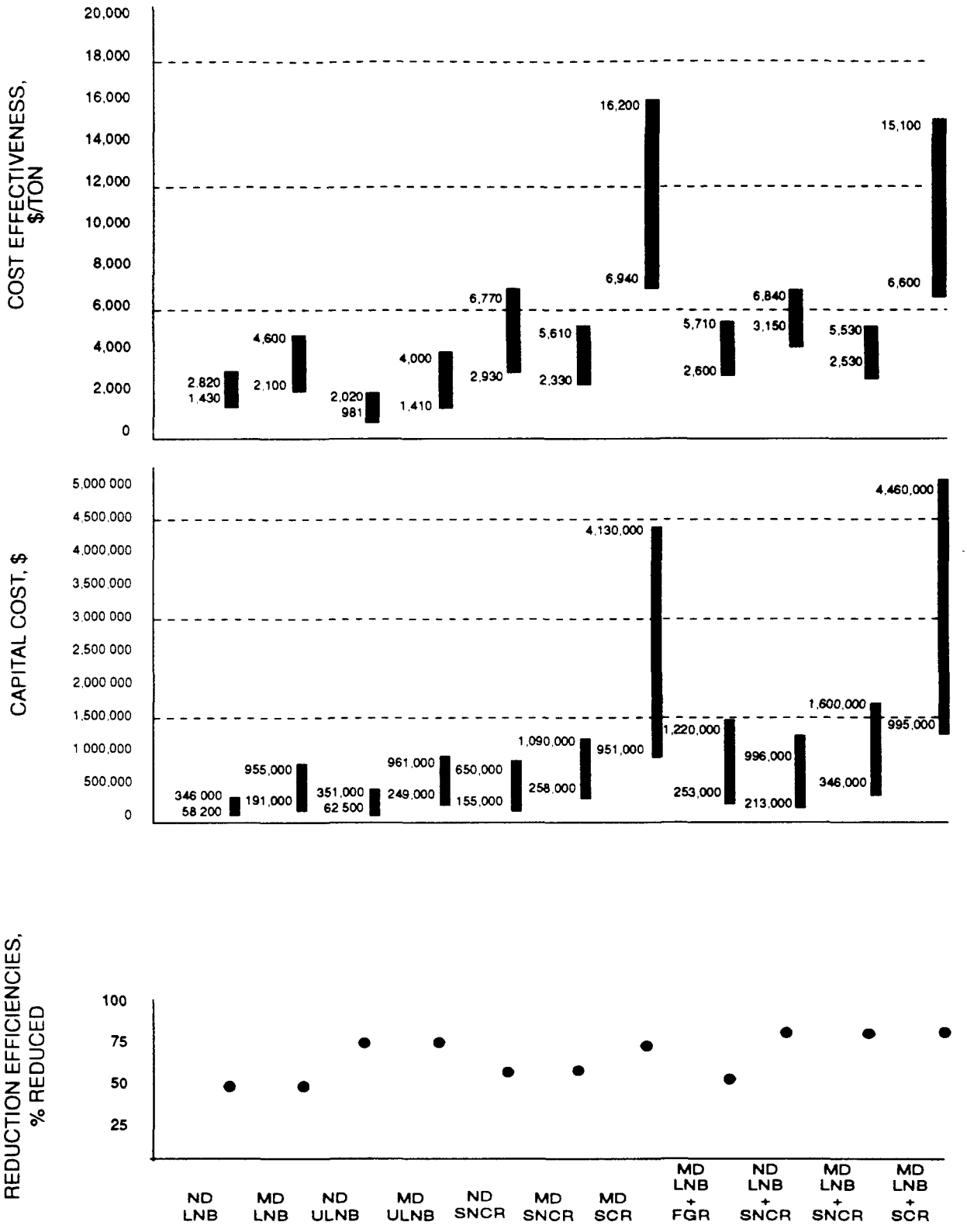


Figure 2-1. Model heaters: NO_x emission reductions, capital costs, and cost effectiveness at a capacity factor of 0.9 for ND, natural gas-fired, low- and medium-temperature heaters.

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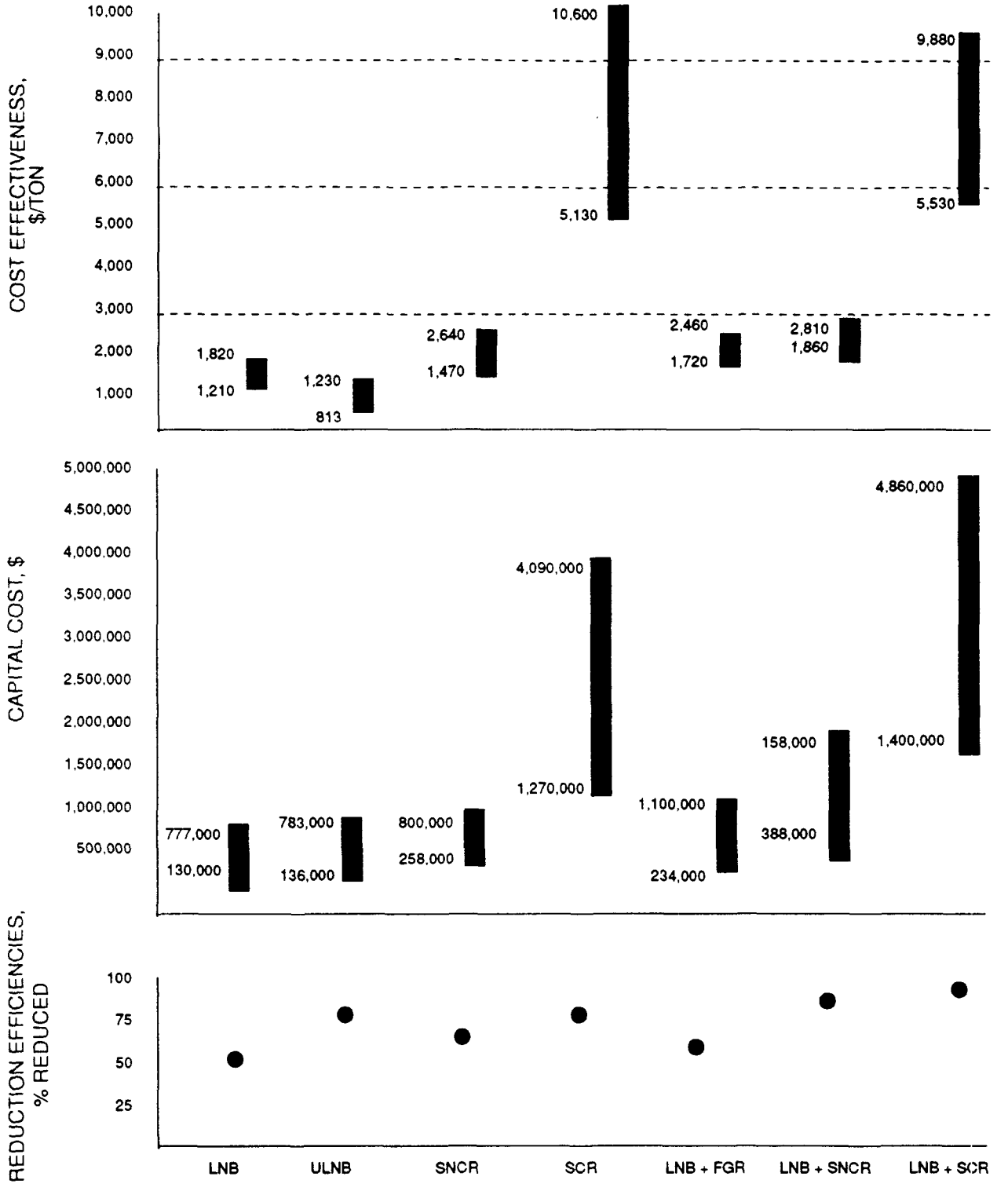


Figure 2-2. Model heaters: NO_x emission reductions, capital costs, and cost effectiveness at a capacity factor of 0.9 for MD, natural gas-fired, low- and medium-temperature heaters.

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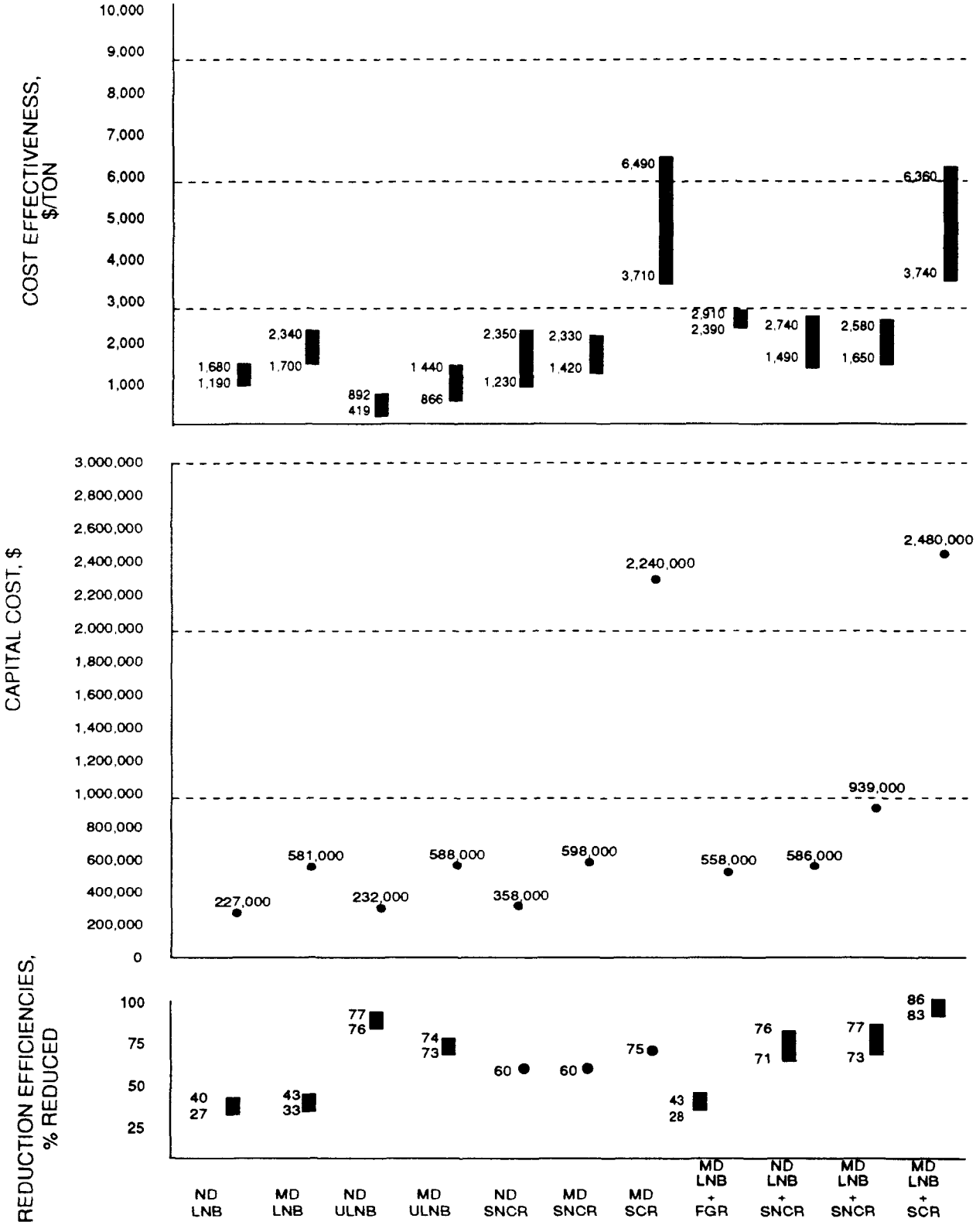


Figure 2-3. Model heaters: NO_x emission reductions, capital costs, and cost effectiveness at a capacity factor of 0.9 for ND, oil-fired, low- and medium-temperature heaters.

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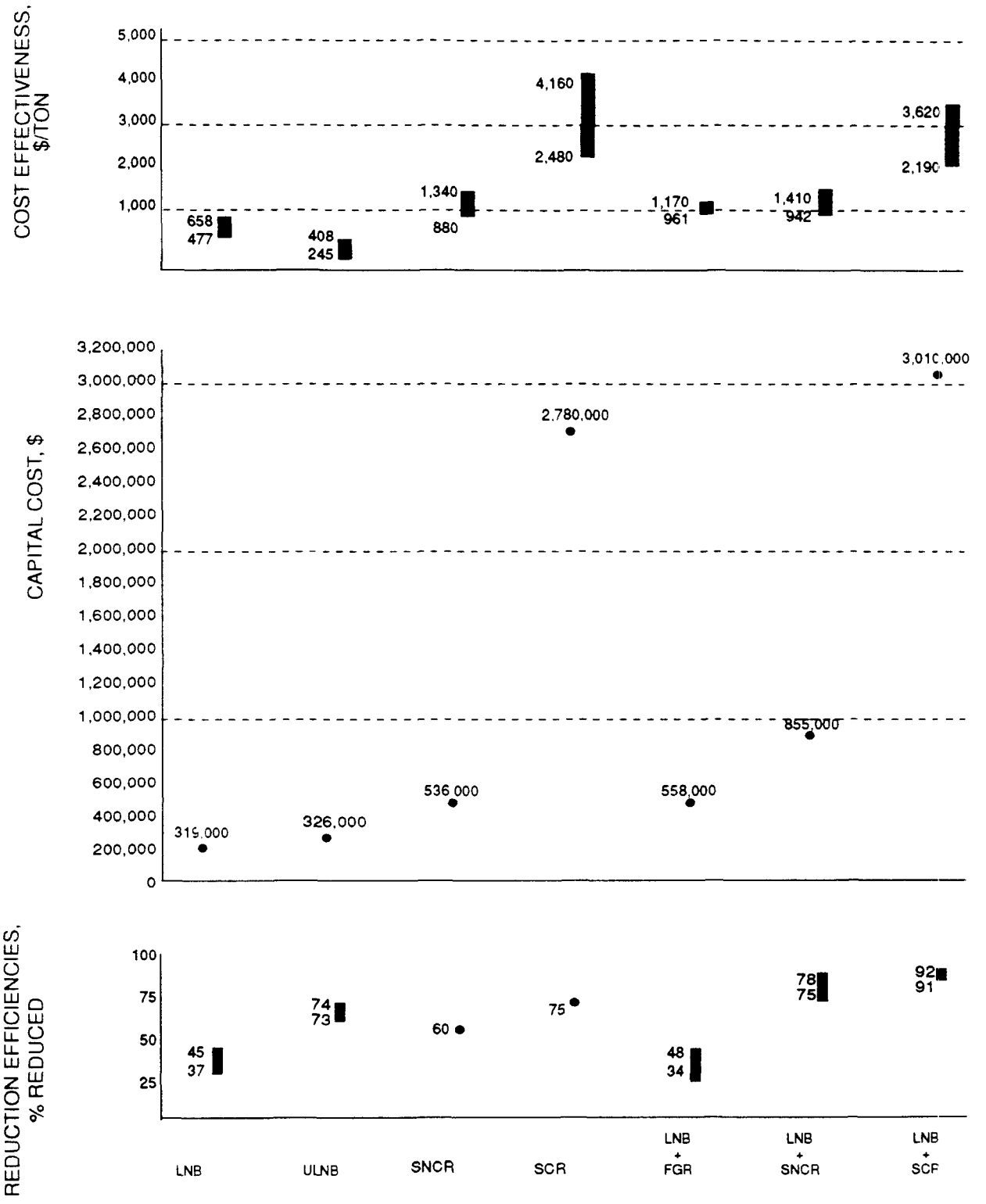


Figure 2-4. Model heaters: NO_x emission reductions, capital costs, and cost effectiveness at a capacity factor of 0.9 for MD, oil-fired, low- and medium-temperature heaters.

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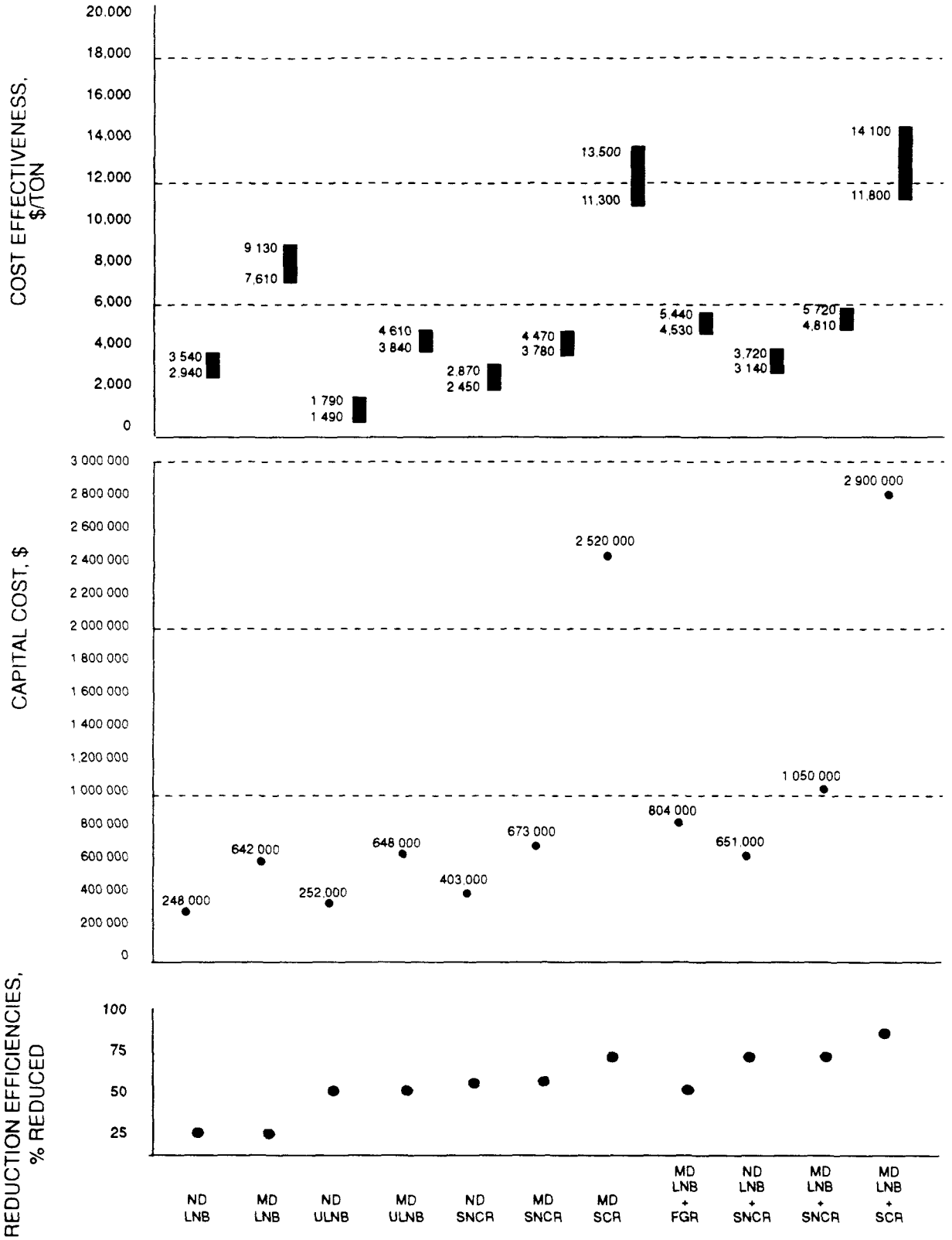


Figure 2-5. Model heaters: NO_x emission reductions, capital costs, and cost effectiveness at a capacity factor of 0.9 for ND olefins pyrolysis heaters.

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2.4 IMPACTS OF NO_x CONTROLS

The use of NO_x control techniques may cause environmental and energy impacts. Environmental impacts associated with combustion controls include carbon monoxide (CO) and unburned hydrocarbon (HC) emissions. Environmental impacts of postcombustion techniques include NH_3, CO, and nitrous oxide (N_2O) emissions with the use of SNCR; NH_3 and sulfite (SO_3) emissions and solid waste disposal concerns with the use of SCR. Ammonia handling and storage also presents safety concerns with SNCR and SCR.

Energy impacts include additional electric energy requirements for fans or blowers and thermal efficiency losses. Thermal efficiency losses result in increased fuel consumption. These impacts are described briefly below.

Combustion controls, such as LNB, ULNB, and FGR, modify the combustion conditions to reduce the amount of NO_x formed. Combustion controls are usually operated in such a manner that reduces NO_x without producing unacceptable levels of CO and HC. Combustion controls reduce NO_x formation by reducing the peak flame temperature and/or O_2 concentrations in the flame zone. Reductions in NO_x formation achieved by reducing flame temperature and O_2 levels can increase CO and HC emissions if NO_x reductions by combustion controls are taken to extremes.

The use of SNCR results in emissions of unreacted NH_3 and increases in CO and N_2O emissions. Reactant-to-NO_x ratios of 1.25 to 2.0:1 are typical of SNCR systems. The high ratio results in unreacted NH_3 emissions, or NH_3 slip. Carbon monoxide and N_2O have been shown to be byproducts of urea injection. Unreacted NH_3 and N_2O are byproducts of NH_3 injection. Selective catalytic reduction NH_3 slip concentrations are generally less than SNCR NH_3 slip concentrations because the catalytic reactor allows a higher reaction rate and lower reactant-to-NO_x injection ratio (1.05:1 or less). Most catalysts used in SCR systems controlling process heaters in refinery service contain titanium and vanadium oxides. Catalyst formulations developed in the early 1980's tend to convert up to 5 percent of any sulfur

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dioxide (SO_2) present in high-sulfur fuels to SO_3, resulting in SO_3 emissions. Newer catalyst formulations that convert less than 1 percent SO_2 to SO_3 are available and have been demonstrated in utility applications.

Safety concerns for NH_3 storage and transport are due to the hazardous nature of concentrated NH_3 vapor. Aqueous NH_3 (NH_3 in a liquid solution at atmospheric pressure) is not considered as hazardous as anhydrous NH_3, which is stored as a concentrated pressurized vapor. Aqueous NH_3 is available for SCR and NH_3 SNCR processes.

State and local regulatory agencies may classify catalysts containing vanadium pentoxide as a hazardous waste, however, and require disposal of these catalyst materials in an approved hazardous waste disposal facility. Such disposal problems are not encountered with other catalyst materials, such as precious metals and zeolites, because these materials are not considered hazardous wastes.

Control techniques that require upgraded or newly installed fans and blowers increase the electrical energy consumption for process heaters using those control techniques. These control techniques are LNB plus SCR, LNB plus FGR and ND heaters converted to MD for MD LNB or MD ULNB use.

Current combustion controls balance NO_x reduction with acceptable fuel efficiency. Adding LNB, ULNB, and LNB plus FGR may cause flames instability and reduced combustion efficiency. However, these impacts are minimal in properly designed systems. Injecting reactants into the flue gas stream in SNCR systems produces approximately a 0.3 percent thermal efficiency loss. The injection of reactants and the pressure drop across the catalyst in SCR systems produces approximately a 1.5 percent thermal efficiency loss. Thermal efficiency losses generally result in increased fuel consumption.

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6.0 CONTROL COSTS

This chapter presents capital and annual costs and cost effectiveness for the NO_x emission control techniques described in Chapter 5. These control techniques are applied to the model heaters presented in Chapters 4 and 5. The NO_x control techniques are low-NO_x burners (LNB's), ultra low-NO_x burners (ULNB's), selective noncatalytic reduction (SNCR), selective catalytic reduction (SCR), LNB's combined with flue gas recirculation (FGR), LNB's combined with SNCR, and LNB's combined with SCR. These control techniques were selected because they are currently used to control NO_x emissions.

Cost estimates are highly variable, and accurate estimates can only be made on a case-by-case basis. The costs presented in this study give approximate costs of implementing the available control techniques. Costing methodologies from References 1 and 2 are used to estimate the costs. These methodologies estimate the costs of retrofitting control techniques on process heaters.[1,2] It is expected that the cost of incorporating a control technique in the design of a new process heater is less than retrofitting a similar heater with the same control technique.

Capital and annual cost methodologies for NO_x control techniques applied to the model heaters are presented in Section 6.1. The total annual costs (TAC) for the NO_x control techniques applied to the model heaters are presented in Section 6.2. The cost effectiveness of the NO_x control techniques applied to the model heaters is presented in Section 6.3. Radiant burner costs are discussed in Section 6.4; radiant burners are not included in the model heater cost

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analysis due to limited costing information. Section 6.5 lists the references used in this chapter.

6.1 CAPITAL AND ANNUAL COSTS METHODOLOGIES

The methodology used to develop capital costs is essentially the same for each NO_x control technique. Because available cost data for this study were limited, capital cost methodologies from References 1 and 2 were used to develop capital costs for each individual control technique. The capital costs were updated to 1991 U.S. dollars using the Chemical Engineering plant cost index.[3] Capital costs for combinations of controls are the sum of the capital costs of the individual control techniques.

The TAC for the NO_x control techniques comprises the annual operating costs of chemicals, electricity, fuel, and maintenance. The costs, in 1991 dollars, for electricity, fuel, chemical reactants, and maintenance are shown in Table 6-1. Capital and annual costs for LNB's, ULNB's, SNCR, SCR, FGR, LNB's plus SNCR, and LNB's plus SCR are presented in Sections 6.1.1 through 6.1.7, respectively. Each of these sections presents the methodology used to develop capital and annual costs. Natural draft (ND)-to-mechanical draft (MD) conversion is not considered a stand-alone control technique but is required to implement some control techniques. The capital and annual costs of ND-to-MD conversion are considerable and are presented in Section 6.1.8.

6.1.1 Costs of LNB's

6.1.1.1 Capital Costs of LNB's. The LNB capital cost methodology from Reference 1 was used to calculate the capital cost of applying LNB's to process heaters. The primary parameters affecting the capital cost include the following:

1. Heater capacity;
2. Number of burners;
3. Burner heat release rate; and
4. Natural or forced draft combustion air delivery system.[1]

The capital cost methodology from Reference 1 for ND heaters is:

$$TIC = 30,000 + HQ\ [5,230 - (622 \times BQ) + (26.1 \times BQ^2)]$$

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TABLE 6-1. UTILITY, CHEMICAL, AND MAINTENANCE COSTS

Electricity[a]	$0.06/kWh
Natural gas[b]	$2.00/MMBtu
Distillate fuel oil[c]	$5.54/MMBtu
Residual fuel oil[c]	$3.00/MMBtu
Ammonia[d]	$0.125/lb
Maintenance[e]	2.75% of capital cost

[a]Reference 4, Table 5-10.
[b]Reference 5.
[c]Reference 6.
[d]Reference 2.
[e]Reference 1.

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where:

TIC = total capital installed cost;

HQ = heater capacity (GJ/hr); and

BQ = burner heat release rate (GJ/hr)

and

$$BQ = HQ/NB \times (1.158 + 8/HQ)$$

where:

NB = number of burners.

The LNB capital cost for MD heaters is calculated to be 50 percent higher than the capital cost for ND heaters. This additional cost is added to account for the following:

1. Increased LNB cost;
2. Additional excess air control equipment; and
3. Combustion air plenum modification.[1]

The capital cost methodology for MD LNB's is:

$$TIC = 1.5 \times \{30,000 + HQ \times [5,230 - (622 \times BQ) + (26.1 \times BQ^2)]\}.$$

The cost methodologies give costs in Canadian average 1990 dollars. For this analysis, the capital costs have been escalated to U.S. average 1991 dollars using the Chemical Engineering plant cost index and an exchange rate of 1 U.S. dollar to 1.15 Canadian dollars.[3]

The cost of the burners, although substantial, represents a fraction of the actual installed costs. Large cost variations for LNB retrofit installations can occur when floor rebuilding is required and space limitations below the heater exist. Typical LNB's do not fit standard burner mounts and may require complete floor rebuilds and refractory replacement. Not all heaters can be retrofitted with current LNB designs. The primary variable influencing the feasibility of an LNB retrofit is the space requirement below the heater necessary to install the combustion air plenums.[8,9]

6.1.1.2 Operating Costs of LNB's. Maintenance costs of LNB's are calculated as 2.75 percent of the LNB's capital costs.[1,2] Installation of LNB's can improve heater efficiency, although this effect (if any) will be strongly heater-dependent.

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The potential increase in heater efficiency may lower fuel costs. Operational costs may be marginally increased due to the decrease in flame stability and the potential for flame-out.[1,8] These operational impacts will tend to offset one another in the cost analysis associated with LNB installation and minimize the effect of the current analysis.[1] These costs are site-specific and are not included in the cost analysis.

6.1.2 Cost of ULNB's

6.1.2.1 Capital Costs of ULNB's. The capital costs of ULNB's are affected by the same parameters as LNB's. The primary parameters that affect the capital costs include:

1. Heater capacity;
2. Number of burners;
3. Burner heat release rate; and
4. Natural or mechanical draft combustion air delivery system.

The capital cost methodology for ND ULNB's is:

$$TIC = 35{,}000 + \{HQ \times [5{,}230 - (622 \times BQ) + (26.1 \times BQ^2)]\}.$$

In the case of MD heaters, an additional 50 percent is added to the capital cost to account for the following:

1. Additional excess air control equipment; and
2. Increased combustion air plenum construction.

The capital cost methodology for MD ULNB's is:

$$TIC = 1.5 \times \{35{,}000 + HQ \times [5{,}230 - (622 \times BQ) + (26.1 \times BQ^2)]\}.$$

The cost methodologies give costs in Canadian average 1990 dollars. For this analysis, the capital costs have been escalated to U.S. average 1991 dollars using the Chemical Engineering plant index and an exchange rate of 1 U.S. dollar to 1.15 Canadian dollars.[3]

Similar to LNB's, large cost variations for ULNB's retrofit can exist. The cost variations and variables influencing the use of LNB's described in Section 6.1.1.1 also apply to ULNB's.

6.1.2.2 Operating Costs of ULNB's. Maintenance costs of ULNB's are calculated as 2.75 percent of the ULNB's capital

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costs.[1,2] Operating costs for LNB's described in Section 6.1.1.2 also apply to ULNB's.

6.1.3 Costs of SNCR

6.1.3.1 Capital Costs of SNCR. The SNCR capital cost methodology from Reference 1 has been used to calculate the capital cost of installing SNCR in process heaters. The cost methodology in Reference 1 uses data from Exxon's Thermal DeNO$_x$® (TDN®) process because Nalco Fuel Tech's process to date has been installed on only a limited number of refinery heaters. The major capital costs for SNCR systems are for the ductwork, reactant storage tank and injection system, insulation, control instrumentation, engineering, and installation. The capital cost methodology for SNCR from Reference 1 is:

$$TIC = 31,850\ (HQ)^{0.6}$$

where:

HQ is the heater capacity, in gigajoules per hour (GJ/hr).

The cost methodology gives costs in Canadian average 1990 dollars. For this analysis, capital costs have been escalated to U.S. average 1991 dollars using the Chemical Engineering plant index and an exchange rate of 1 U.S. Dollar to 1.15 Canadian dollars.[3]

6.1.3.2 Operating Costs of SNCR. The SNCR annual operating cost models from References 1 and 2 are used to calculate the annual operating costs of SNCR operation. Maintenance costs of SNCR are calculated as 2.75 percent of the SNCR capital costs.[1,2] The operating costs include the cost of ammonia reactant, additional electricity, and additional fuel. The Reference 2 cost model was used to calculate the operating costs for NH_3 and electricity. The fuel penalty results from a loss of heater thermal efficiency due to dilution of the hot flue gas with steam or cold distribution air, which lowers the convection section heat recovery.[1] The loss in efficiency is estimated to require a 0.3 percent increase in fuel firing. The cost of the fuel penalty is calculated as a 0.3 percent increase in firing rate.[9]

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The cost methodologies for the annual operating costs of SNCR are:

NH_3 cost = (Q) x (lb NO_x/MMBtu) x (1 mole NO_2/46 lb NO_2) x (17 lb NH_3/1 mole NH_3) x (mole NH_3/mole NO_x) x ($0.125/lb NH_3) x (8,760 hr/yr) x CF,

Electricity cost = (0.3 kWh/ton NH_3) x (ton NH_3/yr) x ($0.06/kWh) x CF

Fuel penalty cost = (0.03) x (Q) x (8,760 hr/yr) x (fuel cost $/MMBtu) x CF,

where:

Q = heater capacity, MMBtu/hr, and

CF = capacity factor expressed in decimal form.[1,2,10]

6.1.4 Costs of SCR

6.1.4.1 Capital Costs of SCR. The SCR capital cost methodology from Reference 2 was used to calculate the capital cost of installing SCR in process heaters. The major capital costs for SCR systems are for the reactor section (including catalyst), ductwork, ammonia storage tank and injection system, foundation, insulation, control instrumentation, engineering, and installation.[2,11] Selective catalytic reductions systems require mechanical draft operation due to the pressure drop across the catalyst. The costs for SCR applied to the ND model heaters includes the costs of converting to MD operation in addition to the SCR costs.[2]

The capital cost model from Reference 2 is:

$$TIC = 1{,}373{,}000 \times (Q/48.5)^{0.6} + 49{,}000 \times (Q/485),$$

where:

Q = heater capacity, MMBtu/hr.[2]

The cost methodology gives costs in U.S. average 1986 dollars. For this analysis, capital costs have been escalated to U.S. average 1991 dollars using the Chemical Engineering plant index.[3]

6.1.4.2 Operating Costs of SCR. The SCR annual operating costs were calculated using the methodologies from Reference 2. The operating costs include the cost of the ammonia reactant,

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catalyst replacement, additional electricity and additional fuel. The Reference 2 cost methodology was used to calculate the NH_3, catalyst replacement, and electricity costs. A 1 to 2 percent loss of heater thermal efficiency can be expected due to dilution of the hot flue gas with cold distribution air, which lowers convection section heat recovery. This loss of efficiency is represented by a fuel penalty; the cost of the fuel penalty is estimated to require a 1.5 percent increase in fuel consumption.[1]

The cost methodology for annual operating costs of SCR:

NH_3 cost = (Q) x (lb NO_x/MMBtu) x (1 mole NO_2/46 lb NO_2) x (17 lb NH_3/1 mole NH_3) x (mole NH_3/mole NO_x) x ($0.125/lb NH_3) x (8,760 hr/yr) x CF;

Catalyst replacement cost = 49,000 x (Q/48.5)/5 yr

Electricity cost = (0.3 kWh/ton NH_3) x (ton NH_3) x ($0.06/kWh) x CF, and

Fuel penalty cost = (0.015) x (Q) x (8,760 hr/yr) x (fuel cost $/MMBtu) x CF,

where:

Q = heater capacity, MMBtu/hr, and

CF = capacity factor expressed in decimal form.

Maintenance costs for SCR are calculated as 2.75 percent of the SCR capital cost.[1,2]

6.1.5 Costs of FGR

6.1.5.1 Capital Costs of FGR. The FGR capital cost methodology from Reference 1 is used to calculate the capital cost of installing an FGR system in process heaters. The capital cost model for FGR from Reference 1 is:

$$TIC = 12,800 (HQ)^{0.6}$$

where:

HQ = heater capacity, GJ/hr.[1]

The cost methodology gives cost in Canadian average 1990 dollars. For this analysis, the capital costs have been escalated to U.S. average 1991 dollars using the Chemical

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Engineering plant index and an exchange rate of 1 U.S. dollar to 1.15 Canadian dollars.[3]

As discussed in Chapter 5, FGR is not considered to be a stand-alone NO_x control technique but is typically combined with LNB's. Flue gas recirculation requires an MD combustion air supply. For ND heaters, implementing FGR as a NO_x control technique incurs the following capital costs: ND-to-MD conversion, MD LNB's, and the FGR system.

The cost methodology is based on boiler data because process heater applications of FGR are limited. An additional consideration for FGR is the high-temperature flue gas associated with process heaters. Boilers use economizers to recover a large amount of thermal energy from the flue gas in boilers. Process heaters do not have economizers and therefore have higher flue gas temperatures than do boilers. Flue gas recirculation fans capable of handling the high-temperature flue gas from process heaters may increase the cost of implementing FGR over the costs presented in this chapter.

6.1.5.2 Operating Costs of FGR. The FGR annual operating cost model from Reference 2 has been used to calculate the annual operating costs of FGR operation. The primary cost associated with FGR operation is the additional electrical energy required to operate the FGR fan. The annual cost model for FGR from Reference 2 is presented below:

Electric power cost = (motor hp) x (0.75 kW/hp) x (8,760 hr/yr) x ($0.06/kWh) x CF

where:

motor hp = FGR fan motor horsepower, (1/5) x (Q);
Q = process heater capacity in MMBtu/hr, and
CF = heater capacity factor.

Maintenance costs for FGR are calculated as 2.75 percent of the capital cost.[1,2]

6.1.6 Costs of LNB's Plus SNCR

6.1.6.1 Capital Costs of LNB's Plus SNCR. The capital cost of LNB's plus SNCR is the sum of the capital cost of LNB's, presented in Section 6.1.1.1, and the capital cost of SNCR,

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presented in Section 6.1.3.1. Selective noncatalytic reduction systems may be applied to ND or MD systems without modifications to the draft system. Therefore, either ND LNB's or MD LNB's may be combined with SNCR.

6.1.6.2 Operating Costs of LNB's Plus SNCR. The operating and maintenance costs of LNB's plus SNCR are the sum of the operating and maintenance costs for LNB's, presented in Section 6.1.1.2, and the operating and maintenance costs for SNCR, presented in Section 6.1.3.2.

6.1.7 Costs of LNB's Plus SCR

6.1.7.1 Capital Costs of LNB's Plus SCR. The capital cost of LNB's plus SCR is the sum of the capital cost of LNB's, presented in Section 6.1.1.1, and the capital cost of SCR, presented in Section 6.1.4.1. Selective catalytic reduction systems require MD operation. Therefore, ND heaters must be converted to MD operation for SCR.

6.1.7.2 Operating Costs of LNB's Plus SCR. The operating and maintenance costs of LNB's plus SCR are the sum of the operating and maintenance costs for LNB's, presented in Section 6.1.1.2, and the operating and maintenance costs for SCR, presented in Section 6.1.4.2.

6.1.8 Costs of ND-to-MD Conversion

6.1.8.1 Capital Costs of ND-to-MD Conversion. The ND-to-MD conversion capital cost methodology from Reference 1 is applied to calculate the capital cost of converting process heaters from ND to MD. The capital cost model for ND-to-MD conversion from Reference 1 is:

$$TIC = 21,350\ (HQ)^{0.6}$$

where:

HQ = heater capacity, GJ/hr.[1]

The cost methodology gives costs in Canadian average 1991 dollars. For this analysis, capital costs have been escalated to U.S. 1991 dollars using the Chemical Engineering plant indexes and an exchange rate of 1 U.S. dollar to 1.15 Canadian dollars.[3]

As discussed in Chapter 5, ND-to-MD conversion is generally not performed as a stand-alone NO_x control technique. The

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capital costs of converting ND heaters to MD heaters is added to the costs of control techniques where conversion from ND to MD is required. The control techniques that require ND heater conversion to MD are MD LNB's, MD ULNB's, MD SNCR, SCR, MD LNB's plus FGR, MD LNB's plus SNCR, and MD LNB's plus SCR.

6.1.8.2 Operating Costs of ND-to-MD Conversion. Maintenance costs for MD heaters are greater than for ND heaters. Maintenance costs associated with ND-to-MD conversion are calculated as 2.75 percent of the ND-to-MD capital cost.[1,2] Conversion from ND-to-MD increases heater thermal efficiency. Potential fuel reductions of 1.5 percent can lead to a yearly savings equivalent to about 4 to 8 percent of the capital cost to retrofit a medium sized heater ND heater to MD LNB's.[1] This efficiency gain is site-specific, however, and has not been included in the cost analysis.

6.2 TOTAL ANNUAL COST FOR MODEL HEATERS

The TAC for applying NO_x control techniques to model heaters is presented in this section. The TAC is the sum of the capital recovery cost and the annual cost. The capital recovery cost is estimated for each NO_x control technique by multiplying the capital costs by the capital recovery factor (CRF). The CRF is estimated by the following method:

$$CRF = [i \times (1+i)^n]/[(1+i)^{n-1}]$$

where:

i = pretax marginal rate of return (10 percent), and

n = equipment economic life (15 years).[4]

The capital and annual cost methodologies are presented in Section 6.1.

Sections 6.2.1 through 6.1.5 present the capital costs, capital recovery, annual costs, and TAC's for NO_x control techniques applied to the model heaters. Total annual costs are calculated for capacity factors of 0.1, 0.5, and 0.9. However, only TAC for the capacity factor of 0.9 are discussed in these sections. Sections 6.2.1 and 6.2.2 present these costs for the ND low- and medium-temperature and MD low- and medium-temperature gas-fired model heaters, respectively. Sections 6.2.3 and 6.2.4

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present these costs for the ND low- and medium-temperature and MD low- and medium-temperature oil-fired model heaters, respectively. Section 6.2.5 presents the capital costs, capital recovery, annual costs, and TAC's for the olefins pyrolysis model heaters. The ND-to-MD conversion costs are presented in Section 6.2.6.

6.2.1 Control Costs for the ND Gas-Fired, Low- and Medium-Temperature Model Heaters

Table 6-2 presents the capital costs, annual costs, and TAC's for the ND gas-fired, low-and medium-temperature model heaters. The capital costs of the control techniques range from $58,200 for ND LNB's used on the 17 MMBtu/hr heater to $4,650,000 for MD LNB's plus SCR used on the 186 MMBtu/hr heater. The TAC's range from $9,250/yr for ND LNB's on the 17 MMBtu/hr heater to $835,000/yr for MD LNB's plus SCR on the 186 MMBtu/hr heater.

6.2.2 Control Costs for MD Gas-Fired, Low- and Medium-Temperature Model Heaters

Table 6-3 presents the capital costs, annual costs, and TAC's for the MD gas-fired, low- and medium-temperature model heaters. The capital costs of the control techniques range from $130,000 for LNB's used on the 40 MMBtu/hr heater to $5,360,000 for LNB's plus SCR used on the 236 MMBtu/hr heater. The TAC's range from $20,700/yr for LNB's used on the 40 MMBtu/hr heater to $988,000/yr for LNB's plus SCR used on the 263 MMBtu/hr heater.

6.2.3 Control Costs for ND Oil-Fired, Low- and Medium-Temperature Model Heaters

Table 6-4 presents the capital costs, annual costs, and TAC's for the ND oil-fired, low- and medium-temperature model heaters. The capital costs of the control techniques range from $227,000 for ND LNB's to $2,580,000 for MD LNB's plus SCR. The TAC's range from $36,100/yr for ND LNB's to $463,000/yr for the MD LNB's plus SCR. These costs are the same for both distillate and residual oil-fired ND model heaters.

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TABLE 6-2. COSTS OF CONTROL TECHNIQUES FOR ND NATURAL GAS-FIRED MODEL HEATERS (1991 $)

Model heater capacity, MMBtu/hr	NO_x control technique	Capital costs, $	Annual costs, $/yr				Total annual costs, $/yr @ capacity factors:[c]		
			Capital recovery[a]	Operating and maintenance costs @ capacity factors:[b]					
				0.1	0.5	0.9	0.1	0.5	0.9
17	(ND) LNB	58,200	7,650	1,600	1,600	1,600	9,250	9,250	9,250
	(MD) LNB	191,000	25,100	5,250	5,250	5,250	30,400	30,400	30,400
	(ND) ULNB	62,500	8,220	1,720	1,720	1,720	9,940	9,940	9,940
	(MD) ULNB	249,000	32,800	6,850	6,850	6,850	39,600	39,600	39,600
	(ND) SNCR	155,000	20,300	4,490	5,420	6,360	24,800	25,700	26,700
	(MD) SNCR	258,000	34,000	7,480	9,000	10,500	41,400	43,000	44,500
	(MD) SCR	951,000	125,000	30,200	32,600	34,900	155,000	158,000	160,000
	(MD) LNB + FGR	253,000	33,300	7,090	7,630	8,170	40,400	40,900	41,400
	(ND) LNB + SNCR	213,000	28,000	6,090	7,020	7,960	34,100	35,000	35,900
	(MD) LNB + SNCR	346,000	45,400	9,880	11,400	12,900	55,300	56,800	58,400
	(MD) LNB + SCR	1,040,000	137,000	32,600	35,000	37,300	169,000	172,000	174,000
36	(ND) LNB	92,600	12,200	2,550	2,550	2,550	14,700	14,700	14,700
	(MD) LNB	302,000	39,600	8,290	8,290	8,290	47,900	47,900	47,900
	(ND) ULNB	96,900	12,700	2,670	2,670	2,670	15,400	15,400	15,400
	(MD) ULNB	308,000	40,500	8,470	8,470	8,470	49,000	49,000	49,000
	(ND) SNCR	243,000	31,900	7,160	9,150	11,100	39,000	41,000	43,000
	(MD) SNCR	405,000	53,300	11,900	14,400	16,900	65,200	67,700	70,100
	(MD) SCR	1,500,000	198,000	49,900	54,900	59,900	247,000	252,000	257,000
	(MD) LNB + FGR	399,000	52,500	11,300	12,400	13,500	63,700	64,800	66,000
	(ND) LNB + SNCR	335,000	44,100	9,710	11,700	13,700	53,800	55,800	57,700
	(MD) LNB + SNCR	544,000	71,500	15,800	19,000	22,200	87,300	90,500	93,700
	(MD) LNB + SCR	1,640,000	216,000	53,700	58,700	63,700	270,000	275,000	280,000
77	(ND) LNB	133,000	17,500	3,670	3,670	3,670	21,200	21,200	21,200
	(MD) LNB	457,000	60,000	12,600	12,600	12,600	72,600	72,600	72,600
	(ND) ULNB	138,000	18,100	3,790	3,790	3,790	21,900	21,900	21,900
	(MD) ULNB	463,000	60,900	12,700	12,700	12,700	73,600	73,600	73,600
	(ND) SNCR	383,000	50,300	11,600	15,800	20,100	61,900	66,100	70,400
	(MD) SNCR	639,000	84,000	19,300	24,600	29,800	103,000	109,000	114,000
	(MD) SCR	2,390,000	315,000	84,100	94,800	106,000	399,000	410,000	420,000
	(MD) LNB + FGR	610,000	80,300	17,400	19,800	22,300	97,600	100,000	103,000
	(ND) LNB + SNCR	516,000	67,900	15,300	19,500	23,700	83,100	87,300	91,600
	(MD) LNB + SNCR	839,000	110,000	24,800	31,700	38,600	135,000	142,000	149,000
	(MD) LNB + SCR	2,590,000	341,000	89,600	100,000	111,000	431,000	441,000	452,000

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TABLE 6-2. (continued)

Model heater capacity, MMBtu/hr	NO_x control technique	Capital costs, $	Annual costs, $/yr				Total annual costs, $/yr @ capacity factors:[c]		
			Capital recovery[a]	Operating and maintenance costs @ capacity factors:[b]					
				0.1	0.5	0.9	0.1	0.5	0.9
121	(ND) LNB	232,000	30,500	6,390	6,390	6,390	36,900	36,900	36 900
	(MD) LNB	685,000	90,100	18,800	18,800	18,800	109,000	109,000	109,000
	(ND) ULNB	237,000	31,100	6,510	6,510	6,510	37,600	37,600	37 600
	(MD) ULNB	691,000	90,900	19,000	19,000	19,000	110,000	110,000	110,000
	(ND) SNCR	502,000	66,000	15,500	22,100	28,800	81,500	88,100	94 800
	(MD) SNCR	838,000	110,000	25,800	34,000	42,300	136,000	144,000	153,000
	(MD) SCR	3,160,000	416,000	116,000	133,000	149,000	532,000	548,000	565,000
	(MD) LNB + FGR	887,000	117,000	25,300	29,200	33,000	142,000	146,000	150,000
	(ND) LNB + SNCR	734,000	96,500	21,900	28,500	35,200	118,000	125,000	132,000
	(MD) LNB + SNCR	1,190,000	156,000	35,300	46,200	57,000	191,000	202,000	213,000
	(MD) LNB + SCR	3,510,000	462,000	125,000	142,000	159,000	587,000	604,000	621,000
186	(ND) LNB	346,000	45,500	9,520	9,520	9,520	55,000	55,000	55 000
	(MD) LNB	955,000	126,000	26,300	26,300	26,300	152,000	152,000	152,000
	(ND) ULNB	351,000	46,100	9,640	9,640	9,640	55,700	55,700	55 700
	(MD) ULNB	961,000	126,000	26,400	26,400	26,400	153,000	153,000	153,000
	(ND) SNCR	650,000	85,400	20,400	30,700	40,900	106,000	116,000	126,000
	(MD) SNCR	1,090,000	143,000	34,000	46,700	59,400	177,000	189,000	202,000
	(MD) SCR	4,130,000	543,000	158,000	183,000	209,000	700,000	726,000	752,000
	(MD) LNB + FGR	1,220,000	160,000	34,900	40,800	46,600	195,000	201,000	207,000
	(ND) LNB + SNCR	996,000	131,000	29,900	40,200	50,400	161,000	171,000	181,000
	(MD) LNB + SNCR	1,600,000	211,000	48,300	64,900	81,500	259,000	276,000	292,000
	(MD) LNB + SCR	4,650,000	611,000	172,000	198,000	224,000	783,000	809,000	835,000

[a]Capital recovery = Capital cost x capital recovery factor.
[b]Operating and maintenance costs at operating capacities of 10 percent, 50 percent, and 90 percent.
[c]Total annual cost = Capital recovery + operating and maintenance cost.

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TABLE 6-3. COSTS OF CONTROL TECHNIQUES FOR MD NATURAL GAS-FIRED MODEL HEATERS (1991 $)

Model heater capacity, MMBtu/hr	NO_x control technique	Capital costs, $	Annual costs, $/yr				Total annual costs, $/yr @ capacity factors:[c]		
			Capital recovery[a]	Operating and maintenance costs @ capacity factors [b]					
				0.1	0.5	0.9	0.1	0.5	0.9
40	LNB	130,000	17,100	3,570	3,570	3,570	20,700	20,700	20,700
	ULNB	136,000	17,900	3,750	3,750	3,750	21,700	21,700	21,700
	SNCR	258,000	34,000	8,000	11,600	15,100	42,000	45,500	49,100
	SCR	1,430,000	188,000	48,800	54,400	59,900	237,000	242,000	248,000
	LNB + FGR	234,000	30,700	6,740	8,010	9,270	37,500	38,700	40,000
	LNB + SNCR	388,000	51,000	11,600	15,100	18,700	62,600	66,200	69,800
	LNB + SCR	1,560,000	205,000	52,400	57,900	63,500	257,000	263,000	269,000
77	LNB	282,000	37,100	7,750	7,750	7,750	44,800	44,800	44,800
	ULNB	288,000	37,900	7,930	7,930	7,930	45,800	45,800	45,800
	SNCR	383,000	50,300	12,200	19,100	26,000	62,600	69,400	76,300
	SCR	2,140,000	281,000	77,000	87,800	98,500	358,000	369,000	380,000
	LNB + FGR	436,000	57,300	12,600	15,000	17,400	69,900	72,300	74,700
	LNB + SNCR	665,000	87,400	20,000	26,900	33,800	107,000	114,000	121,000
	LNB + SCR	2,420,000	318,000	84,800	95,500	106,000	403,000	414,000	424,000
114	LNB	507,000	66,700	14,000	14,000	14,000	80,700	80,700	80,700
	ULNB	514,000	67,600	14,100	14,100	14,100	81,700	81,700	81,700
	SNCR	484,000	63,700	15,900	26,100	36,200	79,500	89,700	99,900
	SCR	2,720,000	358,000	102,000	118,000	134,000	460,000	476,000	492,000
	LNB + FGR	702,000	92,300	20,200	23,800	27,400	113,000	116,000	120,000
	LNB + SNCR	992,000	130,000	29,800	40,000	50,200	160,000	170,000	181,000
	LNB + SCR	3,230,000	425,000	116,000	132,000	148,000	541,000	557,000	573,000
174	LNB	541,000	71,200	14,900	14,900	14,900	86,100	86,100	86,100
	ULNB	548,000	72,000	15,100	15,100	15,100	87,100	87,100	87,100
	SNCR	624,000	82,100	21,100	36,600	52,200	103,000	119,000	134,000
	SCR	3,540,000	466,000	139,000	163,000	187,000	604,000	629,000	653,000
	LNB + FGR	792,000	104,000	23,200	28,600	34,100	127,000	133,000	138,000
	LNB + SNCR	1,170,000	153,000	35,900	51,500	67,000	189,000	205,000	220,000
	LNB + SCR	4,080,000	537,000	154,000	178,000	202,000	690,000	715,000	739,000

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TABLE 6-3. (continued)

Model heater capacity, MMBtu/hr	NO_x control technique	Capital costs, $	Annual costs, $/yr				Total annual costs, $/yr @ capacity factors:[c]		
			Capital recovery[a]	Operating and maintenance costs @ capacity factors:[b]					
				0.1	0.5	0.9	0.1	0.5	0.9
263	LNB	777,000	102,000	21,400	21,400	21,400	123,000	123,000	123,000
	ULNB	783,000	103,000	21,500	21,500	21,500	124,000	124,000	124,000
	SNCR	800,000	105,000	27,900	51,400	74,900	133,000	157,000	180,000
	SCR	4,580,000	603,000	188,000	225,000	262,000	791,000	828,000	864,000
	LNB + FGR	1,100,000	144,000	32,300	40,600	48,900	177,000	185,000	193,000
	LNB + SNCR	1,580,000	207,000	49,200	72,700	96,200	256,000	280,000	303,000
	LNB + SCR	5,360,000	705,000	210,000	246,000	283,000	915,000	951,000	988,000

[a]Capital recovery = Capital cost x capital recovery factor.
[b]Operating and maintenance costs at operating capacities of 10 percent, 50 percent, and 90 percent.
[c]Total annual cost = Capital recovery + operating and maintenance cost.

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TABLE 6-4. COSTS OF CONTROL TECHNIQUES FOR ND OIL-FIRED MODEL HEATERS (1991 $)

Model heater capacity and fuel type, MMBtu/hr	NO_x control technique	Capital costs, $	Annual costs, $/yr[b]				Total annual costs, $/yr @ capacity factors:[c]		
			Capital recovery[a]	Operating and maintenance costs @ capacity factors:					
				0.1	0.5	0.9	0.1	0.5	0.9
69 Distillate oil-fired	(ND) LNB	227,000	29,900	6,250	6,250	6,250	36,100	36,100	36,100
	(MD) LNB	581,000	76,400	16,000	16,000	16,000	92,400	92,400	92,400
	(ND) ULNB	232,000	30,500	6,370	6,370	6,370	36,800	36,800	36,800
	(MD) ULNB	588,000	77,300	16,200	16,200	16,200	93,400	93,400	93,400
	(ND) SNCR	358,000	47,100	31,100	20,900	29,700	78,300	68,000	76,800
	(MD) SNCR	598,000	78,700	19,400	31,100	42,700	98,100	110,000	121,000
	(MD) SCR	2,240,000	294,000	81,500	105,000	129,000	376,000	400,000	424,000
	(MD) LNB + FGR	725,000	95,300	20,500	22,700	24,800	116,000	118,000	120,000
	(ND) LNB + SNCR	586,000	77,000	18,300	27,100	35,900	95,300	104,000	113,000
	(MD) LNB + SNCR	939,000	124,000	28,800	40,400	52,100	152,000	164,000	176,000
	(MD) LNB + SCR	2,580,000	339,000	90,900	115,000	139,000	430,000	454,000	478,000
69 Residual oil-fired	(ND) LNB	227,000	29,900	6,250	6,250	6,250	36,100	36,100	36,100
	(MD) LNB	581,000	76,400	16,000	16,000	16,000	92,400	92,400	92,400
	(ND) ULNB	232,000	30,500	6,370	6,370	6,370	36,800	36,800	36,800
	(MD) ULNB	588,000	77,300	16,200	16,200	16,200	93,400	93,400	93,400
	(ND) SNCR	358,000	47,100	12,900	25,100	37,400	60,000	72,300	84,500
	(MD) SNCR	598,000	78,700	20,200	33,200	46,100	98,900	112,000	125,000
	(MD) SCR	2,240,000	294,000	79,800	97,200	115,000	374,000	391,000	409,000
	(MD) LNB + FGR	725,000	95,300	20,500	22,700	24,800	116,000	118,000	120,000
	(ND) LNB + SNCR	586,000	77,000	19,200	31,400	43,600	96,200	108,000	121,000
	(MD) LNB + SNCR	939,000	124,000	29,400	43,800	58,200	153,000	167,000	182,000
	(MD) LNB + SCR	2,580,000	339,000	89,200	107,000	124,000	428,000	446,000	463,000

[a]Capital recovery = Capital cost * capital recovery factor.
[b]Operating and maintenance costs at operating capacities of 10 percent, 50 percent, and 90 percent.
[c]Total annual cost = Capital recovery + operating and maintenance cost.

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6.2.4 Control Costs for MD Oil-Fired, Low- and Medium-Temperature Model Heaters

Table 6-5 presents the capital costs, annual costs, and TAC's for the MD oil-fired, low- and medium-temperature model heaters. The capital cost of the control techniques range from $319,000 for LNB's to $3,340,000 for LNB's plus SCR. The capital cost for both MD oil-fired heaters are the same. The TAC's range from $50,700/yr for LNB's used on the distillate oil-fired heater to $570,000 for LNB's plus SCR used on the residual oil-fired heater.

6.2.5 Control Costs for the Olefins Pyrolysis Model Heaters

Table 6-6 present the capital costs, annual costs, and TAC for the ND olefins pyrolysis model heaters. The capital costs of the control techniques range from $248,000 for LNB's to $2,900,000 for LNB's plus SCR on both pyrolysis model heaters. The TAC's range from $39,400/yr for LBN's on the natural gas-fired heater to $512,000 for LBN's plus SCR on the high-hydrogen fuel gas-fired heater.

6.2.6 Costs for ND-to-MD Conversion

Table 6-7 presents the capital, annual operating, and TAC of the ND-to-MD conversion for the model heaters. The capital costs range from $104,000 to $434,000; the annual operating cost range from $2,860/yr to $11,900/yr; and the TAC's range from $16,500/yr to $69,000/yr for the 17 and 185 MMBtu/hr natural gas-fired low- and medium-temperature heaters, respectively.

6.3 COST EFFECTIVENESS OF NO_x CONTROLS FOR PROCESS HEATERS

This section presents the cost effectiveness for the control techniques presented in Section 6.2. The cost effectiveness, in dollars per ton of NO_x removed ($/ton), is calculated by dividing the TAC's by the annual NO_x emission reduction, in tons.

Capacity factors of 0.1, 0.5, and 0.9 of heater operation, were included in the cost-effectiveness analysis. The capacity factor affects the operating costs but not the capital costs. The capacity factor also influences the tons per year of NO_x produced by a process heater. For example, approximately

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TABLE 6-5. COSTS OF CONTROL TECHNIQUES FOR MD OIL-FIRED HEATERS (1991 $)

Model heater capacity and fuel type, MMBtu/hr	NO_x control technique	Capital costs, $	Annual costs, $/yr				Total annual costs, $/yr @ capacity factors:[c]		
			Capital recovery[a]	Operating and maintenance costs @ capacity factors:[b]					
				0.1	0.5	0.9	0.1	0.5	0.9
135 Distillate oil-fired	(MD) LNB	319,000	42,000	8,780	8,780	8,780	50,700	50,700	50,700
	(MD) ULNB	326,000	42,800	8,960	8,960	8,960	51,800	51,800	51,800
	SNCR	536,000	70,500	20,500	43,300	66,200	90,900	114,000	137,000
	SCR	3,130,000	411,000	89,900	105,000	121,000	501,000	516,000	532,000
	LNB + FGR	535,000	70,300	15,800	20,000	24,300	86,100	90,300	94,600
	LNB + SNCR	855,000	112,000	29,200	52,100	74,900	142,000	165,000	187,000
	LNB + SCR	3,340,000	440,000	95,800	111,000	127,000	536,000	551,000	566,000
135 Residual oil-fired	(MD) LNB	319,000	42,000	8,780	8,780	8,780	50,700	50,700	50,700
	(MD) ULNB	326,000	42,800	8,960	8,960	8,960	51,800	51,800	51,800
	SNCR	536,000	70,500	22,100	51,700	81,200	92,600	122,000	152,000
	SCR	3,130,000	411,000	90,200	107,000	124,000	501,000	518,000	535,000
	LNB + FGR	535,000	70,300	15,800	20,000	24,300	86,100	90,300	94,600
	LNB + SNCR	855,000	112,000	30,900	60,500	90,000	143,000	173,000	202,000
	LNB + SCR	3,340,000	440,000	96,200	113,000	130,000	536,000	553,000	570,000

[a]Capital recovery = Capital cost * capital recovery factor.
[b]Operating and maintenance costs at operating capacities of 10 percent, 50 percent, and 90 percent.
[c]Total annual cost = Capital recovery + operating and maintenance cost.

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TABLE 6-6. COSTS OF CONTROL TECHNIQUES FOR ND OLEFINS PYROLYSIS MODEL HEATERS (1991 $)

Model heater capacity and fuel type, MMBtu/hr	NO_x control technique	Capital costs, $	Annual costs, $/yr				Total annual costs, $/yr @ capacity factors:		
			Capital recovery[a]	Operating and maintenance costs @ capacity factors:[b]					
				0.1	0.5	0.9	0.1	0.5	0.9
84 Natural gas-fired	(ND) LNB	248,000	32,600	6,810	6,810	6,810	39,400	39,400	39,400
	(MD) LNB	642,000	84,400	17,700	17,700	17,700	102,000	102,000	102,000
	(ND) ULNB	252,000	33,100	6,930	6,930	6,930	40,100	40,100	40,100
	(MD)ULNB	648,000	85,300	17,800	17,800	17,800	103,000	103,000	103,000
	(ND) SNCR	403,000	53,000	12,300	17,100	21,900	65,300	70,100	74,900
	(MD) SNCR	673,000	88,500	19,700	24,500	29,300	108,000	113,000	118,000
	SCR	2,520,000	331,000	89,600	103,000	117,000	421,000	434,000	448,000
	(MD) LNB + FGR	804,000	106,000	22,800	25,400	28,100	128,000	131,000	134,000
	(ND) LNB + SNCR	651,000	85,600	19,100	23,900	28,700	105,000	109,000	114,000
	(MD) LNB + SNCR	1,050,000	137,000	29,900	34,700	39,500	167,000	172,000	177,000
	(MD) LNB + SCR	2,900,000	381,000	100,000	114,000	127,000	481,000	495,000	508,000
84 High-hydrogen fuel gas-fired	(ND) LNB	248,000	32,600	6,810	6,810	6,810	39,400	39,400	39,400
	(MD) LNB	642,000	84,400	17,700	17,700	17,700	102,000	102,000	102,000
	(ND) ULNB	252,000	33,100	6,930	6,930	6,930	40,100	40,100	40,100
	(MD) ULNB	648,000	85,300	17,800	17,800	17,800	103,000	103,000	103,000
	(ND) SNCR	403,000	53,000	12,500	18,400	24,200	65,600	71,400	77,300
	(MD) SNCR	673,000	88,500	20,000	25,800	31,700	109,000	114,000	120,000
	SCR	2,520,000	331,000	90,100	105,000	121,000	421,000	436,000	452,000
	(MD) LNB + FGR	804,000	106,000	22,800	25,400	28,100	128,000	131,000	134,000
	(ND) LNB + SNCR	651,000	85,600	19,400	25,200	31,100	105,000	111,000	117,000
	(MD) LNB + SNCR	1,050,000	137,000	30,200	36,100	41,900	168,000	173,000	179,000
	(MD) LNB + SCR	2,900,000	381,000	100,000	116,000	131,000	481,000	497,000	512,000

[a]Capital recovery = Capital cost * capital recovery factor.
[b]Operating and maintenance costs at operating capacities of 10 percent, 50 percent, and 90 percent.
[c]Total annual cost = Capital recovery + operating and maintenance cost.

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TABLE 6-7. ND-TO-MD CONVERSION COSTS FOR THE ND MODEL HEATERS (1991 $)

Model heater capacity, MMBtu/hr	Capital cost, 1991 US $	Capital recovery, 1991 US $/yr	Annual operating costs, 1991 US $/yr	Total annual costs, 1991 US $/yr
ND NATURAL GAS-FIRED HEATERS				
17	104,000	13,600	2,860	16,500
36	163,000	21,400	4,480	25,900
77	257,000	33,800	7,070	40,900
121	336,000	442,000	9,240	53,400
185	434,000	57,100	11,900	69,000
ND OIL-FIRED HEATERS				
69	240,000	31,600	6,400	38,000
ND OLEFINS PYROLYSIS HEATERS				
84	270,000	35,500	7,430	42,900

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90 percent less NO_x is produced by a heater operating at a capacity factor of 0.1 as opposed to 1.0.

Cost effectiveness for ND natural gas-fired heaters is presented in Table 6-8. The cost-effectiveness range at a capacity factor of 0.9 is from $981/ton for ND ULNB's on the 77 MMBtu/hr heater to $16,200/ton for SCR on the 17 MMBtu/hr heater. The cost-effectiveness range for MD natural gas-fired heaters is shown in Table 6-9. At a capacity factor of 0.9, the cost effectiveness ranges from $813/ton for ULNB's on the 263 MMBtu/hr heater to $10,600/ton for SCR on the 40 MMBtu/hr heater.

The cost-effectiveness range for oil-fired ND heaters is shown in Table 6-10. For a capacity factor of 0.9, the cost effectiveness ranges from $419/ton for ND ULNB's on the residual oil-fired heater to $6,490/ton for SCR on the distillate oil-fired heater. The cost-effectiveness range for oil-fired MD heaters, shown in Table 6-11, is from $245/ton for ULNB's on the residual oil-fired heater to $4,160/ton for SCR on the distillate oil-fired heater at a capacity factor of 0.9.

The cost-effectiveness range for the ND olefins pyrolysis model heaters is shown in Table 6-12. At a capacity factor of 0.9, the cost effectiveness ranges from $1,490/ton for MD ULNB's on the high-hydrogen fuel gas-fired heater to $14,100/ton for LNB+SCR on the natural gas-fired heater.

The cost effectiveness of each control technique for the model heaters generally increases from ULNB to LNB, to LNB plus FGR, to SNCR, to LNB plus SNCR, to LNB plus SCR, to SCR. The cost-effectiveness values for the control techniques applied to the smaller model heaters are generally higher in comparison to the same control techniques applied to the larger heaters. This difference represents an economy of scale because for a given percent reduction, the quantity of NO_x emissions removed per year (tons/yr) from the smaller model heaters was lower than from other model heaters.

Table 6-13 is a summary of the cost effectiveness of selected NO_x emission control techniques as presented by the

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TABLE 6-8. COST EFFECTIVENESS OF CONTROL TECHNIQUES FOR ND NATURAL GAS-FIRED MODEL HEATERS (1991 $)

Model heater capacity, MMBtu/hr	NO_x control technique	Uncontrolled NO_x emissions, ton/yr @ capacity factors:			Total effective reduction, percent	NO_x reduction, ton/yr @ capacity factors:			Total annual costs, $/yr @ capacity factors			Cost effectiveness, $/ton @ capacity factors:[a]		
		0.1	0.5	0.9		0.1	0.5	0.9	0.1	0.5	0.9	0.1	0.5	0.9
17	(ND) LNB	0.730	3.65	6.57	50	0.365	1.82	3.28	9,250	9,250	9,250	25,400	5,070	2,820
	(MD) LNB	1.47	7.33	13.2	50	0.733	3.67	6.60	30,400	30,400	30,400	41,400	8,280	4,600
	(ND) ULNB	0.730	3.65	6.57	75	0.547	2.74	4.93	9,940	9,940	9,940	18,200	3,630	2,020
	(MD) ULNB	1.47	7.33	13.2	75	1.10	5.50	9.90	39,600	39,600	39,600	36,000	7,200	4,000
	(ND) SNCR	0.730	3.65	6.57	60	0.438	2.19	3.94	24,800	25,700	26,700	56,700	11,800	6,770
	(MD) SNCR	1.47	7.33	13.2	60	0.880	4.40	7.92	41,400	43,000	44,500	47,100	9,760	5,610
	(MD) SCR	1.47	7.33	13.2	75	1.10	5.50	9.90	155,000	158,000	160,000	141,000	28,700	16,200
	(MD) LNB + FGR	1.47	7.33	13.2	55	0.807	4.03	7.26	40,400	40,900	41,400	50,000	10,100	5,710
	(ND) LNB + SNCR	0.730	3.65	6.57	80	0.584	2.92	5.25	34,100	35,000	35,900	58,400	12,000	6,840
	(MD) LNB + SNCR	1.47	7.33	13.2	80	1.17	5.87	10.6	55,300	56,800	58,400	47,100	9,690	5,530
	(MD) LNB + SCR	1.47	7.33	13.2	88	1.28	6.42	11.6	169,000	172,000	174,000	132,000	26,700	15,100
36	(ND) LNB	1.55	7.73	13.9	50	0.773	3.86	6.95	14,700	14,700	14,700	19,100	3,810	2,120
	(MD) LNB	3.11	15.5	28.0	50	1.55	7.77	14.0	47,900	47,900	47,900	30,900	6,170	3,430
	(ND) ULNB	1.55	7.73	13.9	75	1.16	5.79	10.4	15,400	15,400	15,400	13,300	2,660	1,480
	(MD) ULNB	3.11	15.5	28.0	75	2.33	11.6	21.0	49,000	49,000	49,000	21,000	4,200	2,330
	(ND) SNCR	1.55	7.73	13.9	60	0.927	4.64	8.34	39,000	41,000	43,000	42,100	8,850	5,150
	(MD) SNCR	3.11	15.5	28.0	60	1.86	9.32	16.8	65,200	67,700	70,100	35,000	7,260	4,180
	(MD) SCR	3.11	15.5	28.0	75	2.33	11.6	21.0	247,000	252,000	257,000	106,000	21,700	12,300
	(MD) LNB + FGR	3.11	15.5	28.0	55	1.71	8.54	15.4	63,700	64,800	66,000	37,300	7,590	4,290
	(ND) LNB + SNCR	1.55	7.73	13.9	80	1.24	6.18	11.1	53,800	55,800	57,700	43,500	9,020	5,190
	(MD) LNB + SNCR	3.11	15.5	28.0	80	2.49	12.4	22.4	87,300	90,500	93,700	35,100	7,280	4,190
	(MD) LNB + SCR	3.11	15.5	28.0	88	2.72	13.6	24.5	270,000	275,000	280,000	99,200	20,200	11,400

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TABLE 6-8. (continued)

Model heater capacity, MMBtu/hr	NO_x control technique	Uncontrolled NO_x emissions, ton/yr @ capacity factors:			Total effective reduction, percent	NO_x reduction, ton/yr @ capacity factors:			Total annual costs, $/yr @ capacity factors:			Cost effectiveness, $/ton @ capacity factors:[a]		
		0.1	0.5	0 9		0 1	0.5	0 9	0.1	0.5	0.9	0.1	0 5	0 9
77	(ND) LNB	3.31	16 5	29.7	50	1.65	8.26	14.9	21,200	21,200	21,200	12,800	2,570	1,430
	(MD) LNB	6.64	33.2	59.8	50	3.32	16.6	29 9	72,600	72,600	72,600	21,900	4,370	2,430
	(ND) ULNB	3.31	16.5	29.7	75	2.48	12 4	22.3	21,900	21,900	21,900	8,830	1,770	981
	(MD) ULNB	6.64	33.2	59.8	75	4.98	24.9	44.8	73,600	73,600	73,600	14,800	2,950	1,640
	(ND) SNCR	3.31	16.5	29.7	60	1.98	9 92	17.8	61,900	66,100	70,400	31,200	6,670	3,940
	(MD) SNCR	6.64	33.2	59.8	60	3.99	19.9	35.9	103,000	109,000	114,000	25,900	5,450	3,170
	(MD) SCR	6.64	33.2	59.8	75	4.98	24.9	44.8	399,000	410,000	420,000	80,100	16,400	9,370
	(MD) LNB + FGR	6.64	33.2	59.8	55	3.65	18.3	32.9	97,600	100,000	103,000	26,700	5,480	3,120
	(ND) LNB + SNCR	3.31	16.5	29.7	80	2.64	13.2	23.8	83,100	87,300	91,600	31,400	6,610	3,850
	(MD) LNB + SNCR	6.64	33.2	59.8	80	5.32	26 6	47.8	135,000	142,000	149,000	25,400	5,340	3,110
	(MD) LNB + SCR	6.64	33.2	59 8	88	5.81	29.1	52.3	431,000	441,000	452,000	74,100	15,200	8,640
121	(ND) LNB	5.19	26.0	46.7	50	2.60	13 0	23.4	36,900	36,900	36,900	14,200	2,840	1,580
	(MD) LNB	10.4	52.2	94.0	50	5.22	26 1	47.0	109,000	109,000	109,000	20,900	4,170	2,320
	(ND) ULNB	5.19	26.0	46.7	75	3.90	19.5	35.1	37,600	37,600	37,600	9,660	1,930	1,070
	(MD) ULNB	10.4	52.2	94.0	75	7.83	39.2	70.5	110,000	110,000	110,000	14,000	2,810	1,560
	(ND) SNCR	5.19	26.0	46.7	60	3.12	15.6	28.0	81,500	88,100	94,800	26,100	5,660	3,380
	(MD) SNCR	10.4	52.2	94.0	60	6.26	31.3	56 4	136,000	144,000	153,000	21,700	4,610	2,710
	(MD) SCR	10.4	52.2	94.0	75	7.83	39.2	70 5	532,000	548,000	565,000	67,900	14,000	8,020
	(MD) LNB + FGR	10.4	52.2	94.0	55	5.74	28.7	51.7	142,000	146,000	150,000	24,700	5,080	2,890
	(ND) LNB + SNCR	5.19	26.0	46.7	80	4 16	20.8	37.4	118,000	125,000	132,000	28,500	6,020	3,520
	(MD) LNB + SNCR	10.4	52.2	94.0	80	8.35	41.8	75.2	191,000	202,000	213,000	22,900	4,840	2,830
	(MD) LNB + SCR	10.4	52.2	94 0	88	9 14	45.7	82.2	587,000	604,000	621,000	64,300	13,200	7,550

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TABLE 6-8. (continued)

Model heater capacity, MMBtu/hr	NO_x control technique	Uncontrolled NO_x emissions, ton/yr @ capacity factors:			Total effective reduction, percent	NO_x reduction, ton/yr @ capacity factors:			Total annual costs, $/yr @ capacity factors:			Cost effectiveness, $/ton @ capacity factors:[a]		
		0.1	0.5	0.9		0 1	0.5	0 9	0.1	0 5	0.9	0.1	0.5	0 9
186	(ND) LNB	7.98	39.9	71 9	50	3.99	20 0	35.9	55,000	55,000	55,000	13,800	2,760	1,530
	(MD) LNB	16.0	80.2	144	50	8.02	40 1	72.2	152,000	152,000	152,000	18,900	3,780	2,100
	(ND) ULNB	7.98	39.9	71.9	75	5.99	29.9	53.9	55,700	55,700	55,700	9,310	1,860	1,030
	(MD) ULNB	16,0	80.2	144	75	12.0	60.2	108	153,000	153,000	153,000	12,700	2,540	1,410
	(ND) SNCR	7.98	39.9	71.9	60	4.79	24.0	43.1	106,000	116,000	126,000	22,100	4,850	2,930
	(MD) SNCR	16.0	80.2	144	60	9.63	48.1	86.7	177,000	189,000	202,000	18,300	3,930	2,330
	(MD) SCR	16.0	80.2	144	75	12.0	60.2	108	700,000	726,000	752,000	58,200	12,100	6,940
	(MD) LNB + FGR	16.0	80.2	144	55	8.83	44 1	79.4	195,000	201,000	207,000	22,100	4,550	2,600
	(ND) LNB + SNCR	7.98	39.9	71.9	80	6.39	31 9	57 5	161,000	171,000	181,000	25,200	5,360	3,150
	(MD) LNB + SNCR	16.0	80.2	144	80	12 8	64 2	116	259,000	276,000	292,000	20,200	4,300	2,530
	(MD) LNB + SCR	16.0	80.2	144	88	14 0	70 2	126	783,000	809,000	835,000	55,700	11,500	6,600

[a]Cost effectiveness = Total annual cost/NO_x reductions.

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TABLE 6-9. COST EFFECTIVENESS OF CONTROL TECHNIQUES FOR MD NATURAL GAS-FIRED MODEL HEATERS (1991 $)

Model heater capacity, MMBtu/hr	NO_x control technique	Uncontrolled NO_x emissions, ton/yr @ capacity factors:			Total effective reductions, percent	NO_x reductions, ton/yr @ capacity factors			Total annual costs, $/yr @ capacity factors:			Cost effectiveness, $/ton @ capacity factors:[a]		
		0.1	0.5	0.9		0.1	0.5	0.9	0.1	0.5	0.9	0.1	0.5	0.9
40	LNB	3.45	17.3	31.1	50	1.73	8.63	15.5	20,700	20,700	20,700	12,000	2,390	1,330
	ULNB	3.45	17.3	31.1	75	2.59	12.9	23.3	21,700	21,700	21,700	8,380	1,680	931
	SNCR	3.45	17.3	31.1	60	2.07	10.4	18.6	42,000	45,500	49,100	20,300	4,400	2,640
	SCR	3.45	17.3	31.1	75	2.59	12.9	23.3	237,000	242,000	248,000	91,500	18,700	10,600
	LNB + FGR	3.45	17.3	31.1	55	1.90	9.49	17.1	37,500	38,700	40,000	19,700	4,080	2,340
	LNB + SNCR	3.45	17.3	31.1	80	2.76	13.8	24.9	62,600	66,200	69,800	22,700	4,790	2,810
	LNB + SCR	3.45	17.3	31.1	88	3.02	15.1	27.2	257,000	263,000	269,000	85,200	17,400	9,880
77	LNB	6.64	33.2	59.8	50	3.32	16.6	29.9	44,800	44,800	44,800	13,500	2,700	1,500
	ULNB	6.64	33.2	59.8	75	4.98	24.9	44.8	45,800	45,800	45,800	9,200	1,840	1,020
	SNCR	6.64	33.2	59.8	60	3.99	19.9	35.9	62,600	69,400	76,300	15,700	3,480	2,130
	SCR	6.64	33.2	59.8	75	4.98	24.9	44.8	358,000	369,000	380,000	71,900	14,800	8,460
	LNB + FGR	6.64	33.2	59.8	55	3.65	18.3	32.9	69,900	72,300	74,700	19,100	3,960	2,270
	LNB + SNCR	6.64	33.2	59.8	80	5.32	26.6	47.8	107,000	114,000	121,000	20,200	4,300	2,530
	LNB + SCR	6.64	33.2	59.8	88	5.81	29.1	52.3	403,000	414,000	424,000	69,300	14,200	8,110
114	LNB	9.84	49.2	88.5	50	4.92	24.6	44.3	80,700	80,700	80,700	16,400	3,280	1,820
	ULNB	9.84	49.2	88.5	75	7.38	36.9	66.4	81,700	81,700	81,700	11,100	2,210	1,230
	SNCR	9.84	49.2	88.5	60	5.90	29.5	53.1	79,500	89,700	99,900	13,500	3,040	1,880
	SCR	9.84	49.2	88.5	75	7.38	36.9	66.4	460,000	476,000	492,000	62,400	12,900	7,410
	LNB + FGR	9.84	49.2	88.5	55	5.41	27.1	48.7	113,000	116,000	120,000	20,800	4,290	2,460
	LNB + SNCR	9.84	49.2	88.5	80	7.87	39.3	70.8	160,000	170,000	181,000	20,400	4,330	2,550
	LNB + SCR	9.84	49.2	88.5	88	8.61	43.0	77.5	541,000	557,000	573,000	62,800	12,900	7,390
174	LNB	15.0	75.1	135	50	7.51	37.5	67.6	86,100	86,100	86,100	11,500	2,290	1,270
	ULNB	15.0	75.1	135	75	11.3	56.3	101	87,100	87,100	87,100	7,730	1,550	859
	SNCR	15.0	75.1	135	60	9.01	45.0	81.1	103,000	119,000	134,000	11,400	2,630	1,660
	SCR	15.0	75.1	135	75	11.3	56.3	101	604,000	629,000	653,000	53,700	11,200	6,440
	LNB + FGR	15.0	75.1	135	55	8.26	41.3	74.3	127,000	133,000	138,000	15,400	3,220	1,860
	LNB + SNCR	15.0	75.1	135	80	12.0	60.1	108	189,000	205,000	220,000	15,700	3,410	2,040
	LNB + SCR	15.0	75.1	135	88	13.1	65.7	118	690,000	715,000	739,000	52,600	10,900	6,250

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TABLE 6-9. (continued)

Model heater capacity, MMBtu/hr	NO_x control technique	Uncontrolled NO_x emissions, ton/yr @ capacity factors:			Total effective reductions, percent	NO_x reductions, ton/yr @ capacity factors:			Total annual costs, $/yr @ capacity factors:			Cost effectiveness, $/ton @ capacity factors:[a]		
		0.1	0.5	0.9		0.1	0.5	0.9	0.1	0.5	0.9	0.1	0.5	0.9
263	LNB	22.7	113	204	50	11.3	56.7	102	123,000	123,000	123,000	10,900	2,180	1,210
	ULNB	22.7	113	204	75	17.0	85.1	153	124,000	124,000	124,000	7,310	1,460	813
	SNCR	22.7	113	204	60	13.6	68.1	123	133,000	157,000	180,000	9,770	2,300	1,470
	SCR	22.7	113	204	75	17.0	85.1	153	791,000	828,000	864,000	46,500	9,730	5,640
	LNB + FGR	22.7	113	204	55	12.5	62.4	112	177,000	185,000	193,000	14,200	2,960	1,720
	LNB + SNCR	22.7	113	204	80	18.2	90.8	163	256,000	280,000	303,000	14,100	3,080	1,860
	LNB + SCR	22.7	113	204	88	19.9	99.3	179	915,000	951,000	988,000	46,100	9,580	5,530

[a]Cost effectiveness = Total annual cost/NO_x reductions.

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TABLE 6-10. COST EFFECTIVENESS OF CONTROL TECHNIQUES FOR ND OIL-FIRED MODEL HEATERS (1991 $)

Model heater capacity and fuel type, MMBtu/hr	NO_x control technique	Uncontrolled NO_x emission, ton/yr @ capacity factors:			Total effective reduction, percent	NO_x reductions, ton/yr @ capacity factors:			Total annual costs, $/yr @ capacity factors:			Cost effectiveness, $/ton @ capacity factors [a]		
		0.1	0.5	0.9		0.1	0.5	0.9	0.1	0.5	0.9	0.1	0.5	0.9
69 Distillate oil-fired	(ND) LNB	6.04	30.2	54.4	40	2.39	11.9	21.5	36,100	36,100	36,100	15,100	3,030	1,680
	(MD) LNB	9.67	48.4	87.0	45	4.38	21.9	39.4	92,400	92,400	92,400	21,100	4,220	2,340
	(ND) ULNB	6.04	30.2	54.4	76	4.59	22.9	41.3	36,800	36,800	36,800	8,030	1,610	892
	(MD) ULNB	9.67	48.4	87.0	74	7.20	36.0	64.8	93,400	93,400	93,400	13,000	2,600	1,440
	(ND) SNCR	6.04	30.2	54.4	60	3.63	18.1	32.6	78,300	68,000	76,800	16,300	3,750	2,350
	(MD) SNCR	9.67	48.4	87.0	60	5.80	29.0	52.2	98,100	110,000	121,000	16,900	3,780	2,330
	(MD) SCR	9.67	48.4	87.0	75	7.25	36.3	65.3	376,000	400,000	424,000	51,800	11,000	6,490
	(MD) LNB + FGR	9.67	48.4	87.0	48	4.59	23.0	41.3	116,000	118,000	120,000	25,200	5,140	2,910
	(ND) LNB + SNCR	6.04	30.2	54.4	76	4.58	22.9	41.2	95,300	104,000	113,000	20,800	4,540	2,740
	(MD) LNB + SNCR	9.67	48.4	87.0	78	7.56	37.8	68.0	152,000	164,000	176,000	20,200	4,340	2,580
	(MD) LNB + SCR	9.67	48.4	87.0	86	8.35	41.7	75.1	430,000	454,000	478,000	51,500	10,900	6,360
69 Residual oil-fired	(ND) LNB	12.7	63.5	114	27	3.38	16.9	30.5	36,100	36,100	36,100	10,700	2,140	1,190
	(MD) LNB	16.3	81.6	147	37	6.04	30.2	54.4	92,400	92,400	92,400	15,300	3,060	1,700
	(ND) ULNB	12.7	63.5	114	77	9.77	48.9	88.0	36,800	36,800	36,800	3,770	753	419
	(MD) ULNB	16.3	81.6	147	73	12.0	59.9	108	93,400	93,400	93,400	7,790	1,560	866
	(ND) SNCR	12.7	63.5	114	60	7.62	38.1	68.5	60,000	72,300	84,500	7,880	1,900	1,230
	(MD) SNCR	16.3	81.6	147	60	9.79	49.0	88.1	98,900	112,000	125,000	10,100	2,280	1,420
	(MD) SCR	16.3	81.6	147	75	12.2	61.2	110	374,000	391,000	409,000	30,600	6,400	3,710
	(MD) LNB + FGR	16.3	81.6	147	34	5.59	28.0	50.3	116,000	118,000	120,000	20,700	4,220	2,390
	(ND) LNB + SNCR	12.7	63.5	114	71	8.97	44.8	80.7	96,200	108,000	121,000	10,700	2,420	1,490
	(MD) LNB + SNCR	16.3	81.6	147	75	12.2	61.0	110	153,000	167,000	182,000	12,500	2,740	1,650
	(MD) LNB + SCR	16.3	81.6	147	84	13.8	68.8	124	428,000	446,000	463,000	31,200	6,480	3,740

[a] Cost effectiveness = Total annual cost/NO_x reductions

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TABLE 6-11. COST EFFECTIVENESS OF CONTROL TECHNIQUES FOR MD OIL-FIRED MODEL HEATERS (1991 $)

Model heater capacity, MMBtu/hr	NO_x control technique	Uncontrolled NO_x emissions, ton/yr @ capacity factors:			Total effective reduction, percent	NO_x reductions, ton/yr @ capacity factors:			Total annual costs, $/yr @ capacity factors:			Cost effectiveness, ton/yr @ capacity factors:[a]		
		0.1	0.5	0.9		0.1	0.5	0.9	0.1	0.5	0.9	0.1	0.5	0.9
135	(MD) LNB	18.9	94.6	170	45	8.57	42.9	77.2	50,700	50,700	50,700	5,920	1,180	658
	(MD) ULNB	18.9	94.6	170	74	14.1	70.4	127	51,800	51,800	51,800	3,680	735	408
	SNCR	18.9	94.6	170	60	11.4	56.8	102	90,900	114,000	137,000	8,010	2,000	1,340
	SCR	18.9	94.6	170	75	14.2	71.0	128	501,000	516,000	532,000	35,300	7,280	4,160
	LNB + FGR	18.9	94.6	170	48	8.99	44.9	80.9	86,100	90,300	94,600	9,570	2,010	1,170
	LNB + SNCR	18.9	94.6	170	78	14.8	73.9	133	142,000	165,000	187,000	9,580	2,230	1,410
	LNB + SCR	18.9	94.6	170	92	17.4	86.8	156	536,000	551,000	566,000	30,800	6,340	3,620
135	(MD) LNB	31.9	160	287	37	11.8	59.1	106	50,700	50,700	50,700	4,290	858	477
	(MD) ULNB	31.9	160	287	73	23.5	117	211	51,800	51,800	51,800	2,210	442	245
	SNCR	31.9	160	287	60	19.2	95.8	172	92,600	122,000	152,000	4,830	1,280	880
	SCR	31.9	160	287	75	23.9	120	216	501,000	518,000	535,000	20,900	4,330	2,480
	LNB + FGR	31.9	160	287	34	10.9	54.7	98.5	86,100	90,300	94,600	7,870	1,650	961
	LNB + SNCR	31.9	160	287	75	23.9	119	215	143,000	173,000	202,000	6,000	1,450	942
	LNB + SCR	31.9	160	287	91	28.9	145	260	536,000	553,000	570,000	18,500	3,820	2,190

[a]Cost effectiveness = Total annual cost/NO_x reductions.

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TABLE 6-12. COST EFFECTIVENESS OF CONTROL TECHNIQUES FOR ND PYROLYSIS MODEL HEATERS (1991 $)

Model heater capacity and fuel type, MMBtu/hr	NO_x control technique	Uncontrolled emissions, ton/yr @ capacity factors:			Total effective reduction, percent	Controlled emissions, ton/yr @ capacity factors:			Reduction, ton/yr @ capacity factors:			Total annual costs, $/yr @ capacity factors:			Cost effectiveness, $/ton removed, @ capacity factors:[a]		
		0.1	0.5	0.9		0.1	0.5	0.9	0.1	0.5	0.9	0.1	0.5	0.9	0.1	0.5	0.9
84	(ND) LNB	4.97	24.8	44.7	25	3.73	18.6	33.5	1.24	6.21	11 2	39,400	39,400	39,400	31,700	6,350	3,530
	(MD) LNB	4.97	24.8	44.7	25	3.73	18.6	33.5	1.24	6.21	11.2	102,000	102,000	102,000	82,200	16,400	9,130
natural gas	(ND) ULNB	4.97	24.8	44.7	50	2.48	12.4	22.4	2.48	12.4	22.4	40,100	40,100	40,100	16,100	3,230	1,790
	(MD)ULNB	4.97	24.8	44.7	50	2.48	12.4	22.4	2.48	12.4	22.4	103,000	103,000	103,000	41,500	8,300	4,610
	(ND) SNCR	4.97	24.8	44.7	60	1.99	9 93	17.9	2 98	14.9	26.8	65,500	71,200	76,900	22,000	4,780	2,870
	(MD) SNCR	4.97	24.8	44.7	60	1.99	9.93	17.9	2.98	14.9	26.8	108,000	114,000	120,000	36,400	7,660	4,470
	SCR	4.97	24.8	44.7	75	1.24	6.21	11.2	3.73	18.6	33.5	421,000	436,000	451,000	113,000	23,400	13,500
	(MD) LNB + FGR	4.97	24.8	44.7	55	2.24	11.2	20.1	2.73	13.7	24.6	128,000	131,000	134,000	47,000	9,600	5,440
	(ND) LNB + SNCR	4.97	24.8	44.7	70	1.49	7.45	13.4	3.48	17.4	31.3	105,000	111,000	116,000	30,200	6,360	3,720
	(MD) LNB + SNCR	4.97	24.8	44.7	70	1.49	7.45	13 4	3.48	17.4	31.3	168,000	173,000	179,000	48,200	9,970	5,720
	(MD) LNB + SCR	4.97	24.8	44.7	81	0.93	4.66	8.38	4.04	20.2	36.3	481,000	497,000	512,000	119,000	24,600	14,100
84	(ND) LNB	5.96	29.8	53.6	25	4.47	22.4	40.2	1.49	7.45	13.4	39,400	39,400	39,400	26,400	5,290	2,940
	(MD) LNB	5.96	29.8	53.6	25	4 47	22.4	40.2	1.49	7.45	13.4	102,000	102,000	102,000	68,500	13,700	7,610
	(ND) ULNB	5.96	29.8	53.6	50	2.98	14.9	26.8	2.98	14.9	26.8	40,100	40,100	40,100	13,400	2,690	1,490
	(MD) ULNB	5.96	29.8	53.6	50	2.98	14.9	26.8	2.98	14.9	26.8	103,000	103,000	103,000	34,600	6,920	3,840
high hydrogen	(ND) SNCR	5.96	29.8	53.6	60	2.38	11.9	21.5	3.58	17.9	32.2	65,700	72,200	78,700	18,400	4,040	2,450
fuel gas	(MD) SNCR	5.96	29.8	53.6	60	2.38	11.9	21.5	3.58	17.9	32.2	109,000	115,000	122,000	30,400	6,440	3,780
	SCR	5.96	29.8	53.6	75	1.49	7.45	13.4	4.47	22.4	40.2	421,000	438,000	454,000	94,300	19,600	11,300
	(MD) LNB + FGR	5.96	29.8	53.6	55	2.68	13.4	24.1	3.28	16.4	29.5	128,000	131,000	134,000	39,200	8,000	4,530
	(ND) LNB + SNCR	5.96	29.8	53.6	70	1.79	8.94	16.1	4.17	20.9	37.5	105,000	112,000	118,000	25,200	5,350	3,140
	(MD) LNB + SNCR	5.96	29.8	53.6	70	1.79	8.94	16.1	4.17	20.9	37.5	168,000	174,000	181,000	40,200	8,350	4,810
	(MD) LNB + SCR	5.96	29.8	53.6	81	1.12	5.59	10.1	4.84	24.2	43.6	482,000	498,000	514,000	99,500	20,600	11,800

[a]Cost effectiveness = Total annual cost/NO_x reductions

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TABLE 6-13. CARB COST EFFECTIVENESS FOR NO_x EMISSION CONTROL TECHNIQUES (1991 $)[12]

Control technology	Annual capacity factor, percent	Unit size range, MMBtu/hr	Cost effectiveness range, thousand/ton NO_x[a]
Low-NO_x burners	10	3.5 to 150	2.61 to 30.6
	50		0.570 to 7.25
	90		0.340 to 4.53
Flue gas recirculation	10	3.5 to 350	7.71 to 32.9
	50		1.81 to 7.71
	90		1.13 to 4.19
Selective noncatalytic reduction	10	50 to 375	2.61 to 22.7
	50		1.70 to 6.80
	90		1.47 to 4.31
Selective catalytic reduction	10	50 to 350	27.2 to 74.8
	50		6.80 to 15.9
	90		4.53 to 10.2

[a]Escalated from 1986 $ to 1991 $ using the Chemical Engineering plant cost index.[3]

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California Air Resources Board (CARB).[12] The accuracy of the cost methodologies used in this study is estimated to be 30 percent plus or minus the actual cost.[1] The cost-effectiveness values of the control techniques for the model heaters are generally consistent with the ranges given in Table 6-13.

When comparing the cost effectiveness of combination control techniques in Table 6-13 to those in Tables 6-8 through 6-12, it is necessary to add the cost effectiveness of each component in Table 6-13. For example, the cost effectiveness of LNB's and SCR should be added to yield the total cost effectiveness of LNB's combined with SCR.

6.4 COST EFFECTIVENESS OF RADIANT BURNERS

This section presents the costs and cost-effectiveness values for a process heater using radiant burners. Data are insufficient to allow the development of model heaters with radiant burners. However, cost data for a new installation were provided for a 6 MMBtu/hr process heater using radiant burners. Retrofit costs are expected to be much higher for most process heater applications due to the major construction cost of modifying existing process heaters to accept radiant burners.[5] Refer to Section 5.1.8 for a discussion of radiant burners.

Emission reduction data for the 6 MMBtu/hr heater were presented in Table 5-6. The capital costs, capital recovery, annual costs, and cost-effectiveness values are presented in Table 6-14. The capital cost for radiant burners for this heater is $38,000. The annual costs range from $12,600/yr to $8,280/yr for capacity factors of 0.9 and 0.3, respectively. The cost effectiveness range from $7,600/ton to $17,600/ton for capacity factors of 0.9 and 0.3, respectively.[5]

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TABLE 6-14. RADIANT BURNER COST EFFECTIVENESS[5]

Heater capacity, MMBtu/hr	Capacity factor	Emission reduction, tons/yr[a]	Cost, $ 1991				Cost effectiveness, $/ton
			Capital	Capital recovery[b]	Annual operating	Total annual	
6	0.9	2.46	38,000	6,150	12,600	18,700	7,600
6	0.5	1.36	38,000	6,150	9,700	15,900	11,700
6	0.3	0.82	38,000	6,150	8,280	14,400	17,600

[a]Emission reduction compared to an MD heater with conventional burners.
[b]The capital recovery factor is 0.131.

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6.5 REFERENCES FOR CHAPTER 6

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CARBON LIMITS

Zero emission technologies for pneumatic controllers in the USA

Applicability and cost effectiveness



NMED Exhibit 110

CARBON LIMITS

This report was prepared by Carbon Limits AS.

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Carbon Limits is a consulting company with long standing experience in supporting energy efficiency measures in the petroleum industry. In particular, our team works in close collaboration with industries, government, and public bodies to identify and address inefficiencies in the use of natural gas and through this to achieve reductions in greenhouse gas emissions and other air pollutants.

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Executive Summary

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. However, these devices release methane into the atmosphere. Pneumatic controllers are the second-largest source of methane from the US oil and gas industry, behind only component leaks, according to US EPA's Greenhouse Gas Inventory.

US Federal rules require that new continuous-bleed controllers be *low-bleed* (defined as designed to emit less than six standard cubic feet/hour) at production sites and compressor stations and be *zero-bleed* at processing plants. Unfortunately, recent measurements have demonstrated that many controllers currently in field use are emitting more than would be expected based on design specifications.

This study was undertaken to determine whether cost-effective non-emitting technologies are available to eliminate this major emissions source. We find that these technologies have evolved considerably over the past decade and are now available and actively in use in oil and gas fields in the United States and Canada. Two technologies are mature, proven, and in relatively wide use, and as we discuss in this report, these technologies provide a cost-effective way to eliminate emissions of methane and other pollutants from pneumatic controllers.

Major findings include:

- Zero emission technologies can virtually eliminate emissions from pneumatic devices.
- A number of technologies are available. The two most promising, which this report focuses on, are electronic controllers – both solar and grid powered – and instrument air**.**

  Electronic controllers can be installed both at sites connected to the electric grid and at sites isolated from the grid.

  Instrument air technology is a well-established, mature solution to run pneumatic control systems and is widely applied globally. The technology requires a reliable power supply, either from the grid or from generators on the site.
- Currently, electronic controllers are generally used at smaller sites while instrument air is used at larger sites, due to the technical limitations of air compressors. These two technologies are on the market today, from multiple suppliers.
- Due to the market conditions, providers of electronic controllers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites; however, no technical barriers were identified for this type of installation.
- A number of other zero emission solutions are available today with more limited applicability (e.g. self-contained devices) or fewer documented implementations (e.g. solar-powered instrument air). Depending on the site specificities, these options can represent useful alternatives to instrument air or electronic controllers.
- Operators have successfully installed hundreds of systems. They report positive experiences on both new and retrofit sites, valuing zero emission solutions for their low maintenance costs and reliability.
- An economic analysis, assuming conservative average emission factors for pneumatic controllers, was performed for 2032 site configurations with 1 to 40 controllers (excluding emergency

shutdown devices). Both retrofit and new installations, with and without electricity on-site, were considered.

- Zero emission solutions have abatement costs below the social cost of methane used by US EPA ($1354/tCH$_4$, mean value calculated for 2020 with a 3% discount rate in 2016 USD) in the vast majority of the site configurations considered (2008 out of 2032 site configurations).
- The abatement costs, calculated as described above, exceed the social cost of methane used by US EPA primarily at very small sites – those with less than three controllers (excluding emergency shutdown devices). However, if higher emission factors, as reported from recent field measurements, are used, the abatement costs at even the very small sites will fall below the social cost of methane.

Overall, we find that zero emission solutions are available today and are cost effective to implement in nearly every situation.

The following table presents a summary of both the technical applicability and economic attractiveness of the different zero emission technologies under different categories of sites. Though this analysis does not provide a detailed evaluation of the distribution of the sites in the US for each of the below categories, existing studies have suggested that the vast majority of the sites have less than 20 controllers.

Type of of site			**Both retrofit and new sites**					
		Number of controllers (excl. ESDs)	**1- 3**		**4-20**		**21-40**	
		Electricity on-site?	Yes	No	Yes	No	Yes	No
Main options: Electric controller Instrument air		**Description** (of the most economic option which is technically feasible)	Grid connected **electric** controller	Solar powered **electric** controller	Grid connected **electric** controller	Solar powered **electric** controller	Instrument **air**	
		Number of cases not cost effective (i.e. abatement cost > social cost of methane) **under central assumptions**	6 / 36	11 / 36	0 / 308	2 / 308	5/ 328	
		Cost effective for <u>every</u> site configuration if emissions factors are:*	> 5.6 scfh for retrofit > 2.8 scfh for new sites	> 7.2 scfh for retrofit > 4.4 scfh for new sites	> 3.6 scfh for retrofit > 1.4 scfh for new sites	> 4.2 scfh for retrofit > 1.8 scfh for new sites	> 4.5 scfh for retrofit > 1.8 scfh for new sites	
Other options potentially applicable depending on the local conditions	Limited applicability	Vent gas recovery	✓	✓	✓	✓	✓	✓
		Instrument air powered by gas	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
		Self contained controllers	✓	✓	✓	✓	✓	✓
	Limited known implementations	Solar powered instrument air	Not relevant	✓	Not relevant	✓	✗	✗
		Electric controllers powered by other power sources (TEG, fuel cell)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
		Large solar powered electric controller (no known implementations)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	Potential solution,** but no example known.

*Emissions factors threshold listed are determined for the site configuration with the highest abatement cost within the category.
** Based on other solar applications. No fundamental barrier identified.

Abbreviations and Notes on Units

CAPEX	Capital Expenditure
CH_4	Methane
CO_2eq	Carbon dioxide equivalent
EF	Emission Factor
ESD	Emergency shut down
GHGRP	Greenhouse Gas Reporting Program – US EPA
GOR	Gas/oil ratio
Mscf	Thousands standard cubic feet
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MMT	Million tons
OPEX	Operational expenditure
SCADA	Supervisory Control and Data Acquisition
Scfh	Standard cubic feet/hour
USD	US dollars
VOC	Volatile Organic compound
VRU	Vapor Recovery Unit

Notes on units:

All the data are presented in metric tons

All monetary figures are presented in US dollars, denoted as $

Social Cost of Methane: This report uses the social cost of methane, as reported by US EPA in recent regulatory analyses, as a benchmark for the cost-effectiveness of measures to abate methane emissions. We use the mean value calculated at the 3% discount rate for emissions in year 2020. EPA calculates this as $1300 per metric ton in 2012 USD. We have converted this to $1354 per metric ton in 2016 USD, using a cumulative rate of inflation of 4.2%.

1. Introduction

1.1 What is the problem?

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. However, these devices vent methane into the atmosphere. Pneumatic controllers are the second-largest source of methane from the US oil and gas industry, behind only component leaks, according to US EPA's Greenhouse Gas Inventory [1].

Over the last few years, regulators have worked to reduce the emission of methane and volatile organic compounds (VOCs) from pneumatic controllers. US Federal rules require that new continuous-bleed controllers be *low-bleed* (defined as designed to emit less than 6 scfh) at production sites and compressor stations and *zero-bleed* at processing plants. Wyoming goes further to include intermittent-vent controllers in its requirement that *all* new controllers are designed to emit less than 6 scfh. It also requires the replacement of existing high-emitting controllers in some areas and caps allowable emissions in other areas. Recently Colorado required that existing high-continuous-bleed controllers be replaced with low-bleed controllers statewide, and other states are currently considering similar measures. Finally, some operators have reported voluntary replacements of high-bleed controllers with low-bleed controllers to programs such as US EPA's Natural Gas STAR.

Unfortunately, recent measurement studies [2,3,4] have reported higher emissions from low-bleed controllers than expected. Some controllers that are considered low-bleed according to manufacturer specifications actually bleed above the low-bleed threshold of 6 scfh. Indeed, a number of controllers appear to malfunction, emitting significantly more than they are designed to emit.

Moreover, as a class, intermittent-vent controllers, which are largely unregulated, far outnumber continuous-bleed controllers, and EPA estimates that emissions from intermittent-vent controllers are considerably higher than emissions from continuous-bleed controllers [1]. Recent work has demonstrated that some controllers designed to emit intermittently fail and begin leaking natural gas continually [2,5].

Given the wide range of applications of pneumatic controllers, their typical installation in remote, unmanned sites, and the limited resources of air quality regulators, it is very challenging for air quality regulators to ensure compliance to emissions standards for pneumatic controllers. Currently, new continuous-bleed controllers are in compliance with EPA rules, if they are designed to emit below the EPA threshold of six cubic feet per hour. In practice, they may emit more depending on installation parameters (such as the pressure of the supply-gas), malfunctions, or even tampering, e.g. production workers modify controllers bleed rates when they believe that it will improve reliability [9]. Finally, it is inherently difficult to quantify the emissions from intermittent-vent controllers, as their actuation frequency is variable and may change over time.

1.2 Objective of this project

Zero emission technologies have the potential to virtually eliminate this emission source. They have evolved extensively over the last few years, as operators have gained experience using them. Yet, although zero emission technologies are often mentioned in best practices documentation and reports, there is very limited information on overall applicability and costs (with the exception of instrument air).

This report documents how zero emission technologies are being used in gas and oil fields, and discusses the zero emissions technologies that are suitable for wide usage in common applications at oil and gas production facilities and compressor stations. The main objectives include:

- Presentation of zero emission technologies that are currently available on the market.
- Discussion of the applicability and the technical barriers to the implementation of these technologies.
- Estimates of implementation and methane abatement costs of these technologies for new installations and retrofits.

1.3 Approach and methodology

In addition to a comprehensive literature review, this report relies on interviews with a number of relevant stakeholders and a detailed cost-benefit analysis.

Interviews: Seventeen interviews were conducted. Nine were with technology providers, and eight with both small and large oil and gas companies. The interviews gathered information on field experience with the implementation of zero emission technologies, in particular on their applicability, technical barriers experienced, and actual costs and benefits.

Cost-benefit analysis of zero emission technology implementation: Based on the information gathered during the interviews, literature reviews, and online equipment quotes, a cost-benefit analysis was performed covering a wide range of possible site configurations.

The cost-benefit analysis is presented in section 4 of this report. Prior to that, section 2 includes an introduction to controller typologies, followed by a brief literature review of emissions from controllers. Section 3 presents the different zero emission controller technologies and includes a description of field experiences with these technologies. The report concludes with a brief overview of existing applicability and costs under a range of circumstances.

2. Gas Driven Pneumatic controllers – What are we talking about?

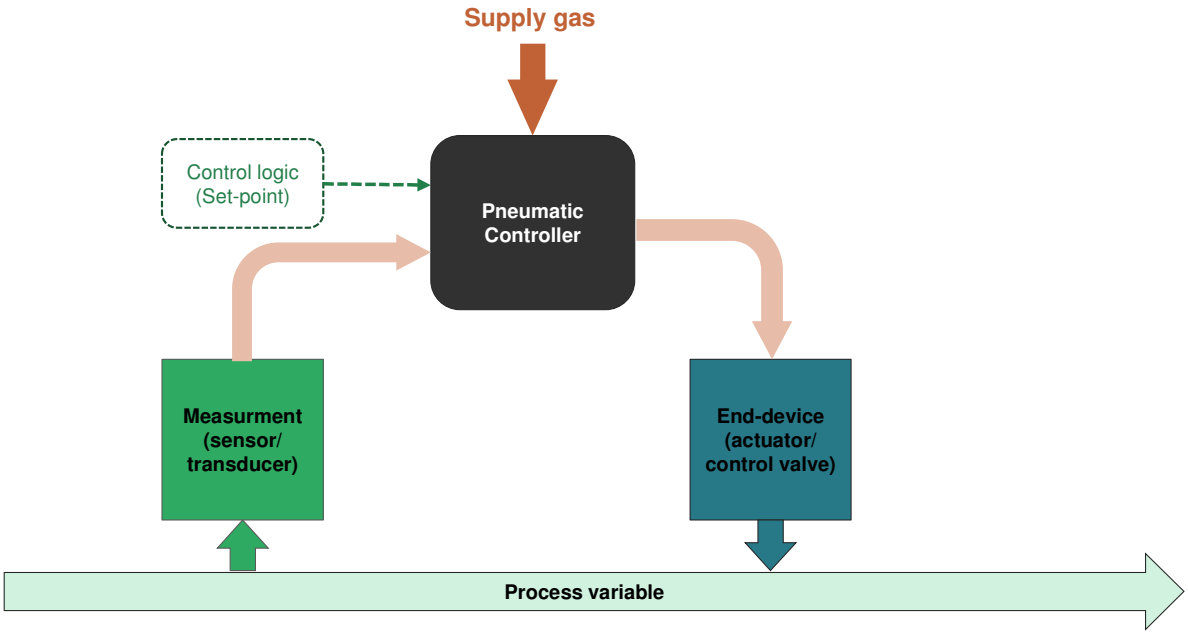
2.1 Definition

A process controller is a device that senses a physical state and then operates automatically to regulate that state[1], based on an established set-point in its control logic. Process controllers can regulate a variety of physical parameters – or *process variables* – including fluid pressure, liquid level, fluid temperature, and differential pressure. An example of a common type is a separator dump valve controller, which operates when it senses that liquid has reached a certain level. Process controllers can be electric, hydraulic, pneumatic or a combination of them. An example of a combination controller would be an electrohydraulic controller operating an electric valve to send liquid pressure to a hydraulic end-device.

Pneumatic controllers convert an input signal to a pneumatic pressure output using gas pressure. The end-device, i.e. the control valve, is adjusted by the actuator in response to signal from the controller. A pneumatic controller uses gas pressure to open or close a mechanical device, such as a valve, when it senses the need to regulate a process condition such as liquid level, pressure, temperature, or flow.

[1] In complex control systems, other process control variables might be modulated to regulate the *state* of that process variable.

Figure 1: Pneumatic Controller - concept sketch



2.2 Typology of controllers

Different typologies have been used in the literature to classify controllers, based on:

- The controller application (i.e. what the controller is used for, such as to control liquid level, pressure, or temperature)
- The emission pattern of the controller (continuous-bleed or intermittent vent)
- The end service (i.e. the way the controller regulate the parameter, such as *on/off* service or *throttle* service)

Controller application

Pneumatic controllers are widely used in upstream oil and gas operations, most commonly to regulate fluid level in separators and tanks, temperature of heaters and fans, pressure of vessels, and differential pressure of lines.

Emission pattern of the controllers

Pneumatic controllers can be designed to release supply-gas continuously or intermittently. Pneumatic controllers are thus classified as **continuous-bleed** or **intermittent-vent** (equivalent to intermittent bleed in all EPA documents), depending on whether or not they are *designed* to emit continuously.

In this study,

- emissions occurring from intermittent-vent controllers, where there is a physical barrier between the supply-gas and the end-device, are referred to as ***vent***; and
- emissions from continuous-bleed controllers, where the supply-gas provides required pressure to the end-device while the excess amount of gas is emitted, are referred to as ***bleed***.

The continuous-bleed controllers are classified into high-bleed and low-bleed in this report, depending on whether or not the controller is deemed to have a bleed rate above or below 6 scfh, in line with EPA regulations.[2]

The typology used in this report differs from the one presented in Allen et al. [2] where controllers are classified depending on their measured emissions pattern as opposed to their designed emissions pattern.

End-service typology

The end-device can be in *on/off* service or *throttle* service, depending on the process requirements. An example of on/off service is a dump-valve that controls the level of a vessel. In the "on" state, the valve is completely open to "dump" liquid. When the desired level has been achieved, the valve completely closes to its "off" state. An example of throttle service is a pressure control valve, which increases or decreases the flow of gas as needed to maintain line pressure at a fixed value. Both continuous-bleed and intermittent-vent controllers are commonly used to perform both on/off and throttling services.

A summary of pneumatic controller typology is presented in the table below. As this study focuses on eliminating emissions from these devices, only the emission pattern typology is used in the rest of the report.

Table 1: Summary of controller typology (mainly based on [6])

		Type of Service	
		On/Off	**Throttling**
Emission characteristics	**Intermittent-vent**	- Gas vented at de-actuation - Designed to emit no gas between de-actuation instances - De-actuation frequency depends on process variability	- Gas vented when end-device needs to throttle-off - Designed to emit no gas between throttle-off instances - Throttling frequency depends on process fluctuations
	High-bleed continuous controller	- Gas emitted continuously with higher bleed rates when end-device needs "off" service - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be higher than 6 scfh	- Gas emitted continuously with higher bleed rates end-device needs to throttle-off - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be higher than 6 scfh
	Low-bleed continuous controller	- Gas emitted continuously with higher bleed rates when end-device needs "off" service - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be lower than 6 scfh	- Gas emitted continuously with higher bleed rates end-device needs to throttle-off - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be lower than 6 scfh

2.3 Number of controllers and emission factors – Brief literature review.

Important work has been taking place over the last few years to measure and understand methane and VOC emissions from pneumatic controllers. This work includes measurement surveys [2,3,4,7], count of controllers per facility [1,2,8], and engineering calculations [8]. The methodology and the sampling approach vary significantly between different sources of information; thus comparisons should be made with particular care [8].

[2] It should be noted that the bleed rate is not a specification of the controller only, but also depends on the pressure and flow-rate of the supply-gas in addition to the size of the restriction orifice.

How many controllers per site?

The number of controllers per site varies depending on the number of wells and more generally the number and type of equipment used. Recent studies have demonstrated that the vast majority of sites have less than 20 controllers.

Most of the existing studies have focused only on emitting controllers [3,5,7], thus underestimating the number of controllers reported for each site, since some intermittent-bleed controllers actuate infrequently (e.g., controllers for emergency shut-down valves) and are unlikely to do so while a site is being surveyed. Two studies have performed a thorough count of the number of controllers per site [2,8]. The distribution of controller functions reported by these studies varied, perhaps due to differences in the types of sites sampled in the studies, but the overall distribution of controller counts at production sites were quite similar (Figures 2 and 3):

- Very small and medium sites (with less than 20 controllers) account for the vast majority (97%) of the sites evaluated in both studies (Figure 2)
- These sites represent 85% of the controllers (Figure 3)

Figure 2: Share of the sites depending on the total number of controllers per site

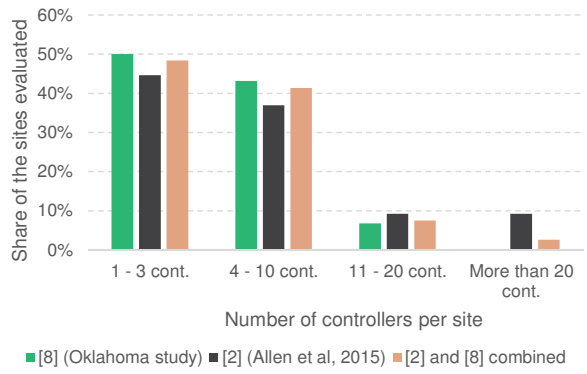
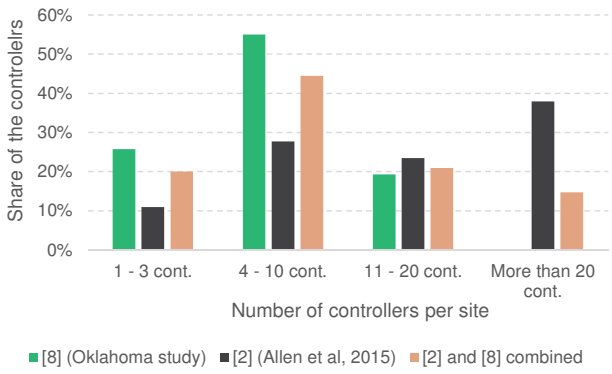


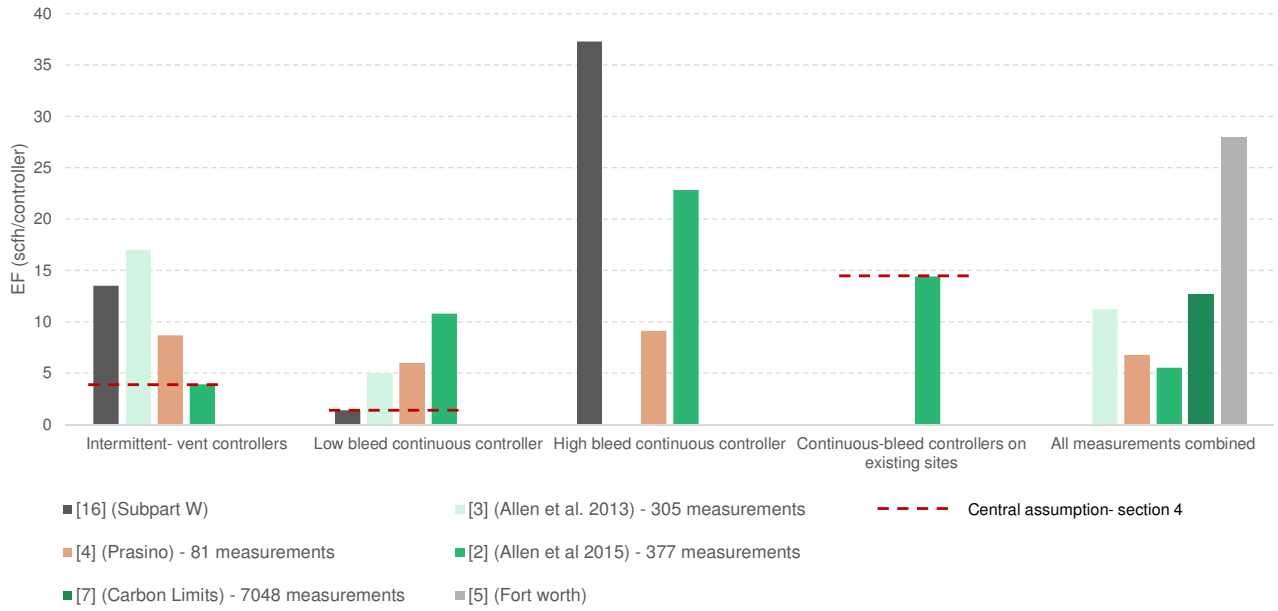
Figure 3: Share of the controllers depending on the total number of controllers per site



How much do controllers emit?

Despite the important work performed over the last few years, there is still significant uncertainty regarding emissions factors from controllers. The following figure summarizes the current emission estimates available for the different categories of controllers.

Figure 4: Emissions factors by controller category from different information sources[3]



A number of important conclusions can be drawn from the review of existing publications:

- Emissions from controllers vary between controller models and, for some models, for the same controller model between sites [2,4,7]
- A small subset of the controllers account for the vast majority of the emissions [2,7]
- Overall, recent research has demonstrated that a number of controllers behave differently than originally designed. In particular,
    - Average emission rates exceed the manufacturers' specifications [4], including some controllers designated low-bleed which emit above the threshold rate of 6 scfh [4,7]
    - Some controllers designed to emit intermittently fail and begin emitting natural gas continually [2,5]

In the analysis presented in the report, we have very conservatively adopted the lowest of the above average EFs for low-bleed in new installations and for intermittent-vent controllers. For continuous bleed controllers at existing sites, we have used the results of the recent measurement [2]. This average is consistent with a mix of low- and high-bleed in the field. The EFs are illustrated in Figure 4 and are described further in Section 4.1.

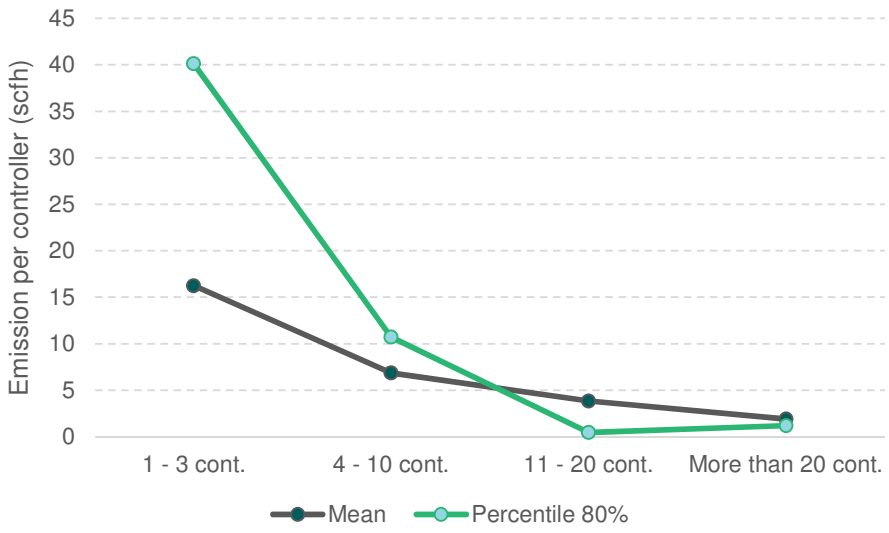
Do controllers from smaller sites emit more?

There is very little information available on how emission factors vary depending on the site's size. Analysis of recent measurements [2] suggests, however, that controllers are likely to emit much more in small than in large sites.

The following graph, plotting the mean and the eightieth percentile emission factors, shows a clear downward trend as the number of controllers per site increases. This trend could potentially be explained by the difference in terms of maintenance practices for small sites (typically unmanned and in remote area) and larger sites. In the follow-up analysis, a constant emission factor is assumed for both small and large sites.

[3] The data from [3] and [4] have been categorized and presented as described in [8]. The data from [2] have been categorized based on the "company classification into EPA category" (excluding ESD) and not based on the measured emission typology.

Figure 5: Average emission factors depending on the number of controllers per site [2]



3. Zero emission technologies – Description and technical applicability

This section provides an overview of a number of zero emission technologies available as an alternative to gas driven pneumatic controllers, based primarily on interviews and on a general literature review. A technology is considered "zero emission" if there is no methane or VOC emissions associated with its utilization.

3.1 Overview of the zero emission technology presented.

Five different technologies have been reviewed: Electronic controllers, instrument air provided by compressors (with electric power from the grid or existing on-site generation), solar-powered instrument air, vent recovery, and self-contained pneumatic controllers. Of these five different zero emission technologies, two – electronic controllers and instrument air – have reached a reliable level of maturity and are widely applicable. The remaining three technologies are either less mature (solar-powered instrument) or are applicable only in certain circumstances (self-contained pneumatic controllers and vent recovery).

The economic feasibility of the two mature and widely applicable technologies, electronic controllers and instrument air, is evaluated in detail in section 4 of this report.

The following table presents a brief summary of the different technologies evaluated.

Table 2: overview of the zero emission technologies presented

Technology	Maturity of the technology	Technical applicability limitations	Main strengths
Electronic controllers (ref section 3.2)	The technology has reached a reliable level of maturity, with hundreds of installations identified throughout this study.	Operators interviewed continue to use pneumatic ESDs. Some limitations with large numbers of controllers or high power demand chemical injection pumps.	• Can operate off grid • Reduced maintenance costs, in particular compared to wet gas driven controllers • Enables or simplifies automation of systems

Instrument air (ref section 3.3)	Extensive global experience for many years	Requires a reliable source of power Limited to installations with an air compressor > 5 HP	•	Reliability • Reduced maintenance costs, in particular compared to wet gas driven controllers
Solar-powered Instrument air (ref section 3.4)	Less than 100 installations identified	Compressor up to ~20 scfh	•	Operates off grid • Reduced maintenance costs, in particular compared to wet gas driven controllers
Vent Recovery (ref section 3.4)	The study identified less than 100 installations, with uncertain performance	Requires the presence of a VRU or a gas engine on site	•	Reliability
Self-contained pneumatic controllers (aka "Bleed to Pressure" or integral controllers) (ref section 3.4)	Although this solution has been deployed since early 2000s and is considered a relatively well-developed technology, controllers of this type are only available for certain specific applications	Applicability is limited by a number of conditions (e.g. pressure differential, downstream pressure, etc.)	•	Low-cost solution

3.2 Electronic controllers (solar powered and grid powered)

Electronic controllers adjust the position of the end-device by sending an electric signal to an electric actuator or positioner (as compared to pneumatic controllers which send a pneumatic signal to a pneumatic actuator or positioner). A motor powers the electric actuator to adjust the control valve to the desired position.

This section provides a description of the benefits, costs, and applicability of electronic controllers to both new sites and existing sites, where retrofits would be required. The description is based mainly on interviews with four oil and gas production companies that have installed these systems in their operations (from 3 to 40 installations per operator interviewed), complemented by interviews with technology providers.

Description of the technology

Electronic controllers can be installed both at sites connected to the electric grid, and at remote sites isolated from the grid. These systems typically include a control panel, electric actuators, electronic controllers, control valves, relevant switches (e.g. pressure, level or temperature switch) and a power source – connection to the grid, solar panels and batteries, or power generation on site. An electronic control system is generally designed to completely replace all pneumatically powered devices with electronic controls (with the exception of ESD, see below).

Electrically powered sites: Electronic controllers can be powered using 120 VAC or 220 VAC input from the grid or from on-site generation (three-phase power is not needed).

Remote sites: Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. Systems can be customized for every application; those installed to date include up to three solar panels and eight batteries [9]. Use of solar-powered chemical injection pumps has become widespread over the past years.

Rationale for the use of electronic controllers:
For the operators interviewed, the two main drivers for project implementation were (i) to reduce methane and VOC emissions and conserve gas otherwise emitted and (ii) to reduce maintenance costs. Electronic systems have much lower maintenance costs than traditional gas-driven controller systems [10], in particular if the gas used is not perfectly dry and sweet.

Higher operating costs are also experienced for gas driven controller systems on sites where there is a need to purchase fuel gas from another source or use imported propane. These include sites with overly sour or wet gas, or with drastic drop in gas supply due to low gas/oil ratio (GOR) /low production.

Investment Costs
Each electronic control system is designed on a case-by-case basis. The investment costs depend on the number of controllers/pumps, but also on other factors such as pressure differential, pipeline diameter, and methanol volume requirement, which varies according to such factors as climate and production patterns[4]. The following table summarizes typical equipment costs for the cases evaluated:

Figure 6- Calscan pictures- Bear solar control system: Top: solar panel and control panel, bottom: Electric Actuator



Table 3: Electronic controllers – Typical investment costs for main equipment

Main items	**Approximate unit costs** USD
Level Controller & Level Control Valve	4000
Pressure Controller & Control Valve	4000
Chemical injection Pump	6000
Control panel	4000
Solar panel (140W unit)	500
Battery (100 Ah unit)	500

The operators interviewed experienced fairly smooth installations, with installation costs decreasing as they gained experience with the technology[5]. The installation costs vary by site, estimated at between $5000 and $8000 per well site. For a retrofit project, the well needs to be shut in for one or two days;

[4] Chemical injection pumps (e.g. methanol pumps) usually are the most important power consumer. Sites requiring high volumes of methanol volume injection would cause higher costs for scaled-up solar panel and batteries.
[5] After the first few sites installations.

NMED Exhibit 110

retrofit will generally take place when other maintenance is scheduled, to take advantage of that shut-down time. Solar powered electric systems do not require back-up generators[6].

Maintenance costs

The major maintenance costs include the replacement of batteries and panels. Most batteries last three to six years, while solar panels last twenty to thirty years. The operators interviewed highlighted that they experienced minimal maintenance costs on the sites converted to electronic controllers over the last five years.

Benefits of electronic controllers

Operators highlighted a number of benefits:

- Revenue from the sale of gas: Electronic controllers eliminate methane and VOC emissions and thus increase the volume of gas available for sale.
- Automation: Electronic control systems can provide additional benefits by enabling or simplifying the installation of automation systems (SCADA, Supervisory Control and Data Acquisition), though these systems are not required in order to use electronic controllers. This can potentially reduce the need for site inspections, reducing those costs for operators. For example, an alarm can be programmed to warn the operator if the dump has been open for more than 10 min. The system can be as sophisticated or as simple as required. (Note that we have not included any estimate of these cost reductions in the calculations of cost-effectiveness discussed in Section 4.)
- Reliability: As highlighted above, operators report that the electronic system is more reliable than a gas driven pneumatic control system, as operation of the latter with even slightly wet gas can lead to condensation issues, which over time will impact the performance of the system. One operator reported corrosion issues with sour gas used for pneumatic controllers and pumps.

Technical challenges with electronic controllers

- Snow: One operator reported that snow can be a problem with solar panel and battery lifetime.
- Theft or damage: Solar panels have reportedly been stolen or used as targets for shooting.
- Chemical injection pumps: Pumps consume far more energy than controllers/actuators. Sites with a large number of pumps or with pumps with high energy or power demand may represent a challenge for 100% solar powered electric systems. In addition, shortly after completion, some wells may require high volumes of methanol injection, and powering pumps to inject this high volume can strain these systems. Some of the operators interviewed reported that this technical barrier can be solved by bringing a portable stand-alone generator to the site for a few weeks to ensure that the power requirement is met.
- Safety considerations: Due to the very low voltage of the system, the safety risks are considered acceptable by the operator who evaluated this risk.

Applicability of electronic controllers

According to interviews with operators, this solution can technically be implemented on any well site. Generally, for the sites with these systems in place, the pressure differential is up to 2000 psi and the pipe diameters are between 2- 3 inches, but the system can be designed for larger pressure drops and larger diameters as required.

[6] When properly designed (e.g. with sufficient reserve margin in the batteries), recent solar powered electric systems do not require back-up generators, due to the reduced cost of solar-panels and the availability of low-power components. These systems are routinely installed without back-up generators in North America, including in Northern Canada where in winter there is only 1 to 2 hours of full sunlight a day. [9]

The only general limitation is the incremental costs. According to the operators, given the current gas prices, implementation costs are not compensated by the value of the gas saved. The project can be economical when other factors such as lower maintenance costs improve the return on investment.

Note on Emergency Shut-Down Valves (ESD): As a rule, electric controllers/actuators will stay in position if the system fails and power is lost, wires are cut, or other failures occur. This differs from some other solutions that can be designed so that valves close (or open) if the system fails (for example if the supply gas pressure is lost). Although Calscan is developing a "fail safe" electric ESD, operators have reportedly been using pneumatic or hydraulic ESD valves, as they are "fail-safe".

Sunlight: In northern latitudes (e.g. northern Alberta) and when the energy demand is high (e.g. several pumps), solar panels may not generate enough power, in particular for chemical injection pumps. Other power sources such as thermal electric generators or methanol fuel cells have been used in pilot implementations.

Electronic controllers at medium and large sites: Due to the market conditions, providers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites. No technical barriers were identified for the installation of electronic controllers in sites with available electricity. Given the recent progress in both solar panel technologies and large battery solutions, solar-powered solutions may also be appropriate for large sites without available power. However, we are not aware of any such installations. Therefore, to be conservative, we do not examine the use of electronic controllers at large sites without electricity available.
Medium or large sites may also be the result of a combination of a number of small sites (e.g. several well pads). In practice, several small independent electronic controller installations can thus be installed on one medium to large site.

Suppliers
The following table presents a non-exhaustive list of relevant providers:

Table 4: Non-exhaustive list of relevant providers:

Name of the suppliers	Website	Offer	Comments
Calscan	http://www.calscan.net/products_bearcontrol.html	Provide full customized system	Cascan's Bear Solar Electric Control System is designed mainly for well head separators, but it can also be used in other applications. It includes solar panels, batteries, electric actuators, control valves, switches, control panels and other control equipment.
Spartan	http://www.spartancontrols.com/	Provide full customized system	Spartan designs electronic control systems assembling a number of components including Emerson/Fisher electronic controllers and actuators.
Ameresco	http://www.amerescosolar.com/solar-power-solutions-oil-and-gas-industry	Provide full customized systems	Amaresco Solar designs customized off-grid solar power systems.
Emerson/ Fisher		Manufacture elec. controllers and actuators	Different brands under Emerson Process Management (including Fisher, EIM) supply electronic and electro-pneumatic control components (controllers, positioners, actuators, control valves, transducers, etc.)
Exlar	http://exlar.com/	Manufacture elec. actuators	Exlar currently offer electric actuators that can replace pneumatic actuators.

3.3 Instrument air

Instrument air controllers are systems where pressurized natural gas is replaced with compressed air as a source of energy and signaling medium for pneumatic controllers and pneumatic actuators. Since controllers use air, instead of natural gas, they only vent air to the atmosphere, eliminating emissions from pneumatic controllers. Instrument air controllers are applicable to both new sites and existing sites; however, the technology can only be implemented when a reliable power supply is available.

This section provides a description of the benefits, the costs, and the applicability of instrument air controllers and is mainly based on interviews with oil companies, reviewing their recent experience installing instrument air systems.

Description of the technology

Instrument air technology is a well-established mature solution to run pneumatic control systems and is widely applied globally. In many countries (e.g. Norway, Iran, Kazakhstan [11]), the majority of the pneumatic control systems run on instrument air.

Systems typically include:

- Heavy-duty industrial air compressors. Two compressors are generally installed for redundancy, but for cost reasons, an operator has reported using only one.
- Air dryers - part of the air compressor package.
- Wet air receiver tank - part of the air compressor package.
- Dry air receiver tank - helps provide a buffer to secure longer system autonomy in the event of a power outage or demand surge.

Investment costs

Interviewers highlighted that the investment costs for instrument air installation vary significantly from site to site, depending on the layout and the type of equipment already on site. Investment costs can be classified as follows:

- Air compressor package: This includes the purchase of the main equipment (compressors, dryers and air receiver tanks). The size of compressors, dryers, and other equipment depends on the number of pneumatic controllers to be supplied with compressed air, and on their specifications (i.e., their demand for compressed air). A small compressor station would require around 5 HP of air compression capacity, while a larger facility would require up to 20 HP. This system can be purchased as individual components or as a package, for between $20,000 and $70,000 [12].
- Mechanical & installation costs: Mechanical and civil work may be required, depending on the layout of the existing facility. These costs are often higher for older facilities and can include:
    - Pipe cleaning and upgrades.
    - Trenching and tubing installation, since large sites may have several independent natural gas supply systems for controllers and pumps, and air would need to be piped through the full site.
- Electrical/instrumentation equipment and supplies: Depending on the site and the specific project requirement, this category may include:
    - Remote terminal unit or SCADA system installation or upgrade. The control system for some plants (e.g. shutdown/start-up, safety systems etc.) may have to be upgraded to accommodate the air compressor package.
    - Upgrades and wiring needed to add the additional electrical loads from the air compressor motors.
    - Repair/replacement of a controller in case of malfunctioning controller.
- Engineering/consulting: The site might require additional expenditures for electrical engineering and consulting.

Although air compressors and their auxiliary equipment represent a large part of the CAPEX, the engineering, preparation and installation costs can comprise up to 70% of the total upfront investment. Installation and preparation costs may include electrical and instrumentation supplies, mechanical and civil works, additional wiring, piping, valves and fittings. These costs are higher for older facilities that are not capable of handling the extra power, or don't have a suitable layout for utilities. Overall, the total cost for a project varies between $50,000 and $250,000 [10].

Maintenance costs

Maintenance costs typically include:

- Power consumption
- Air compressor servicing, generally every 6 months.

Benefits of instrument air controllers

Operators highlight a number of benefits:

- Revenue from the sale of gas: Instrument air eliminates methane and VOC emissions and thus increases the volume of gas available for sale.
- Reliability**:** The instrument air system is a highly reliable alternative to a natural gas driven pneumatic system for grid-connected facilities.
- Reduced maintenance costs**:** Although there are some additional operating costs with the deployment of air systems, some maintenance expenses are cut as a result of stopping the use of natural gas, particularly wellhead gas (or separator gas). Due to fluctuations in the GOR, some operators reported gas shortages on-site and thus they had to use other sources, such as propane, or to purchase gas from an adjacent field. Maintenance costs due to liquids condensing in the system or sour gas damage are also avoided by replacing untreated natural gas with air.

Applicability of instrument air controllers

Two main applicability limitations were identified during the interviews:

Size of the installation:

Instrument air controllers require heavy duty industrial air compressor packages designed for continuous duty (24/7). This in effect precludes the use of air compressors smaller than 5 HP, since available 2-3 HP air compressor packages present reliability problems. One operator reported that the one-year lifetime of a smaller compressors makes them unacceptable, so a minimum of 5 HP is assumed.

Access to power

Instrument air systems may only be used in locations with access to a sufficient and consistent supply of electrical power. Operators have used instrument air at:

- Grid connected sites.
- Sites with onsite power generation. Many sites (e.g. compressor plants) have power generation for other purposes: lighting, automation and control systems, etc. The same system can also be used for instrument air if generation capacity is available. We note that a sufficient, reliable, good quality gas stream is required for power generation. Wet or sour gas may not always be used for on-site power generation, depending on the specification of generator engines, etc.

In theory, diesel powered instrument air could be installed; however, this project identified no concrete examples of this technology. One operator stated he considered, and then rejected, the use of diesel to run air compressors, due to the high costs and low perceived environmental benefits.

3.4 Other technologies

This section reviews other "zero emission" technologies at various stages of maturity. In general these technical options are either (i) not widely applicable (such as self-contained controllers and vent gas recovery) or (ii) fewer than 100 installations were identified as part of this project (such as solar powered instrument air).

Solar powered instrument air
This study identified about 40 installations of small, energy efficient motor-compressors powered by solar panels/batteries, to replace natural gas with instrument air as the pneumatic medium. TRIDO industries, the technology provider interviewed as part of this study, indicated that these systems have a maximum capacity of ~20 scfh, making them suitable for some small to medium sites which use a few low-emitting controllers. High-bleed controllers have to be retrofitted to reduce air consumption in order to reach the feasible level. Despite the lack of extensive deployment so far, an attraction of this solution lies in the fact that controllers and actuators do not need to be replaced.

Instrument air powered by other power sources
Other power sources, such as thermal electric generators or methanol fuel cells, have been used in pilot implementations to power traditional instrument air systems.

Vent Gas Recovery
Re-routing to VRU
Vapor Recovery Units (VRUs) have a long, well-established track record in the upstream oil and gas industry to recover VOCs and methane from vented sources. Typically, they consist of capturing and piping equipment, a de-liquefaction drum, and compressor(s) to inject the recovered gas into pipelines. In theory, all vent lines can be connected to the VRU, including pneumatic controllers' lines.

Nevertheless, there have been limited implementations (only one example identified in this study) of well-site vent gas recovery projects using the recovered gas from pneumatic controllers in non-engine applications. SlipStream®, as further presented below, is a technology that facilitates recovery of the gas and use of it in gas-fired engines. Another technology, Cata-Dyne™, utilizes the recovered gas as a feed to a small, flameless appliance that converts natural gas or propane into infrared radiant heat that is usable if industrial heating is required.

SlipStream®
Spartan's SlipStream® system captures vented hydrocarbons and uses them as a supplementary fuel source for natural gas-fired engines, reducing fuel consumption. This technology can thus be applied only to sites with gas-fired engines, e.g. compressor engines. Despite concerns about costs, one operator emphasized specifically the reliability of the technology, as it reportedly does not interfere with normal operations. Nevertheless, if the volume of gas emitted by the combined vents (including the controllers) exceeds the engine fuel requirements, natural gas would still be vented or otherwise controlled.

Self-contained (aka Bleed-to-Pressure or Integral Pneumatic Controllers)
Self-contained systems are designed to contain the gas typically vented from controllers and then discharge it to the control valve's downstream piping, thus resulting in zero emission.

A number of operational requirements limit the applicability of self-contained systems, the most important of which is the need for a high differential pressure across the control valve [6,13]. For instance, GE's Bleed-to-Pressure system requires more than 80 psi, and both GE and VRG Controls require a downstream pressure of maximum 300 psi [13]. Also, sour or untreated gas could cause disturbances in

the operation of self-contained controllers. Nevertheless, if applicable, the technology may be cost-effective or economical in cases where the total baseline emissions are high.[7]

Due to the limited applicability or the lack of widespread field experience, the technologies described above are not further analyzed in this report. However, depending on the site specifics, these options may be applicable and cost-effective, and can represent useful alternatives to instrument air or electronic controllers; thus they are presented as potential alternative options in section 4.4.

4. Cost effectiveness of electronic controllers and instrument air

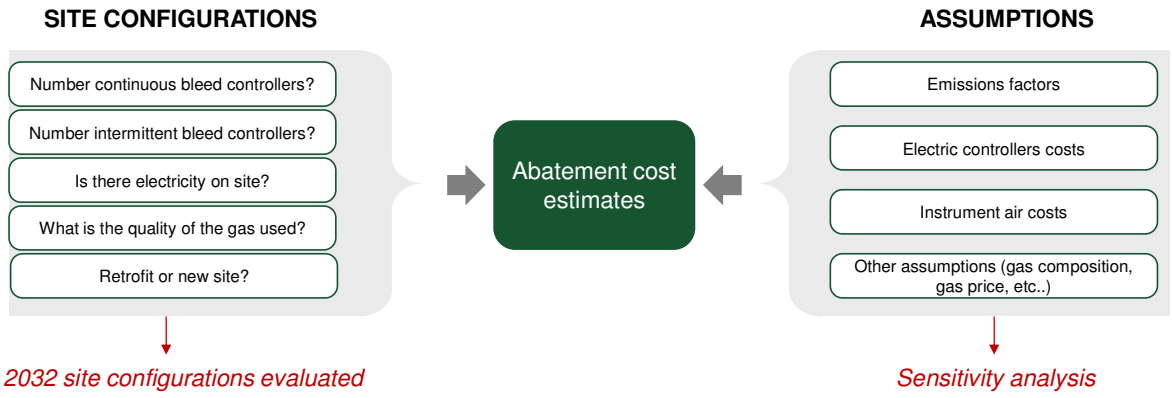
This section presents an analysis of the *cost-effectiveness* – net cost in USD per ton of avoided pollution – of employing the two main zero emission technologies, air-driven pneumatic controllers and electronic controllers, instead of natural gas-driven pneumatic controllers at new and existing sites. These results are applicable at both oil and gas production sites (well pads) and compressor stations.

4.1 Analytical approach

The cost-effectiveness of zero emission technologies will vary with the number and type of controllers at a site, in addition to many other factors, as we discuss below. Given the variety of site configurations (number and type of controllers per site, connection to the grid, type of gas handled) across the US, and the lack of information on the frequency of occurrence of these configurations, we opted to carry out cost-effectiveness assessments for both electronic and instrument air controllers for a broad spectrum of permutations of those site configuration parameters.

A number of assumptions have been made for the analysis. Key assumptions are discussed in the section below; all assumptions are detailed in the Appendix.

Figure 7: Overview of the methodology



For each permutation of the site configuration parameters, a CH_4 abatement cost (cost per metric ton of avoided pollution) was estimated.

[7] A technology provider reports an average of less than $3000 per Bleed-to-Pressure control system, leading to a payback period of less than 2 years for replacing 8 controllers.

For this analysis, a zero emission technology implementation is considered
- "economical" if the CH_4 abatement cost is negative (i.e. if the project NPV is positive)
- "cost effective" if the CH_4 abatement cost (net cost per ton of abated pollution) is lower than the social cost of methane that EPA has used in recent regulatory analyses [19] (Social cost of methane for 2020, calculated with a 3% discount rate, $1354 (2016 USD). [8]

The following sections provide more insight on:
- The abatement cost calculation
- The main assumptions
- The site configurations evaluated.

Abatement cost calculation – methodology

For each site configuration, the following were estimated:
- The CAPEX and OPEX of the zero emission technology implementation (either electronic controllers or instrument air)
- The CAPEX and OPEX of the baseline scenario (i.e. the cost incurred by the operator if the conventional pneumatic technology had been used instead of zero emission systems)
- The emissions of CH_4 and VOC under the baseline scenario

Since methane and VOC emissions will be zero if the zero emission technology is used, the abatement cost (in \$/t CH_4) is then estimated as follows:

$$Abatement\ cost\ = -\frac{NPV(Cash\ flow_{zero\ emission\ project} - Cash\ flow_{baseline\ scanerio})}{NPV(Emission_{baseline\ scanerio})}$$

This approach, and its underlying assumptions, is compared to the annualized cost approach typically used by EPA in the appendix.

Main assumptions

The following table provides a list of the main assumptions applied. A full list of assumptions is available in the Appendix.

Table 5: Central assumptions

Description	Central Assumption	Comment
Gas price	2 \$/Mscf	The value of recovered gas has been assumed to be similar for all emission sources, independent of the composition of the gas. Gas values from 1 to 3 \$/Mcf have been assessed in sensitivity analyses.
Discount rate	7%	A 7% per year real term discount rate has been assumed. A sensitivity is presented for a 3% per year real term discount rate. This approach is consistent with EPA/BLM practice.
Remaining lifetime for a new project	15 years	The lifetime for new controller installation is assumed to be 15 years in line with EPA practice.
Remaining lifetime for retrofit project	10 years	The remaining lifetime for existing sites is assumed to be 10 years. A sensitivity is presented for a 5 years remaining lifetime.
Gas composition	0.0167 tCH_4/Mscf	Gas composition assumptions for dry gas (wet gas assumptions are presented in the Appendix)
	0.0046 tVOC/Mscf	

[8] EPA reports that the 2020 social cost of methane (mean value at 3% discount rate) is \$1300 / metric ton of methane in 2012 USD; this is adjusted to \$1354 / metric ton of methane in 2016 USD using a 4.2% cumulative inflation rate.

Average emissions factors assumptions

The emission factors used for this analysis are conservative averages based on the literature review (See section 2.3). The following table presents the emission factors used and the rationale for each value.

Table 6: Emission factors assumptions – central assumptions

Description	Central Assumption	Comment
Continuous-bleed controller(s) – retrofit sites only	14.4 scfh	This emission factor is applied for all the continuous bleed controllers on retrofit sites. Assumption based on [2] (Company classification into EPA categories excluding ESD)
Low bleed continuous controller (s)	1.39 scfh	This emission factor is applied for all the continuous bleed controllers on new sites. Current federal regulation (OOOO) requires that new continuous bleed controllers be low bleed. Assumption based on [16], most conservative average value between [16], [3], [4] and [2]
Intermittent-vent controller(s)	4.4 scfh	Assumption based on [2], most conservative average value between [16], [3], [4] and [2]
Chemical injection Pumps	13.3 scfh	Assumption based on [16], most conservative average value between [4], [7] and [16]
ESD	0.41 scfh	Assumption based on [2], average of the controllers classified as ESD

While measurements show that emission factors vary widely in the field, using conservative average emission factors, we are able to calculate conservative (i.e. high) abatement costs for widespread adoption of zero-emitting technologies. Sensitivity analyses are presented in the section 4.2 to reflect the field variability, which impact the site specific abatement costs.

Site configurations evaluated

As described above, we performed economic modeling on a total of 2032 permutations of site configuration parameters, covering a wide range of possible combinations of site parameters.

The following parameter inputs were used to construct the site configurations:

- Total number of controllers – from 1 to 40 controllers.
- A varying mix of continuous-bleed and intermittent-vent controllers (from 0% to 100% of intermittent-vent controllers).
- One emergency device (ESD) was added for every five controllers[9] (rounded up).
- New site (construction of new facilities) or retrofit (upgrade of existing facilities).
- Access to electricity or not.
- Whether pneumatic driven controllers currently operate on dry gas or wet gas.

To simplify the presentation of the results, the 2032 possible site configurations were then grouped into 20 larger categories depending on the total number of controllers, the presence of electricity on site, and whether the site is new or would need to be retrofit with zero emission controllers. The following table presents a matrix of the 20 different categories of site configurations evaluated, with the number of sites in each category presented in green. Each cell of this table includes a number of site configurations

[9] This number of ESDs has no impact on the final conclusion. Operators do not currently replace ESDs with electric controllers, so number and the emission factor of ESD have no effect on the cost-effectiveness of electric controllers. On the other hand, ESDs will generally be converted to instrument air, but the effect of including reasonable numbers of ESDs on the final cost-effectiveness is small due to the small air consumption of ESD. In this context, the assumption on the number of ESD did not affect the final number of sites with an abatement cost higher than the social cost of methane.

depending on the number of intermittent-vent or continuous-bleed controllers and the type of gas used to power the controllers.

Table 7: Site configurations categories (number of site configurations presented in green)

Number of Pumps	Number of controllers (excluding ESD)	New sites		Retrofit	
		No elec. on site	Elec. on site	No elec. on site	Elec. on site
0	1 to 3 controllers	18	18	18	18
	4 to 10 controllers	56	56	56	56
	11 to 20 controllers*	98	98	98	98
	21 to 40 controllers*		164		164
1	1 to 20 controllers*	172	172	172	172
	21 to 40 controllers*		164		164

* Based on the analysis presented in section 3, we did not model either technology for larger sites (≥21 controller excluding ESD) without electricity on-site

- Electronic controllers were modeled at sites of all sizes with electricity available, and smaller to medium sites (up to 20 controllers) with no electricity available. Medium and large sites with electricity on-site are presented, as no technical barriers were identified for the installation of electronic controllers in such installations. However, there seems to be much less field experience for these types of installations compared to smaller sites.
- Instrument air was presented at larger sites with electricity available. For sites smaller than 20 controllers, electronic controllers were always more cost efficient than instrument air (see below).

This approach reflects the current industry experience and practice as presented by the interviewees. It is, however, important to highlight that the threshold in terms of number of controllers (20 in the analysis), depends in reality on site-specific parameters, and should only be considered as an **illustrative** threshold based on information available.

4.2 Main findings – electronic controllers

The findings of the cost-benefit analysis for electronic controllers are presented in four different sections:

- First, the full cost-benefit analysis is presented for one site configuration, to illustrate the methodology by exploring one example in detail.
- Second, a sensitivity analysis is performed for the same site configuration to show the impact of the main assumptions.
- An overview of the results for all the site configurations evaluated is then presented.
- Finally, the impact of the emission factors assumptions is described.

Example of abatement cost estimate for one example site configuration

The following table presents a full analysis for an example site configuration. The project is the retrofit of an existing site with four different controllers (one continuous-bleed, two intermittent-vent, one ESD and no pump) which represents the most common number of controllers in [8,2]. The site is not connected to the grid and currently uses dry supply gas for the controllers.

Table 8 presents the CAPEX estimate for the conversion to electronic controllers. As the project is a retrofit project, the baseline CAPEX is zero.

The detailed assumptions for the size of the electronic system (such as number of solar panels and battery requirements) are presented in the appendix. Overall, the system is oversized and always includes, for example, 10 days of energy storage.

Table 8: CAPEX estimates for electronic controller implementation (central assumptions)

Item	Assumption	#	Total USD
Controllers	$ 4000/unit	3	12 000
Control Panel	$ 4000/unit	1	4 000
140 W Solar Panel	$500 /Unit	1	500
100 Amh battery	$400 /Unit	3	1 200
Installation and engineering costs	20% of equipment costs	NA	3 540
Total CAPEX			**21 240**

Table 9: Emissions estimates (central assumptions, new sites)

Whole gas emissions in scfh	EF assumption	#	Total
Intermittent – vent controllers	4.43	2	8.9
Continuous –bleed controller	14.4	1	14.4
Total gas emissions			**23.3**

In terms of OPEX, it is assumed that batteries are replaced every 4 years and solar panels every 10 years. Given the operators' reports of minimal maintenance for electronic controllers, it has thus been assumed, conservatively, that general maintenance costs for are similar to those for continuous-bleed controllers functioning properly[10]. We do not include any estimate of savings in inspection costs due to automation (conservative assumption). Table 9 above presents emission estimates for the baseline scenario and finally Table 10 includes the abatement costs estimated.

Table 10: Final results – central assumptions

Item	Unit	Value USD
CAPEX	$	21 240
Value of the gas saved	$/year	408
NPV of the OPEX	$	1 672
NPV	$	-19 266
ABATEMENT COSTS	**$/tCH$_4$**	**751**

As presented in Table 10, for the small and remote site configuration presented, the abatement costs is well below the social cost of methane as defined above. The abatement cost for same site configuration, but at a new facility, as opposed to a retrofit, is estimated to be $847/ton CH_4. The difference is due to the difference in baseline costs and baseline emissions between new and retrofit sites (see below).

[10] Which is lower than the maintenance costs for continuous bleed controllers operating with wet supply gas.

Info Box 1: Electric conversion of pneumatic pumps

Pumps at well sites and well pads are typically used for methanol, corrosion inhibitor, de-waxing agents, or soap injection. Federal regulation (OOOOa) rules already require that emissions from new and modified chemical injection pumps be controlled in a number of circumstances.

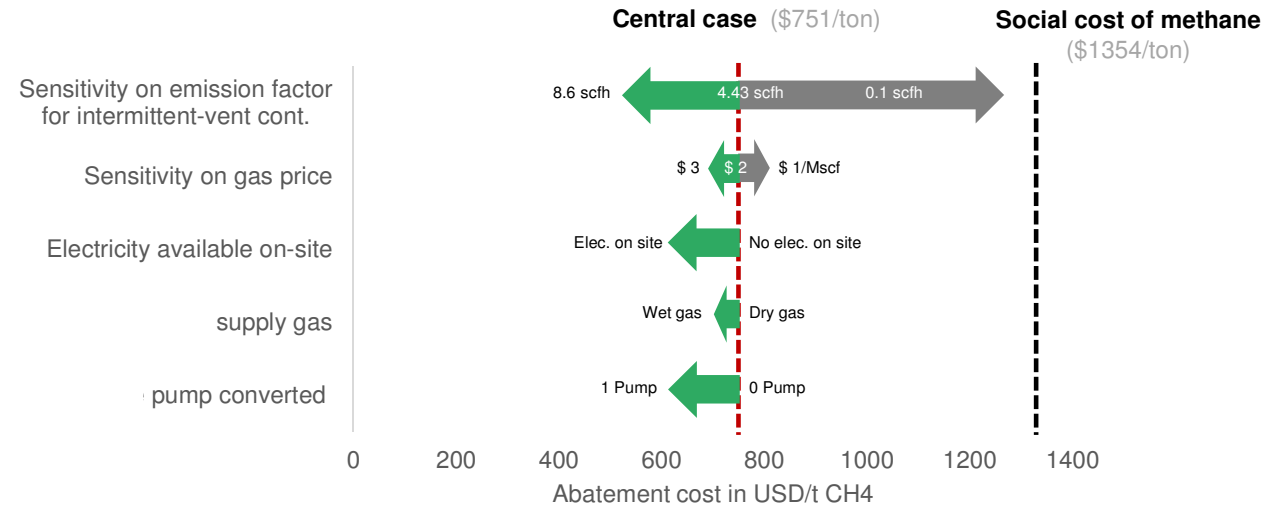
As highlighted in Section 3, conversion of chemical injection pumps to electric is both a mature and a cost effective technology.

In the analysis presented in this section, the conversion of one chemical injection pump per site is presented as a potential added benefit for the project developer. In cases with many pumps, or of major energy requirements for the pumps, the conversion of pumps to zero emission technologies could be assessed as a separate emission reduction project.

Sensitivity analysis for one example site configuration

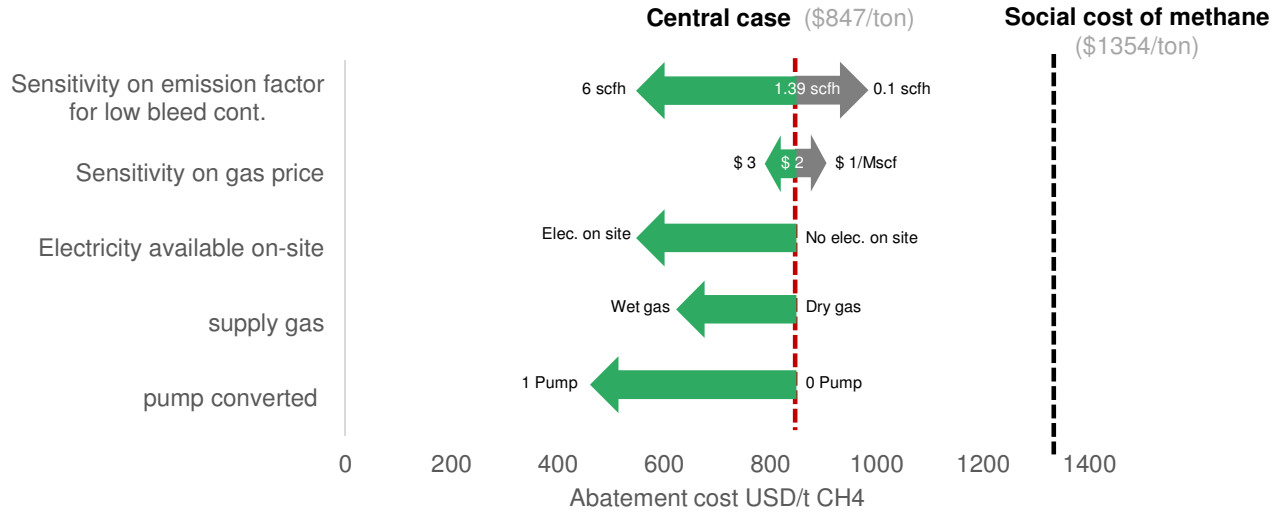
In this analysis, a number of assumptions have been made which impact the abatement cost. The following figures present sensitivity analyses for the site configuration described in the previous section, for both the retrofit case and the new site case. We examine the sensitivity of the abatement cost to changes to a few key sensitivities. A more exhaustive sensitivity analysis is presented in the appendix.

Figure 8: sensitivity analysis – electronic controllers - retrofit



The next figure presents a similar sensitivity for the same site configuration, but at a new facility as opposed to a retrofit.

Figure 9: sensitivity analysis – electronic controllers - new



The emission factor has by far the largest impact on the abatement cost and clearly heavily impacts the cost effectiveness of the option for retrofit sites. Excluding the emission factors, the other assumptions impact up to +33% of the abatement costs and no sensitivity leads to an abatement cost higher than the social cost of methane (see appendix).

In general terms, the abatement cost is more sensitive to changes for new sites than for retrofit sites. This is due to the fact that both the incremental costs and the emissions reductions are much smaller for new sites than for retrofit sites. A small change in either of these is thus relatively larger for new sites than for retrofit sites.

The following few paragraphs describes in more detail the impact of the main assumptions:

Electricity on site

The investment costs for sites without an electricity supply are higher than for sites with electricity due to the need to install solar panels and batteries. As a result, the abatement cost for site configurations with electricity is generally ten to one hundred percent lower than for site configurations without power. In a few site configurations the abatement cost is negative (i.e. NPV>0).

Wet versus dry supply gas

Operators have reported that the quality of the supply gas affects maintenance costs. Even slightly wet (or sour) gas can lead to condensation (or corrosion) issues, which over time will impact the performance of the system. The maintenance cost for sites with wet supply gas is estimated at $200/year/controller [10] compared to $80/year/controller for dry supply gas [18]. As a result, sites with wet gas have an abatement cost generally 5 to 100 % lower than sites with dry gas, and, in a few site configurations, the abatement cost is negative (i.e. NPV>0). Gas quality is also likely to impact the average emission rate. Due to the lack of quantitative data on this impact, however, this factor has not been taken into consideration during the analysis, but it would reduce the abatement costs of sites with wet gas even lower.

Chemical injection pumps

As pumps have high emissions factors, sites where one pump (or several) can be converted to electric power have much lower abatement costs than sites without. All the sites with one pump have an

abatement cost lower than the social cost of methane. In addition, the abatement cost of converting a single chemical injection pump (without any controller) to a solar powered electric pump is lower than the social cost of methane in all the sites configurations evaluated.

New versus retrofit sites

The costs and the emissions abatement structures differ greatly for new and for retrofit sites. The main differences include:

- The incremental CAPEX (i.e. the difference between the zero emission technology CAPEX and the baseline CAPEX) for a retrofit site is usually much higher than for a new site.
- Given the current regulatory framework, it is assumed that new sites use low-bleed continuous controllers as a default, and we conservatively use the EPA emissions factor [1] for these controllers, despite measurements showing higher emissions for low-bleed controllers [3,4]. The emissions reduction for retrofit sites is higher than for new sites, as we use an emissions factor based on actual measurement [2] for continuous-bleed controllers at existing sites.

The first difference makes the abatement cost higher for retrofit sites than new sites, while the second difference has the opposite effect. Overall, in the vast majority of the site configurations evaluated, the abatement cost for new sites is higher than for the equivalent retrofit site configuration.

Overview of the results for all the site configurations

Overall, the abatement costs for electronic controller installations at 2032 site configurations were estimated during this project. Under the central assumptions, 20 of the 2032 site configurations evaluated have abatement costs higher than the social cost of methane, $1354/t. The following table shows in red the number of site configurations with abatement costs higher than that figure for each category.

Table 11: Number of site configurations with abatement costs superior to the social cost of methane – central assumptions

Number of Pumps	Number of controllers (excluding ESD)	New sites		Retrofit	
		No elec. on site	Elec. On site	No elec. on site	Elec. On site
0	**1 to 3 controllers**	**6 / 18**	**4 / 18**	**5 / 18**	**2 / 18**
	4 to 10 controllers	**2 / 56**	**0 / 56**	**0 / 56**	**0 / 56**
	11 to 20 controllers*	**0 / 98**	**0 / 98**	**0 / 98**	**0 / 98**
	21 to 40 controllers*		0 / 164		0 / 164
1	**1 to 20 controllers***	**0 / 172**	**0 / 172**	**0 / 172**	**0 / 172**
	21 to 40 controllers*		0 / 164		0 / 164

* Sites with more than 10 controllers were presented for the installation of electronic controllers. However, there seems to be much less field experience for this type of installation, compared to smaller sites. Sites with more than 20 controllers and without electricity on-site were not modelled. Though no major technical barriers were identified, we could identify no examples of installations of solar powered electronic controllers on very large sites.

A number of conclusions can be drawn from this analysis. Under the central assumptions:

- For almost all the site configurations evaluated with four or more controllers (excluding ESDs), it is cost-effective to install electronic controllers.
- For all site configurations evaluated with one chemical injection pump, it is cost effective to install electronic controllers.

A site configuration is not cost effective if the volume of gas saved does not justify the cost of implementation. In general, for a given type of site configuration (wet/dry, on or off grid, new or existing, share of intermittent controllers), the cost-effectiveness improves (fewer $/ton) with the number of controllers.

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In addition, we can highlight the following patterns for the site configurations with abatement costs higher than the social cost of methane:

- For new facilities, these sites have only low-bleed continuous controllers (5 or fewer). The low bleed emission factor assumption has an important impact on the conclusion (see below).
- For retrofit facilities, these sites have only intermittent-vent controllers (3 or fewer). For retrofit sites, the emissions factor used for intermittent-vent controllers is less than that used for continuous bleed controllers (see section 4.1)

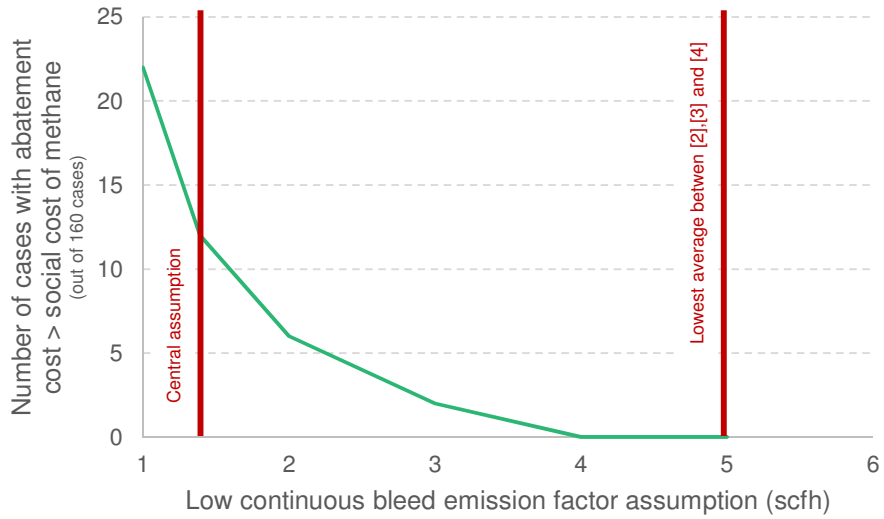
The full list of site configurations with an abatement cost higher than the social cost of methane is presented in the appendix.

Impact of the emission factors assumptions

The results of the analysis are quite dependent on the emissions factors used for the various types of pneumatic controllers.

The following graph illustrates the impact of the continuous low-bleed emission factor on the cost effectiveness of new sites with at least one continuous low-bleed device. This represents 12 of the 19 site configurations deemed not cost effective. The central assumption for the low-bleed emission factor is 1.39 scfh. But an emission factor of 4 scfh would make all sites with at least one continuous bleed controller cost effective. It is interesting to compare this figure to the results of past measurement campaigns presented in the Figure 4, which suggest that average emission factors for low-bleed devices are likely higher than 5 scfh.

Figure 10: Impact of the continuous low bleed emission factor on the cost effectiveness of new sites with at least one continuous low bleed device.



In a site without an electricity supply and with just a single controller, an electronic controller is cost-effective if the emissions from that single controller are more than 4.4 scfh for a new site and more than 7.2 scfh for a retrofit site. The point of cost-effectiveness is lower for sites with 2 or more controllers, for sites using wet supply gas, or for sites with on-site electricity. These thresholds should be compared with emissions factors observed in Figure 5 for small and very small sites.

As mentioned above, while emissions from pneumatic controllers vary widely from device to device, this analysis uses average emissions factors based on recent measurements, aiming at evaluating the cost-effectiveness of using electronic controllers on a widespread basis.

To conclude, the analysis shows that conversion to electronic controllers would be cost effective in most site configurations even using conservative average emissions assumptions. If higher emissions assumptions are considered -- as reflected in recent field measurements – virtually all site configurations evaluated would be fall below the social cost of methane

4.3 Main findings – Instrument air

As in the previous section, the finding of the analysis for instrument air is presented in three different sections:

- First, the full cost-benefit analysis is presented for one site configuration, to explain the methodology applied to one example.
- Secondly, a sensitivity analysis is performed for the same site configuration to illustrate the impact of the main assumptions.
- Finally, an overview of the results for all the site configurations evaluated is presented.

Contrary to electronic controllers, instrument air installation is only presented for site configurations with electricity available on-site.

Example of abatement cost estimate for one example site configuration
The following tables present a full analysis for an example site configuration. The project is retrofit of an existing site with 20 different controllers (5 continuous-bleed, 11 intermittent-vent, and 4 ESD). This configuration is illustrative; it is not known how representative it would be of larger sites. The site is connected to the grid or has power already generated on site, and currently uses dry gas for the controllers.

The first table presents the CAPEX estimate for the instrument air project. The detailed assumptions for the size of the instrument air system (share of the air bypassed in dryer, share of the utility air supply,[11] size of compressor, load of the compressor) are presented in the appendix. The approach in terms of system sizing proposed by Natural gas star has been applied [14], after having been quality checked against nine recently implemented projects. Overall, the system is oversized (as per the industry standard) and always includes, for example, one spare compressor. Equipment costs (including industrial grade compressors designed for 24/7 duty) have been assumed using online quotes.

As highlighted previously, installation costs for instrument air are highly site specific. Interviews have reported very low installation costs in particular when retrofitting many sites with similar designs. On the other side of the spectrum, operators have also reported high installation costs in cases where important investments, such as electric system upgrades and trenching between building or clusters of equipment, were required on the installations. The investment cost estimates presented below include some relatively conservative assumptions (i.e., high cost) in terms of equipment and installation costs. Some sensitivities are presented (appendix) to reflect the variability of the local circumstances.

[11] Because it is useful to have compressed air at a site for a variety of tasks and uses, operators typically oversize compressed air systems installed to drive pneumatic controllers. In this analysis, we assume that operators will do so, and consider the costs of the oversized system but do not make any estimate of the value of having compressed air available onsite. This approach is conservative (since operators do not strictly need oversize compression capacity for this purpose to use instrument air for pneumatic controllers), though the effect is not large.

Table 12: CAPEX estimates for instrument air controller implementation – central assumptions

Item	Assumption	Sizing /#	Value USD
Controllers and installation costs for the controllers	NA	retrofit projects (it is assumed that controller can be re-used)	0
Compressor package (Assuming 2 compressors, air drying unit and wet air receiver unit)	See list of assumption in the appendix [12]	10 HP	32 000
Other supplies costs (Instrumentation Supplies & Pipe/Valve/Fittings, electrical supplies, etc..)	1400 $/cont	20	28 000
Electrical, mechanical & civil Installation Costs, engineering	Retrofit: 100% New: 50% of equipment costs	NA	60 000
Total CAPEX			120 000

In terms of OPEX, it is assumed that compressors are replaced every 6 years. In addition, 4% of the equipment costs are accounted for normal compressor maintenance (typically every 6 months). Other OPEX costs include, for example, electricity costs.

Table 13 presents the emissions estimates while Table 14 present the final results.

Table 13: Emission estimates – central assumptions

Emissions is scfh	EF assumption	#	total
Intermittent-vent Controllers	4.43	11	48.7
Continuous-bleed controllers	14.43	5	72.1
ESD	0.41	4	1.64
Total gas emissions			122.5

Table 14: Final results for the site configuration analyzed – central assumptions

Item	Unit	Value USD
CAPEX	$	120 000
Value of the gas saved	$/year	1073
NPV (Opex)	$	24 683
NPV	$	-121 652
ABATEMENT COSTS	$/tCH4	972

The abatement cost for the same site configuration, but at a new facility, as opposed to a retrofit, is estimated to be $886/ton CH_4. The difference is because the baseline costs are higher and the baseline emissions are lower for new sites than for retrofits.

Info Box 2: Conversion of pneumatic pumps to instrument air

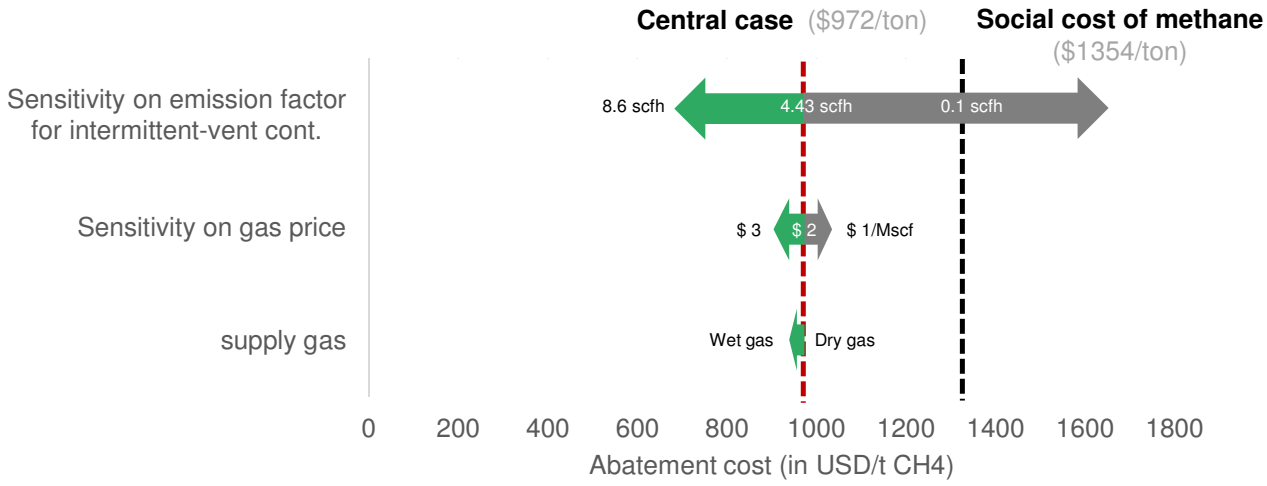
Pneumatic pumps typically emit more per device than pneumatic controllers, so converting pumps to air can represent a large emission reduction and potentially reduce significantly the abatement cost of conversion. However converting pumps to instrument air is not always technically and/or economically feasible. For sites with access to reliable source of electricity, conversion to air is applicable and cost-effective for the majority of chemical injection pumps. However, even for grid-connected sites, conversion to instrument air is not always the preferred option, as electric pumps are proven effective and low-cost.

In summary, in a number of cases, emissions reduction for pumps could be considered as a separate project from controllers. In the follow up analysis, conversion of 1 pump to instrument air is only presented as part of the sensitivity analysis.

Sensitivity analysis for one example site configuration

The following figures present a sensitivity analysis for the same site configuration as in the section above. The CH_4 abatement cost for a few key sensitivities is compared to the abatement cost with the central assumptions. A more detailed sensitivity assessment is presented in the appendix.

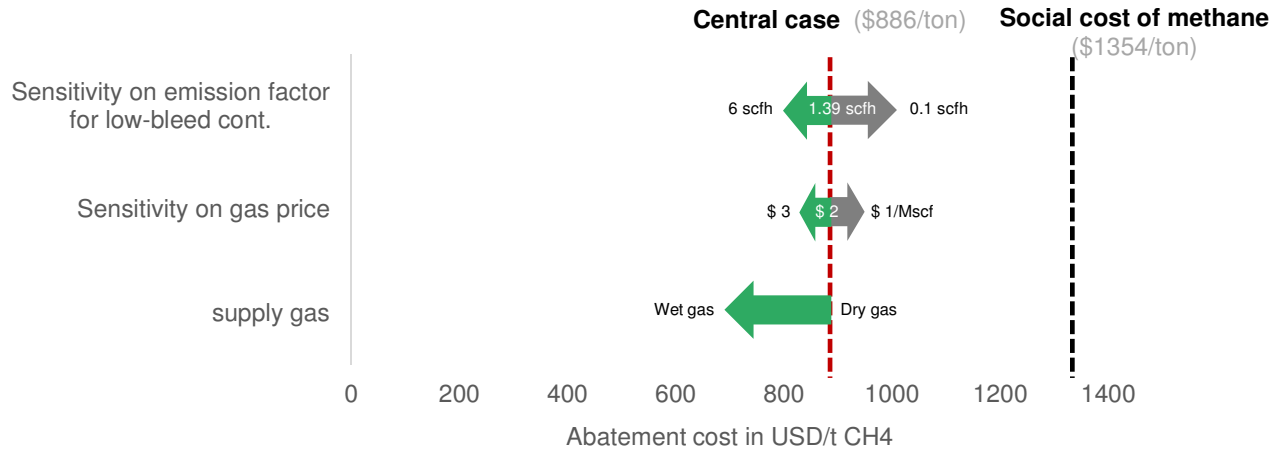
Figure 11: Sensitivity analysis – instrument air - retrofit



The next figure presents a similar sensitivity for the same site configuration but at a new facility.

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Figure 12: Sensitivity analysis – instrument air - new site



As with the electronic controllers, the emission factor heavily impacts the attractiveness of the option. Excluding the emission factor, no other assumption affects the abatement cost per ton by more than 30% (see appendix).

Wet versus dry supply gas

As with electronic controllers, sites with wet gas have an abatement cost generally 5% to 50 % lower than sites with dry gas due to the difference in maintenance costs.

Overview of the results for all the site configurations

The overall abatement costs for about 328 site configurations, all with an electricity supply and no pneumatic pump conversions, were estimated, with a total number of controllers ranging from 21 to 50 (in various permutations of intermittent-vent and continuous-bleed controllers). Sites with fewer than 20 controllers are not presented, as conversion to electric is cheaper (on a per ton basis) in most of the site configurations with fewer than 20 controllers.

In terms of CAPEX, the total investment for retrofit sites varies between $90,000 and $230,000, while the investment (excluding controllers and their installation) for new sites varies between $60,000 and $120,000.

Under the central assumptions, 5 of the 328 site configurations evaluated have abatement costs higher than the social cost of methane. The following table shows in red the number of sites with abatement costs higher than $1354 /t$CH_4$ for each category of sites.

Table 15: Number of site configurations with abatement costs higher than the social cost of methane – central assumptions

Number of Pumps	Number of controllers (Excluding ESD)	New Sites	Retrofit
0	**21 to 25 controllers**	**3 / 42**	**0 / 42**
	26 to 30 controllers	**2 / 40**	**0 / 40**
	31 to 40 controllers	**0 / 82**	**0 / 82**

A number of conclusions can be drawn from this analysis. Under the central assumptions:

- For almost all the site configurations evaluated with more than 21 controllers (excluding ESDs), it is cost effective to install instrument air.
- For all the retrofit site configurations evaluated, it is cost effective to install instrument air.
- In a few of the new site configurations considered, it is not cost effective to install instrument air.

A site configuration is not cost effective if the volume of gas saved does not justify the cost of implementation. The new site configurations with abatement costs greater than the social cost of methane have a vast majority of low bleed continuous controllers, which we have conservatively assumed have very low emissions (1.39 scfh emission factor, see Section 4.1).

The full list of site configurations with abatement costs higher than the social cost of methane is presented in the appendix.

4.4 Summary of the analysis

As described in the section above, an economic analysis assuming conservative average emission factors was performed for 2032 permutations of site configurations with 1 to 50 controllers. Both retrofit and new installations, with or without electricity, were considered. A number of key conclusions can be drawn:

- Zero emission solutions had abatement costs below the social cost of methane (for 2020) described in the EPA 2015 Regulatory Impact Analysis in the vast majority of site configurations considered.
- The abatement costs exceeded the social cost of methane mostly for small sites – those with less than three controllers (excluding ESDs). If higher emission factors, as reflected in field measurements, are used, the abatement costs at even the very small sites fall below the social cost of methane.

The following figure presents a summary of both the technical applicability and economic attractiveness of the different zero emission technologies under different categories of sites. Though this analysis does not provide a detailed evaluation of the distribution of the sites in the US for each of the categories below, existing studies have suggested that the vast majority of the sites have less than 20 controllers.

Table 16: Summary table

Type of of site		Both retrofit and new sites					
	Number of controllers (excl. ESDs)	1- 3		4-20		21-40	
	Electricity on-site?	Yes	No	Yes	No	Yes	No
Main options: Electric controller / Instrument air	**Description** (of the most economic option which is technically feasible)	Grid connected **electric** controller	Solar powered **electric** controller	Grid connected **electric** controller	Solar powered **electric** controller	Instrument **air**	
	Number of cases not cost effective (i.e. abatement cost > social cost of methane) **under central assumptions**	6 / 36	11 / 36	0 / 308	2 / 308	5/ 328	
	Cost effective for <u>every</u> site configuration if emissions factors are:*	> 5.6 scfh for retrofit > 2.8 scfh for new sites	> 7.2 scfh for retrofit > 4.4 scfh for new sites	> 3.6 scfh for retrofit > 1.4 scfh for new sites	> 4.2 scfh for retrofit > 1.8 scfh for new sites	> 4.5 scfh for retrofit > 1.8 scfh for new sites	
Other options potentially applicable depending on the local conditions	Vent gas recovery	✓	✓	✓	✓	✓	✓
Limited applicability	Instrument air powered by gas	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
Limited applicability	Self contained controllers	✓	✓	✓	✓	✓	✓
Limited known implementations	Solar powered instrument air	Not relevant	✓	Not relevant	✓	✗	✗
Limited known implementations	Electric controllers powered by other power sources (TEG, fuel cell)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
Limited known implementations	Large solar powered electric controller (no known implementations)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	Potential solution,** but no example known.

* Emissions factors thresholds listed are determined for the site configuration with the highest abatement cost within the category.
** Based on other solar applications.

The applicability of electronic controllers for small sites and instrument air for large sites reflects the current industry experience and practice as presented by the interviewees. It is, however, important to highlight that the threshold in terms of number of controllers (20 in the analysis), depends in reality on site-specific parameters, and should only be considered as an illustrative threshold based on information available.

Due to the market conditions, electronic controller providers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites; however, no technical barriers were identified for this type of installation.

These analyses indicate that the widespread adoption of zero-emitting technologies is cost effective in the vast majority of the site configurations considered. Furthermore, several factors listed should be considered:

- Conservative (low) average emissions factors have been used for low-bleed pneumatic controllers, even though recent research indicates that actual average emissions from those pneumatic controllers may be higher.
- Some of the important benefits of switching to zero-emitting technology, such as the ease of automation or remote operations associated with electrifying pneumatic controllers, are not included in our analysis of the cost-effectiveness of using zero emission technologies.
- Finally, pneumatic controllers emit natural gas, which includes (in varying amounts) other pollutants aside from methane, such as volatile organic compounds (VOCs), which are precursors to ground level smog, and toxic hazardous air pollutants (HAPs). Replacing natural-gas driven pneumatic controllers with zero-emitting technologies will eliminate emissions of these other

pollutants, in addition to emissions of methane, but we have not included the benefits of VOC or HAP abatement in our calculation of abatement costs for methane.

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6. Appendix

6.1 Quantitative assumptions for the model

Table 17: Quantative assumptions for the model

Description	Central Assumption	Unit	Source
GENERAL ASSUMPTIONS			
Gas price	2	$/Mscf	[15]
Interest Rate	7%	%	NA
Share methane in the gas – Dry gas	0.0167	tCH_4/Mscf	[15]
Share of VOC in the gas – Dry gas	0.0046	tVOC/Mscf	[15]
Share methane in the gas – wet gas	0.0150	tCH_4/Mscf	[15]
Share of VOC in the gas – wet gas	0.0050	tVOC/Mscf	[15]
Remaining lifetime for retrofit	10	years	[15]
Remaining lifetime for new site	15	years	[15]
EMISSION FACTORS			
Continuous Controller (s)	14.43	cf/h	[2] (Company classification into EPA categories excluding ESD)
Intermittent Controller (s)	4.43	cf/h	[2] (Company classification into EPA categories excluding ESD)
Chemical Pumps	13.3	cf/h	[16]
ESD	0.41	cf/h	[2]
Continuous Controller (s)	1.39	cf/h	[16]
Intermittent Controller (s)	4.43	cf/h	[2]
Chemical Pumps	13.3	cf/h	NA
ESD	0.41	cf/h	[2]
INSTRUMENT AIR – ENGINEERING ASSUMPTIONS			
Share of the air bypassed in dryer	17%	%	[14,10]
Share of the utility air supply	200%	%	[14,10]
Sizing of compressor - variable component	0.2026	HP/cfm	[14,10]
Sizing of compressor - constant component	4.2356	HP	[14,10]
Load of the compressor (main)	50%	%	[14,10]
Sizing of the tank	6	gallon/cfm	[10]
Lifetime of the compressors	6	years	[10,14]
ELEC CONTROLLER - COST ASSUMPTIONS			
Continuous Controller (s) + control valve	4000	$/unit	[9,10]
Intermittent Controller (s) + control valve	4000	$/unit	[9,10]
Chemical injection pump	6000	$/unit	[9,10]
Control Panel	4000	$/unit	[9,10]
Solar Panel	500	$/unit	[9,12]
Battery	400	$/unit	[9,12]
Installation Costs	20%	of Equipment costs	[9,10]
Annual check up	80	$/controller/year	[15]

ELEC CONTROLLER - ENGINEERING ASSUMPTIONS			
Battery replacement frequency	4	years	[9,10]
Solar Panel replacement frequency	10	years	[9,10]
Continuous Controller (s)	0.08	Amps/unit	[9]
Chemical injection pumps	0.17	Amps/pump	[9]
ESD	0.16	Amps/unit	[9]
Other systems	0.29	Amps/site	[9]
System Voltage	12	V	[9,12]
Battery Average Efficiency	85%	%	[9,12]
Avg. Peak Sun	4	h/days	[9,10] (Confirmed with NREL)
Battery - At Maximum Depth of Discharge	80%	%	[9]
Days of Energy Storage	10	days	[9]
Rating of the solar panel	140	W	[9,12]
Rating of the battery	100	Ah	[9,12]
Oversizing of the solar panel	50%	%	[9,10]
INSTRUMENT AIR - COST ASSUMPTION			
Compressor Package – Main -5 HP	22000	$	[12,10]
Compressor Package – Main -10 HP	32000	$	[12,10]
Compressor Package – Main -15 HP	48000	$	[12,10]
Compressor Package – Main -20 HP	70000	$	[12,10]
Compressor - Unit cost - 5 HP	7000	$	[12]
Compressor - Unit cost - 10HP	10000	$	[12]
Compressor - Unit cost - 15 HP	15000	$	[12]
Compressor - Unit cost - 20 HP	23000	$	[12]
Other supply	1400	$/controller	[10]
Other supply	1000	$/controller	[10]
Installation	100%	%	[10]
Installation	50%	%	[10]
Compressor maintenance	4%	% of Capex	[10,15]
BASELINE - COST ASSUMPTION			
Continuous Controller (s) + control valve	2698	$/cont.	[17]
Intermittent Controller (s) + control valve	2471	$/cont.	[17]
Chemical injection Pump	1500	$/unit	[12]
Labor - installation - Controller	387	$/unit	[18]
Maintenance costs - Controller- wet gas sites	200	$/cont./year	[10]
Maintenance costs - Controller- dry gas sites	80	$/cont./year	[18]

6.2 Other assumptions for the model

- General assumptions

- Retrofitting is assumed to be performed during a planned maintenance, hence retrofit activities do not cause production losses; thus, no potential revenue losses are accounted for in the estimates presented.

- Electronic controllers:
  - In all the site configurations, it is assumed that ESDs are gas driven pneumatic controllers.
  - Electronic controllers can reduce the need for site inspections. The subsequent reduced labour costs have not, however, been taken into consideration in the analysis. (conservative assumption)
- Instrument air
  - CO_2 emissions from power consumption (for non-solar powered options) have been neglected; this represents a very small volume of emissions compared to the CH_4 emissions (typically a few per cent, assuming a GWP of methane of 21).

6.3 Detailed sensitivity analysis

In the analysis presented, a number of assumptions have been made which affect the abatement cost. The following sections present the detailed sensitivity analysis performed.

Electronic controller – Retrofit

The following table presents a sensitivity analysis for the site configuration described in the section 4.2 (site with four controllers). The CH_4 abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: $751/t CH_4. The abatement cost under all the sensitivities is below the social cost of methane.

Table 18: Sensitivity analysis – retrofit site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in $/t CH_4
Number of pumps	0 pump	1 pump	614
Type of supply gas	Dry supply gas	Wet supply gas	702
Power on-site	No power on-site	Power on-site	611
Gas price	2 $/Mscf	1 $/Mscf	811
Gas price		3 $/Mscf	692
Discount rate	7%	3%	635
Emission factors intermittent-vent cont.	4.43 scfh	8.6 scfh	522
		0.1 scfh	1267
Control Panel equipment cost	$4000	$6000	845
Installation Costs	20% of Equipment Costs	40% of Equipment Costs	889
Battery replacement freq.	4 years	2 years	823
Average peak sun	4 hours	2 hours	775

Electronic controller – New

The following table presents a sensitivity analysis for the site configuration described in the section 4.2 (site with four controllers). The CH_4 abatement cost for a few key sensitivities should be compared to the

abatement costs under the central assumption: $847/t CH_4. The abatement costs for all the sensitivities are below the social cost of methane.

Table 19: Sensitivity analysis – New site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in $/t CH_4
Number of pumps	0 pump	1 pump	459
Type of supply gas	Dry supply gas	Wet supply gas	624
Power on-site	No power on-site	Power on-site	548
Gas price	2 $/Mscf	1 $/Mscf	906
Gas price		3 $/Mscf	787
Discount rate	7%	3%	680
Emission factors low bleed controllers	1.39 scfh	6 scfh	547
		0.1 scfh	986
Control Panel equipment cost	$4000	$6000	1011
Installation Costs	20% of Equipment Costs	40% of Equipment Costs	1089
Battery replacement freq.	4 years	2 years	1046
Average peak sun	4 hours	2 hours	905
Low Bleed Cont. - Equipment cost	$2698 per controller	$554 per controller	993
Intermittent Cont. - Equipment cost	$2471 per controller	$387 per controller	1131

Instrument air – Retrofit

The following table presents a sensitivity analysis for the site configuration described in the section 4.3 (site with twenty controllers). The CH_4 abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: $972/t CH_4.

Table 20: Sensitivity analysis – retrofit site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in $/t CH_4
Type of supply gas	Dry supply gas	Wet supply gas	945
Gas price	2 $/Mscf	1 $/Mscf	1037
Gas price		3 $/Mscf	908
Discount rate	7%	3%	848
Emission factors intermittent-vent cont.	4.43 scfh	8.6 scfh	679
		0.1 scfh	1656
Other supplies costs	$1400/controller	$1800 /controller	1100
		$1000 /controller	844
Electrical, mechanical & civil installation costs	100% of equipment and supplies costs	150% of equipment and supplies costs	1212
		50% of equipment and supplies costs	732

Instrument air – New site

The following table presents a sensitivity analysis for the site configuration described in the section 4.3 (site with twenty controllers). The CH_4 abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: \$886/t CH_4.

Table 21: Sensitivity analysis – retrofit site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in \$/t CH_4
Type of supply gas	Dry supply gas	Wet supply gas	690
Gas price	2 \$/Mscf	1 \$/Mscf	949
Gas price		3 \$/Mscf	824
Discount rate	7%	3%	734
Other supplies costs	\$1000/controller	\$1200 /controller	963
Electrical, mechanical & civil installation costs	50% of equipment and supplies costs	100% of equipment and supplies costs	1154
Emission factors low bleed controllers	1.39 scfh	6 scfh	800
		0.1 scfh	1011

6.4 List of site configurations with abatement cost superior to the social cost of methane

The following table presents a complete list of all the site configurations with an abatement cost higher than the social cost of methane.

Electronic controller – New sites

The abatement cost is presented for the central assumptions, but also (right column) for a low-bleed emission factor of 5 scfh (compared to 1.39 in the central assumption).

Table 22: Site configurations with abatement cost superior to \$1354/ton - Electric controller – New sites

Site configuration ID	New/ retrofit	Electricity on site?	Supply gas	Pump #	Continuous Cont. #	Intermittent Cont. #	ESD #	Abatement costs – central assumptions	Abatement costs – Higher EF assumption
13	New	Electricity	Wet	0	1	0	1	1985	456
349	New	Electricity	Dry	0	1	0	1	2838	703
355	New	Electricity	Dry	0	2	0	1	1793	412
361	New	Electricity	Dry	0	3	0	1	1445	315
685	New	No electricity	Wet	0	1	0	1	3777	954
691	New	No electricity	Wet	0	2	0	1	2009	462
697	New	No electricity	Wet	0	3	0	1	1643	361
1021	New	No electricity	Dry	0	1	0	1	4446	1150
1027	New	No electricity	Dry	0	2	0	1	2595	635
1033	New	No electricity	Dry	0	3	0	1	2179	520
1039	New	No electricity	Dry	0	4	0	1	1820	420
1045	New	No electricity	Dry	0	5	0	1	1605	360

Electronic controller – Retrofit sites

The abatement cost is presented for the central assumptions, but also (right column) for an intermittent-vent controller emission factor of 7 scfh (compared to 4.43 in the central assumption).

Table 23: Site configurations with abatement cost superior to $1354/ton - Electric controller – Retrofit

Site configuration ID	New/ retrofit	Electricity on site?	Supply gas	Pump #	Continuous Cont. #	Intermittent Cont. #	ESD #	Abatement costs – central assumptions	Abatement costs – Higher EF assumption
1345	Retrofit	Electricity	Wet	0	0	1	1	1593	960
1681	Retrofit	Electricity	Dry	0	0	1	1	1750	1064
2017	Retrofit	No electricity	Dry	0	0	1	1	2282	1400
2018	Retrofit	No electricity	Dry	0	0	2	1	1573	952
2019	Retrofit	No electricity	Dry	0	0	3	1	1406	846
2353	Retrofit	No electricity	Wet	0	0	1	1	2186	1335
2354	Retrofit	No electricity	Wet	0	0	2	1	1486	891

Instrument air – Retrofit sites

The abatement cost is presented for the central assumptions, but also (right column) for a low-bleed emission factor of 5 scfh (compared to 1.39 in the central assumption).

Table 24: Site configurations with abatement cost superior to $1354/ton – Instrument air – Retrofit

Site configuration ID	New/ retrofit	Electricity on site?	Supply gas	Pump #	Continuous Cont. #	Intermittent Cont. #	ESD #	Abatement costs – central assumptions	Abatement costs – Higher EF assumption
437	New	Electricity	Dry	0	20	1	5	1651	612
438	New	Electricity	Dry	0	20	2	5	1466	589
447	New	Electricity	Dry	0	25	0	5	1595	515
448	New	Electricity	Dry	0	25	1	6	1426	501
457	New	Electricity	Dry	0	30	0	6	1392	436